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Delayed Carbon Policy Certainty and Electricity Prices in Australia*

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The power industry has been grappling with regulatory uncertainty in relation to carbon since late 2004 when Australian state governments committed to the introduction of an emissions trading scheme. This article estimates the additional cost to electricity users associated with the sub-optimal introduction of new power generating capacity given regulatory delays. We find the costs to be significant; under a business-as-usual electricity demand growth scenario, prices in 2020 would be about $8.60/MWh higher than necessary. We also find that costs to consumers are lower where complementary policies are introduced to encourage energy efficiency and renewable energy.

Keywords: carbon tax, policy uncertainty, decision-making, electricity prices.

1. Introduction

The climate change policy environment within Australia at the time of writing could only be described as uncertain. Since 2007, the primary policy instrument for addressing anthropogenic greenhouse gas emissions, a cap-and-trade Emissions Trading Scheme (ETS), has wavered between bipartisan support for a 2010/2011 commencement date to single party support for introduction in 2013. This wavering approach to setting public policy is having profound consequences for investors in power generating capacity given that such investments are large (i.e. between $300 million and $2 billion), have extensive lead development and construction lags (i.e. 3–7 years) and particularly long useful lives (i.e. 30–50 years).

In 2004, the Labor-dominated Australian States and Territories agreed to implement an ETS if the Liberal Commonwealth Government did not. The States and Territories established the National Emissions Trading Task Force, a working group of senior officials that developed a model for a cap-and-trade ETS in 2006 (NETT (National Emissions Trading Taskforce), 2006). By late 2006, it had become clear to the energy industry that the Task Force should be taken seriously. In February 2007, State Premiers, through a Communiqué issued by the Council of Australian Federation, confirmed this by committing to ''conclude the development phase and begin the implementation of the national emissions trading scheme'' (CAF, 2007).

In December 2006, the then Prime Minister John Howard announced the establishment of a joint government business Task Group on Emissions Trading. On 31 May 2007, the Task Group

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released its report to the Prime Minister recommending the adoption of a cap-and-trade ETS commencing in 2011 (PMTGET, 2007). The Prime Minister adopted many of the recommendations from the Task Group and in the event, climate change policy became a major issue during the 2007 Commonwealth election. Importantly, both major political parties committed to introducing an ETS early in the next decade. After several years of policy debate, industry had at long last been provided with relative policy, and therefore, investment certainty and could finally start to incorporate a carbon price into future investment decisions with a degree of confidence around timing.[3]

In 2008 and 2009, the newly elected Rudd Commonwealth Government began the process of designing, consulting and introducing legislation for their Carbon Pollution Reduction Scheme (CPRS), a cap-and-trade ETS covering almost all of the Australian economy. Whilst initially enjoying bipartisan support from the Liberal Opposition, support evaporated in late 2009 following a change in the Opposition Leadership. The change in leadership was in fact driven by an anti-ETS sentiment within the Liberal Party. The investment certainty which was gradually emerging from the CPRS similarly began to evaporate. By any reasonable analysis, industry certainty had been wound back to the same position it had been in just prior to 2006. At the time of writing, investors in carbon-intensive capital stock such as power generation are now unable to accurately plan new base load plant investments until certainty is restored with the introduction of an ETS.

The purpose of this article is to examine wholesale electricity prices using a levelised cost model of plant technologies and a dynamic, partial equilibrium model of the National Electricity Market (NEM) under conditions of policy certainty and perfect competition under a uniform first price auction clearing model, which is consistent with the NEM design. Given the non-trivial impact of carbon regulatory uncertainty, we find that investors will seek to minimise capital costs to reduce the risk of stranded assets in a period of uncertainty. Our modelling estimates the higher prices associated with this sub-optimal capital stock being introduced because of the underlying policy uncertainty.

Importantly, this article does not estimate the costs associated with a particular carbon trajectory. Instead, it assumes a binary decision for investors in meeting new and uncertain electricity demand and estimates the costs associated with deploying either base plant or peak plant; the latter having a much lower capital cost but a considerably higher marginal running cost and carbon emission intensity. By examining the additional costs associated with regulatory uncertainty, this article provides a minimum estimate of the costs associated with delayed ETS policy settings.

This article is structured as follows. Section 2 provides a historical outline of the development of climate change policy in Australia. Section 3 outlines the binary decision making between base and peak plant investments to meet demand under conditions of regulatory certainty and uncertainty. In Section 4, we outline the optimal plant mix and average system cost for 2010 based upon a CY09 electricity load duration curve for the NEM. Section 5 then produces estimates of the optimal plant mix in 2020 based upon regulatory certainty being established in 2013 (applying the current timing for operation of the CPRS) and contrasts this with a scenario where regulatory certainty was theoretically established during 2010 as initially envisaged at the 2007 federal election. The limitations of this analysis with specific regard to renewable energy proliferation are discussed in Section 6. The quantitative results are then analysed in Section 7 to determine the additional costs for electricity consumers associated with delayed regulatory certainty in relation to climate change policy. Our conclusions follow.

2. Climate Change Policies in Australia

Australia has long been aware that its coal-dominated power generation sector is the largest point source of greenhouse gas (carbon dioxide equivalent – CO_2e) emissions with less than 100 sites producing more than one-third of national emissions. The policy debate on an optimal national

[3] Of course, the price of carbon remained highly uncertain. But industry, especially the power industry, has long grown accustomed to dealing with, and managing the risk of, commodity price uncertainty.

approach to mitigate carbon emissions has been ongoing for the better part of two decades. The following provides an important historical account of the history of this debate, including the policy milestones and the measures that have been successful from a legislative perspective.

In June 1992, at the Rio Earth Summit, Australia together with 152 other countries signed the United Nations Framework Convention for Climate Change (UNFCCC). Later in that same year, the Commonwealth Parliament's Senate Standing Committee on Industry, Science and Technology released the report *Gas and Electricity Combining Efficiency and Greenhouse (Senate Standing Committee on Industry, Science and Technology, December 1992)*. A key recommendation of this report was that the use of natural gas in power generation should be increased to reduce emissions.[4] This 1992 report is regarded as the commencement of government recognition that the power generation sector will require specific policy intervention to mitigate greenhouse gas emissions given Australia's resource endowments.[5]

Following the Senate Standing Committee report in 1992, Australia's deliberations on what would be the most appropriate mechanisms to mitigate greenhouse gas emissions went through a number of iterations. In 1997, the Inter-Governmental Committee on Ecological Sustainable Development released a discussion paper on directions for a National Greenhouse Gas Strategy. The Productivity Commission (then known as the Industry Commission) made a submission to the Committee urging further research into the use of market mechanisms, including the use of tradeable emission permits, to minimise the cost of emission reductions over the long-run.[6] The Productivity Commission's research noted that tradeable permits between power generators could deliver a lower cost outcome than an externally determined tax rate on carbon emissions.

The Generator Efficiency Standards (GES) programme was introduced on 1 July 2000.[7] Using a voluntary Deed of Agreement between government and business, the GES required existing power generators above 30 MW of capacity and with output of 50 GWh/annum or more to report their emissions performance annually. In addition to reporting, generators were obliged to implement efficiency improvements which faced costs of \$10/t CO_2e or less. Importantly, the GES also included performance standards for new generation plant and were set at international best practice for natural gas, black and brown coal generation plant.[8]

What is believed to be the world's first mandatory greenhouse gas, ETS commenced in New South Wales (NSW) on 1 January 2003. As the earliest example of a baseline-and-credit ETS (as distinct from a cap-and-trade), the Greenhouse Gas Reduction Scheme (GGAS) imposes a liability on electricity retailers in NSW to meet annual emission targets through the acquisition and surrender of abatement certificates (Greenhouse Gas Abatement Certificates or NGACs) that each represent 1 t of greenhouse gases (CO_2e). Owing to NSW participation in the NEM, eligible sources of NGACs exist across all jurisdictions connected to the NEM. Targets are based on a per capita metric, and the current target is 7.27 t CO_2e.

The point of liability under GGAS is on the electricity retailer. However, generators have an implicit carbon price incentive through the ability to create NGACs for emission reductions from individual power stations. Participation has been strong, and eligibility is not restricted to any particular fuel or technology. Around 130 generators are accredited abatement providers under GGAS[9] and to date over 73 mt CO_2e of abatement has been achieved.[10] A number of legislative amendments in recent years prepared GGAS for transition to a national ETS and in 2009 the Commonwealth Government offered a \$130 m package to assist those adversely affected by the transition. GGAS is now closed to new projects and abatement targets are no longer tightening.

[4] http://www.aph.gov.au/library/pubs/bp/1997–98/98bp04.htm.

[5] Australia has very low cost coal resources relative to unit gas costs. For further details on the dilemma facing gas relative to coal in power generation, see Simshauser (2010a).

[6] Industry Commission, April 1997: http://www.pc.gov.au/ic/research/submission/icesd/mediarelease.

[7] http://www.environment.gov.au/settlements/ges/index.html.

[8] Annual reports under the GES were last submitted in 2008. The programme has since been abandoned.

[9] GGAS Annual Report, July 2009.

[10] See GGAS Registry (June 2010) at: http://www.ggas-registry.nsw.gov.au.

Prompted by the successful commencement of GGAS, and the refusal of the Commonwealth Government to consider a national ETS, the states and territories collaborated to form the National Emissions Trading Taskforce or NETT in 2004. Over the ensuing two years, the NETT set about developing the detailed policy framework of a national cap-and-trade ETS for application to the stationary energy sector. After a number of key investigative publications, the NETT concluded in December 2007 with the release of its final report on a possible design for a national ETS. The design was influenced by the European Union ETS which had already commenced, and recommended a number of domestic offsets also be eligible.

The NETT was borne out of inaction by the Federal Government, and similarly industry and other stakeholders were also concerned by the national uncertainty, given strong progress at the state level. Two key groups assembled to address this issue. The World Wildlife Fund Australia, together with Frontier Economics and the Australian Gas Light Company (AGL) performed an economic evaluation on how to achieve emission reductions in the electricity sector. The study found that Australians could pay as little as $250 each to achieve a 40 per cent reduction in greenhouse gas emissions from the country's power generation industry by 2030.[11] In addition, the Australian Business Roundtable on Climate Change, composed of industry and environment groups, undertook a series of investigations to conclude Australia should not delay action on climate change as early affordable steps in the near term may avoid costly actions later.[12]

Recognising the degree of state government and industry momentum, the Prime Minister commissioned a Task Group on Emissions Trading in December 2006. Its report, recommending the development of a national cap-and-trade ETS, was released in May 2007 and the Prime Minister adopted this recommendation as Coalition Government policy on 4 June 2007. Given the opposing Labor Party's support for a national ETS, this was the first time that bipartisan support existed at the national level. The main point of difference at this stage was the commencement date, although the difference was only 18 months. This bipartisan support captured 15 years of debate on the relative merits of a national ETS to mitigate greenhouse gas emissions in Australia.

Later in 2007, the National Greenhouse and Energy Reporting Act 2007 came into effect obligating all large emitters to report on greenhouse gas emissions, and the current Labor Government was elected committing to a national ETS in 2010. The year 2007 finished with Australia ratifying the Kyoto Protocol at the UN Conference of the Parties in Bali.

The Garnaut Climate Change Review was commissioned in early 2007, as a preemptive action by the then Federal Labor Opposition and the Labor State and Territory Governments. With a change of federal government, the conclusions of the Garnaut Review regarding the need to end uncertainty and introduce a national ETS[13] ultimately dovetailed with policy development for the CPRS in 2008.

The CPRS was introduced in a Green Paper in July 2008. It was the first detailed step by a Federal Government towards the introduction of a national ETS. The subsequent White Paper provided conclusive direction on the Government's intent to legislate a national ETS with wide coverage of the economy, and a 2020 target range of 5–15 per cent below Australia's CY2000 emission levels. Exemplifying the firmness of this direction, a fledgling carbon market emerged for Australian Emission Units, the tradeable permits under the CPRS. This market steadily built upon the first trade of Australian Emission Units (AEUs) in May 2008, as power generators began to hedge in anticipated future input costs.

Legislation to enact the CPRS was introduced to Parliament in May 2009. The legislation was consistent with the White Paper, however, it now featured scope to tighten the 2020 targets to

[11] *Options for moving towards a lower emission future*, December 2006: http://www.wwf.org.au/publications/lower-emission-future/.

[12] Australian Business Roundtable 2007: http://www.developmentgateway.com.au/.

[13] The Garnaut Climate Change Review, Final Report, 2008.

25 per cent and the commencement date had been delayed to 2011 following an extensive consultation process. This was the first attempt to legislate, but was voted down in the Upper House (i.e. the Senate) some three months after being introduced to Parliament. Negotiations between the Government and the Liberal–National Party Coalition Opposition together with an independent Senator failed to progress. The Government shortly reintroduced the CPRS Bills in October 2009, aiming to achieve passage of the legislation before the landmark Copenhagen UN Climate Change Conference in December 2009. This second attempt to pass the CPRS was subject to intense negotiations between the Government and the Coalition Opposition. A number of key amendments were agreed to, focused on smoothing the transitional impacts to industry, including a marked increase in structural adjustment assistance to eligible coal-fired generators, and a mechanism to facilitate low emission reinvestment in the sector.

In a dramatic turn of events, the Coalition Opposition leadership changed just as bipartisan support for the CPRS emerged. With a change of leadership came a change of policy, and the re-negotiated CPRS was voted down for a second time by the Senate at the beginning of December. The legislation was introduced for a third time to Parliament in February 2010; however, the Government eventually announced a delay of legislating a price on carbon until at least 2013, subject to greater public consensus domestically and progress on international action.[14]

For nearly two decades now, the power generation sector has been the subject of policy speculation with respect to controls on greenhouse gas emissions. Without exception, power generation has been the key sector to be subject to this policy debate, and in at least two scheme iterations, power generators have participated in measurement, reporting and efficiency improvement regimes. There is little doubt that the sector has suffered from this uncertainty, and Energy Ministers from both sides of politics have publicly acknowledged this. Serendipity based on the legacy of initial government investment in power plants has broadly carried the industry through this uncertainty, but as demand growth continues and capacity tightens, a decisive conclusion is increasingly required.

3. Binary Decision for New Plant: Base or Peaking Plant

In considering the optimal plant mix for 2020, it is necessary to first consider the options available to investors in new power generation plant designed to meet rising electricity demand. The Australian generation plant mix is vastly different when considered on a capacity and output basis. In output terms, Australian power generation is dominated by coal with around 81 per cent of all output being produced by black and brown coal-fired generators. However, only 58 per cent of Australian power generation capacity is coal-fired. Table 1 contains the output and capacity across the three major generation types in the Australian electricity market.

The stark contrast between capacity and output within the Australian electricity market is because of the inability of the industry to manage variable demand through inventory management. As electricity cannot be stored economically, production must match consumption on a real-time basis. Accordingly, as electricity demand increases, additional generation capacity must be brought online. This results in some proportion of the capital stock being utilised for much lower periods of time than in other industries.

Based upon this unique feature of electricity markets, investors in new plant capacity consider the economics of the technology being developed against a backdrop of different growth trajectories across the various demand categories. At present, growth in peak demand is outstripping growth in base or underlying energy demand. Table 2 outlines the ratio of peak demand growth to underlying growth in energy demand in the different jurisdictions in the NEM within Australia from 2010 to 2020.

Managing this economically requires market participants to invest in plant based upon characteristics matched to the relevant demand conditions. Effectively, this falls into three categories:

[14] Minister for Climate Change and Energy Efficiency, 28 April 2010: http://www.climatechange.gov.au/minister/wong/2010/transcripts/April/tr20100428a.aspx.

Table 1. *Output and Capacity of Australian Electricity Generators*

Type	Output (GWh)	Per cent of total	Capacity (MW)	Per cent of total
Coal	186,464	81	29,407	58
Gas	28,321	12	13,253	26
Renewables	14,970	7	8154	16

Source: Energy Supply Association of Australia (ESAA, 2010).

Table 2. *Annual Growth in Electricity Demand to 2020*

State	Per cent growth in peak demand	Per cent growth in underlying energy demand	Ratio of growth (%)
Queensland	3.6	3.2	113
New South Wales	2.2	1.5	147
Victoria	2.2	1.2	183
South Australia	2.0	2.0	100

Source: Derived from Australian Energy Market Operator (AEMO, 2009).

- Generation plant with relatively high capital costs but low operating costs is used to meet base load demand (demand that occurs for most of the time). Historically, black and brown coal generation which is slow to start or shut down has been used to meet base load demand and such plant typically operates at a 75–90 per cent annual capacity factor.
- Intermediate demand (nominally the higher ''daytime demand'') is generally met by plant with medium capital and operating costs and flexible operating capacity (i.e. can be ramped up quickly). Combined cycle gas turbine (CCGT) plant is generally used to meet intermediate demand and typically runs at an annual capacity factor of between 40 and 60 per cent.
- Generation plant with relatively low capital costs but high operating costs is used to meet peak demand (demand that only occurs on the hottest and coldest days of the year, or during power system contingency conditions such as unexpected plant outages). Open cycle gas turbine (OCGT) plant or hydro generation (preexisting capacity built by governments) which can be ramped up very quickly is generally used to meet peak demand and typically operates at annual capacity factors of between 5 and 30 per cent.

The long-run marginal cost (LRMC) of various power generating technologies is presented in Figure 1. The levelised cost model specifications used to produce the results in Figure 1 have been documented extensively in Simshauser and Wild (2009), and accordingly will not be reproduced here.[15]

Figure 1 notes that the underlying LRMC of black coal-fired generation, CCGT and OCGT plant is about \$50, \$58 and \$96 per MWh, respectively. In the absence of a carbon price, investors could choose to install coal-fired generation to meet base load demand because of its low overall cost. The flexibility (i.e. fast start nature) of CCGT and OCGT plant is preferred for intermediate and peak demand because they have lower fixed operating costs, which makes them more economic on a unit cost basis for shorter annual run-times.

But the economics of meeting variable demand is not the only decision faced by investors. As outlined in Section 2, climate change policy and uncertainty about long-term policy settings is a critical factor in considering what type of generation to build. Currently, the average intensity of power generation in the NEM is about 0.95 t of greenhouse gases per MWh. It is generally

[15]Equations (1)–(11) in Simshauser and Wild (2009, pp. 347–9) provide a comprehensive overview of the Levelised Cost Model for power generating equipment.

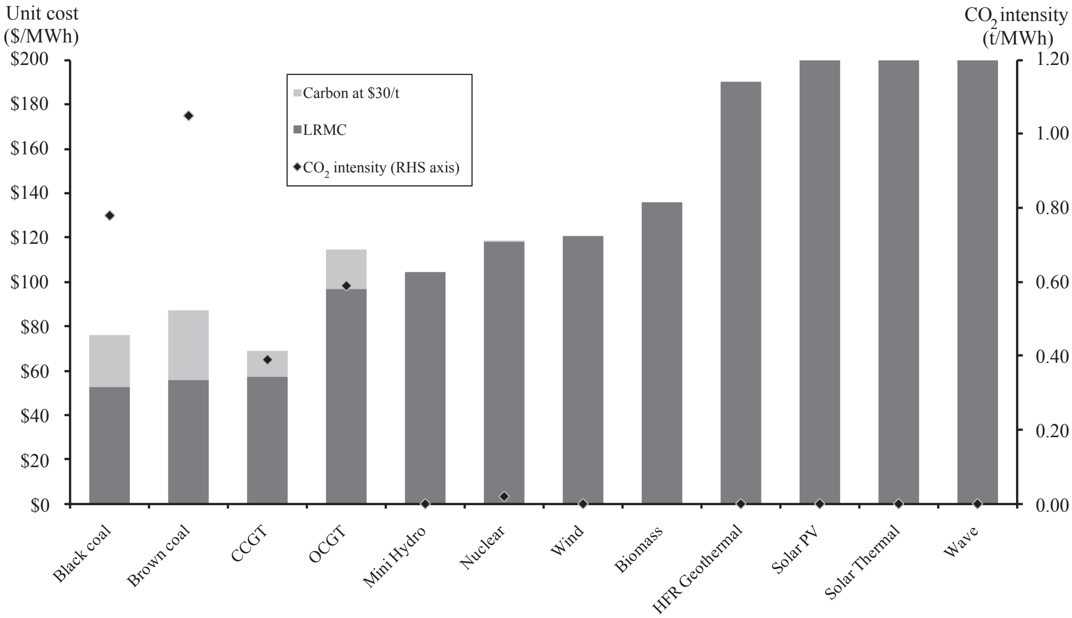

Figure 1. *Long-run Marginal Cost of Power Generation Technologies*

accepted that targets for limiting climate change to a 2°C temperature increase will require Australia's power generation fleet to operate at an intensity level of around 0.17 t of greenhouse gases per MWh by 2050.[16]

At a practical level, even though coal-fired power stations are the lowest cost technology available to meet base load electricity demand, they are unlikely to be built in Australia by private sector participants based upon current or projected policy settings because both the equity capital markets and project banks would find it difficult to accept the heightened risk of manifest asset stranding that would arise if and when an ETS is eventually legislated; note in Figure 1 that when a carbon price of $30/t is added to the cost structure, CCGT plant becomes the lowest cost producer.

The reason for this reversal in the economic position of plant is that a Greenfield coal-fired power station emissions profile is about 0.8 t/MWh, and as an aside, is inconsistent with the longer-term targets accepted by all levels of government in Australia. On the other hand, electricity generated by CCGT plant emits just 0.39 t/MWh (although in the absence of a price on carbon, face higher running costs as noted in Figure 1). The economic crossover point between coal and CCGT plant is a carbon price of about $19.50/t. As a result, given the roughly 40-year investment horizon associated with power plant investments, it is widely accepted that no bank would provide finance while the risk of carbon pricing remains prevalent, particularly when modelling predicts carbon prices starting at $25/t. All investors are aware that even in the absence of a carbon price today, a shadow carbon price exists and when it is eventually revealed, it is highly likely to render any investment in coal plant today as unprofitable in the future. For this reason, debt and equity providers are highly unlikely to commit to a 40-year investment in new coal plant.

[16] To contribute to a global target of 450 ppm – Commonwealth Treasury (2008, p. 174).

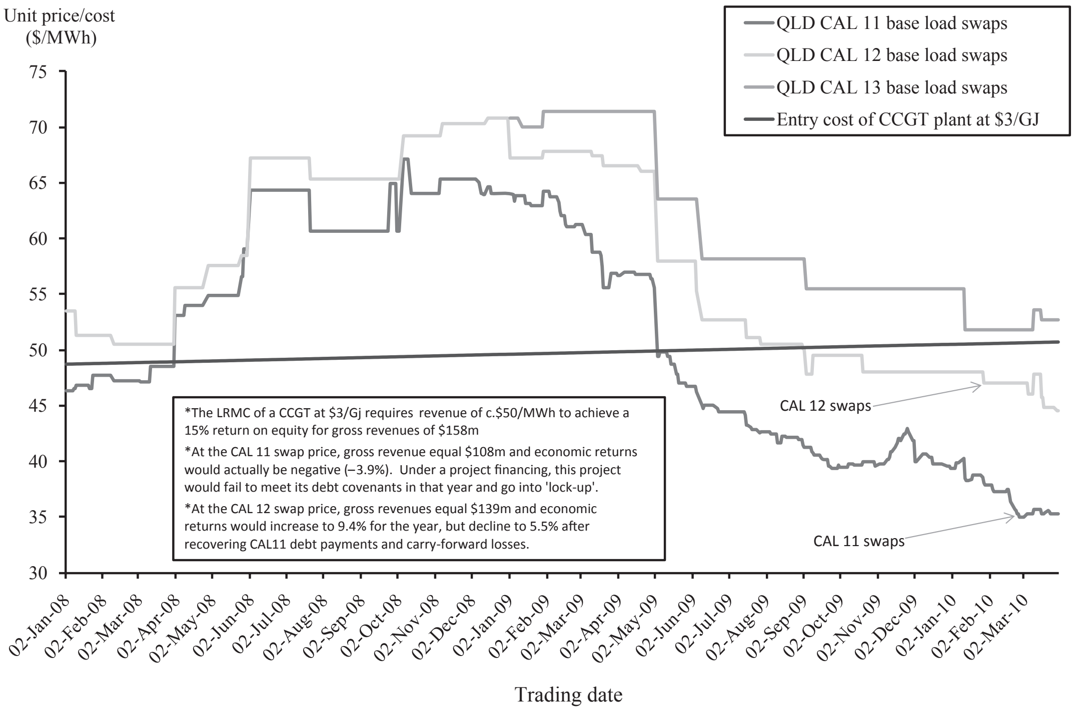

Figure 2. *Economic Returns on a Greenfield 380 MW Combined Cycle Gas Turbine Plant in Queensland*

Ironically, investors today are also unable to secure project finance for base load thermal alternatives to coal (e.g. CCGT) while policy settings explicitly allow coal to be built. While all reasoned logic dictates that coal would not be built under current conditions, this cannot be guaranteed. So while a CCGT plant would have a substantially lower emissions intensity than coal at 0.39 t/MWh, the absence of an explicit carbon price creates unacceptable risks for investors in CCGT plant as the higher cost structure of CCGT plant would be undermined by existing coal plant should it be financed and constructed.

To illustrate this point, we have modelled a 380 MW CCGT plant in Queensland under a conventional project financing arrangement using the project financing model contained in Simshauser (2009). The model specifications and major financing assumptions such as credit margins, debt sizing conventions and the debt service coverage ratios were documented in detail in Simshauser (2009) and again we do not propose to reproduce them here. The required annual revenue line (i.e. the ''Entry Cost of CCGT Plant at $3/GJ'' line illustrated in Figure 2) for this 380 MW plant was derived from the project finance model.[17]

Under optimal conditions, the project requires a gross income stream of about $158 million which in turn would enable all fuel, operations and debt service costs to be covered and provide equity investors with a 15 per cent return on funds employed, which is appropriate for a merchant generator.[18] But FY11 forecast modelling using live market data from the NEM reveals that the 380 MW CCGT plant would produce an expected gross income stream of only $108 million.

[17]In particular, forward prices were derived from ICAP and spot prices from the Australian Energy Market Operator.
[18]The cost of equity capital calculations for a power generator are contained in ACIL Tasman (2009).

Table 3. *Scenario Options for Investment in New Power Plant Capacity*

Scenario	Base load	Intermediate	Peaking
Regulatory certainty	CCGT	CCGT	OCGT
Regulatory uncertainty	None	OCGT	OCGT

Notes: CCGT, combined cycle gas turbine; OCGT, open cycle gas turbine.

After deducting fuel, operation and maintenance costs, the project would have just $22 million in free cash flows available to service its annual debt obligations of $30 million. As a result, such a project would enter financial default in its first year of operations. Of course, if the plant was developed ''on balance sheet'', then the project could internalise any losses in the broader corporate financial structure. But as noted in Simshauser (2010b), more than 80 per cent of the NEM's privately owned generating plant capacity has been project financed, and under such structures, once a project's cash flows fall below *1.35 times* debt service costs in three successive quarters, the project will enter ''financial lock-up,'' and if cash flows fall below *1.1 times* debt service costs, the project will enter ''outright default'' (Simshauser, 2009).[19] Figure 2 provides a graphical illustration of the economics of a CCGT plant versus market prices in the absence of a carbon price.[20]

Figure 2 demonstrates that wholesale electricity swap prices (CAL11 and CAL12 swaps) are significantly below the entry cost of a CCGT plant which is based upon an input fuel price of $3/GJ and no carbon price. However, at any time between March 2008 and May 2009, forward electricity swap prices were high enough to justify an investment in a new CCGT. This is not a coincidence. In fact, it demonstrates our key thematic. The only time at which prices could justify commitment to a new CCGT was between the start of 2008 and May 2009, the exact timeframe where investors had confidence in bipartisan support for emissions trading being developed within Australia.

Without mandatory performance standards that reflect the long-term emission reductions required or a broad-based ETS with long-term targets, ''investment paralysis'' is entirely predictable. This effectively leaves investors with one option for investment to ensure security of supply, OCGT plant, because it minimises ''capital at risk.'' In summary, the options facing investors under scenarios of regulatory certainty and regulatory uncertainty are summarised in Table 3.

The short to intermediate-run consequences of this situation are dire for the power industry. Until certainty is provided, investors will seek to minimise capital costs (and therefore the risk of asset stranding) by investing in OCGT to maintain security of supply. As noted in Simshauser *et al.* (2010a), the capital costs of CCGT and coal generation are 1.5 and 2.6 times greater than the capital costs of OCGT. The prudent action to minimise the risk of stranded assets is to install OCGT rather than CCGT irrespective of the demand profile, given regulatory uncertainty around carbon policy. For so long as uncertainty remains a feature of the policy environment facing power generators, OCGT will be sub-optimally used to satisfy growth in energy demand, resulting in lower capital cost exposure for investors, but higher prices and carbon emissions for end consumers.

4. Optimal Plant Mix in 2010

In assessing the optimal plant mix in 2010, we have used cost assumptions derived from ACIL Tasman (2009) and the levelised cost model in Simshauser and Wild (2009) to produce our LRMC estimates. Rather than adjusting costs over time to reflect changes in input fuel prices and capital

[19]See in particular table 4 in Simshauser (2009) for details of debt service coverage ratios and debt covenants for a project financed power station.

[20]This analysis of course assumes that the 380 MW CCGT plant replaces an existing plant. If a new plant was in fact added to the grid with demand held constant, power prices would be even lower and financial losses magnified.

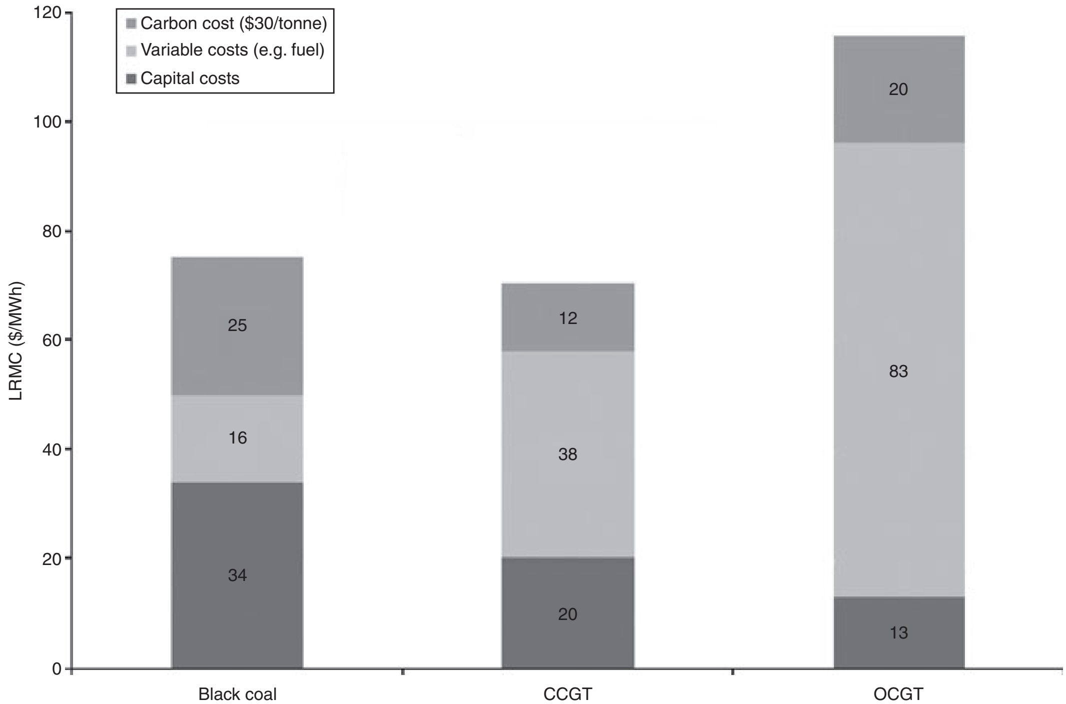

Figure 3. *Long-run Marginal Cost of Thermal Technologies*

costs, we have held constant the LRMC of all plant. The purpose of this restriction on cost variability is to demonstrate that even with constant prices and all other things being equal (such as the marginal efficiency of capital deployed), there is a significant cost associated with policy uncertainty. The LRMC of the three technologies discussed in the previous section are outlined in Figure 3.

Figure 3 highlights that the proportion of fixed (capital) and variable costs for the three technologies varies substantially. While the underlying LRMC of black coal generation (ex-carbon) is lowest at about $50/MWh, capital costs represent 68 per cent of the cost structure when operating at full load. The underlying LRMC of CCGT plant is higher at $58/MWh, but fixed costs representing just 34 per cent of the cost structure at full load. Importantly, when carbon is included, variable or, more importantly, avoidable costs represent over 70 per cent of the CCGT cost structure, and this of itself highlights one of the key advantages of base load gas plant as opposed to coal under carbon constraints (i.e. a lower and a more flexible cost structure in an energy-only market institutional setting).[21] OCGT has a substantially higher underlying LRMC at $96/MWh with the vast majority of costs (86 per cent) being variable, although to be sure, investment in such a plant is generally biased towards peaking operation as distinct from base load operations.

As outlined in the previous section, the rich blend of fixed and variable costs has significant implications for the optimal technology mix, a characteristic which was noted long ago by Boiteux

[21]As Atherton (2010) noted in the case of a nuclear plant in the British electricity pool, the predominance of fixed costs associated with nuclear plant makes them a particularly risky investment in an energy-only market environment.

(1949), Berrie (1967), Turvey (1968) and Carew and Kleindorfer (1976).[22,23] In establishing a national load duration curve for the NEM, we have aggregated existing state-based load data using historic Australian Energy Market Operator load data.[24] Based upon the cost structure of the technologies outlined before and the shape of the load duration curve, we are able to determine the optimal mix of generation. This is demonstrated graphically using Berrie's (1967) static partial equilibrium model, in Figure 4. The ''Optimal Plant Mix'' model used to derive the results in Figure 4 has been comprehensively documented in Simshauser and Wild (2009), and as a result, once again we do not propose to reproduce it here.[25]

Note in Figure 4 that the intersecting plant running cost curves (in the top graphic) provide the lowest cost-generating technology for any given plant capacity factor. When this investment frontier is transposed down to the bottom graphic, known as a load duration curve (representing electricity demand),[26] an optimal plant mix can be determined. Based upon this analysis, we have calculated that the optimal mix of generation for the aggregated 2010 load duration curve would be about 22,100 MW of black coal, 4700 MW of CCGT and 14,000 MW of OCGT plant. This analysis is based upon a 15 per cent reserve margin included for security of supply purposes, which is consistent with international reserve margin benchmarks. With this capacity in place, the Optimal Plant Mix model produces an average system cost of $62.57/MWh. This result can be contrasted with the contract prices presented in Figure 2. This pricing outcome is well within the range of pricing that has occurred in recent years.

New plant capacity additions in the NEM between 1998 and 2010 have totalled 5366 MW (ESAA, 2010). As evident in Simshauser (2010b), capacity additions between 1998 and 2002 were overwhelming new base load coal (2525 MW or 47 per cent), with peaking OCGT plant comprising the majority of the balance at 1633 MW (or 30 per cent). However, from 2005 onwards, gas plant represented 76 per cent of aggregate new investment, with only one coal plant, Kogan Creek, arriving in 2007 and no further coal investment proposals of note since.

5. Optimal 2020 Plant Mix in Australia with and without Regulatory Certainty

We have made three primary assumptions in relation to the impacts of uncertainty on investment decision making:

- A carbon scheme commences in 2013 as per the current Commonwealth Government policy;
- investors face a five-year delay in plant being available. This represents a reasonable estimate of the timeframe required to develop a new CCGT plant given planning, permitting and construction timeframes;[27]and

[22]Joskow (1975) noted that these theoretical models regarding the optimal pricing of non-storable commodities with periodic demand can generally be divided into three analytical approaches: (i) The American approach focuses on peak prices being set at marginal running costs plus marginal capacity costs with a focus on shifting peak loads (Carew and Kleindorfer, 1976); (ii) the British approach has a heavy focus on specifying the optimal mix of supply-side technologies (Berrie, 1967; Turvey, 1968); and (iii) the French approach is fundamentally a combination of both the American and British approaches where peak demand can be shifted and supplied by an optimal mix of different technologies (Boiteux, 1949).

[23]See also Stoft (2002) or Simshauser (2006) amongst others for applied examples in the context of thermal power systems.

[24]See load data at: http://www.aemo.com.au/data/price_demand.html.

[25]For a detailed overview of the Optimal Plant Mix model, see in particular equations (12)–(22) in Simshauser and Wild (2009, pp. 349–52).

[26]A load duration curve plots MW of demand for each half hour of the year in descending order.

[27]In an investor presentation, Origin Energy (http://www.originenergy.com.au/files/3InvestorsDDPS.pdf) has previously indicated that projects are generally developed over a 6–7-year timeframe. We have used a five-year timeframe to reflect that preliminary site assessments and planning work is likely to have been undertaken for many potential projects.

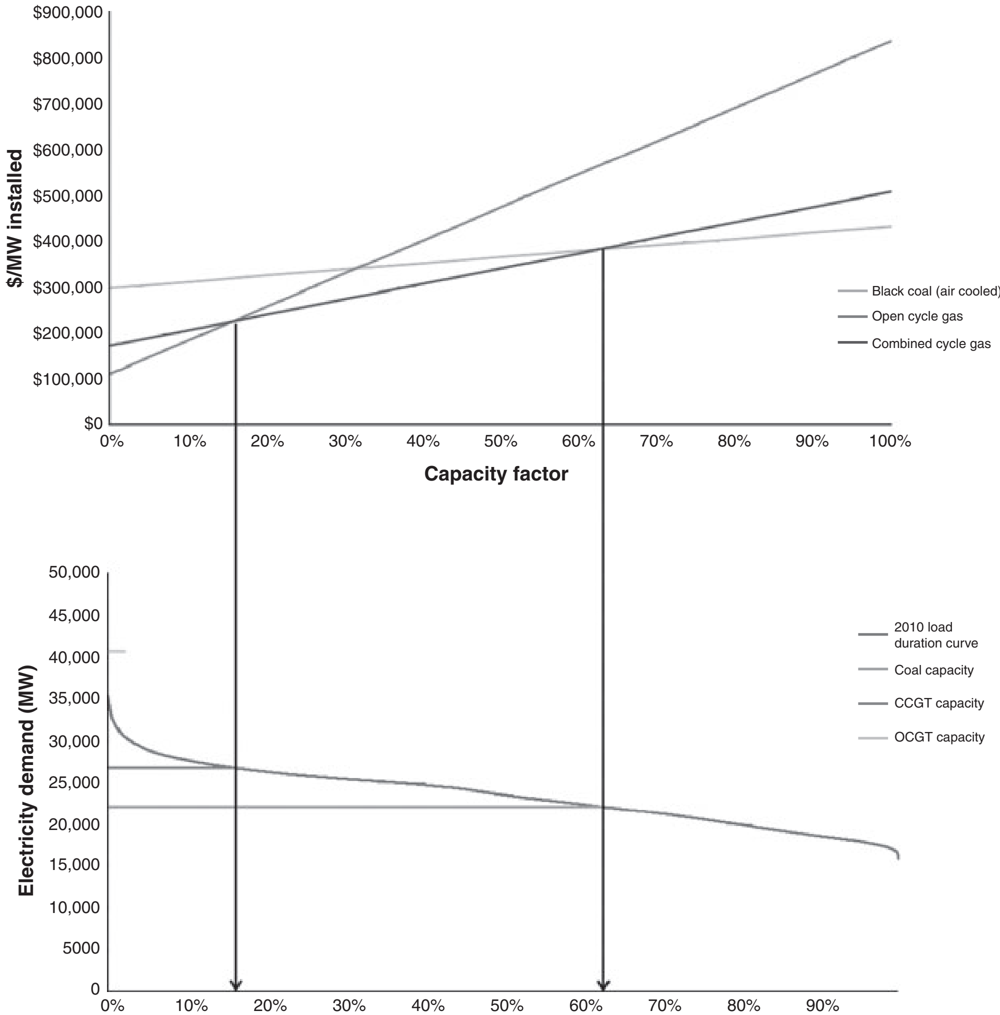

Figure 4. *Optimal Plant Mix in 2010*

- existing climate change policies such as the NSW Greenhouse Gas Abatement Scheme and the Queensland 18 per cent Gas Scheme do not alter investment decisions before 2013 when certainty is provided, and they are discontinued after 2013.[28]

To contrast the optimal plant mix in 2020 under conditions of regulatory certainty and regulatory uncertainty, we have developed two optimal plant combinations, again using the Optimal Plant Mix model from Simshauser and Wild (2009). In the first combination, regulatory certainty is presumed from 2010 with commitments able to be made immediately to construct new CCGT plant to meet increased intermediate and base load demand, given that coal plant investments

[28]As at October 2010, NSW NGAC and Gas-fired Electricity Certificate Prices were well below historical averages indicating a significantly long market. This implies that these policies are unlikely to have any impact on investment decisions over the timeframe between 2010 and 2013.

present too high a risk for equity and debt capital providers. We have called this scenario ''Immediate Certainty,'' In the second combination, regulatory certainty is not provided until 2013 with all new demand until 2017 met by new OCGT generation. Beyond 2017, CCGT is able to be installed to meet new intermediate and base load demand. We have called this scenario ''Delayed Certainty.'' Importantly, there is no need to include any assumptions in relation to the prevailing carbon price as a sub-optimal capital stock will be the result of Delayed Certainty, irrespective of whether a carbon price is introduced or ruled out in 2013.

Load duration curves were developed for 2017 and 2020 to determine the optimal plant mix under each of these scenarios. For each scenario, two different load duration curves were developed. The first assumes that the average annual growth in electricity demand seen in the NEM states over the period between 2000 and 2009 will continue through to 2020. Average annual demand growth for each decile of the load duration curve was calculated, and applied to predict demand for each half-hour of the load curve in 2017 and 2020. In summary, this assumes growth in electricity demand of approximately 1.5 per cent per annum, with the increases occurring primarily during peak and high demand periods. We have called this demand scenario ''BAU'' or business-as-usual.

The second set of load duration curves developed for 2017 and 2020 assumes that BAU will be curbed by the widespread implementation of energy efficiency (EE) schemes, smart meters and time-of-use charging throughout the NEM states between now and 2020. We have called this demand scenario ''EE'' or energy efficiency. EE assumes that the implementation of energy efficiency schemes will reduce annual energy consumption by 4 per cent (compared with BAU), with savings occurring uniformly across the load duration curve. This case assumes that by 2020 there will be EE targets in place throughout the NEM similar to those of the NSW Energy Savings Scheme, which for the period of 2014–2020 has a reduction target of 4 per cent of annual NSW electricity sales. EE also assumes that there will be a broad introduction of smart meters and a limited form of dynamic tariffs, and a moderate adoption of enabling (''smart'') technologies. In their study of the benefits of introducing dynamic tariffs in Europe, Faruqui *et al.* (2009) estimated that under these market conditions there could be an overall residential peak period demand reduction of 10 per cent. EE assumes slower growth in system-wide electricity demand (1.1 per cent per annum), with growth spread more evenly across the load duration curve compared with the BAU case. The results of our analysis for the BAU load growth scenario utilising the Optimal Plant Mix model from Simshauser and Wild (2009) are presented in Table 4 and presented graphically in Appendix 1.

Table 4 shows that by 2017, an additional 7000 MW of capacity is required to meet demand using the Optimal Plant Mix model. However, there is a substantial difference between the Delayed Certainty and Immediate Certainty scenarios. The difference in timing for the provision of regulatory certainty significantly skews the distribution of optimal plant to meet demand. By

Table 4. *Optimal Plant Mix – Business-as-Usual*

	Coal	CCGT	OCGT	Installed capacity (MW)
Immediate certainty				
2010	22,100	4700	13,900	40,700
2017	22,100	8500	17,100	47,700
2020	22,100	10,100	18,400	50,700
Delayed certainty				
2010	22,100	4700	13,900	40,700
2017	22,100	4700	20,900	47,700
2020	22,100	7600	20,900	50,700

Notes: CCGT, combined cycle gas turbine; OCGT, open cycle gas turbine.

Table 5. *Optimal Plant Mix – Energy Efficiency*

	Coal	CCGT	OCGT	Total installed capacity (MW)
Immediate certainty				
2010	22,100	4700	13,900	40,700
2017	22,100	6200	12,700	41,000
2020	22,100	7700	13,800	43,600
Delayed certainty				
2010	22,100	4700	13,900	40,700
2017	22,100	4700	14,200	41,000
2020	22,100	7200	14,200	43,500

Notes: CCGT, combined cycle gas turbine; OCGT, open cycle gas turbine.

2017, there is 3800 MW less CCGT and more OCGT in the Delayed Certainty scenario relative to the Immediate Certainty scenario. The other stark conclusion is that even with three years to correct this imbalance, the 2020 mix is still 2500 MW overweight OCGT and underweight CCGT. This has profound consequences for electricity prices which will be discussed in the following section.

The results of our analysis for the EE scenarios are outlined in Table 5 and presented graphically in Appendix 2.

The results of the EE scenarios outlined in Table 5 are similar to those discussed previously in relation to the BAU scenario with one important difference. The magnitude of the sub-optimal investment in 2017 and 2020 is significantly lower than in the BAU case. By 2017, the total installed capacity in the EE scenarios is 6700 MW lower than in the BAU scenario and by 2020 is 7100 MW lower. By reducing the growth in energy demand and in particular, peak demand, we have effectively reduced the amount of extra capacity required to satisfy security of supply thresholds. Accordingly, the results are less skewed when considered by plant type. By 2017, there is 1500 MW less CCGT and more OCGT in the Delayed Certainty scenario relative to the Immediate Certainty scenario. This should be contrasted with the BAU case discussed previously where the corresponding figure was 2300 MW higher at 3800 MW. Similarly, by 2020, with three years to correct some of the sub-optimal investment, there is still 500 MW more OCGT and less CCGT than in the optimal case.

There are two primary conclusions we can draw from this analysis:

- Delayed regulatory certainty on carbon skews the optimal plant mix materially even if uncertainty exists for three years. In our BAU analysis, 3800 MW of plant has been constructed by 2017 using a sub-optimal technology. This has significant implications for price which will be discussed in the following section.
- EE can have a material impact (assuming the regulatory drivers are known immediately) on reducing this sub-optimal plant mix result. Our EE analysis shows that by 2020, the sub-optimal investment is likely to be reduced to less than 500 MW.

6. Impacts Associated with the Large-scale Renewable Energy Target (LRET)

A limitation of this analysis is the absence of consideration of the additional energy produced as a result of renewable generation installed in response to the LRET. This policy requires electricity retailers to progressively install new large-scale renewable capacity to meet legislated targets. In particular, it requires retailers to purchase an additional 20 GWh of renewable energy by 2017 and 34 GWh by 2020. This has two impacts on our analysis:

- the additional energy produced is likely to reduce the need for all types of new capacity installed in both scenarios; and

- introduces a technology type which is intermittent and cannot always be relied upon for system security purposes, and must therefore be discounted from its nameplate capacity.[29] Wind and solar forecasting and geographical diversity of investment are likely to reduce this system-wide intermittency but modelling these developments is inherently difficult.

To consider the impact of LRET on the Optimal Plant Mix, we developed additional load duration curves for 2017 and 2020 incorporating the additional energy produced as a result of the new renewable capacity installed to meet the legislated targets using a similar methodology developed by Martin and Diesendorf (1983), and more recently, Bushnell (2010). The following assumptions were used:

- the new renewable energy produced within the system in 2017 and 2020 is assumed to be the difference between the legislated target and the 6.5 GWh produced in 2009;[30]
- the new renewable energy is produced evenly across the entire year which implies additional ''reliable'' renewable capacity of 2,350 MW and 3,950 MW in 2017 and 2020, respectively.

With these assumptions in place, the results are significantly different from those contained within BAU. By 2017, only 1500 MW of capacity is sub-optimal OCGT and not optimal CCGT capacity. Furthermore, by 2020, this sub-optimal capacity is reduced to just 400 MW. While we believe these results should be treated with caution, the clear implication from this analysis is that the introduction of LRET in 2010 will significantly reduce the costs of broader climate change policy uncertainty associated with installation of a sub-optimal capital stock, *ceteris paribus*. This finding is consistent with those in Simshauser and Wild's (2009) assessment of the Western Australian base load dilemma, in which higher renewable energy output may unexpectedly provide a power system with breathing space to find a tractable, long-run, base load solution.

7. Implications for the Price of Electricity

There are significant implications for electricity prices associated with delays in the carbon regulatory framework by government. However, our analysis uses a theoretical cost model for 2010 and 2020 to determine the impact on prices, exclusive of a carbon price uplift. While the difference between the Delayed Certainty and Immediate Certainty scenarios is likely to be representative and can be used to draw conclusions about the cost of uncertainty, the actual prices in 2010 and 2020 are likely to be different from that calculated in this analysis. This is because of:

- the fact that the plant stock in place today is not optimal from a cost perspective using only three technologies. In fact, a significant proportion of existing capacity within the NEM is hydro and other forms of generation technology not included in our analysis; and
- prices at any point in time in the NEM can be quite volatile as a result of rapid increases or decreases in demand. Accordingly average annual wholesale electricity prices can be affected disproportionately by this volatility.[31]

Importantly, all of the prices presented next are ''carbon exclusive'' – we have not made any assumptions in relation to what carbon price may prevail. We have used an LRMC model with a single-shot, uniform first-price auction clearing mechanism to determine an average electricity price under the two scenarios. The results for 2020 are presented in Table 6.

It is clear from Table 6 that any delay in the provision of certainty has material implications for any price forecast associated with the plant mix in 2020. Recall from Section 4 that the LRMC of the 2010 system load was determined to be \$62.57/MWh. In the BAU scenario, the implied price

[29]It is worth noting, however, that the typical assumption surrounding this discount is often overstated. See Roam (2010) or Simshauser (2010c) for further details of the contribution of wind generating capacity to system security.

[30]Based on the analysis of the Renewable Energy Certificate registry.

[31]Although as the NEM uses a uniform first-price auction clearing mechanism, prices should theoretically rise to the entry costs of the technologies used in the analysis.

Table 6. *Implied Price of Optimal Plant Mix in 2020 in Constant 2010 Dollars*

Scenario	BAU ($/MWh)	EE ($/MWh)
Immediate certainty	$64.49	$63.75
Delayed certainty	$73.09	$67.72

Notes: BAU, business-as-usual; EE, energy efficiency.

rises from $62.57/MWh in 2010 to $64.49/MWh in 2020 in the Immediate Certainty scenario. This increase is because of the load duration curve becoming ''peakier'' (i.e. peak demand growth is rising faster than underlying demand growth). However, the Delayed Certainty scenario shows that the delay in provision of regulatory certainty, which in turn results in a sub-optimal capital stock being deployed, results in a much higher underlying price of $73.09. This is an increase of $8.60/MWh or 13 per cent relative to the Immediate Certainty scenario.

The introduction of LRET as discussed in Section 6 has significant implications for these prices. With additional renewable capacity assumed to be uniformly available across the year, prices rise to $63.15/MWh in 2020 with Immediate Certainty. This is a significantly lower implied price than the BAU (no LRET) scenario. With Delayed Certainty, prices increase by a further $1.15/MWh to $64.31/MWh, However, as discussed in Section 6, these results should be treated with caution as renewables are a more intermittent type of generation than traditional thermal options. In reality, the additional electricity price associated with a sub-optimal capital stock is likely to be between the $1.15/MWh estimated incorporating LRET and the $8.60/MWh estimated without the inclusion of renewable energy as a ''firm'' source of energy from a reliability perspective.

Similar to the impacts of LRET, the introduction of energy efficiency in the EE scenario has a significant impact on the price structure in 2020. In this scenario, the implied price is moderated to only $63.75/MWh in 2020 with the provision of immediate regulatory certainty, a reduction in increase of about one-third relative to the BAU scenario. With less energy growth, and peak demand growth in particular, the price structure is less impacted relative to the BAU scenario. This has important implications for the price structure in the Delayed Certainty scenario. With EE measures in place, delaying the provision of regulatory certainty increases the implied price in 2020 from $63.75/MWh to $67.72/MWh, an increase of $3.97/MWh or only 6 per cent.

There are a number of important policy implications that arise from this analysis.

- Delaying the introduction of a robust carbon policy has material implications for electricity price. Delayed introduction of a robust carbon policy for the electricity sector could see household electricity prices increase by as low as $1.15/MWh and as high as $8.60/MWh. Based upon a final FY08 residential tariff of around $140/MWh (Simshauser *et al.*, 2010b, p. 5), this implies increases of around the range of 1–6 per cent in the price of electricity for an average household.[32]
- The marginal increase in price is mostly a ''deadweight loss.'' There is no benefit at all to consumers, new producers or governments. Price rises are the result of a sub-optimal capital stock being deployed to maintain system security in the absence of a carbon regime that provides investors with regulatory certainty to make optimal investment decisions. The increase in prices would occur irrespective of whether a carbon regime is or is not introduced in 2013 because once OCGT plant is committed it will remain sub-optimal compared with a certainty scenario (whether carbon is ruled ''in'' or ''out''). They are the costs of uncertainty. The only way they could be avoided is for agreement to be reached on climate policy with immediate announcement. This would allow investors to make decisions today to optimise investment, thereby avoiding the costs associated with the introduction of a sub-optimal capital stock.

[32]Based upon average household consumption of 7000 kWh/year.

- Complementary policies can reduce, but not eliminate, the costs associated with higher electricity prices. This study has shown that the additional costs could be halved if effective complementary EE polices are introduced which reduce the need for new investment in generation. This is an important conclusion and provides additional public policy rationale for the development of new EE policies as proposed by the 2010 Prime Minister's Task Group on Energy Efficiency.

8. Conclusion

This study has analysed the unit cost of the plant stock required to satisfy demand in 2010, 2017 and 2020 under conditions of policy certainty, and delayed policy certainty. The results indicated that there are likely to be material cost increases and higher electricity prices from a lack of regulatory certainty around climate change policy. Unfortunately, at the time of writing the climate change policy environment within Australia could be described as uncertain at best. Since 2007, the primary policy instrument for addressing anthropogenic greenhouse gas emissions, a cap-and-trade ETS, has wavered between bipartisan support for a 2010/2011 commencement date to single party support for introduction in 2013. This wavering approach to setting public policy is having profound consequences for investors in long-lived power generation assets.

Our analysis indicates that the increase in electricity prices at the residential level is likely to be as low as 1 per cent and as high as 6 per cent depending upon the demand growth scenario used. These price increases are primarily a ''deadweight loss'' to the economy associated with the introduction of a sub-optimal capital stock designed to minimise capital costs in an environment of carbon policy uncertainty. It is critical that policy-makers note this dilemma and move quickly towards establishing a carbon policy framework that is accepted by all sides of politics. If this does not occur, these price increases are likely to be experienced irrespective of whether a broad-based climate change policy is introduced or not. It is also critical that policy-makers focus on complementary policies such as EE schemes and mandated renewable energy schemes to reduce the magnitude of any increase in prices associated with carbon policy uncertainty.

This article does not estimate the net present value associated with: the costs to the broader economy associated with climate change not being addressed between the time of writing and 2013; the benefits to consumers associated with lower prices between the time of writing and 2013; and the costs associated with a sub-optimal capital stock over the period between 2010 and 2020. This would require significant work beyond the scope of this article but is an area recommended for further research by Australian policy-makers.

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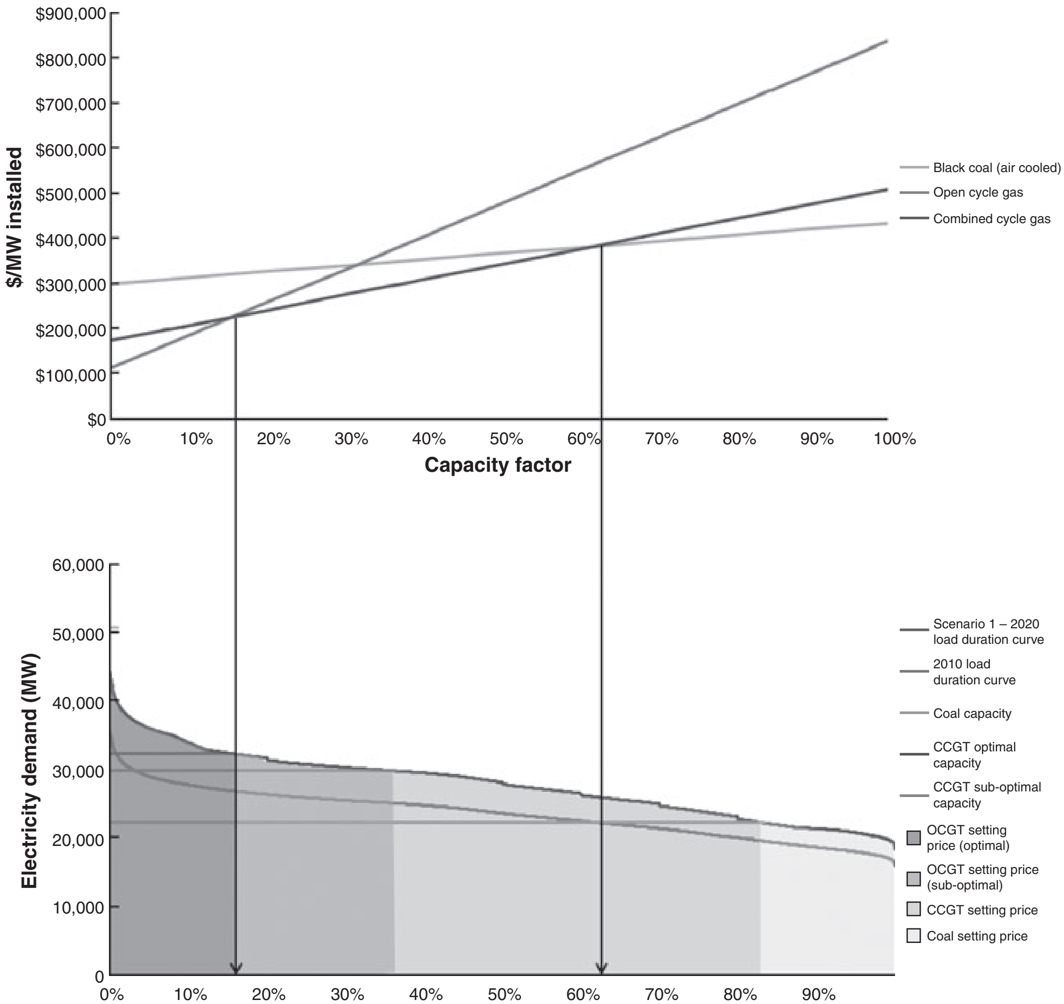
Appendix 1: BAU Demand – Graphical Representation of Sub-optimal Capital Stock



Appendix 2: EE Demand – Graphical Representation of Sub-optimal Capital Stock