Impacts of climate change policies on generation investment and operation

A REPORT PREPARED FOR THE AUSTRALIAN ENERGY MARKET COMMISSION

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INTRODUCTION

Frontier Economics (Frontier) has prepared this report for the Australian Energy Market Commission (the AEMC or Commission) on the implications of climate change policies for the economics of generator operation and investment in the National Electricity Market (NEM).

Specifically, Frontier was asked to advise the Commission on what impacts the Carbon Pollution Reduction Scheme (CPRS) and expanded national Renewable Energy Target (RET) scheme might have 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; and
- Parties who transact with generators in the NEM, in respect of *how* they transact.

EFFECTS OF THE CPRS

A summary of the likely impact of the CPRS on key issues facing generators in the NEM is outlined in Table 1. These issues include forward contracting strategies; strategies for spot market offers; strategies for managing physical and financial risk; modes of technical operation, plant retirement; investment in new plant; organisational structure; and behaviour of counter-parties.

.Issues	*Likely impact of the CPRS*
(i) Forward contracting	• The introduction of a variable and uncertain carbon price will increase wholesale electricity price volatility, and hence risk. • Generators and Retailers are both exposed to this regulatory risk, hence they will be unable to hedge against it through contracting. • This is likely to lead to a shortening of the contract market

.Issues	Likely impact of the CPRS
	and/or and increased tendency toward contracts that are vary with the carbon price.
(ii) Spot market offers	• Generators will add the cost of carbon to bids regardless of whether permits are auctioned or grandfathered (due to opportunity costs). • The extent of cost pass-through depends on the emissions intensity of the marginal plant (before and after the CPRS), and demand elasticity. • The carbon price will likely flatten the merit order, since it increases the cost of cheaper high emissions plant (coal) more than the cost of low emitters (e.g. gas). Although this might theoretically lower the opportunity for strategic bidding, this is likely to be offset by the effect of delays in new investment (due to the more uncertain market).
(iii) Management of physical and financial risk	• The introduction of the CPRS is not expected to materially impact congestion in the NEM as compared to the status quo. • Changes to dispatch and power flows may either improve or erode the firmness of IRSRs on the margin. • As a result, this policy is unlikely to materially change the way in which market participants currently manage physical risk in the NEM. • As a consequence of carbon price risk, generators may have reduced incentives to enter into long-term swap contracts to hedge their financial risk – this is since carbon costs are likely to represent a larger component of SRMC than fuel costs for most generators.
(iv) Technical operation	• The carbon price should change the merit order such that low emissions plant should increase output to displace high emissions output. • This may provide complications for existing coal plant, which is not suited to running as flexible intermediate plant at low capacity factors.
(v) Plant retirement	• The carbon price increases the marginal cost of generation. At higher carbon prices, the viability of high emissions plant will decline, as it will become cheaper to build new low emissions plant to replace existing high emissions plant. • Once the SRMC of existing high emissions plant (including carbon costs) rises above the LRMC of new low emissions plant then early retirements are likely. This is likely to occur at prices of around \$30-\$45/tCO_2 for brown coal plant and

.Issues	*Likely impact of the CPRS*
	at marginally higher prices for black coal plant (contingent of current gas prices). • There are also potential credit market implications of imposing the CPRS with full auctioning. This will reduce the value of existing high emissions generators, and the resulting asset write-downs will reduce the security for existing debt. This may trigger clauses in existing hedge agreements, which may create more systemic problems.
(vi) Investment in new plant	• The carbon price will increase investment in low emissions plant, though the increased uncertainty regarding carbon prices may result in delays in investments. • Higher electricity prices resulting from the CPRS may result in lower demand (or slower demand growth), which may reduce the need for new investment. However, electricity demand is typically inelastic. • The location of gas investments should be more flexible than coal due to the greater potential to transport gas. This may see plant locate closer to major load centres • In the longer term there will be increased reliance on CCS and Renewables to meet abatement targets. The location of these plant will be dictated by a combination of the location of fuel and sinks in the case of CCS (though carbon can also be transported) and location of natural resources in the case of renewables.
(vii) Organisational structure	• The incentive to vertically integrate retail and generation is similar to the incentive for contracting, which is to hedge risk. • Since it is difficult to hedge against carbon price, the CPRS is unlikely to increase incentives to vertically integrate.
(viii) Behaviour of counter-parties	• The shortening of the contract market (above) and the general ability of generators to pass-through a large portion of costs mean that retailers and large customers are potentially exposed to the risk of higher energy prices. • This may be mitigated somewhat if they sign contracts for energy that are indexed to the carbon price, (though they will still be exposed to the carbon price risk). • It is not clear whether existing contracts will allow for revisions to account for the introduction of a carbon price. • The exposure of retailers depends on whether retail price

.Issues	Likely impact of the CPRS
	regulation allows for pass-through of carbon costs to end-users.

Table 1: Summary of impact on issues facing generators: CPRS

Source: Frontier Economics

EFFECTS OF THE EXPANDED NATIONAL RET SCHEME

A summary of the likely impact of the expanded national RET scheme on key issues facing generators in the NEM is outlined in Table 2. These issues include forward contracting strategies; strategies for spot market offers; strategies for managing physical and financial risk; modes of technical operation, plant retirement; investment in new plant; organisational structure; and behaviour of counter-parties.

Issues	Likely impact of the expanded national RET scheme
(i) Forward contracting	• Retailers typically contract for RECs unbundled from the energy (which is often intermittent). Most RECs are currently contracted, and this is unlikely to change. Wind plant typically contract for 10-15 years. • The increase in intermittent generation (by itself) is likely to increase the volatility of the pool price compared to an equivalent increase in thermal capacity, since wind cannot guarantee supply of energy at times of high demand. • This should similarly translate to higher contract premiums (a similar price signal for new peaking plant). • The increased incidence of high price events should provide a market signal for new peaking capacity to complement the additional intermittent capacity. Therefore the combined effect of additional wind and peaking plant should have a dampening effect on prices, since it reduces the potential for strategic bidding.
(ii) Spot market offers	• The increase in intermittent generation (by itself) is likely to increase the volatility of the pool price compared to an equivalent increase in thermal capacity, since wind cannot guarantee supply of energy at times of high demand. • This should be tempered by the expected entry of peaking plant in response to the price signal, which will dampen prices.

Issues	*Likely impact of the expanded national RET scheme*
(iii) Management of physical and financial risk	• Renewable generation is not exposed to carbon price risk in the same way that CO_2-emitting plant are. • Due to their virtually zero SRMC, wind is unlikely to face the same level of physical risk as thermal plant, since they are typically dispatched first in the merit order. • The expanded RET scheme is not expected to materially increase the level of congestion in the NEM over the status quo. • This implies that renewable generators are unlikely to face any increased (financial or physical) risk *ex post* introduction of the expanded RET.
(iv) Technical operation	• The displacement of thermal plant by renewable generation may lead to a decrease in the operating efficiency of thermal plant going forward. • At the extreme, thermal coal plant may be limited to their minimum stable generation levels at low load times (such as overnight). • In response, most system operators seek to curtail renewable plant output when conventional thermal plant are approaching minimum stable levels. • However, much of the flexibility to operate around intermittent wind should be provided by additional peaking plant.
(v) Plant retirement	• Increases in the RET target over the course of the scheme are largely consistent with anticipated increases in demand over time. • This means that more new renewable plant will be built to meet growing demand rather than to displace existing thermal generation.

Issues	***Likely impact of the expanded national RET scheme***
(vi) Investment in new plant	• The intent of the scheme is to encourage new investment in renewable plant, which is to be expected. • The choice of location for investment in renewable generation is determined by natural resources (eg wind quality, geothermal potential etc) and availability (cost) of network connection. • Victoria, New South Wales and Queensland are expected to experience the greatest growth in installed wind capacity. • Other potential renewables going forward include solar thermal and geothermal. Both of these technologies are more suited to remote regions of South Australia and Queensland. • The increase in intermittent generation (by itself) is likely to increase the volatility of the pool price compared to an equivalent increase in thermal capacity, since wind cannot guarantee supply of energy at times of high demand. • This should similarly translate to higher contract premiums (a similar price signal for new peaking plant). • The increased incidence of high price events should provide a market signal for new peaking capacity to complement the additional intermittent capacity. Therefore the *combined* effect of additional wind and peaking plant should have a dampening effect on prices, since it reduces the potential for strategic bidding.
(vii) Organisational structure	• The extension of the RET is unlikely to change the incentives for organisational structure significantly. Given that most retailers contract for RECs unbundled from electricity, there does not appear to be a strong incentive for retailers to build new renewables. • The increase in price volatility (and contract premiums) resulting from a larger share of intermittent generation might increase the tendency for retailers to build peaking plant as a physical hedge. This would mitigate any increase in volatility from new build of wind alone.
(viii) Behaviour of counter-parties	• Retailers typically contract with renewable generators to ensure supply of RECs and not for the supply of energy. • Regulation allows for retailers to pass-through this cost to end-users.

Table 2: Summary of impact on issues facing generators: Expanded RET

Source: Frontier Economics

1 Introduction

Frontier Economics (Frontier) has prepared this report for the Australian Energy Market Commission (the AEMC or Commission) on the implications of climate change policies for the economics of generator operation and investment in the National Electricity Market (NEM).

This work was requested to assist the Commission in undertaking a review initiated by the Ministerial Council on Energy (MCE) of the impacts of climate change policies on the energy markets. The purpose of this review is to advise the MCE on whether changes to energy market frameworks, as a result of these policies, is warranted in order to promote the market objectives of efficient, secure, safe and reliable supplies of electricity and gas.

Specifically, Frontier was asked to advise the Commission on what impacts the Carbon Pollution Reduction Scheme (CPRS) and expanded national Renewable Energy Target (RET) scheme might have 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; and
- Parties who transact with generators in the NEM, in respect of *how* they transact.

The report is to comment on impacts by class of generation, including by fuel type, mode of operation and organisational form. This report is structured as follows:

- Section 2 introduces the details of the climate change policies in the NEM, namely the CPRS and the expanded national RET scheme;
- Section 3 discusses generator behaviour in the NEM in the absence of these climate change policies. This section is divided into operational decisions and investment decisions;
- The likely effects of an emissions trading scheme (ETS) such as the proposed CPRS are explained in section 4. This includes short-run effects on generator

dispatch and bidding, long-run effects on new investment, the likely impact on prices and generator values, and effects on generator contracting; and

- Section 5 provides a similar analysis of the likely effects of the expanded national RET scheme, including the interaction between these two policies.

A complete collection of references can be found at the end of this report.

2 Climate change policies

This section provides a brief outline of the key elements of the CPRS and expanded national RET scheme.

2.1 CARBON POLLUTION REDUCTION SCHEME

2.1.1 Objectives and key features

The CPRS is a form of ETS. The objective of the CPRS is to limit greenhouse gas emissions in a way that encourages the abatement of those emissions at least cost to society.

The CPRS aims to achieve emissions reductions at least-cost by:

- Capping greenhouse gas emissions through the allocation of permits to emit greenhouse gasses;
- Requiring emitters to buy permits to emit, and applying penalties in excess of the permit cost if emitters do not have sufficient permits; and
- Allowing participants to freely trade these permits between themselves.

For this reason, the CPRS is referred to as a 'cap-and-trade' scheme.

The CPRS is scheduled to commence in 2010 and is aimed at reducing Australia's emissions in the long term. The long-run emissions reduction pathway is achieved by progressively reducing the number of permits in circulation. At this stage, it is proposed that the CPRS will cut Australian emissions to 60 percent of 2000 levels by 2050.[1]

The Commonwealth Government has proposed that the CPRS will cover approximately 75 percent of Australia's emissions and will involve approximately 1000 firms, each of which emit more than 25,000 tonnes of carbon dioxide-equivalent (CO_2-e) pollution per year. The Government has proposed that the CPRS will include the six gases covered by the Kyoto Protocol (i.e. *carbon dioxide, methane, nitrous oxide, sulphur hexafluoride, hydrofluorocarbons, and perfluorocarbons)* and will include the following sectors:

- Stationary energy;
- Transport;
- Fugitive emissions;

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1 Australian Government (2008a), p.8.

- Industrial processes; and
- Waste.

Agriculture is proposed for inclusion from 2015, while forestry can opt-in and create offset permits, but will be liable for these offsets if they later reduce their stock of stored emissions.

At this stage, the Government has not released specific interim pollution reduction targets or forecast carbon prices. However, most estimates of potential for abatement by sector suggest that electricity and forestry will be heavily relied upon to deliver the required aggregate abatement (even with the potential for international imports), since the potential for abatement in other sectors is limited. Details of the Government's proposed CPRS can be found its July 2008 Green Paper.[2] The effects of a generic ETS are discussed below.

2.1.2 ETS and the determination of a carbon price

The operation of an ETS is expected to generate an implicit price for greenhouse gas emissions based on the prices at which permits trade in the market.

As with any commodity, the determination of a price for CO_2 is a function of the supply and demand for that commodity. In the present case, the commodity is the abatement of greenhouse gases. In the absence of an ETS, demand for abatement is zero and hence the price of permits is zero. The setting of an emissions cap creates scarcity – this creates demand for abatement – which in turn produces a positive price for CO_2 emissions. Ideally, this price should reflect the social (environmental) costs of emissions, referred to as the Marginal Social Benefit in Figure 1. In practice, this cost is impossible to estimate and is a function of global emissions, so demand for domestic abatement will reflect the difference between Business-as-Usual (BaU) emissions (without a carbon price) and the emissions cap imposed by the Government.

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2 Australian Government (2008a).

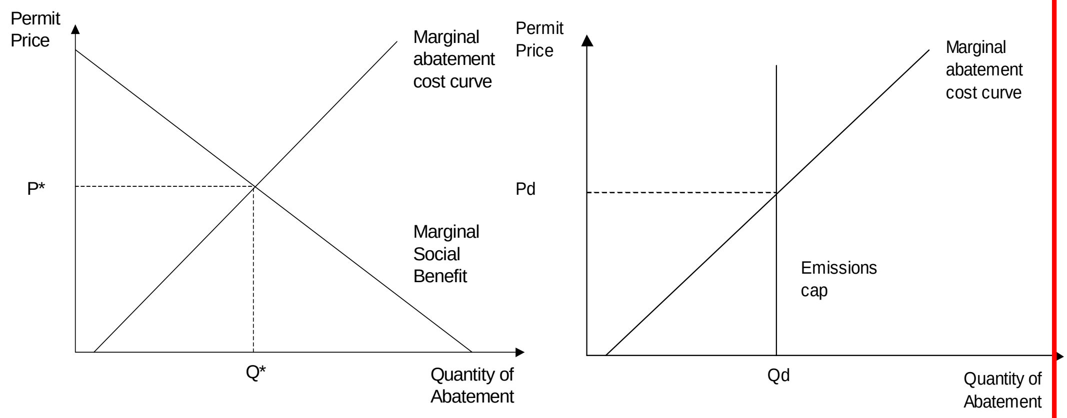

Figure 1: Stylised examples of the market for CO_2 abatement

Source: Frontier Economics

This cap is represented as a fixed vertical line in the right-hand chart in Figure 1. Demand for abatement will increase over time (shift right) as BaU emissions rise and the cap on total emissions declines.

The supply curve for abatement reflects the cost of different abatement options. For the electricity sector, options may include:

- Reducing the emissions intensity of output;
- Energy efficiency measures (to reduce output);
- Carbon sinks (e.g. reforestation); and
- International linkage, or "importing abatement" through the purchase of permits from other schemes.

This supply curve is typically referred to as the Marginal Abatement Cost Curve (MACC), which is upward sloped in Figure 1 to reflect the increasing cost per tonne of abated emissions. As long as the emissions cap is below BaU emissions, this will result in a positive carbon price, which will impose an additional cost of production on emissions-intensive goods.

International linkage

Linkages with other international schemes can act as a price cap, or even a price floor. If Australia is a price-taker in the market for emissions trading and unlimited bilateral trading is introduced, then the Australian price will achieve parity with the international price; the carbon price will be fixed similar to a carbon tax. If the international price is lower than Australia's domestic marginal cost of abatement, then Australia will buy international permits ("import" abatement) and reduce the level of domestic abatement until the domestic price falls to the international price level.

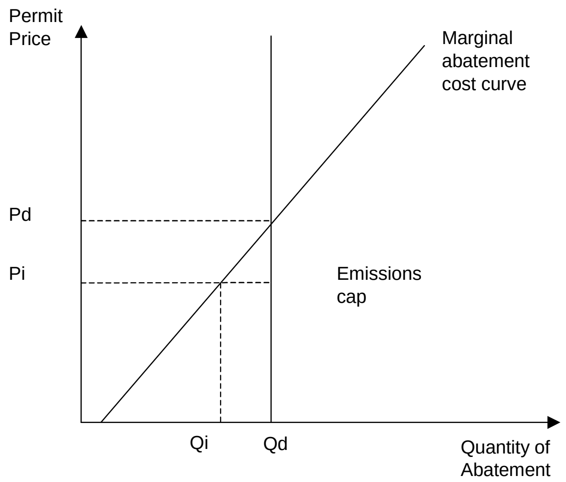

Figure 2: Stylized example of international linkage effect on supply and demand

Source: Frontier Economics

Figure 2 presents an example of Australia as a net importer of permits: the international price (Pi) is lower then the initial domestic price (Pd), so Australia will undertake domestic abatement up to the level of Qi, and will import the remainder (Qd-Qi), resulting in a domestic price equal to the international price (Pi). The converse is true if Australia's domestic marginal cost of abatement is lower than the international price. Australia may choose to restrict international trade, at least initially, since unrestricted bilateral trading may expose Australia to the risk of policy changes internationally (for example due to particularly onerous, or possibly lax, emissions targets elsewhere).

2.2 EXPANDED NATIONAL RET SCHEME

The Government's proposed expanded national RET scheme aims to consolidate and extend several State and Commonwealth-based renewable energy target schemes, both existing and proposed. These schemes are summarised in Table 3. A comparison of the targets is provided in Figure 3.

Existing renewable energy targets		
Jurisdiction	*Scheme*	*Comment*
National	MRET	Renewable target of 9,500 GWh by 2010 (until 2020).
Victoria	VRET	Renewable target in Victoria of 10% by 2016 – additional 3,274 GWh. Ramps down to 2030 (15 yr limit per project).
NSW	NRET[3]	Renewable target in NSW of 10% by 2010 (additional 1,317 GWh) and 15% by 2020 (additional 7,250GWh).
Proposed renewable/clean energy targets		
Jurisdiction	*Scheme*	*Comment*
South Australia	SARET	Renewable target of 20% by 2014 has been enacted, but no scheme is yet in place.
Western Australia	WARET	Climate change policy includes a renewable target of 15% by 2020, 20% by 2025.
Queensland	QLET	Climate change policy includes a renewable/low emissions target of 6% by 2015 and 10% by 2020.

Table 3: Summary of renewable/clean energy targets

Source: Frontier Economics

Broadly speaking, the expanded national RET scheme aims to ensure that at least 20 percent of Australia's electricity supply (approximately 60,000 GWh) is generated from renewable sources by 2020. This will involve extending renewable energy targets to 45,000 GWh, which, in addition to approximately 16,000 GWh of pre-MRET renewable generation, will achieve the scheme's target.[4]

3 The Renewable Energy (New South Wales) Bill 2007 has been introduced to Parliament, but the legislation is currently on hold pending the outcome of the expanded national RET design process.

4 This comprises primarily of output from Snowy and Hydro Tasmania plant.

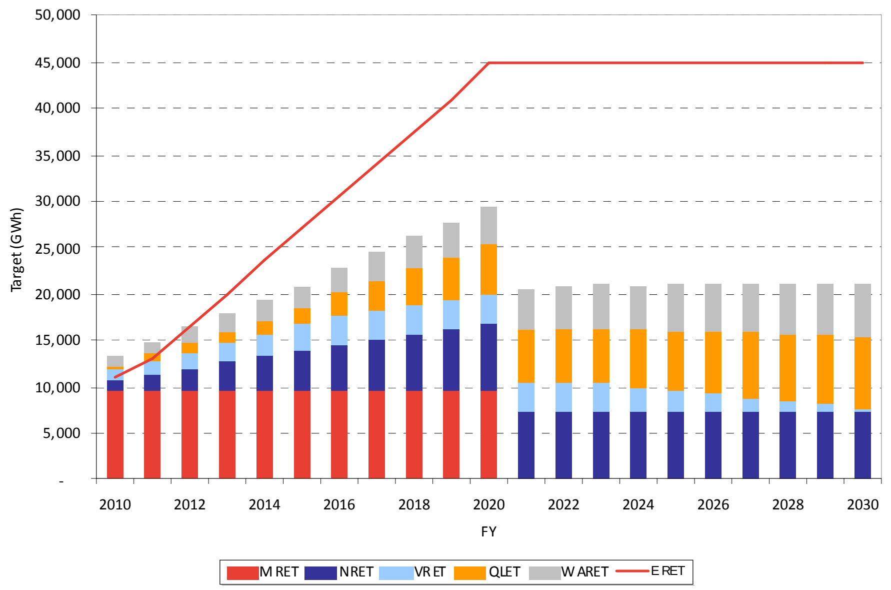

Figure 3: Summary of renewable energy targets

Source: Frontier Economics

The expanded national RET scheme creates a market for renewables-based generation using a mechanism of tradeable Renewable Energy Certificates (RECs). The demand for RECs is created by legally obliging parties who buy wholesale electricity (retailers and large users) to source an increasing percentage of their electricity purchases from renewables-based generation in the form of annual targets. The supply of RECs is created by allowing renewable generators to create certificates and sell them to liable parties. The price of RECs is set by the market at the point where demand equals supply.

The expanded national RET scheme is designed to increase the deployment of renewable energy in Australia's electricity supply in the short to medium term. The scheme will be phased out between 2020 and 2030, by which time it is expected that pricing signals emanating from the CPRS will be sufficient to encourage investment in renewable generation going forward. Details of the Government's proposed expanded national RET scheme can be found in its consultation paper.[5]

5 Australian Government (2008b).

3 Generator decision-making in the NEM

This section discusses the economic incentives faced by generators and investors in generation assets in the NEM. These incentives concern:

- Generator operational decisions – being decisions surrounding generator bidding in the spot market and contracting in the market for financial derivative instruments; and

- Generator investment decisions – being decisions surrounding the type, timing and location of new plant.

In describing these incentives, this section seeks to provide a framework for considering how the implementation of climate change policies might affect generator decision-making going forward.

3.1 GENERATOR BIDDING AND CONTRACTING

3.1.1 Dispatch in the NEM

Generators in the NEM are dispatched by the market and system operator, NEMMCO, each 5-minute dispatch interval using the NEM dispatch engine (NEMDE). NEMDE calculates the least-cost way of dispatching generation to meet load, based on the prices and quantities contained in the bids and offers submitted by participants, while remaining within the pre-defined security and reliability parameters of the power system as set out in the Rules. These parameters reflect thermal and stability limits on the transmission network, which are incorporated within 'constraint equations' in NEMDE. The application of constraint equations in NEMDE ensures that dispatch outcomes minimise costs subject to all applicable power system limits. The implications of network limits being reached and constraints 'binding' as a result are discussed in more detail in section 4.1.1 below.

To the extent generators are dispatched, they are settled on the basis of the 'regional reference price' (RRP) applicable to the NEM 'region' in which they are located (NSW, Queensland, Victoria, Tasmania and South Australia).[6] Therefore, a generator dispatched to 100 MW for one hour at a price of $40/MWh will receive $4,000 for that hour's output. These spot market revenues are an important source of revenue for generators in the NEM.

3.1.2 Contracting in the NEM

In addition to spot market revenues, generators in the NEM typically enter into financial derivative contracts in order to hedge their exposure to volatile spot

6 Ignoring adjustments for electrical losses.

prices and thereby smooth their future revenues. These contracts may take the form of swaps, caps or other varieties of risk management instruments. Further, as almost all electricity in the NEM must be traded through the spot market, hedge contracts are most often settled against wholesale spot prices. For example, swap contracts with a given 'strike price' ensure that even if prices turn out to be relatively low in the spot market, the generator will receive 'difference payments' from its counterparty such that overall, the generator receives the strike price on its output.

Generators' counterparties to derivative contracts are typically participants with a reverse exposure to NEM spot prices – namely, retailers and large industrial loads. These parties use derivative contracts to hedge the risk that spot prices will turn out to be relatively high.

3.1.3 Bidding in the NEM

In a highly competitive market and in the absence of binding transmission constraints (see below), generators will have incentives to bid at their opportunity cost (also referred to as their short-run marginal cost or SRMC). This is because bidding at SRMC will ensure, through the dispatch price, that:

- If the spot price is above their opportunity cost of generation, they will be dispatched and earn a price that provides a return over variable costs (also known as 'intra-marginal rents');

- If the spot price is below their opportunity cost of generation, they will not be dispatched and at least make no variable loss on their output.

However, to the extent that generators have the ability to bid in such a way as to affect the spot prices they receive, they may have incentives to withhold output in the short term in order to boost spot prices and profits.

Such 'strategic bidding' can be profitable in the NEM primarily because of the low short-term elasticity of demand of electricity. This means that during tight demand-supply conditions, a relatively small reduction in supply by one generator can lead to spot prices rising to many multiples of typical prices. Thus, the loss in potential inter-marginal rents on output foregone due to the withholding strategy is more than made up for by very high intra-marginal rents on the (remaining) dispatched output. Having said that, generators cannot definitely know in advance whether their bidding strategies will be profitable. This is because they cannot precisely predict the level of demand or the bidding behaviour of other generators in any given future 5-minute dispatch interval.

Another key factor influencing the extent to which generators will have incentives to engage in strategic bidding is the proportion of their capacity in respect of which they have entered into hedging contracts. For example, other things being equal, in a static, risk averse world, a generator that has entered a swap contract will have incentives to bid its swap quantity into the market at its SRMC, even if it has the ability to withhold output and raise spot prices. This is because even if the generator can successfully drive up the spot price through its bidding behaviour, it will just have to make larger difference payments to its counterparty to ensure that the effective price for electricity paid by the counterparty is the swap strike price. For this reason, many policy makers and competition regulators take comfort in generators having a high level of contract cover. Nevertheless, generators with high contract positions may still have longer-term incentives to engage in strategic bidding if, by doing so, they can influence the prices at which future contracts are struck. This would be particularly the case where these generators are not risk averse. In this case the world with and without contracts are likely to be broadly similar.

3.2 GENERATION INVESTMENT IN THE NEM

Outlined below is a broad overview of existing generation capacity in the NEM. This status quo mix of generation technology is contrasted with the new investment environment that generators will face as a result of the both the CPRS and expanded national RET, in sections 4.2 and 5.3.

According to NEMMCO, total installed capacity in the NEM in 2010 is expected to be 47,174 MW[7]. A breakdown of this expected capacity by generation technology is illustrated in Figure 4. Installed capacity in the NEM is dominated by coal-fired generation (28,317 MW), followed by gas-fired generation (10,300 MW), hydro generation (7,000 MW) and finally wind generation (1,557 MW).

7 NEMMCO (2008). Due to short-term planned outages, expected capacity in 2010 is used rather than 2009 to provide a more accurate estimates of actual installed generation. Some plant included in this estimate have yet to be commissioned, but are expected to be operation by 2010. Oil-fired generation has been included as gas-fired generation.

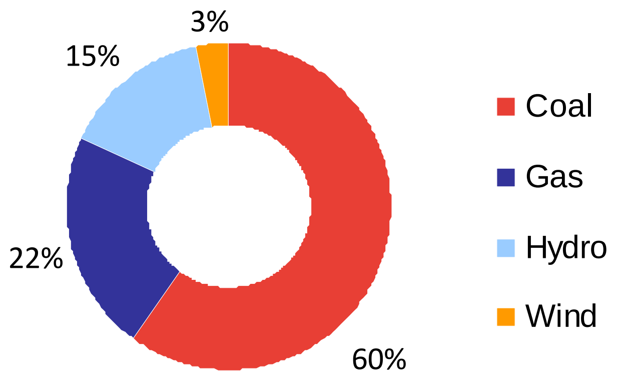

Figure 4: Breakdown of 2010 NEM installed capacity by technology

Data Source: NEMMCO (2008)

To illustrate the representative operating cost of installed generation across the NEM, the weighted-average[8] SRMC of both installed coal- and gas-fired generation in each NEM region for 2007/08 is summarised in Table 4. The SRMC of oil-fired generation has been omitted due to its very low utilisation, which was approximately 0.02% of primary energy used in generation in the NEM in 2005/06[9].

Fuel	**Weighted-average SRMC by region ($/MWh)**				
	QLD	*NSW*	*VIC*	*SA*	*TAS*
Coal	$11.73	$14.39	$2.80	$18.86	-
Gas	$36.74	$31.15	$46.14	$44.37	$59.45

Table 4: Weighted-average SRMC by region, 2007/08

Data Sources: ACIL (2007), NEMMCO (2008)

To provide a contextual background for discussions regarding investment issues considered in sections 4 and 5, the expected 2010 installed capacity of 47,174

8 Costs have been weighted according to installed capacity in each region.

9 ACIL Tasman (2007), p.87.

MW noted above has been broken down by both NEM region and generation technology in Figure 5.

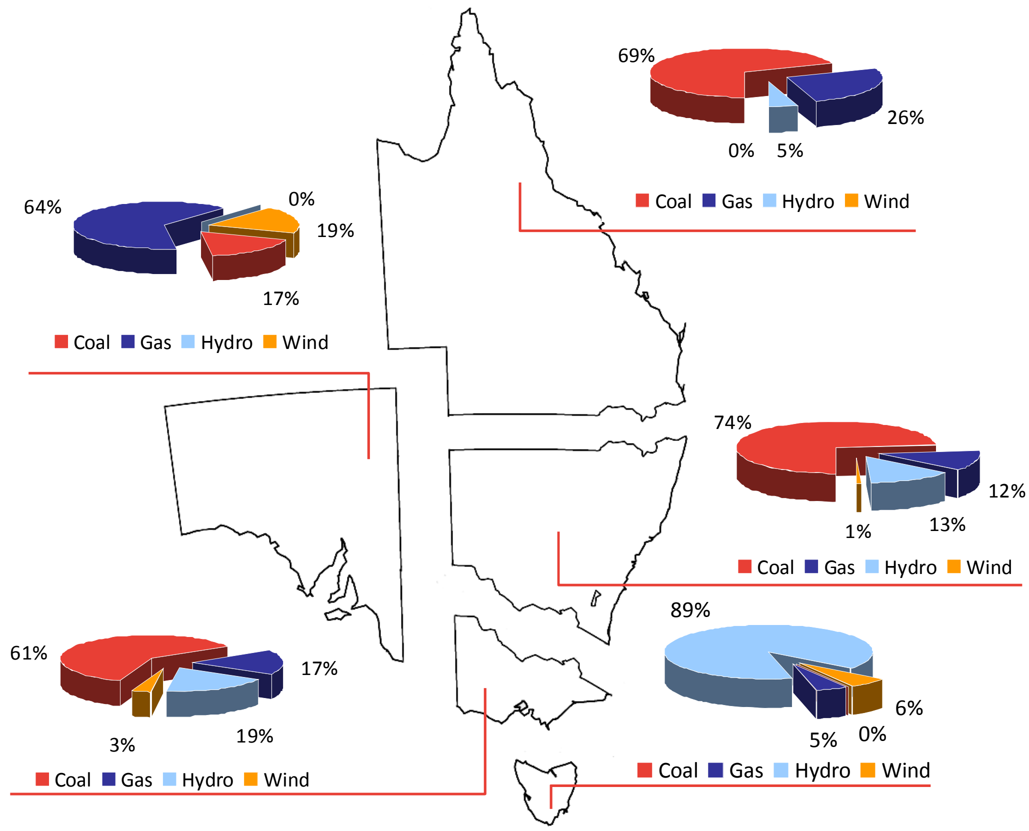

Figure 5: Expected 2010 installed capacity by region and technology

Data Source: NEMMCO (2008)

It is evident from this analysis that:

- Queensland, New South Wales and Victoria have the highest proportion of installed coal-fired generation in the NEM;
- Over 95% of Tasmania's installed generation capacity is zero-emission; and
- South Australia currently has the highest proportion of installed wind capacity in the NEM, at 19.1% of total installed capacity.

Given the preponderance of high emitting generators in certain regions and low emitters in others, this could give rise to substantial shifts in where power is being generated relative to the location of users. This could create unforeseen pressure on the existing high voltage grid, which in turn could have important consequences for prices and power system security and reliability, in the absence of appropriate network augmentations. The locational consequences of new generation investment as a result of both the CPRS and expanded national RET scheme are further considered in sections 4 and 5.

4 Effects of the CPRS

The CPRS is likely to have a variety of impacts on generator operational and investment decisions. As investment decisions and outcomes can feed back into generators' (subsequent) operational decisions, discussing operational and investment impacts discretely would lead to an artificially partial assessment of the CPRS impacts. Therefore, the discussion in this section makes a key point of distinction between:

- Short-run impacts of the CRPS on generator decision-making – which will primarily but not wholly comprise operational decisions; and
- Long-run impacts of the CPRS on generator decision-making – which will focus on investment decisions, but also consider how changing patterns of investment may influence future bidding and contracting behaviour.

4.1 SHORT-RUN EFFECTS

In the short-run, generators will experience different increases in costs according to their relative emissions intensity. This will result in a change in operation, with a general trend of reduced output from coal generators and an increase in output from gas generators in the short to medium term. In the extreme, this may include the early retirement of existing high emission plants.

The short-run impacts of the CPRS on generator operational decisions is discussed in the following manner:

- Bidding and dispatch under price-taking conditions – assuming perfect competition and the absence of any transmission constraints;
- Prices and cost pass-through – a range of factors will limit the ability of generators to pass-through higher costs in prices. This discussion also considers the implications of generator market power for the extent of cost pass-through;
- Generator values and credit market implications – this will depend on the method of permit allocation and the ability to pass-through higher costs to retailers and end-consumers. While the effect on prices is generally determined by the market, generators will experience different increases in costs. By policy design, this should be favourable for low-emission generators but unfavourable for most emissions-intensive generators;
- Contracting levels and permit allocation design – this will depend on the liquidity of the forward market for carbon. A full auction of permits may result in lower levels of forward contracting, as generators will be more exposed to the risk of higher carbon prices; and
- Counterparty effects.

4.1.1 Bidding and dispatch under price-taking conditions

Impacts on generator bidding

As discussed in section 3.1.3, generators will often have incentives to offer their capacity into the spot market at their opportunity cost or SRMC. In the present context, a generator's SRMC will include the cost of its carbon emissions, as derived from the product of permit prices and the emissions intensity of the generator's output.

Carbon costs are added to a generator's SRMC regardless of whether it procures permits through an auction or a grandfathered allocation.[10] More specifically, if generators have to purchase permits, the costs will be included in their bidding decisions as with any other variable cost. Equally, if generators receive grandfathered permits, there is an opportunity cost associated with the use of those permits (as opposed to selling them). By way of a simple analogy, a house that is inherited has the same value as a house that is purchased, irrespective of how it was initially acquired. The main difference will lie in wealth distribution effects, which are discussed in section 4.1.3.

One exception to this opportunity cost principle is where permit allocation is dependent on output, such as an Output Based Allocation (OBA, also known as Output Based Updating). Under an OBA of permits, if a generator does not produce output, it does not receive the baseline allocation of permits. This means it does not have the opportunity to sell unused permits, so the opportunity cost of generating is lower.

To the extent that transmission constraints arise, generators may have incentives to bid away from their SRMC, even if they hold no market power at all. The implications of congestion for bidding and dispatch are discussed below. Further, to the extent that generators have transient market power, the impact of the CPRS on bidding and spot price outcomes may be different. This is discussed in section 4.1.2 below.

Impacts on dispatch

In the short-run, the mix of generation capacity in the electricity sector is relatively inflexible and the opportunities for abatement are limited to changing the operations of existing plant, such as running existing gas plant more often and coal plant less often (fuel-switching). As demand grows and existing plant is retired in the longer run, more opportunities arise to reduce emissions through investment in new lower emissions plant. These long-run effects are discussed in section 4.2. Existing plant may also be retired early and replaced with new low-

10 This was evident in Europe following the introduction of the EU ETS, where permits were largely grandfathered yet electricity prices increased. See Sijm et al (2005), Sijm et al (2006) and Reinaud (2007).

emission plant, but this would be a more costly option given that the capital cost of existing plant are sunk.

A simple example of the effect of the carbon costs on prices is presented below. The carbon cost will increase the costs of black coal and brown coal more than others plant types, as these are higher emitters. It will also increase the cost of gas plant, but by a lesser amount because gas emits less greenhouse gas then coal generators. In this highly stylised example, the supply curve for electricity can be represented by the "merit order" – plant is ordered by SRMC from lowest to highest, and the intersection of demand and supply determines the market price.

For the purpose of this example, four types of generating plant are considered, each with constant marginal costs over output. The corresponding merit order is represented in Figure 6. At this carbon price the change in costs is not sufficient to change the merit order, which means that there will be no reduction in the emissions intensity of supply. At the level of demand shown, black coal will be the marginal plant that sets wholesale electricity prices before and after the CPRS. The change in price in this example is a function of the carbon cost of black coal plant, though this is discussed in detail in section 4.1.2.

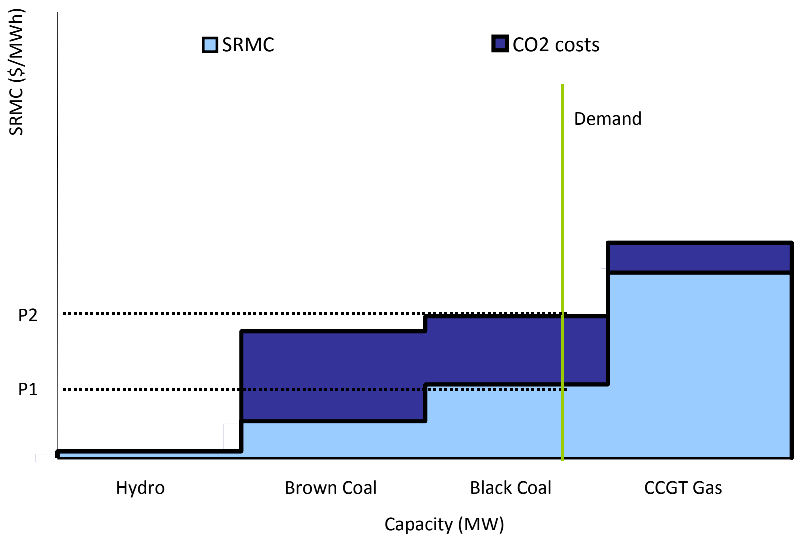

Figure 6: Stylised example of carbon costs: no change in merit order

Source: Frontier Economics

In order to achieve abatement, the carbon price must rise to a level that encourages a change in the merit order and hence a reduction in the emissions intensity of the market[11]. In Figure 7, the higher carbon price is sufficient to change the merit order and achieve abatement. In this simple example, CCGT becomes the marginal plant and the wholesale price increases by more than in the

11 Even if the international market sets the carbon price and the electricity sector is a price taker, most estimates suggest that the carbon price will encourage changes in the merit order.

previous case. Gas plant displaces the brown coal generator in the merit order, which results in a reduction in emissions. The market supply curve moves upwards, and in this instance has also flattened since lower cost generators tend to be more emissions intensive and experience a greater increase in costs.

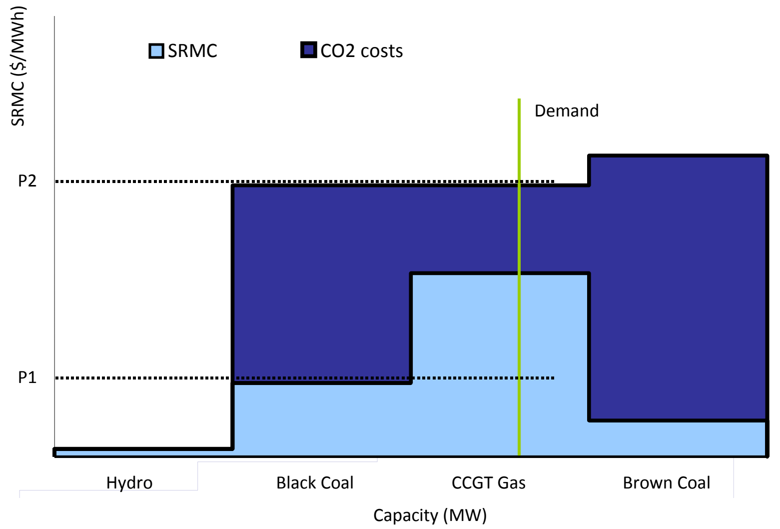

Figure 7: Stylised example of carbon costs: with change in merit order

Source: Frontier Economics

Fuel price interaction

Fuel-switching is an important abatement option in the electricity sector in the near term. Fuel switching refers to either increasing output from existing gas plant (displacing output from existing coal) or potentially increased investment in new gas plant.[12] Given the importance of fuel-switching, in the short-term the price of permits can be expected to be correlated to the difference in cost between coal and gas plant, which is otherwise known as the Spark-Dark Spread.[13] To induce the necessary abatement from this sector, permit prices will rise to the point where sufficient abatement becomes viable. It is possible that the increased output from gas plants may lead to higher gas prices. However, if gas prices increase (and the Spark-Dark spread is wider) then permit prices would need to increase to achieve the same level of abatement. The correlation between the two will also depend on the extent of abatement options in other sectors,

12 It is not intended to suggest that existing coal-fired generators will be able to run on gas as a result of *operational* changes to existing plant.

13 The Dark Spread represents gross margins on coal plant, or the difference between the price of electricity and the variable cost of coal generation. The Spark Spread represents the gross margins on gas plant, or the difference between the price of electricity and the variable cost of gas generation. Hence the Spark-Dark spread represents the difference between the variable costs of each.

which may set the carbon price. However, most studies estimate that electricity will provide the most significant source of abatement.[14]

Transmission constraints and generator bidding

The impacts of the CPRS on generators' and their counterparties' operational decisions are likely to be influenced by the management of network congestion.

Bidding and transmission constraints

It is necessary to understand how bidding is affected by transmission constraints in the NEM to appreciate the effects of the CPRS on bidding in the future. This section very briefly describes the current arrangements.

When least-cost dispatch results in constraint equations binding, the result is transmission 'congestion'. This implies that the marginal value of electricity (known as the 'local' or 'shadow' nodal price) varies throughout the network by more than is accounted for by electrical losses. However, while the dispatch process in the NEM takes account of the differing marginal values of electricity generated at each location in the network to determine which plant should be dispatched in order to minimise the overall costs of serving load, settlement is based on prices that are uniform (though loss-adjusted) throughout each NEM 'region'. Such RRPs are based on the marginal value of electricity at a certain location within the region known as the 'regional reference node' (RRN). This means that in the presence of congestion, the price at which participants who are not at the RRN are settled may diverge from their local nodal price, being the value of electricity they produce or consume at their location.

Where such a mismatch between dispatch and settlement prices occurs, generators bidding competitively at their SRMCs can be:

- Dispatched even though their SRMC and local nodal price is above the RRP – this is referred to as being 'constrained-on'; and

- Not dispatched even though their SRMC and local nodal price is below the RRP – this is referred to as being 'constrained-off'.

Under these conditions, even price-taking generators may have incentives to bid at prices that do not reflect their underlying resource costs. For example:

- A constrained-off generator may have incentives to bid below its SRMC in order to get dispatched and receive a RRP that is greater than the value of electricity produced at its location; and

[14] See McKinsey & Company (2008), Burge and MacAlpine (2007) and Nous (2007).

- A constrained-on generator may have incentives to bid well above its SRMC to avoid being dispatched and receiving a RRP on its output that is less than its SRMC.

The effect of such 'disorderly' bidding can be to distort dispatch and produce outcomes that are not actually cost-minimising given the network limitations.

Effect of CPRS on generator bidding and dispatch

As noted above, by altering generators' variable costs of production, the CPRS will tend to alter the pattern of dispatch away from high-emission plant in favour of low-emission plant. This shift in dispatch is likely to change the direction and volume of various power flows in the NEM, which, in turn, is likely to alter the nature, frequency and duration of binding transmission constraints. This may feedback into generators' bidding and contracting incentives.

While it is difficult to predict the precise nature of changes to dispatch, flows and constraints that are likely to emerge from the introduction of the CPRS in the absence of modelling (and even then any predictions must be extremely tentative), it is possible to make a number of analytical generalisations.

An important observation to note it that high emission plant, such as coal-fired steam turbine plant, tend to be located further from electricity load centres and closer to fuel sources than low-emission plant. This is because, unlike lower-emission generation fuels such as gas, coal has few domestic or commercial uses. Therefore, it has not been necessary to develop infrastructure for the transportation of coal from mines to major load centres. In addition, due to coal being heavy and bulky, it is cheaper to transport power than coal.

By contrast, gas is often used for domestic heating and a range of industrial applications. To accommodate these uses, pipelines have been specifically developed to bring gas to major cities and towns. The more decentralised availability of gas means that gas-fired generators have tended to either co-locate with industrial loads (thereby minimising reliance on the transmission network to sell their output) or in parts of the network that have historically experienced fewer constraints and where they are most likely to avoid being constrained-off. To the extent that low-emissions plant are located in areas that experience fewer constraints than high-emission plant, intuition suggests that the introduction of the CPRS may lead to fewer constraints binding, and/or constraints binding for shorter periods of time.

Due to the complex nature of flows through power systems, however, it is possible that such locational changes may lead to increased congestion at other points in the network. Discussed below is an example of how decentralised gas-fired generation may alleviate a traditional 'city gate' transmission constraint. Specific examples of potentially increased congestion due to changes in generation mix and location, however, are difficult to identify without the aid of quantitative modelling. The impact of locational shifts in renewable generation on the transmission network is further discussed in section 5.3.2 with respect to the expanded national RET scheme.

The potential relieving effect of gas-fired plant located close to load centres (and hence on the 'nearside' of transmission constraints) is demonstrated in Victoria, where gas-fired plant located in inner-west and -north Melbourne can alleviate a significant transmission constraint at South Morang during peak times. The South Morang F2 transformer constraint has historically been one of the more frequently binding constraints in the NEM[15]. When this constraint binds, generators in Victoria (especially in the Latrobe Valley) can find themselves being constrained-off. This can result in mis-pricing at virtually all connection points in Victoria, and can encourage Latrobe Valley generators to bid in a disorderly manner (as low as -$1,000/MW) in order to be dispatched. Several gas-fired plant on the nearside of the South Morang constraint can alleviate congestion resulting from imports from Snowy and/or the Latrobe Valley. These plant include Newport and Laverton[16] and Somerton[17].

As noted by Powercor, the extent to which such generation can alleviate the South Morang constraint depends on their level of dispatch. These generators operate peaking plant, and hence are only dispatched a few hours each year during extremely high demand periods. While the dispatch patterns of these specific plant is unlikely to materially change *ex post* the CPRS introduction, their location on the nearside of 'city-gate' constraints, and their ability to alleviate such congestion when dispatched, highlights the potential role that decentralized gas-fired generation could play in alleviating traditional constraints. Should mid-merit gas-fired plant located close to load-centres become increasingly more common under the CPRS, historically binding 'city gate' constraints could be somewhat alleviated.

If the CPRS leads to fewer constraints binding going forward, this could have several beneficial secondary effects that may help offset the primary cost and price implications of the CPRS:

- More competitive bidding (i.e. bidding closer to SRMC) as the reduction in constraints limits the ability of unconstrained plant to engage in withholding strategies to increase spot prices and spot market revenues;

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15 We note that VENCorp has recently announced a funded augmentation of the South Morang Terminal Station 220 kV connection, due for completion in early 2009. The extent to which this constraint will continue to bind *ex post* augmentation is unclear. See: http://www.vencorp.com.au/index.php?action=filemanager&pageID=7767&sectionID=7766&searchstring=morang&search.x=0&search.y=0&search=search&search=search

16 http://www.aemc.gov.au/pdfs/reviews/Split%20Snowy%20Region/submissions%201/000Snowy%20Hydro%20Supplementary%20Submission%20-%2027%20March%202007.pdf

17 http://www.powercor.com.au/docs/pdf/Electricity%20Networks/Powercor%20Network/TCPR/__SMTS %2066.pdf

- Fewer incentives for constrained plant to engage in disorderly bidding in response to being constrained-on or -off. This could promote more efficient dispatch; and

- As a result of the above effects, generators may have stronger incentives to enter hedge contracts, which will reinforce their incentives to bid at prices aligned to their SRMCs.

All of this means that although the CPRS will undoubtedly increase the (monetary) wholesale costs of producing electricity to supply loads, some of the effect may be blunted by a less constrained network and more cost-reflective bidding behaviour.

It is also worth noting that the CPRS may affect the binding of traditional constraints (both positively and negatively) involving inter-regional flows for the same reason that it may impact the binding of constraints more generally. For example, greater dispatch of gas-fired plant in South Australia could, on the margin, reduce the incidence of constraints on the Victoria-South Australia interconnector at peak summer times. Conversely, the increased dispatch of gas-fired generation relative to coal-fired generation may result in dispatch patterns that adversely affect interregional flows and constraints at other points on the network.

Closely related to the issue of congestion and interregional flows is the potential impact that the CPRS may have on the reliability (or 'firmness') of inter-regional settlement residue (IRSR) units. To the extent that the CPRS reduces the incidence of congestion that leads to;

- differences in RRPs between regions, even though flows on interconnectors between regions are below their notional limits; and/or

- counter-price flows between regions, which results in NEMMCO clamping interconnectors to prevent the accumulation of negative settlement residues;

then the firmness of IRSRs may increase. Firmer IRSRs could encourage greater inter-regional contracting, which may facilitate greater choice of counter-parties for electricity retailers in the NEM. As noted above, however, the converse is also possible – the CPRS may lead to an increased incidence of constraints causing RRP divergences, and/or increased incidences of counter-price flows between regions, and thus the firmness of IRSR units may deteriorate. Sound *a priori* judgements cannot be made in this regard – in order to make tentative statements regarding the incidence of congestion and flows *ex post* the CPRS introduction, quantitative modelling would be required.

4.1.2 Prices and cost pass-through

The previous sub-section discusses factors affecting generator bidding and dispatch in the presence of an ETS under price-taking conditions. This sub-section discusses the factors that determine how much of the carbon cost is passed-through to electricity prices, and what this means for generator margins. Relevant factors include:

- Emissions intensity of the marginal plant;
- Demand elasticity; and
- Strategic bidding and market structure.

Emissions intensity of the marginal plant

As discussed above, the wholesale electricity price depends on demand and the bid of the marginal generator. In Figure 8, demand is higher than the previous example and CCGT plant is the marginal plant that sets the price. In a perfectly competitive market this should equal marginal cost. The producer surplus (grey) represents the gross margin for all generators, which is the difference between price and marginal costs. These gross margins must be positive if a generator is to recover fixed capital costs.

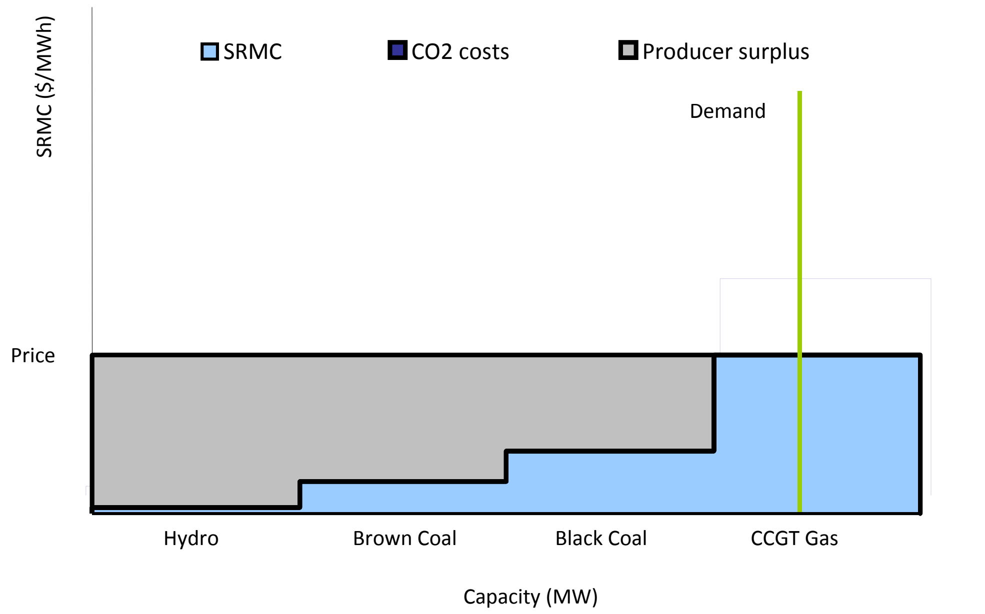

Figure 8: Merit order without an ETS

Source: Frontier Economics

When an ETS is introduced, generators will add the carbon cost to their bids. However, the change in wholesale price depends on (a) the carbon price and (b) the emissions intensity of the marginal plant before and after the cost of carbon is introduced. Figure 9 presents the situation where the merit order is unchanged by the carbon price – gas remains the marginal generator and so the emissions intensity of the gas plant will determine the change in wholesale price (P_2-P_1).

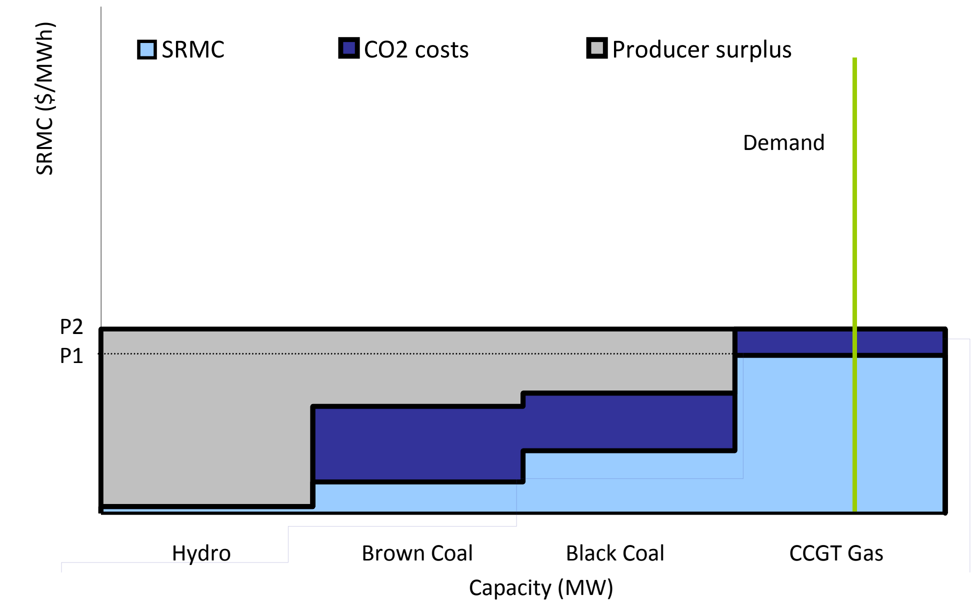

Figure 9 Merit order with an ETS (Low carbon price)

Source: Frontier Economics

Although the change in price is the same for all generators, the change in cost is different for each generator according to their emissions intensity. Gas is able to pass-through its carbon cost. Black Coal and Brown Coal will experience a higher increase in costs, and their gross margins are reduced.

At a higher carbon price the merit order changes and the emissions intensity of the market is reduced, as in Figure 10. Estimating cost pass-through in this instance is more difficult since the marginal plant changes when the ETS is introduced. In this instance, the change in price is P_2-P_1, or the difference between the marginal cost of CCGT *without* an ETS and the marginal cost of Brown Coal *with* an ETS. This is still less than the full carbon cost of brown coal plant, which was previously receiving a price above its SRMC. In this case, gross margins for high emissions plant will still be reduced, which will constrain their ability to recover their capital costs. However, so long as gross margins are positive they should continue to operate. Existing Hydro plant earn higher gross margins since prices increase but costs do not.

It is also worth noting that in these simple examples, when demand is high and gas is the marginal plant prior to the introduction of the CPRS (as in Figure 9) the level of cost pass-through is lower than at times of low demand when black coal is the marginal plant prior to the introduction of the CPRS (as in Figure 6 and Figure 7). This suggests that levels of cost pass-through will differ depending on peak and off-peak periods.

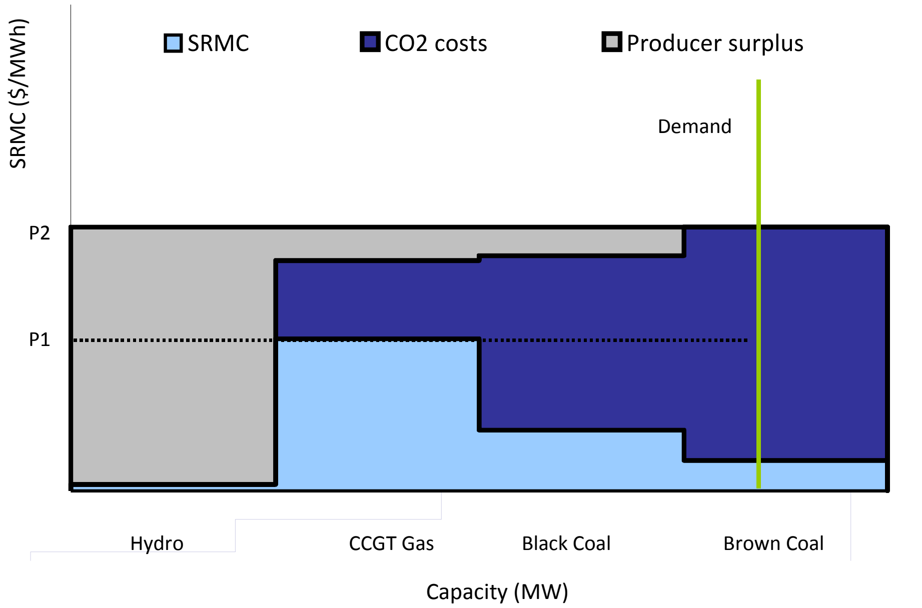

Figure 10: Merit order with an ETS (High carbon price)

Source: Frontier Economics

Demand elasticity

Elasticity of demand also affects the ability of generators to pass-through carbon costs. As illustrated in Figure 11, when demand is perfectly inelastic the marginal generator is able to pass-through the full cost of carbon – as in the previous section. If demand falls in response to higher prices, the fall in demand will limit the ability of generators to add on the full increase in carbon cost because there is a change in the marginal generator.

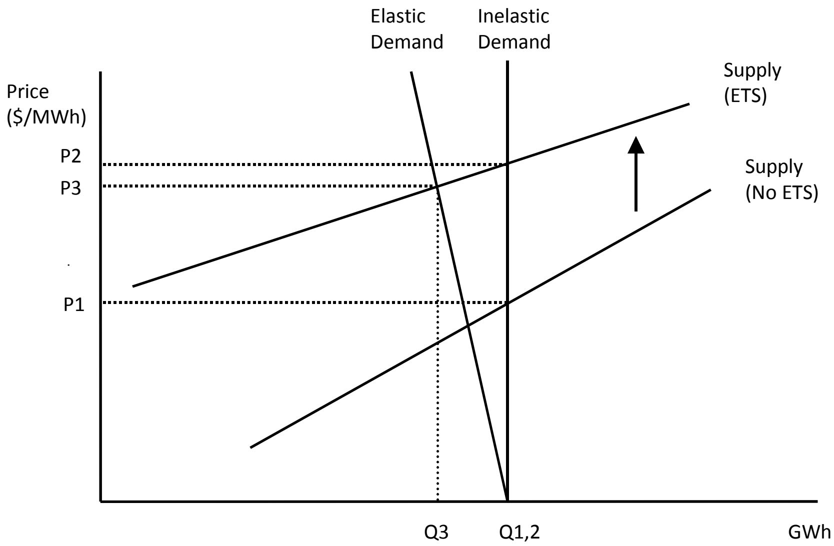

Figure 11: Illustrative change in electricity supply curve

Source: Frontier Economics

Given that electricity demand is relatively inelastic in the short-term it is more likely that future demand growth will slow rather than fall significantly, however the elasticity assumption has important implications for modelling of prices and generator value effects.

Market power and strategic bidding

In general, full pass-through of an increase in marginal costs due to a carbon price is consistent with perfect competition. Under perfect competition, individual generators face perfectly elastic demand, hence price equals marginal cost and any change in costs is fully passed-through to consumers. This is demonstrated in Figure 7.

In the case of market power, generators will pass-through less than the full amount of any change in costs (assuming linear demand). Generators face less elastic demand, which allows them to profitably price above marginal cost before the introduction of the ETS. Hence it is not profit maximising behaviour for generators to pass-through the full amount of any cost increase or decrease, including the addition of a cost of carbon.

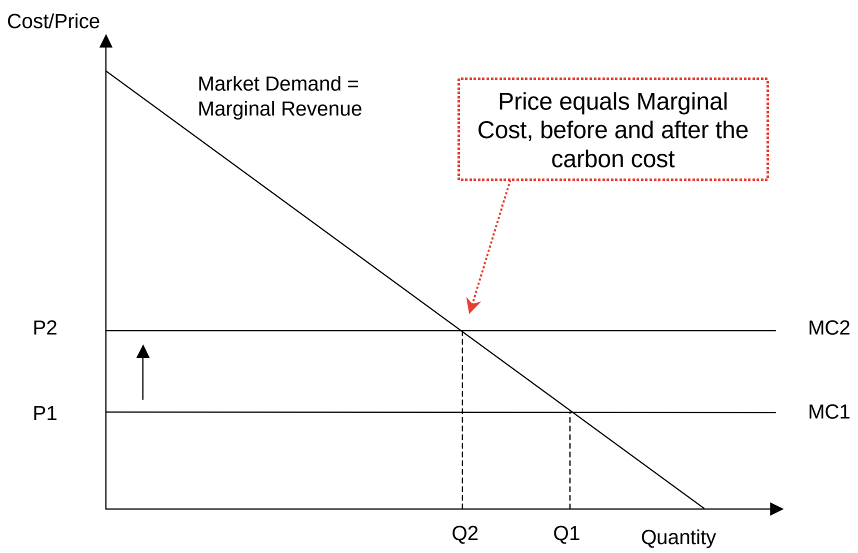

Figure 12: Pass-through with perfect competition

Source: Frontier Economics

It is worth noting that in instances of market power, the shape of the demand function is also relevant. Where demand is convex (i.e. constant elasticity of demand) it is profit maximising for generators to add on 100% (or more) of any change in costs. This is illustrated in Figure 13 and Figure 14. Hence the issue of individual generator pass-through is partly an empirical question. The key point is that higher carbon cost pass-through does not necessarily imply a less competitive market.

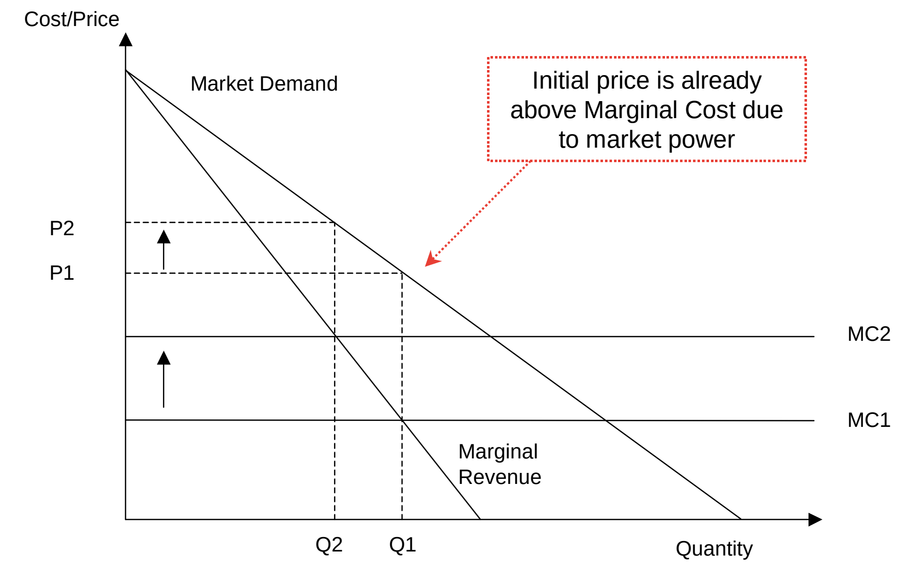

Figure 13: Pass-through with market power (linear demand)

Source: Frontier Economics

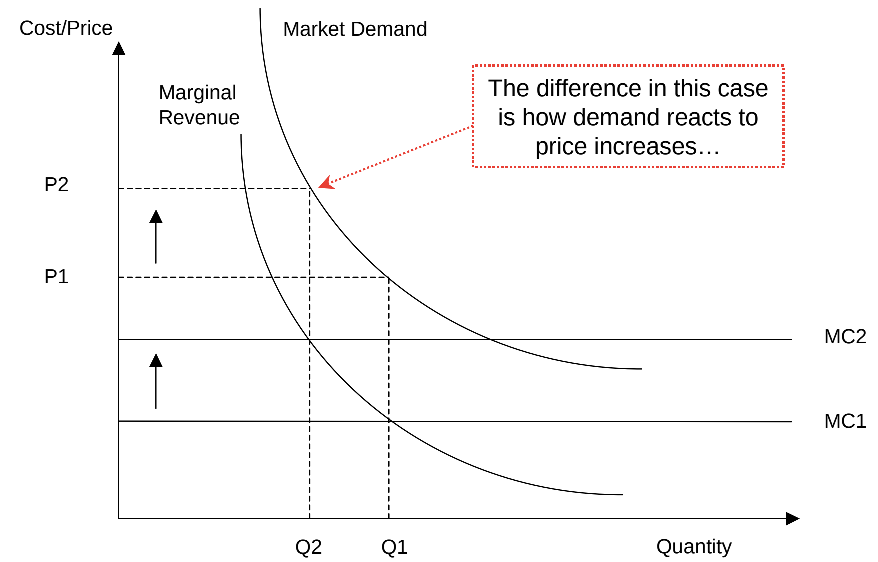

Figure 14: Pass-through with market power (convex demand)

Source: Frontier Economics

The introduction of a carbon price is also likely to flatten the merit order when high emissions plant such as coal is cheaper than low emissions plant such as gas. This may suggest that opportunities for strategic bidding behaviour are reduced if the differences in cost between different generation options are lower. However, there are countervailing factors that offset this. Firstly the introduction of an uncertain carbon price introduces another source of volatility into the electricity price. This was certainly the case in Europe following the introduction of the EU ETS, and this issue is discussed in relation to the contract market in Section 4.1.4. A second (and related) issue is that the higher uncertainty relating to carbon prices will most likely result in delays in investments in new capacity, and this tightening of the market will result in greater price volatility.

4.1.3 Generator values and credit market implications

The CPRS will affect the value of existing generation assets due to a margin effect and a quantity effect.

The ***Margin Effect*** reflects the difference between the increase in wholesale electricity prices and the increase in the generator's marginal cost (i.e. the emission intensity multiplied by the carbon price). The ***Quantity Effect*** reflects changes in generator's output levels driven by the scheme's encouragement of increased output from low emissions generation to supplant output from high emissions generation.

Generators will all receive the same increase in prices, but will experience differing increases in carbon costs to reflect their different emissions intensities.

For existing low-emission generators, higher prices should be sufficient to compensate for increased costs, so margins should increase, or at least be maintained. These plant will also likely increase output, since they become more competitive. This is the intent of the scheme. These factors should contribute to an increase in generator values.

For existing high-emission generators, the increase in prices will generally be insufficient to compensate these plant for their increased costs, and their gross margins should decline. Many will also experience a decrease in output in the long-term as carbon prices increase. This will be most pronounced for the most emissions intensive plant, such as thermally inefficient brown coal generators. These factors both point toward a reduction in generator values.

Permit allocations

The discussion above assumes that permits are auctioned, as proposed by the Government's Green Paper. If permits are granted to the generator for no consideration (i.e. grandfathered) the effects on market price will be the same as when the permits are purchased, due to the notion of opportunity-cost pricing. However, the grandfathered permits will represent a lump sum transfer in value designed to offset (some or all) losses resulting from the inability of generators to pass through all of the costs of acquiring permits. Grandfathered permits will offset, to some degree, the Margin Effects, since the grandfathered allocation represents a transfer in value equivalent to the size of the opportunity cost. Any pass-through of the opportunity cost of carbon permits represents a potential increase in margins. Roughly, if a black coal generator is able to pass-through around 60-70% of carbon costs into higher electricity prices (due to the factors above) then gross margins will still be reduced, but a grandfathered allocation of between 30-40% of required permits should approximately offset this. This ignores potential Quantity Effects. This rough estimate is relatively robust to different carbon prices – at a higher carbon price the reduction in margins is greater, but so is the value of the grandfathered allocation.

Credit market implications

Without some form of transitional compensation, generators have argued that write-downs of the accounting value of a large number of existing generation assets is likely.[18] This is entirely feasible given the discussion above.

To the extent they occur, such write-downs could have potentially severe implications for the financing and hedging strategies of participants, particularly for generators in the NEM. Large valuation write-downs may trigger provisions in financing arrangements that result in reductions in the size of permissible loans, the length of time for loans to be repaid, or the cost of servicing such loans post refinancing. Additionally, asset write-downs may trigger clauses in bilateral and hedge contract agreements due to credit downgrades, which in turn have the potential to lead to withheld payments under such agreements, exposing participants to spot market prices. This would likely lead to further defaults by other parties, due to the interrelated nature of hedging arrangements. In the extreme this default contagion posses a very real threat to the integrity and stability of the market. Even more importantly, this financial market instability could spillover into the financing of new power stations. This would make it very difficult to achieve the required abatement given that large emissions reductions can only be achieved by massive and ongoing investment in new technology.

In addition, the CPRS will also likely increase the prudential risks faced by participants, due mainly to higher and potentially more volatile wholesale electricity prices expected under the scheme[19]. The extent to which participants are able to absorb such increased risk will depend mainly on their existing financial position. Increased prudential risk presents a serious threat to the efficacy of the policy, since it is these businesses that the Government will be relying on to make the investments required to reduce aggregate emissions.

4.1.4 Contracting

The likely impacts on the contract market are complex, but largely revolve around who bears the risk introduced by the carbon price. Generators and retailers currently manage and hedge wholesale electricity price risk by entering into contracts (or potentially vertically integrating). This hedge is possible because when generators benefit from high electricity prices, retailers suffer (and

18 ESAA (2008), p.4.

19 Volatility of electricity prices is likely to increase due to volatility in the carbon price, which is readily observable in the early stages of the EU ETS (discussed in Reinaud (2007), p70).

conversely). The main source of external risk is currently due to fluctuating fuel prices. To counter this, many generators secure their own fuel supply or enter long term supply contracts. This security enables them to enter long term energy contracts of similar duration.

The introduction of a carbon price with full auctioning introduces another source of considerable uncertainty for generators and retailers. This is significant, since for many generators carbon prices will represent a larger variable cost than fuel purchases. There are two key problems confronting generators in this regard.

If generators are required to sign long term hedging contracts in the presence of the CPRS they must either:

- secure a matching quantity of emissions permits *ex ante* and include this cost in the price of the hedging contract sold to a buyer (in which case the buyer takes on the risk that the contract could be stranded); or

- take a risk that they will be able to secure a sufficient quantity of permits at a negotiated contract price that is reflected in the hedging contract (in which case the generator takes both price and quantity risk on acquiring permits); or

- include a permit cost pass-through clause in the hedging contract with the buyer (in which case the seller takes on the risk that they can't secure a sufficient quantity of contracts for the prevailing price, the buyer takes the risk they can't sell the energy they have purchased under contract for the prevailing price, or if the buyer has on-sold the energy to, say, a final customer, the final customer takes the risk that they are paying more than others in the market who may have contracted by one of the other methods described above).

While generators (and retailers) are used to functioning in a volatile market, what the CPRS does is introduce a major new cost the level of which is determined by regulation, which will inevitability be the subject of change over time. This introduces a new regulatory risk that is potentially material. Unfortunately, generators and retailers have little opportunity to manage this regulatory risk except to contract over shorter time frames. If generators respond in this way, this will mean that retailers will respond to this risk by shortening the duration of firm price contracts offered to final customers.

This risk is potentially more of an issue if permits are to be allocated via auctioning, since generators are fully exposed to the risk of higher carbon prices and the potential that they are unable to secure permits. This differs from the European experience where permits were almost entirely grandfathered in the EU ETS during Phase I (2005-2007) and Phase II (2008-12). In those instances, the allocation of permits provided something a natural hedge against the risk of higher carbon prices, and generators would arguably be more willing to enter forward contracts knowing that they are able to secure sufficient permits (rather than risk non-delivery). On the other hand, generators may be similarly averse to entering longer-term forward contracts due to the opportunity cost of committing to using permits that may be worth more if sold.

This shortening of the market can have some serious operational and investment consequences along the energy supply chain. For example, generators will find it more difficult to finance new power stations when they have less certainty about revenues in the medium and certainly in the longer term. On a closely related point, generators will be less prepared to enter into long term take-or-pay fuel supply deals since they could face greater stranding risk from changes in the CPRS rules (e.g. a change in the emissions target or the trajectory towards a target). This will increase the difficulty of financing new fuel sources and related infrastructure. Also, to the extent that final consumers cannot secure longer term energy supply contracts, this could compromise the viability of their businesses, particularly where these firms are competing with firms that do not face a similar business environment (i.e. firms who operate in jurisdictions without an ETS).

This less certain environment will be ultimately reflected in higher energy costs and consequently lower economic growth. Higher prices derive from the direct effect of carbon costs and the premium investors will want to justify making investments in a new, riskier environment. This premium will be attained by investors delaying investment decisions until prices are sufficiently high to yield a return that is reasonably expected to justify the investment. These delays in timeliness of investment could result in a degradation of supply reliability and security. To the extent that this results in breaches to reliability and security standards, this may result in more market interventions by NEMMCO to ensure maintenance of these standards. More regular market interventions by NEMMCO (or perhaps even jurisdictions) will heighten the perception of investment risk. This will exacerbate the risk to investors, which could in turn delay investments, which would cause reliability and security standards to deteriorate and so on.

Finally, another source of cost pressure will be from the costs of managing the prudential requirements of NEMMCO. These costs are directly related to the market price and the value of trade in the NEM. For the target being considered under the CPRS, the value of the wholesale market is likely to more than double in a very short period. This will mean the costs of participants' meeting their prudential obligations to NEMMCO will also double. While this represents a significant cost under any circumstances, in a world where the global finance system has collapsed, it is unclear whether some businesses will be able to secure the required funding. The costs of meeting these prudential requirements could present a material barrier to entry to new entrants, particularly retailers, where these costs are significant compared to margin revenue.

4.1.5 Organisational Structure

The incentive to vertically integrate retail and generation is driven by similar incentives to contracting, which is generally to hedge risk. As such, the discussions relating to the contract market are equally applicable. The current incentive to vertically integrate generation and retail functions arises, in part, due to the offsetting risks that these parties face with regarding to spot prices – generators 'gain' from high spot prices while retailers 'lose' and vice-versa.

As noted above, generators and retailers are not able to hedge against carbon price risk because they are both exposed to carbon price risk in the same direction – the potential counterparty in this situation with an offsetting exposure is the Government. This suggests that vertical integration is of limited use in hedging carbon price risk.

In this way, the CPRS introduces a form of risk that cannot be mitigated through vertical integration, since in effect the risk faced by both generators and retailers is a form of regulatory risk derived from the Government's long-term emissions reduction pathway. As such, the incentives to vertically integrate are not expected to increase as compared to the status quo *ex post* the introduction of the CPRS.

4.2 LONG-RUN EFFECTS

4.2.1 Generation plant type and technology

Introduction

The previous section dealt with the short-run implications of the CPRS for generators in the NEM. In the longer term, the CPRS will encourage increased investment in low emissions sources, including gas, carbon sequestration and renewables (depending on the emissions target and hence the carbon price). This will tend to result in a general flattening of the merit order due to changes in the relative costs of generation. This may have potential implications for strategic bidding behaviour.

Long-run abatement opportunities in the electricity sector may involve generation from gas, renewables, nuclear or with Carbon Capture and Storage (CCS) displacing higher emissions generation from coal. The cost per tonne of abatement is a function of the increased cost of low emissions generation and the resulting reduction in emissions.

A comparison of different new generation costs relative to emissions intensity is presented in Figure 15. The inverse of the slope in this diagram represents the approximate cost of abatement for *new* investment in the NEM – moving down the line represents a reduction in emissions intensity and an increase in long-run marginal cost (LRMC). This will change over time as technology develops, as emerging technologies become cheaper, and fuel prices change. In addition, the costs of capital (and hence LRMCs) are contingent on whether a plant operates as baseload or peaking plant. At higher gas prices, this curve becomes flatter – CCGT technologies would be shifted to the right due to higher LRMC, indicating an increase in the cost of abatement.

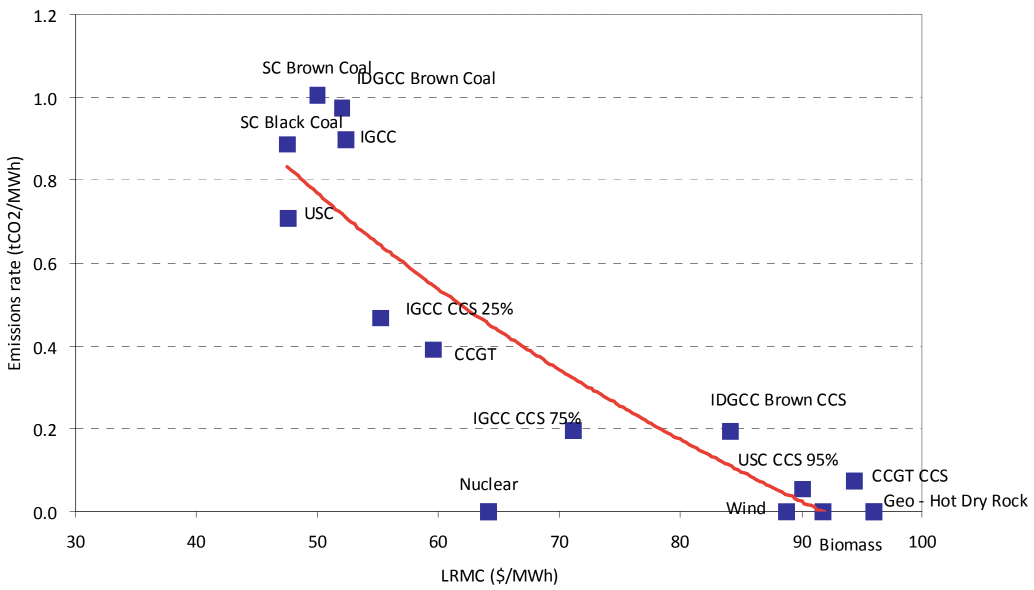

Figure 15: LRMC and emissions intensity trade-off

Source: Frontier Economics

Renewables such as wind and small hydro are also limited by site availability, since as more plant is built, the quality of new sites declines. For example, the annual capacity factors of new wind plant will be lower as more wind plant is built, reflecting an upward sloped supply curve for wind plant.

Any estimate of an abatement cost curve is also complicated by the fact that the choice of abatement is a function of both cost and quantity of abatement. While gas may provide the lowest cost abatement, for a given level of energy demand it doesn't provide as much abatement as zero emissions technologies such as CCS, nuclear or geothermal. This may lead investment preferences away from gas in the longer term, even if it is relatively cheaper per tonne abated.

Figure 16 presents a simple comparison of the relative LRMC of different technology options and how these costs change with carbon prices. This chart indicates the preferred lowest cost option for new investment only for a limited set of assumptions regarding capacity factors and fuel prices. However, it gives an indication of approximate carbon prices required to favour a particular technology. These indicators suggest that renewable generation investment in the short to medium term will be driven primarily by the expanded national RET scheme, and that gas plant will be favoured as a transition technology.

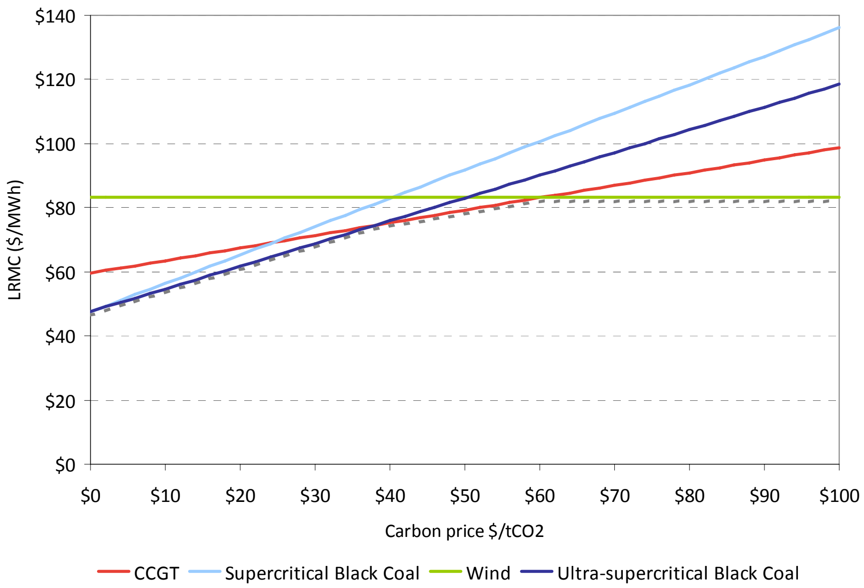

Figure 16: Carbon prices and generation costs

Source: Frontier Economics

Fuel-switching from coal to gas

In the short to medium term, CO_2 abatement in the electricity industry is likely to be dominated by fuel switching from coal to gas, since gas plant represents a relatively low cost abatement option. Gas-fired generation is attractive due to:

- The relative ease of gas transportation through a large network of transmission and distribution pipelines already delivering gas to commercial and industrial customers;
- The relatively low capital costs of gas-fired plant per kW of capacity compared with alternatives;
- The potential to invest in smaller increments of new capacity, since economics of scale are attained at a lower plant size; and
- The greater operational flexibility that gas-fired plant afford over coal-fired plant.

The latter factors provide greater flexibility and reduce the potential costs of stranded investments in an uncertain environment. This trend toward more flexible and less capital intensive plant is evident in Europe following the introduction of the EU ETS (see Reinaud (2007), p70).

Location of investment

While it is not possible to make sound *a priori* statements regarding the location of gas-fired generation as a result of the CPRS, several broad observations can be made by looking at the location of existing key gas and coal infrastructure in the NEM.

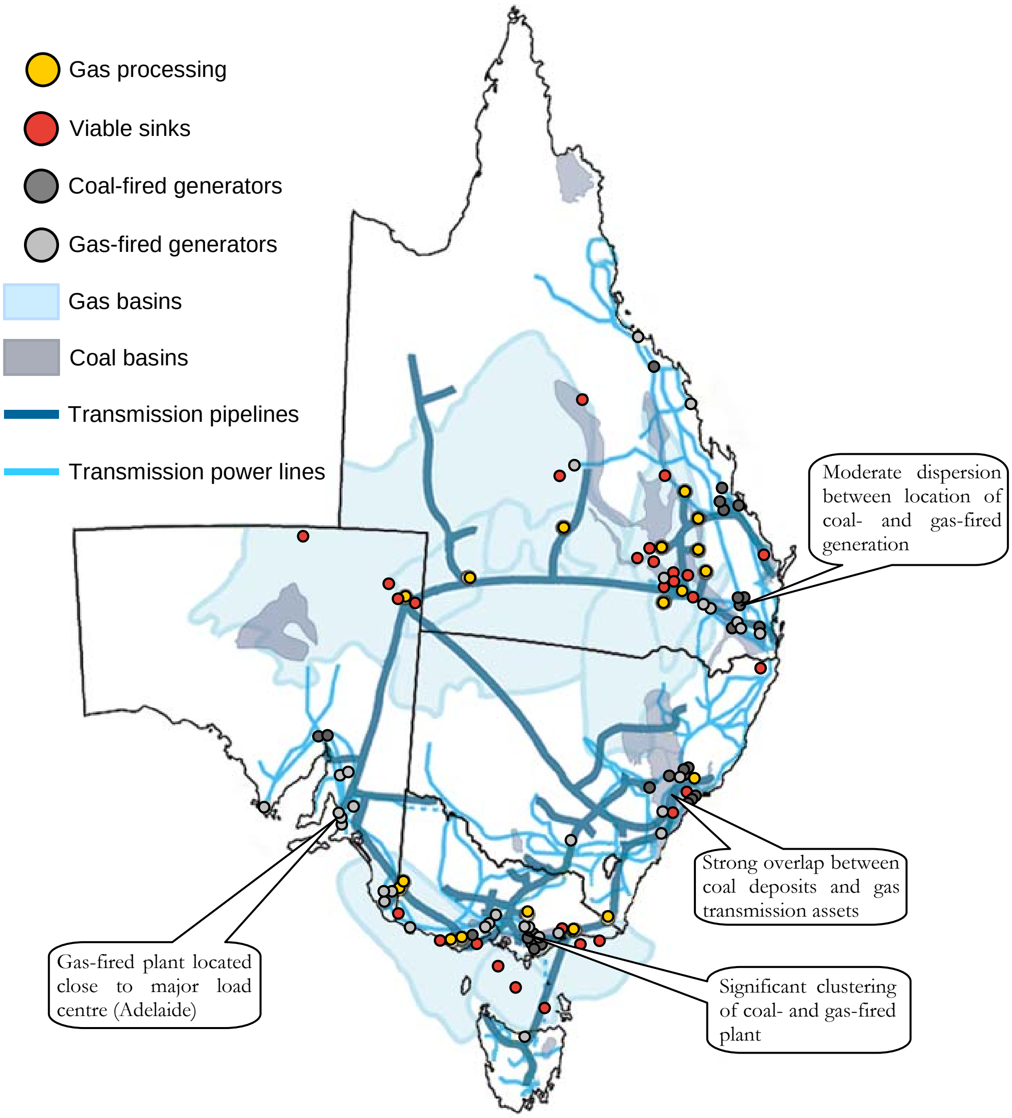

Figure 17: The NEM's key gas and electricity infrastructure

Source: ABARE (2008), AER (2008), Bradshaw (2002) and Frontier Economics

Figure 17 illustrates primary gas and coal infrastructure in the NEM – namely major gas basins, coal basins, gas processing plants, existing coal- and gas-fired generation and transmission power lines and pipelines.

Several observations can be drawn from this representation:

- There is a large locational overlap between coal and gas basins;
- Similarly, there is a large locational overlap between the gas and electricity transmission networks;
- As expected, coal-fired generators locate close to coal deposits, while gas-fired generators locate close to either gas transmission assets or basins;
- There is reasonably strong 'clustering' of coal- and gas-fired plant; and
- Generators located close to major load centres (region capital cities) tend to be gas-fired plant[20].

These observations indicate that, as a result of increased gas-fired generations *ex post* ETS introduction, the location of generation investment in the NEM is unlikely to change drastically. However, given the locational flexibility that gas-fired plant have as compared to coal-fired plant (coal-fired plant are locationally constrained to be at or relatively near coal deposits because of high transport costs), the location of generation investment as a result of the CPRS may change on the margin. This locational flexibility is demonstrated by the ability of gas-fired plant to locate closer to load centres than coal-fired plant. As noted in section 4.1.1, the extent to which this alleviates or aggravates existing transmission constraints will depend on (i) the nature and location of existing constraints and (ii) the nature and location of any new gas-fired generation.

<u>Timing of investment</u>

As with the location of investment, it is difficult to comment on the precise timing of when fuel-switching from coal to gas, due to changing investment patterns, will occur as a result of the CPRS. However, several broad observations can be made:

- Carbon prices of around \$30-60/tCO_2 should be sufficient to encourage more investment in gas rather than coal (at gas prices of \$3.50-\$4.00/GJ). This is indicative only based on limited assumptions;

[20] More specifically gas-fired 'peaking' plant, which tend to be OCGT rather than CCGT technology due to OCGT's lower capital costs.

- Generally, growth in demand will be the main driver of new investment. As discussed in Section 4.1.1, it would be more costly to replace existing plant early than to wait for plant retirements. An existing plant should not consider its sunk capital costs in its decision to run, so a higher carbon price is required before investment in a new plant with additional capital costs would be economic. If new plant is required due to demand growth then both plant options (e.g. coal or gas) would factor in their capital costs and a lower carbon price would be needed to change the investment decision in favour of gas. Since demand growth is somewhat stochastic, the timing and location of fuel-switching is difficult to predict; however

- Given their relatively high CO_2 emissions intensity, brown coal generators in Victoria (which emit 1.05-1.4tCO2/MWh) are expected to close earlier (i.e. at a lower carbon price) than the majority of black coal generators in New South Wales and Queensland (which emit approximately 0.8-1tCO2/MWh).

Zero-emission technologies

In the longer term, CCS, geothermal, wind and solar thermal are all zero-emissions technologies that are likely to play an increasingly important role in the NEM's generation portfolio. These technologies are all presently immature and are currently higher-cost alternatives – in the absence of the expanded national RET scheme, carbon prices in excess of $60/t CO_2 will be required before these technologies become viable in their own right. Given that investment in renewable generation (in particular wind) will largely be driven by the expanded national RET scheme in the short to medium term, investment in renewable technology is further discussed in section 5.

Location of investment

While coal to gas fuel-switching represents a cost-effective abatement option in the short to medium term, even 100% fuel switching can, at most, reduce emissions output by roughly half[21]. In order to meet increasingly tough emissions targets, even lower- (or zero-) emissions technology will be required. Going forward, CCS and geothermal technologies will become increasingly important sources of zero-emission baseload generation. In our view, it is highly doubtful that either of these technologies will be commercially proven and viable on a large scale before 2020.

While traditionally the choice facing a gas-fired plant as to where to locate was primarily a function of the location of gas and electricity transmission assets, CCS introduces an additional variable into this decision: the location of carbon 'sinks', or points at which captured CO_2 can be injected underground. Thus the choice of location for gas-fired CCS plant must take into account:

21 This assumes a switching from 100% coal to 100% gas, and emissions intensity's for coal and gas of 1.0 tCO_2/MWh and 0.5 tCO_2/MWh respectively.

- the viability and cost of connecting to gas sources (via transmission pipelines or direct location at gas basins);
- the viability and cost of connecting to electricity transmission assets (via connection to existing assets or the provision of new assets); and
- the viability and cost of delivering captured CO_2 to sink sources (via pipelines or direct location at sinks).

In addition to illustrating the NEM's primary gas and electricity infrastructure, Figure 17 also outlines viable CCS sink locations, as discussed in Bradshaw (2002). The majority of these potential locations align reasonably closely with the location of existing coal- and gas-fired generation, and existing gas and electricity transmission assets. These locational overlaps support the notion that, while the location of generation investment under the CPRS in the long term is likely to change on the margin due to the additional constraints imposed by CCS sinks, the magnitude of these locational changes is unlikely to be dramatic. This is consistent with the discussion above, where it was noted that the location of generation investment in the short to medium term is only likely to change marginally as a result of fuel-switching, *ex post* the CPRS introduction.

4.2.2 Plant retirement

As discussed above, emissions intensive generators should experience a reduction in gross margins and values, but this in itself is not enough to result in early plant retirement. Generators should rationally continue to operate so long as they are able to recover their variable costs (SRMC), even if the reduction in margins means that they are no longer able to recover their capital costs (which are sunk). However, at higher carbon prices, the LRMC of new entrant plant will be lower than the SRMC of existing high emissions plant, and this should lead to early retirements.

For example, a carbon price of around \$20/tCO_2 may be enough to encourage new build of CCGT rather than new Brown Coal, but at a carbon price of \$30-\$40/tCO_2 this should move the LRMC of new gas plant below the SRMC of some existing Brown Coal plant, which should result in an early retirement. As above, these are indicative only based on limited assumptions, including as gas price of \$3.50-4 GJ. Given that this is an operational decision, the choice to reduce output or retire should not necessarily be affected by the method of permit allocation (auctioned or grandfathered).

The exception to this is if different allocation rules are adopted for new entrants and closures. For example, in the EU ETS, plant closures mean that unused allocated permits must be returned. Given that permits are grandfathered under the EU scheme, this effectively penalises a plant for closing and encourages high emitting plant to remain operating for longer. This is not an issue if the method of allocation is consistent.

4.2.3 Network augmentation and connection issues

The responsibility for planning and funding transmission investment in the NEM depends on the nature of the services provided by the relevant assets, namely:

- Shared transmission services; and
- Connection services.

Shared transmission services

For shared services provided by the shared transmission network, TNSPs are responsible for evaluating the merits of the project:

- Under the existing arrangements for transmission investment, TNSPs are required to ensure their augmentation investments satisfy the Regulatory Test. The Regulatory Test is made up of two limbs: the reliability limb and the market benefits limb. The reliability limb requires electricity network businesses to minimise the costs of any investment directed at achieving mandatory reliability standards. The market benefits limb requires electricity network businesses to conduct a full cost-benefit analysis of investment proposals. Under this limb, the network business must select the project that maximises the market benefits of the investment.[22]
- Under the AEMC's proposed new arrangements, the Regulatory Test is to be replaced by the Regulatory Investment Test for Transmission (RIT-T).[23] The primary motivation behind the RIT-T was to establish a new project assessment and consultation process, which would amalgamate the reliability and market benefits limbs of the current Regulatory Test, in order to allow proposed transmission projects to be assessed against both local reliability standards as well as their ability to maximise benefits to the national market.[24] By amalgamating the reliability and market benefits limbs of the Regulatory Test, it is intended that the new RIT-T will require TNSPs to broaden the scope of possible market benefits they consider in examining project options. The RIT-T will involve four substantial changes to the current Regulatory Test arrangements[25]:

22 http://www.aer.gov.au/content/index.phtml/itemId/715898

23 In July 2007 the Ministerial Council on Energy (MCE) formally requested the Commission to develop a detailed implementation plan for the national transmission planning function. The proposed RIT-T was one of the outcomes of the Commission's National Transmission Planner Arrangement Review.

24 AEMC (2008c), p.44.

25 AEMC (2008c), p.xi.

- First, the amount of consultation on the available options to address a given transmission issue will be substantially increased;
- Second, the RIT-T will demand a more rigorous analysis of the costs and benefits of any proposed transmission investment;
- Third, the RIT-T will bring within the scope of a single test network reconfigurations and projects which combine replacement and augmentation; and
- Fourth, the greater level of consultation will allow potentially viable non-network options to be identified and appropriately assessed.

We note that in its response to the AEMC's National Transmission Planning Arrangements Review, the MCE has endorsed the proposed RIT-T and requested that any rule changes required to implement the RIT-T be progressed through the fast-tracked rule change process.[26]

Both tests support investments that maximise net benefits as compared to a range of appropriate alternatives. This should encourage investors to develop new remote generation projects where it is likely to be efficient to do so.

Further, if augmentations to the shared network do not satisfy the Regulatory Test or RIT-T, it is open to willing participants to fund these investments. The framework and principles governing such arrangements are contained with Part D of Chapter 6A of the Rules.

A practical demonstration of how TNSPs apply these arrangements is provided by VENCorp's electricity network connection augmentation guidelines[27]. The guidelines allow connection applicants to request augmentations that increase network transfer capability but do not satisfy the regulatory test so long as the connection applicant funds the shortfall (see Guidelines 5, 12 and 13).

Notably, the provision of such funding does not provide the funding participant with any physical or financial rights to the additional network transfer capability. Therefore, participants' incentives to fund such new shared network capacity will be limited by the extent and duration of their private benefits from the new capacity.

Connection services

New connection services provided by transmission assets between a participant's plant and the point of connection to the transmission network are referred to as

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26 http://www.mce.gov.au/assets/documents/mceinternet/National_Transmission_Planning_Arranements_Final_Report20081106104510.pdf

27 VENCorp (2007a).

'negotiated services' under the Rules[28]. For these services, the participant is required to negotiate with the TNSP, who is itself required to comply with the principles outlined in Part D of Chapter 6A of the Rules.

In general terms, the responsibility for funding negotiated services lies with the connecting participant. However, some TNSPs have guidelines in place outlining how they intend to deal with the allocation of costs pertaining to new connections. In particular, VENCorp's guidelines referred to above provide an indication to connecting participants as to how their applications will be handled and the types of costs they may be required to pay.

For example, the guidelines incorporate provisions for rebates from subsequent connection applicants to earlier connection applicants where the later applicant seeks to 'piggy back' on connection assets paid for by the earlier applicant.[29] VENCorp notes that such provisions are necessary to overcome the free-rider problem associated with certain network connections, and to ensure fair and reasonable access to the shared transmission network to all participants. Such arrangements help promote the efficient timing of connections to the network by providing confidence to prospective participants that they will not be disadvantaged by being the first party to connect and pay for new connection assets. VENCorp do not provide firm details as to how this process operates in practice.

In addition, the VENCorp guidelines also provide the following in relation to non-scheduled (including wind) generator connections:

- Non-scheduled generators will be required to install generation control equipment if VENCorp deems it appropriate to ensure power system security and reliability; and

- Connection agreements for non-scheduled will incorporate sharing provisions where the combined capacity of non-scheduled generators is or is likely to exceed the power transfer capability of the downstream network.[30]

Although other TNSPs have not published guidelines of an equivalent level of detail, we expect that other TNSPs are likely to adopt a broadly similar approach to the treatment of connection applications, including how they deal with non-scheduled generator connections. We note, however, that differences in the specific treatment of intermittent generation do exist between TNSPs – for

28 See Chapter 10 of the Rules.

29 See VENCorp (2007a), Guidelines 8-11B, p.7.

30 See VENCorp (2007), Guidelines 14-15, p.8.

example, South Australia requires intermittent generation to register with NEMMCO as scheduled rather than non-scheduled generation.[31]

Discussion

The current regime for network connections and augmentations largely amount to a framework where:

- Costs relating to net beneficial shared network investments are recovered from customers generally; while

- Costs relating to other shared network investments and connection assets (including investment necessary for the network to accommodate increased non-scheduled generation) are recovered from the relevant connection applicant(s).

Broadly speaking, these arrangements should be able to accommodate changes in generation investment patterns, locations and timings resulting from the CPRS. Shared network augmentations should only proceed where they are net beneficial or where particular parties are willing to pay for them to proceed. This means that the network regulatory arrangements should accommodate greater gas-fired generation located closer to load centres. To the extent that new connections impose costs on the rest of the network, the existing arrangements allow for those costs to be allocated to the responsible party.

As noted by the Commission in the Congestion Management Review (CMR)[32]:

> Analytical work by the Australian Energy Regulator (AER) and by us suggests that productive inefficiencies from disorderly bidding have been relatively minor to date. In addition, empirical research from NEMMCO shows that congestion has tended to be transitory and influenced significantly by network outages.

Both the non-material and transient nature of congestion in the NEM are testament to the efficacy of the current network connection and augmentation arrangements, as governed by chapters 5 and 6 of the Rules. The key question then becomes: is the incidence (and hence materiality) of congestion in the NEM, as the result of the introduction of the CPRS, likely to significantly increase?

It is Frontier's view that, while changes to the pattern of dispatch (due to the economics of the CPRS) and changes in locational investment (due to fuel-switching and reliance on zero-emissions technologies) may impact congestion on the margin, it is unlikely that such impacts will be of an order of magnitude large enough to render the existing arrangements governing network investment inadequate. Thus we do not expect that generation investment efficiency will

31 http://www.escosa.sa.gov.au/webdata/resources/files/050930-R-WindGenerationStatementofPrinciples.pdf

32 AEMC (2008a), p.viii.

greatly suffer due to the CPRS going forward, because of the robustness of the existing transmission investment regime.

As noted in section 4.2.3, we would expect the CPRS will lead to more gas generation and less coal generation going forward as compared to BaU, and to the extent that gas is easier and cheaper to transport to load centres than coal, generators may locate closer to load than otherwise. Importantly, we do not expect that this will reflect a significant inefficiency – the more proximate location of generation to load under the CPRS is a likely and natural consequence, rather than an unintended inefficient implication of, this policy.

For these reasons, existing network regulatory arrangements should neither accentuate nor attenuate the issues created by the CPRS. Section 5.3.3 below discusses this issue in the context of the expanded RET scheme, but comes to the same conclusion.

4.2.4 Summary

A summary of the likely impact of the CPRS on key issues facing generators in the NEM is outlined in Table 5. These issues, as outlined in section 1, include forward contracting strategies; strategies for spot market offers; strategies for managing physical and financial risk; modes of technical operation, plant retirement; investment in new plant; organisational structure; and behaviour of counter-parties.

Issues	***Likely impact of the CPRS***
(i) Forward contracting	• The introduction of a variable and uncertain carbon price will increase wholesale electricity price volatility, and hence risk. • Generators and Retailers are both exposed to this regulatory risk, hence they will be unable to hedge against it through contracting. • This is likely to lead to a shortening of the contract market and/or and increased tendency toward contracts that are vary with the carbon price.
(ii) Spot market offers	• Generators will add the cost of carbon to bids regardless of whether permits are auctioned or grandfathered (due to opportunity costs). • The extent of cost pass-through depends on the emissions intensity of the marginal plant (before and after the CPRS), and demand elasticity. • The carbon price will likely flatten the merit order, since it increases the cost of cheaper high emissions plant (coal) more than the cost of low emitters (e.g. gas). Although this might theoretically lower the opportunity for strategic bidding, this is likely to be offset by the effect of delays in new investment (due

Issues	***Likely impact of the CPRS***
	to the more uncertain market).
(iii) Management of physical and financial risk	• The introduction of the CPRS is not expected to materially impact congestion in the NEM as compared to the status quo. • Changes to dispatch and power flows may either improve or erode the firmness of IRSRs on the margin. • As a result, this policy is unlikely to materially change the way in which market participants currently manage physical risk in the NEM. • As a consequence of carbon price risk, generators may have reduced incentives to enter into long-term swap contracts to hedge their financial risk – this is since carbon costs are likely to represent a larger component of SRMC than fuel costs for most generators.
(iv) Technical operation	• The carbon price should change the merit order such that low emissions plant should increase output to displace high emissions output. • This may provide complications for existing coal plant, which is not suited to running as flexible intermediate plant at low capacity factors.
(v) Plant retirement	• The carbon price increases the marginal cost of generation. At higher carbon prices, the viability of high emissions plant will decline, as it will become cheaper to build new low emissions plant to replace existing high emissions plant. • Once the SRMC of existing high emissions plant (including carbon costs) rises above the LRMC of new low emissions plant then early retirements are likely. This is likely to occur at prices of around \$30-\$45/tCO2 for brown coal plant and at marginally higher prices for black coal plant (contingent of current gas prices). • There are also potential credit market implications of imposing the CPRS with full auctioning. This will reduce the value of existing high emissions generators, and the resulting asset write-downs will reduce the security for existing debt. This may trigger clauses in existing hedge agreements, which may create more systemic problems.
(vi) Investment in new plant	• The carbon price will increase investment in low emissions plant, though the increased uncertainty regarding carbon prices may result in delays in investments. • Higher electricity prices resulting from the CPRS may result in lower demand (or slower demand growth), which may reduce the need for new investment. However, electricity demand is

Issues	*Likely impact of the CPRS*
	typically inelastic. • The location of gas investments should be more flexible than coal due to the greater potential to transport gas. This may see plant locate closer to major load centres • In the longer term there will be increased reliance on CCS and Renewables to meet abatement targets. The location of these plant will be dictated by a combination of the location of fuel and sinks in the case of CCS (though carbon can also be transported) and location of natural resources in the case of renewables.
(vii) Organisational structure	• The incentive to vertically integrate retail and generation is similar to the incentive for contracting, which is to hedge risk. • Since it is difficult to hedge against carbon price, the CPRS is unlikely to increase incentives to vertically integrate.
(viii) Behaviour of counter-parties	• The shortening of the contract market (above) and the general ability of generators to pass-through a large portion of costs mean that retailers and large customers are potentially exposed to the risk of higher energy prices. • This may be mitigated somewhat if they sign contracts for energy that are indexed to the carbon price, (though they will still be exposed to the carbon price risk). • It is not clear whether existing contracts will allow for revisions to account for the introduction of a carbon price. • The exposure of retailers depends on whether retail price regulation allows for pass-through of carbon costs to end-users.

Table 5: Summary of impact on issues facing generators: CPRS

Source: Frontier Economics

5 Effects of the expanded national RET scheme

The effects of the expanded national RET scheme on Australia's electricity markets are discussed below. Broadly, the scheme operates as a targeted subsidy to renewable generation. The cost of this subsidy is recovered through a retail tariff, but the net effect is an increase in renewable generation that displaces thermal generation.

This section includes discussion of the following:

- The generic economic effects of renewable energy targets;
- The short-run impact of the expanded national RET, including:
  - impact on generator operation; and
  - impact on the merit order and generator bidding.
- The long-run effects of the expanded national RET, including:
  - effects on new investment;
  - forward contracting, including the behaviour of counterparties and implications for organisational structure;
  - plant retirements; and
  - effects on network congestion, augmentation, ancillary services etc; and
- Interaction between the RET and the CPRS.

5.1 THE ECONOMICS OF THE EXPANDED NATIONAL RET SCHEME

Renewable energy schemes provide a targeted subsidy for renewable generation so that they can compete with cheaper, non-renewable forms of generation. The Government imposes an obligation on retailers and large customers to purchase a given quantity of renewable generation, with these targets increasing over the course of the scheme as outlined in Figure 3. This creates demand for renewable energy. Renewable generators are able to create Renewable Energy Certificates (RECs) and sell them to liable parties. This allows renewable generators to earn revenue from RECs in addition to the wholesale energy price.

The economics of the scheme is illustrated in Figure 18. In this stylised diagram, the LRMC of renewable energy is higher than that of non-renewable – this is represented as the green line at the top of the supply curve. Without a renewable energy target, the electricity price is set at P* and the quantity Q* is met entirely by thermal generation.

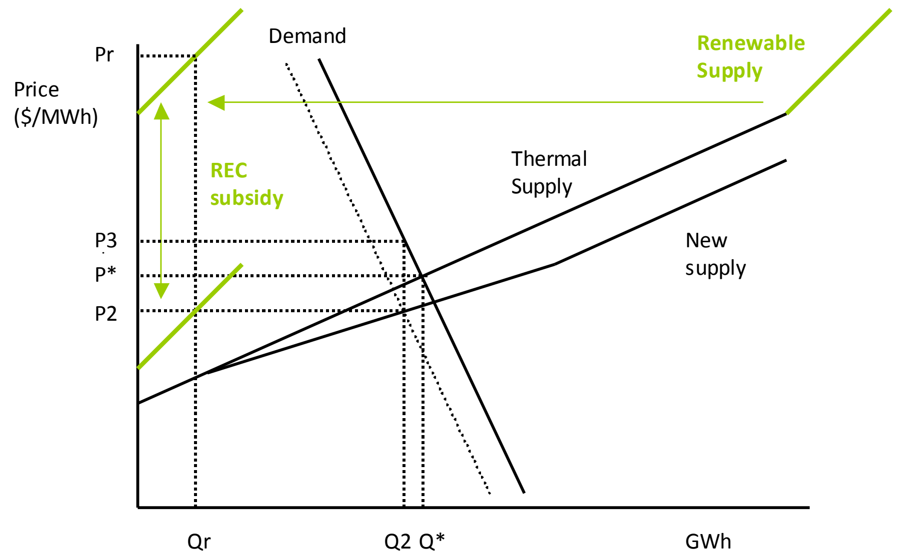

Figure 18: Illustrative effect of a renewable energy target

Source: Frontier Economics

The introduction of the RET provides a targeted subsidy to renewable generators, allowing them to sell electricity at prices lower than their LRMC. This is because the sale of RECs provides revenue in addition to the wholesale energy price. This shifts the renewable supply to the bottom of the merit order, and shifts the thermal supply curve to the right. This is represented as New supply, which is a combination of thermal and subsidised renewable generation. Regarding Figure 18:

- **Renewable output:** The renewable target is set at Q_r in this example;

- **REC price:** The value of RECs is the difference between the long-run marginal cost of renewable generation and the wholesale electricity price. In this diagram, at a renewable target of Q_r the LRMC of renewables is $P_{r.}$ and so the required REC price to encourage that level of renewable capacity is P_r-P_2. (where P_2 is the final wholesale price). Due to the upward sloped supply curve for renewable technologies, any increase in the REC target will result in an increase in required REC prices (all else remaining equal) – i.e. P^r will increase but P_2 will remain constant or will fall. Although this example is simply illustrative, this effect was evident in the increased REC prices following the proposals for the Victorian and NSW RETs, (which effectively increase the national target)[33];

- **Retail levy**: The targeted subsidy must be funded, and liable parties pass-through the cost of RECs via a retail levy. In this diagram, the retail levy is (P_3-P_2). This represents the total cost of the scheme [Q_r x (P_r –P_2)] divided by total output (Q_2). The final retail price (P_3) is higher than P*, so in this diagram there is a slight reduction in demand to Q_2

- **Thermal output:** The subsidised renewable generation (Qr) displaces some thermal generation, and this results in a lower wholesale pool price (P_2). This is offset by the increase in the retail price (P_3). Since total demand is also lower, thermal output is reduced further. Final thermal output in this example is (Q_2-Q_r).

In some circumstances (e.g. when the supply curve for renewables is very elastic or flat) the final retail price may be less than the initial price. Although the scheme increases generation costs, this result is plausible because it reduces producer surplus for thermal generators due to a reduction in output and wholesale prices. If this reduction in producer surplus is greater than the cost of the scheme, the retail price may be less than without the scheme. Since consumers may pay lower or higher retail prices, thermal generators receive lower wholesale prices (and reduce output) and renewable generators receive higher prices (and increase output) the main effect of the scheme is effectively a transfer from thermal generators to renewable generators (and an increase in the resource costs to supply energy).

An important implication of this result is that total revenues are a function of both the REC price and the black energy price. Under a national RET, renewable generators will earn the same return for sale of RECs, however if black energy prices are higher in a particular region (e.g. WA or SA) then this region will be a more favourable location for new investment in renewables since total revenue per MWh of output will be higher. A countervailing factor is that each region also has a limited number of sites and hence an upward sloped renewable supply curve – even if total revenues might be higher in a region it may reach saturation more quickly.

An alternative representation of this effect on an illustrative merit order is presented in Figure 19. The RET scheme means that wind generation (in this example) will be built and dispatched to displace non-renewable generation in the merit order. The final price such generation receives, which is the wholesale energy price plus REC revenue, must be equal to its LRMC of supply. The difference between this cost and the price received in the spot market is the REC price paid under the scheme.

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33 The REC price increased from a low of $15 per REC in late 2006 to $33-35 per REC by mid 2007 and reached a peak of over $50/REC in mid 2008. This rise coincided with the announced State based targets (and reduced output from hydro plant due to the drought).

This example considers a wind plant that has an LRMC of $70/MWh. At an average spot price of $36/MWh this plant would not be built without a REC payment. Providing this plant with a stream of revenue in addition to its average wholesale earnings in the form of a REC payment encourages this plant's entry into the market. Once built, this plant offers its generation to the market at a negligible cost, reflecting its very low SRMC, and hence displaces non-renewable generation in the merit order. The REC price thus represents the difference between the average wholesale spot price received by this plant ($36/MWh) and the average LRMC of this plant's supply ($70/MWh) – in this example the REC price is $34/MWh[34].

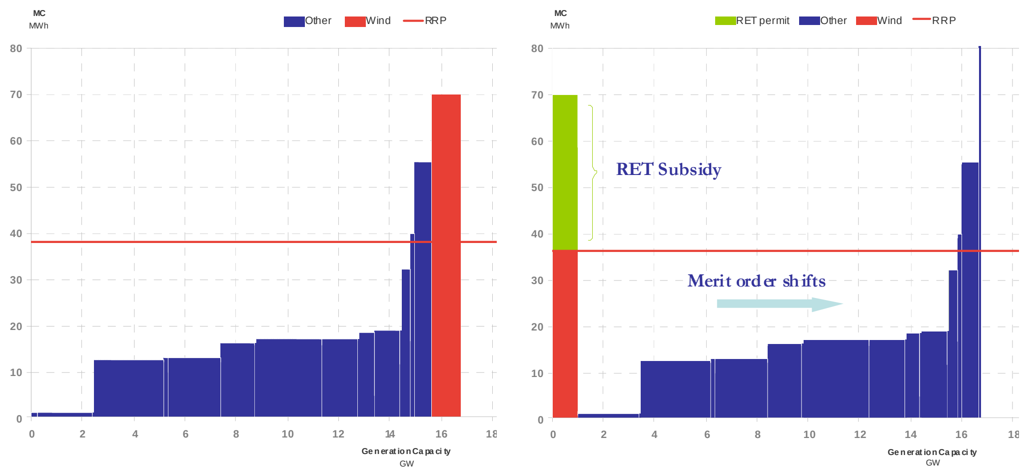

Figure 19: Impact of a renewable energy target on the merit order

All else being equal (i.e. for a given energy price) the renewable energy target under the scheme sets the demand for RECs, which in turn sets the REC price depending on the supply of renewable generation. As such, a low target results in a low REC price, since only the most productive (lowest cost) renewable generation would enter the market. By contrast, a high target would encourage more marginal (higher cost) renewable plant to enter, and hence REC prices will need to be higher. The interaction between the expanded national RET scheme and the CPRS (considering is effects on energy prices) is considered in section 5.4

It is important to recognise that in reality the effects will be more complex than in this stylised example. In particular, increased investment in intermittent wind should also change the *distribution* of prices (as opposed to the *mean*) and this may have second order effects on the competitiveness of the market and bidding behaviour. These issues are discussed below.

34 Note that the slight average spot price decrease between these two examples (with and without the scheme) is due to the shifting effect of the scheme on the merit order as explained above.

5.2 SHORT-RUN EFFECTS OF THE EXPANDED NATIONAL RET SCHEME

This section considers the short-run effects of the expanded national RET scheme on generators in the NEM. In addition to considering the impact of intermittent generation, this section discusses the consequences of increased intermittent generation for thermal generators.

5.2.1 Impact on generators

Impact on operation of thermal plant

As per the discussion above, the expanded national RET will result in increased generation from renewable sources that will displace investment in new thermal plant and potentially output from existing thermal generation. In the short term, this will tend to reduce the operating efficiency of thermal plant. At the extreme, thermal coal plant may be limited to their minimum stable generation levels at low load times (such as overnight). If the system operator cannot curtail the output of renewable plant, it may be necessary for thermal plant to shut down at low load times. This is unlikely to be practicable on a routine or regular basis and even if it does occur, there are likely to be significant lags in bringing such plant back on line when they are needed, such as the following day.

In response, some system operators curtail renewable plant output when conventional thermal plant are approaching minimum stable levels. Depending on the technology of the renewable (say, wind) plant concerned, such curtailment can be achieved by, for example, making adjustments to the angle of the blades on wind turbines. To the extent that this results in renewable plant running less than they can, this has clear implications for the economics of renewable plant.

The longer-term effects on generation investment patterns are discussed in Section 5.3.

Merit order and bidding behaviour

A key impact of the expanded national RET scheme will be, by design, to increase the amount of wind generation in the NEM. Since wind generation has virtually zero SRMC, and assuming generators bid at SRMC, wind will be dispatched whenever it produces (i.e. when the wind blows), subject to the ability of NEMMCO to limit wind dispatch pursuant to the Rule change described above.

A key difference between the RET and the CPRS is that the RET will shift the residual (thermal) merit order to the right, without changing the relative competitiveness of different types of thermal generation. In other words, gas generation will remain typically more expensive than coal, and so the plant that is most likely displaced by the extension of the RET is intermediate gas plant (as opposed to coal in the case of higher carbon prices under the CPRS). This will not result in any potential flattening of the merit order, as is the case with the CPRS.

However, all other things being equal, the increased share of intermittent generation should increase the frequency of high price events since this plant cannot guarantee supply of energy at times coinciding with high demand. This should provide a price signal for additional peaking plant to complement the greater share of intermittent generation. Whether this price signal is sufficient to maintain reliability is discussed under investment in Section 5.3.

The net effect of increased investment in peaking capacity (in addition to increased wind) may also have implications on bidding behaviour and the competitiveness of the market. This is a complex issue that is also discussed in the following section.

5.3 LONG-RUN EFFECTS OF THE EXPANDED NATIONAL RET SCHEME

This section discusses the long-run effects of the expanded national RET, which are broadly divided between:

- generator effects, which include investment and contracting behaviour, and
- network effects, which include discussions on the effect of increased capacity of intermittent generation and congestion issues.

5.3.1 Generator effects

Effect on investment

The effects of an expanded RET scheme on investment in generation are complex and contingent on the precise assumptions adopted regarding strategic bidding behaviour and the existing market settings surrounding the maintenance of reliability, in particular, the level of the market price cap (VoLL).

Assuming competitive bidding behaviour and an adequate level of VoLL, the impact of an expanded RET on generation investment can be examined by considering the likely bidding behaviour and, hence, of market prices in response to the scheme. In this context, it is useful to broadly distinguish between average prices (mean) and the volatility of prices (the distribution). This is important because of the different cost characteristics of different plant technologies: for example, it is typically efficient (and, in an energy-only market), profitable, to develop baseload generators when expected (post-entry) mean prices are high. This is because such plant have relatively high fixed costs and relatively low variable costs. Conversely, it is more likely to be efficient to develop peaking plant when mean prices may not be so high, but there are frequent high-price events or price spikes. This is because the capital costs of peaking plant are lower than baseload plant and are physically more responsive than base load plant, so they (peaking plant) tend to provide a more efficient means of supplying energy for a relatively small number of hours per year.

Because of the non-strategic nature of wind generators, the increased prevalence of intermittent wind capacity in response to an expanded RET scheme might initially lower the *mean* pool price relative to the counterfactual of no expanded scheme. If demand is also growing then the mean price might be stable as opposed to increasing in the counterfactual. To simplify things, this would tend to discourage new entry of baseload thermal, which is more concerned with mean prices.

However, because wind output is non-firm, an increased share of wind capacity in overall capacity will tend, at least initially, to result in more variable residual demand and hence a wider distribution of prices than in the counterfactual of no expanded RET scheme. Due to the relatively high variable and low fixed costs of thermal peaking plant, this is likely to encourage the development of thermal peaking plant for use during peak periods when wind plant is not operational. Hence an increased share of wind should provide more favourable conditions for more peaking plant entry/output (i.e. it is complementary to wind due to its flexible operation).

Finally, it is also crucial to note that the above discussion is contingent on the integrity of the other settings in the market surrounding the maintenance of reliability. In particular, efficient investment in an energy-only market such as the NEM will only take place if there is a correspondence between the desired level of reliability (in terms of unserved energy) and the level of VoLL and related measures. If VoLL is 'too low', then generation investment will be inadequate to incentivise adequate generation capacity. Furthermore, this problem would be accentuated under an expanded RET scheme, due to the greater reliance it imposes on price spikes to promote new generation investment. Whether VoLL is high enough to provide a sufficient price signal to encourage enough new entry of thermal peaking plant to fully offset the effects of additional wind capacity is a separate question that may require a more detailed review, especially in light of an expanded RET scheme.

If VoLL is not high enough to sustain reliability, the Reserve Trader requirement (or some variant) may be required to deliver the additional requirements of reliability capacity, otherwise reliability is likely to decrease. As with the case of more unscheduled generation, it is worth noting that such a scheme may potentially result in a more competitive market that reduces strategic bidding and lowers average pool prices if the combined additional capacity of peaking plant and wind results in a net increase in non-strategic available capacity (allowing for the fact that wind is generally not available on demand). If the resulting increase in peaking plant results in a *more* competitive market (i.e. the increased peaking plant more than offsets the effects of variable wind generation), there may be less frequent high price events. If that is the case then VoLL may actually need to be higher to provide sufficient returns on investment. Again, this may also be a transitory disequilibrium - over time, this may result in deferred new investment until the supply and demand balance restores and average prices rise to levels that provide sufficient returns.

These effects mostly apply to wind, which is intermittent. It is also important to note that in the medium to long-term, other renewable technologies will increasingly compete with wind generation. Geothermal hot dry rock, for example, is expected to become increasingly competitive and it has the potential to operate more like baseload generation, which should alleviate potential problems associated with wind described above. Renewable technology investment is discussed in more detail in Section 5.3.

Contracting

Retailers typically contract with renewable generators to ensure supply of RECs to meet their liabilities under the RET scheme. The duration of these contracts is typically around 10-15 years for wind generation. However, the intermittent nature of wind (and the inability to guarantee supply when required) means that retailers are less likely to enter contracts for electricity with renewable suppliers – i.e. the contract is for RECs rather than bundled with electricity. The corollary of this is that there is arguably less incentive for retailers to build new wind generation than to contract for the REC supply.

Plant retirement

The growth in the RET target is largely consistent with anticipated growth in demand over time. This means that more new renewable plant will be built to meet growing demand rather than to displace existing thermal generation. However, since the RET does not change the relative costs of thermal plant, the enhanced target will most likely result in displacement of new intermediate gas plant. As discussed above, this will increase the requirement for more flexible peaking plant to provide energy at times of high demand when wind is unable to provide energy.

Locational investment issues

The location of investment in renewable generation is primarily driven by the suitability of renewable sites – suitability includes the 'capacity factor' of the site, and availability (cost) of network connection at that location. Such sites tend to be remote from traditional electricity networks, and hence the location of potential renewable generation (in particular wind plant) has implications for network connection and augmentation arrangements.

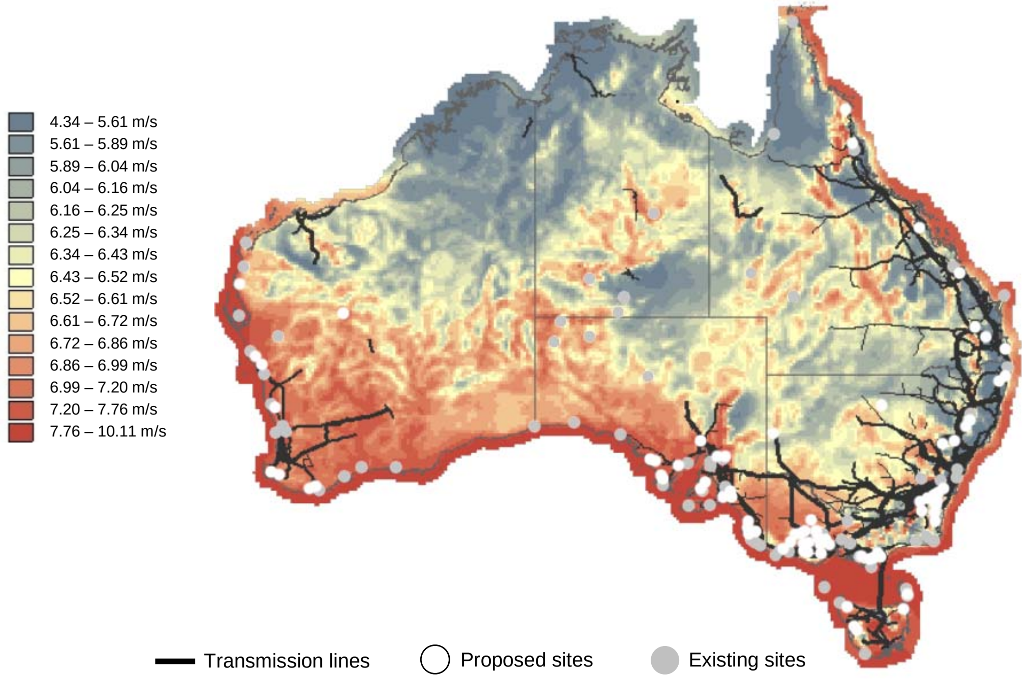

Figure 20: Predicted wind speed at an altitude of 80m (m/s)

Source: Australian Government (2008c), Geoscience Australia (2008), Frontier Economics

Outlined in Figure 20 is a graphical representation of predicted average wind speed in Australia, at an altitude of 80m. The approximate locations of existing and proposed wind plant rated 3 KW and above have been overlaid.

As expected, the majority of the NEM's existing wind plant are located on the Southern coast of South Australia and Victoria, and at various locations around Tasmania (Figure 20). Proposed wind plant, as reported by Geoscience Australia, are indicative only of the likely location of new wind generation in the NEM. Relative to the other regions, Victoria and New South Wales have the highest number of proposed plant. The majority of proposed plant in Victoria are located in the south-west of the state, west of Melbourne, while in New South Wales the majority of proposed plant are located in the south-east of the state, between Canberra and Sydney.

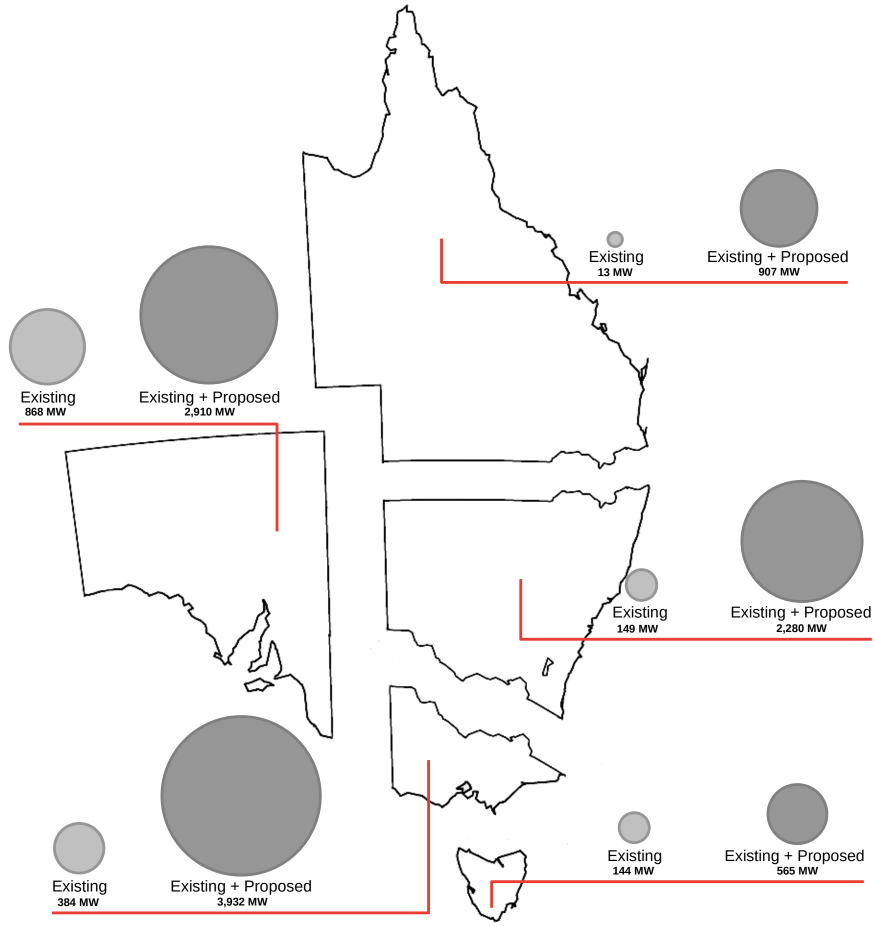

Figure 21: Existing and proposed wind capacity by region

Data source: Geoscience Australia (2008), Frontier Economics

Figure 21 illustrates the existing and potential installed wind capacity by NEM region, assuming all proposed wind plant reported by Geoscience Australia is built. While the extent to which these proposed projects reach fruition is uncertain, the data regarding proposed wind plant reported by Geoscience Australia provides a rough indication of the relative intensity of wind farm development across the NEM. We note that the indications of proposed installed wind capacity as reported by Geoscience Australia are broadly consistent with those reported by NEMMCO[35] and VENCorp (2007b).

Highlighting the existing and potential installed wind capacity by region illustrates the relative growth in installed wind capacity in each region that could be experienced going forward. While South Australia currently has the largest

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35 http://www.nemmco.com.au/about/057-0401.pdf

quantity of installed wind capacity in the NEM, Victoria, New South Wales and Queensland are all likely to experience greater growth in wind generation going forward. We note that the majority of proposed new plant in Victoria and New South Wales is likely in response to (or anticipation of) the VRET and NRET schemes in those states. Assuming all proposed plant are built, Victoria would have the greatest quantity of installed wind capacity (3,932 MW) followed by South Australia (2,910 MW), New South Wales (2,280 MW), Queensland (907 MW) and Tasmania (565 MW). Consistent with the number of proposed wind plant in each region cited by Geoscience Australia, Queensland, New South Wales and Victoria (respectively) are expected to have the largest *percentage* increase in wind generation over the short to medium term. This growth in proposed plant in Victoria and NSW may be partly driven by the introduction of the VRET and the NRET, though this does not fully explain why the new plant is mostly located in these states. Firstly, the proposed NRET recognises generation from renewables across the NEM. Secondly, although the VRET only recognises generation in Victoria, this will also have implications for the national REC price (since Victorian generation can produce either RECs or VRECs). Other reasons must contribute to the decision to locate in these regions, such as demand growth and quality of sites.

While slightly outdated, Outhred (2003) suggests that up to 8,400 MW could be readily accepted in the NEM provided plant where widely and evenly dispersed, utilised the latest wind turbine technology, and advanced wind forecasting techniques were developed and used to predict the future behaviour/output of plant. In addition, VENCorp (2007b) reports that, under certain conditions, up to 4,000 MW of wind capacity could be accommodated in Victoria alone. The combined estimates of Outhred (2003) and VENCorp (2007b) suggest that up to 10,200 MW of installed wind capacity could be accommodated in the NEM under the right conditions.

Outlined in Figure 22 is a graphical representation of predicted daily solar exposure in Australia, measured in MJ/m^2. The approximate locations of existing and proposed solar plant rated 3 KW and above have been overlaid. The majority of existing solar plant are located in the Northern Territory and northern Western Australia. Several solar plant have been proposed in Victoria and New South Wales, however the scale of proposed solar projects is far less than that of wind – current total potential installed solar capacity in the NEM is 685 MW, while current total potential installed wind capacity is 10,594 MW. To the extent that solar technology matures to the point where large-scale solar generation becomes viable, purely from a capacity factor perspective, such plant will likely be best suited in north-western Queensland and northern South Australia, where daily solar exposure is generally highest. Any locational decision, however, would need to consider the availability (cost) of network connection at these locations.

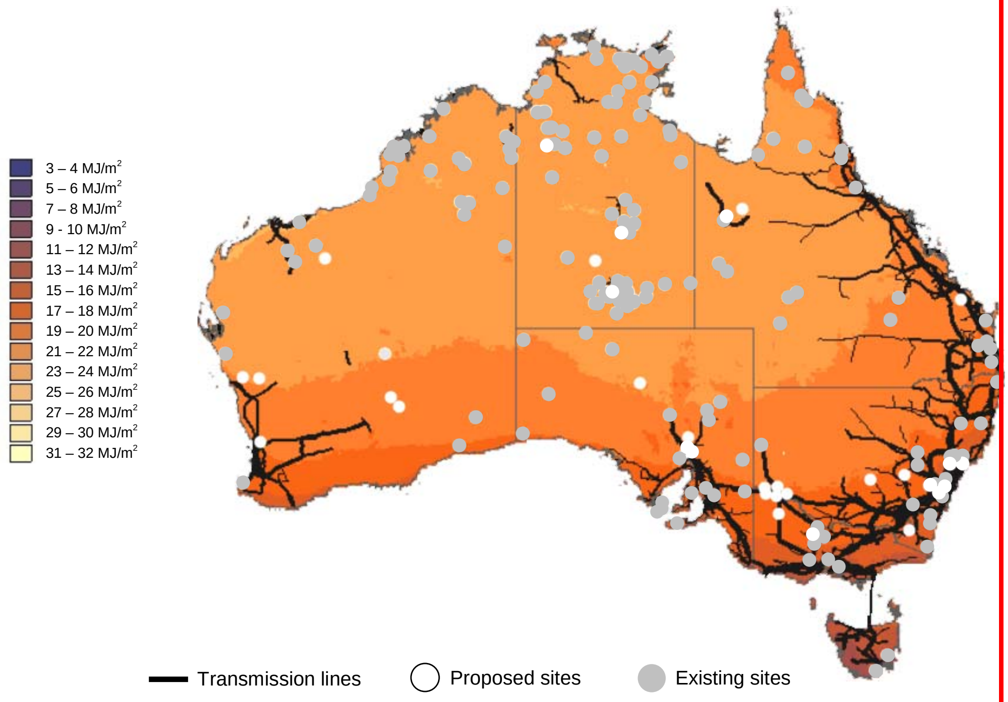

Figure 22: Average daily solar exposure (MJ/m^2)

Source: Source: Australian Government (2008c), Frontier Economics

An alternative source of zero-emission generation to CCS that is also suitable for base-load supply is geothermal generation. A form of geothermal technology known as an Engineered Geothermal System (EGS) is currently the most promising geothermal technology in Australia. An EGS involves engineering an underground reservoir into which water can be pumped through wells. Due to the high subterranean heat in such reservoirs, this water is naturally converted to steam, which is then brought to the surface and used to drive traditional steam turbines to generate electricity.[36]

Figure 23 illustrates the crustal temperature at a depth of 5km in Australia. Within the NEM, the areas most suitable for geothermal generation are north-eastern South Australia and south-western Queensland. Given its high underground crustal temperatures, the Cooper Basin in South

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36 http://www.agea.org.au/information/about-geothermal/

Australia/Queensland is currently one of the most attractive geothermal locations. An 80 KW geothermal plant is currently in operation at Birdsville in far western Queensland. Further 'proof-of-concept' plants have also been proposed.[37]

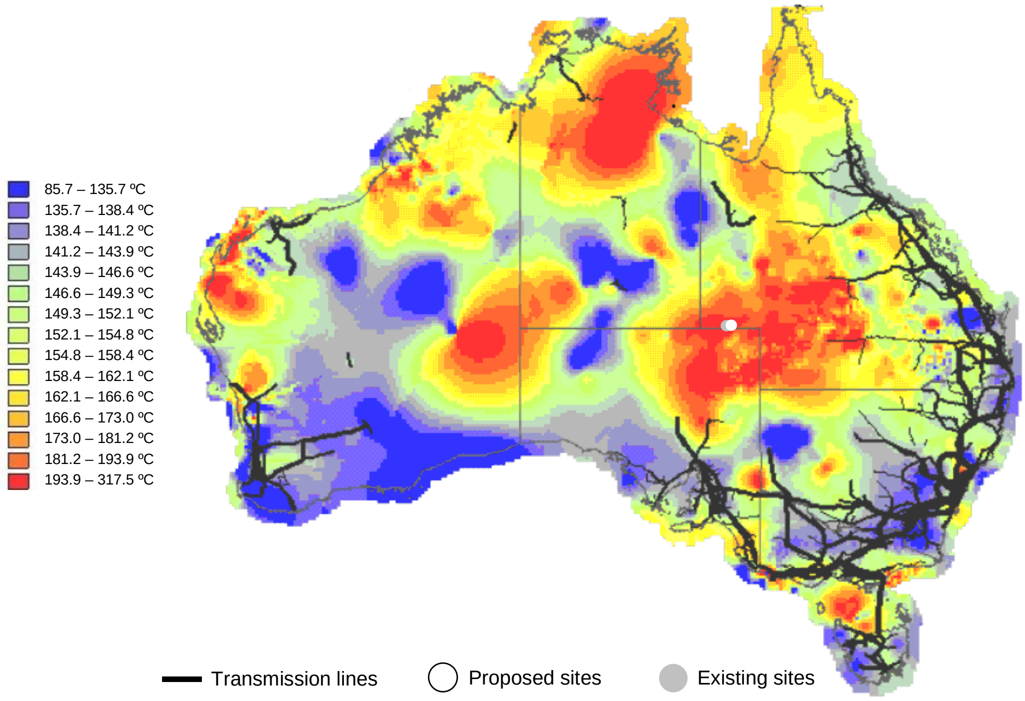

Figure 23: Crustal temperature at 5km

Source: Australian Government (2008c), Frontier Economics

5.3.2 Network effects of increased intermittent generation

The previous sections discuss the increases in investment in intermittent generation that will result from the expanded national RET. This sub-section discusses the consequential effects of this increased intermittent generation on the network, and the resulting issues that this raises.

Impact on power flows and secure network limits

The intermittent nature of much renewable generation can compromise the system operator's ability to keep the power system within thermal, voltage and stability limits, which can potentially jeopardise system security and can raise the costs of providing ancillary services to manage these issues.

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[37] http://www.geodynamics.com.au/IRM/content/about_progresstodate.html

In response, system operators may need to increase safety margins within network constraint equations, or invoke more frequent directions to participants, both at the cost of operational efficiency and good regulatory practice. Alternatively, system operators may need to impose some operational constraints around the output of renewable plant. For example, in the NEM, the AEMC has recently approved a modified version of NEMMCO's proposed 'semi-scheduled dispatch' Rule change (SSD Rule Change). [38] The final accepted SSD Rule Change, *inter alia*:

- Created a new registration category for 'Semi-Scheduled Generators' for intermittent plant over 30 MW nameplate capacity and allowing for some aggregation;[39]
- Allowed NEMMCO to formulate constraints with semi-scheduled generating units on the left-hand (controllable) side of the constraint equation;[40]
- Required Semi-Scheduled Generators to limit their output below a unit-based dispatch level set by NEMMCO, but only during dispatch intervals in which a higher level of generation could lead to the violation of secure network limits or in the case where the intermittent plant was constrained-off;[41] and
- Allowed Semi-Scheduled Generators to bid inflexible and subject to ramp rate constraints, but applies the same rebidding restrictions as for Scheduled Generators.[42]

Impact on forecasting of demand and supply conditions

System operators typically seek to forecast demand and supply conditions in order to ensure there is sufficient capacity to reliably serve load for the foreseeable future. To the extent that intermittent plant are not required to submit information about their expected availabilities to the system operator, this could compromise the integrity of these forecasts and ultimately impose higher costs and/or risks of unserved energy on consumers.

Impact on Frequency Control Ancillary Services

To maintain power system frequency within required bounds, system operators must adjust the output of generators to match moment-by-moment variations in the demand of loads and supply from generators. The integration of intermittent

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38 AEMC (2008b), pp.12-13.

39 SSD Rule Change, pp.27-37.

40 SSD Rule Change, p.44.

41 SSD Rule Change, pp.50-52.

42 SSD Rule Change, pp.39-42

generators into the system, the output of which may vary rapidly and unpredictably, generally makes the task of frequency control more difficult. An increase in intermittent generation may therefore increase the requirement for Frequency Control Ancillary Services (FCAS), such as regulation (or load-following) reserve, to maintain system frequency within required bounds.

Currently in the NEM, the costs of regulation FCAS are recovered from market participants according to the 'Causer Pays' methodology.[43] In the SSD Rule Change, the Commission provided that the costs of regulation services are allocated to intermittent plant to the extent they are unable to reach their dispatch levels based on a straight-line trajectory during a dispatch interval. This decision was based on the view that intermittent generators ought to face the full costs their presence imposes on the rest of the power system, in order to encourage an efficient mix of generation investment in the NEM.[44]

Impact on voltage control

Variations in load and output lead to voltage variations, which can in turn cause interference or damage to users' equipment. A large variation in the power output of a generator will cause voltage swings at the connection point and nearby points due to changing current flows in the system lines and transformers. A system operator's task of minimising generation (and hence voltage) swings is made significantly more difficult with the integration of additional intermittent generators into the system. In order to manage the impacts on voltage of the connection of wind generators, it is typically necessary for the system operator to perform detailed studies to assess the impact of each new generator on the power system.

5.3.3 Network congestion

As noted in section 5.3.2 above, a potentially important consequence of increased intermittent generation will be the impact that such generation has on existing stability constraints, which may need to be lowered for system security purposes in the absence of network augmentations. This has consequential implications for network congestion.

The potential for increased intermittent generation to reduce the stability limit of part(s)of the network, and hence increase the likelihood of congestion, is discussed in DIgSILENT (2006). Modelling conducted by DIgSILENT on behalf of NEMMCO illustrated that increased wind penetration in the southeast of South Australia had the potential to reduce the transient stability limit on the Victoria-South Australia interconnector. According to DIgSILENT, the negative

43 See NEMMCO (2001), p.6.

44 SSD Rule Change, pp.53-55.

effects of increased wind penetration in South Australia could be managed through the introduction of suitably designed reactive power support systems.

The current network connection and augmentation arrangements, as governed by chapters 5 and 6 of the Rules, should ensure that intermittent generation located in remote areas of the network who desire connection pay the total incremental cost of their connection to the grid. This cost may involve both the direct costs associated with connecting to the grid and any indirect costs as a result of connection (network augmentations at other points on the grid, installation of equipment to mitigate or offset the effect of intermittent output, etc).

Regulatory regime for transmission augmentation and connection

As noted above, the regulatory arrangements for transmission augmentation and connection are targeted towards ensuring that new renewable plant pay for the costs their connection imposes on the power system. As such, this cost will be factored into the investment decision. For example, initially investors will prefer wind investments with high capacity factors and minimal network costs. Once these sites are exhausted, investors will face choices between (a) high quality wind sites (with high capacity factors) that have higher network costs and (b) lower quality wind sites (lower capacity factors) with lower associated network costs[45]. If the difference in site quality is material then investors will be willing to pay the additional network costs (and conversely). This should all be reflected in the REC prices required to justify the additional investment.

An important consideration in this regard is the extent to which current regulatory arrangements ensure that new intermittent plant pay for the additional network costs their connection imposes on the system. According to VENCorp's transmission connection guidelines[46]:

> Wind farm developments, as well as all other non-scheduled generators, will be subject to the arrangements set out in notes 1 to 12 of the Guidelines, as are all other new connection applicants. That is, they will be required to fund any augmentations to the shared transmission network required to enable their connection to meet the relevant access standards and can elect to fund an augmentation to the shared transmission network to increase or maintain a specified power transfer capability. This will ensure a consistent application of these Guidelines by VENCorp (p.30); and
>
> To this end, VENCorp considers that there are occasions that warrant imposing additional obligations on wind farms by means of their connection agreements. One such requirement will be to require a wind farm to install generation control equipment as a term of its connection to ensure that network limitations are not violated (p.31).

45 The quality of wind sites and the associated network costs are not necessarily related – these simple examples are included for illustrative purposes.

46 VENCorp (2007a).

Thus, based on VENCorp's interpretation of the Rules, wind plant seeking connection to the grid should, in effect, pay for the total incremental cost of their connection. That is:

- Costs directly associated with connection; and
- Costs indirectly associated with connection – for example, network augmentations and/or the cost of installing generation control equipment to mitigate any negative impacts on the power system in terms of system stability.

Interpretation of the Rules in this way should ensure that the connection of intermittent generation does not have a detrimental impact on either the thermal or stability limits of the network.

As such, the economic materiality of network congestion as a result of increased intermittent generation is not expected to significantly increase. As noted in section 4.2.3, the existing transmission regulatory arrangements should be able to accommodate changes in generation investment patterns, location and timing resulting from the expanded national RET scheme.

5.4 INTERACTION BETWEEN THE CPRS AND EXPANDED NATIONAL RET SCHEME

The primary impact of the CPRS will be to increase the cost of emissions-intensive generation in Australia. In the longer term, the CPRS will provide pricing signals to encourage investment in renewable generation. However, this requires relatively high carbon costs before renewable generation is the preferred option. In the interim, gas is the cheaper option at moderate carbon price levels.

The primary purpose of the expanded national RET scheme is thus to increase the supply of renewable generation in the short to medium term, during which time the CPRS is unlikely to encourage such investment. The transitional role that the expanded national RET scheme will play in Australia's long-term climate change strategy results in an interesting dynamic between this scheme and the CPRS.

As noted in section 5.1, the REC price received by renewable generation is a function of the average wholesale electricity price. Under the CPRS, wholesale prices will increase, due to the cost that carbon-emitting generators will incur through permit prices. This increase in wholesale prices will close the gap between renewable generators' LRMCs and the average spot market price. Hence, for a given quantity of renewable generation, REC prices will fall. REC prices will continue to fall as permit prices (and hence average wholesale prices) rise, until the point where average wholesale prices are equal to the LRMC of the marginal renewable plant. At this point, the expanded national RET scheme will be redundant since, for a given quantity of renewable generation, the CPRS will be providing the pricing signals necessary to encourage that level of renewable generation investment.

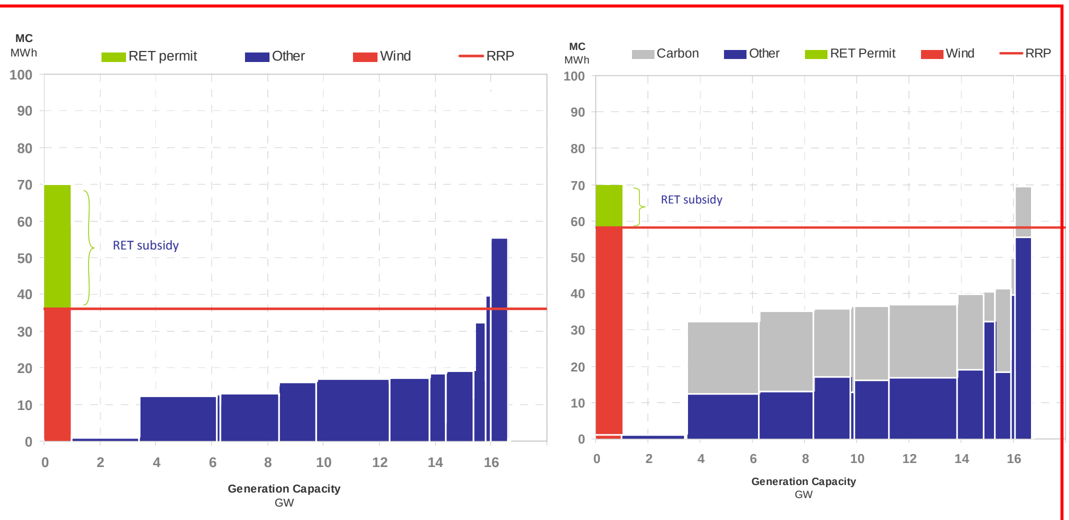

Figure 24: The impact of the CPRS on REC prices

Source: Frontier Economics

Falling REC prices due to higher wholesale energy prices post-CPRS introduction are illustrated in Figure 24. As this example shows, the introduction of the CPRS, which imposes a cost of carbon on emitting generation, forces up the average wholesale spot price. In the example outlined in 5.1 (where there was no CPRS), the average wholesale spot price was $36/MWh, while in this case the average spot price is $58/MWh. The $22/MWh increase is due to the CPRS.

As noted above, the price of RECs is defined as the difference between the average wholesale electricity price and the LRMC of the marginal renewable generator, which in this case is a wind plant with a LRMC of $70/MWh. To encourage this plant to enter the market, the REC price must equal the difference between the average wholesale spot price and this plant's LRMC, which is $12/MWh. This compares to a REC price of $34/MWh in the first (no CPRS) example. The $22/MWh reduction in the price of RECs is due to the corresponding $22/MWh increase in the average wholesale spot price, which in turn was caused by the cost of carbon priced under the CPRS.

Similarly, the expanded national RET scheme should have a dampening effect on the carbon price, since the scheme encourages abatement beyond BaU. This reduces the residual demand for abatement. Interestingly, this may actually favour high emitters in limited circumstances. While the CPRS will change the merit order and eventually displace brown coal plant (i.e. encourage early retirement), the expanded national RET scheme shifts the thermal merit order to the right but does not change the order. Under the scheme, it is typically gas plant that will be displaced.

Observed prices

Modelling of the proposed CPRS suggests carbon prices of between $24-34/tCO2 in the early stages of the scheme, and Commonwealth Government modelling suggests that much of this cost will be passed through into higher electricity prices[47]. This being the case, the theory would suggest that this should have a dampening effect on REC prices, though observed market prices for RECs does not seem to reflect this. REC prices have risen to around $50/REC during 2008, and forward prices in 2010 and 2012 were recently around $68-72/REC (Figure 25). There are several possible explanations for this result:

- The market expects that the marginal cost of meeting an extended RET is much higher than the previous target (i.e. the supply curve for renewables is upward sloped). This implies that the cost of providing new renewables increases by more than the increased wholesale energy price resulting from the CPRS – hence a higher REC subsidy is required; and/or

- The market anticipates that carbon prices (or the ability of generators to pass-through the carbon cost) will be lower than projected by the Government; and/or

- The market has simply not accounted for the increase in wholesale prices resulting from the CPRS, hence REC prices are higher than they should be.

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[47] Australia's Low Pollution Future The Economics Of Climate Change Mitigation (2008)

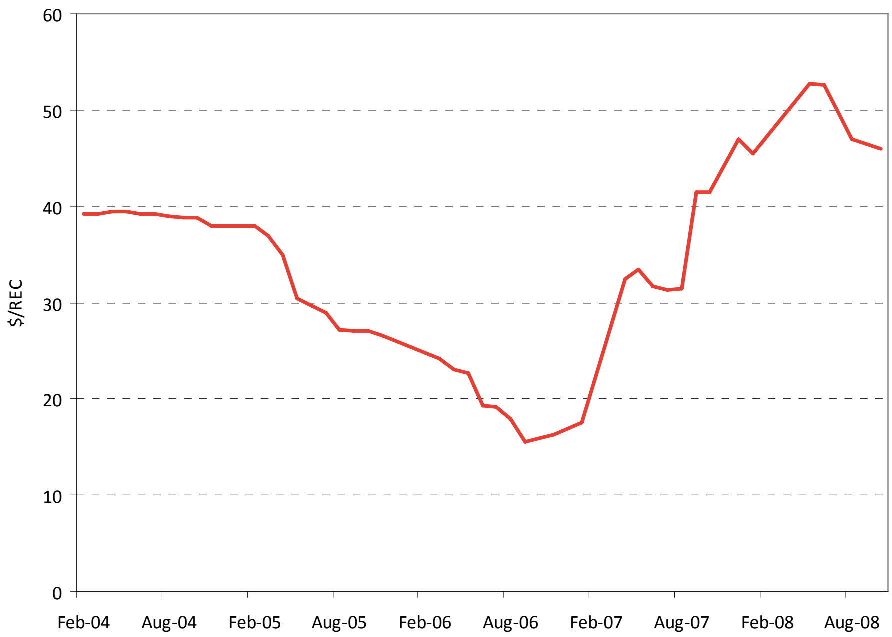

Figure 25 Historical REC prices

Source: BCSE/Nextgen

5.4.1 Summary

A summary of the likely impact of the expanded national RET scheme on key issues facing generators in the NEM is outlined in Table 6. These issues, as outlined in section 1, include forward contracting strategies; strategies for spot market offers; strategies for managing physical and financial risk; modes of technical operation, plant retirement; investment in new plant; organisational structure; and behaviour of counter-parties.

Issues	***Likely impact of the expanded national RET scheme***
(i) Forward contracting	• Retailers typically contract for RECs unbundled from the energy (which is often intermittent). Most RECs are currently contracted, and this is unlikely to change. Wind plant typically contract for 10-15 years. • The increase in intermittent generation (by itself) is likely to increase the volatility of the pool price compared to an equivalent increase in thermal capacity, since wind cannot guarantee supply of energy at times of high demand. • This should similarly translate to higher contract premiums (a similar price signal for new peaking plant). • The increased incidence of high price events should provide a market signal for new peaking capacity to complement the

Issues	***Likely impact of the expanded national RET scheme***
	additional intermittent capacity. Therefore the combined effect of additional wind and peaking plant should have a dampening effect on prices, since it reduces the potential for strategic bidding.
(ii) Spot market offers	• The increase in intermittent generation (by itself) is likely to increase the volatility of the pool price compared to an equivalent increase in thermal capacity, since wind cannot guarantee supply of energy at times of high demand. • This should be tempered by the expected entry of peaking plant in response to the price signal, which will dampen prices.
(iii) Management of physical and financial risk	• Renewable generation is not exposed to carbon price risk in the same way that CO_2-emitting plant are. • Due to their virtually zero SRMC, wind is unlikely to face the same level of physical risk as thermal plant, since they are typically dispatched first in the merit order. • The expanded RET scheme is not expected to materially increase the level of congestion in the NEM over the status quo. • This implies that renewable generators are unlikely to face any increased (financial or physical) risk *ex post* introduction of the expanded RET.
(iv) Technical operation	• The displacement of thermal plant by renewable generation may lead to a decrease in the operating efficiency of thermal plant going forward. • At the extreme, thermal coal plant may be limited to their minimum stable generation levels at low load times (such as overnight). • In response, most system operators seek to curtail renewable plant output when conventional thermal plant are approaching minimum stable levels. • However, much of the flexibility to operate around intermittent wind should be provided by additional peaking plant.
(v) Plant retirement	• Increases in the RET target over the course of the scheme are largely consistent with anticipated increases in demand over time. • This means that more new renewable plant will be built to meet growing demand rather than to displace existing thermal generation.
(vi) Investment in new plant	• The intent of the scheme is to encourage new investment in renewable plant, which is to be expected.

Issues	***Likely impact of the expanded national RET scheme***
	• The choice of location for investment in renewable generation is determined by natural resources (eg wind quality, geothermal potential etc) and availability (cost) of network connection. • Victoria, New South Wales and Queensland are expected to experience the greatest growth in installed wind capacity. • Other potential renewables going forward include solar thermal and geothermal. Both of these technologies are more suited to remote regions of South Australia and Queensland. • The increase in intermittent generation (by itself) is likely to increase the volatility of the pool price compared to an equivalent increase in thermal capacity, since wind cannot guarantee supply of energy at times of high demand. • This should similarly translate to higher contract premiums (a similar price signal for new peaking plant). • The increased incidence of high price events should provide a market signal for new peaking capacity to complement the additional intermittent capacity. Therefore the *combined* effect of additional wind and peaking plant should have a dampening effect on prices, since it reduces the potential for strategic bidding.
(vii) Organisational structure	• The extension of the RET is unlikely to change the incentives for organisational structure significantly. Given that most retailers contract for RECs unbundled from electricity, there does not appear to be a strong incentive for retailers to build new renewables. • The increase in price volatility (and contract premiums) resulting from a larger share of intermittent generation might increase the tendency for retailers to build peaking plant as a physical hedge. This would mitigate any increase in volatility from new build of wind alone.
(viii) Behaviour of counter-parties	• Retailers typically contract with renewable generators to ensure supply of RECs and not for the supply of energy. • Regulation allows for retailers to pass-through this cost to end-users.

Table 6: Summary of impact on issues facing generators: Expanded RET

Source: Frontier Economics

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