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The implications of Australia's carbon pollution reduction scheme for its National Electricity Market

Regina Betz [a,*], Anthony D. Owen [b]

[a] Centre for Energy and Environmental Markets, School of Economics, The University of New South Wales, Sydney, NSW 2052, Australia
[b] School of Energy and Resources, University College London, Torrens Building, 220 Victoria Square, Adelaide, SA 5000, Australia

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ABSTRACT

This paper assesses the major implications for the National Electricity Market of the introduction of a domestic cap-and-trade carbon pollution reduction scheme in Australia. The electricity sector is the largest source of emissions in the Australian economy, and it is this sector, therefore, that will bear the brunt of the impact of the proposed scheme. The paper addresses core issues for the electricity market up to 2020 operating under the scheme. It focuses specifically on its impact on electricity prices and generation technology mix. These two variables have been assessed using a number of models, each applying different assumptions about key impact factors. In this paper we present a comparative summary of the results of the three highest-profile models and compare their assumptions in order to explain differences in projected outcomes. This comparison will give an indication of the likely range of impacts on the market of the current design of the scheme.

0. Introduction

This paper assesses the major implications for the Australian National Electricity Market (NEM) of the introduction of a Carbon Pollution Reduction Scheme (CPRS). The CPRS is the proposed domestic cap-and-trade greenhouse gas (GHG) emission reduction scheme in Australia, which is currently awaiting Parliamentary approval. The electricity sector accounted for 35% of Australia's total GHG emissions in 2006 (Garnaut, 2008), making it the largest source of emissions in the Australian economy, and it is this sector, therefore, that will bear the brunt of the impact of the proposed scheme.

The paper addresses core issues for the electricity market up to 2020 operating under the CPRS. It focuses specifically on its impact on electricity prices and generation technology mix, based upon the following factors that will have a significant impact on the NEM over this period:

- the design of the scheme, such as the price cap and other design specifications;
- the price for the Australian Emissions Units[1] (AEUs), which depends on the emissions reduction target for Australia, marginal mitigation costs in Australia, and international linkages which permit the use of overseas units to achieve compliance;
- future fuel cost developments (mainly gas and coal prices);
- the timing and cost of major technological innovations, such as Carbon Capture and Storage;
- the range of future investment in renewable energy technologies, and their locations, resulting from incentives arising from the extended Renewable Energy Target; and
- the extent of the pass-through of carbon pricing to wholesale and retail electricity prices and the consequent level of price-induced demand-side reduction.

The impact of the CPRS on the generation mix and electricity prices has been assessed using a number of models, each applying different assumptions about the key impact factors listed above. In this paper we present a comparative summary of the results of the three highest-profile models (MMA, 2008; CRA, 2008; ACIL Tasman, 2008) and compare their assumptions in order to explain differences in projected outcomes. This comparison will give an indication of the likely range of impacts on the NEM of the current design of the CPRS.

The next section of this paper gives an overview of Australia's planned CPRS scheme. In Section 3 we elaborate on the future development in the NEM and derive major impact factors. Section 4 assesses the different models and the final section contains our conclusions.

1. The proposed Carbon Pollution Reduction Scheme

The Carbon Pollution Reduction Scheme Bill was introduced into the Australian Parliament in May 2009, together with some

* Corresponding author. Tel.: +61 2 9385 3354.
E-mail address: r.betz@unsw.edu.au (R. Betz).

[1] One AEU represents 1 tonne CO_{2-e}.

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enabling regulations. However, some key regulations which will specify the free allocation process and auctioning as well as registry details are still to be published. Details are contained in a government White Paper (Commonwealth of Australia, 2008). The government anticipated that the legislation would be passed in 2009, but opposition parties combined to defeat the legislation in the Upper House twice. At the time of writing this article it is unclear when the legislation is going to be passed and enter into force. It is likely that it will be postponed and the start of the scheme will be delayed. The main features of the CPRS, and the related fact sheets published by the Australian Government, can be summarized as follows[2]:

- The CPRS is to cover around 70% of Australia's greenhouse gas emissions which will include a wide range of emitting sources from electricity generation to the transport sector, some of them will be covered downstream some upstream.[3]
- The Scheme is scheduled to commence on 1 July 2011.
- In the first year (2011–2012), permits can be acquired at a fixed price of $10/tonne of carbon dioxide equivalent ($CO_{2\text{-}e}$). There will be no cap on permits and permits cannot be transferred into future periods, i.e. banking will not be permitted. Full trading of permits will start in 2012-2013.
- From 2012 to 2013 onwards, permits, the so-called Australian Emissions Units (AEUs), will be date-stamped (i.e. given a vintage) and bankable. This means if an AEU is not being used for compliance in a given year, it can be transferred to, and used in, later years without restriction. In addition, a small amount of borrowing will be permissible (5% of future vintages can be used before they become valid).
- For the first four years of the trading scheme (2012–2013 to 2015–2016), a price cap will be operational[4]. This cap will start at $40/AEU and will be raised by 5%, plus inflation, annually. The future relevance of the permit price cap will be reviewed at the first independent review of the CPRS.
- Some free permits will be allocated to so-called strongly affected industries (coal-fired electricity generation), coal mining sector as well as Emissions-Intensive Trade-Exposed Industries (EITE). For coal-fired electricity generation the total amount is capped and free allocation will stop after 10 years, whereas the free allocation to EITE is uncapped and without a closing date.
- Free permit allocation to coal-fired electricity generation is based on historic electricity output (2004–2007) and their emissions intensity relative to the average emissions intensity (0.86). Thus it will only be granted to the most polluting plants. Compensation is paid on the basis that any possible retirement would not compromise energy security and ongoing operation of the National Electricity Market.
- EITE will receive free allocation based upon output data multiplied by a benchmark.[5]
- Auctioning of the residual permits which have not been issued for free will commence before the start of the scheme.
- Permits must be surrendered on the basis of annual monitoring and reporting.
- Unlimited one-sided international linkages will be made possible by the use of the Clean Development Mechanism (CDM) and Joint Implementation (JI). The export of AEUs, however, will not be permitted.

2. Impact on the National Electricity Market

By introducing an emissions trading scheme which establishes a price for carbon there will be a resulting increase in the cost of fossil fuel power generation. As a consequence, electricity prices for consumers will be increased thus reducing their demand for electricity and lowering power generation requirements (i.e. the demand-side effect). In addition, by raising the cost of power generation using fossil fuels, the price of alternative, lower-carbon, technologies will become more price competitive and hence the preferred option financially for investment in new plant (i.e. the supply side effect). To the extent permitted by market forces, the cost of carbon would be passed on through the NEM electricity pool to retailers and hence final consumers. However, depending on several factors, not all costs can be passed through and coal-fired generators could experience a decline in their net revenue if not compensated by free permit allocation. Renewable energy generators, with negligible carbon footprints, will experience net revenue gains due to the electricity price increases, while relatively (to coal) low carbon intensity gas generators may also experience net revenue gains. However, all is dependent upon the extent of the impact on total electricity demand and the position of coal-fired generators in the marketplace in the context of specific design features of the CPRS. In the following section we assess the impacts on the NEM in more detail.

2.1. Background

The NEM is the world's longest interconnected power system, stretching from Port Douglas in North Queensland to Port Lincoln in South Australia, a distance of around 5000 km. The vast bulk of electrical energy in Australia is traded through the NEM.[6] Although an emissions trading scheme has the potential to initiate rapid and profound structural transformation arising from changes in the relative cost structures of coal, gas, and renewable generators, the Mandatory Renewable Energy Target (MRET), the Queensland gas scheme, and the NSW Greenhouse Gas Reduction Scheme (GGAS) have given the Australian Energy Market Operator (AEMO), previously the National Electricity Market Management Company, substantial experience in handling such changing structures.[7]

2.2. Generation technology mix

The impact of carbon pricing on the generation technology mix clearly depends upon the marginal cost of abatement of the various options open to the generators in combination with the industry-wide emissions cap (and its future trajectory) imposed by the Commonwealth. In the short term, the choice of abatement measures with a short lead time is rather limited, therefore

[2] In May 2009 and November 2009 some new measures and changes were proposed to the White Paper proposed design for the CPRS, see latest regulation text: http://parlinfo.aph.gov.au/parlInfo/search/display/display.w3p;query=Id%3A%22legislation%2Fbillhome%2Fr4221%22

[3] A *downstream* approach requires fossil fuel users to acquire emission allowances in contrast to an *upstream* approach which requires permits to be acquired by fuel producers.

[4] The diverse impacts of the price cap on efficiency, effectiveness and fairness are discussed in Jotzo and Betz (2009).

[5] For details on the allocation rules for EITE industries see the White Paper and accompanying documents: www.climatechange.gov.au.

[6] Only the Northern Territory and Western Australia are not part of the NEM. Their exclusion is due to the vast distance between their load centres and the interconnected electricity network across the NEM member states.

[7] The AEMO administers and manages the NEM in accordance with the National Electricity Rules. An introduction to the NEM is given in AEMO (2009).

abatement will largely occur as a result of fuel switching to low emission intensity gas plant.

In the long run, abatement will have to increase significantly to reflect tighter emissions caps. This may be reflected in:

- a marked increase in the level of renewable generation;
- conversion of integrated gasification combined cycle (IGCC) coal plant to include pre-combustion carbon capture and storage (CCS);
- change in the dispatch order of existing plant; and
- limited retirement of some old coal-fired plants in the NEM.

Throughout this timeframe, however, significant increases in the (real) price of electricity may encourage energy efficiency in end-use thus reducing the growth of demand below what it would have been in the absence of a carbon price.

Specific design features in the CPRS such as the price cap and the link between free permit allocations for high polluting coal-fired electricity generators to the condition of future power generation will reduce the speed of transformation of the electricity industry by preventing old coal-fired plants from closing down.

The role of carbon capture and storage (CCS) in combating climate change is currently widely debated. In simple terms, carbon dioxide is captured from fossil fuel power plants (and potentially other major sources of emissions) and then put into long-term storage in deep geological formations instead of releasing it into the atmosphere. The separate elements of capture, transport and storage of carbon dioxide have all been demonstrated, but the integration into a complete CCS process has not been achieved to date. Technology for large scale capture of CO_2 is already commercially available and fairly well developed. Although CO_2 has been injected into geological formations for various purposes, the long-term storage of CO_2 is a relatively untried concept. Therefore it is unclear if and when this technology will be available in delivering significant CO_2 sequestration.

CCS applied to a modern conventional power plant could reduce CO_2 emissions to the atmosphere by approximately 80–90% compared to a plant operating without CCS. However, capturing and compressing CO_2 requires significant amounts of energy and would increase the fuel needs (and hence fuel costs) of a coal-fired plant with CCS by about 30%. In addition, pipeline transport of CO_2 to the site of storage would be required. Unit (i.e. \$/tonne CO_2) transportation costs are heavily dependent on quantities and, to a lesser extent, the distances involved. Not surprisingly, therefore, indicative costs for coal plant with CCS vary widely, with the International Energy Agency (IEA, 2008) quoting a range of from US\$40 to US\$90 per tonne of CO_2 captured and stored depending on the power plant fuel and the technology used. It anticipates that costs could fall below US\$35 per tonne of CO_2 captured for coal-fired plants by 2030 with sufficient R&D support. This amounts to approximately US\$0.01–US\$0.03 per kWh in 2030 for capture, transport and storage.

This relatively optimistic projection for CCS by the IEA suggests that it could be a relatively low cost future option for mitigating CO_2 emissions, especially in countries such as Australia that have access to significant reserves of cheap coal for power generation. A carbon price of a minimum of \$35 will be essential for the widespread deployment of CCS, in the absence of other significant commercial benefits flowing from the technology (such as enhanced oil recovery). CCS may also render coal-to-liquids technology economically viable in the presence of high oil prices.

2.3. Implications for the gas industry

Natural gas as an energy source has significant environmental benefits over both coal and oil in terms of lower greenhouse gas and other emissions per unit of energy. Whilst Australia has natural gas resources capable of sustaining domestic and export markets for well into the current century, they are distributed asymmetrically across the continent, with over 60% of the reserves and resources located off northwest Western Australia and in the Timor Sea. Nevertheless, significant reserves of natural gas are located both on- and off-shore in eastern Australia and these currently supply the domestic market in those states.

The proposed introduction of carbon pricing has led to a move towards greater use of gas for future power generation requirements. Gas turbines and/or hydro have always been regarded as the preferred technologies for meeting peak demand, but the efficiency and lower carbon emissions associated with Combined Cycle Gas Turbine (CCGT) plant has raised that technology as a commercially viable alternative to coal. Gas-based power generation technologies have a lower capital cost and shorter construction time than coal-fired plants. In addition, they can be built in modular form, expanding by small increments to meet increases in demand. Thus capital outlay is lower than for coal and a revenue stream commences earlier. With discount rates in the private sector significantly higher than those for public sector corporations, these factors explain the appeal of gas. On the downside, gas has traditionally been a more expensive fuel than coal and hence the predominance of coal generation technologies in the NEM. However, the adoption of carbon pricing will off-set this fuel cost advantage, albeit to an unknown degree at present, provided the cost of gas does not rise in response to higher demand to more than off-set any competitive gain.

Without a delivery infrastructure gas is "stranded". Even with a local pipeline infrastructure the resource may be stranded locally due to the limited volumes that can be recovered. In other words, it may not be able to command world parity pricing. At present this accounts for the much lower cost of natural gas in the eastern states, in contrast to Western Australia which is currently reliant for additional requirements on the North West Shelf producers where netback[8] liquefied natural gas (LNG) export prices have placed a lower bound on the price of future supplies of domestic gas. Export LNG prices tend to be linked to international oil prices because of the long-term nature of the contracts.

Over the past decade, Australia's gas resources have been extended by the rapid development of coal seam gas, generally referred to as coal seam methane (CSM), in Queensland and New South Wales. Although regarded as a major hazard in coal mining and traditionally vented to the atmosphere,[9] modern technology has enabled CSM to now be regarded as a valuable energy resource. EnergyQuest has estimated the total 2P[10] gas resource of eastern Australia at 26,240 PJ, approximately 50 years of forward production at current rates.[11]

There are currently three publicly announced plans for constructing LNG export terminals in Gladstone using Queensland CSM gas as feedstock. If these planned investments come to fruition it could be expected that international LNG prices would

[8] The netback price is the price at which LNG producers would be getting the same return on domestic gas sales as for LNG, taking into account the relevant infrastructure required to produce the two products.

[9] With a warming potential 21 times higher than carbon dioxide, methane is a highly intensive greenhouse gas.

[10] 2P resources refers to both proven and probable reserves, and represents the industry's expected volume of gas that can be produced and sold. It is general industry practice in Australia to contract based on 2P gas reserves volumes.

[11] Essay contained in AER (2009).

place significant upward pressure on domestic gas prices in Queensland and, potentially, NSW. However, in the near term, CSM producers are likely to monetise their resource domestically in order to obtain a revenue stream to support any expansion into the high up-front capital cost LNG industry. Unlike their North West Shelf counterparts they cannot benefit from the high value condensate that is generally associated with natural gas and provides a significant revenue stream early in the project life-cycle.

The gas transmission system in Australia is privately owned. It operates in two modes: one as a link between gas fields and gas markets, the other as an interconnection of regional systems. The pipeline network has worked effectively under conditions of rapid expansion of gas demand and diversification of gas supply sources, in a largely unregulated marketplace. With the anticipated expansion in gas requirements for power generation, the commercial interests of both producers and consumers are likely to ensure that this situation continues. Gas is of no value without a delivery system (i.e. a pipeline)!

Gas is delivered by high pressure pipelines from the fields to designated points (known as city gates) for subsequent delivery to industrial and residential consumers via lower pressure distribution grids. These pipelines have permitted the rapid expansion of gas availability to NSW and Queensland, and a number of new pipeline developments are planned to link the CSM resources in these two states with the major centres of demand.

Wood Mackenzie (2007) has calculated the long run marginal cost (LRMC) of new coal and new CCGT generation plants (75% loads factor) for NSW for a range of carbon and gas prices. The calculations imply that:

- at the current delivered cost of gas (around \$4.50/GJ), CCGT would not be competitive with coal for a carbon price below \$15/t CO_2;
- with a carbon price between \$15 and \$20/t CO_2, CCGT would be competitive with coal with a delivered gas cost of up to \$5.50/GJ; and
- with a carbon price greater than \$25/t CO_2, coal is not competitive with CCGT unless the price of gas is greater than \$5.50/GJ.

The critical issue, therefore, is the gas price trajectory to 2020 given the anticipated increase in demand from the power generation sector in eastern Australia. Whilst reserves appear to be more than adequate to meet projected demand, the prices of gas and carbon will, between them, ultimately determine the technology mix for power generation.

2.4. System operation and security impacts of greater reliance on intermittent generation

Determining the optimal portfolio of long-term electricity generation assets is a complex task requiring assessment of many technical and financial factors. The introduction of carbon pricing (or other policies designed to improve the competitive position of renewable technologies) adds another dimension to the problem. The characteristics of generation from intermittent sources such as wind and solar differ fundamentally from those of conventional fossil fuel and hydro generation technologies. For example, wind generation displaces base-load energy, but because of its intermittent nature reduces and alters the load shape rather than serving it. To maintain system reliability, therefore, back-up generating capacity is required and typically this will be provided by peak load plant (such as open cycle gas turbine) which can be switched on and off quickly, as necessary. Depending on the location of wind farms, back-up capacity may vary from around half the wind capacity (where all wind power is provided from a single location) to one-fifth (for widely dispersed wind farms). Clearly, the extent to which back-up generation is required has implications for the carbon footprint of wind generation itself.

Other renewable generation technologies have different intermittent characteristics to wind. For example, peaks in solar generation typically match peaks in demand thus providing a high degree of reliability during daylight hours. Tidal power has complete reliability, but is extremely intermittent without ancillary investments in support canals. At the other extreme, biomass, such as bagasse, can provide reliable base-load with no intermittency, provided the fuel is readily available. Another source of reliable base-load is geothermal (or "hot rocks") energy, which is potentially a large volume, emissions free, renewable, energy source that also has the advantage that it is not sensitive to fuel price volatility.

Currently, in the absence of carbon pricing, renewable projects (with the exception of existing hydro projects) are not generally commercially viable in Australia without incentives such as the MRET. However, one impact of carbon pricing could be that renewable technologies will feature more prominently in least cost generation portfolios in the future and this would have implications for the nature and mix of the remainder of the plant operating in the system. Briefly, these are:

- they will displace the existing plant supplying base-load as their marginal cost is lower;
- depending on the nature of the renewable resource they may not necessarily contribute to the peak load when it occurs and additional reserve plant is likely to be necessary;
- renewable plants may need to be constrained at times so that the amount of change that can occur, due to a sudden change in the renewable energy supply rate, is within the limits of the system to respond. Alternatively, additional reserve plants may be required; and
- depending upon the location of the renewable plant, its output could be constrained by the inter-connectors (in the NEM) or other network constraints.

Wind power is a mature technology with about 150,000 MW of capacity expecting to be operating worldwide by year-end 2009. Existing installed wind power in Australia is relatively modest, with just 1300 MW installed at year-end 2008, accounting for 1.3% of annual electricity demand. Another 6785 MW is either under construction, has planning approval, or is seeking planning approval. Development has been primarily in the southern states of Victoria, South Australia, and Tasmania, as well as Western Australia, assisted by various State renewable energy initiatives and the Commonwealth's MRET.

The extended Renewable Target anticipates a 20% deployment of renewable energy by 2020. However, some of the design features such as the eligibility of solar hot water (which is not electricity but rather heat generation) or existing hydro for further creating Renewable Electricity Certificates (REC), as well as the REC multiplier for small generators (first 1.5 kW of system capacity, starting at 5 RECs/MWh of deemed renewable energy to June 2012, ramping down to 1 REC/MWh from July 2015), appear to reduce the necessary investment to 'meet' the target. However, changes in the legislation are underway which may ensure that the target is not compromised by those design features.

The implications of the 20% extended MRET, in combination with an emissions trading scheme commencing in 2010, have been analysed by Matysek and Fisher (2007). They concluded that a mandated renewable energy target in combination with an ETS is less efficient at achieving a given environmental outcome than an unadulterated ETS because it forces higher cost renewable energy into the electricity generation mix at the expense of exploiting lower cost emissions abatement opportunities elsewhere in the economy. To reach an emissions abatement target of 67 Mt CO_{2-e} in 2020, their modelling shows that the combined ETS and 20% renewable energy target policy:

- costs Australia $1.8 billion more in 2020 than a pure ETS policy in terms of economic welfare (GNP) losses;
- costs Australia $1.5 billion more in 2020 than the ETS in output (GDP) losses;
- results in the loss of an additional 3600 full time equivalent jobs in 2020;
- causes substantial switching away from gas-fired generation compared with an ETS in the order of 12,620 GWh per year by 2020;
- results in electricity prices rising at least 6% more than would be the case under an ETS alone—the price of electricity rises 24% under the combined policy approach, and by 18% under an ETS that delivers equivalent emissions abatement.

However, it must be borne in mind that the MRET is designed to encourage additional generation of electricity from renewable sources to the point where the technology passes the "early innovation" stage of industry development. Thereafter, and in the presence of a carbon pricing regime, a mature industry may be able to compete with other technologies in the absence of subsidies.

2.5. Implications for transmission and distribution

Many technologies that could dramatically reduce GHG emissions depend on the electricity delivery system, including integrated distributed and small-scale generation sources, grid-connected intermittent renewable energy sources and energy storage technologies.

The transmission and distribution systems in Australia are largely based on technology from the 1960s and require substantial upgrading to meet increasing levels of electricity trading and network congestion.[12] Clearly, one major impact may be a requirement for additional interconnector capacity between the states, as the relative costs of brown coal, black coal, and gas generators vary following the imposition of a cost for carbon, and inter-state flows adapt accordingly. If interconnector capacity were insufficient to meet requirements, then the market would become fragmented and potential gains in efficiency lost. Of course, over-investment in interconnector capacity would also give rise to efficiency losses. Thus there would need to be a trade-off to ensure that investment in additional capacity is determined in a socially optimal manner.

A significant increase in investment in renewable energy technologies, particularly where they are located in remote locations, may also require additional, or upgraded, transmission lines. The current transmission system was developed radially within each of the states, connecting the major load centres with the major generating sectors; the latter often located on major coal basins. The system gets thinner as the network reaches more remote areas. Currently, new generators connecting to the NEM are required to pay for their connection to the nearest node on the system. Renewable generators, such as wind farms, are no exception. This approach discourages a socially optimal level of investment in transmission, since initial capacity will be financed solely by the initial investor and would ignore future system expansion. If, in the future, additional generation is proposed from nearby sites, then the transmission network would require augmentation. Given the long lead time involved in transmission investment, adjustment to a socially optimal position may again be frustrated.

In addition, the shape of the electricity load curve is changing with more extremes in peak load demand, whilst the integration of more distributed and intermittent generation sources poses additional challenges.

Future electricity infrastructure and associated control systems will, therefore, have to be equipped to handle higher and more complex loads, and to recognise and dispatch small-scale components. However, power systems face more challenges with the increasing size and complexity of networks, because of problems related to load flow, power oscillations and voltage quality. Thus, modernising and improving the reliability and security of electricity networks and providing the network architecture for a low-emissions energy system will require new technologies, new information and control systems, and new approaches to system management. New large scale technologies, such as underground compressed air storage systems, will be needed to cope with significant amounts of electricity from intermittent sources. With regard to system management, emerging technologies include large scale devices for routing power flows on the grid, advanced information systems for observing and assessing grid behaviour, and real time controls and operating tools.

Demand-side technologies that reduce electrical consumption at the point of use are a key cost-reduction element in modern electricity systems. These technologies have several requirements: control hardware and a consumption profile, which can allow for load control; frequent electricity price information; and special metering that allows users to keep track of electricity consumption at different price levels. "Real time pricing" systems will permit large commercial and industrial consumers to modify their electrical loads in response to changes in electricity prices. For smaller users, where metering costs are high relative to the total electricity bill, the development of low-cost metering technologies is critical for demand-side control.

2.6. Distributed power generators

Distributed power generators are small, modular electricity generators sited close to customer loads. They are commercial options in markets with varying characteristics, from densely populated urban areas, where supply reliability and energy efficiency are key advantages, to sparsely populated regions with abundant renewable resources and high grid-connection costs. Combined heat and power production is the largest segment of the existing decentralised generation market, but decentralised power supply systems using renewable energy have been introduced in areas where the transmission and distribution system is absent or inadequate. Where the latter replace conventional oil or diesel technologies, significant reductions in GHG may result.

A small amount of fluctuating wind power in a grid is, in effect, indistinguishable from variations in demand and hence can be handled using existing peak load plant. However, under high levels of wind penetration power (greater than 20% of generation-meeting load), impacts on system operation and transmission

[12] The issue of network congestion in the NEM is the subject of AEMC (2008a, b). The primary issue was the adoption of a pricing regime that would reflect the true cost of congestion in transmission. However, it concluded that "evidence to date does not show that transmission congestion has been a material problem" and therefore no change to existing practices was necessary.

capacity could be expected. This is mainly due to the large penetration of wind power at one or two network connection points and the uncorrelated nature between wind generation and load that requires large amounts of balancing power for frequency control and stabilisation.

An important distinction between conventional and intermittent generators is that tripping (i.e. outage) of a conventional generator generally occurs instantaneously, whereas large output changes from intermittent generators typically occur over several hours in response to weather events (such as changes in sunlight or wind speed). In addition, intermittent generation can vary in both positive and negative directions, while conventional generation is subject only to sudden output loss. High output swings due to intermittent generation are managed in the same way as for conventional generation or for significant changes in demand. The market operator contracts with market participants to add or remove net generation as necessary to correct the deviations in frequency that result from unforeseen output swings. However, when intermittent energy penetration approaches levels of 20% or more then additional control requirements become a significant cost to the system.

The best wind resources in Australia are typically in remote places far from the load centres, thus requiring significant investment in the transmission network. In addition, the variability of wind farm generation introduces uncertainty regarding the contribution they will make to meeting the forecast maximum demand over the range of NEM forecasting horizons. Forecasts of wind farm generation levels are important for the operation of the power system, for the management of supply reserves, and also for the market to support the accuracy of forward spot market information.

3. Modelling comparison

In order to determine the likely impact of the CPRS on the Australian electricity sector, we compare different models with respect to the assumptions employed and results obtained.[13] The following models and scenarios have been assessed:

MMA Treasury

CPRS-5: this scenario assumes that Australia's allocation is 5% below 2000 emission levels by 2020 and CPRS starts in 2010.
CPRS-15: this scenario assumes that Australia's allocation is 15% below 2000 emission levels by 2020 and CPRS starts in 2010.

MMA Garnaut

Garnaut-10 this scenario assumes that Australia's allocation is 10% below 2000 emission levels by 2020 and CPRS starts in 2013.
Garnaut-25: this scenario assumes that Australia's allocation is 25% below 2000 emission levels by 2020 and CPRS starts in 2013.

ACIL Tasman (Energy Supply Association of Australia, ESAA)

AcilTas-10: this scenario assumes that the CPRS (start: 2010) will reduce emissions in electricity sector (NEM and SWIS) by 10% below 2000 emission levels by 2020.
AcilTas-20: this scenario assumes that the CPRS (start: 2010) will reduce emissions in electricity sector (NEM and SWIS) by 20% below 2000 emission levels by 2020.

CRA (National Generator Forum, NGF)

CRA-7: this scenario assumes that the CPRS (start: 2010) will reduce emissions in electricity sector by 7% below 2000 emission levels by 2020.

One major difference between the models asssessed is their scope. Although the MMA model is a model of the electricity sector, it uses results from the Monash Multi-Regional Forecasting (MMRF) model (an economy-wide model) and the Global Trade and Environment Model (GTEM) (modelling the international sector) as inputs, as well as feeding results back into the MMRF model in order to obtain implications for the whole Australian economy. The CRA and ACIL Tasman models, on the other hand, model the electricity sector only. Thus the whole percentage reduction has to be achieved within that sector, whereas the MMA model allows for reduction in other domestic sectors or through international offsets. Observing the projected electricity sector emissions for 2020 in Fig. 2, these effects are clearly visible.

As a result of allowing emissions to be reduced in other parts of the economy as well as internationally, emissions of the electricity sector in three of the four MMA scenarios rise above 2000 levels by 2020, whereas in the CRA and ACIL Tasman models the exact percentage reduction is achieved by the electricity sector. Important to note is the impact of the extended Renewable Energy Target (eRET), which is included in the MMA CPRS, the CRA and ACIL Tasman models, but is not modelled in the MMA Garnaut scenarios, where the eRET as well as all state and territory policies, are assumed to cease when emissions trading starts in 2013. Another interesting observation is the difference in assumed baseline emissions. They are 175 Mt CO_{2-e} for all MMA scenarios, whereas CRA and ACIL Tasman start from 2000 emission levels of 165 Mt CO_{2-e} resulting in a smaller absolute reduction, but lower emissions levels in 2020.

Since the MMA model expects unlimited use of international offsets, the carbon price equals the international price and is therefore exogenous in the model, whereas the CRA and ACIL Tasman models make the permit price endogenous, modelling it according to the emissions levels that have to be achieved by the electricity sector. The expected permit prices at the start of the scheme are shown in Fig. 3. The MMA CPRS model, as well as those of CRA and ACIL Tasman, use a 2010 starting date, whereas in the Garnaut scenarios the scheme starts in 2013. As stated above, the CPRS Bill includes a price cap of $40 for the second year of the scheme (2012). Converting this into $2008, yields a price cap of $36. Considering a possible reduction target of 25% (as one proposal of the Bill) (see Fig. 1), modelled by the Garnaut-25

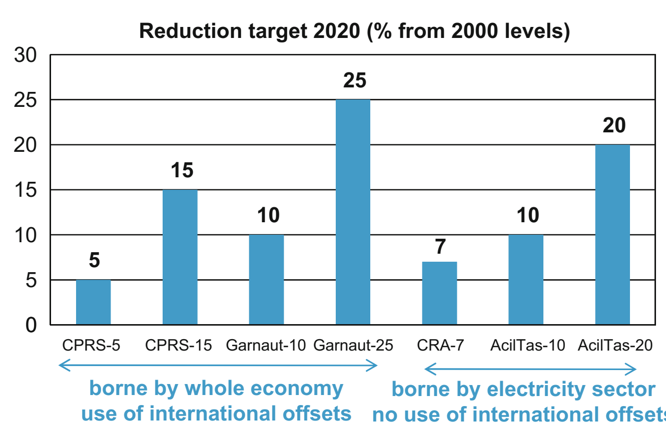

Fig. 1. Reduction target 2020.
Source: MMA (2008, p. 2); CRA (2008, Exhibit 4.3, p. 103); ACIL Tasman (2008, p. 2).

[13] Details are given in the Appendix.

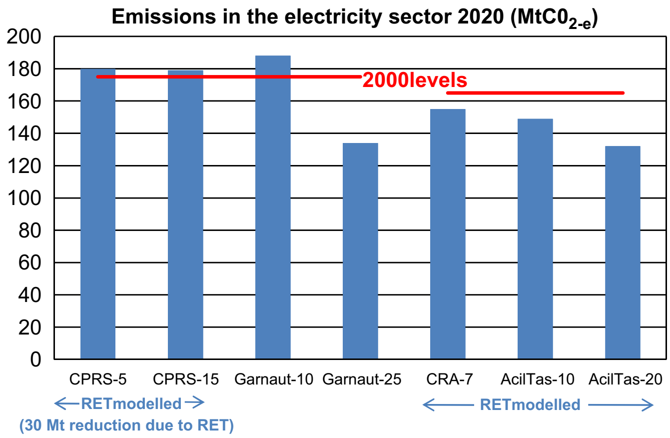

Fig. 2. Emissions in the electricity sector 2020 (Mt CO_{2-e}).
Source: MMA (2008, Table 3-1, p. 34); CRA (2008, Exhibit 4.3, p. 103); and ACIL Tasman (2008, Fig. 4, p. 20).

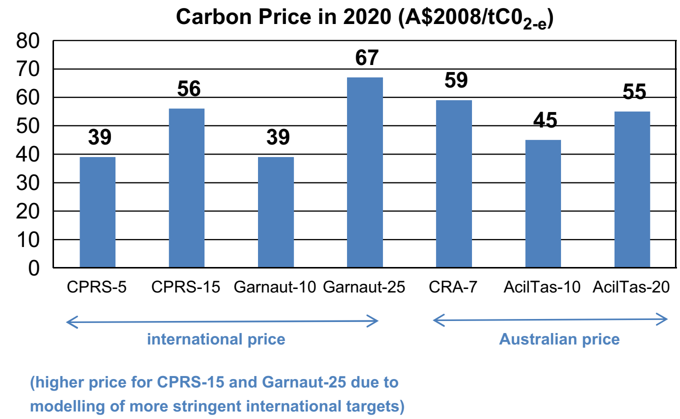

Fig. 4. Carbon price in 2020 (A\$2008/t CO_{2-e}).
Source: Prices for MMA scenarios in A\$2005 from Treasury Summary (2008, Table 3.2, p. 19) and Treasury (2008, Table 6.9, p. 139), converted into A\$2008 using RBA Inflation Calculator; CRA scenario prices in A\$2007 from CRA (2008, Exhibit 4.3, p. 103), converted into A\$2008 using RBA Inflation Calculator; ACIL Tasman (2008, p. 4f).

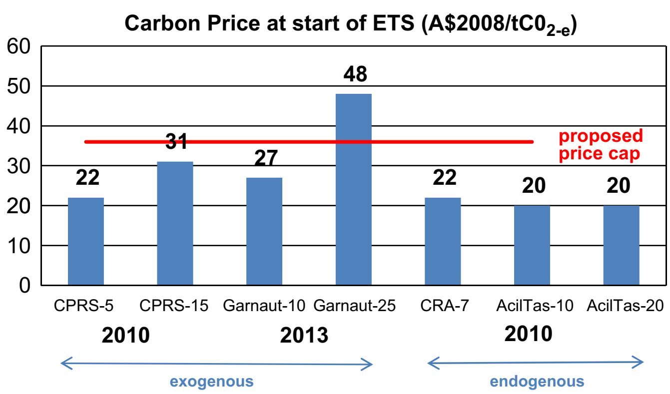

Fig. 3. Carbon prices at start of ETS (A\$2008/t CO_{2-e}).
Source: Prices for MMA scenarios in A\$2005 from Treasury Summary (2008, Table 3.2, p. 19) and Treasury (2008, Table 6.9, p. 139), converted into A\$2008 using RBA Inflation Calculator; CRA scenario prices in A\$2007 from CRA (2008, Exhibit 4.3, p. 103), converted into A\$2008 using RBA Inflation Calculator; ACIL Tasman (2008, p. 4f).

scenario, one can see that the initial carbon price is well above the proposed price cap.[14] This raises the issue of whether introducing a more stringent target while maintaining the price cap is politically risky because of its potential implications for the budget. Since Australia is going to be bound by its international target, the price cap will increase the likelihood that the Australian government will need to buy permits to cover the shortfall on the international market and will also need to finance the gap between the international price and the price cap (Jotzo and Betz, 2009).

Looking at the 2020 prices in Fig. 4 it can be seen that for the lower reduction scenarios the international price is lower than the Australian price (\$39 in Garnaut-10 including international linkage vs. \$45 in AcilTas-10 Australian electricity market only). The higher prices for the CPRS-15 and Garnaut-25 scenarios are due to modelling of more stringent international targets (emission stabilisation at 510 and 450 ppm CO_{2-e}, respectively). It is striking that these prices are similar to the ones ACIL Tasman calculates, even though in their model emissions reductions have to be achieved in the electricity sector alone and companies cannot resort to international offsets. As noted above, this is another indication of the substantial impact of the RET, which is responsible for a large share of the reductions in the electricity sector, thus achieved without the incentive of a price on emissions. Consequently, the prices modelled to achieve a certain reduction do not have to rise as high as they would have without the RET. The CRA 2020 price of \$59 seems very high, significantly higher than prices in both ACIL Tasman scenarios although they make similar modelling assumptions. This result (in conjunction with a weak demand-side response) will also lead to higher wholesale and retail prices in the CRA scenario as compared with the other models.

Since, under an emissions trading scheme, liable parties (fossil fuel power generators) must hold carbon permits in order to cover their greenhouse gas emissions, the price of these permits is effectively added to a generator's short run marginal costs and thus increases both the wholesale and retail price of electricity. This rise in electricity prices is vital in order to encourage both investment in low-carbon generation technologies and more efficient end-use.

Experience from the EU ETS has shown that electricity generators add-on the price of carbon regardless of the method of allocation used. Although most of the allowances were allocated for free in the first phases of the EU ETS (2005–2007; 2008–2012), electricity producers treated their value as an opportunity cost (since they could otherwise sell them on the market) and passed it on, essentially treating it as another cost of production. As a large percentage of these permits were issued for free, they realised substantial additional (so-called 'windfall') profits. Matthes (2008) has estimated annual average "windfall profits" of approximately €7 billion for the German electricity industry (of which €4 billion is for CO_2-free electricity production plants, such as nuclear and hydro, that already exist) for the second period of the EU ETS (2008–2012).

The actual impact on electricity prices depends on:

- the cost of carbon (i.e. the price of emission permits);
- the carbon intensity of electricity production; and
- the pass-through rate to final consumers.

The pass-through rate is determined by a whole range of different factors, including:

- *Market structure*: Typically, the more competitive a market the higher the pass-through rate as prices in such markets closely track actual costs.

[14] The price cap is giving companies the option to buy as many permits as necessary at a "fixed charge" (e.g. \$40 in 2012/2013) in the reconciliation phase. This means de facto that the emissions in those first 5 years of the scheme are not capped and that no company will choose to pay the penalty if it is higher than this fixed price charge (see Section 89 of the Bill).

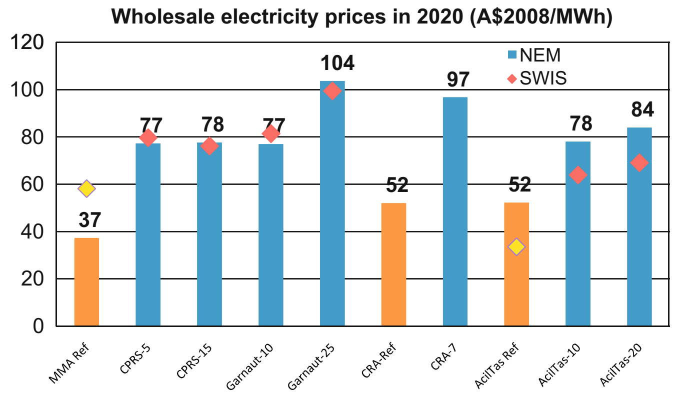

Fig. 5. Wholesale electricity prices in 2020 (A$2008/MWh).
Source: Reference prices per state for MMA scenarios from MMA (2008, Fig. 4-1, p. 43), increase 2015–2020 from Treasury (2008, Table 6.14, p. 176) (this is the estimate closest to 2020 and with the smallest time frame:5 years), averaged using predicted BAU consumption from MMA (2008, Table A-1, p. 58), converted into A$2008 using RBA inflation calculator, compared to MMA (2008, Fig. 4-3, p. 46 (consistent results)); CRA (2008, Exhibit 4.3, p. 103), converted into A$2008 using RBA Inflation Calculator; ACIL Tasman (2008, Table 1, p. 5), averaged using predicted BAU consumption from ACIL Tasman (2008, Table 20, p. 54).

- *Outside competition*: Unlike other industries, electricity generation in Australia does not face international competition. However, as low-carbon installations become more cost competitive, it could become harder for carbon costs to be passed through.
- *Market regulation and voluntary agreements*: In order to protect end consumers from the negative impacts of higher electricity prices, price restrictions can be set or agreements reached with the government.
- *Market demand response (elasticity)*: Particularly in the long run, the electricity demanded might fall as consumers have time to respond to higher prices and adopt power-saving technologies, which would make the pass-through less attractive.
- *Changes in merit order*[15]: A change in merit order can be, for example, when a coal plant is the marginal plant (i.e. the plant which determined the market price for electricity) but after the introduction of an emission trading scheme, when the price of carbon is taken into account, a gas plant becomes the marginal plant.

The modelling of wholesale electricity prices in 2020 indicates that higher carbon prices generally translate into higher wholesale prices (Fig. 5). Again, the impact of a high permit price (e.g. for the CPRS-15 scenario) might be diminished by the Renewable Energy Target, meaning that energy generators have to invest in renewable energy regardless of the permit price, thereby incurring investment costs that are decoupled from this price. Although the scenarios make quite different assumptions regarding reference prices in 2020, MMA and ACIL Tasman obtain similar results (except for the Garnaut-25 scenario where the permit price in 2020 was much higher than in all other scenarios in the absence of the RET). The price of $97 for the CRA model corresponds directly to the very high carbon price modelled, especially when one considers a rather small emissions reduction of only 7%. Again this can be explained by the modelling approach of achieving the emissions reductions only within the electricity sector.

The impact of an emissions trading scheme on retail prices (Fig. 6) is typically lower in percentage terms than on wholesale prices because the cost of electricity is only part (45% is generally taken as an indicative figure) of the total retail price to consumers. Again, the assumed reference scenario prices are very different, leading to a difference in retail prices and again, the MMA and ACIL Tasman estimates are very similar, whereas the CRA price of $180 seems rather high for an achieved reduction of 7%. The comparably low retail price for the Garnaut-10 scenario is a consequence of not including the RET in this model. ACIL Tasman, for example, attributes roughly one third (around $10) of the increase in retail prices to the RET.

As discussed above, an increase in retail prices is usually accompanied by a reduction in electricity demanded via efficiency measures implemented by households and industry (Fig. 7). Once again, MMA and ACIL Tasman obtain similar figures of −11% to −16% and −12% to −14% with a more substantial reduction of −23% for the Garnaut-25 scenario, corresponding to the highest wholesale and retail price of all scenarios. CRA bases their reduction estimates on a very inelastic electricity demand of 0.2, leading to an energy efficiency response of only −3%. This, together with high permit prices, is the reason for high wholesale and retail prices in the CRA model, thereby suggesting a much greater burden for households and industry than the other models.

As noted above, a price on emissions not only encourages more efficient end-use, but also investment in low-emission technology. The generation mix modelled for 2020 shows only slight differences between the MMA modelling and CRA/ACIL Tasman (Fig. 8). CRA and ACIL Tasman assume a slightly higher use of gas and lower use of brown coal. Since emissions reductions in the CRA model are not achieved via reduced demand, the generation mix has to change in order to reduce emissions while maintaining nearly the same output. This, together with high permit prices, is a possible explanation for the rather high use of gas, very low use of brown coal, and the existence of CCS in the 2020 generation mix. One might have expected a bigger shift from coal to gas also in the MMA modelling. But considering a probable reduction in demand (reducing need for the peaking plant, which is usually gas-fired) and, once again, additional renewable energy production by means of the RET in almost all scenarios, a big shift to gas by 2020 does not seem necessary, which seems reasonable given the limited gas network in the short run.

With regard to the renewable energy mix, as expected, the impact of the RET on the installation of these energy generation technologies is significant (Fig. 9). The Garnaut-25 scenario, due to the high carbon price in 2020, achieves the same deployment of

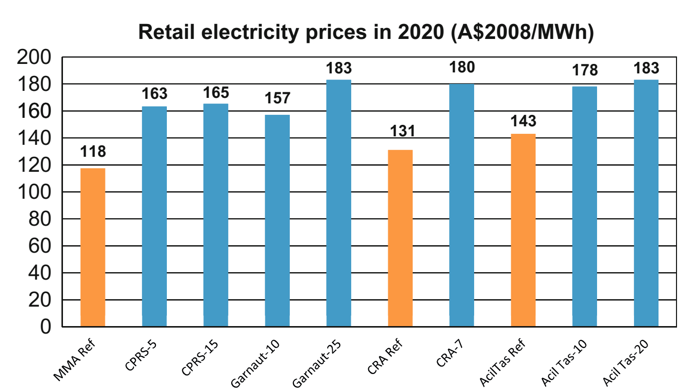

Fig. 6. Retail electricity prices in 2020 (A$2008/MWh).
Source: MMA (2008, Fig. 4-4, p. 48); CRA (2008, Exhibit 4.5, p. 105); and ACIL Tasman (2008, Table 2, p. 7).

[15] Different generation units are ranked according to their production capacity and their production costs. This ranking is referred to as merit order. The higher up the merit order, the cheaper the unit cost of generation and hence the more likely that unit's output will be dispatched.

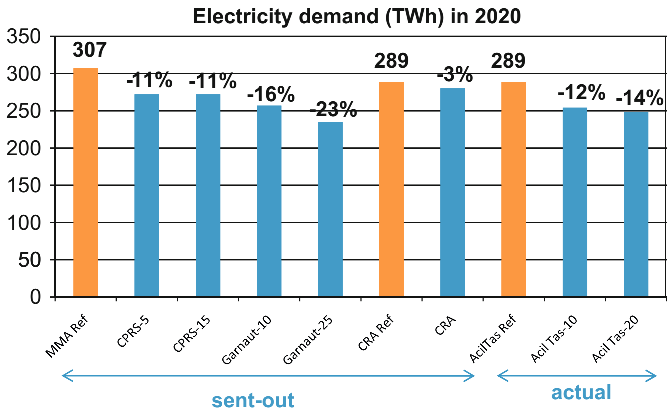

Fig. 7. Electricity demand (TWh) in 2020.
Source: MMA (2008, Table 3-2, p. 37); CRA (2008, Exhibit 4.7, p. 108); and ACIL Tasman (2008, Table 18-20, p. 53f).

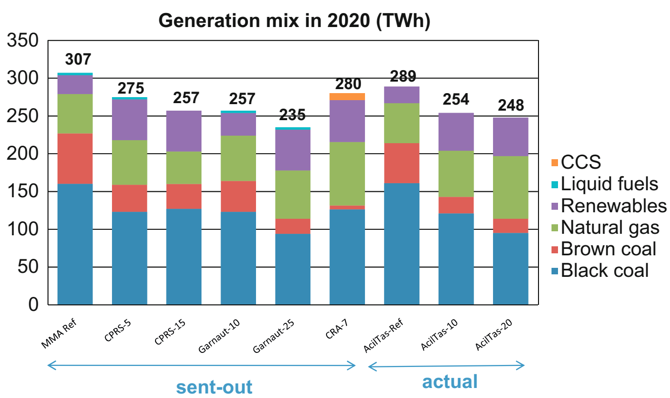

Fig. 8. Generation mix in 2020 (TWh).
Source: MMA (2008, Table 3-3, p. 38); CRA (2008, Exhibit 4.13, p. 113); ACIL Tasman (2008, Fig. 23, p. 73 and Fig. 25, p. 76).

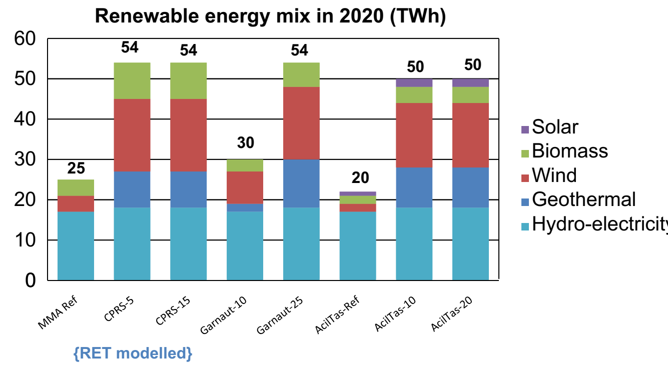

Fig. 9. Renewable energy mix in 2020 (TWh).
Source: MMA (2008, Fig. 3-4, p. 37); ACIL Tasman (2008, Fig. 23, p. 73 and Fig. 25, p. 76).

renewables as the other scenarios, even without modelling the RET. Contrary to the MMA model, the ACIL Tasman model assumes solar energy as part of the generation mix in 2020 (at a capacity of 1110 MW). However, it is unclear how much of the design changes of the actual legislated eRET have been reflected in the modelling. In particular, the inclusion of solar hot water and the multiplier for small generation systems will significantly reduce overall investment in renewable electricity generation by 2020. This has been reflected in significant REC price decreases in 2009. Changes are underway to address at least some of these concerns.

4. Conclusions

In conclusion, the introduction of an emissions trading scheme will have several short term and long term impacts on the electricity market in Australia. The viability of Australia's coal-based sector clearly depends upon the price of carbon and the sector's ability to adjust to the new trading environment.

In the short term it will at best give an incentive to switch from coal to gas. The sector will also have the opportunity to invest in international offsets, which may be cheaper than the price of permits where these can be derived from investments in (for example) the Clean Development Mechanism (CDM). However, it is the combination of permit prices and gas prices that represent the key to the short-term (i.e. pre-CCS technology) financial viability of coal-fired power generators.

In the long-term the pricing signal will encourage investment in technological adjustment of generation processes, thus increasing emission efficiency in power production (i.e. lower levels of emissions per MWh generated) leading to a change in generation mix. How the long-term generation mix (beyond 2020) in Australia will look like depends on the level of domestic gas prices relative to LNG prices and the extent to which Carbon Capture and Storage will play a role.

However, the likelihood of the retirement of coal-fired plants in the medium term in Australia is reduced by the chosen scheme design which issues free permits to coal-fired electricity generators to cover the first 10 years. Thus, the emissions targets in Australia will only be reached by significant acquisitions of international permits. Even if international prices increase substantially, the Australian permit price is capped at levels which may prevent significant increases in electricity prices and reduce incentives for energy efficiency.

Given those compromises in the CPRS design it seems that the major impact on the NEM will be caused by the extended Renewable Energy Target. The increased share of renewables will require more transmission lines and interconnector capacity as the infrastructure will need to change from a centralised network to a decentralised network. But again, the eRET design also suffered during the policy process and the 20% share of renewables in 2020 may actually not be reached due to compromises in the scheme design (e.g. solar hot water, multiplier for small generation units).

Our comparison of models has shown that the estimates of the extent of increases in electricity prices and expansion of renewable technologies depend on the underlying modelling approach and its assumptions. It should be remembered that the models lack some key variables which may determine the actual outcome, such as weather, load variability, interconnection constraints or bidding behaviour. While keeping these modelling limits in mind, our comparison of models has shown that the results of the MMA and ACIL Tasman models are quite similar, even though they make different assumptions regarding the carbon price (international vs. domestic price). This is due to the substantial impact of the RET (at least up to 2020), which reduces the importance of the price signal in reducing emissions. Once the RET starts to be phased-out after 2020, the price signal will play a more important role in shaping the Australian electricity market. The results of the CRA model appear quite different as compared to the other models and imply a much greater impact on electricity generators and consumers than the others. Again specific assumptions of energy efficiency, elasticity of demand and fuel prices as well as the structure of the model which allows only for reductions in the electricity sector can explain the

Table A1

Model	**MMA Treasury** Ref: MMA (2008)	**MMA Garnaut** MMA (2008)	**CRA (NGF)** CRA (2008)	**ACIL Tasman (ESAA)** ACIL Tasman (2008)
Exogenous variables	• **permit price (international price)**→**MMRF** • fuel/commodity prices→GTEM • initial demand forecast • electricity market characteristics (emissions intensity, costs, etc.) • wholesale/retail prices		• **emissions** • fuel/commodity prices • demand projections • electricity market characteristics (emissions intensity, costs, etc.) (database)	
Endogenous variables	• **emissions** • demand response • generation mix (cost of generation, fuel usage, investments)		• **permit price** • wholesale/retail prices • demand response • generation mix (retirement, new entry)	
Targets for 2020—compared with 2000 levels	• CPRS-5: 5% • CPRS-15: −15%	• Garnaut-10: −10% • Garnaut-25: −25%	• CRA-7: −7%	• ACILTas-10: −10% • ACILTas-20: −20%
Emissions of electricity sector (Mt CO_{2-e}) in 2020/reduction (Mt CO_{2-e}) compared to 2000 levels	**2000** **s5** **s15** **level** 175 180 179 **red.** 5 4	**2000** **s10** **s25** **level** 175 188 134 13 −41	**2000** **s7** **level** 165 155 −10	**2000** **s10** **s20** **level** 165 149 132 −16 −33
Carbon price (2008A$/t CO_{2-e})	**s5** **s15** **2010** 22 31 **2020** 39 56 **ppm** 550 510 Global price—higher price for s15 due to modelling of more stringent international emission stabilisation goals	**s10** **s25** **2013** 27 48 **2020** 39 67 **ppm** 550 450 Global price—higher price for s25 due to modelling of more stringent international emission stabilisation goals	**s7** **2010** 22 **2020** 59 Determined by model to achieve −7%	**s10** **s20** **2010** 20 20 **2020** 45 55 Determined by model to achieve −10%/−20% reduction
Wholesale electricity price in 2020 (2008A$/MWh)	**Ref** **s5** **s15** **NSW** 39 80 81 **VIC** 36 78 79 **QLD** 34 72 71 **SA** 47 82 80 **TAS** 37 72 74 **WA** 58 80 76 **NT** 126 138 145 **NEM** 37 77 78 **SWIS** 58 80 76	**Ref** **s10** **s25** **NSW** 39 79 104 **VIC** 36 76 106 **QLD** 34 73 101 **SA** 47 88 107 **TAS** 37 70 98 **WA** 58 81 99 **NT** 126 138 156 **NEM** 37 77 104 **SWIS** 58 81 99	**Ref** **s7** **NEM** 52 97	**Ref** **s10** **s20** **NSW** 52 79 85 **VIC** 50 77 82 **QLD** 53 79 88 **SA** 57 77 80 **TAS** 57 71 72 **WA** 34 64 69 **NEM** 52 78 84 **SWIS** 34 64 69
Retail electricity price in 2020 (2008A$/MWh)	**Ref** **s5** **s15** **118** 163 165	**Ref** **s10** **s25** **118** 157 183	**Ref** **s7** **131** 180	**Ref** **s10** **s20** **143** 178 183
International link (use of CERs/ERUs)	Yes, permit price determined by international price	Yes, permit price determined by international price	No	No
Sectors covered	• GTEM: international sector • MMRF: Australia/whole economy • MMA: Electricity sector	• GTEM: international sector • MMRF: Australia/whole economy • MMA: Electricity sector	Electricity sector only	Electricity sector only

Table A1 (*continued*)

Model	**MMA Treasury** Ref: MMA (2008)	**MMA Garnaut** MMA (2008)	**CRA (NGF)** CRA (2008)	**ACIL Tasman (ESAA)** ACIL Tasman (2008)
Electricity demand in reference scenario	2% p.a. increase	2% p.a. increase	2.5% p.a. increase	2% p.a. increase
Gas price (2008A$/GJ)	City node gas prices, NSW **2011** **4.8** **2020** 6.6	City node gas prices, NSW **2011** **4.8** **2020** 6.6	Average gas prices **2010** **4.1** **2020** 4.2 ● flat in base scenario ● price ramped sensitivity scenario (30 Mt higher reduction): rising to 6.0 in 2020	Gas prices per state **2008** **4.0–5.5** **2020** 5.0–7.5
CCS technology	None by 2020	None by 2020	First CCGT with CCS built by 2020 (1,129MW)	None by 2020
Energy efficiency response	Sent-out basis **Ref** **s5** **s15** **level** 307 272 272 **%red.** −11 −11 Calculated by MMRF model using prices from MMA model	Sent-out basis **Ref** **s10** **s25** **level** 307 257 235 **%red.** −16 −23 Calculated by MMRF model using prices from MMA model	Sent-out basis **Ref** **s7** **level** 289 280 **%red.** −3 Assuming an elasticity of demand of 0.2	Actual generation **Ref** **s10** **s20** **level** 289 254 248 **%red.** −12 −14 On the basis of NEMMCO SOO and IMO with adjustment by ACIL Tasman for ETS
Renewable Energy Target (RET) (additional MW installed capacity in 2020)	Expanded RET is modelled around 30 Mt CO_{2-e} of reduction can be attributed to the expanded RET	Existing RET and other state and territory policies cease when emissions trading starts in 2013	Expanded RET is modelled (total: 8950 MW, wind: 6313, geothermal: 1350, biomass: 1287)	Expanded RET is modelled (total: 9046—wind: 5896, geothermal: 1500, biomass: 540, solar: 1110)
Generation mix in 2020 (TWh)	**Ref** **s5** **s15** **Black** 160 123 127 **Brown** 67 36 33 **Gas** 52 59 43 **Renew.** 25 54 54 **Liquid** 3 3 0 **Total** 307 275 257	**Ref** **s10** **s25** **Black** 160 123 94 **Brown** 67 41 20 **Gas** 52 60 64 **Renew.** 25 30 54 **Liquid** 3 3 3 **Total** 307 257 235	**s7** **Black** 126 **Brown** 5 **Gas** 84 **Renew.** 55 **CCS** 9 **Total** 280	**Ref** **s10** **s20** **Black** 161 121 95 **Brown** 53 22 19 **Gas** 53 61 83 **Renew.** 22 50 51 **Total** 289 254 248
Renewable Energy mix in 2020 (TWh)	**Ref** **s5** **s15** **Hydro** 17 18 18 **Geo** 0 9 9 **Wind** 4 18 18 **Bio** 4 9 9 **Solar** 0 0 0 **CCS** 0 0 0 **Total** 25 54 54	**Ref** **s10** **s25** **Hydro** 17 17 18 **Geo** 0 2 12 **Wind** 4 8 18 **Bio** 4 3 6 **Solar** 0 0 0 **CCS** 0 0 0 **Total** 25 30 54	**n/a**	**Ref** **s10** **s20** **Hydro** 17 18 18 **Geo** 0 10 10 **Wind** 2 16 16 **Bio** 2 4 4 **Solar** 1 2 2 **CCS** 0 0 0 **Total** 22 50 50
Monetary values in report	2007A$→1.04 2008A$ 2005A$→1.11 2008A$	2007A$→1.04 2008A$ 2005A$→1.11 2008A$	2007A$/2008A$	2008A$

differences between the modeling results as shown in our detailed analysis.

Finally, if Australia is going to commit to a 25% reduction target internationally, the proposed price cap is substantially lower than the initial carbon price modelled by the highest reduction scenario (Garnaut-25). This clearly poses a threat to the environmental integrity of the scheme and a budgetary risk which appears to be missing in the political debate.

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Appendix. Comparison of models

See Table A1.

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