Review of Energy Market Frameworks in light of Climate Change Policies

Scoping Paper

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About the AEMC

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

Preface

The AEMC

The AEMC is an independent, national body with responsibility for rule making, market development and policy advice concerning both the National Electricity Market (NEM) and elements of natural gas markets. This includes our role to provide advice on energy market issues when requested by the Ministerial Council on Energy. Our vision is to promote efficient, reliable and competitive energy markets in the interests of all Australians.

What this review is about

The Australian Government is in the process of developing new policies in response to climate change, most notably a Carbon Pollution Reduction Scheme (CPRS) and an expanded national Renewable Energy Target (expanded RET). These new policies will particularly affect the energy sector, as it is a major emitter of carbon with a large proportion of our electricity produced by burning coal. The introduction of these policies will inevitably lead to changes in behaviour and the entry of new participants into Australia's energy markets (both electricity and gas).

The outcomes of this Review

The Ministerial Council on Energy (MCE) has asked the Australian Energy Market Commission (AEMC) to undertake a Review of energy market frameworks to determine whether they should be amended to accommodate the planned introduction of the CPRS and expanded RET. The outcomes of the Review are to:

- identify the potential impacts on the energy markets with respect to achieving the market objectives of efficient, safe, secure and reliable energy supplies that are provided in the interests of consumers; and
- provide advice on what, if any, amendments to the national energy frameworks are necessary and how these should be implemented.

The purpose of this scoping paper

This Scoping Paper sets out a range of issues that we consider to be relevant to the Review. The purpose of the Scoping Paper is to seeks views from stakeholders on the following:

- whether we have identified the scope of issues appropriately;
- what issues are most material; and
- what evidence is relevant to assessing the materiality of each issue.

This will contribute to our assessment of which issues are most important, and therefore which require further detailed analysis of options for change.

How stakeholders can be involved

During the course of the Review, the AEMC will be utilising a range of mechanisms to consult with stakeholders. These include a range of public consultation papers, bilateral discussions and public forums. The table below outlines our timelines for delivery.

14 November 2008	**Submissions close on this Scoping Paper**
31 December 2008	1st Interim report – analysis of the priority issues
February 2009	Public Forum
30 June 2009	2nd Interim report – detailed analysis and mitigation strategies
September 2009	Final report – closing recommendations

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Acronyms

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
CMR	Congestion Management Review
CO_2-e	Carbon dioxide equivalent
COAG	Council of Australian Governments
CPRS	Carbon Pollution Reduction Scheme
CRR	Comprehensive Reliability Review
CSM	Coal seam methane
DSP	Demand Side Participation
ENA	Energy Networks Association
GWh	Gigawatt hour
IMO	Independent Market Operator
LNG	Liquefied Natural Gas
NCC	National Competition Council
NEL	National Electricity Law
NER	National Electricity Rules
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company Ltd
NEO	National Electricity Objective
NGL	National Gas Law
NGR	National Gas Rules
NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
MCE	Ministerial Council on Energy
MoU	Memorandum of Understanding
MRET	Mandatory Renewable Energy Target
MWh	Megawatt

Acronyms

NWIS	North West Interconnected System
STEM	Short Term Energy Market
STTM	Short Term Trading Market
SRMC	Short Run Marginal Cost
SWIS	South West Interconnected System
OECD	Organisation for Economic Co-operation and Development
REC	Renewable Energy Certificate
RET	Renewable Energy Target
PT	Petajoule
PV	Photovoltaic
TEC	Total Environment Centre
WEM	Wholesale Electricity Market

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1. The Review

1.1 Background

The Australian Government is developing a range of policies and measures that aim to address the environmental and economic challenges of climate change and to reduce greenhouse gas emissions. In this Review, we are analysing the impacts of the Government's two key climate change policies: the Carbon Pollution Reduction Scheme (CPRS) and the expanded national Renewable Energy Target (expanded RET). Both of these policies will have large and direct impacts on the energy markets. This is because Australia's energy sector is a large emitter of carbon and the CPRS will put a price on those carbon emissions. The expanded RET's objective is to increase the amount of electricity generated from renewable sources.

Noting the potential changes that energy markets will need to accommodate, the Ministerial Council on Energy (MCE) on 13 June 2008, agreed that there was a need to conduct a review of the current energy market frameworks to determine whether they require amendment to accommodate the introduction of CPRS and the expanded RET. The MCE has directed the Australian Energy Market Commission (AEMC) to undertake the Review and provide a Final Report to the MCE by 30 September 2009.

The Review is to:

- examine the potential impacts of the CPRS and expanded RET on both the electricity and gas markets across all jurisdictions;
- determine what adjustments may be necessary within the existing energy market frameworks, having regard to the National Electricity and Gas Law objectives – to deliver efficient, safe, secure and reliable energy supplies in the long term interests of consumers; and
- provide detailed advice to the MCE on implementation of any amendments required.

The AEMC is to have regard to:

- the MCE's requirement that amendments will only be supported if they contribute to the energy market objectives;
- the need for amendments to be proportionate;
- the value of stability and predictability in the energy markets regulatory regime; and
- any other AEMC Reviews, Rule changes or MCE reforms that may relate to this Review.

More information about the MCE direction is provided at:
www.aemc.gov.au/electricity.php

What is not covered in the Review

The MCE has indicated that the Review is not to assess the merits of the policy design of the CPRS or expanded RET. The review of these schemes is being undertaken through other government policy processes; however it is possible that this Review may generate evidence that may be relevant to those processes.

Interactions with other AEMC work

The Review is expected to bring forward a range of issues, which may impact or at least intersect with current work being undertaken by the AEMC and reforms being progressed by the MCE. The MCE has requested that the AEMC take these into account for the Review.

Of particular relevance to the Review is the AEMC Review of Demand Side Participation (DSP) and the Total Environment Centre (TEC) demand management Rule Change proposal. These projects are important to consider in parallel to this Review because the CPRS will impact on the potential costs and benefits of demand side solutions in the market. For this reason we have aligned the timetable of these projects to that of the Review.

Other reviews that may be relevant to this Review are the recently completed Review of the National Transmission Planner (NTP), Congestion Management Review (CMR) and the Reliability Panel's Comprehensive Reliability Review (CRR).

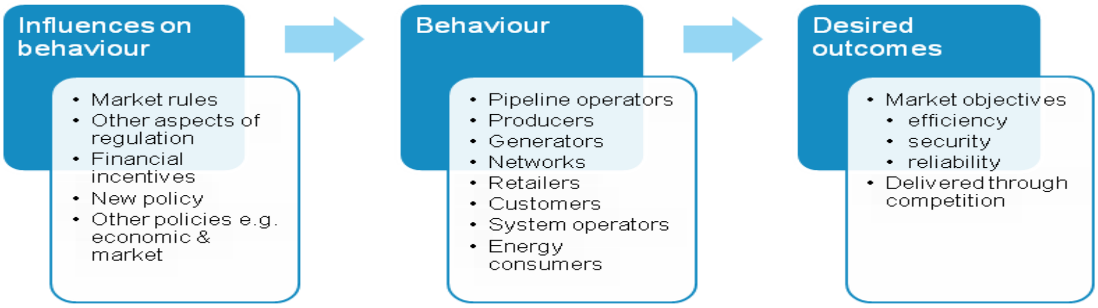
More information on AEMC Reviews and Rule changes can be found at www.aemc.gov.au

1.2 Evaluation framework

Issues and objectives

The Review will analyse a series of specific issues to test whether the new policies operating in concert with existing market frameworks will deliver the desired outcomes of efficient, reliable and secure long-term supplies of electricity and gas. We will focus on issues where we consider that continuing with existing market frameworks has significant risks – and will assess a range of options to reducing those risks through amendment to existing market frameworks. This requires us to identify:

- the factors that condition behaviour in energy markets currently;
- how the new policies may alter behaviour;
- whether the altered behaviour results in desirable outcomes; and
- how we may change the factors to promote behaviour for more desirable outcomes.



The key points to note are the importance of clearly defining and assessing the relevant set of issues and mitigation options based on evidence. We are committed to identifying options for change which are proportionate and to undertake this through rigorous and systematic analysis. We note that evidence and views provided by stakeholders are a critical input to these processes.

Key assumptions

It is important to note that we will be undertaking our Review in parallel with the Australian Government's program for designing the CPRS and the expanded RET. Consequently, our work will need to be based on assumptions about the precise final form of the policies. Our assumptions will be based on the best available public information and tested with the Review's stakeholder Advisory Committee.[1]

1.3 The Review timetable

Document	Purpose	Date
Scoping Paper	To set out and seek views on the range of risks to be considered in the Review, and seek initial views from stakeholders on possible mitigation measures.	**Submissions Due 14 November 08**
1st Interim Report	To provide a "short list" of issues that we think are appropriate to focus on, together with our supporting reasoning. We will also provide directional comments on mitigation.	By 31 Dec 08
Public Forum		Feb 09
2nd Interim Report	To update 1st Interim Report in light of the White Paper and set out what mitigation measures we intend to recommend and why.	By 30 Jun 09
Final Report	To finalise the advice to the MCE on the range of mitigation measures we are recommending and why. We will also provide advice on legal and operational implementation.	30 Sep 09

[1] Australian Government's Green Paper, Carbon Pollution Reduction Scheme July 2008, White Paper expected to be released in December 2008, Garnaut Climate Change Review Report 30 September 2008 and the Australian Government Treasury Department modelling process expected to be released at the end of 2008.

1.4 Stakeholder engagement

We are committed to undertaking this Review in an open and transparent manner. Effective engagement with our stakeholders is essential to ensure all issues can be canvassed and addressed. A key part of this will be the submissions to our consultation documents, bilateral discussions with stakeholders and public forums. Information on consultation documents is provided above. The public forum is expected to be held in February 2009 after the release of the First Interim Report. The focus of the forum will be to discuss the prioritised list of issues and the potential strategies for addressing them.

Stakeholder Advisory Committee

In accordance with the MCE direction, the AEMC has established a stakeholder Advisory Committee with its membership comprising energy market operators and planners, regulators, industry and energy end-user groups.

The purpose of the Advisory Committee is to provide advice and views to the AEMC regarding the Review and on the consultation documents to be produced. The first meeting of the Advisory Committee was held on 8 September 2008. Outcomes of the meeting and the Committee membership can be found at **www.aemc.gov.au**.

How to make a submission

If you want to make a submission, please send it to: submissions@aemc.gov.au

Or in hardcopy to:

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

The closing date for submissions is **Friday, 14 November 2008**. Submissions sent via e-mail/mail should reference the following: Company/Organisation name and Scoping Paper, October 2008 - Reference EMO 0001.

If your submission contains results of quantitative analysis, we request that you cite sources and provide explanations or references for how the results were derived. This will enable the AEMC to give due weight to the analysis. We recognise that this material might contain information that is confidential in nature.

2. The New Policies and the Energy Markets

2.1 Introduction

The purpose of this chapter is to provide an overview of the different environments that are relevant to the Review. The chapter is organised into three parts:

- The policy environment – the Terms of Reference of the Review require an examination of the impacts of the CPRS and expanded RET. It is therefore important to understand how these policies are expected to operate;

- The market environment – we are examining the impacts of new policies on energy markets. It is therefore useful to have an understanding of these markets; and

- The regulatory environment – energy markets are subject to different forms of regulation. Understanding the different regulatory frameworks is important as they influence behaviour in the markets we are reviewing.

2.2 The Policy Environment

A range of new policies are being introduced at the national and jurisdictional level that seek to move Australia to a low emissions economy. The two policies relevant to this Review are the CPRS and expanded RET.

The Carbon Pollution Reduction Scheme

The Australian Government has announced the introduction of a national Carbon Pollution Reduction Scheme (CPRS) by 2010 as a key component of its climate change policy. The Green Paper, released on 16 July 2008, outlines the Australian Government's approach to the design of the CPRS.

The CPRS will require businesses that emit more than 25 000 tonnes of carbon dioxide equivalent gases (CO_2-e) as part of their industrial processes to pay for the right to do so. Businesses will demonstrate that they have complied with this requirement by buying and surrendering permits, and will be subject to periodic audits. If businesses do not surrender permits equivalent to their emissions they may be subject to a financial penalty.

The policy is economy-wide, although certain sectors might be exempt or provided with transitional assistance. Coal-fired electricity generators are one of the sectors that may receive transition assistance. The profile on which permits are released for sale over time is called the "trajectory".

Permits are expected to be released for sale through an auction or an administered allocation. Businesses will then be able to buy and sell permits on the open market. The price of permits will be determined by their scarcity and by any regulated price limits. The scarcity of permits will be influenced by the "trajectory", and any ability to "bank" or "borrow" permits. The permits will be released for sale by an independent regulator established by the Australian Government. [2]

The CPRS is based on the concept that the cost of carbon emissions should be factored in to economic decision-making, and that trading in the right to emit carbon will, over time, result in targets for carbon reductions being met at least cost. This is because the CPRS will create financial incentives that reward lower-emission processes, and over time the processes that can reduce emissions most efficiently will be the ones that reveal themselves to be most profitable in the market. The policy does not need to identify what those processes might be in advance.

For more detailed information about the CPRS please see:
http://www.climatechange.gov.au/emissionstrading/index.html.

The Expanded National Renewable Energy Target

In 2001, a mandatory Renewable Energy Target (MRET) scheme was introduced by the Australian Government to increase the uptake of renewable energy in Australia's electricity supply and to reduce greenhouse gas emissions. The initial target was to supply 9500 gigawatt-hours (GWh) of renewable energy per year by 2010.

In 2007, the Australian Government announced its commitment to ensuring that 20 per cent of Australia's electricity supply comes from renewable sources, that is approximately 60 000 GWh by 2020. The commitment included: increasing the existing MRET to 45 000 GWh and consolidation of the existing state-based target schemes into a single, national scheme. The Australian Government has also announced an intention to phase out the scheme between 2020 and 2030 as the CPRS matures. There are presently two main design options, which imply different profiles for change over time - for the expanded RET that is under consideration.

The expanded RET is similar to the CPRS in that part of its rationale is to reduce greenhouse gas emissions. However, it differs from the CPRS because it provides market incentives to accelerate the uptake of specific technology such as wind, solar and geothermal energy and to reduce carbon emissions, i.e. by using less carbon in the process of generating electricity.

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[2] Australian Government Carbon Pollution Reduction Scheme Green Paper, July 2008.

The policy is specific to electricity markets, and is given effect through an obligation on electricity retailers and large users to procure a set proportion of certificates from renewable based generation each year.

The required proportion (of each retailer and large users electricity demand) increases over time consistent with meeting the 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).

Retailers can comply with the obligation by either surrendering the appropriate volume of certificates or paying a "buy out" price for any deficit. The "buy out" price is regulated, and is $40 for the existing mandatory scheme of 9 500 GWh.[3]

The design of the expanded RET is being developed in cooperation with the states and territories through the Council of Australian Governments (COAG) Climate Change and Water Working Group. Additional information about the expanded RET is found at http://www.climatechange.gov.au/renewabletarget/index.html.

Other policies

There are a wide range of other, smaller policy initiatives at the national and jurisdictional levels which in various ways relate to the objective of reducing greenhouse gas emissions. Some of these have particular relevance to energy markets, e.g. initiatives to provide financial support for the uptake of solar photovoltaic (PV) cells on domestic premises, and initiatives relating to energy efficiency such as the National Framework for Energy Efficiency, which has been operating for a number of years.

The MCE has stipulated in its Terms of Reference that the Review examine the impacts of the CPRS and expanded RET. Hence, we do not consider the impacts of these other policies to be within the scope of the Review.

2.3 The Market Environment

Energy markets in Australia operate under several different regimes. The markets themselves consist of the interconnected National Electricity Market (NEM), the eastern states interconnected Gas Market, and the markets of the Northern Territory and Western Australia.

The markets, are the arrangements through which buyers and sellers of electricity and gas transact. This covers physical spot and balancing markets, bilateral trading and trading in financial contracts derived from the physical markets. The markets also

[3] COAG Working Group on Climate Change consultation paper, Design Options for the Expanded National Renewable Energy Target Scheme, July 2008.

encompass how access to the physical networks required to transport electricity and gas is provided and priced.

Electricity network services are almost entirely subject to economic regulation which caps charges for using the networks. However, there is one unregulated transmission link and some scope for further unregulated investment. Retail prices are subject to competition but most jurisdictions combine this competition with price regulation for the mass market.[4]

In the gas sector production is not subject to economic regulation. Pipeline services may be subject to economic regulation, "light handed" regulation or they may be unregulated.[5] Different approaches are taken to gas balancing. Retail prices are set through competition but as in electricity, this is combined with price regulation for small customers in most jurisdictions.

The National Electricity Market

Scope

The NEM is the market through which wholesale electricity is traded in the eastern and southern states of Australia. The scope of the NEM is defined by the interconnected transmission network that runs from Queensland (QLD) to South Australia (SA), and across to Tasmania (TAS). The market operates across jurisdictional regions; these are (QLD), New South Wales (NSW), Victoria (VIC), SA and TAS. The NEM commenced operation in 1998, however since that time has undergone a series of reforms to establish the current market arrangements.

Key facts

Annual electricity consumption in the NEM rose from 160 000 GWh in 1999-2000 to over 208 000 GWh in 2007-08. In 2007-08, annual electricity consumption was distributed across the NEM regions as follows: NSW (38 per cent); VIC (25 per cent); QLD (25 per cent); SA (6.5 per cent); TAS (5 per cent); and Snowy (0.5 percent).[6]

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[4] Victoria currently has pricing oversight and a Review is underway in South Australia on the effectiveness of competition in the retail market at the request of MCE.

[5] Full regulation applies to certain covered pipelines. Under full regulation, a service provider is required to submit (in an access arrangement) the tariff and non-tariff terms and conditions of access to the services provided by the pipeline for the AER's approval. Other covered pipelines may be subject to light handed regulation. In this case, a service provider need not submit an access arrangement to the AER. However, it must provide certain terms and conditions of access on its website. Other pipelines are not subject to regulation and are not subject to the economic regulation provisions of the NGL and NGR.

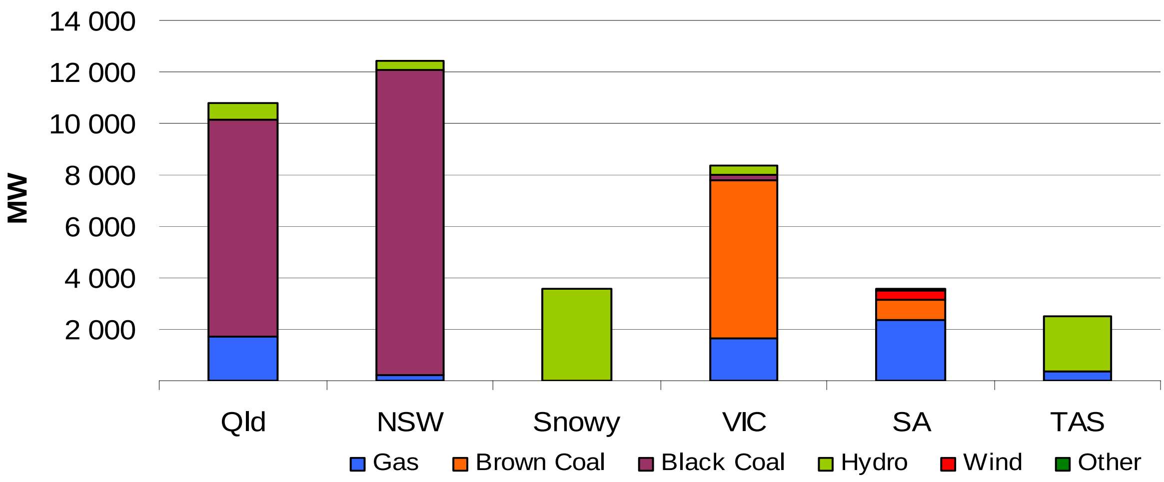
[6] The Snowy Region was abolished on 1 July 2008.

Maximum demand is forecast to grow at between 2.5 per cent under medium economic growth conditions over the next 10 years.[7]

Generation capacity in the NEM comprises coal (49 per cent black coal and 17 per cent brown coal), gas (natural and coal seam methane combined accounts for 15 per cent), and hydro-electric (17 per cent). Wind, biomass and other sources account for the remaining two per cent.[8]

Within the NEM, there are different fuel mixes across each of the regions. These are provided in Figure 1.

Figure 1: The NEM regional principal generation capacity (MW) by fuel type.



Australian Energy Regulator, The State of the Market Report, 2008, AER, publication pending.

Wholesale trading

All generators connected to the network must sell their output through the NEM, and all large users and retailers supplying customers served from this network must buy their electricity from the NEM.

The NEM is an "energy-only" market. This means that generators do not get paid for making capacity available. As noted, the NEM is a regional market, which means that prices are calculated separately for each region in the NEM. Prices are calculated every thirty minutes for each of the five NEM pricing regions. These are the "spot" prices that generators receive for their output, and the prices retailers and large customers pay for their consumption.

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[7] NEMMCO Statement of Opportunities for the Electricity Market, July 2008.

[8] Australian Energy Regulator, The State of the Energy Market Report, 2008, AER, publication pending.

Market and system operation

The NEM is managed and operated by National Electricity Market Management Company (NEMMCO).

In managing the system, NEMMCO determines which generators will run at any point in time. This process is called 'dispatch'. The dispatch is calculated to minimise the total cost of meeting demand, based on the prices offered into the market by generators, while also continuing to operate the network securely. Operating instructions are issued to generators every five minutes.

NEMMCO manages the financial settlements based on production of electricity, consumer consumption volumes and the prices at the time. Because this settlement process takes time (around five weeks in total), NEMMCO requires retailers and large customers to provide credit security ("prudentials") against the value of the electricity they have consumed but not yet paid for.

NEMMCO is a not-for-profit organisation. In 2009, NEMMCO will become part of the new organisation, the Australian Energy Market Operator (AEMO). AEMO will integrate the management of the electricity and gas markets. NEMMCO's core functions in the electricity market will not change, but it will have some additional functions, e.g. to prepare and publish a National Transmission Network Development Plan (NTNDP) each year.

Contract markets

Retailers and generating businesses both have an interest in managing the risk of price variations in the spot market. A key vehicle for market participants to manage this risk is to enter into contracts either bilaterally (e.g. between a retailer and a generator) or through exchanges.

There are a number of different types of contract, but the basic purpose of the contract is to convert a variable price (the spot price) into a fixed price (the contract price) for a specified volume. This can include contracts that cap prices at times of very high demand. The pricing of these contracts can provide important signals as to the value of additional capacity in the market.

Some of these contracts might be long term in nature. Investment in new generation might be predicated on signing such a long-term contract with a retailer. Some market participants have opted for vertical integration as a way of managing trading risk in the NEM in lieu of using contracts. Vertical integration is the consolidated ownership of both generation and retail portfolios. Instead of managing risk through contract markets, vertically integrated players manage risk internally with their own generation capacity.

The Western Australian Electricity Market

The Western Australian market's infrastructure consists of several distinct systems: the South West Interconnected System (SWIS), the North West Interconnected System (NWIS) and 29 regional, non-interconnected power systems. The largest network, the SWIS, serves Perth and other major population centres in the south-west. The SWIS is the major interconnected electricity network in Western Australia, supplying the bulk of the south-west region. It extends to Kalbarri in the north, Albany in the south and Kalgoorlie in the east.

In WA, electricity is predominantly generated by natural gas (60 per cent), with coal (35 per cent), oil (2 per cent), and wind, hydro and biomass (three per cent) providing the balance.

The supply of electricity in WA across networks other than the SWIS is undertaken by a regulated, vertically integrated utility (Horizon). The SWIS, however, has market arrangements, including the Wholesale Electricity Market (WEM), which commenced in September 2006. The main players in the WEM are Synergy (retail) and Verve (generation). There are also some new entrants, e.g. Griffin Power.

While the NEM is a gross pool (with all energy sold through the market), the WEM is a net pool. This means that most electricity is bought and sold under bilateral contracts, including the "vesting" contracts between Verve and Synergy. There is also a Short Term Energy Market (STEM) which operates in the 24 hours before real time. The STEM trades in differences between actual and contracted volumes and is operated centrally by the Independent Market Operator (IMO).

Another important difference between the WEM and the NEM is the presence in the WEM of a Reserve Capacity Mechanism. Retailers have an obligation to buy adequate levels of capacity and if this does not occur bilaterally, then the capacity is bought on behalf of the retailer by the IMO through periodic auctions. The IMO determines what levels of capacity are adequate. Generators in the WEM therefore have two sources of revenue from the WEM: for the electricity they produce; and for the capacity they provide.

The physical task of managing the system in real time is undertaken by Western Power System Management. An important tool in doing this is System Management's ability to direct the largest generator (Verve) to provide ancillary services (e.g. by modifying its levels of generation from particular plant). In contrast with the NEM, there is no market in these ancillary services.

Further information on the WEM can be found at http://www.imowa.com.au.

Northern Territory Electricity Market

The Northern Territory's electricity industry is relatively small, with three regulated systems, of which the largest is the Darwin-Katherine system with a capacity of around 340 MW. The majority of electricity is generated by natural gas.

While the NT is a signatory to the COAG Australian Energy Market Agreement, its system is not part of the national electricity market. The NT Government has, however, established a competitive electricity market, that in some respects mirrors the arrangements of the NEM.

Much of the electricity in the NT is traded through bilateral contract arrangements. However, in the absence of competition, wholesale trading occurs as an internal transfer between the generation and retail business units of the vertically integrated corporation of Power and Water (PWC).

All generation in the Territory connects directly to the distribution network. There is no transmission network as defined in the NEM. In the retail market consumers using more than 750 MWh a year are "contestable" (open to competition). Small consumers are not contestable and pay a uniform tariff set by the Territory Government.

National Gas Markets

Scope

Australia's natural gas market is characterised by the eastern interconnected gas network and the separate Northern Territory and Western Australia markets. The eastern interconnected gas network includes: NSW, the Australian Capital Territory (ACT), VIC, SA, TAs and will include QLD when the QSN link is commissioned in January 2009.

Key facts

Australia's proved and probable gas reserves stand at approximately 52 700 petajoules (PJ), comprising 40 300 PJ of conventional supplies and 12 400 PJ of coal seam methane (CSM).

Australia produced approximately 1700 PJ of natural gas in the year to June 2008, of which around 60 per cent was for the domestic market. CSM accounts for around eight per cent of total production, but its share is rising rapidly. Around 40 per cent of Australia's gas production, all currently sourced from Western Australia and the Northern Territory is exported as liquefied natural gas (LNG).[9]

[9] Australian Energy Regulator, The State of the Energy Market Report, 2008, AER, publication pending.

Market and system operation

The supply of natural gas is predominately undertaken through long term commercial contracts (usually 10 to 15 years) between producers, large industrial end users and/or retailers. Within the markets, there are also intermediaries to supply the natural gas between producers and retailers (known as gas shippers). The contracts establish the term, prices and quantities under which natural gas is supplied. It is important to note that in Victoria, the bilateral contract market is complemented by a balancing market that operates close to real time.

Gas is transported across an interconnected network across eastern Australia (Queensland is expected to join through the QSN link in 2008). WA and the NT are not connected with other jurisdictions. WA and NT operate under their own separate market schemes.

Both the transmission and distribution pipelines may be subject to economic regulation where a pipeline or distribution system is regulated (including 'light handed" regulation); such a pipeline is referred to as a covered pipeline. The key tool for regulation is the establishment of an "access arrangement". An access arrangement must specify the tariff and non-tariff terms and conditions relevant for parties to obtain access to the pipeline services available from the pipeline. This typically forms basis for negotiated pipeline services.

There are three gas market operators that operate under the appropriate jurisdictional market rules. These are: the Gas Market Company (NSW/ACT), VENCorp (Victoria and Queensland), and Retail Energy Market Company (SA/WA).

The gas markets have undergone a series of regulatory reforms to encourage competition in the various market segments. Some of the recent reforms have included:

- establishing the National Gas Laws and Rules for regulation of the services provided by certain transmission and distribution pipelines;
- introduction of National Gas Market Bulletin Board;[10]
- consolidating market operators into a single market operator, the AEMO from July 2009;[11] and
- planned introduction of a Short Term Trading Market (STTM), which is expected to come into operation in 2010.

Some of these reforms will improve the ability of gas market participants to trade and compete with each other. Other reforms will enable greater consistency in the

[10] http://www.gasbb.com.au/aboutus.aspx.

[11] Note: WA will not be part of the national gas market Bulletin Board, or the STTM. The functions of REMCo as they apply to WA are not being transferred to the AEMO.

application of economic regulation between gas transmission and distribution services providers. The reforms will also provide for the ability to improve regulatory consistency between gas and electricity where this is appropriate.

Information about the reforms to the gas markets can be found on the MCE website at www.mce.gov.au.

2.4 The Regulatory Environment

National frameworks

The 2004 COAG Australian Energy Market Agreement (AEMA) formalises the energy policy reform framework and establishes the governance arrangements for the national energy markets. National energy policy is delivered through the MCE.

The national electricity and gas legislative frameworks reflect the 2004 COAG AEMA as amended in 2006. The National Electricity Law (NEL) and National Gas Law (NGL) (set out in *National Electricity (South Australia) Act 1996*, *National Gas (South Australia) Act 2008* and on AEMC's website) currently provide for the regulation of the wholesale electricity market, the gas market Bulletin Board, and the economic regulation of electricity and natural gas transportation services. For each participating jurisdictions, the NEL and NGL are applied in, and take force through, legislation made by those parliaments. The NT and WA do not participate in the NEL or NGL but are signatories to the AEMA. [12]

The AEMA provides for the energy market institutions and the NEL and the NGL establish and confer a number of functions and powers to those entities. The market institutions include the AEMC and the Australian Energy Regulator (AER) and "the market operator". There are a number of other agencies and entities which have specific roles in energy markets, such as jurisdictional planning bodies and regulatory agencies.

The AEMC is responsible for making the National Electricity Rules and the National Gas Rules (together the "Rules") for the NEM and interconnected eastern states gas market. Under the Rules, the AER monitors the wholesale electricity market and is responsible for compliance with and enforcement of the Rules. The AER is also responsible for the economic regulation of the electricity transmission and distribution services as well as gas transportation services.

[12] The NT is considering joining the NEM. In WA, only the access arrangement under the NGL will apply. The NEL does not apply in WA.

Rule making

The NEL and the NGL set out a process for the AEMC to adopt when considering Rule changes. Generally the process involves a Rule change to be proposed, consulted on and assessed against an objective, the National Electricity Objective (NEO) or the National Gas Objective (NGO). The AEMC can only make Rules for those areas for which it is given Rule making responsibility under the NEL and the NGL. In other areas, such as the operation of the wholesale gas markets, the jurisdictional market operators make the rules.

The "Rules" currently cover a range of matters that include technical, economic regulation of commercial negotiations and trading and regulatory issues. These can range from technical standards with which electricity generators are required to comply, through with the procedural steps that must be taken in by the AER in determining the revenues that can be recovered by a network business.

Guidelines and procedures

In some areas, the Rules provide for the development of guidelines and procedures. These guidelines and procedures generally relate to technical and procedural issues relating to how the markets operate in practice – and are usually made in accordance with principles and consultation processes prescribed in the Rules.

Jurisdictional and other regulatory arrangements

As outlined above, the NEL and the NGL govern certain aspects of the electricity markets. There are plans to transfer other areas to the national framework in the future. In the meantime, these other areas are governed by various jurisdictional arrangements such as price regulation fro example the requirement for energy retail price regulation for the mass market.

Australia's energy markets do not operate in isolation; there are a number of other regulatory requirements that intersect with the regulatory regime specific to the energy markets. Some examples are competition laws, environmental laws and corporate governance laws.

An overview of the governance and institutional arrangements that support the operation of the existing the electricity and gas markets can be found at www.mce.gov.au.

3. The Issues

Introduction

The chapter sets out the main issues that we consider to be relevant to the Review. As outlined in Section one, the purpose of the Review is to identify where continuing with existing market frameworks might result in behaviour which is inconsistent with the market objectives of secure, reliable and efficient supplies of electricity and gas, as a direct result of the introduction of a CPRS and expanded RET.

We have therefore focussed on issues where there would appear to be a potential risk, and where further investigation and analysis is justified to establish whether the risks are material or not. The issues cover a wide range. Each issue is discussed using the same structure. We first define the issue and some contextual background. We then discuss how the new policy will affect the issue, and what risks might result. We conclude each section with a series of questions.

The CPRS will directly affect both gas and electricity markets. In contrast, the effects of the expanded RET are more focused on electricity markets. Some issues therefore raise issues in the context of gas and electricity markets, while other issues are more specifically electricity-related. The materiality of the risks we identify below is likely to be conditioned by the precise form of the policy. In particular, the role of the CPRS trajectory in determined the required speed of adjustment in an important factor.

Issue 1: Convergence of gas and electricity markets

Climate change policies will mean a larger role for gas, but differences between gas and electricity markets may mean that the market response is inefficient.

What is the situation?

Gas markets and electricity markets have evolved separately and are structured quite differently. Both structures have supported effective trading across a wide geographical area.

Regulated centralised markets play a large role in electricity, There is a centralised real time (“spot”) market in the NEM, and a centralised day-ahead market in the WEM. In the NEM, this provides a reference point against which bilateral forward contracts can be written. The NEM also has a centralised market for purchasing ancillary services that are required by the system operator, e.g. to “fine tune” the system in order to maintain frequency.

Gas markets are predominately based on commercial agreements between market participants with a limited role for centralised trading through regulated markets. A National Bulletin Board Service was launched earlier this year, and there are plans for a national gas STTM in 2010. Both of these developments represent moves toward a more centralised trading market in the interconnected eastern States.

The size of gas markets has been increasing. This is strongly linked to the increased use of natural gas as a fuel source for electricity generation. Its main use has been in open cycle gas turbines, that have low capital and high operating costs, which are designed to run for short periods; at times of high demand and high prices. Over time there may be an increasing share of combined cycle gas turbines, operating for longer periods. The size of gas markets might also be affected by shifts in behaviour, such as the use of gas hot water systems.

As consumers of natural gas, generators have particular characteristics. For example they use large amounts of gas and their demand for gas can change quickly as conditions in electricity markets change. New gas-fired generators can also be important determinants of the need for expansions of the gas pipeline network.

How will the new policies affect the situation?

The CPRS will improve the economics of gas-fired generation relative to coal-fired generation as it has a lower emissions-intensity (that is, less emissions per MWh generated). This is likely to result in an accelerated trend towards more gas-fired generation being built. The competitiveness of gas-fired generation is also affected by gas prices. Gas prices in Australia have been low by international standards, but are increasing over time.

There might also be an indirect stimulus to investment in gas-fired generation from the expanded RET. This is because investment in other forms of (non-intermittent) generation capacity will be required to complement wind generation at times when wind farms cannot generate. Gas-fired generation is the more likely technology in these circumstances because it is capable of ramping its output up and down quickly and reliably. Hydropower generators also have this capability.

What are the risks?

There is a risk that existing gas markets will not be sufficiently flexible and responsive to handle the increased volumes and more sophisticated consumption patterns of gas-fired generators. A key issue is the ability to trade efficiently in the short term. There is also a risk of an increased scope for “contractual congestion” on gas networks, if new gas users are unable to secure adequate access to existing pipelines through contractual negotiation.

There is also the risk that existing differences between gas and electricity markets have larger impacts. Differences in the market rules, e.g. when and how prices are calculated, may create profitable arbitrage opportunities, which may distort outcomes in both markets.

Our questions

We welcome submissions on the following:

1. **How capable are the existing gas markets of handling the consequences of a large increase in the number of gas-fired power stations and their changing fuel requirements?**

2. **What areas of difference between gas and electricity markets might be cause for concern and how material might the impacts of such differences be?**

Issue 2: Generation capacity in the short term

Delays to generation investment due to current uncertainty on the future policy settings, and timescales required to commission new investment, could result in a transitional problem in respect of the adequacy of generation capacity.

What is the situation?

Reliable supplies of electricity are critically important for the Australian economy and for society more generally. If uncertainty regarding the current policy of the CPRS and expanded RET has led to businesses deferring investment in new generation this may give rise to transitional reliability problems, during the process of adjustment and implementation of new investment.

Market responses

Consumers and policy makers primarily rely on market participant responses to deliver reliable supplies of electricity and gas. Prices and the scope for profitable investment are key drivers. In the NEM, the primary vehicle for investment signals is the energy price. There is a maximum price at which output can be offered into the market (currently set at $10 000 per MWh). In the WEM, market participants also need to consider capacity prices.

Under the energy-only pricing arrangements in the NEM, revenue from energy sales needs to be sufficient in periods of high prices to recover capital costs and earn a return on new generation investment. If this is not expected to be the case, private investment is unlikely to proceed. This differs to the WEM where generators also receive revenue for providing available capacity. The NEM and the WEM are relatively new markets. Both started with spare generation capacity. Hence, there is limited experience of large scale investment in new generation plant.

By historical standards, existing reserves of generation for electricity are low. In the absence of new investment in generation capacity, there is a projected shortfall today of reserve generation capacity relative to demand in a number of NEM regions in the period 2011 to 2014. This does not mean that the reliability standard of 0.002 per cent of unserved energy per year will be necessarily breached. It does, however, mean that the risk of breach will be higher in the absence of new investment in generation capacity or new forms of demand reduction at times of high demand.

The Reliability Panel has highlighted a range of factors that have contributed to these circumstances, and might condition this risk going forward.[13] The factors include: the continuing strong growth in demand; changes to input costs; and the availability of equipment and resources. Commercial uncertainty during the past three years as a result of the potential for greenhouse gas policy responses has also been a significant factor.

For example, there has been uncertainty regarding the form of the CPRS and the level of new renewable generation facilitated by the expanded RET. In some jurisdictions there has also been uncertainty over the acceptability of new coal-fired generation investments.

The Reliability Panel has recommended that (absent any additional impacts from climate change policies) it was prudent to respond to reliability concerns based on the factors above to increase the maximum market price to $12 500 per MWh.

System operation interventions

If market responses are not sufficient, then there are processes in place to allow for short term intervention in the market by the system operator. The need for large-scale and/or more regular intervention by the system operator in the future would be an indicator of problems in the operation of the market.

The system operator interventions include powers to contract for reserves and to direct the operations of participants in real time. If circumstances are such that system security is put at risk, then the ultimate form of intervention is to curtail supply to some customers.

Adjustments have already been recommended in this context, with the recent Rule change to amend NEMMCO's powers to contract for emergency reserves and to routinely publish information on constraints other than capacity (e.g. access to water supplies).

How will the new policies affect the situation?

The clarification of policy about the CPRS will reduce the factors contributing to the current investment uncertainty. This might bring forward some investments that are currently being deferred. However, it will not remove all uncertainty. A number of the factors, such as the availability of equipment and resources, cited by the Reliability Panel, will also continue to be relevant.

The CPRS will also impact on the value of existing generators. Because coal-fired generators will be relatively more expensive to operate as a result of the CPRS, those plants may run less frequently.

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[13] AEMC Reliability Panel, Exposure Draft, NEM Reliability Settings: VoLL, CPT and Future Reliability Review, July 2008, Sydney

Coal-fired generators can not easily ramp output up and down, and there is an increased risk of technical unreliability failure if it does so. The reduction in expected future profits and therefore value of coal-fired generation could also lead to earlier retirement of some coal-fired generation. There might also be smaller scale investment decisions for existing generators, e.g. to enable plant to operate reliably with more flexibly in the short to medium term.

The expanded RET will continue to promote new connections of wind-farms in the short term. This will place more pressure on the existing challenges of system operation that are already evidence in SA and WA.

What are the risks?

There is a risk that the timing of the investment response is not rapid enough due to practical constraints on delivering the requisite level of generation reserves. This issue may only be for a temporary period while the market adjusts, but is still a cause for concern.

Investment in new capacity takes time to plan and implement. Land use planning consents need to be acquired, network connections need to be secured and equipment needs to be ordered. There are risks of delay at all of these stages. Strong global demand for electricity infrastructure may further increase the risk of delays. These factors have been noted by the Reliability Panel.

In such a transitional situation, we would expect to see greater involvement in the market by the system operator. The tools available to the system operator in this regard would be tested. In the NEM, for example, the existing powers for the system operator to procure reserves to cover a shortfall are designed to be short term and by exception. They might not work effectively or efficiently if they are required to be used more extensively.

This risk would be exacerbated if there were decisions by existing generators to retire some plants prematurely. This might be unlikely if the generator can still be profitable as a result of high prices, as might be expected in periods of tight supply.

On the other hand, for example, plant might retire unexpectedly due to a technical failure, which is uneconomic to repair, given the otherwise short expected overall life of the plant. The risk of this occurring is probably increased if there are changes to how plant is operated and maintained, e.g. if coal-fired generation is required to run more flexibly than it does currently, and if maintenance expenditures are reduced due to the shorter remaining economic life.

Our questions

We welcome submissions on the following:

3. **What are the practical constraints limiting investment responses by the market?**

4. **How material are these constraints, and are they transitional or enduring?**

5. **How material is the likelihood of a need for large scale intervention by system operators? How likely is it that this will be ineffective or inefficient?**

Issue 3: Investing to meet reliability standards with increased use of renewables

If standards relating to the reliability of electricity supplies are going to continue to be met, then investment in intermittent generation (such as wind-farms) will need to be matched by investment in other forms of generation (or transmission) – to ensure that supplies are reliable when wind generation is unavailable. Existing market frameworks might not deliver investment in such "back up" capacity at an acceptable cost.

What is the situation?

As outlined in Issue 2, the NEM and the WEM – and the contract markets derived from them - provide price signals to encourage timely investment in generation. Network regulation also facilitates investment to assist in delivering reliable supplies. To date, these mechanisms have been largely successful.

How will the new policies affect the situation?

The CPRS will introduce a cost for CO_2 emissions. This will encourage investment in generation with low or zero emissions.

The expanded RET will magnify some of the effects of the CPRS. It will make renewable generation more profitable. In the short term, it will stimulate investment in wind farms. This is because wind is currently the most mature and commercially viable renewable technology for large scale generation capacity. In the longer term, other technologies, such as solar and geothermal might be expected to play a greater role.

Wind generation is an intermittent form of generation. Its level of output depends on prevailing wind speeds. If there is no wind, it cannot generate. This is a particular consideration for areas where peak demand is driven by the use of air conditioning units in summer, and also where the hottest days can be relatively still.

The immediate impact will be to increase the overall level of generation in relation to demand. However, over time as load grows and as existing plant retires, there is likely to be the need for additional and more predictable generation capacity to ensure reliable supply when generation from intermittent sources is not available.

What are the risks?

As raised in Issue 2, there is a risk that investment in additional generation to maintain reliability, given retirement plants of existing plant, is not forthcoming. In areas where penetration of wind farms is expected to be high relative to demand (such as SA and WA), the back-up investment will only be utilised very infrequently. This makes the economic case for private investment in such plant more challenging.

It would rely on infrequent high-price periods or the sale of cap contracts to recover its costs. It is uncertain whether investors would be willing to invest on this basis. Existing limits on prices in the market might not be sufficient to support the required investment.

A related risk is that reliability standards are only capable of being met by investment in transmission infrastructure – to utilise generation capacity from other areas. There is a risk of unnecessarily high costs through a transmission, as compared to a generation, solution (and vice versa) if the market settings for generation are inappropriate.

Our questions

We welcome submissions on the following:

6. **How material is the risk of a reduction in reliability if there is a major increase in the level and proportion of intermittent generation?**

7. **What responses are likely to be most efficient in maintaining reliability?**

Issue 4: Operating the system with increased intermittent generation

Climate change policies may require more flexible operation of thermal generation plant, and this may create technical challenges or inefficient market outcomes.

What is the situation?

The task of operating electricity systems in real time requires constant monitoring and assessment. This includes ensuring that required tolerances for frequency and voltage are met and that the network is operated securely. Greater use of intermittent generation, such as wind farms, increases unpredictability, and makes the task of managing the system more difficult.

The services that the system operator uses to ensure stable operation of the network are called ancillary services. In the NEM, there are markets for ancillary services. These generally relate to services which are used by NEMMCO in the period less than five minutes before real time. In the WEM, the system operator manages the network in the period within 24 hours of real time by issuing directions to the largest generating business, Verve Energy.

A number of changes have already been made to facilitate greater integration of wind generation. This has included investment in sophisticated wind forecasting technology, and changes in the rules to provide system operators with more operational control over the permitted output of wind generators. In WA and SA, additional controllability has been required as part of obtaining a generator licence or obtaining a network connection. Existing levels of wind farm penetration in WA and SA are large by international standards as a proportion of demand.

How will the new policies affect the situation?

CPRS will improve the economic viability of intermittent forms of renewable generation; however it will also intensify the challenges for system operation. The expanded national RET is likely to have a larger impact.

Meeting the expanded RET target will require a very large increase in the amount of installed renewable capacity. Much of this, at least in the short term, will be intermittent, i.e. largely wind farms.

As the amount of intermittent generation grows, the system operator will routinely need to manage the risk of larger, unexpected changes in output from all of the wind farms connected to its network. This task is particularly challenging on a relatively thin, radial network such as the NEM or the WEM because there are fewer options for responding as compared to a large, meshed network.

An additional challenge is that the generation plant being relied upon to respond more flexibly may be technically less suited to this type of operation. This may be because the plant is relatively old and was designed to operate at more stable levels of output ("baseload").

What are the risks?

The main risk is that the existing tools available for system operation, including the definition of and means of procuring ancillary services, will be put under greater pressure and will prove to be insufficient for the task. There may be increased risk of frequency and voltage problems, which could precipitate some loss of supply. It may also result in greater constraints being imposed on intermittent generation as conditions of connecting to and using the network. This is an additional risk for private investors to manage.

There is also a risk that the generation plant being relied upon to respond more flexibly can only do so at high costs, and with less reliability.

Our questions

We would welcome submissions on the following:

8. **How material are the challenges to system operations following a major increase in intermittent generation?**

9. **Are the existing tools available to system operators sufficient, and if not, why?**

10. **How material is the risk of large scale intervention by system operators and why might such actions be ineffective or inefficient?**

11. **How material are the risks associated with the behaviour of existing generators, and why?**

Issue 5: Connecting new generators to energy networks

Differences between gas and electricity networks, and the reliance on bilateral negotiation over connection, means that the significant expansion of gas and electricity networks may not be delivered in a timely way or at an efficient level of cost.

What is the situation?

Electricity networks need to accommodate new generators as existing plant retires, or as the demand for electricity increases. This requires planning and investment in new infrastructure. In a competitive market, the behaviour of network businesses also plays an important role in influencing short term and long term market outcomes.

The frameworks for connecting new generators in the NEM and the WEM are based on negotiation. A generator enters into an agreement with a transmission business for connection. The agreement stipulates the service being provided and the associated charges. In the NEM, connection charges generally cover the cost of providing the infrastructure to get the generator's output from the power station to the main interconnected network. The costs of any deeper network reinforcement are not generally included in connection charges although there is scope for this in the Rules.

The current processes for managing new connection have worked reasonably effectively to date. However, the volumes of new connection have been relatively low and the environment has been relatively stable. The process of issuing connection offers is relatively complex and resource-intensive, and requires system modelling.

There are indications of emerging issues in WA, with a growing queue of connection applications and concerns being raised about the time taken for connection applications to be processed. There is also evidence from overseas (e.g. the United Kingdom) of problems in processing large volumes of connection applications in a coordinated and efficient way.

How will the new policies affect the situation?

CPRS is likely to stimulate investment in gas-fired generation. The best sites will be close to gas supplies and close to electricity transmission. Less attractive sites will involve tradeoffs between building gas network infrastructure and building electricity network infrastructure. This is, in effect, a trade-off between transporting fuel or electricity.

The expanded RET will stimulate investment in renewable generation capacity. This type of connection activity has a particularly challenging set of issues. In part this is driven by the likely volume of applications over a short period of time, and to some extent the remote nature of many of the best resources of renewable generation such as wind and geothermal.

The existing transmission system has been built to serve demand given the location of existing generators. Hence, many of the best renewable resources are not close to the transmission system, and are likely to seek to connect to relatively weak parts of the network. Transmission connections for remote renewable generation may therefore be very expensive. There is a trade-off with less resource-rich locations, but which are closer to the existing network.

What are the risks?

The interface between regulated networks and unregulated generators is a critical interface. The behaviour of networks should be regulated to be stable, predictable and consistent with efficient outcomes. It should be responsive to the needs of the market, but should not "crowd out" market investment.

One potential risk is that these decisions are skewed because of differences in the connection regimes between gas and electricity. These differences might relate to charges or to the type of service provided. For example, there are differences between gas and electricity in respect of the circumstances under which network capacity is shared in the event that new users subsequently connect.

A key challenge is the ability of network businesses (and other generators) to handle current and potential applications which relate to similar parts of the network. There is a coordination problem. It is unlikely to be efficient to treat each application in isolation. However, the existing framework is designed around bilateral negotiation; hence, there is a risk of uncoordinated network investment. This could increase costs and delay new connections.

Another risk is that treating connection applications on a bilateral basis might result in arbitrary differences between parties in the risks and costs of new connection. Transmission capacity can only be provided in discrete amounts, the party who triggers the next large "chunk" of investment will face the total cost of this, even if it provides surplus capacity for use by others.

While the Rules in the NEM provide for this party to get some of its money back as and when new parties connect, it also has to bear the risk of this not happening. The bilateral model therefore has a strong incentive to "size" a connection to be the minimum necessary. However, in a period of growth in new connections, this might not be the most efficient investment strategy in the medium term. More generally there is a need to minimise the costs of network investment during a period of rapid growth in connections and uncertainty. This may require some parties to form a view on the likely nature and scale of future demand.

These risks and challenges are compounded by the remote nature of many renewable generation options. This means that small inefficiencies in investment decision-making might have larger cost impacts.

Our questions

We welcome submissions on the following:

12. **How material are the risks of decision-making being "skewed" because of differences in connection regimes between gas and electricity, and why?**

13. **How large is the coordination problem for new connections? How material are the inefficiencies from continuing with an approach based on bilateral negotiation?**

14. **Are the rules for allocating costs and risks for new connections a barrier to entry, and why?**

Issue 6: Augmenting networks and managing congestion

Climate change policies may result in higher levels of congestion on energy networks and there is a risk that congestion costs are not minimised, or that they create a significant risk for potential investors.

What is the situation?

The extent to which generators are able to generate depends on the price at which they offer their output in to the market, and the ability of the network to handle the electricity produced. In some cases, generation that is more expensive will run ahead of less expensive generation because of network limitations. The capability of the shared network is therefore an important determinant of market outcomes.

The provision of network services is subject to economic regulation. The regulation covers the total level of charges, and the processes that must be followed before investment is undertaken. It also includes financial incentives to promote efficiency and optimal use of network capacity. In some areas, network businesses must also have regard to information published by planning bodies. This will be strengthened with the establishment of a NTP in 2009.

There is scope for network users individually to fund augmentations to the shared network. This has not been used extensively in practice. There is also scope for parties to build their own transmission infrastructure on a merchant basis. The interconnection between Tasmania and Victoria is the only current example of merchant transmission.

"Open access"

Physical constraints on the network can lead to temporary limits being placed on generator behaviour. In the NEM and WEM (with some limited exceptions) there is no compensation if this occurs. This is called "open access". In an "open access" regime, the process through which the shared network is augmented is very important. It can materially affect market outcomes and the ability for generators to sell contracts to retailers. Contracts are important tools in managing trading risk and underwriting investments.

Congestion

Network congestion means that the system operator needs to dispatch more expensive ("out of merit") generators in order to meet demand, which increases costs. Congestion can also create incentives for generators to submit offers which do not reflect the true costs. For example, to manage the risk that a generator will not be dispatched due to network congestion (being "constrained off").

Losses

Another potential commercial impact is transmission losses. As electricity is transported a proportion of energy is lost, e.g. in the form of heat. The amount of electricity deemed to have been sold in the NEM is adjusted for losses. Within each region, NEMMCO does this by applying a loss factor to adjust downwards the gross volume produced at the generator's location. These loss factors are re-calculated every year.

How will the new policies affect the situation?

Historically, there has been a relatively close balance between generation and demand within regions – with a relatively limited role for trading electricity across regions. Over time, CPRS and expanded RET will change the location of generation relative to demand, and geographic concentrations of new generation capacity are likely to arise, e.g. in areas of good wind resource and good access to gas. There may also be changes in the level and location of demand, as a response to higher prices. This will change the pattern of flows across electricity networks and also place new demands on gas networks, e.g. to support new gas-fired power stations. It may also increase the extent to which geographical regions are net importers and exporters of electricity and has.

These new patterns of network flows may reveal new pockets of network congestion – and change the costs and benefits of different investments on the shared network. If individual regions are to be large net exporters or importers of electricity, then investment in more interconnection will be needed. This requires coordination between transmission companies.

There may in turn be an increased interest in the ability of generators to "firm up" their access to the shared network to manage the potential risk of being "constrained off" as a result of network congestion.

Changing patterns of network flows may also be reflected in changes to loss factors.

What are the risks?

There is a risk of time lags between new pockets of congestion emerging and the network investment responses. This might increase the costs imposed by network congestion. This risk might be heightened if new generators do not have strong financial incentives to factor in network costs when they connect. The costs of congestion might also increase if new patterns of congestion create new opportunities for generators to bid strategically.

In respect of gas markets, there is a risk of "contractual congestion" on gas networks having more material effects. This might occur if new users are reliant on contractual negotiation to secure access to existing pipelines. There is a risk that what is available contractually does not reflect what is available physically.

Another risk includes how the costs of investing in the shared network are recovered. Currently, customers in each region pay for the transmission network in that region. This might be viewed as inefficient or unfair if investment is facilitating flows of cheaper electricity or volumes of renewable-based electricity to other regions rather than benefiting customers within the region.

How effectively transmission businesses respond is also an issue. More weight is being placed on the ability of transmission companies to plan effectively and to assess the costs and benefits of network investment in more sophisticated ways, in a more rapidly changing environment. In some cases, they will be required to plan jointly. There is a risk that the existing set of obligations and incentives on transmission businesses do not deliver a coordinated and efficient response.

If the future risk of not being able to generate due to network constraints is perceived to be high, which may well be the case in an environment of significant new connection activity – then there is a risk that finance to support new generation projects might be more expensive, or withheld (see Issue 4). New investors in generation might therefore be interested in seeking to obtain "firmer" access to the network when they connect. While there is some scope in the Rules currently to negotiate firmer access, these are untested in practice. There are reservations about how effectively they can work.

There is also a risk that loss factors change materially from one year to the next. This is more likely to occur when there are large changes in network flows, e.g. as a result of new generator connection. This would affect the amount of generation deemed to have been sold. Uncertainty over future changes in the loss factors could increase the risk (and therefore cost) of investing and of contracting.

Our questions

We welcome submissions on the following:

15. **How material are the potential increases in the costs of managing congestion, and why?**

16. **How material are the risks associated with continuing with an "open access" regime in the NEM?**

17. **How material are the risks of "contractual congestion" in gas networks and how might they be managed?**

18. **How material is the risk of inefficient investment in the shared network, and why?**

19. **How material is the risk of changing loss factors year-on-year?**

Issue 7: Retailing

Changes in the level or volatility of costs faced by retailers, combined with ongoing price regulation, may reduce the effectiveness of retail competition.

What is the situation?

Retailers are the interface between the end consumer and the supply chain. A retailer's own direct costs are a very small proportion of its total costs. The bulk of its costs represent the costs of buying wholesale energy and network charges. An individual retailer has only limited control over these costs.

The ability of electricity retailers to manage wholesale energy costs depends in part on the availability of different duration contracts with generators. The availability of contracts is very limited currently. This reflects the reluctance of generators to make long-term financial commitments when there is uncertainty, as a result of climate change policies over future costs and revenues. Similar issues may apply to gas retailers to the extent that climate change policies affect their supply costs materially.

The profit margins available to retailers depend on the relationship between costs and revenues. Price regulation is a significant influence over revenues. Each State regulates electricity and gas prices differently. The MCE policy framework is to remove price regulation over time when there is effective competition between retailers in a region. Victoria is the first jurisdiction to legislate to remove price regulation. The AEMC is currently reviewing the effectiveness of competition of South Australia's retail electricity and natural gas markets.

Competition between retailers will, over time, reveal different businesses and business models to be more profitable than others. This, in turn, is likely to see some retailers exit the market, while other businesses grow in size. This can be illustrative of healthy, competitive markets. There are a number of ways in which retailers might exit the market. The most likely and least disruptive scenario is through merger or acquisition.

How will the new policies affect the situation?

CPRS will increase wholesale energy costs for retailers and large customers. It may also increase related costs, e.g. prudential.

In the short term, the removal of uncertainty around the precise form of CPRS should increase the availability of contracts. The CPRS may also prompt retailers to review the risk associated with existing contracts. This would be particularly relevant if some existing generators were to be in financial difficulty as a result of CPRS.

The expanded RET represents an increase in compliance costs for retailers. The scheme also increases the obligation to buy RECs from generators or pay the costs of "buying out" their obligation.

What are the risks?

The main risks are that the costs of an efficient retailer increase, but they are not able to recover those costs through higher prices to customers. This could result in financial distress. This might be a direct result of inflexibility in the form of price regulation. It might also result in disputes arising from incompleteness or ambiguity in existing contracts.

In the short term, this risk might be exacerbated by volatility in contract markets, as retailers seek to rebuild their contract positions quickly, and as individual generators learn what constitutes prudent contracting in the new environment. Volatility in spot markets would also exacerbate this risk, through increased requirements to provide financial security against credit risk.

There is also a risk of disorderly market exit. If, for example, a retailer experiences financial difficulties quickly and unexpectedly as a result of cost volatility attributable to the CPRS and expanded RET. In these circumstances, there is scope for exit to impact more widely on the market. There are "safety net" arrangements in place to manage this type of situation. The "Retailer of Last Resort" is a jurisdictional process to transfer customers to an alternative retailer in the event of a retailer leaving the market unexpectedly. These processes are relatively untested, and have already been identified as a potential weakness in the market arrangements.

Our questions

We welcome submissions on the following:

20. **How material is the risk of an efficient retailer not being able to recover its costs, and why?**

21. **What factors will influence the availability and pricing of contracts in the short and medium term?**

22. **How material are the risks of unnecessarily disruptive market exit, and why?**

Issue 8: Financing new energy investment

Climate change policies will require large investment in renewable and non-renewable generation capacity – and in energy networks. Current market settings may result in risks which increase the costs (or reduce the availability) of debt and equity finance.

What is the situation?

There has been a rapid increase in privately financed gas pipeline investment. There has also been significant private investment in electricity generation and networks. International investors have entered the Australian energy market, although many have also exited over the last decade.

How will the new policies affect the situation?

A large amount of new investment will be required in response to climate change policies. The expanded RET will require an additional 45 000 GWh of renewable energy. Much of this energy is likely to come from intermittent generation. This plant has low capacity factors (that is, low energy output in relation to installed capacity). This requires a larger volume of installed capacity to meet reliability targets. This plant is also likely to have relatively high initial capital costs. These factors will increase the initial financing requirement.

The CPRS will alter the variable costs of existing plant. This may lead to early retirement of some existing capacity. The CPRS may also lead to an increased role for gas-fired generation. This would require a very significant increase in gas processing and transport infrastructure.

The electricity markets on the eastern seaboard were originally developed on a regional basis. As noted in Issue 5, demand and generation capacity have been reasonably balanced within regions to date. However, the expanded RET is likely to lead to a large increase in renewable generation located close to the best sources of wind, geo-thermal capacity or other technologies. Closures of some existing thermal generation and investment in new capacity may further alter the regional balance of supply and demand. This may lead to a significant increase in the need for network investment.

Climate change policies are therefore likely to lead to major new requirements for financing energy infrastructure over a short period.

What are the risks?

The CPRS and expanded RET are likely to lead to a large requirement for investment up to 2020 during a period when many other countries are seeking similar investments.

The energy market settings will affect the willingness of equity investors and debt financiers to support the required investment and therefore may affect the availability of finance between different energy markets in Australia.

These settings have been successful in attracting investment to date. In some cases that has been facilitated by governments. There is a risk that they will be less successful in attracting the large amount of additional investment that will be required, or that investors will seek higher returns in response to the risks they face.

There is also a risk that the differing commercial frameworks in Australian electricity and gas markets will result in a sub-optimal response to the required generation and network investments.

- Electricity networks do not provide firm access. This exposes generation investors to risks in terms of their access to the network and their potential for future stranding. This contrasts with gas pipelines which in many cases do provide firm access. It also contrasts with some international electricity markets which provide firm access for generators.
- The NEM does not provide capacity payments. This exposes investors to risks if their generation is not dispatched, while the WEM does provide capacity payments.

Our questions

We would welcome submissions on the following:

23. **What factors will affect the level of private investment required in response to climate change policies?**

24. **What adjustments to market frameworks, if any, would be desirable to ensure this investment is forthcoming at least cost?**

4. List of Issues and Questions

Issue	Question
1. Convergence of gas and electricity markets	1. How capable are the existing gas markets of handling the consequences of a large increase in the number of gas-fired power stations and their changing fuel requirements? 2. What areas of difference between gas and electricity markets might be cause for concern and how material might the impacts of such differences be?
2. Generation capacity in the short term	3. What are the practical constraints limiting investment responses by the market? 4. How material are these constraints, and are they transitional or enduring? 5. How material is the likelihood of a need for large scale intervention by system operators? How likely is it that this will be ineffective or inefficient?
3. Investing to meet reliability standards with increased use of renewables	6. How material is the risk of a reduction in reliability if there is a major increase in the level and proportion of intermittent generation? 7. What responses are likely to be most efficient in maintaining reliability?
4. Operating the system with increased intermittent generation	8. How material are the challenges to system operations following a major increase in intermittent generation? 9. Are the existing tools available to system operators sufficient, and if not, why? 10. How material is the risk of large scale intervention by system operators and why might such actions be ineffective or inefficient? 11. How material are the risks associated with the behaviour of existing generators, and why?

Issue	Question
5. Connecting new generators to energy networks	12. How material are the risks of decision-making being "skewed" because of differences in connection regimes between gas and electricity, and why? 13. How large is the coordination problem for new connections? How material are the inefficiencies from continuing with an approach based on bilateral negotiation? 14. Are the rules for allocating costs and risks for new connections a barrier to entry, and why?
6. Augmenting networks and managing congestion	15. How material are the potential increases in the costs of managing congestion, and why? 16. How material are the risks associated with continuing with an "open access" regime in the NEM? 17. How material are the risks of "contractual congestion" in gas networks and how might they be managed? 18. How material is the risk of inefficient investment in the shared network, and why? 19. How material is the risk of changing loss factors year-on-year?
7. Retailing	20. How material is the risk of an efficient retailer not being able to recover its costs, and why? 21. What factors will influence the availability and pricing of contracts in the short and medium term? 22. How material are the risks of unnecessarily disruptive market exit, and why?
8. Financing new energy investments	23. What factors will affect the level of private investment required in response to climate change policies? 24. What adjustments to market frameworks, if any, would be desirable to ensure this investment is forthcoming at least cost?