Carbon taxes, toxic debt and second-round effects of zero compensation: the power generation meltdown scenario

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April 2011

One of the most problematic areas of the Australian carbon policy debate is the treatment of incumbent CO_2 intensive coal generators. Policy applied to the energy sector is rarely well guided by macroeconomic theory and modeling alone, especially in the case of carbon where the impacts are concentrated, involve a small number of firms and an essential service. We find that if zero compensation results in the financial distress of coal power stations, funding costs rise for all plant including new gas and renewables, leading to unnecessary increases in electricity prices. Accordingly, an unambiguous case for providing structural adjustment assistance to coal generators exists on the grounds of economic efficiency.

Keywords: Carbon Tax, Project Finance, Electricity Prices.
JEL Codes: D61, L94, L11 and Q40.

1. Introduction

One of the most problematic areas of the Australian carbon policy debate is the treatment of incumbent coal-fired generators. Whereas energy-intensive trade exposed industries are seeking compensation, and policymakers seem willing to provide it, assistance to privately owned brown coal generators in Southern Australia remains divisive. Much of the debate is remarkably uninformed or misguided and has resulted in public confusion. The purpose of this article is to analyse whether a public policy rationale for structural adjustment assistance to incumbent CO_2 intensive coal-fired generators exists.

Pricing carbon is designed to hasten the exit of coal plant from power systems. Despite the pointed and business-disruptive nature of the policy intent, debate on carbon pricing and coal-fired generation does not centre on whether such a framework should be implemented. All sides of the debate, including coal-fired asset owners, agree it should. The issue comes down to how plant might exit; with or without compensation. At one extreme is the “asbestos argument”; that incumbent generators should not receive assistance. At the other is the “expropriation argument”; that full compensation for asset loss is warranted. Policy is rarely well guided by emotive arguments. Nor will carbon policy applied to the energy sector be well guided by macroeconomic theories and modeling alone given that wealth impacts are concentrated, non-trivial, involve a small number of firms and an essential service.

Our analysis is primarily focused on the 7,000 MW brown coal power station fleet. The reason for this is that all brown coal generators have above grid average CO_2 intensity coefficients and are therefore more likely to experience financial distress in the short run. Additionally, they are privately owned and mostly financed by non-recourse project debt. The case for structural adjustment assistance to the 22,000MW black coal fleet is weaker; more than 70% of black coal plants are owned by State Governments and financial distress is therefore unlikely to produce material efficiency losses in capital markets. Also, black coal generators have grid-average

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carbon intensity coefficients and are therefore less likely to experience acute financial distress in the short run. To be sure however, over the long run, the same fate ultimately awaits black coal plant, albeit on a slower-burn trajectory.

Above all, our modeling results reveal adverse second-round effects for power project finance under a zero compensation scenario with brown coal plant financial distress. We therefore find an unambiguous case for structural adjustment assistance on the grounds of economic efficiency, and the Electricity Sector Adjustment Scheme, as proposed under the previous iteration of carbon policy in Australia, is justified on public policy grounds. While economists can advise on the quantum and allocation of funds that might be contained within a Scheme, the ultimate decision is a matter of judgment for policymakers. But modeling results later in this article leave no doubt that such a scheme is justified.

This article is structured as follows; Section 2 reviews the theory of structural adjustment. Section 3 analyses the impact of carbon prices on generator cost structures. Section 4 assesses the extent to which firms could account for carbon pricing in historical investment decisions. Section 5 analyses capital flows and reviews our survey results on project finance in the National Electricity Market. Section 6 presents our project finance modeling results. In Section 7, the entry cost estimates from Section 6 are translated to our dynamic partial equilibrium model to produce power system economic efficiency losses. Policy recommendations follow.

2. On the theory of structural adjustment assistance

In the carbon policy debate, advisors and policymakers with a macroeconomic bias seem to favour a *cut-and-run* approach, underscored by limited to zero compensation or incumbent coal-fired generators. This reflects a *Washington Consensus* approach to reform.[1] This approach observes that carbon pricing has been well telegraphed and asset owners have had years to prepare, and government should not provide taxpayer funded protection to sunset industries or those who produce negative externalities (asbestos, tobacco, coal-fired power). Moreover, from a transitional perspective, neo-classical economic theory and modeling has long been comfortable with the notion that short run capital losses reflect the workings of an efficient market and new owners will acquire distressed assets at more appropriate (post-policy) values without any disruption to supply. History abounds with examples; producers forecast dire consequences when Australia's 10% Goods and Services Tax (GST) was being introduced in 2000. Yet no assistance was offered, and the economy adjusted without incident.

Garnaut (2011) made an important contribution to the debate on why compensation may not be necessary for generators, noting that Australia's highly successful National Electricity Market (NEM) has an extremely robust gross pool spot market institution. It follows that if a plant is distressed and begins to withdraw partial capacity, wholesale electricity prices will rise, thereby averting acute energy security disruptions in the first place since every incentive will exist for requisite generation capacity to remain on-line for active duty. Indeed, Simshauser and Doan's (2009) *Wounded Bull Scenario* demonstrated this to be entirely feasible to an otherwise financially distressed generator, albeit in the short run.

Simshauser (2008) noted that economists must commence the analysis of any reform with the notion that there is no basis for compensation mechanisms to offset direct or indirect losses associated with a policy that is designed to drive economic efficiency. If it were not for this

[1] The term "Washington Consensus" relates to a consensus reached in the 1980s between the US Treasury, World Bank and the International Monetary Fund. At its core is a deep belief in economic reform and the efficiency of markets, in particular, fiscal policy discipline, trade liberalisation, deregulation of capital markets, privatisation of state enterprises, industry deregulation, establishment of property rights and so on. The Washington Consensus, and the virtual blind faith in the efficiency of markets, was largely abandoned in late-2010 following the effects of the global financial and economic crisis (for example, see Macquarie Securities, 2011). In contrast, a Keynesian approach for example favours markets and competition, but accepts the potential for market failure and the necessary role of government in subsequent economic stabilization.

default approach, governments would be unable to function properly as Pasour (1973), Neary (1982), Johnson (1994), Argy (1999) and many others have noted. It is simply impractical to assess economy-wide losses for all policy changes. Besides which, efficiency gains and losses from reform programs tend to even-out over the long run, with society considerably better off in the end.

Moreover, in many cases the delivery of assistance would impair the economic efficiency that a policy measure is trying to drive in the first place. For example, providing production subsidies (rather than structural adjustment assistance) to coal generators whilst introducing a carbon tax would clearly be a destructive log-rolling policy;[2] the tax is designed to drive coal generators out of business while production subsidies are designed to protect firms and keep them in business. Furthermore, if every change included adjustment programs, the outcome would more than likely lead to moral hazard, whereby investors believe their future actions are protected against policy change through government intervention. Accordingly, the notion of zero compensation has solid foundations in theory and practice.

But for markets to adequately solve for large shocks, *all* the conditions and assumptions of economic theory and models must be present. Stiglitz (2002) observed that one of the great achievements of modern economics has been to demonstrate how rarely this occurs in practice. To that end, there are clear conditions in economic theory and in practice where structural adjustment assistance is desirable on the grounds of economic efficiency (Argy, 1999). If a given reform is likely to lead to a *material* misallocation of resources, then there is a case for further analysis and intervention. In Australia, and the US, industries tend to qualify for structural adjustment assistance where reform shocks are (a) large, (b) policy driven events, (c) breach long standing expectations and (d) are likely to produce highly uneven or magnified losses in discrete industrial segments (Argy, 1999).

Given the theory on structural adjustment, policymakers with an energy economics bias tend to baulk at a *Washington Consensus* approach to the application of carbon policy. The 2008 global financial crisis aptly demonstrated that great care must be taken when guiding policy exclusively via macroeconomic theory and modeling. Stiglitz (2002) provides a long list of reform policy failures which can be traced back to an overreliance on macroeconomic constructs. Requisite caution is necessarily heightened when wealth impacts of a policy reform are concentrated, large, involve a small number of firms with large productive capacity, and the reform target is an essential service like electricity supply. This latter point is critical and distinguishes coal generation from other products with negative externalities such as asbestos, where substitutes are immediately available at equivalent cost.

In Computable General Equilibrium (CGE) Modeling, a staple input to macroeconomic decision making, firms and production processes within an industry segment are essentially passive variables. The equivalent of a 2000MW base load power station could theoretically produce 1MW in a year in a CGE Model, despite being technically and economically intractable in the real world.[3]

On the other hand, the primary tools used in microeconomic analysis, dynamic multi-period partial equilibrium models, by necessity deal with a level of detail entirely unfamiliar to CGE Modeling, albeit with an intensely narrow focus. Electricity sector models typically involve half-hourly resolution of resource allocation across multiple years and crucially, capture plant-specific constraints, transmission congestion and regional demand, thus attempting to mimic the rich

[2] Log-rolling policies are implemented in conjunction with reform policies to dampen the sharpest effects of a reform, in the event making it more politically feasible. An example of carbon log-rolling policy would be compensation to low income households.
[3] Of course, a macroeconomic model would not incorporate any specific plant level details. But the point is that CGE models can produce outcomes which, given the existing plant stock, are technically intractable due to technical limitations of power systems.

dynamics of high impact events on demand, production, price, and in this case, NEM emissions, energy security and systemic security.

Coal power plants tend to be very large relative to other plant types and supply a non-trivial component of aggregate demand. As Table 1 later illustrates, about 81% of Australia's power comes from just 31 coal-fired generation plants. And so electricity sector modeling tends to reinforce the view that systemic or physical disruption events arising from policy-induced financial distress of coal plants is more than a theoretical possibility. Conversely, a macroeconomist would argue that the withdrawal of supply will be divisible, will raise price, and that the market will quickly equilibrate at a new and higher level. A *Washington Consensus* approach to such matters would be that new owners would acquire distressed brown coal assets, thus averting collapse and in the process reset the cost-base of the plant in the post-policy environment. Perhaps.

But in this instance it is obvious that unique conditions exist; carbon policy is designed to drive coal generators out of business. And so the field of buyers for a terminal coal power station with negative operating margins and looming, non-trivial closure costs associated with asbestos removal and mine rehabilitation must surely be zero; a prospect that would trouble the natural owner of last resort, the State or Federal Government (i.e. taxpayers). Additionally, coal plant cannot be operated economically on an intermittent basis when it has been purposefully designed, engineered, manned and more importantly, financed for base load duties. SKM (2011, p. 9) noted returning a brown coal plant to service within three days after a prolonged shutdown would pose a "major challenge with respect to the management of operational manning."

A *systemic shock* in the NEM is plausible if a large CO_2 intensive coal facility without assistance collapsed unexpectedly under the weight of a carbon price. The reason for this is straightforward enough; forward electricity hedge contracts form part of the unsecured market for derivative instruments, and Administrators of moribund plant have broad powers to cancel committed hedge contracts. This is not contentious. Administrators would only cancel forward hedge contracts at the very point in time that they are most needed by demand-side participants; that is, when they are deeply out-of-the-money. Further contagion in the NEM could result, causing the financial distress of other energy businesses that were otherwise stable. A more sobering thought is that given the nature of deregulated wholesale energy markets and the presence of retail price regulation, no retailer in the NEM is too big to fail on financial grounds under shock conditions, especially when the market price cap is 200 times average price.[4]

Energy economists therefore harbor reservations about the prospect of market stability under sustained structural shocks to power systems, not because they fear the wholesale market will not respond correctly, but *because* it will respond correctly. Given the regulation of retail electricity tariffs, there is an imperfect transmission of price movements from wholesale to retail markets. Successive federal governments have been unable to solve this as retail price regulation is controlled by State Governments.

Deregulated wholesale energy markets like the NEM will perform to all economists' expectations in that prices can and will rise sharply when structural shocks occur. But the NEM has demonstrated on several occasions that regulated retail prices are simply incapable of keeping pace with seismic shifts by comparison to the ½ hourly spot market clearing mechanism and the instantly responding forward contract market. Two niche retailers and one government owned retailer became technically insolvent over such mismatches.[5] Moreover, the NEM recently demonstrated that retail prices were incapable of adjusting for trivial (i.e. circa $6/MWh) changes

[4] The administered price cap in the NEM is currently $12,500/MWh.
[5] Far North Queensland government owned retailer "Omega Energy" was absorbed into Ergon Energy in 1998 due to structural shocks in the wholesale market.

in a timely manner when the 20% Renewable Energy Target was split into small- and utility-scale schemes. Retailers were forced to absorb the cost of the small-scale renewable scheme for six months in at least two regions due to inflexible price regulation.

This issue is material. Price-cap regulation dictates electricity tariff caps to more than 72% of the 8.9 million households in the NEM. And the deregulated tariffs of the remaining 28% of households (i.e. in VIC) are constrained to six-monthly movements. The last time a deregulated wholesale energy market *snapped* where retail prices were regulated, two of the largest Investor-Owned Utilities in the US were bankrupt within six months of the initial shock event (Joskow, 2001; Bushnell, 2004).[6] Apart from its ability to bankrupt retailers, the NEM has also demonstrated that drought affecting supply and price in Southeast QLD was an equal problem for SA, given the interconnected nature of the grid. And so a problem for brown coal generators in VIC will be a problem for the entire NEM.

Competitive energy markets were designed to drive productive, allocative, and dynamic efficiency. The NEM has been enormously successful at driving all three (Simshauser, 2005). But the dynamic efficiency objective function was largely one-directional; providing appropriate signals for new entry and consequences for excess entry. Energy markets are not typically designed, or well equipped, to deal with policy-induced lumpy plant exit. And nor should they be since such events must be rare in practice. But if plant exit is induced by tangential carbon policy, and exit is not carefully orchestrated, systemic or physical disruption is plausible.

But in our view, these short-run impacts pale into insignificance by comparison to the long run consequences arising from the capital markets, which is the prime focus of this article. Power generation is the world's most capital-intensive industrial activity. In Australia, this activity occurs in an economy with a severe structural reliance on foreign capital. Consequently, policy-induced disruption to power generation investments could have adverse impacts on capital market participation rates, costs of capital, and capital inflows to the industry. In the balance of this article, we quantify efficiency losses in capital markets relating to remaining and future generating equipment under conditions of a *Washington Consensus*, free market approach involving zero compensation to brown coal generators.

3. The impact of carbon prices on power station cost structures

Australia's aggregate generating capacity is 53,216 MW as Table 1 notes. The fleet produces 229,756 GWh and emits about 200Mtpa of carbon. Table 1 distinguishes between brown coal, black coal, gas and renewables (i.e. hydro and wind). There are 155 sites of which 8 will be intensely affected in the short-run from carbon pricing. There is 7,335 MW (14.2%) of brown coal plant which produces a quarter of Australia's aggregate electricity output with emissions intensities up to 1.55t/MWh. The average age of the power station fleet is 24.8 years, with brown coal averaging 32.2 years. Our *rule-of-thumb* valuation estimate[7] of the brown coal fleet is $7.8 billion. Importantly, existing coal-fired plants in the NEM are thought to have significant remaining technical useful lives. Outhred (2011) estimated this to be in excess of 20 years, a number few would disagree with.

This data highlights that the number of intensely affected sites in the short run is minimal, and the value of those affected is small in the context of the aggregate generation portfolio. The value is also small by comparison to the roughly $6 billion 'annual take' in carbon taxes that will accrue from the power sector at $30/t.

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[6] Joskow (2001) also noted that the otherwise highly successful SOx emissions trading scheme actually made a contribution to the Californian market shock event. It was one of six variables which conspired simultaneously.

[7] We use a simple new entrant cost multiplier of about $3000/kW for brown coal plant, over a 50-year term.

Table 1: Australian power station fleet in 2010 (grid-connected, excluding embedded plant)

Technology	Sites (No.)	Capacity (MW)	Share (%)	Output (GWh)	Share (%)	CO2 Intensity (t/MWh)	Replacement ($M)	Fleet Value ($M)	Fleet Age (Years)
Brown coal	8	7,335	13.8	57,063	24.8	1.10 - 1.55	22,005	7,829	32.2
Black coal	23	22,280	41.9	129,401	56.3	0.80 - 0.97	49,016	24,128	25.4
Gas	74	15,285	28.7	28,322	12.3	0.38 - 0.70	18,342	9,872	13.9
Hydro & Wind	50	8,316	15.6	14,970	6.5	n/a	24,594	13,016	36.8
Total	155	53,216	100.0	229,756	100.0	0.92	113,957	54,845	24.8

Source: esaa (2010), AGL Energy Ltd.

While not evident in Table 1, brown coal plant is concentrated in VIC and SA. In VIC, brown coal plant represents 63% of local plant capacity, but being base load machines, produce more than state demand and therefore export considerable surplus production to neighboring regions.

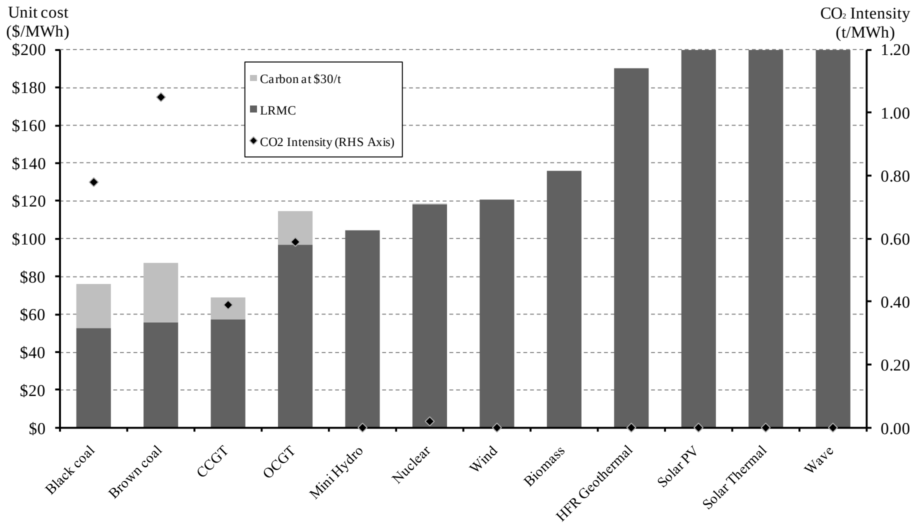
Applying a price to carbon is designed to shift the industry cost structure, and the most adversely affected will be the brown coal fleet due to their especially high CO_2 intensity. To determine the degree of asset value loss for a discrete generator, the emission intensity of the plant must be compared to the rate of carbon pass-through in the wholesale market. Where a generator's emission intensity is greater than the rate of the whole-of-market pass-through, it will incur carbon costs that are greater than recoverable through the market. It is in these circumstances that a generator is likely to experience asset value loss through reduced operating margins, lower volumes and a truncated economic life.

In the short-run before significant substitution of capital can occur (i.e. given development lags of 5 years), the rate of carbon pass-through in the wholesale market is likely to reflect the fleet average CO_2 intensity of about 0.9t/MWh (Nelson et al, 2011). In the long-run (i.e. beyond 5 years), the pass-through rate is likely to decay from the grid average as new lower-intensity generation becomes the marginal generator for non-trivial price-setting periods each year.

The shortening of a generator's economic life is therefore a function of two variables: the spread between its individual emissions intensity and the market intensity (reduced operating margins); and the rate at which the average intensity declines. Policymakers must establish whether they should provide structural adjustment assistance to debt and equity capital investors to deal with reduced operating margins, lower volumes and truncated economic life, and subject to the geographic location of substitution outcomes, displaced workers. The short run objective of any structural adjustment assistance therefore needs to enhance the predictability of capacity exit to avoid disruption events; and as modeling results later in this article reveal, the long run objective should be to short-circuit second-round effects in the capital markets.

From an entry cost perspective, levelised cost modeling in Simshauser (2011) highlighted the comparative effects that carbon pricing would have on new coal plant relative to rival technologies. Note in Figure 1 that the relative carbon tax accruing to brown and black coal plant is materially higher than Combined Cycle Gas Turbine (CCGT) plant. Consequently, on generalized Long Run Marginal Cost (LRMC) modeling at least, new plant using existing coal technologies is uneconomic.

Figure 1: Generalised LRMC of utilities-scale energy technologies



Source: Simshauser (2011)

The analysis in Figure 1 deals with new investment. More important to the carbon debate is the impact on incumbent plant. Figures 2 and 3 illustrate generalized marginal running costs of the NEM's roughly 38,000MW thermal fleet before, and after, a $30/t carbon price. In Figure 2, where carbon prices are excluded, the Victorian brown coal fleet sits at the bottom of the aggregate supply function with marginal running costs of about $5/MWh. In contrast, the marginal running cost of base load gas plant (at $4.50/GJ) is over $30/MWh.

Figure 2: Generalised marginal running cost of the NEM's thermal fleet ($/MWh)

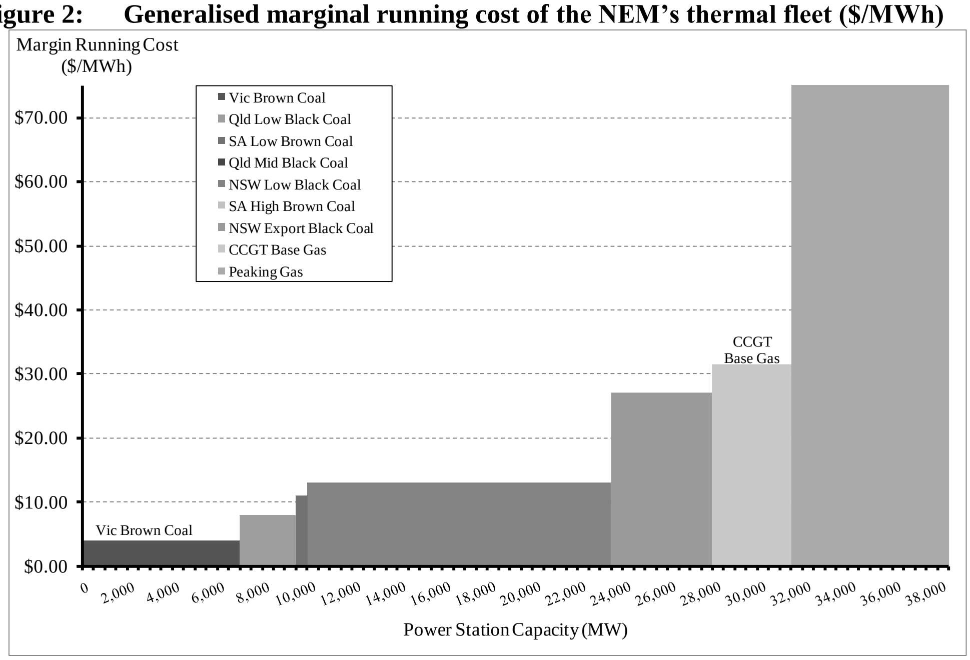
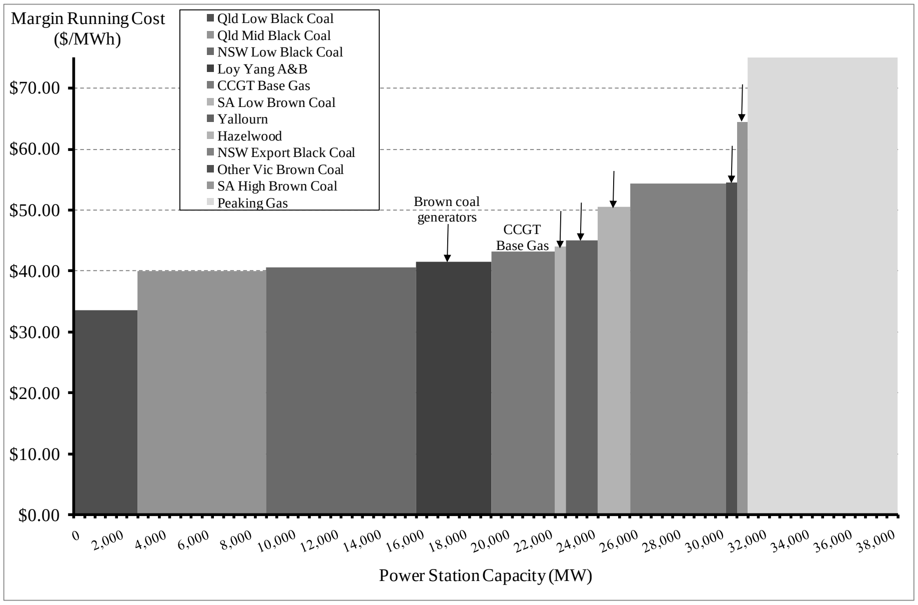


Figure 3 illustrates the change in the plant pecking order or *merit order* once carbon taxes are introduced. The arrows identify the location of brown coal generators in the newly formed aggregate supply function. Note the CCGT base load plant is creeping up the merit order, dislodging brown coal plant and any black coal plant exposed to export prices. CCGT's will also become more competitive as the price of carbon rises due to their low carbon coefficient.

Figure 3: Generalised marginal running cost of the NEM's thermal fleet at $30/t CO_2



A characteristic evident from Figures 2 and 3 is the relative size of the incidence of a carbon tax. On a production-weighted basis, a $30/t carbon tax increases the marginal running cost of brown coal plant by *10.2 times*. For black coal plant, marginal costs increase by 3.0 times, and 1.4 times for CCGT plant. These marginal running cost multipliers provide some insight into the impact on brown coal plant, and why gas plant has such a material advantage as carbon prices rise. The marginal running cost multipliers also highlight why other tax reforms such as the GST should not provide policymakers with comfort under zero compensation. The GST resulted in input costs of goods and services increasing by a multiplier of 1.1 times, a trivial amount. The carbon impact on brown coal plants is *9.1 times* greater than the GST. Comparisons of carbon policy with previous broader economic reforms in the context of deciding sunset industry assistance would therefore be misguided at best and dangerous at worst due to the impacts being an order of magnitude different.

Over the past ten years, there have been a number of studies completed by businesses, governments, industry associations and non-government organisations on the impacts of carbon pricing on coal-fired power station asset values. Losses for NEM generators have been modeled at $11.0 billion by ACIL Tasman (2011); $16.7 billion by ACIL Tasman (2008)[8]; $17.5 billion by ROAM (2008); and $0.1 billion by MMA (2008). The privately owned brown coal generators have been forecast to experience losses of $7.1 billion, $7.9 billion and $2.3 billion in the respective 2008 studies.[9] Differences between studies will invariably be driven by assumptions around market behavior, structure, and the carbon pass-through rate. We are unaware of any modeling literature in Australia that indicates brown coal generators will not experience disruptive losses. Based upon these results, it is not surprising that the structural adjustment assistance negotiated under the Carbon Pollution Reduction Scheme in 2008 by the Commonwealth Government involved $7.3 billion in nominal terms (DCC, 2009). Asset loss will be material due to declining operating margins, loss of market share and a truncated economic life. None of this is contentious. It underscores the whole point of carbon pricing.

[8] The 2008 and 2011 ACIL Tasman results reflect both different input assumptions (one study was commissioned by the Department of Climate Change whereas the other utilises ACIL figures) and different reduction scenarios.
[9] All figures are in $2007 except the ACIL Tasman (2011) study which is in 2011$.

4. Historical investments: should they have known better?

Economists involved in the carbon debate and opposed to providing compensation observe that existing debt and equity investors should have explicitly priced carbon into their original investment decisions, presumably based on the fact that the UN's Intergovernmental Panel on Climate Change identified carbon trading as early as 1993. In addition, the Federal Government undertook extensive consultation processes in 1999, 2004 and in 2007. The State Governments undertook their own process in 2006 (NETT, 2006). However, bipartisan support for carbon pricing was not actually achieved until 2007, and disintegrated once again in 2009.

With this history, it is not entirely clear to the authors when debt and equity investors could have incorporated a price on carbon as a central scenario prior to 2007. Simshauser (2009) noted that while inquiries on carbon pricing occurred on many occasions, the reality is that the Federal Government's formal policy position was, until mid-2007, 'no Emissions Trading Scheme (ETS) until the technology for abatement is readily available'. That equity market participants, and perhaps more intriguingly, Project Banks, noted for their conservative business practices, invested in thermal assets on 'business-as-usual' economics provides the only practical evidence of how the business community interpreted government policy. So why would industry and project banks presume 'business-as-usual' in economic assessments? We would argue they did for two reasons. First, the history of ETS has always included log-rolling policies, and second, carbon has a short history of elevated prices.

In a speech delivered in mid-2007, the former Prime Minister, the Hon John Howard MP declared that all coal power assets as at 3 June 2007 would qualify for structural adjustment assistance under an Australian ETS. Moreover, incumbent generators in the EU ETS received 95% of required permits for free over an eight year period, although *windfall gains* were said to have occurred due to poor policy application (rather than the policy design itself). The NETT (2006) process, originated by the Australian States in parallel with the Federal ETS process[10], also proposed a substantial allocation of permits to generators for the express purpose of compensation. In summary, we are not aware of an ETS debate prior to 2007 where generators did not receive some form of adjustment assistance.

Carbon does not have an especially long history of elevated price forecasts. When the 850MW Millmerran project in QLD was seeking to raise project finance in 1999, the sponsors included a carbon scenario in their due diligence documents which stress-tested plant performance with CO_2 priced at \$5/t (InterGen, 2008). The analysis was produced by independent economic consultants who presumably considered this a reasonable carbon price scenario at that point in time. In hindsight, this may appear unreasonable. But to put these numbers into context, esaa (2003) undertook a power industry study four years later in which the members' base case assumed a price of \$10/t. And in 2007, the IPCC surveyed over 100 peer-reviewed academic papers on carbon pricing to 2006 and found that the central value was just US\$12/t (IPCC, 2007).

So why were estimates of carbon prices so low in Australia and abroad up to 2006? The required cuts in greenhouse gas emissions are now more substantial than previously thought, and the abatement task considered more urgent through the Stern (2006) and Garnaut (2008) reports. Besides which, predicting carbon prices was less critical because up until that point, firms expected administratively allocated permits (i.e. per EU ETS).

Simshauser (2009) examined what a sensitivity study of carbon pricing would have actually looked like in a 2004 brown coal plant acquisition. The analysis assumed an ETS would commence in 2013 with underlying energy costs equilibrating to a CCGT plant, and with carbon

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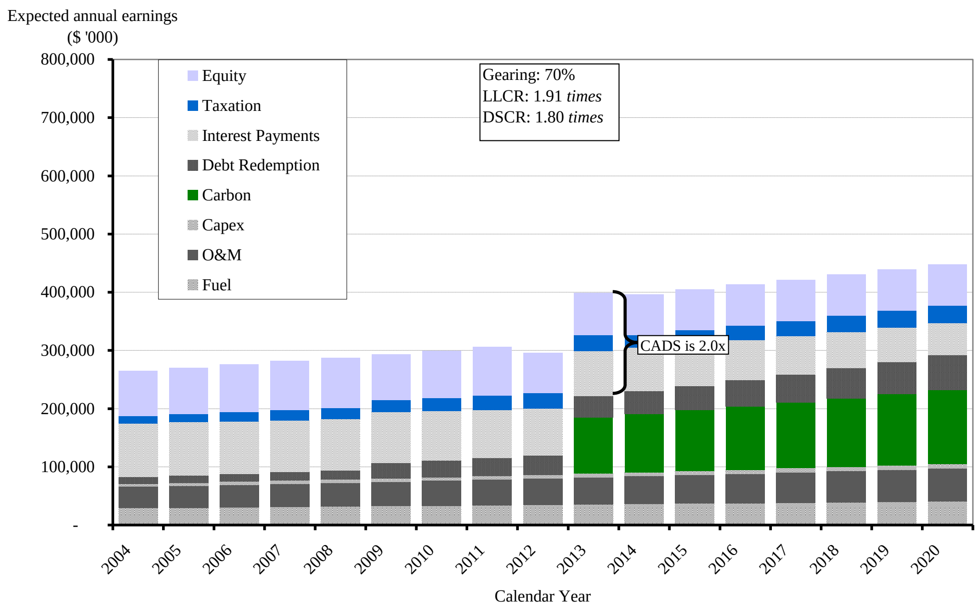
[10] See in particular Prime Minister's Task Group on Emissions Trading (2007), *Report of the Task Group on Emissions Trading*, Commonwealth Government, Canberra.

at $10/t in line with relevant 2004 literature. The 1000MW plant had an acquisition price ex-carbon of $1.9 billion. Cash flow modeling from that study has been reproduced in Figure 4; the effect of the carbon price is clearly depicted from 2013. Given these conditions, the impact as at 2004 was found to be trivial. The $1.9b acquisition price would have been adjusted downwards by just $140m if carbon formed the base case. And of course, this assumes no administratively allocated emission permits, whereas at the time generators in the EU were being allocated 95% of requirements for free.

Figure 4: Expected cash flows from a 2004 coal power station acquisition with CO_2 at $10/t



A more pertinent question is whether firms *could* have incorporated carbon pricing in base case economics whilst maintaining power system stability under conditions of carbon policy uncertainty. In other words, could a company build low-emissions plant and maintain financial stability given a carbon price did not eventuate. The reality is that any attempt to do so would have been met with financial catastrophe for the firm. To illustrate why, we have made use of the Project Finance Model (PF Model) from Simshauser (2009). The PF Model is a dynamic, multi-period cash flow simulation model of a power project in which all the parameters of a given plant and required project finance are incorporated to determine unit costs, debt sizing and structuring. The model calculates annual energy production, revenues, fixed and variable operations and maintenance costs, fuel costs, capital works, taxation schedules and establishes project finance bullet and semi-permanent amortising term facilities. Refinancings are undertaken while all structured debt facilities are extinguished within a 25-year aggregate tenor. The model specifications have been documented in Simshauser (2009) and therefore we do not propose to reproduce them here. The principle assumptions incorporated in our current modeling, for a CCGT plant in 2008, are depicted in Table 2.

Our assumed plant is a 400MW F Frame CCGT with fully developed capital costs of $1500/kW (including interest during construction). We assume a 2008 plant commissioning with term facilities arranged two years prior, thus averting the worst effects of the global financial and economic crisis and capturing the tail-end benefits of the mid-2000's global liquidity boom. Two debt facilities are assumed; a 7-year interest-only 'bullet' and a 12-year semi-permanent amortising facility, with interest rate swaps matching the tenors and spreads of 120 basis points (bps) and 140bps over the Bank Bill Swap Rate (BBSW) respectively. QLD coal seam gas is assumed to be supplied to the power station at pre-LNG prices of $3.00/GJ. In the PF Model, we initially set the forward curve for base load power to the LRMC of plant which in turn allows us to put the optimal capital structure in place, at 67.5% gearing, thus minimizing the overall unit cost of the plant. With this assumption, the other guiding parameters to debt sizing, viz. Debt Service Cover Ratio (DSCR) and Loan Life Cover Ratio (LLCR)[11] therefore do not bind with modeling results producing ratios of 1.9 and 2.1 respectively, within the guidance envelope of 1.8-2.2 times per Table 2.

Table 2: PF assumptions for a 400MW CCGT plant banked in 2008

Inflation			Taxation		
- CPI	(%)	2.50	- Tax rate	(%)	30.00
- Elec Price Inflation	(%)	2.13	- Useful life	(Yrs)	30
Plant Costs & Prices			Debt Sizing Parameters		
- Plant size	(MW)	400	- DSCR	(times)	1.8 to 2.2
- Capital cost	($/kW)	1,500	- LLCR	(times)	1.8 to 2.2
- Acquisition price	($M)	600	- Gearing	(%)	67.5
LRMC of CCGT			- Lockup	(times)	1.35
- CCGT in 2008$	($/MWh)	49.75	- Default	(times)	1.10
- Heat rate	(kJ/kWh)	7,000			
- Unit fuel	($/GJ)	3.00	Facilities	Swap	Spread
- Variable O&M	($/MWh)	3.00	- 7 year tenor	5.59%	1.20%
- O&M costs	($M pa)	12.4	- 12 year tenor	5.67%	1.40%
- Capex	($M pa)	3.0	- Refinance (Headline)	5.67%	1.40%
- CO2 footprint	(t/MWh)	0.39	- Post Tax Equity		15%
- Remnant life	(Yrs)	40	- Pre Tax WACC		12%

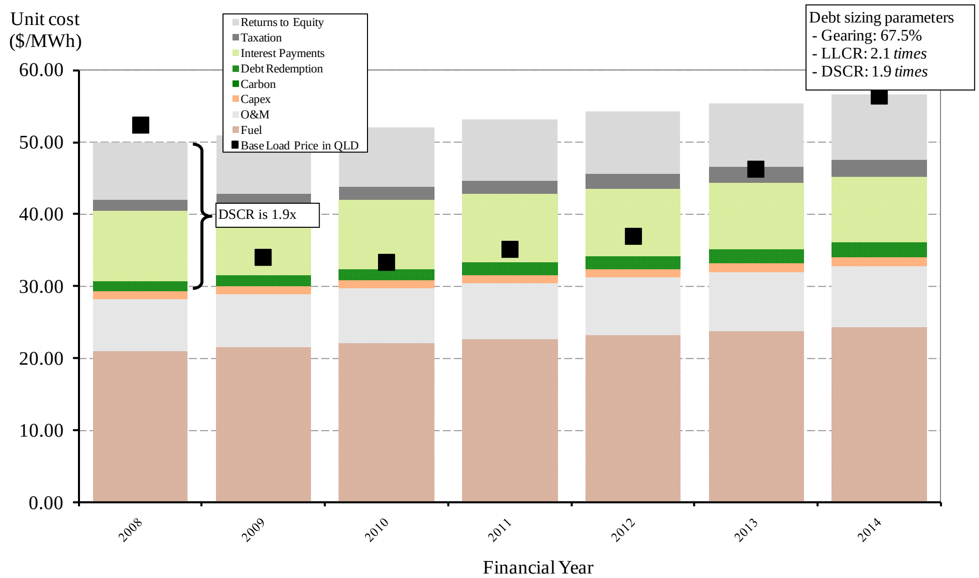
It is worth noting that all of these conditions, reflecting those prevailing in 2006, were ideal for minimizing plant costs. The LRMC was determined to be $50/MWh – considerably lower than contemporary estimates of $64.50/MWh (as revealed later in Figure 8).

Figure 5 illustrates how the unit cost structure of this optimally financed CCGT plant compares to base load market prices in QLD using AEMO data for 2008-2010, and d-cypha data for future years 2011-2012. Note that 2008 is the only year in which the plant meets earnings expectations, and in the event delivers a running yield of about 12.5%, driven by the FY08 drought.

Critically, with base load prices falling from $52/MWh in 2008 to mid-$30's in 2009 given the absence of a price on carbon, the DSCR for the project falls from 2.30 to just 0.80. Table 2 notes that when the DSCR falls below 1.35 times, the project goes into "lockup", meaning that any cash generated above operating expenses are swept by project banks and applied to debt facilities until the ratio is restored. If the DSCR falls below 1.1 times as it has in this case, the project is in outright "default". With a DSCR of 0.80 times in 2009 and 0.68 times in 2010, the plant is clearly technically insolvent by mid-2009. While highly stylized, this analysis demonstrates why factoring carbon into project economics when no such price exists is simply not feasible. And if incorporating carbon pricing into base case investment decisions would have resulted in insolvency, it seems unreasonable to state that investors acted improperly.

[11] In a project finance, three parameters typically limit the size of the facilities; (1) absolute project gearing, in this case 67.5%; (2) Debt Service Cover Ratio (DSCR) at 1.8-2.2 times; and (3) Loan Life Cover Ratio (LLCR) at 1.8-2.2 times the present value of future cash flows. The DSCR is calculated by reference to period revenues less expenses before debt servicing – also known as Cash Available for Debt Servicing (CADS), divided by debt payment obligations. In any future period, the forecast DSCR must be greater than 1.8. The debt facilities will be reduced until this ratio is met in the project financial model. Similarly, the LLCR is calculated by reference to the present value of a projects' free cash flows, divided by outstanding debt facilities. Once again, if the LLCR drops below 1.8, facilities will be reduced until the ratio is restored in the project model.

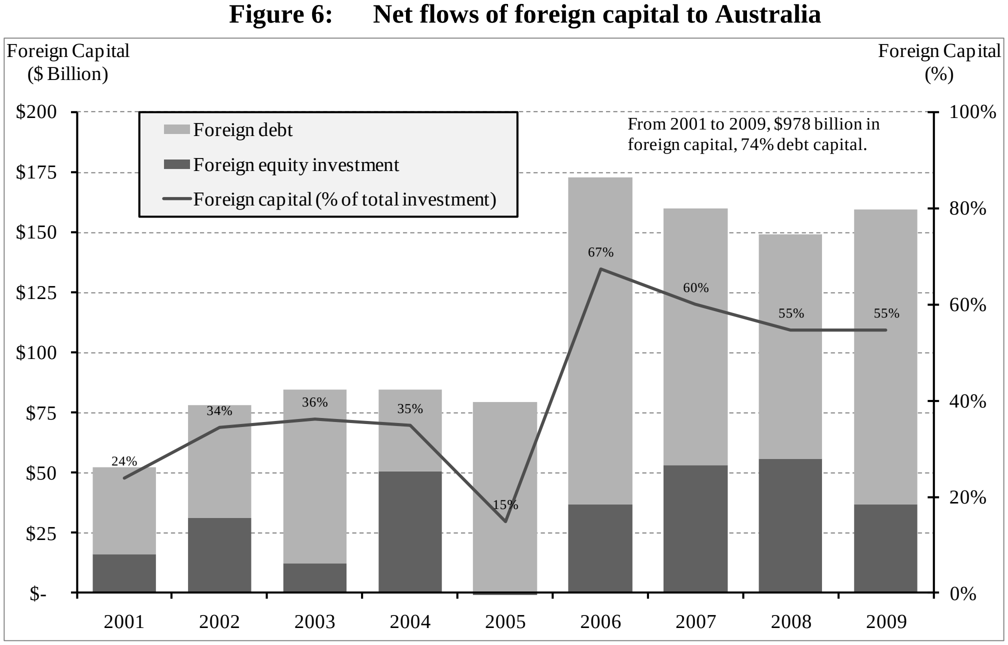
Figure 5: Unit cost structure vs. base load price for a 400MW project financed CCGT in QLD



5. Capital flows and project finance survey results

An important characteristic of the Australian economy is a severe structural reliance on foreign capital for investment purposes. This is due to Australia's low household saving rates, an above-average proportion of capital-intensive industries such as energy, metals manufacturing, utilities and mining, along with a small population of 22.5 million people spread over a large area, which raises requirements for transport and distribution infrastructure (Simshauser, 2010). The out-working of this is best illustrated by net capital flows into the Australian economy, in Figure 6. Note that from 2001-2009, about $1 trillion of net foreign capital flowed in-bound. Since 2006, foreign capital inflows have financed about 58% of Australia's new fixed assets. Since the utilities sector is the world's third largest borrower of debt behind governments and banks respectively, capital flows should be of considerable importance to carbon policymakers (Simshauser, 2010).

Figure 6: Net flows of foreign capital to Australia



Source: Simshauser (2010), ABS, AGL Energy Ltd.

Foreign capital flows provide important background context to the debate on structural adjustment assistance to brown coal generators. If a concentrated portfolio of assets in the capital-intensive power sector becomes systematically distressed as a result of policy change, no matter how novel that policy might be, it is unlikely that financing conditions will remain constant thereafter. Table 3 outlines debt facilities on the four large brown coal-fired power stations in VIC.

Table 3: Latrobe Valley Syndicated Debt (A$ million)

Banks	Loy Yang A	Loy Yang B	Hazelwood	Yallourn	Total
ANZ	113	123	64	75	375
NAB	183	123		90	396
BTMU	126	123	47	29	325
Westpac	82		45	120	247
RBS	162		103	120	385
BNP Paribas	81	123	41	71	316
SMBC	126	98		36	260
CBA		221		36	257
Societe Generale	125		64		189
DBJ	150				150
Credit Agricole Indosuez	90		52		142
West LB	71		62	45	178
Mizuho	126			30	156
BOS International	70		52		122
China Construction Bank	108				108
Dexia	70		31		101
STB	100				100
CIBC		98			98
Deutsche Bank		98			98
MUFJ		98			98
United Overseas Bank	71		22		93
KBC Bank	81				81
UniCredit Group	70				70
Aozora	50				50
Other Foreign Banks (12)	108	0	161	548	817
Total	2163	1105	744	1200	5212

Source: Reuters, AGL Energy Ltd, Macquarie Capital, TRUenergy.

Syndicated debt at the four power stations totals $5.212 billion, which is spread across 36 institutions. About 14 banks are currently active in originating debt facilities, with the involvement of others by way of syndication. Importantly, if one or more of the brown coal generators defaults on debt facilities under conditions of zero compensation, capital market perceptions of the regulatory environment within the Australian electricity industry will deteriorate further. We opted to test the following proposition:

- *That the combination of a default on a project debt facility and zero compensation at a brown coal power station would result in a step-change in debt finance costs for all plant, including future gas and renewable plant.*

Substantive risk premia are already being applied to existing coal plant. Hazelwood attempted to refinance a roughly $400m term facility that was nearing the end of its 10-year tenor in 2010. It is well understood that in the process, the syndicate opened up not only the existing facility, but another established term facility despite the fact that it was not maturing. Fully 400bps was applied to both structures with a tenor of just 2½ years and a cash-sweeping mechanism. On an incremental basis, the $400m facility had an effective margin of 700bps.

To test our proposition, we issued a survey to Australia's top 30 project finance bankers who represent the 14 active foreign and domestic banks in power project financings. The bank response rate to the 22 question survey was 65%. The survey had two primary sections, and purposes. The first sought bankers' views on historic and current power project financings in

Australia. Questions focused on spreads for term facilities, maximum tenors and gearing levels achievable, the number of Mandated Lead Arranging (MLA) banks required to close a $500 million facility for a gas-fired power station, the number of banks likely to be included in any syndication, and the number of active banks in the broader market for a power Project Finance (PF). We selected three points in time; 2006 to represent the period before the global financial crisis, 2008 as representative of 'during the crisis', and 2011 given 'carbon policy uncertainty'. Summary results from the first segment of the survey are contained in Table 4. Observed spreads for BBB credit-rated 3-year Australian corporate bond issues are also included to provide a benchmark to compare the movement in PF spreads.

Table 4: Survey results on perceptions of PF facilities in 2006, 2008 and 2011

	2006	2008	2011
PF Spreads	100-120bps	400-450bps	350-400bps
Spread Movement	*Stable*	*Up 3.8×*	*Down 11%*
Max tenor	12 years	3 years	7 years
Max gearing	65%+	Approx 55%	Approx 60%
MLA Banks	3 or less	7-8 banks	7-8 banks
Syndication Banks	3 or less	Club deal	4-8 banks
Active Banks	29	11	14
Spread on BBB Bonds	85bps	360bps	240bps
Spread Movement	*Stable*	*Up 4.2×*	*Down 33%*

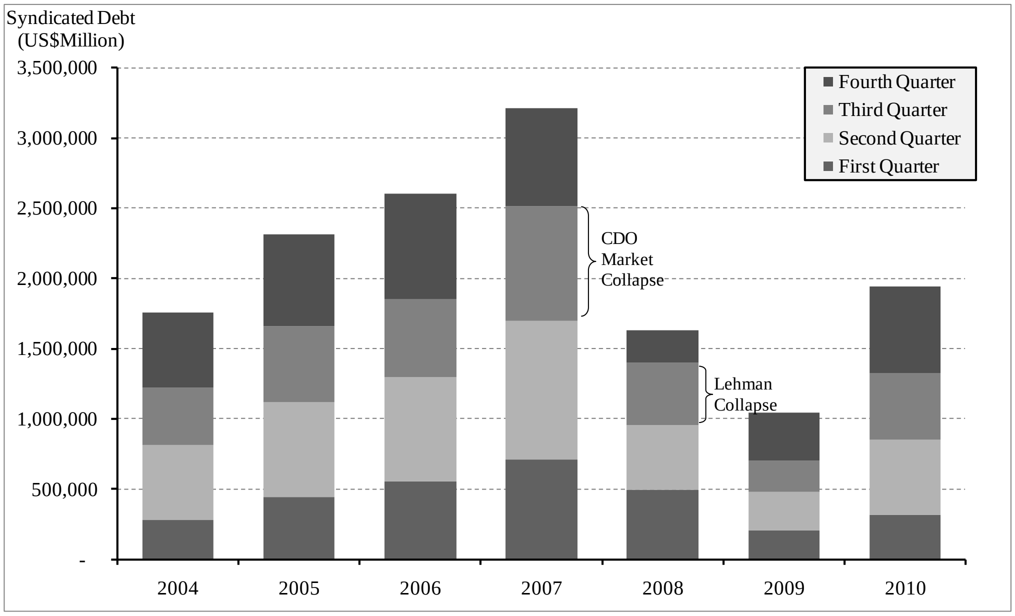
Source: AGL Energy Ltd, Bond data from CBA.

Conditions to minimize the cost of power projects were ideal in 2006, with spreads at 100-120bps over swap, 12 year tenors (which reduces refinancing risk, thereby facilitating) gearing levels of 65%+, and low transaction costs with only 3 MLA banks required to close facilities. If 2006 was the low water mark, 2008 must surely represent the high water mark. Spreads increased nearly four-fold as global liquidity evaporated in line with the global financial crisis. Figure 7 illustrates the rapid deceleration of global liquidity in the market for syndicated debt; it notes debt issuance across all industries during 2007 was fully US$3.2 trillion, but shrunk three-fold to just US$1.05 trillion after the Lehman collapse in 2008 (Simshauser, 2010).

In the case of Australian power PF, note from Table 4 that tenors reduced from 12 years to just 3 years in 2008, while the number of MLA's required to close a $500m power PF deal increased substantially from 3 to 7-8 banks. None would take syndication risk; all transactions were *club deals* (i.e. debt provided on a 'take and hold' basis). Finally, the number of active banks has reduced considerably although a small number have returned since 2008.

The striking result in Table 4 is the PF spread movement for power projects by comparison to corporate bonds. There was a parallel run-up in bond and PF spreads between 2006 and 2008 with a multiplier of approximately *4 times*, but a sharp differential in the retreat to 2011. Table 4 notes that bond spreads have fallen from 360bps to 240bps (33%) since 2008 whereas power PF spreads have reduced by just 11%.

Figure 7: Global market for syndicated debt



Source: Bloomberg, AGL Energy Ltd.

We tested whether Australian power PF data is out of step with global trends by analysing a comprehensive listing of global power project financings from their recorded inception in 1981 through to the time of writing in Q1 2011. This data represents 3140 individual transaction facilities across 101 countries, with a total facility value of A$2.76 trillion (in 2011$). Summary results are provided in Table 5.

Table 5: Aggregate global power PF deals from 1981 to Q1 2011

	Number of Power Station PF's (#)	Average PF Facility Tenor (Years)	Average PF Facility Spread (%)	Average PF Facility Size (2011$) (AUD Million)	Global Syndicated Debt (2011$) (AUD Million)
1981-2007	2,028	11.5	143	938.0	1,902,198
2008-2011	1,112	13.2	236	772.3	858,800
Total	3,140	12.1	176	879.3	2,760,997

Source: Reuters, AGL Energy Ltd.

Intriguingly, whereas Australian power PF have shortened in tenor from 12 years in 2006 to seven years in 2011, and margins remain elevated at 350-400bps as noted in Table 4, global PF data in Table 5 presents a very different picture. Of the more than 1100 transactions completed globally during 2008 – 2011, average tenors actually lengthened from 11.5 years to 13.2 years and margins, while elevated, have averaged 236bps. The explanation for this is straightforward enough; the rest of the world does not have the same uncertainty over carbon policy that Australia does. One of Australia's most respected power project bankers recently noted that "the investment community correctly attaches a risk premium for the added uncertainty, which effectively increases the cost of capital to the industry" (Satkunasingam, 2011, p. 1). Had the ETS been legislated back in 2009 when first brought before the Senate, our view is that PF tenors and margins in Australia would have been more likely to gravitate towards global average trends and the trend in corporate bonds, that is, spreads below 300bps and tenors of 10+ years.

This leads us to the second segment of our survey, given uncertainty over carbon policy. Here, bankers' views were sought on the potential impact of the financial distress of an existing coal asset as a direct result of carbon pricing, but crucially, under conditions of *zero compensation*.

Bankers were asked for their views on any potential "penalty spread" which might apply to all three types of power project technologies in Australia. Our reasoning here was twofold. Conflicting signals from political parties results in risk being priced, and bad debts represent business costs which must be recovered by firms to remain profitable; this includes banks. The results from the second segment of our survey are illustrated in Table 6.

Table 6: Survey results on PF "penalty spreads"

Technology	bp premium
Existing coal	150-200
New gas	100-150
New renewable	50-100

Source: AGL Energy Ltd.

This survey data from Australia's top utilities project bankers provides us with unique insights around the extent of potential economic efficiency losses that might accumulate in the electricity sector if a brown coal power station defaulted on debt facilities under conditions of *zero compensation*. Clearly, expanding credit spreads will increase the underlying cost of power generation through higher interest costs, shortened tenors and consequent lower gearing levels.

It does not take complex financial or power system modeling to assess the impact on existing coal plant. We know from Table 3 that there is at least $5.2 billion in existing term facilities. We also know that PF margins in Australia are 400bps whereas global spreads are about 240bps. Our view is that with policy clarity and well designed structural adjustment assistance, PF spreads in Australia should be closer to 275bps (i.e. down 33%). We also know from Table 6 that with ongoing policy uncertainty, debt default and zero compensation, spreads would be closer to 600bps (i.e. existing 400bps + 200bps penalty spread). Therefore:

- Economic efficiency losses arising in capital markets as a result of policy uncertainty in VIC is $65m pa, i.e. $5.2 billion x (400bps - 275bps); and
- With a default arising from zero compensation, efficiency losses from the capital markets including policy uncertainty would be $169m pa, i.e. $5.2 billion x (600bps - 275bps).

Policy makers may well be indifferent about wealth transfers between VIC brown coal equity holders and debt holders. But any policymaker would be rattled by the 2nd line result in Table 6 relating to new gas plant (+150bps), and policy advisors to the Greens will no doubt be stunned by the 3rd line result relating to new renewables (+100bps); and they should be. Even though penalty spreads in Table 6 clearly decline with the emissions intensity of the technologies, renewables are the most capital-intensive power generating technology with low capacity factors and are therefore *hyper-sensitive* to changes in the cost of capital.

In the event, new renewables experience the most profound 'hit' to generalized long run marginal cost estimates, and as modeling results in the next section reveal, they are non-trivial in every respect. In short, policy uncertainty and zero compensation actually does *much more damage* to the entry prospects of new renewable plant than it does to existing coal plant or new gas plant.

To make matters worse, if the new entrant cost of gas and renewable plant is adversely affected, it does not just affect the economics of singular new entrant plant. Even though only a handful of plants may be directly affected by this change, the nature of energy markets means that clearing prices must rise to the cost of entry, and so if an outcome of *zero compensation* is a 'penalty spread' being added to the underlying cost of capital and gearing levels reduce, then this will increase wholesale electricity prices, and in turn, retail electricity prices across the entire 8.9 million households in the NEM; a sobering thought for policymakers of all persuasions.

It stands to reason that margins on all new plant would be elevated if a brown coal plant collapses due to zero compensation; we considered this to be entirely predictable and survey results merely confirmed this. Gas and renewable plant are being developed in response to (appropriate) government policy settings. But if government policy disrupts historic investments, policy risk will be priced into the generation sector until such risk is perceived to have diminished to trivial levels. While the Government and the Opposition support a 5% carbon target, the Greens do not. And while the Government and Greens support a price on carbon, the Opposition does not. And the fact that the Opposition has stated it will repeal government plans will not help to diminish policy risk perceptions in Australia.

6. Scenarios and project finance modeling results

To see how changes in parameters affect the underlying cost structures of benchmark base load CCGT plant, peaking OCGT plant and renewable plant in the NEM, we have taken our PF Model and applied current market conditions from observed capital market data and the survey results from Tables 4 and 6 to quantify economic efficiency losses. We have modelled three scenarios:

1. **Certainty Scenario:** Key assumptions in this scenario are that carbon pricing is implemented, structural adjustment assistance is well designed, bipartisan support is achieved and so perceptions over policy uncertainty are diminished to trivial levels (for example, as in UK and Europe). Spreads on PF facilities therefore reduce to levels in-line with reductions in the debt capital markets and global power PF markets. Recall that spreads for corporate bonds have reduced by 33% to 240bps since 2008, and global PF facilities now average about 240bps over swap. In our Certainty Scenario, we assume power PF spreads reduce by 33% and narrow in range, from 350-400bps to 250-275bps. We assume 12 year tenors in line with global data, and gearing levels of 65.0-67.5% in-line with historic conditions.

2. **Uncertainty Scenario:** Primary assumptions in the uncertainty scenario are that well-designed structural adjustment assistance forms a central part of carbon policy but unresolved policy conflicts remain between the Government, the Opposition and Greens on the mechanism and targets respectively. Margins for new plant reflect those from our Table 4 results at 350-400bps, 7-year tenors and gearing of 60%.

3. **Meltdown Scenario:** Key assumptions in this scenario are that zero compensation applies, that coal generators experience financial distress, and policy conflicts remain between political parties, representing the worst of all worlds with spread premiums applying at the rates outlined in Table 6 and gearing reverting to 55%.

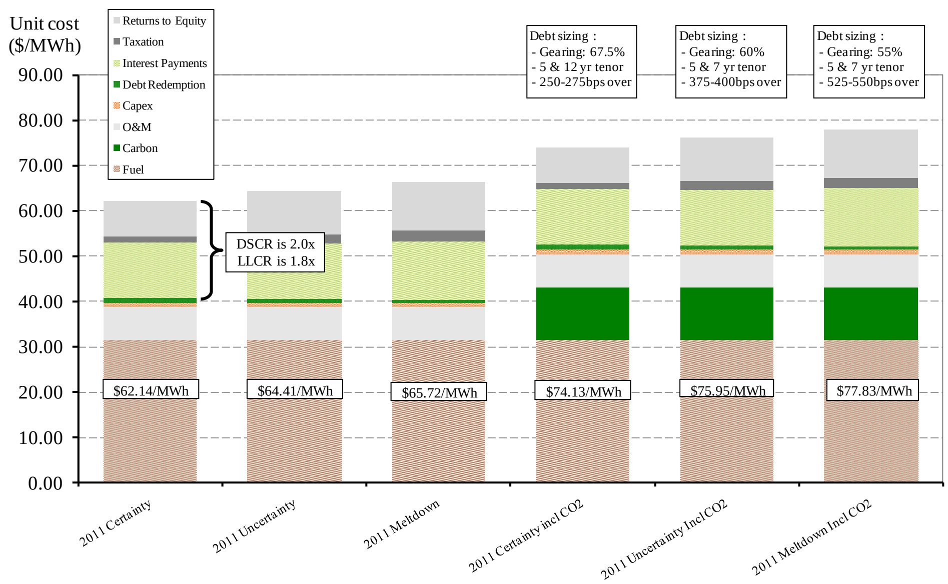
Table 7 sets out the assumptions that apply for a 1 x 400MW CCGT project, a 3 x 175MW OCGT project and a 200MW wind project in 2011, with changes to spreads, tenors and gearing as outlined above.

Table 7: PF assumptions for power plant banked in 2011

Inflation					Taxation		
- CPI	(%)	2.50%			- Tax rate	(%)	30.00
- Elec Price Inflation	(%)	2.13			- Useful life	(Yrs)	30
Plant Costs & Prices		CCGT	OCGT	Wind	Debt Sizing Parameters		
- Plant size	(MW)	400	525	200	- DSCR	(times)	1.8 to 2.2
- Capital cost	($/kW)	1,500	980	2,500	- LLCR	(times)	1.8 to 2.2
- Acquisition price	($M)	600	515	500	- Gearing	(%)	55 to 67.5
LRMC Statistics					- Lockup	(times)	1.35
- LRMC in 2011$	($/MWh)	76.14	14.22	120.39	- Default	(times)	1.10
- Heat rate	(kJ/kWh)	7,000	11,400	-			
- Unit fuel	($/GJ)	4.50	6.00	-	Facilities	Swap	Spread bps
- Variable O&M	($/MWh)	3.00	8.00	1.00	- 5 year tenor	5.76%	250-525
- O&M costs	($M pa)	12.4	6.8	8.6	- 7 year tenor	5.94%	275-550
- Capex	($M pa)	3.0	0.2	0.5	- 12 year tenor	6.11%	275-550
- CO2 footprint	(t/MWh)	0.39	0.59	-	- Refinancings	6.11%	250-375
- Remnant life	(Yrs)	40	30	30	- Post Tax Equity		15%

PF Model results for CCGT plant under the three scenarios are illustrated in Figure 8. Primary debt covenants are within tolerance with DSCR at 2.0 times and the LLCR at 1.8 times in the *certainty* (i.e. benchmark) scenario. The first three bars illustrate underlying LRMC excluding carbon, and the final three bars illustrate headline LRMC including carbon at $30/t. The range in headline LRMC spans $3.70/MWh, from $74.13 to $77.83/MWh. This result is material as Section 7 subsequently reveals.

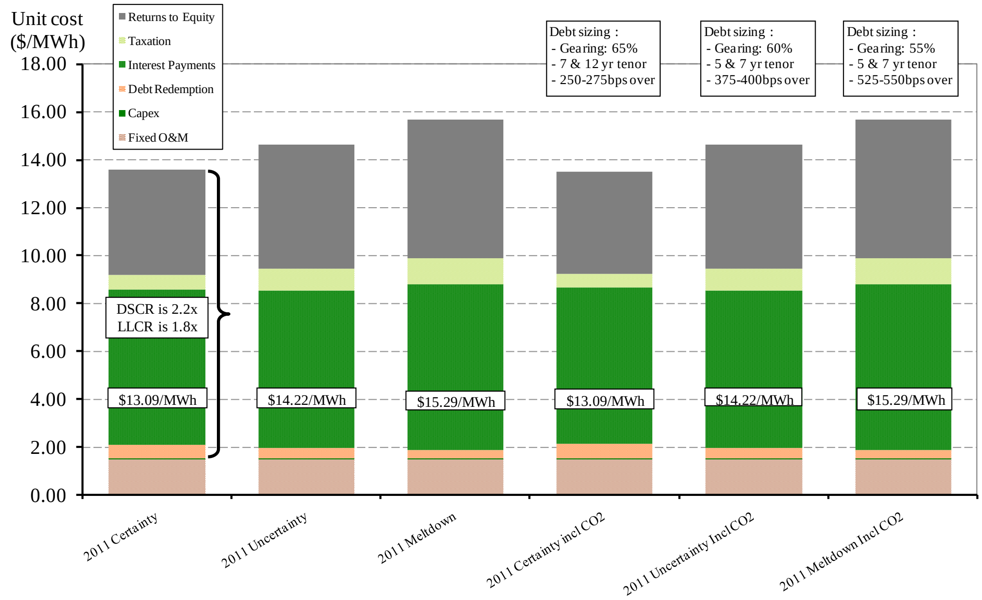
Figure 8: PF Model results for CCGT under certainty, uncertainty and meltdown conditions



Next, we analysed the economic inefficiency that would apply to the fleet of peaking OCGT plants, which is illustrated in Figure 9. We measure peaking plant by their ‘carrying cost’ or ‘fixed costs’ including profit recovery. This can be thought of as the fair value for call options (in $/MW/h) written by new entrant peaking plant with a $300/MWh strike price. The marginal running cost of such plant, regardless of fixed costs, is about $76/MWh without carbon, or about $94/MWh including carbon at $30/t. The PF Model produces carrying costs ranging from $13.09/MW/h to $15.29MW/h under the three scenarios. This $2.20/MW/h differential is also significant because the NEM will carry about 11,000MW of peaking plant by 2015. Accordingly, potential economic inefficiencies arising from our *meltdown scenario* amount to $212 million pa by comparison to the *certainty scenario*.[12]

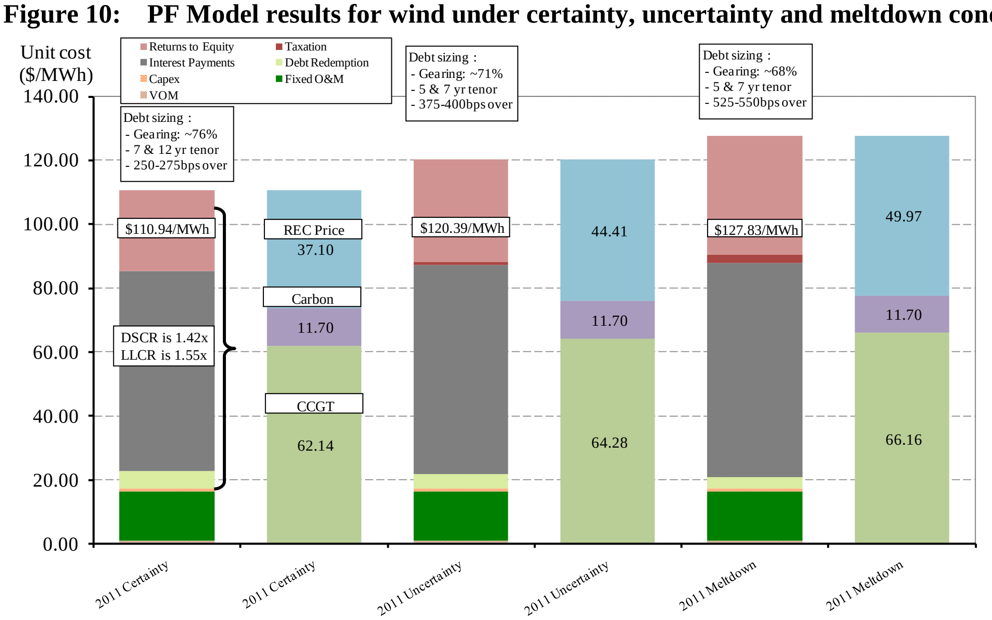
[12] The key assumption here is that peaking plant recover their principle cost structure through the forward market.

Figure 9: PF Model results for OCGT under certainty, uncertainty and meltdown conditions



Our PF Model results for renewable plant (i.e. wind) are illustrated in Figure 10. In modeling wind projects, we applied substantially higher gearing levels than Table 7 indicates, and this is appropriate. The *certainty scenario* is geared at 76% with differential gearing equivalent to our thermal plant modeling. Debt sizing parameters were also different. Whereas thermal plant typically faces DSCR's of 1.8-2.2 for sizing, the capital intensive nature of wind means that the ratios are relaxed, in this instance to 1.35-1.45 times. Our sizing ended up with a DSCR of 1.42 times, well within the acceptable envelope.

Figure 10: PF Model results for wind under certainty, uncertainty and meltdown conditions



In Figure 10, for each scenario we have illustrated the PF Model "cost stack" and in addition, how the market might price Renewable Energy Certificates (REC) at the long end of the forward curve given modeled base load energy costs from Figure 8, and assuming no discount for wind intermittency. Note that the LRMC of wind in the *certainty scenario* is $110.94/MWh. The second bar in Figure 10 depicts how this might be derived from the broader market; the LRMC of a CCGT at $62.14/MWh, CO_2 of $11.70/MWh, and REC's forming the balance at $37.10 per certificate. The LRMC of wind in the *meltdown scenario* is $127.83/MWh with RECs at $49.97

per certificate. Above all, the difference in the cost of wind plant between the *certainty* and *meltdown scenarios* is a surprisingly large $16.89/MWh, three times higher than the cost impact on CCGT plant due to the capital intensive nature of rewnewables. The 2015 LRET target is about 18,000GWh, and so economic efficiency losses arising from the meltdown scenario would total $232 million pa. If they persisted to 2020 when the LRET target reaches 41,000GWh, economic efficiency losses would total $528 million pa.

The analysis presented in this section has for the first time quantified the potential disruption to capital market efficiency. However, we are not the first to have raised this as a potential outcome. Garnaut (2011, p.27) also identified the potential problems associated with disruptions to debt markets. His recommended solution focused on providing certainty for up to 75% of any existing term facilities at risk of defaulting:

> *A government loan guarantee on the debt of generators will have the effect of reducing the short-medium term probability of generator insolvency first of all by strengthening creditor confidence. There are well known examples of one nervous bank within a consortium causing or going close to causing a commercially sound arrangement to unravel. The loan guarantee facility will reduce the probability of such behaviour interfering with the adjustment to a carbon price. In addition, a government loan guarantee will allow incumbent generators to refinance their generation assets at a lower rate. This will increase the chance of generators refinancing their assets on terms which maintain positive cash flows after payment of interest...*

In our opinion, this approach has intuitive appeal because it attempts to deal to the primary issues raised in our analysis; reduced tenors, refinancing risks, elevated spreads and so on. But the concept provides only front-end comfort to financiers, which is of little use because carbon pricing is an enduring and intensifying problem for brown coal power stations; default risk rises over time and the probability of successful refinancing decreases. Such facilities might be refocused to projects with short remaining lives and fully amortising facilities. But our view is that once a power station is characterized by sharply declining operating margins, reduced volumes and truncated economic life, facilitating predictable exit rather than offering life-support would provide for better policy outcomes.[13]

7. Partial equilibrium modeling results

Higher LRMC for new gas and renewable plant have obvious and non-trivial impacts on forward electricity prices. As the NEM operates under a uniform, first-price, energy-only gross pool auction design, the value of spot and forward prices must ultimately rise to the cost of entry prior to new plant being built. To assess the economic impact of our different scenarios on electricity prices, we assume financing costs calculated in previous sections begin to bind immediately, but are revealed in the market from 2015 onwards as new plant is commissioned. CCGT forms the dominant base and intermediate load technology while OCGT undertake peaking duties.[14] Individual plant costs under the *certainty*, *uncertainty* and *meltdown scenarios* are then applied between 2015 and 2020, which by implication represents investment origination commitments over the period between 2013 and 2017. We consider any elevation in margins must ultimately be mean-reverting; hence our limited five-year period of analysis.

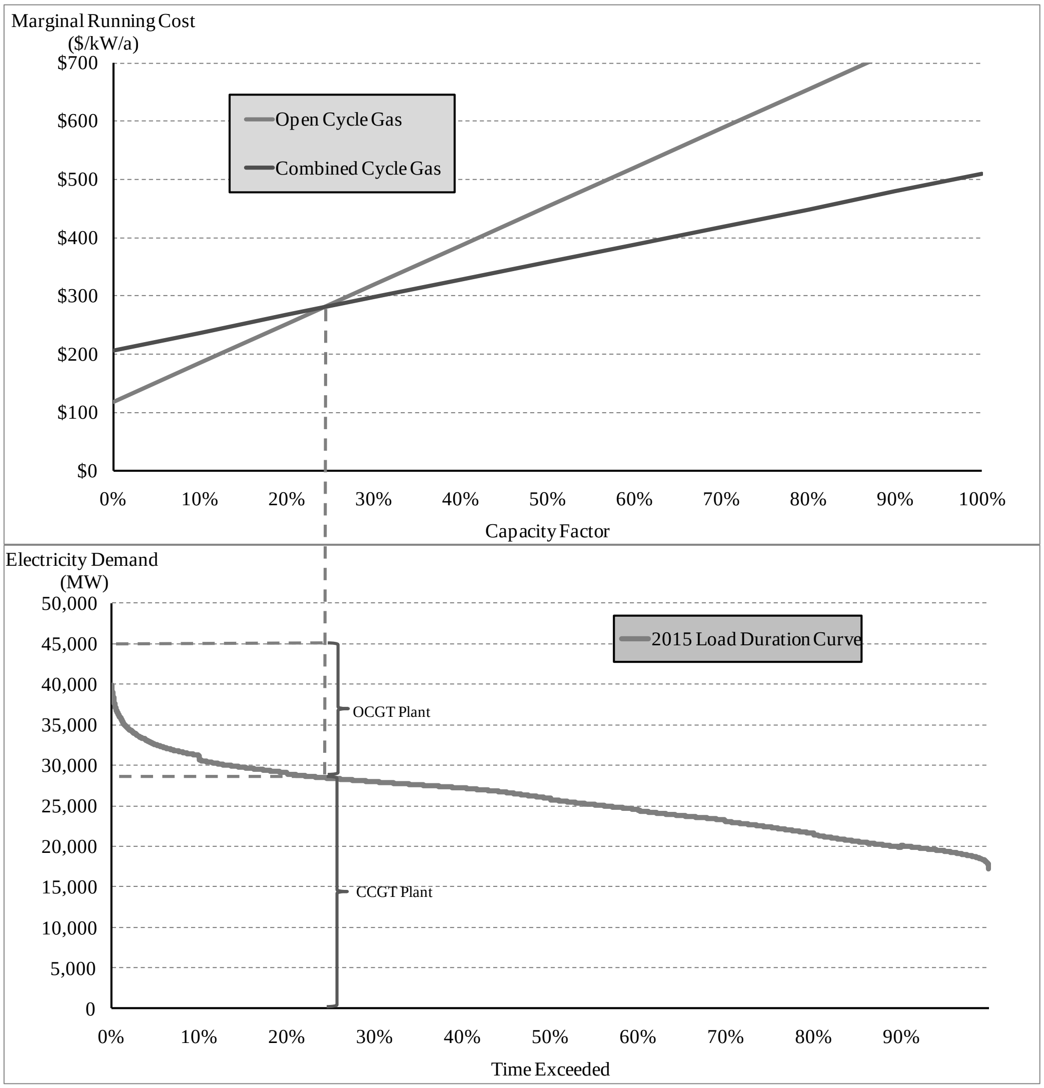
We utilise the Optimal Plant Mix Model (OPM Model) from Simshauser and Wild (2009) to undertake the analysis. This partial equilibrium electricity system model simulates half-hour

[13] Also, this solution does not acknowledge that the same issues identified in our syndicated debt survey are likely to be concurrently prevalent in equity markets. Since debt and equity are substitutes, a loan guarantee solution on existing debt facilities may distort investment markets and create further disruptions.

[14] At one level, higher base load prices might appear to reduce asset impairments of incumbent plant. However, penalty margins on coal plant are likely to exceed incremental margins applied to gas plant, as noted in Table 6.

resolution and assumes perfect competition and essentially free entry to install any combination of capacity that satisfies differentiable conditions. The lumpiness of capacity is a constraint; firms may chose either 400MW CCGT base load plant or clusters of OCGT plant with unit sizes of 175MW, the latter based on conventional 'E Frame' gas turbine technology. As this model has been thoroughly documented in Simshauser and Wild (2009), we do not intend to reproduce it here. A graphical representation of the half-hourly modeling results is presented in Figure 11.

Figure 11: 2015 Load Duration Curve and Implied Optimal Plant Mix



The top graph in Figure 11 is a transformation of PF Model results for CCGT and OCGT plant into marginal running cost curves. The y-axis intercepts represent annual fixed costs of the plant, and the slope of the curves represent marginal running costs (i.e. fuel and variable O&M). The cross-over point, at about 25%, identifies the annual capacity factor at which all gains from investing in low capital cost OCGT plant are exhausted by the higher capital but more operationally efficient CCGT plant.

The bottom graph in Figure 11 presents the 17520 half-hourly electricity load points for 2015. This equilibrium-demand data has been plotted in descending order to form a load duration curve. In establishing our load curve for the NEM, we have aggregated historical State-based loads. Utilising the methodology in Nelson et al. (2010), load duration curves were developed for the years 2015 to 2020, with the OPM Model used to calculate supply-side investment optimality in each of our three scenarios. We assume average annual growth for each decile of the load duration curve at the historic 10-year moving average, and apply this to predict demand for each half hour of the curve in the years between 2015 and 2020. This translates into energy growth rates of about 1.5% per annum, with increases occurring primarily during peak and high demand periods. Our approach to quantifying the costs of uncertainty is identical to that in Nelson et al. (2010) in that our analysis is largely quarantined to the period between 2015 and 2020. System average cost for each scenario is presented in Table 8.

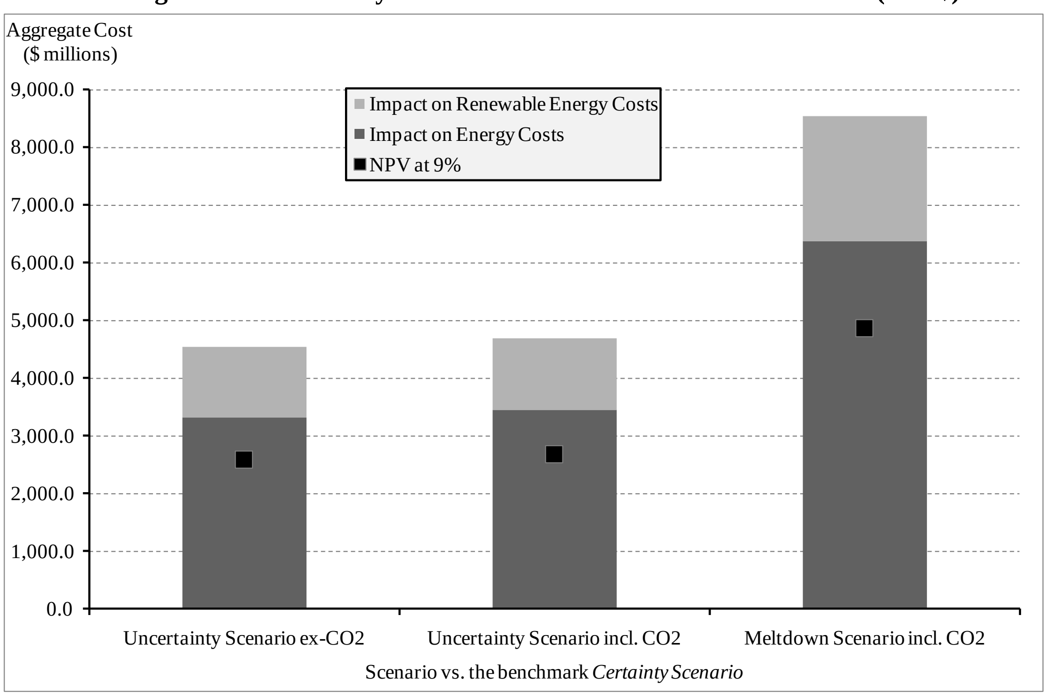
Table 8: NEM system average cost between 2015 and 2020 (2011$)

	Certainty $/MWh	Uncertainty $/MWh	Meltdown $/MWh
Underlying energy costs excluding CO_2	70.24	72.60	74.62
Headline energy cost including CO_2	82.54	85.00	87.07

There is a material difference in NEM-wide system average cost between scenarios. Underlying average costs (i.e. excluding CO_2) in the *uncertainty* and *meltdown scenarios* are $2.36/MWh and $4.37/MWh higher than our benchmark *certainty scenario*, representing increases of between 2.36% and 4.37%. Headline average increases (i.e. including CO_2) are $2.46/MWh and $4.54/MWh respectively, representing 2.46% and 4.54%.

Importantly, the Table 8 results exclude renewable plant impacts; Section 6 noted these were surprisingly large in the *meltdown scenario*. When combined, it is clear that there are material consequences for electricity prices associated with implementing a *Washington Consensus* approach to carbon policy.[15] System aggregate economic efficiency losses across the 2015-2020 period are illustrated in Figure 12.

Figure 12: Efficiency losses in the NEM between 2015 and 2020 (2011$)



[15] These impacts also need to be considered against a background of electricity prices doubling between FY08 and FY15, being driven by network capital investments (Simshauser et al., 2011).

The first two bar results in Figure 12 illustrate the aggregate power system cost impact of ongoing policy uncertainty between the Government, Opposition and the Greens and amounts to $4.5 billion without CO_2 pricing, and $4.7 billion with CO_2 pricing. The reason for the trivial difference between these two scenarios should be obvious enough; unless the Government provides a framework for a formal carbon price, a shadow carbon price fills the void in any event. In short, both the energy and finance industries view a carbon price as inevitable whether one exists or not, and thus all of the uncertainty remains. Our partial equilibrium modeling results for the *meltdown scenario* (including CO_2) puts aggregate economic efficiency losses of $8.5 billion, the details of which are summarized as follows:

- Power system economic efficiency losses in 2015 total $1.25 billion (i.e. $1021m in headline energy costs and $231m from renewable energy);
- Power system economic efficiency losses in 2020 total $1.63 billion (i.e. $1102m in headline energy costs and $527m from renewable energy);
- Aggregate power system efficiency losses between 2015-2020 amounts to $8.6 billion (i.e. $6.4b in headline energy costs and $2.2b in additional renewable energy costs); and
- The Present Value of economic efficiency losses over the 2015-2020 period at a 9% private sector real discount rate amounts to $4.9 billion (with economic efficiency losses assumed to be zero until 2015).

8. Policy recommendations and concluding remarks

It is clear that climate change reforms without adequate structural adjustment assistance run a high risk of a material misallocation of resources. We noted that this is one trigger to justify the use of structural adjustment assistance. We also noted that where a reform results in economic shocks that are large; driven by policy changes; involving a breach of long standing expectations and result in highly uneven or magnified losses in discrete industrial segments are another trigger. All of these conditions are satisfied. While dated, modeling completed for the Commonwealth Government in 2008 demonstrated that the impact on brown coal-fired generators is likely to be in the order of $7.9 billion. Our contribution to understanding the impacts has been to highlight economic efficiency losses that might arise under a Washington Consensus counterfactual scenario of zero compensation. Our modeling results therefore provide an important message – there is a sound public policy case for providing structural adjustment assistance to intensely affected brown coal generators. Our modeling results (in 2011$) concluded economic efficiency losses of $1.63 billion per annum in 2020 and $8.6 billion in aggregate over the period 2015-2020, which is undesirable from a welfare perspective and from an electricity consumer's viewpoint. Yet even if structural adjustment assistance is well designed, the *uncertainty scenario* would still result in an additional $4.7 billion in electricity costs being absorbed by consumers between 2015 and 2020. The implications from this analysis are clear. Policy certainty and structural adjustment assistance are critical elements in relation to carbon policy.

While we have quantified costs of zero compensation, we have not quantified what level of structural adjustment assistance is necessary to avoid such outcomes. That is an entirely separate exercise for economists in conjunction with and investment bankers. As we noted at the outset, economists can provide advice, but the ultimate decision is a matter of judgment for policymakers.

The introduction of a carbon price involves upfront costs to all participants in the economy, which is a key distinction from prior economic reforms. The purpose of carbon pricing is to internalise negative externalities by taxing the release of greenhouse gas emissions into the atmosphere. While economic welfare through such a policy is likely to be improved over the very long-run through the avoidance of costs associated with adapting to climate change, immediate changes to economic welfare will be dominated by negatives. As a result, it would be unwise to ignore temporal aspects of carbon policy. Since pricing carbon has short run negative impacts on economic welfare with gains revealed several decades later, minimising unnecessary short run costs should be a priority for policymakers.

Since the costs of our counterfactual zero compensation scenario are substantial, policymakers must turn their attention to how structural adjustment assistance should be provided. We hold some reservations with Garnaut's (2011) government credit wrapping facility as the sole mechanism. While it may find useful deployment in specific circumstances, offering life support to terminal coal power stations seems counterintuitive, and delaying the inevitable, and so we believe the better view would be to simply facilitate orderly exit, especially given retail electricity price regulation. Besides which, credit wrapping may expose taxpayers to liabilities which exceed the cost of originating structural adjustment assistance at the outset.

The obvious 'outset mechanisms' for brown coal plant include an administrative allocation of permits, or cash payments. We believe that an administrative allocation of permits has the distinct advantage over other options because it 'self-corrects' where anticipated abatement costs do not materialize. If the value of the permits falls, so too does the need to provide structural adjustment assistance. This option formed the basis of the Electricity Sector Adjustment Scheme (ESAS) as part of the Carbon Pollution Reduction Scheme (CPRS) legislation in 2009. ESAS contained a measured approach to providing transitional assistance which attempted to reflect adverse financial impacts to coal-fired generators. Generators qualified if their carbon intensity coefficient exceeded 0.86t/MWh. Generators received a share of the ESAS based upon the margin between their own intensity and the threshold intensity. Generators receiving assistance would have been able to close their plant at any time subject to maintaining capacity (but not necessarily output) for system security purposes, and provisions existed to claw-back any so-called windfall gains.

In a public policy design, it is necessary to be clear about the objectives being pursued. The provision of structural adjustment assistance to greenhouse intensive coal-fired generator should have a short-run objective function of ensuring energy security and avoiding systemic shocks to the NEM given the Governments' inability to reform State-based retail price regulation, and a long-run objective of avoiding economic efficiency losses from emerging in the market for capital, and in turn, minimizing electricity price impacts on consumers. In any environment where the probability of an event occurring is significant, and the consequence extreme, it is prudent to take action to prevent the event from taking place. This *precautionary principle* guides policymakers in all aspects of economic management, and given electricity is an essential service, carbon policy design should be no different.

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