Impacts of climate change policies on electricity retailers

A REPORT PREPARED FOR THE AUSTRALIAN ENERGY MARKET COMMISSION

May 2009

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1 Introduction

The Australian Energy Market Commission (AEMC) is undertaking the Review of Energy Market Frameworks in light of Climate Change Policies. The AEMC is considering whether the current regulatory frameworks for customers being supplied at a regulated price are flexible enough to allow the efficient costs of the Carbon Pollution Reduction Scheme (CPRS) to be recovered from end use customers. Critical factors to be considered in this context include:

- The materiality of the CPRS impact on retailers, which is a function of:
  - the likely scale of the uplift in wholesale electricity costs driven by the CPRS;
  - the impacts on wholesale electricity costs at different levels of average carbon costs across regions; and
  - the likely drivers of, and extent of volatility in, carbon costs and wholesale electricity costs driven by the CPRS, and
- the strategies an efficient electricity retailer might effectively use to manage the risks posed by CPRS costs and volatility.

This report discusses factors affecting carbon prices and the likely impact on electricity prices, including estimates from previous modelling exercises, to illustrate the materiality of the cost and volatility impact on retailers. The discussion of options for retailers for managing carbon costs/risks is included to highlight similarities and differences between CPRS costs and other energy costs, and to identify potential issues arising out of retail price regulation. The report is not intended to provide price forecasts for use in future retail price reviews, or to prescribe a specific methodology for determining regulated prices.

This report is structured as follows:

- Section 2 discusses the likely effects of the CPRS on wholesale electricity costs and volatility;
- Section 3 canvases retailer options for managing carbon risk in the contract market, and includes evidence of emerging trends; and
- Section 4 includes a high level summary of issues for retail price regulation.

Appendix A to this report outlines in detail the theory behind the pass-through of carbon costs into wholesale electricity prices.

2 Wholesale electricity costs and volatility

This section provides a summary of the expected materiality of increased carbon costs (and risks) on electricity retailers. These costs and risks will be a function of a number of factors, including expected future carbon prices, the resulting increase in wholesale energy costs (as generators seek to recover their increased carbon costs) and increased risk associated with volatile carbon prices. This section includes:

- a summary of the Commonwealth's proposed CPRS;
- key drivers of carbon prices, including aspects of scheme design that cap or limit carbon prices;
- factors affecting how increased carbon costs will likely effect wholesale electricity prices (often referred to a carbon cost pass-through);
- a summary of Australian modelling of emissions trading effects on the electricity sector, with particular emphasis on the likely level of cost pass-through (from carbon costs to wholesale energy costs);
- empirical observations from Europe following the introduction of the EU Emissions Trading Scheme (EU ETS); and
- comparison of estimated uplift in wholesale electricity costs against indicative retail costs and margins.

Particular factors that affect the level and volatility of carbon prices which will be considered include:

- the effects of unlimited banking/limited borrowing;
- the effects of unlimited permit imports/limited exports; and
- the impact of the proposed permit price cap.

Broadly, current forward prices suggest that carbon costs will contribute to an increase in wholesale energy costs in the order of 50%, and future carbon costs will constitute a far larger component of total future wholesale electricity costs than fuel costs currently do, hence the importance of the issue.

2.1 CARBON POLLUTION REDUCTION SCHEME

2.1.1 Objectives and key features

On 10 March 2009, the Federal Government released exposure draft legislation for the proposed Carbon Pollution Reduction Scheme (CPRS)[1]. The original intent was to establish an Australian emissions trading scheme in 2010. However, on 4 May 2009, the Federal Government announced changes to the proposed CPRS, including a delay in the start date of one year (to be phased in from 1 July

[1] Carbon Pollution Reduction Scheme Bill 2009 (Cth) (CPRS Bill)

2011) and a one year fixed price period, set at \$10/tCO_2-e in 2011-12.[2] Key features of the scheme, based on the draft legislation and the changes announced on the 4th May, 2009 are summarised in Table 1.

Table 1. CPRS summary

Category	Detail
Title	Carbon Pollution Reduction Scheme (CPRS)
Overview	Cap and Trade emissions trading scheme
Reduction Targets	5% reduction on 2000 levels by 2020 15% by 2020 if other countries take similar action 25% by 2020 if the world agrees to global deal to stabilise levels of CO_2 equivalent in the atmosphere at 450 parts per million or less by 2050 (Announced 4 May 2009) 60% reduction on 2000 levels by 2050
Covered sectors	Approximately 75% of Australian emissions, including stationary energy, transport, fugitive emissions, industrial processes and waste. Forestry may opt-in Agriculture is not covered initially – (likely inclusion from 2015, TBC in 2013)
Threshold	Greater than 25ktCO_2 per year (approximately 1000 firms)
Permit Allocation	Mostly via monthly auctions for the current vintage, plus annual "advance auctions" of three future vintages Free allocation to Emissions Intensive Trade Exposed Industry (EITE) and Electricity Sector. (Approximately 25-45% - see below)
Banking and borrowing	Unlimited banking after 2011-12 (permits available for \$10/tCO_2-e price cap in 2011-12 cannot be banked) Limited borrowing (up to 5% of the entity's liability)
International linkage	No restriction on permit imports; exports of permits not allowed for first 5 years The eligible international units (EIUs) that will be accepted are: • certified emissions reductions (CERs) issued under the Kyoto Protocol's Clean Development Mechanism (other than temporary and long-term CERs); • emission reduction units (ERUs) issued under the Kyoto Protocol's Joint Implementation mechanism; • removal units (RMUs) created from land use, land use change and forestry activities; and • Other international units may be accepted in the future.

2 Media Release – New Measures for the Carbon Pollution Reduction Scheme, 4 May 2009

Table 1. CPRS summary

Category	Detail
Assistance to trade exposed industry	The CPRS will allocate a percentage of free AEUs to emissions intensive trade exposed industries (EITEs) to reduce the risk of 'carbon leakage', (a) 90% of the historical industry average for activities that have an emissions intensity above 2.0k tCO_2-e /$M revenue or 6.0ktCO2-e /$M value added (b) 60% of the historical industry average for activities that have an emissions intensity between 1.0-2.0 $ktCO_2$-e /$M revenue or between 2.0–6.0ktCO2-e /$M value added. The 4 May announcement proposes a 5% 'buffer' for category (a) and a 10% 'buffer for category (b), though details of this are not yet clear.[1] Assistance rate declines at 1.3% per year. After 2020, assistance will be phased out over five years, assuming an acceptable global agreement is in place.
Assistance to electricity sector	The CPRS will provide assistance to 'strongly affected industries' (SAI): non-trade exposed industries that are emissions-intensive, have significant sunk capital costs, and lack significant economically viable abatement opportunities. Coal-fired electricity generation was the only industry meeting these characteristics. Limited direct assistance would be provided to coal-fired electricity generators through the Electricity Sector Adjustment Scheme (ESAS). The ESAS provides a one off allocation of free permits worth approximately $3.9B over 5 years Division of assistance calculated on the basis of historic energy output (1 July 2004 and 30 June 2007) and the extent to which a generator's emissions intensity exceeds the baseline level of 0.86tCO2/MWh generated. In practice, this means that brown coal generators will receive most of the compensation.
Penalty	A one year fixed price period, set at $10/$tCO_2$-e in 2011-12 (announced May 4).[1] A price cap of $40/$tCO_2$-e was originally proposed from 2010-2015 (rising by 5% + CPI per year): this price cap will still apply from 2012-2015. Penalties will apply where companies emit greenhouse gases without surrendering sufficient AEUs or EIUs. The penalty will be an additional 10 per cent on the average cost of AEUs in the relevant period with an additional 20 per cent penalty if the penalty is not paid on time. There will also be a 'make-good' obligation requiring the shortfall to be made up in the following year.

Source: CPRS White Paper, Carbon Pollution Reduction Scheme Bill 2009, Media Release – New Measures for the Carbon Pollution Reduction Scheme, 4 May 2009

2.1.2 ETS and the determination of a carbon price

The CPRS will provide a price for greenhouse gas emissions based on the prices at which permits trade in the market. 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 very difficult 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.

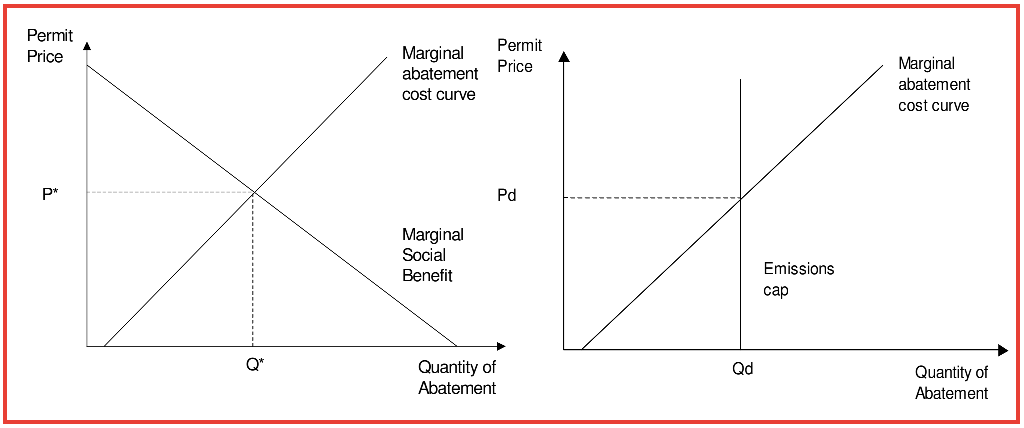

Figure 1: Stylised examples of the market for CO_2 abatement

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.

The supply curve in Figure 1 is typically referred to as the Marginal Abatement Cost Curve (MACC), and is upward-sloping 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. In practice, other aspects of scheme design will act to constrain the market price for permits. These include the extent of international linkage, penalties for non-compliance and banking and borrowing. These are discussed below.

Penalty for non-compliance

Carbon trading schemes can impose a penalty for non-compliance where permits acquitted are less than actual emissions. In some schemes, penalties can be paid in lieu of the liability to acquit permits for all emissions: in this instance the penalty will act as a price cap (or upper limit) on permit prices, since liable parties can accept a penalty rather than purchase permits at a higher price. This also means that actual emissions are allowed to rise above the administrative cap (i.e. there will be a shortfall in required abatement). This is illustrated in Figure 2a.

Other schemes may include a "make-good" provision, whereby any shortfall in permits acquitted in a given period must still be met in a later period. This form of penalty does not cap permit prices since the liability must still be met.

The proposed CPRS (according to the CPRS Bill) allows for the purchase of additional fixed price permits at a price of $40/t$CO_2$-e (rising by 5%+CPI) for the first five years of the scheme. This will effectively cap the permit price in the first five years of operation (and allow for actual emissions to rise above the emissions cap). However, this will only be required if the international price of permits is greater than the price of the cap (discussed below).

The announced changes on 4 May 2009 delays the commencement of the scheme by one year (until July 2011) and reduces the fixed price permits to $10/t$CO_2$-e in the first year of scheme operation (2011-12). The $40/t$CO_2$-e cap will continue to apply between years 2013-2015[3].

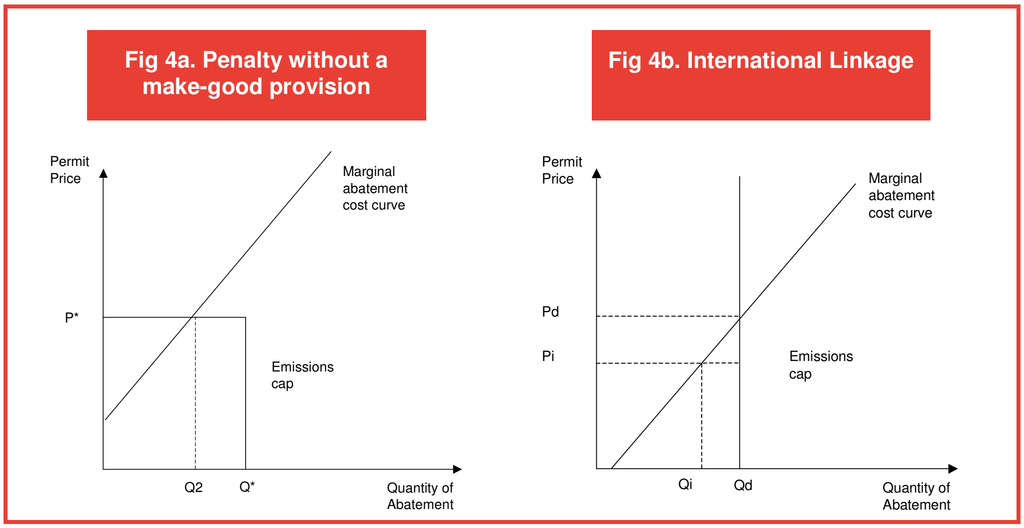

Figure 2 Stylized example of penalty and international linkage on supply and demand

Source: Frontier Economics

International linkage

Linkages with other international schemes can act as a price cap (if Australia is a net importer of permits), or a price floor (if Australia is a net exporter of permits). If Australia is a price-taker in the global market for emissions permits and unlimited bilateral trading is introduced (unrestricted imports and exports), then the Australian price will achieve parity with the international price; the carbon price will be fixed at the international price, 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 its level of domestic abatement until the domestic price falls to the international price level.

3 Carbon Pollution Reduction Scheme Bill 2009, Explanatory Memorandum, Chapter 3.

Figure 2b 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).

The proposed CPRS allows for unilateral international linkage, at least for the first five years of operation:

- Import of international permits is unlimited: this means that the international price will act as an effective cap on the domestic price of Australian Emission Units (AEUs); and
- AEUs cannot be exported: this means that the AEU price could fall below the international price.

Consequently, any consideration of future carbon prices must take account of international policy and projections.

Banking and borrowing

Banking and borrowing of permits is a measure designed to introduce flexibility and thereby reduce permit price volatility over time. Banking of permits refers to the use of a permit of an earlier vintage in a later period; borrowing refers to the use of a permit of later vintage in an earlier period. If an emissions cap is relatively linear over time but economic cycles (and emissions) are more variable, then the required level of abatement will also vary over time – demand for abatement (and hence abatement costs) will be lower in times of recession, and conversely higher during times of expansion. If banking and borrowing of permits is not allowed, this would result in more volatile carbon prices. The ability to bank and borrow reduces this inter-temporal volatility: if future expected prices are higher than current prices (allowing for carrying costs) then liable parties should bank permits.

This is illustrated in Figure 3, where the black line represents actual abatement costs and the red line represents permit prices rising in line with real interest rates (the cost of holding permits). In this stylized example, liable parties should bank permits when the abatement cost is lower than the price and borrow permits (or use previously banked permits) when the abatement cost is higher than the permit price. This will mitigate carbon price volatility, although only to the extent that the market can anticipate price fluctuations. It won't mitigate against regulatory risk, for example, due to unexpected changes in emissions targets in other countries.

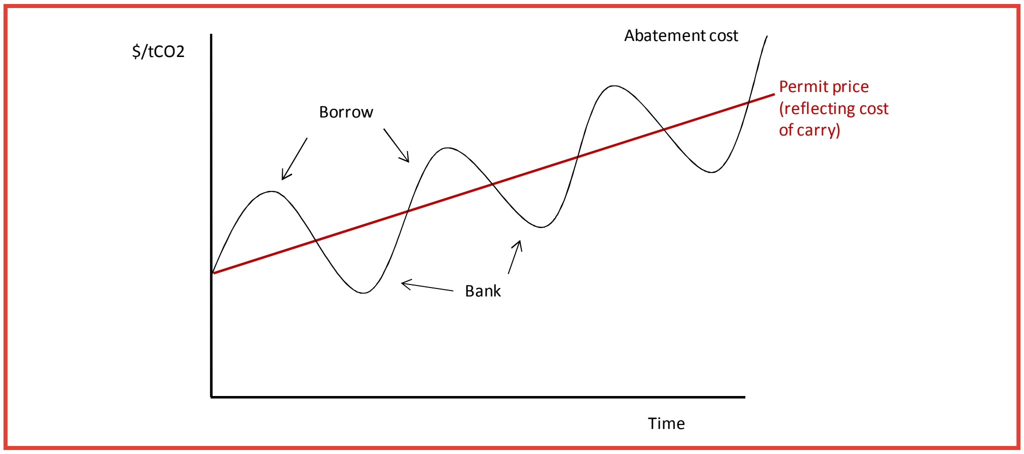

Figure 3: Stylized example of banking/borrowing of permits

Source: Frontier Economics

2.2 CO_2 PRICE ESTIMATES

The section above describes the factors affecting carbon prices. The effect of linking the CPRS with global markets means that estimation of prices through modelling is extremely difficult, since it requires the modelling of global carbon markets. Few modelling exercises have attempted to estimate the global carbon price, and those that have are highly uncertain and largely driven by input assumptions. Figure 4 presents the projected carbon prices for the CPRS-5 and CPRS-15 scenarios as estimated by the Commonwealth Treasury[4], expressed in real $2008-09. The chart includes the penalty price for the first five years, as this represents an upper bound of potential carbon price for the first five years of the scheme[5]. The changes announced on 4th May 2009 mean that (i) there will be no price applicable to financial year ending 2011 (the modelling estimates for that year are included for completeness) and (ii) the penalty will be $10/tCO$_2$-e in the first year of operation (FY2012). The price cap continues as proposed in FY2013-2015.

For indicative purposes the chart also includes recent CER prices (converted to AUD equivalent based on current exchange rates), since this should provide an important source of permit imports that may also cap prices. At current CER prices and exchange rates, Australia's carbon price is more likely to be near the CPRS-5 estimates, although as discussed below CER prices have been historically volatile, and hence the extent to which this remains the case going forward is uncertain.

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4 Australia's Low Pollution Future: The Economics of Climate Change Mitigation (2008)

5 The level of the cap will depend on the tax treatment for penalty payments relative to purchase of permits. This is yet to be confirmed: if both penalty payments and permit purchases are taxable (as we expect) then the permit price should not rise above the penalty level ($40/tCO2, increasing by 5%). If penalty payments are not taxable and permit purchases are, liable parties would be prepared to pay up to $40/(1-company tax rate) to purchase permits (ie $57/tCO2 based on the company tax rate of 30%.

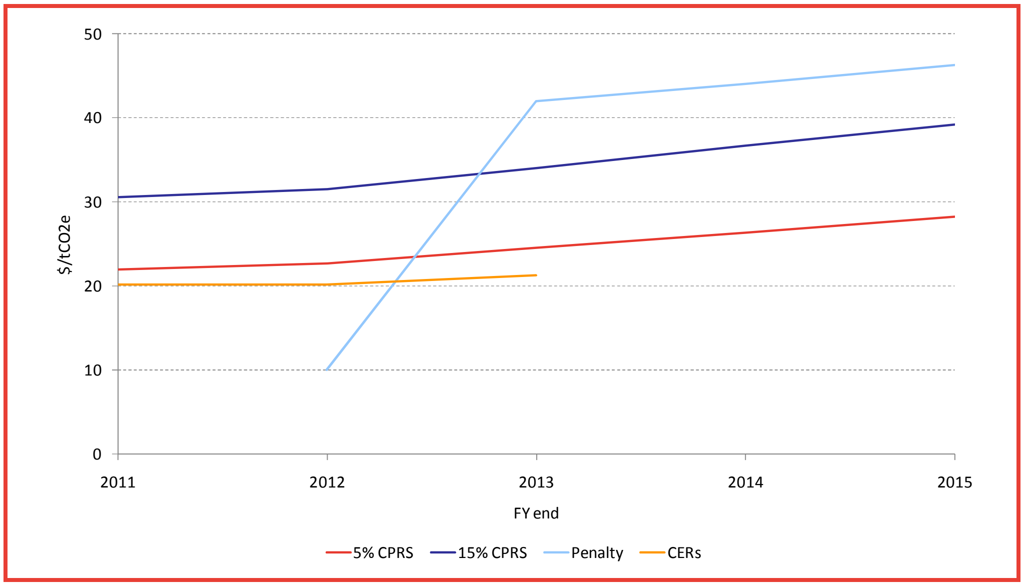

Figure 4: Projected permit prices (and penalty upper bound)

Source: Commonwealth Treasury, European Climate Exchange, 21 April 2009 (http://www.ecx.eu/CERemindx)

Figure 5 provides data for recent historical EU Allowance Units[6] (EUAs) and CER prices; this provides an indication of the range of prices (and volatility) experienced in the European and global carbon markets. This emphasises the difficulty in forecasting future carbon prices. Points worth noting include:

- The significant fall in permit prices around April 2006 (from €30/tCO_2 to around €10-15/tCO_2). This was largely due to a lack of information regarding actual emissions – once the market became aware that actual emissions were far less than expected (a fall in permit demand) the price fell accordingly. Although Australia arguably has better data regarding actual emissions than the EU at the commencement of the scheme (which should mitigate this issue) similar variance may result from other market failures, such as imperfect information about global abatement options and costs, and unanticipated changes to emissions targets adopted in key global regions;

- Permit prices during Phase 1 (2005-07) were more volatile due to restrictions on banking/borrowing of permits *between* periods. While this increased the volatility of Phase 1 prices (which fell to a price of less than €1/tCO_2), it also acted to stabilise prices in Phase 2 (2008-12). Without the restrictions, Phase 1 permits could have been banked into Phase 2, and the prices for permits in each Phase would have converged;

- CER prices have tended to follow a similar path to EUA prices, which is expected since CERs can be imported (in limited amounts) into the EU ETS scheme. The relatively large spread between EUA and CER in prices in early 2008 coincides with a period of high EUA prices – since there are quantitative restrictions on CER imports into the EUA scheme, it is

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6 EUAs are permits for the EU ETS

reasonable for the price spread to widen during periods of high EUA prices; and

- The CER prices in late 2008 were significantly higher that current CER prices which were used in Figure 4.

In general, while day-to-day volatility can be partly managed through contracting, the cost of hedging will generally increase for more volatile prices. Also, it is harder (or more costly) to manage the price level shifts (as opposed to day-to-day volatility) that can occur due to imperfect information and general regulatory risk. Future permit prices will be affected by climate change policies in the EU, the US and China (among others), and these policy changes may be somewhat difficult for markets to anticipate. Importantly, if carbon permits are mostly distributed by auctioning then the options for managing volatility will differ from the options in many other commodity markets. This is because under auctioning, governments are the beneficiaries of higher carbon prices and this makes it more difficult for parties exposed to higher carbon costs to find natural counterparties to hedge their carbon exposure – this is discussed in more detail in section 3.

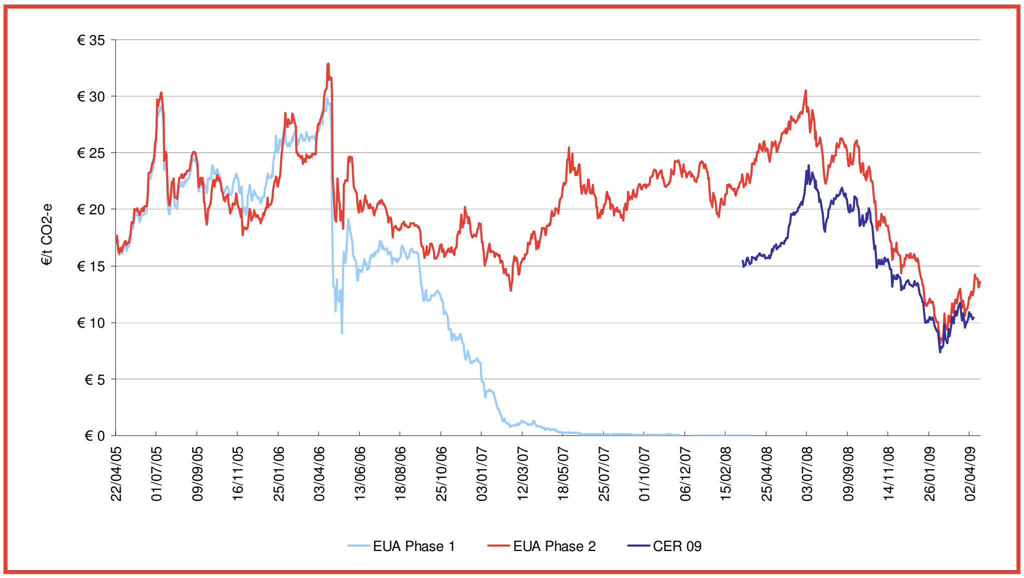

Figure 5: Historical EUA/CER prices

Source: European Climate Exchange, 21 April 2009 (http://www.ecx.eu/CERemindx)

2.3 CARBON COST PASS-THROUGH

The additional cost impost of a carbon scheme on electricity retailers is a function of both carbon prices and the extent of "pass-through" of carbon costs into wholesale electricity prices. A detailed discussion of the theory of carbon cost pass-through is provided in Appendix A. The theory suggests that the emissions intensity of the marginal plant (both before and after the introduction of emissions trading) will be a critical driver of carbon cost pass-through. Broadly we expect that 60-80% of generator carbon costs may be passed through into higher wholesale electricity prices, though experience suggests that estimating pass-through even *ex-post* is extremely difficult. This range is based on:

- a range of modelling estimates from various Australian studies; and
- EU ETS empirical studies.

Modelling estimates

The range of Australian modelling estimates (Figure 6) is approximate only since many reports do not include an explicit estimate of cost pass-through. These estimates have been calculated from reported changes in electricity prices and the corresponding carbon prices at the time: both of these vary across regions and over time, so average conclusions are indicative only. Differences can be attributed to modelling approaches and differences in assumptions that may also contribute to changes in electricity prices. For example, changes in gas price assumptions or demand elasticity may also cause changes in electricity prices, so it is difficult to separate these influences from changes caused by increasing carbon costs.

While these estimates typically reflect average modelling results over a period of 10-20 years after the introduction of the CPRS, we expect that generators should be able to pass-through a greater proportion of their carbon costs into wholesale electricity prices in the near term, where there is limited opportunity to change the composition of the generation market through new investments. In the longer term, new entrant (low emissions) plant will act as a greater constraint on the ability of high emitting plant to pass-through carbon costs in the wholesale market.

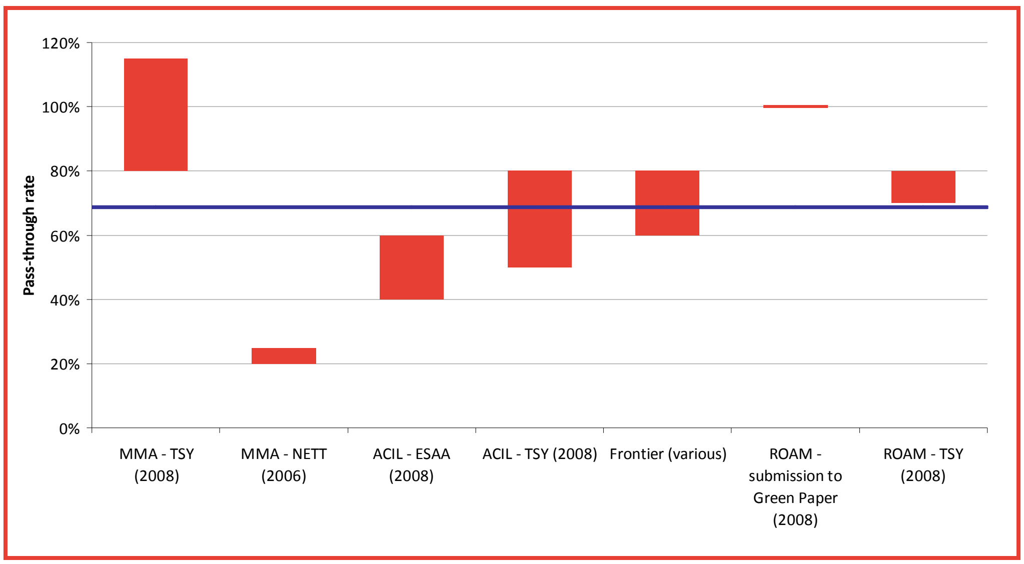

Figure 6: Approximate modelling estimates of carbon cost pass-through in electricity prices

Source: Frontier Economics

Evidence from EU ETS

Evidence of cost pass-through from Europe should be treated with caution due to differences in fuel prices, plant characteristics and market structures as compared with the NEM. For example, the spread between coal and gas fuel costs is generally narrower in the European markets (as compared with the NEM) and there is a very different mix of plant, including hydro and nuclear. Importantly, the results from Europe suggest that even estimating cost pass-through *ex post* is difficult, since it requires comparison with a counterfactual that cannot be observed. For example, it is difficult to differentiate the effects of fuel price changes and competitive effects from carbon price effects. Despite this, several studies have attempted to estimate the level of pass-through in wholesale prices based on empirical evidence from the EU ETS:

- Sijm et. al. (2006) estimate CO_2 cost pass-through rates of between 60% and 100% for wholesale power markets in Germany and the Netherlands based on analysis over the period January-July 2005 (depending on peak/off-peak periods);[7]
- Levy (2005) estimated that "35% to 65% of the opportunity cost of CO_2 will be passed through to wholesale power prices". The study suggested that "this pass through provides an efficient price signal, as it narrows the difference between the generation costs of gas-fired and coal-fired plants and therefore should incentivize investments in low CO_2 technologies in the long run."[8]; and
- A Finnish study (Honkatukia et al, 2006) estimated, based on the first 16 months of the EU ETS, that, on average, approximately 75% to 95% of the price changes in the EU ETS were passed on to Finnish Nord Pool day-ahead prices.[9]

2.4 POTENTIAL ELECTRICITY PRICE CHANGES IN AUSTRALIA

Based on the weight of evidence above, we can estimate the possible effects on wholesale electricity costs as a function of projected carbon prices (Figure 4) multiplied by a range of pass-through rates (assumed to be between 60-100%). Three scenarios are represented in Figure 7:

- low CO_2 price (CPRS-5) combined with a pass-through rate of 60%;
- high CO_2 price (CPRS-15) combined with a pass-through rate of 80%; and
- the CO_2 penalty price (as an upper limit) combined with 100% pass through.

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7 Sijm, J., Neuhoff, K., Chen, Y., (2006): "CO2 cost pass through and windfall profits in the power sector", CWPE 0639 and EPRG 0617, Working Papers.

8 Levy, C. (2005): Impact of Emissions Trading on Power Prices: a Case Study from the European Emissions Trading Scheme. Université Paris Dauphine, DEA d'Economie Industrielle, Paris.

9 Honkatukia, J., Mälkönen, V., Perrels, A., (2006): Impacts of the European Emissions Trade System on Finnish Wholesale Electricity Prices, VATT-Discussion Papers, Helsinki.

The estimated change in electricity prices from these scenarios ranges from around \$10/MWh to \$40/MWh.

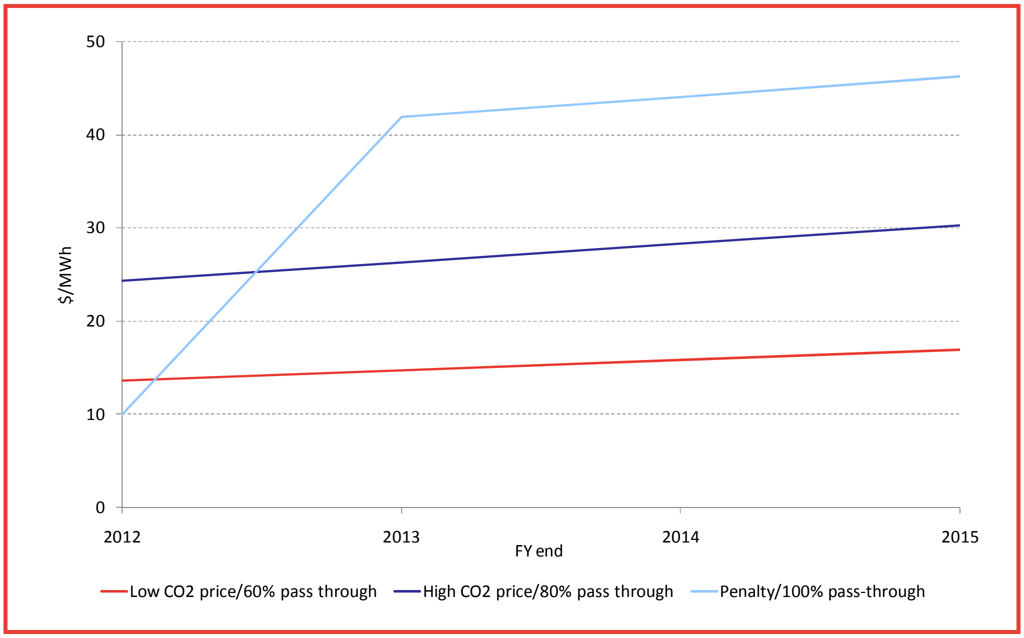

Figure 7: Indicative effects on energy costs

Source: Frontier Economics

2.5 INDICATIVE EFFECT ON RETAIL COSTS

The potential change in wholesale electricity prices (above) can be compared against existing retail costs to understand the materiality of this change in costs. The indicative effects on energy costs (Figure 7) would represent approximate increases against recent LRMC estimates of between 25-90%, or around 10-15% in the first year where the price is set at \$10tCO_2-e and assuming 60% pass-through. These calculations are presented in Table 2.

Table 2. Approximate change in LRMC: NSW

Retailer	LRMC (\$/MWh)	% Change in LRMC			
	2009/10	\$10/tCO_2e – 60% pass through	Low CO_2 price – 60% pass through	High CO_2 price – 80% pass through	\$40/tCO_2e - 100% pass-through
Low	43	14%	31%	55%	89%
High	50	12%	26%	47%	76%

Source: Frontier Economics calculations

LRMC costs are typically adjusted to account for market purchase costs, which include contracting costs, volatility allowance and energy losses. The total cost of energy is closer to \$50-60/MWh in this example. This represents approximately

40-45% of total retail cost, which also include network and retail costs. Once all costs are allowed for, the indicative change in wholesale energy costs (on an LRMC basis) represent an approximate change in total costs of between 10-30% (see Table 3). This represents the potential step change in costs in the first two years of the scheme, though costs will continue to increase over time as carbon prices rise. At the very least – with the \$10/tCO_2-e penalty in year one and assuming low pass-through – the increase in total costs is around 5%.

This level of costs (and potential variance in costs) is material when compared with average retail margins of around 5%. These estimated effects are also broadly consistent with the conclusions of the AEMC Survey of Evidence on the Implications of Climate Change Policies for Energy Markets (2008). Importantly, these estimates do not account for the additional risk introduced through carbon price volatility, nor costs of increased prudential requirements. Although some (but not all) of this risk may be hedged in contract markets, the cost of hedging will further increase costs. This is discussed in the following section.

Table 3. Approximate change in total retail costs

Costs	Low retailer ($/MWh)	Mid Retailer ($/MWh)	High Retailer ($/MWh)
Energy costs	50	60	70
Network costs	55	60	65
Retail costs	6	6	6
Margin	7	6	6
Total (Retail price)	**118**	**132**	**147**
Approximate % change in costs resulting from introduction of CPRS			
\$10/tCO_2e/60% Pass-through	5%	5%	4%
Low CO_2/60% Pass-through	11%	10%	9%
High CO_2/80% Pass-through	20%	18%	16%
\$40/tCO_2.e/100% Pass-through	33%	30%	27%

Source: Frontier Economics calculations; IPART Regulated electricity retail tariffs and charges for small customers 2007 to 2010 (2007)

3 Possible retailer hedging strategies

This section outlines the possible strategies that an efficient retailer might use to effectively manage the risks posed by the increased price and volatility of both wholesale energy and carbon due to the introduction of the CPRS. To effectively deal with this issue, this section is structured in two parts:

- First, brief consideration is given to the existing arrangements available to retailers to hedge the current risks they face. This background material forms a basis for discussions in the later stages of this section;
- Second, detailed consideration is given to the possible options available to retailers to hedge both wholesale energy and carbon price risk *ex post* the introduction of the CPRS. This section considers options that have or are beginning to emerge, including forward contracting for carbon-inclusive energy and forward contracting for carbon permits. Some observations from the contract markets are discussed, although it is difficult to draw any firm conclusions until there is more certainty around future CPRS policy direction.

3.1 CURRENT RETAILER HEDGING ARRANGEMENTS

3.1.1 Background

This section outlines the rationale behind retailer hedging strategies and describes how retailers most typically manage the risks they face in the wholesale electricity market through the use of derivative contracts.

3.1.2 Contracting in the NEM

Spot prices in the NEM can vary between the minimum and maximum price caps imposed on the market, or between -$1,000/MWh and $10,000/MWh. An unhedged retailer faces varying energy costs (due to variations in spot market prices), while the price that retailers receive from end users is fixed (at least in the short term) either due to price regulation (non-contestable customers) or fixed-term contracts (contestable customers).

Generators and retailers in the NEM typically enter into financial derivative contracts in order to hedge their exposure to volatile spot prices and thereby smooth their future revenues/costs. These contracts may take the form of swaps, caps or other varieties of risk management instruments (see below).

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 high in the spot market, the retailer will receive 'difference payments' from its counterparty such that overall, the retailer pays the strike price on its purchased energy. A schematic of physical and financial flows in the NEM is represented in Figure 8 below.

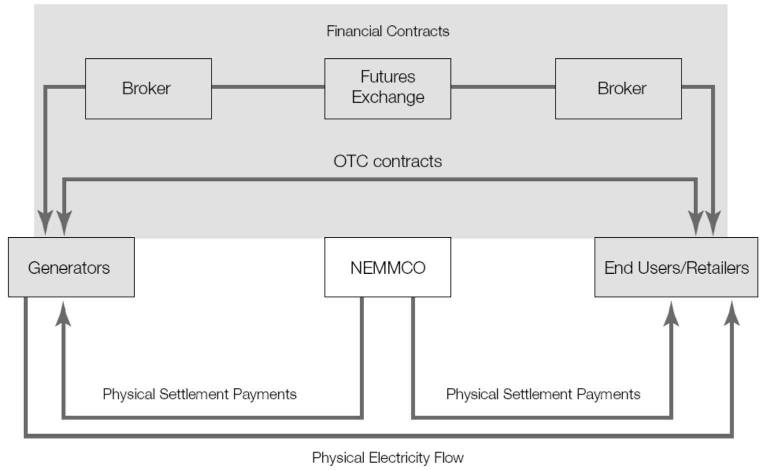

Figure 8: Physical and financial flows in the NEM

Source: http://www.erig.gov.au/assets/documents/erig/ERIG_main_report20070413181231.pdf, p.243.

In order to hedge spot price risk, it is necessary for retailers to gain exposure to the opposing side of the spot market to that on which they typically operate – that is, it is necessary for retailers to be exposed to the 'long' side of the market, where high spot prices reflect a gain and low prices reflect a loss. This can be achieved in one of two ways:

- physical hedge – this involves a retailer being physically exposed to the long side of the spot market by either purchasing or establishing a generation business. By operating a generation business, the retailer's gain from its generation interests at times of high spot prices can offset its losses from its retail interests, and vice versa; or
- financial hedge – this involves entering into a financial contract with a generator (i.e. a derivative contract) that financially exposes the retailer to the long side of the market. Since generators and retailers face opposing sides of the same risk in the spot market, they can hedge spot price risk by signing a financial contract that distributes cash flows to offset spot price movements.

There are several key financial instruments available to retailers that allow them to hedge spot price risk (primarily swaps, caps and floors), and two key markets in which retailers obtain financial hedging instruments (over-the-counter and exchange-traded). Each of these concepts are further explored below.

Financial hedging instruments

As noted above, the three key instruments that retailers use to hedge spot price risk are swaps, caps and floors.

Swap contracts

Swap contracts are broadly defined as a series of financial forward contracts between two parties, whereby one stream of cash flows is 'swapped' for another stream of cash flows at regular intervals over the term of the contract. Given that swaps are a form of forward contract, each party to the swap has an *obligation* to exchange the agreed cash flows on the settlement date.

Typically, swaps involve the swapping of a variable stream of cash flows based on (variable) spot prices with a fixed stream of cash flows based on an agreed strike price.

In the case of electricity swaps, parties agree to swap cash flows based on the wholesale spot price of electricity at a given point in time (e.g. half-hourly trading intervals). Swap contracts thereby allow parties exposed to the spot price to effectively 'lock in' a fixed price, called the strike price of the contract, and thereby reduce cash flow uncertainty.

For example, assume a generator (*G*) and retailer (*R*) enter into a swap contract at a strike price of $25/MWh. This contract implies that at each settlement interval:

- *G* will pay *R* the difference between the spot price of electricity and the strike price of the contract if the spot price is greater than the strike price; or
- *R* will pay *G* the difference between the strike price of the contract and the spot price of electricity, if the spot price is less than the strike price.

Under such an agreement, both the retailer and generator have certainty regarding the price they will either pay or receive per unit of energy covered by the contract.

The strike price struck under a swap contract is based on an expectation of future spot prices. Most swap contracts trade at a premium to spot prices: the AER note that over the last two years, futures prices traded through the Sydney Futures Exchange (SFE) have tended to reflect a fairly constant premium over NEM spot prices of roughly $2/MWh.[10] This positive premium indicates that participants in the contract markets face asymmetric risk: there is greater potential for prices to rise rather than to fall.

Cap contracts

Cap contracts are a form of option contract. An option contract bestows upon the buyer the right, but not the obligation, to exercise the contract (in the case of caps, to buy the underlying asset at a specified price known as the strike price).

The buyer of the option pays the seller of the option a 'premium' to obtain this right. This premium compensates the seller of the option for the risk they incur in writing the contract.

A cap contract is a form of call option, with the strike price of the contract set at the desired cap. In the context of the NEM:

- For spot prices *below* the cap price, the owner of the option *will not* exercise its right to purchase electricity at the cap price (since the spot price is less than the cap price) and so the option will expire; but

10 See AER (2007). *State of the Energy Market 2008*, p.109, accessed from: http://www.aer.gov.au/content/index.phtml/itemId/723386

- For spot prices *above* the cap price, the owner of the option *will* exercise its right to purchase electricity at the cap price (since the cap price is less than the spot price) and so the option will be exercised.

Cap contracts are one-sided – they allow the owner of the contract to be exposed to (favourable) up-side risk when spot prices are low, but prevent the owner from being exposed to (unfavourable) down-side risk when spot prices are high, since the maximum price paid will be the cap price.

Floor contracts

A floor contract is the converse to a cap contract – that is, a floor contract is a put option with the strike price set at the desired floor. A floor contract bestows upon the owner the right, but not the obligation, to sell the underlying asset at the strike price. Thus when the spot price is below the strike price, the option is exercised, while when the spot price is above the strike price, the option expires.

Retailers often sell floor contracts and use the proceeds to purchase cap contracts – in doing so, retailers can construct what is known as a 'collar'. The advantage of collars is that they can be revenue neutral (i.e. the premium received from selling the floor can offset the premium paid to obtain the cap) whilst bounding the price that retailers pay between the floor and cap strike prices. It should be noted that collars do not *eliminate* spot price risk, since the energy price retailers face can float between the floor and cap strike prices.

In addition to swaps, caps and floor, various other derivative instruments are available to hedge spot price risk, including swaptions, asian options and profiled volume options.[11]

Obtaining financial hedging instruments

Retailers can obtain financial hedging instruments such as swaps and caps through two main avenues – over-the-counter (OTC) or through a securities exchange (exchange-traded).

OTC contract markets involve customised bilateral contracts between two parties (generally retailers and generators). OTC contracts can either be directly negotiated (i.e. no financial intermediary between contracting parties) or transacted through a broker. Contracts in OTC markets exhibit the following characteristics:

- Highly customised to suit the needs of the two contracting parties;
- Non-transparent due to private negotiations and settlement; and
- Subject to credit default risk in the event a counterparty defaults on its obligation.

Exchange-traded contract markets involve standardised contracts that are brought and sold through a securities exchange. In Australia, exchange-traded electricity contracts are designed and developed by d-cyphaTrade[12] and sold

[11] See AER (2007), p.99.

[12] www.d-cyphatrade.com.au

through the SFE[13]. Contracts in exchange-traded markets exhibit the following characteristics:

- Highly standardised in terms of contract type, size, price fluctuations (ticks) and settlement;
- Transparent and publicly reported (aggregated volumes, prices etc); and
- Not subject to credit default risk due to the presence of a financial intermediary (clearing house) between contracting parties.

The OTC and exchange-traded electricity contract markets in Australian are further discussed below.

3.1.3 Over-the-counter versus exchange-traded markets

This section discusses in more detail the differences between OTC and exchange-traded markets for financial hedging instruments and outlines historical trading volumes by contract type in each market.

Historically, most trade of financial derivatives in the electricity market has taken place OTC, although more recently the exchange-traded market has been growing at a faster rate (Figure 9). The volume of total contracts (OTC and exchange-traded) increased substantially during 2006/07 relative to prior years. This includes contracts maturing before the introduction of the CPRS, hence the data does not yet reflect the impact of the CPRS on market liquidity.

As noted by KPMG in their financial markets review[14] for the Energy Reform Implementation Group in 2006, trade in OTC markets is dominated by contracting between generators and retailers, whilst (at least historically) exchange-traded markets have been more popular with speculators.

Given the large uptake in exchange-traded volume in the last few years (particularly since 2006/07), anecdotal evidence suggests that either more generators and retailers are hedging their spot market exposure through the exchange-traded market as opposed to OTC, and/or speculators or other participants are becoming more active in the exchange-traded market.

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13 The SFE merged with the Australian Stock Exchange in 2006 and the combined entity now operates under the name of Australian Securities Exchange.

14 KPMG (2006). Review of energy related financial markets: Electricity trading, prepared for the Energy Reform Implementation Group, accessed from: http://www.erig.gov.au/assets/documents/erig/__Financial_markets_review_KPMG20070413120316.pdf

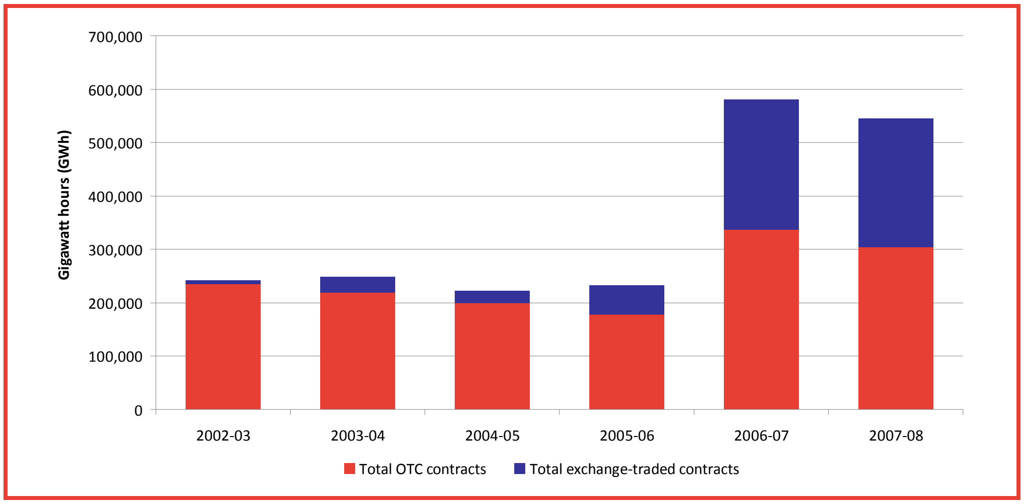

Figure 9: OTC versus exchange-traded market volumes, year on year

Data sources: AFMA Financial Markets Review 2008 and d-cyphaTrade[15]

Over-the-counter markets

The primary derivatives traded through the OTC market are swaps, caps, swaptions and other options (asian options, collars). As noted above, OTC contracts can either be directly negotiated between parties (generally retailers and generators) or can be traded through a broker.

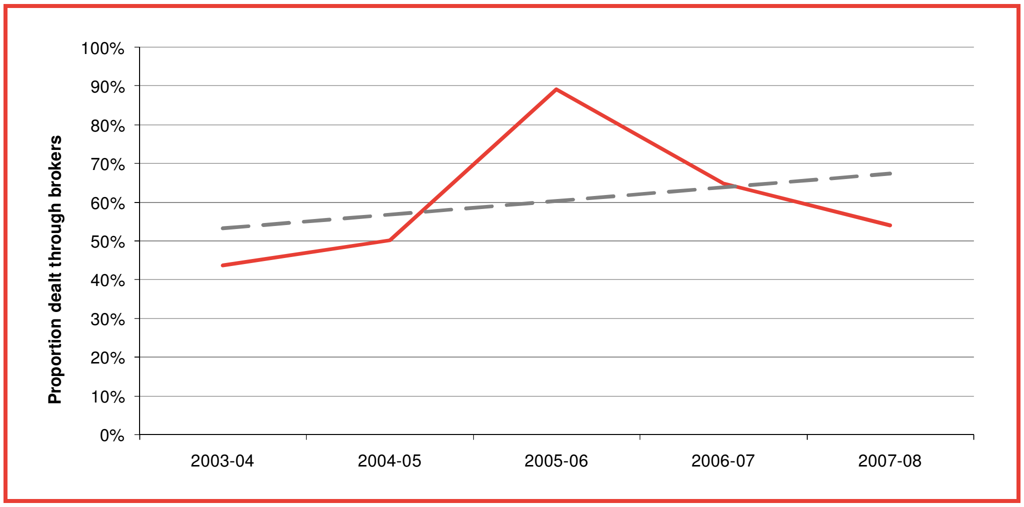

Figure 10: Proportion of OTC contracts dealt through brokers, year on year

Data source: AFMA Financial Markets Review 2008

15 OTC contract data is taken from AFMA's 2008 Financial Market Review: http://www.afma.com.au/scripts/nc.dll?AFMAV6.65710:STANDARD:257844585:pc=L6C4S1. No central repository for OTC contract data exists. AFMA data is based on respondent surveys, and whilst AFMA note that their surveys are detailed and thorough, OTC volumes and breakdowns should be taken as indicative only.

Over the last five years there has been a mild upward trend in the proportion of OTC contracts dealt through brokers versus directly negotiated between participants, although this relationship has been volatile (Figure 10). Over the period, the average proportion of total OTC contracts dealt through brokers was 60.4%.

In terms of contract type, the OTC market has historically been dominated by swaps, with a growing share of options (caps and other options) emerging more recently (Figure 11). OTC contract data by contract maturity is not published by AFMA, and hence it is not possible to discern from the chart below the direct impact of the CPRS on OTC contract volumes or hedging strategies. It is possible that the greater reliance on options (as opposed to swaps) over the last few years may be a response to the expected introduction of the CPRS. As is evident from Figure 11, contract volumes in the OTC market increased quite significantly during 2006/07 relative to prior years.

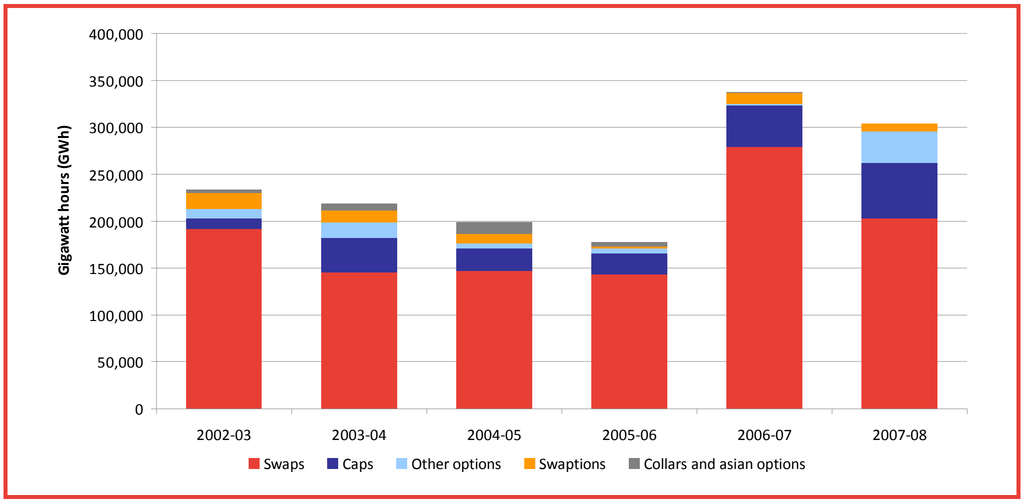

Figure 11: Breakdown of OTC derivative contracts, year on year

Data source: AFMA Financial Markets Review 2008

Exchange-traded markets

The primary derivatives traded through the exchange-traded market are futures (i.e. swaps[16]) and various types of options (primarily caps and calendar options). Due to the standardised nature of exchange-traded derivatives, d-cyphaTrade futures and options sold through the SFE are classified as either base or peak contracts valid during a given calendar-year quarter. Base contracts cover 1MW of electrical energy between 00:00 and 24:00 Monday to Sunday (i.e. 24 hours a day, seven days a week). Peak contracts cover 1MW of electrical energy between 07:00 and 22:00 Monday to Friday (excluding public holidays).[17]

16 Exchange-traded forward contracts, such as swaps, are by convention called futures.

17 http://www.d-cyphatrade.com.au/products/electricity_futures/futures_and_options_contract_.pdf

Much like the OTC market, the exchange-traded market has historically been dominated (in terms of contract type) by base futures (Figure 12). More recently, there has been a growing shift towards greater volumes of options (in particular calendar options), possibly in anticipation of the introduction of the CPRS: this is discussed in section 3.2.2. Calendar options are option contracts that combine four quarterly 'stripped' futures to provide the holder with an option that covers an entire calendar year (as opposed to a single quarter)[18]. As was noted above and is evident from Figure 12, contract volumes in the exchange-traded market increased significantly in 2006/07 relative to prior years.

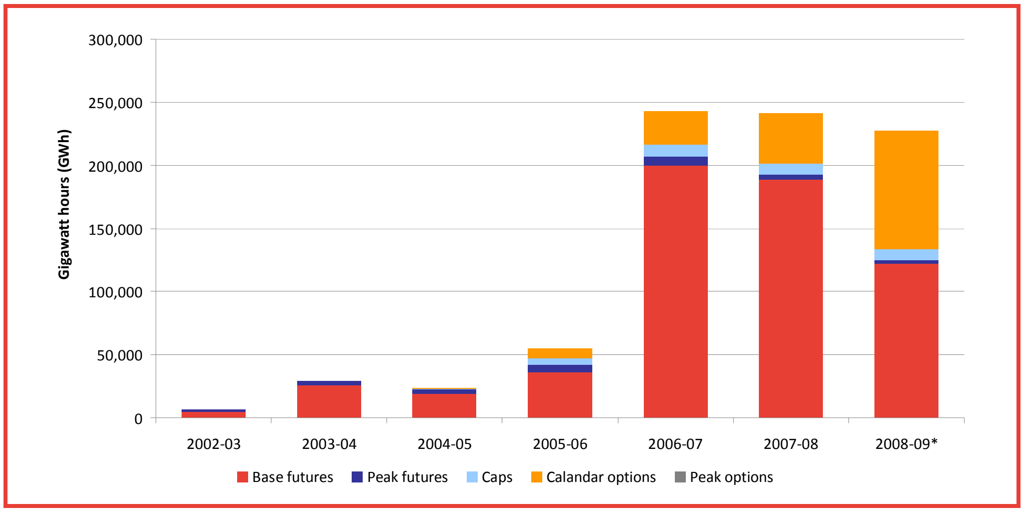

Figure 12: Breakdown of exchange-traded derivative contracts, year on year[19]

Data source: d-cyphaTrade

3.2 RETAILER HEDGING ARRANGEMENTS *EX POST* CPRS

As discussed above, the introduction of a carbon price will increase electricity purchase costs and volatility due to varying carbon prices. While generators and retailers are used to functioning in a volatile market, the CPRS introduces a significant new cost which is heavily influenced by regulation (domestically and internationally), which will change over time. This introduces a new regulatory risk that is likely to be material (discussed in previous sections). Unfortunately, generators and retailers have limited opportunity to manage this regulatory risk, except to contract over shorter time frames. If generators respond in this way, it is likely that retailers will respond to this risk by in turn shortening the duration of firm price contracts they offer to final customers.

The type of risk introduced by the CPRS is different from traditional contracting in the wholesale electricity market. In the typical contract market, generators and retailers are natural counterparties facing opposing risks – generators seek to limit exposure to low wholesale electricity prices and retailers seek to limit exposure to

18 http://www.d-cyphatrade.com.au/products/electricity_futures/cal_strip_options

19 * Financial year 2008-09 is represented as of 23 April 2009.

higher wholesale electricity prices. In this instance, contracting (or even vertically integrating) can reduce the risks faced by both parties. In contrast, the CPRS introduces a risk that cannot be hedged since both generators and retailers are exposed to higher costs as carbon prices rise.

This risk is potentially more of an issue if permits are to be allocated via auctioning (as proposed by the CPRS), 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 mostly grandfathered in the EU ETS during Phase I (2005-2007) and Phase II (2008-12). In those instances, the allocation of permits provides something of 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, or face high carbon prices). 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.

Under the CPRS, contracts can be designed to assign carbon risk to generators or retailers. Options for retailers to manage purchase costs and risk (both energy and carbon) include:

- **Maintain current contract levels, based on a carbon *exclusive* contract price.** In other words, contract for an underlying energy price (exclusive of carbon) plus a carbon adjustment based on a prescribed emissions intensity rate multiplied by a carbon price (i.e. indexed to the carbon price). In this instance, retailers bear the carbon price risk. This can be considered a carbon tolling agreement, where an increase in the carbon price results in an increase in the contracted wholesale electricity price and retailers must either hedge carbon price risk via other instruments or face reduced margins (where retailer prices are fixed). AFMA is developing a Carbon Addendum to OTC contracts that is based on a carbon exclusive energy price; or
- **Maintain current contract levels, based on a carbon *inclusive* energy price.** In other words, contracted wholesale electricity prices would not vary with carbon prices. In this instance, generators bear carbon price risk since the contracted energy price will not vary with their carbon costs. An increase in carbon price will reduce generator gross margins for any contracted volumes. Exchange traded contracts are an example of "carbon inclusive" contracts[20]; or
- **Reduced level of contracting (or contract duration) altogether:** In this case retailers bear increased energy price risk as well as carbon price risk, since they are more exposed to spot prices. We expect that this option is unlikely to emerge, given the current retailer preference for contracting to manage energy price risk – retailers should still be able to manage this risk through one of the options above, although in doing so they may be required to bear a measure of carbon price risk.

20 http://www.d-cyphatrade.com.au/newsroom/industry_news/electricity-futures-not-subje

Ultimately, the preferred option should come down to the efficient trade-off between risk and contract premia – if retailers are unwilling to face reduced contract levels (and exposure to higher energy price volatility as well as carbon risk) then they will presumably be willing to pay higher premiums for carbon exclusive (or inclusive) contracts. In either case, one would expect premiums to rise until the demand for hedging by retailers is met by generators or carbon contract providers.

These various contract options are discussed in detail in the following sections. In all cases, retailer costs will increase by more than just the level of carbon cost increase observed in the wholesale electricity spot market: risk will increase in the case of carbon exclusive contracts (where retailers bear carbon price risk) or contract premiums would increase in the case of carbon inclusive contracts (where generators bear carbon price risk).

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 cost to participants' of meeting their prudential obligations to NEMMCO will also increase. 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.

3.2.1 Carbon exclusive energy contracts

One contracting option involves contracts for an underlying energy price plus a carbon adjustment. This means that the total energy cost faced by retailers is indexed to the carbon price, and retailers bear the carbon price risk. This is more reflective of what will occur in the wholesale energy market (where the spot price will be correlated with the carbon price).

Current AFMA hedge contracts (OTC) do not provide for carbon cost pass-through. This has led to the development of the AFMA: Australian Benchmark Carbon Addendum, which aims to reflect the level of carbon costs that will be passed through in the wholesale electricity market and add this as a carbon uplift to existing agreements. Some view this as a transitionary measure until energy contracts become carbon inclusive; this view presumes that generators will be best placed to manage carbon price risk in the longer term, though it is possible that some generators/retailer may prefer to maintain contracts indexed to carbon and allow retailers to manage their carbon risk through other financial instruments The Carbon Addendum calculates a carbon uplift for existing contracts ($/MWh) based on:

- the average carbon intensity of generators registered under the National Electricity Rules; multiplied by
- a carbon reference price ($/t$CO_2$). The reference price is still to be determined, but could include the daily closing spot price for AEUs published by the ASX (or a weekly/monthly average).

Using average NEM emissions intensity means that some generators (such as gas) may recover more than their carbon costs, while higher emissions generators (such as brown coal) will recover less than their actual costs. This is the intent of the scheme, and it would most accurately reflect what would likely occur in the spot market. Basing cost pass-through on actual costs would be counterproductive, since it would reduce generator incentives to reduce emissions if any saving in emission costs is passed through to end-users. It is analogous to other generator costs: all generators earn the market clearing price even if their actual costs incurred are less than the market clearing price.

One potential issue of this approach is the use of a NEM-wide average emissions intensity, while averages vary by State – for example, Victoria (which is dominated by brown coal) will have a higher average emissions intensity than NSW (dominated by black coal). In a higher emitting state this may potentially lead to lower contract pass-through than could occur in the spot market (and conversely). This potential issue is mitigated to some extent by the interconnected nature of the NEM, which means that the lower emissions intensity of one region may partly constrain the ability of generators in connected regions to pass-through costs.

Another potential issue is that carbon exclusive contracting requires an estimate of pass-through rates (in the wholesale market) *and* an underlying energy price over time. In the longer run this may become more complicated since future generation options will necessarily trade-off lower emissions intensity and higher (underlying) energy costs. However, this is unlikely to be a significant issue in the short-term.

Hedging carbon

If retailers enter into carbon exclusive energy contracts (indexed to carbon) then they will be exposed to carbon price risk. Retailers can seek to hedge this risk through:

- contracting carbon permits in forward (futures) markets;
- contracting with offset providers; and
- potentially contracting with low emissions generators.

There is some indication of forward carbon markets emerging, although liquidity will be an issue in the short term, particularly as there is uncertainty around the CPRS design. The lack of transparency in the OTC market means that there is very limited information regarding how retailers and generators are managing potential future carbon risk in this market.

3.2.2 Carbon inclusive energy contracts

A second option involves contracting on a carbon inclusive basis. Exchange traded contracts are currently more reflective of this alternative, whereby contract energy prices do not vary with carbon costs. In the exchange traded market, there is emerging evidence that the uncertainty surrounding the CPRS is reducing market liquidity. Trade of base futures grew rapidly in 2006-08; although only part year data is available for 2008-09, on a pro-rata estimate the volume of base futures traded has declined (Figure 13). This has been offset somewhat by strong growth in the options market, which is likely an attempt by participant's to hedge carbon price risk. However, much of the contract volume traded may reflect contracts maturing between now and the expected commencement of the CPRS in mid-late 2010.

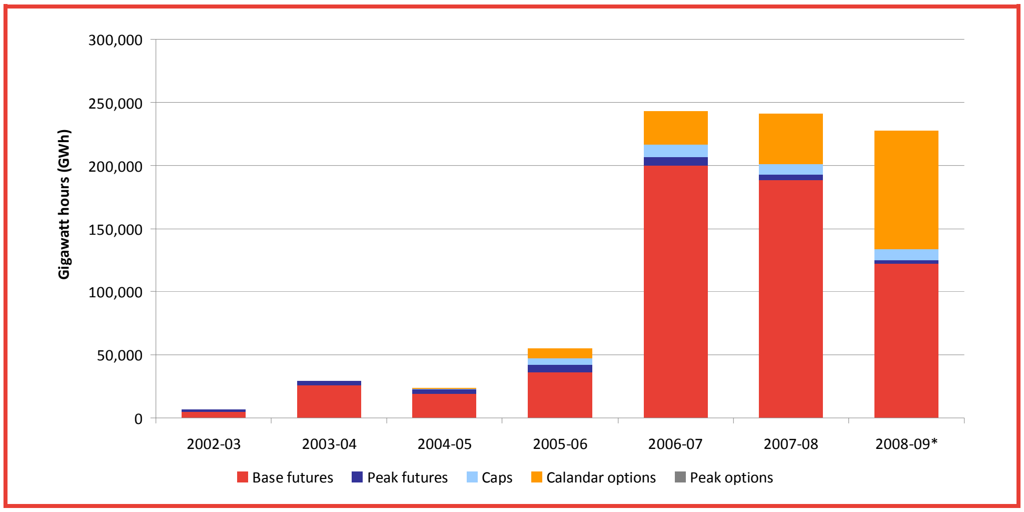

Figure 13: Breakdown of exchange-traded derivative contracts, year on year

Data source: d-cyphaTrade
**Financial year 2008-09 is represented as of 23 April 2009*

A more useful indicator of the effects of the CPRS is to consider contracts by time to maturity rather than time of trade. Figure 14 presents open interest in contracts according to quarters to maturity, where each series represents the year of maturity.

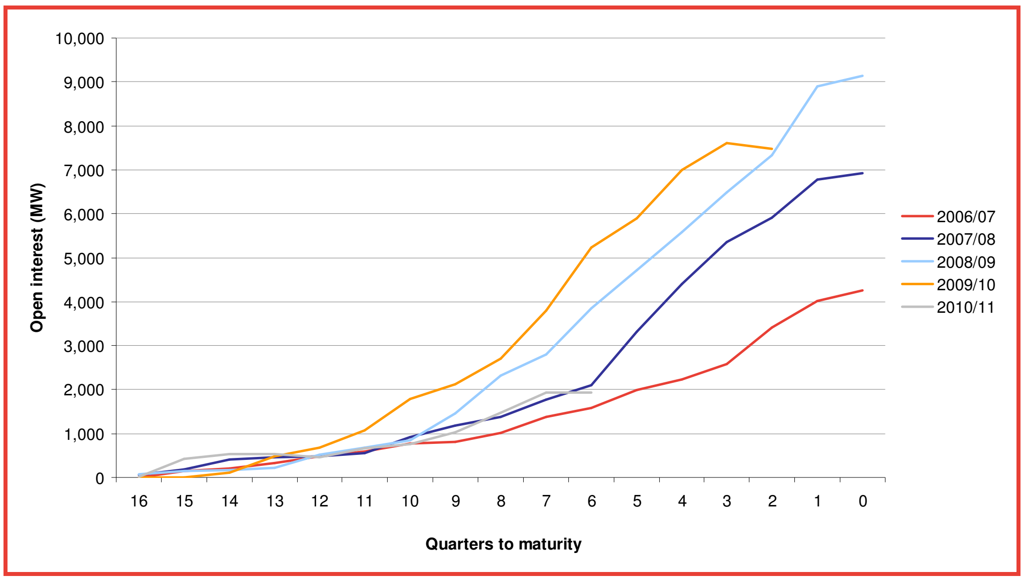

Figure 14: Market liquidity: open interest by quarters to maturity

Data source: d-cyphaTrade

Possible retailer hedging strategies

The chart demonstrates that contract volumes have been generally increasing from 2006/7 to 2009/10. Although some contracting occurs up to 4 years (16 quarters) in advance of maturity, most contracts are for two years or less. Given this, it is still too early to assess the likely effect of the CPRS, although it is clear that 2010/11 open interest levels are significantly below the levels of 2008/9 and 2009/10 at the equivalent point in time. This data reflects the market prior to the announcement of 4 May 2009, which delayed the CPRS by one year and imposed a price cap of \$10/tCO_2e. It will take some time before the effects of this announcement will be visible in the market data.

The exchange traded market also provides some insight into the market's expectations of the effect of the CPRS on wholesale pool prices: Figure 15. The National Power Index (NPI) represents the national average price of SFE Electricity Futures contracts for a calendar year. It represents a single basket of electricity futures listed across the NEM regions of NSW, VIC, SA and QLD.

From August/September 2008, as information became available regarding the proposed CPRS and expected carbon prices, the NPI for 2011 and 2012 increased by \$15-20/MWh. Again, the data reflects the market's expectations prior to the announced CPRS delay/price cap of May 4, since insufficient data exists to capture these effects. Even then, although this represents a small volume of contracts traded, it is approximately consistent with the earlier analysis regarding future carbon prices and levels of cost-pass through in the wholesale market (prior to the announcement of a lower price cap).

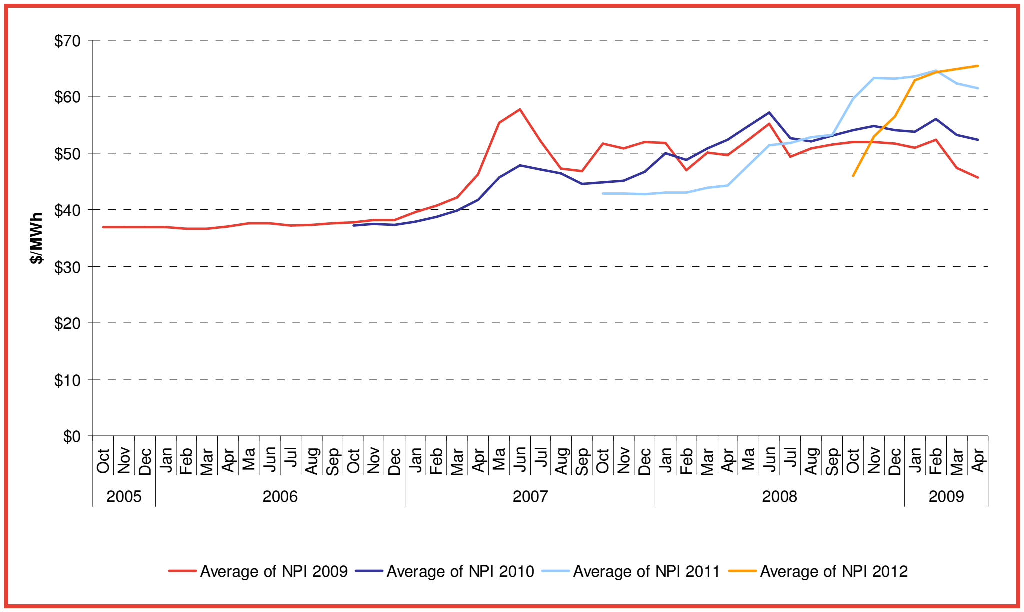

Figure 15: Market expectation of carbon cost pass-through

Data source: d-cyphaTrade

Possible retailer hedging strategies

3.2.3 Lower levels of contracting altogether

The third option raised in this section is that retailers may reduce contracted levels, or contract over shorter durations. In this scenario retailers bear energy price risk as well as carbon price risk, since they are more exposed to spot prices. We do not expect that this option would be preferred in the long-run, since the introduction of the CPRS should not change the current preference for contracting to manage energy risk. The contracting options discussed above still enable generators and retailers to contract for energy (and hence manage this risk); the difference is in how they assign carbon price risk. There is no reason to suggest that retailers would prefer exposure to energy and carbon risk over exposure to carbon risk alone.

3.3 CONCLUSION

In all cases, retailer costs will increase by more than just the level of carbon cost increase observed in the wholesale electricity spot market: risk will increase in the case of carbon exclusive contracts (where retailers bear carbon price risk) or contract premiums would increase in the case of carbon inclusive contracts (where generators bear carbon price risk). It is not possible to conclude from this analysis whether generators or retailers are better positioned to mitigate carbon price risk, and hence whether carbon inclusive or carbon exclusive contracting is clearly preferable. While the recent changes to the proposed CPRS, including a one year delay and a one year price cap ($10/tCO_2$-e), provide some temporary certainty on these issues, this announcement only delays the increase in risk to be faced by retailers.

4 Conclusions

This report is not intended to address all issues faced by regulators, or to recommend a particular methodology for future retail price regulation under a CPRS. However, this section briefly considers some implications of the CPRS for regulators. Given the discussion above, margin squeeze and a threat to the financial viability of retailers are of real concern if regulated tariffs to end-use consumers do not adequately address the increased costs and risks that retailers will face under the CPRS. Specific issues include:

- How to allow for higher CPRS costs and risks;
- Timing of reviews; and
- CPRS principles.

The delay in the CPRS and the increased price certainty in the first year (due to the \$10/tCO_2-e price cap) only delay these issues. They must still be addressed in the near future, and they are discussed in more detail below.

4.1 ALLOWANCE FOR CPRS COSTS

An important issue for regulators is how to estimate and allow for the costs associated with the CPRS. As discussed above, this includes both an increase in wholesale energy costs and an increase in expected volatility. While the discussion above identifies the broad range of potential cost effects, it is also intended to highlight the extent of uncertainty surrounding future carbon costs and volatility. Retailers may seek to manage these risks by contracting for a carbon inclusive energy price, although this will require an increase in premiums paid to generators to offset these costs. Alternatively, retailers may contract on the basis of a carbon exclusive energy price and manage the carbon risks separately. The implication of these options is that there is a trade-off between risk and costs, and there is not necessarily a dominant preferred strategy. As such, regulators must consider not only the projected future energy costs, but also the increased costs of managing carbon volatility and meeting higher prudential requirements. It may be appropriate to:

(a) Attempt to value the costs for retailers to hedge carbon risk in the markets (even then it may not be possible to fully hedge regulatory risk[21]); or

(b) Do not allow for an increase in direct hedging costs, but allow for increased risk (through higher margin or WACC).

A combination of the two may also be appropriate. This suggests that there is some flexibility in how regulators can address the impact of the CPRS.

[21] This includes the risk of changes in government policies, in Australia and/or internationally.

4.2 TIMING OF REVIEWS

The analysis in previous sections suggests there is declining liquidity in contract markets as uncertainty has increased. As prices become more volatile, it will likely become more costly to contract over longer time frames. This suggests that, if regulation is to be maintained on a 3 year basis (as in some jurisdictions) then it would be prudent to consider the additional costs that this imposes. The opposing consideration is that retailers are likely to be better placed to manage carbon risks than customers, and there is likely to be higher cost involved in updating/reviewing retail prices too regularly.

Given that retailers will likely seek to provide some price certainty for contestable customers (and will manage this risk) it should be reasonable to expect that retailers can manage the carbon risk of retail regulation in a similar manner. The most appropriate time frame will be an empirical question and will trade-off certainty and cost: i.e. longer term regulation should be feasible so long as the higher costs associated with managing this risk are accounted and allowed for.

4.3 CPRS PRINCIPLES

Another principle worth considering is the intent of the CPRS, which is to provide a carbon price signal to end users to encourage abatement. As such, it is important to balance the objectives of retail price regulation against the competing objective of the CPRS. This will be difficult given that these objectives may be somewhat conflicting, but the principle is that retail price regulation should not unnecessarily mute the price signal of the CPRS, particularly when the Commonwealth Government has committed to providing compensation to offset higher costs associated with the introduction of the CPRS.

Appendix A: Cost pass-through

This appendix discusses the factors that determine how much of carbon costs may be passed-through to electricity prices. Key factors include the emissions intensity of the marginal plant (before and after the introduction of a carbon price) and elasticity of demand.

The importance of the marginal plant in determining carbon cost pass-through is illustrated using a stylised example of an electricity market (Figure 16). Electricity supply consists of a merit order of generation options, stacked from lowest cost to highest cost. The market price depends on demand and the bid of the marginal generator: in the example presented, gas is the marginal plant that sets the pool price. In a perfectly competitive market, generators will tend to bid close to marginal cost, and this will set prices.

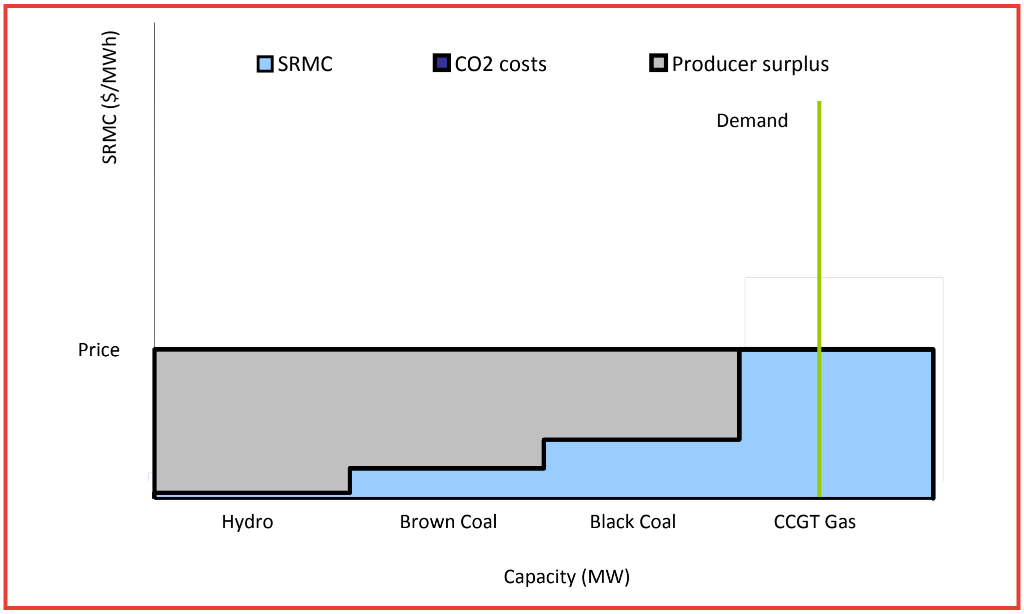

Figure 16: Merit order without an ETS

Source: Frontier Economics

When an ETS is introduced, generators will add the carbon cost to their bids. However, the change in pool price depends on (a) the carbon price and (b) emissions intensity of the marginal plant before and after carbon cost. Figure 11 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).

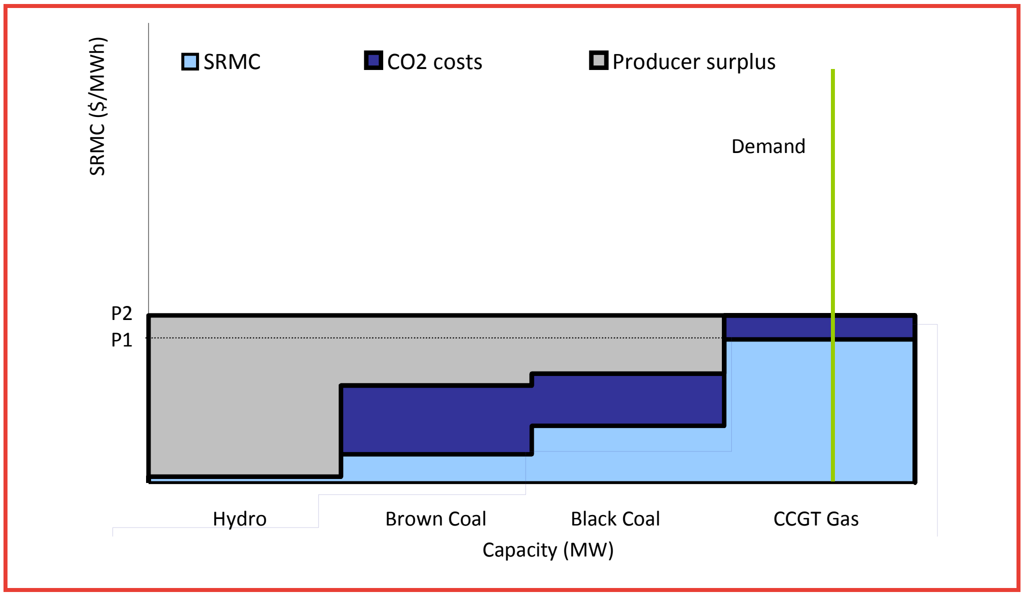

Figure 17 Merit order with an ETS (Low carbon price)

Source: Frontier Economics

In Figure 17, there is no change in merit order and hence no reduction in the emissions intensity of output; the only abatement that will be achieved is if total output is reduced due to lower demand. If a sectoral emissions cap were to be imposed on the electricity sector, then the carbon price would need to rise until the merit order changed and the emissions intensity of the market was reduced, as in Figure 18. [22] 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.

22 Under the CPRS, the Australian electricity sector will be able to import permits from other sectors and overseas to meet the abatement task, hence the carbon price will not need to rise to force changes in the merit order.

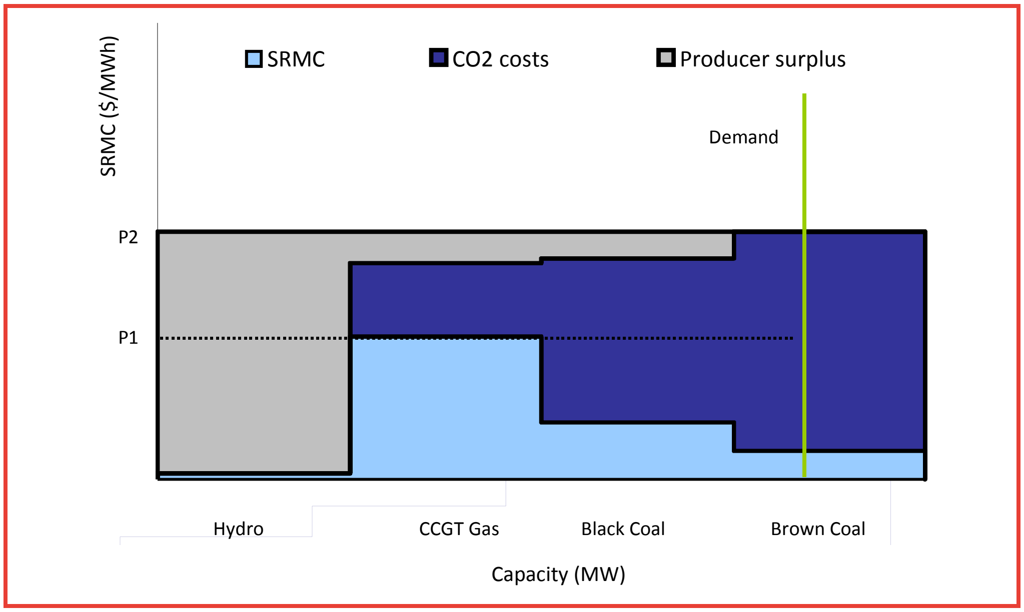

Figure 18: Merit order with an ETS (High carbon price)

Source: Frontier Economics

In these simple examples, when demand is high and gas is the marginal plant prior to the introduction of the CPRS (as in Figure 17) 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 19 and Figure 20). This suggests that levels of cost pass-through will differ depending on peak and off-peak periods.

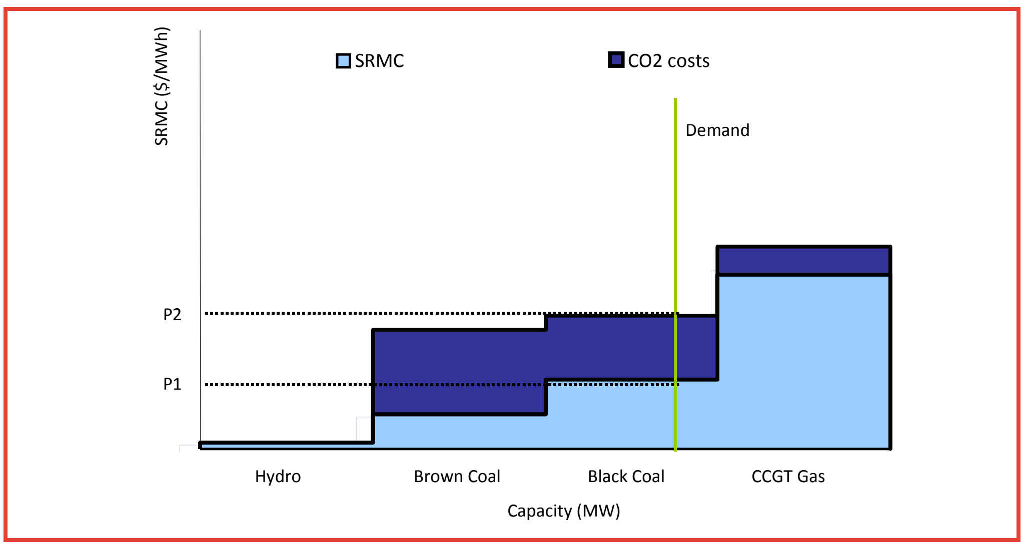

Figure 19: Stylised example of carbon costs: no change in merit order

Source: Frontier Economics

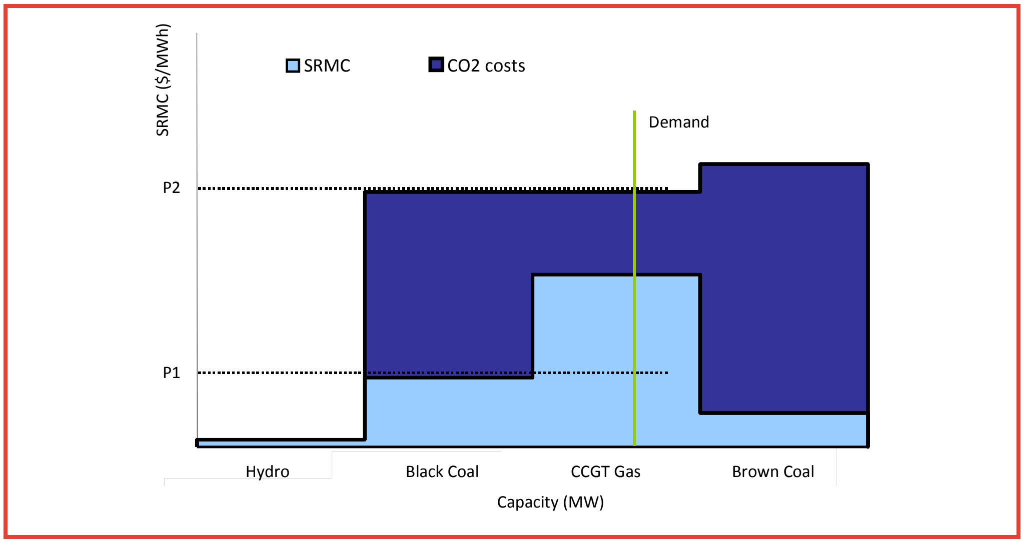

Figure 20: Stylised example of carbon costs: with change in merit order

Source: Frontier Economics

Appendix A: Cost pass-through

THE FRONTIER ECONOMICS NETWORK

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Frontier Economics Pty Ltd, 395 Collins Street, Melbourne 3000

Tel. +61 (0)3 9620 4488 Fax. +61 (0)3 9620 4499 www.frontier-economics.com