Is the Merchant Power Producer a Broken Model?

James Nelson and Paul Simshauser[♣]

Deregulated energy markets were founded on the Merchant Power Producer, a stand-alone generator that sold its production to the spot and short-term forward markets, underpinned by long-dated project finance. The initial enthusiasm that existed for investment in existing and new merchant power plant capacity shortly after power system deregulation has progressively dissipated, following an excess entry result. In this article, we demonstrate why this has become a global trend. Using debt-sizing parameters typically used by project banks, we model a benchmark plant, then re-simulate its performance using live energy market price data and find that such financings are no longer feasible in the absence of long-term Power Purchase Agreements.

Keywords: Electric Utilities, Energy Prices, Project Finance.

JEL Codes: L94, L11 and Q40.

1. Introduction

The National Electricity Market (NEM) represents one of Australia's key microeconomic reforms over the last two decades. Its success is not contentious. Australia's 50,000MW NEM has long been acknowledged as one of the more successful microeconomic reforms of a power industry globally (IEA, 2005). But

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the industrial organisation ‘blueprint’ set out by policymakers during the mid-1990s has since been heavily modified by the industry.

Prior to the NEM reforms, the Electricity Supply Industry (ESI) on the east coast of Australia was dominated by 4 state-based monopoly Electricity Commissions that spanned power generation, the high voltage transmission network, the distribution networks and retail supply. The first step of reform involved the vertical structural separation of the competitive industry segments (generation and retail supply) from the natural monopoly segments of transmission and distribution networks. A second round of horizontal reform led to the creation of competing generators and retailers. Retail supply has been privatised in all but two franchise areas, along with a large part of the east coast generation fleet. By the time the real-time market for electricity supply was established, the east coast ESI had been transformed from four state-based utilities into a vibrant competitive market comprising 20 independent generators, 16 franchise retail suppliers and a further 5-6 new entrant and material (non-franchise) retailers competing across state boundaries.

One of the striking features of the NEM’s early years was the initial enthusiasm for investment in existing State-owned and new entrant merchant power plant capacity. As Finon (2008) noted, the canonical supply-side business model in deregulated energy markets was the Merchant Power Producer, a stand-alone generator that sold its production to the spot and short-term forward markets (i.e. without long-term contracts or a retail supply business), and acquired pre-existing or newly developed power plant capacity, underpinned by non-recourse project finance. In the Australian case, from 1998-2002 more than 9,000MW of pre-existing plant capacity was privatised on this basis, with an aggregate value of $13.4 billion. Over the same period, a further 4,000MW of new merchant plant capacity was developed at an investment cost of about $4.5 billion. In aggregate, in just five years about $18 billion was invested in pre-existing and newly committed Merchant Power Plants in the NEM, the overwhelming majority of which was project financed.

This was a global trend. Joskow (2006) noted that in the US from 1997-2005, almost 230,000MW of capacity was added or acquired, most of which was Merchant Power Plants relying on project finance. Similarly, Finon (2008) noted that about 6,000MW of project financed plant was added to the largely stagnant UK market in its early years of development in the so-called *dash-for-gas*. This investment enthusiasm has been described as an 'excess entry result' (Armstrong, Cowan and Vickers, 1994; Simshauser, 2001), an environment in which investment activity in deregulated energy markets was so prolific that electricity commodity prices would be in a continual state of boom-and-bust (Moore, 1999).

The 'excess entry result' ran its inevitable course. Of the 230,000MW of project financed plant in the US, 123,000MW experienced financial distress by 2005 (Finon, 2008). In the UK, Drax Power Station (the largest coal plant in Europe) entered bankruptcy proceedings and Britain's largest generator, British Energy, narrowly averted insolvency by 2003 through a debt-equity swap. Many of Australia's Merchant Power Plants experienced similar distress, with 10 generators being sold or restructured under new owners (Mayne, 2010). Steed and Laybutt (2011) observed that the NEM's $50 billion merchant generation sector has incurred economic losses of almost $6 billion over the last decade.

Recurring economic damage to the profit and loss statements of merchant power producers became a clear industry thematic by the mid-2000s. The conditions under which banks would provide project finance to power projects would thereafter be heightened considerably. At this point, economic analysis of energy markets was in many respects turned on its head, with the focus shifting from an 'excess entry result' to the inverse problem of 'Resource Adequacy', that is, whether adequate new plant would be built *in a timely manner* in order to avoid system blackouts. This issue remains relevant. In the Australia Energy Market Operator's (AEMO) *2011 Electricity Statement of Opportunities*, installed capacity in the NEM was noted to require new capacity in Queensland in 2013/14 (AEMO, 2010; AEMO, 2011), yet short run wholesale prices remain critically low. In this article, we aim to test two primary propositions using historic live Queensland energy market data, as follows:

> Proposition I: Despite looming capacity shortages, investment in stand-alone, merchant power plant is no longer feasible.
>
> Proposition II: That project finance is no longer a tractable method of investing in stand-alone power plant in the absence of a Power Purchase Agreement (PPA).[i]

In order to test these two propositions, we present a model designed to simulate the economic cost and operating conditions of a hypothetical merchant power plant that has been project financed in the Queensland region of the NEM. We note that market conditions in each of the NEM sub-regions varies, but the Steed and Laybutt

(2011) results are clear in that this is a whole of market problem, and applying the same quantitative analysis to each region after adjusting for resource endowments will not reveal a different momentum in another region. To that end, we start by establishing a *"perfect world scenario"* whereby all energy market risks are largely assumed away, thus defining the industry long run marginal cost of supply.[ii] We then re-simulate the plant performance using live market data and compare these results against those obtained in our perfect world scenario. The ability of the hypothetical merchant power plant to meet its debt obligations as and when they fall due, using debt-sizing parameters and gearing levels applied by project banks, are used to determine the part that project financed Merchant Power Producers *might* play in the ESI moving forward. We say *might* because the ESI was transformed by the introduction of a price on carbon dioxide emissions in July 2012, and it is beyond the scope of this article to model how such a reform has impacted the finances of Merchant Power Producers. Our findings, therefore, should be tempered by the fact that carbon pricing may well have changed the economics of Merchant Power Producers.

To be sure, the industry has been able to navigate these conditions through industrial organisation (i.e. vertical integration). By combining two countercyclical businesses (i.e. generation and retail supply), firms have been able to 'balance the books' and continue to invest in plant on-balance sheet, or write long-dated PPAs to facilitate the entry of project financed Independent Power Producers. But as one peer reviewer noted, if policymakers and regulators over-regulate retail tariffs based on short run dynamics, it may have the effect of disrupting the very mechanism that the industry has utilised to achieve resource adequacy.

This article is structured as follows: Section 2 provides an overview of project finance. Section 3 introduces our key model assumptions. Section 4 then outlines our Project Finance Model. Section 5 reviews the results of our perfect world scenario and our real world scenario. Section 6 provides our policy implications and concluding remarks.

2. Overview of Project Finance

Practitioners note that the exact definition of project finance is quite ambiguous (Nevitt & Fabozzi, 2000; Esty, 2004; Finnerty, 2007; Tapper and Regan, 2007). For the purposes of this article, project finance can be considered as a method of structured finance used for the development or acquisition of long-lived, capital intensive infrastructure assets. It entails the issuance of non-recourse debt to a project company, which is ‘sized’ on the expected future cash flows of the project itself, not those of the project sponsor (IPFA, 2011). In an applied sense, project finance involves the creation of a Special Purpose Vehicle (i.e. a Proprietary Limited Company) by a firm wishing to invest in a project and as such is “off-balance sheet”. Project financing capital intensive projects has the distinct benefit of minimising the equity capital initially required, at least by comparison to an “on-balance sheet” investment. How this is achieved is underpinned by the fact that the debt is issued to the project on the strength of the project’s expected future cash flows, not by the credit rating of the sponsor. The debt is known as non-recourse due to the fact that in the event of default, the sponsor is protected to a large extent from creditors, who can only pursue the project’s Special Purpose Vehicle and its assets for remedy purposes.

The World Bank formed the view that the project finance "party", for want of a better word, was over by the mid-1990's (Lock, 2003). This was no doubt met with amusement by the energy and broader infrastructure sectors as project finance was truly in its prime. For example, only 300 power project financings, worth $210 billion (in $2011), were written from 1981-1995. But since the mid-1990s, in the energy sector alone, more than 2,800 power project financings worth $2.106 trillion have been written across 101 countries (Simshauser & Nelson, 2012). Project finance is evidently a popular finance method for the energy industry. Indeed, Finon (2008) observed that it was the favoured method by which Merchant Power Producers had financed their investments in privatised or new-entrant plant.

Finnerty (2007) noted that project financing structures are designed to allocate risks and returns more efficiently than conventional finance methods for capital intensive assets with long expected useful lives. More specifically, Esty (2003) argued that project financing is sought by sponsors as a result of three primary motivations: (1) the agency cost motivation, (2) the debt overhang motivation, and (3) a risk management motivation:

1. The agency cost motivation recognises that large, infrastructure assets often characterised by high free cash flows and operating margins are prone to agency conflicts, which can be costly (Esty, 2003; Chen, 2005; Hillier, Grinblatt, & Titman, 2008). The issue here is that management of such projects might be tempted to sub-optimally invest the high free cash flows in incremental projects, thereby eroding the value of the firm by taking on negative NPV investments. Given the often limited scope for re-investment,

the better view is to return free cash flows to providers of capital. By setting up project companies, sponsors have the opportunity to create asset-specific governance systems, which in turn lower the potential for agency conflicts and facilitates a greater return on invested capital (Shleifer & Vishny, 1997; Esty, 2003; Chen, 2005). Kleimeier & Megginson (2000) show that credit spreads over LIBOR for project finance (versus corporate debt) typically had lower spreads given relative gearing, thereby implying that agency costs in the creditor/borrower relationship are reduced by project finance structures.

2. The debt overhang motivation refers to a sponsor-level issue – the fact that off-balance sheet financings allows firms to participate in a much greater number of projects than would otherwise be the case had they been financed on-balance sheet. Through non-recourse project structures, which invariably have higher leverage than on-balance sheet projects, firms are better able to allocate scarce equity capital to a larger number of positive NPV projects, thus fully capturing the benefits of a wider portfolio of investments while not affecting the underlying debt-to-total capitalisation ratio of the sponsoring firm.

3. The risk management motivation highlighted by Esty (2003) and Hillier et al. (2008) refers to the fact that project failure can cause severe damage to a sponsoring firm. Project finance largely negates this risk to the sponsor by the use of non-recourse debt, which in turn does not allow creditors to pursue the other assets of the sponsor firm.

Nevitt & Fabozzi (2000) and Hillier et al. (2008) agree on much of this. However, we should highlight that the literature is clear on the fact that project finance, as a method of funding, raises tangential risks due to the inherently high level of leverage (Churchill, 1996; Pollio, 1998; McKeon, 1999; White, Poats and Borghi, 2000; Lock, 2003; Arowolo, 2006; Vaaler, James and Aguilera 2008; and Shen-fa and Xiao-ping, 2009).

3. Model Assumptions

In order to test the robustness of the Merchant Power Producer model, we create, and then stress-test, a benchmark power plant. For this, we opted for a scale-efficient 400MW base load Combined Cycle Gas Turbine (CCGT), considered the optimal technology given future risks of carbon pricing.[iii] We assume the plant is acquired at the end of a 26-month construction period, with operations commencing in 2005.[iv] Table 1 provides the main economic and engineering cost parameters utilised in our Project Finance Model for our perfect world scenario.

Table 1: **Assumptions for a 400MW CCGT Plant - Banked in 2005**

Inflation			Taxation		
-CPI	(%)	2.50	-Tax Rate	(%)	30
-Electricity Prices	(%)	1.9	-Useful Life	(Years)	30
Plant Costs & Prices			Debt Sizing Parameters		
-Plant Size	(MW)	400	-DSCR	*Times*	1.80
-Construction Cost	($/MW)	1,250	-LLCR	*Times*	1.80
-Capitalised Interest	($/MW)	150	-Gearing	(%)	64
-Acquisition Price	($M)	560	-Lockup	*Times*	1.35
			-Default	*Times*	1.10
CCGT Running Costs					
-Unit Fuel	($/GJ)	3.20	Finance	Swap	Spread
-Heat Rate	(GJ/MWh)	7.00	-7 Year Tenor	6.93%	1.20%
-Variable O&M	($/MWh)	3.00	-10 Year Tenor	7.19%	1.40%
-Fixed O&M	($M p.a.)	12.4	-12 Year Tenor	7.21%	1.40%
-Capex	($M p.a.)	3.00	-Post-Tax Equity IRR		15%
-Remnant Life	(Years)	40			
-Auxillary Load	(%)	3.0	-Annual Capacity Factor	(%)	85.0
-Plant Availability	(%)	92.0	-LRMC ($2005)	($/MWh)	51.15

Our CPI assumption is the mid-point of the Reserve Bank of Australia's target range of 2-3%. Wholesale electricity price inflation is lower than CPI, reflecting an established industry assumption given technological advances.[v] ACIL Tasman (2007, 2009) is widely used by the energy industry, banking sector, policy makers and regulators as a credible reference point for plant costs and we have drawn on these for fuel costs ($/GJ), heat rates, auxiliary loads, variable and fixed Operations & Maintenance (O&M) expenses, plant capital costs, useful life and availability factors for our 2005-built plant. In our modelling, the Short Run Marginal Cost (SRMC) is calculated as the sum of Variable O&M costs and Unit Fuel Costs measured in $/MWh.[vi] This results in an SRMC of $26.74 for the plant[vii] which was then used as an input to our Half-Hourly Production Model (HHP Model) which we discuss later in Section 4.

We assume risk-adjusted equity returns of 15%, which has been drawn from Simshauser (2009) and Simshauser & Nelson (2012). This is an important variable in calculating the Long Run Marginal Cost (LRMC) of the plant in our *perfect world scenario* within our Project Finance Model. By setting a normal profit of 15%, the LRMC is solved by calibrating the headline convergent energy price to a level that would produce this result. We assume an availability factor of 92% which is readily achievable for this technology, and an Annual Capacity Factor (ACF) of 85%, a value at the higher end of the spectrum for CCGT plants but nonetheless valid on both technical and economic grounds. In total, practical plant production is equivalent to about 2900 GWh annually.[viii] To put this level of output into context, Queensland aggregate energy demand in FY11 was 49,000GWh and aggregate NEM energy demand was 197,000GWh (AEMO, 2011).

Interest rate swaps, which fix the interest rates for various tenors against Australia's floating interest rate (known as the "Bank Bill Swap Rate" or BBSW), were drawn from an internal Commonwealth Bank of Australia database used in Simshauser & Nelson (2012). We analysed interest rate swaps for 3, 5, 7, 10 and 12 year tenors, which allowed for a substantial amount of flexibility in structuring debt facilities. For financing the acquisition in 2005, the 2004 average swap rate for each debt term was utilised. We model the plant's structured finance in two tranches. For tranche 1, we selected a 7-year bullet (i.e. interest only) facility refinanced in year 8 with an amortising facility for a further 20 years and tranche 2 as a 12-year amortising facility set within a 27-year semi-permanent structure.[ix] Debt tranches are therefore refinanced in years 7 and 12 respectively, with both facilities repaid by year 27. To be clear, the selection of the "bullet facility" enhances the cash flows to equity during the first seven years of operation, or holding equity returns constant, lowers the apparent cost structure of the facility upon commissioning (because principal repayments are delayed). We applied credit spreads (i.e. the bank's profit margin) over swap rates to account for risk as is normal practice in the industry. We assumed credit spreads over BBSW to be 120 basis points (bps) for the 7-year bullet, and 140bps for the 12-year amortising facility. These pre-Global Financial Crisis values, given our 2005 commissioning date, were drawn from a survey of Australian power project finance bankers conducted in Simshauser (2009) and again in Simshauser & Nelson (2012), and to be sure, are not replicable in the post-crisis world.

Debt Service Cover Ratio (DSCR) describes the ability of the project's cash flows to meet scheduled principal and interest payments. The targeted DSCR was 1.8 *times*, an assumption used in Simshauser (2009) and in Simshauser & Nelson (2012) following their consultation and survey results with power project bankers in the NEM. Similarly, the Loan Life Cover Ratio (LLCR) describes the number of times a project's discounted future cash flows can repay outstanding debt at a given point in time. Taken as the present value of cash flows discounted by the weighted average cost of debt, divided by the outstanding debt balance, the LLCR should be a similar number to DSCR. As in Simshauser (2009) and Simshauser & Nelson (2012), the assumption for the LLCR is a minimum of 1.8 *times* which is met throughout the life of the perfect world scenario.

4. Project Finance Background and Model

Our Project Finance Model (PF Model) is a dynamic, multi-year, integrated production and project finance model of a power project. The PF Model was designed and built to simulate the project's cash flows for 40 years from 2005 onwards. This gas-fired PF Model is largely consistent with the coal-fired PF Model in Simshauser (2009) and in Simshauser & Nelson (2012).[x]

Given the assumptions in Section 3, two variations of the PF Model were constructed: a "perfect world" which derives a formal estimate of industry LRMC. The LRMC point estimate is produced as an assumed all-encompassing convergent spot and hedge contract price (for year 1) which is escalated at 75% of CPI. Gearing and LRMC were determined simultaneously by the model in the perfect world scenario. After establishing initial estimates, the model sought to minimise the convergent energy price and maximise debt levels, subject to the constraints of (1) the DSCR ratio, (2) the LLCR ratio, and (3) equity returns of 15%. The model iterates until all conditions are satisfied.

The second case is a simulation involving *"real-world scenario"* spot, forward and Gas Electricity Certificate (GEC) prices[xi], along with modelled production levels and marginal running costs from 2005 to 2011, holding all other assumptions from the *perfect world scenario* constant. The intent of the second case is to test Propositions I and II.

4.1 Operations Section

This section of the model develops the revenue stream for the plant depending on whether the perfect world or real world scenario was being modelled. Costs were inflated by CPI and energy prices at 75% of CPI. Inflation rates for revenue streams (π_R) and cost streams (π_C) in time *t* are calculated in the model as follows:

$$\pi(t)_R = \left[1 + \left(\frac{CPI \times \alpha_R}{100}\right)\right]^t \text{, and } \pi(t)_C = \left[1 + \left(\frac{CPI \times \alpha_C}{100}\right)\right]^t$$

(1)

where α_C is the adjustment factor of 1.0 for costs and α_R relates to revenues at 0.75. Whereas in the perfect world model we use a single energy price, in the real world model live market data is used from the spot, forward and GEC markets. Hedge revenues were based on a progressive hedging policy, which we have derived from ACIL Tasman (2011). This approach layers in hedge contracts every six-months over a three year window as illustrated in Table 2. We also assume that 75%

(300MW) of plant capacity is hedged at fixed prices, and by implication, the remaining 25% of plant capacity takes a floating price exposure.

Table 2: **Hedge book build-up**

Period	Hedge (%)	Hedge (MW)
t-36 months	10%	30
t-30 months	10%	30
t-24 months	20%	60
t-18 months	30%	90
t-12 months	20%	60
t-6 months	10%	30
Total	100%	300

Regardless of the scenario selected, ancillary service revenues arising from the provision of operating and spinning reserves to the market are based on an input assumption of 0.25% of annual energy revenues, which is consistent with recent aggregate market trends. Similarly, the Fuel and Variable O&M costs were designed to change value based on simulated production levels.

For the perfect world model, Energy Revenues were considered as a single line item under Spot Revenues (i.e. essentially a convergent spot and hedge contract price). Energy Revenues Rev_E can be calculated as the product of this convergent price ($Spot$) and energy sent out (ESO):

$$Rev(t)_E = Spot(t) \times ESO(t)$$

(2)

Where *Spot* was defined by:

$$Spot(t) = LRMC \times \pi(t)_R$$

(3)

And *ESO*:

$$ESO = \frac{ACF \times YrHrs \times Unit\ Size \times (1 - Aux)}{1000}$$

(4)

In (4), *ACF* is the plant Annual Capacity Factor, which as noted earlier has been set to 85%, *YrHrs* is the number of hours in the forecast year which is normally 8760, *Unit Size* is the nameplate capacity of the plant at 400MW and *Aux* is the auxiliary load of the plant which has been set at 3.0%. As noted above, Ancillary Services Revenue Rev_{AS} has been set at 0.25% of Energy Revenues such that:

$$Rev(t)_{AS} = Rev(t)_E \times 0.0025$$

(5)

Therefore, for the simulated model, Gross Operating Revenues, *Rev*, was calculated as the sum of Energy Revenues and Ancillary Services Revenue.

$$Rev(t) = Rev(t)_E + Rev(t)_{AS}$$

(6)

4.2 Expenses Section

This section comprises Fuel Costs, Variable O&M and Fixed O&M. The sum of these three costs was Total Operating Costs, *TOC* which is highlighted in (10) below. Fuel Costs (*FuelC*) were calculated as a function of the heat rate (*HR*), the generator's fuel consumption (*GFC*) measured in $/GJ, energy sent out and inflated over time.

$$FuelC(t) = \left(\frac{(HR \times GFC)}{1000}\right) \times ESO(t) \times \pi(t)_C$$

(7)

Variable O&M Costs (*VOM*), are calculated by reference to *UVar*, measured in $/MWh and are multiplied by energy sent out and then inflated for the appropriate period.

$$VOM(t) = UVar(t) \times ESO(t) \times \pi(t)_C$$

(8)

$$FOM(t) = \frac{FixC \times Unit\ Size \times \pi(t)_C}{1000}$$

(9)

Fixed O&M Costs (*FOM*) are the fixed costs of the plant measured in $/MW of installed capacity, thus they are multiplied by *Unit Size* and inflated. Total Operating Costs (*TOC*) are then given by:

$$TOC(t) = FuelC(t) + VOM(t) + FOM(t)$$

(10)

Revenues less expenses plus any working capital adjustments gave the model the important output of Net Operating Revenues. This is illustrated by Equation (6) less Equation (10).

$$Net\ Rev(t) = Rev(t) - TOC(t)$$

(11)

4.3 Capital Investments Section

This section forecasts all capital related costs. Capital investment included a major capital cost in year 1 of \$560M, the cost of acquisition, and a half-life refit of \$40M inflated at CPI was assumed. The half-life refit was assumed to be paid through cash flows and would not be capitalised. Capital Costs in time *t*, $Costs(t)_K$, were calculated in the model by the following decision rule:

$$if\ t \begin{cases} = 1, & Costs(t)_K = CapCost(t) + (\pi(t)_C \times Capex(t)) \\ \neq 1, & if\ t \begin{cases} = Life/2, & Costs(t)_K = \pi(t)_C \times (Capex(t) + Refit(t)) \\ \neq Life/2, & Costs(t)_K = \pi(t)_C \times Capex(t) \end{cases} \end{cases}$$

(12)

Life is the variable used to set the life of the project. *CapCost* is the ‘overnight capital cost’ of the plant (i.e. the Construction Cost and Capitalised Interest in Table 1) multiplied by the Unit Size. *Capex* is the fixed amount of annual capital works expenditure inflated by CPI. *Refit* is a set amount required to refit the plant halfway through the project's life which is inflated by CPI.

A site residual value was assumed to exist at year 40, set at 10% of the initial acquisition cost and inflated by CPI. A decision rule was used in the model such that:

$$if\ t\begin{cases} = Life, & Sale = \pi(t)_C \times Residual \times CapCost \\ \neq Life, & Sale = 0 \end{cases}$$

(13)

Pre-tax and Finance Project Cash Flows are calculated as Net Operating Revenues less Capital Costs plus Proceeds on Disposal of Plant as illustrated by Equation (14).

$$PreTFPCF(t) = Net\ Rev(t) - Costs(t)_K + Sale$$

(14)

4.4 Taxation Section

This section calculates tax depreciation shield, checks depreciation claimed over the project's life against the total project capital costs and calculates the annual tax payable by the project company. When tax was deducted from net operating revenues, Cash Available for Debt Service (CADS) was realised. CADS is an important result which is later used to establish the critically important financial ratios – DSCR and LLCR.

The model assumed that the plant had a tax life (Useful Life) of 30 years as in Simshauser (2009) and so the plant was depreciated in a straight-line over this period. The decision rule for the Asset Depreciation Shield (*ADS*) was that if the current period was greater than 30 years, then the value was $0, otherwise:

$$ADS(t) = \frac{CapCost}{Useful\ Life}$$

(15)

Similarly the Capex Depreciation Shield (*CDS*) makes a decision that if the current period is greater than 30 years, then the full capex amount is used as the value, otherwise:

$$CDS(t) = CDS_{t-1} + \frac{CapCost(t)}{(Useful\ Life+1-t)}$$

(16)

Tax Depreciation Shield is the sum of Equations (15) and (16).

$$TDS(t) = ADS(t) + CDS(t)$$

(17)

From here Taxable Income, *TaxInc*, is calculated as Net Operating Revenues less Interest Paid on Loans defined later in (22), less Total Depreciation Shield, less Loss Carried Forward.

$$TaxInc(t) = Net\ Rev(t) - IntPaid(t) - TDS(t) - Loss(t)$$

(18)

Loss was calculated as the minimum of $0 or *TaxInc*. This amount was carried through to the following year for use in calculating tax payable by the project. Taxable Income is taxed at the Australian company tax rate of 30%, thus Cash Tax was found:

$$Cash\ Tax(t) = 0.3 \times TaxInc(t)$$

(19)

Post-tax, Pre-finance Project Cash Flows are then found by subtracting Cash Tax from Pre-Tax and Finance Project Cash Flows that is, equation (14) less (19).

4.5 Debt Structuring Section

The debt profile computes the interest and principal repayments on the different debt tranches depending on the type and tenor of each facility. For example, tranche 1 debt is a 7-year bullet, requiring interest-only payments. In year 8, tranche 1 debt is refinanced with two consecutive 10-year amortising facilities, on which principal repayments are payable. Tranche 2 debt commences as an amortising facility with an initial 12-year tenor, refinanced in year 13 and extinguished over a further 15 year period. All debt is extinguished by year 27. The decision tree for the two debt tranches was the same, so for line item Tranche X Debt (where X = 1 or 2) the calculation is as follows:

$$if\ t\begin{cases} > 1, & Tranche\ X\ Debt(t) = Tranche\ X\ Debt_{t-1} - Principal_{t-1} \\ = 1, & Tranche\ X\ Debt = Total\ Debt \times Split \end{cases}$$

(20)

Principal refers to the amount of principal repayment for tranche *X* in period *t* and is calculated as an annuity less the interest payment for the corresponding period:

$$Principal(t) = \frac{Tranche\ X\ Debt(t)}{\left[\frac{1-(1+i)^{-n}}{i}\right]} - Interest(t)$$

(21)

Where *i* = interest rate on debt tranche and *n* = the term of the loan. *Total Debt* refers to the amount of debt used in the project and is determined by the product of the gearing level and the acquisition cost. *Split* refers to the manner in which the debt is apportioned to each debt tranche. We assume 35% of the debt was assigned to Tranche 1 and the remainder to Tranche 2. Interest Payment in time *t* is calculated as the product of the (fixed) interest rate on the loan by the amount of loan outstanding:

$$Interest(t) = Tranche\ X\ Debt(t) \times i$$

(22)

Loan balance was the sum of the two Tranche *X* Debt lines in time *t* while Total Interest Paid and Total Principal Paid were the sum of the Interest and Principal lines for both tranches. Loan Drawings was equal to Loan Balance in year 1, otherwise it was $0 and Debt Service represented the sum of Total Interest Paid and Total Principal Paid.

Project finance typically involves a significant gearing level with minimal equity contribution by the sponsor. Thus a major goal of the model was to find the gearing level which would yield an IRR of 15% while still being serviceable by the project's cash flows.

4.6 Financial Parameters Section

This section came after having built the debt profile. The model took Post-Tax and Pre-Finance Cash Flows plus Loan Drawings less Debt Service to arrive at Post-Tax and Finance Project Cash Flows which was used to calculate the IRR of the project.

$$PostTFPCF(t) = PostTPreFPCF(t) + Drawings(t) - Debt\ Service(t)$$

(23)

The equity IRR could now be calculated using these cash flows over the life of the project.

Next is analysing the debt sizing parameters: DSCR and LLCR. These were calculated annually in the model and the value displayed in Table 1 was the minimum attained over the life of the project. This is because when the model sought to find the LRMC and optimal gearing level, two of the binding constraints were a minimum DSCR and minimum LLCR of 1.8 *times*.

To arrive at the LRMC and optimal gearing level, the model initially sought the energy price in the perfect world model for an estimated gearing level which resulted in an IRR of 15% while ensuring the DSCR never breached the imposed floor of 1.8 *times*. After this, the model sought to maximise the gearing level while pushing the DSCR or LLCR right to the constraint of 1.8 *times*. These two steps were solved continuously until the LRMC and optimal gearing level were found that was within the constraints of a 15% IRR and a minimum DSCR and LLCR of 1.8 *times*.

Within the PF Model is a Half-Hour Production Sub-Model (HHP Model) which produces plant availability, production, variable costs and revenues under the real world scenario. Availability figures are derived for each half-hourly interval using a Monte Carlo simulation.[xii] If the plant is available and the headline energy price (i.e. spot plus GEC price) was greater than SRMC, then the plant operates at full load (400MW). If prices are less than SRMC, the plant operates at minimum stable load (100MW).[xiii] Where the plant was unavailable, output was set to zero. In addition to these output constraints, we also apply a minimum aggregate annual production level constraint to reflect ‘take-or-pay’ contract quantities of gas purchases (set at 16PJ/a) and thus in some instances, output of a forced nature is designed to minimise losses on fuel purchases. The sum of half-hourly production, and corresponding market prices, revenues and variable costs are then rolled-up into annual results for inclusion in the PF Model’s cash flow analysis.[xiv]

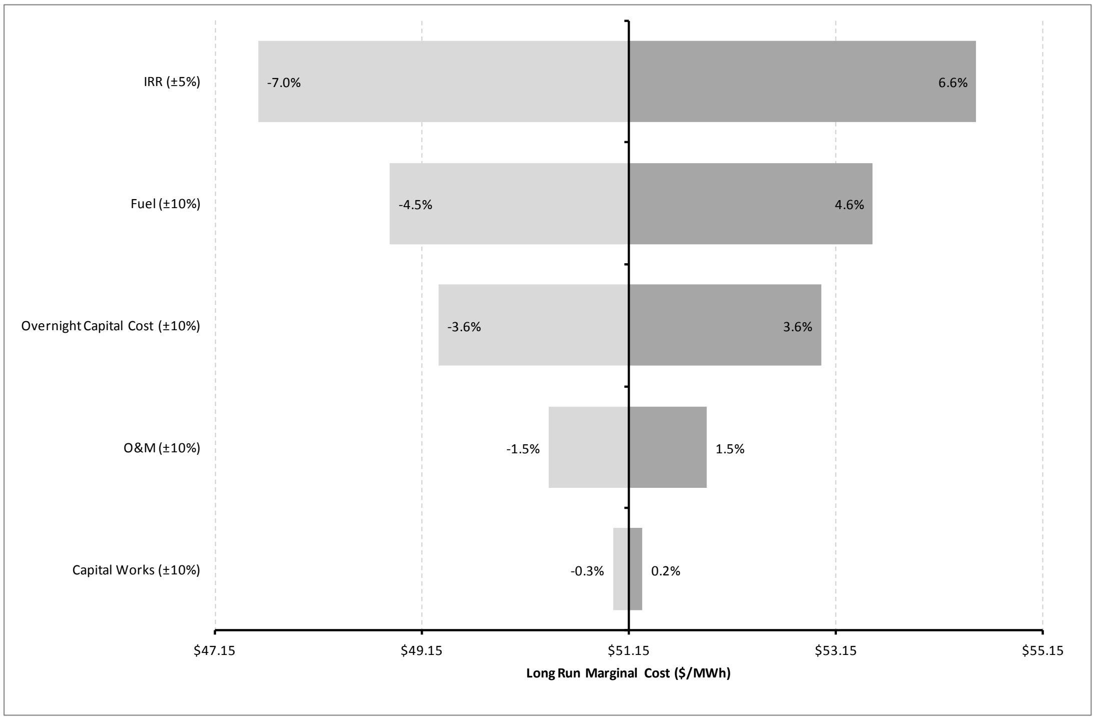
5. Model Results

The market operator's 2003 Statement of Opportunities flagged supply shortages in 2005/06, hence our examination of this timeframe (NEMMCo, 2003). By 2005, spot energy prices had started to recover from the market collapse of the early-2000's, which had been driven by the excess entry result as outlined in Simshauser (2001). The capacity surplus was substantially diminished by 2007 and a shortfall was exacerbated by severe drought conditions (which even affected cooling water supplies to some coal plants) in 2007-08.

5.1 Results from the "Perfect World Model"

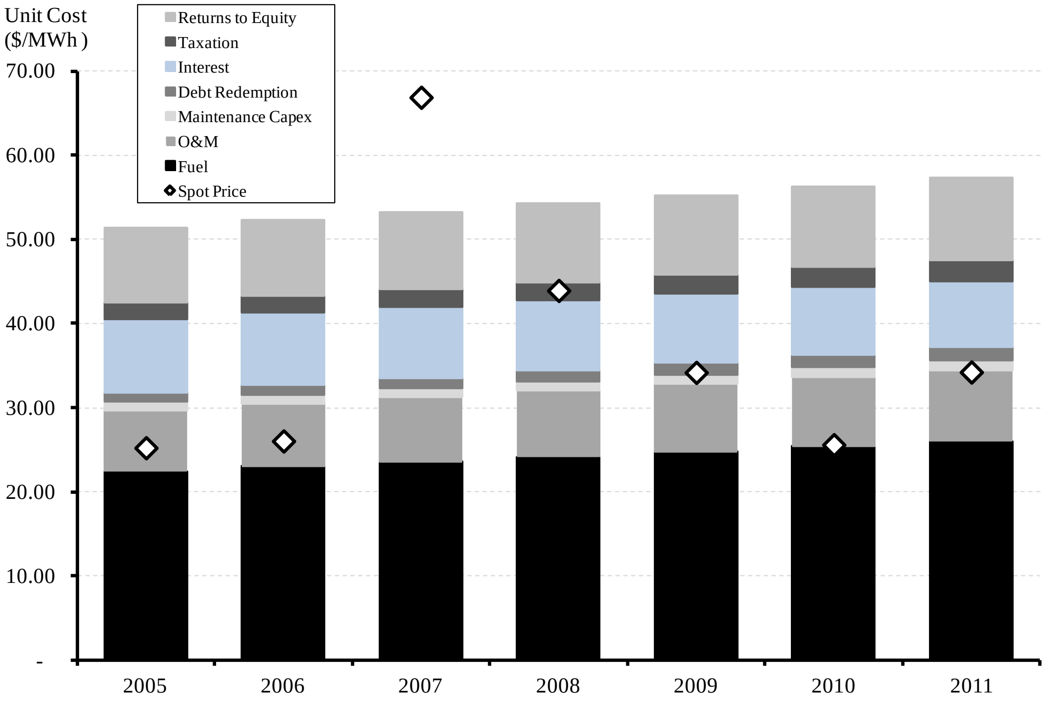
The perfect world model seeks to analyse a benchmark plant under long run equilibrium conditions. Crucially, the perfect world model derives the unit price/cost that would ensure sufficient cash flows for a plant to enter at optimal scale and recover its debt obligations and achieve a normal profit (i.e. industry LRMC). Combining the PF Model outlined in Section 4 with the inputs from Section 3 reveals that this unit price/cost was $51.15/MWh in 2005. Underpinning the model was the assumption that project financing had been obtained for around $357M (64% gearing). This result was driven by the debt sizing parameters in accordance with Table 1. We noted earlier that the structured finance was segmented into two tranches. Annual revenues, calculated as the product of the annual energy produced and the nominal price, equalled $148M in year 1. Fuel costs were $65M and O&M costs amounted to $21M. Net operating revenues were 42% of gross revenues. Some of our assumptions are more sensitive to change than others. Since some of our assumptions may be contentious, we present a *tornado graph* in Figure 1 to illustrate how changes to our key input assumptions impact the $51.15/MWh LRMC estimate. Equity returns were changed by +/- 5 percentage points, while all other inputs were moved by +/-10%. It is interesting to observe how sensitive LRMC is to fuel and capital-related costs (i.e. IRR and the overnight capital cost).

Figure 1: **Results from Input Sensitivity Analysis**



The detailed unit cost stack (expressed in $/MWh) based on the expected future cash flows of our perfect world model is illustrated in Figure 2, along with historic spot price outcomes (represented by the diamond markers).

Figure 2: **Expected Future Cash Flows for the 400MW CCGT Plant**



In terms of the plant's unit cost structure, fuel costs clearly dominate and at $22.40/MWh ($3.20/GJ) are expected to account for 44% of the plant's total average cost. We assume that this 2005 fuel cost was locked-in by way of a long-dated gas supply contract, escalating at CPI annually. Note that an equivalent plant seeking development in 2011 would face a much higher unit gas cost, more likely in the $5-7/GJ range for unity-load gas.[xv] Marginal running costs (i.e. Fuel and VOM) equate to 50% of the cost structure, which is quite different to this CCGT plant's coal-fired peers, whose marginal running costs are typically less than 20% of total cost (and by implication, have fixed costs of 80%+). While not visible in Figure 1, capital (acquisition) costs in year 1 total $560M. Given the capital intensive nature of the investment, debt servicing costs represent 19% of total average cost, while (expected) normal returns to equity are 17% of the cost structure. Debt servicing costs and equity returns are therefore the second and third largest cost components of the plant. The perfect world scenario has an IRR of 15% and both the DSCR and LLCR are covered in any given year at 1.8 *times* or greater.

Note in Figure 2 that we have layered-in average annual spot electricity prices from Queensland, represented by the diamond-shaped markers. Energy-only commodity markets are noted for their extreme half-hourly price volatility. This is driven by several characteristics including (1) the non-storability of electricity, (2) the requirement to match supply and demand instantaneously and without the ability to draw on inventories to smooth shocks; (3) the unpredictability of weather and of plant outages; (4) high market price caps, which in the NEM is currently $12,900/MWh (400 times our LRMC estimate); and (5) the virtual necessity for supply-side participants to economically withdraw capacity throughout the year in order to reduce the extent of what is known as the power generators' 'missing money'. Besser, Farr and Tierney (2002), Bidwell and Henney (2004), Booth (2005) and Simshauser (2008) observed that in energy-only markets, natural market equilibrium is inherently unstable and therefore the exercise of transient market power by generators is, to some extent, justified on the grounds that bidding at short-run marginal cost cannot possibly lead to the recovery of reasonable costs, an outcome which is aggravated by the presence of wholesale market price caps.

Cramton and Stoft's (2006) 'missing money' is well understood in the energy industry, and is perhaps best explained by Bidwell and Henney (2004, p.22) when they demonstrated through power system modelling that for an energy-only market to be remunerative to all plants whilst remaining in a state of competitiveness, the power system would need to be *"near the edge of collapse"* – which is what we mean when stating above that the natural market equilibrium of energy markets is inherently unstable. In simple terms, because marginal running costs represent a small component of total costs, spot prices are typically very low for much of the year in energy markets, and so a large number of blackout events would be required (i.e. with spot prices binding at the market price cap) in order for plants to recover aggregate costs in any given year.

The key issue here is that most of the existing fleet of power stations have very low marginal running costs and very heavy fixed costs and new entrant renewable capacity, such as wind and solar, only exacerbate this effect. Additionally, because electricity markets cannot draw on inventories to satisfy demand, and because systemic blackouts are entirely politically unacceptable, a reserve plant margin is required. This purposefully designed oversupply increases costs and adds further competitive pressure to power system clearing prices. And so when these drivers are considered in aggregate, spot electricity prices are frequently set too low, too often, to be remunerative to some or all plant participants. Compounding these effects thus translates into a large gap between aggregate power market revenues, and aggregate generator costs, which is known as the 'missing money'.

In the case of the NEM, Simshauser (2008) demonstrated that under competitive market conditions, the generation fleet would recover (at best) 66% of their cost structures given (1) a market price cap of $10,000/MWh (as was relevant at the time) and (2) a reliability constraint equivalent to the NEM's objective function of no more than 0.002% lost load.[xvi] And as noted earlier, Steed and Laybutt (2011) estimated that ‘missing money’ in the NEM over the last decade amounted to a surprisingly large $6 billion.

To be sure, economic theory has long demonstrated that spot electricity markets can clear demand reliably, and provide suitable investment signals to independent generators. But such analysis typically presumes unlimited market price caps, no political or regulatory interference in the wholesale market, and by implication at least, a largely equity capital-funded generation fleet able to withstand wildly fluctuating business cycles. Unfortunately the real world simply isn’t this convenient as de Vries (2003) and Roques, Newbery and Nuttall (2005) have noted. Wholesale price caps do exist, they are enforced and in some cases excessively so by regulatory authorities. Modelling results in Simshauser (2008) demonstrated that to eliminate ‘missing money’ in the NEM, the market price cap would need to be raised from (then) $10,000/MWh to $24,500/MWh. However, as highlighted by AEMC (2009), few participants support such a move due to the tangential risks such a change would introduce (i.e. during large system shocks, a price spike of this magnitude leading to single-event bankruptcy risks for any exposed business). One might expect energy prices to rise unnecessarily were such an event to occur. Regardless, rarely are generators devoid of scheduled quarterly debt repayments, and so theories of spot energy markets suffer from the inadequate treatment of inter-temporal cash flows, or more specifically, how large future capital costs are in fact financed (Besser, Farr and Tierney 2002; Simshauser, 2008; Finon, 2008). This is of course the key objective of this article – to clearly demonstrate where the economic theory of electricity markets collides with the harsh realities of real-world corporate financing constraints.

Contrasting annual spot prices with the cost stack in Figure 2, it is obvious that with very few exceptions, spot prices are simply inadequate to cover financing costs let alone deliver a normal level of profit to equity investors. Put another way, if our optimal, scale-efficient 400MW plant had relied on spot prices for its income stream, it would be comprehensively bankrupt in five out of seven years. We must therefore analyse the role that hedging plays.

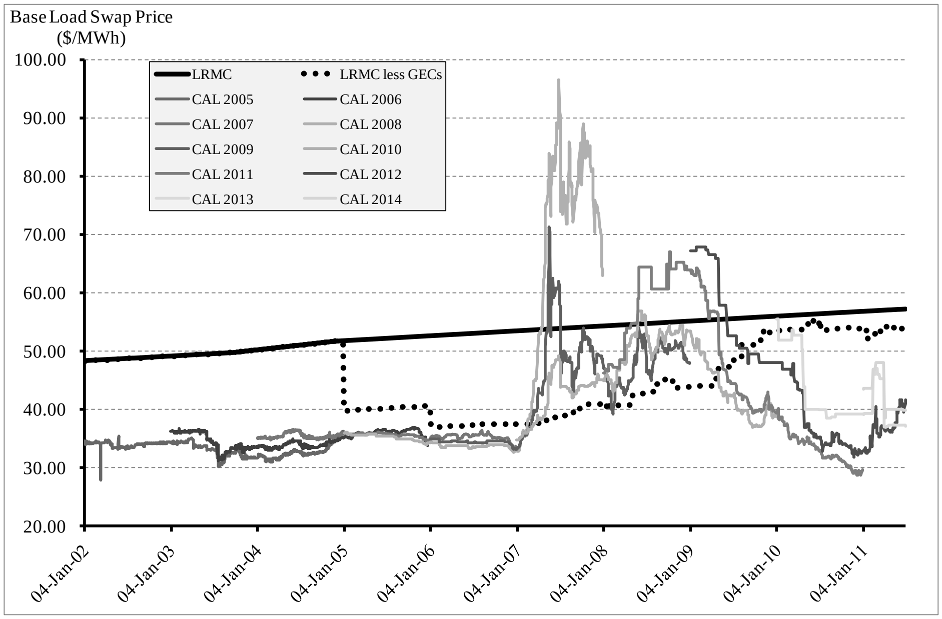
5.2 Real World Scenario – is such an investment feasible?

Figure 2 leads one to the conclusion that such an investment is not tractable. However, Figure 2 only contrasted spot prices with a static result, as distinct from dynamic modelling of production against volatile spot prices with a balanced mix of income streams from multi-period hedges, the spot market and GECs. In our modelling, plant hedge revenues were based on the sale of swap contracts exercised in time *t*, layered into the plant's hedge book over three prior years per Table 2.

As is visibly evident from Figure 3, which plots the daily trade in calendar year swap contracts (from CAL2005 to CAL2011), swap contracts with an exercise date prior to 2007 had an average price ranging from $34/MWh to $36/MWh. From 2007, the average swap contract jumped to at least $50.00/MWh, but from mid-2009 onwards, prices fell back below $50/MWh.

Figure 3 also incorporates two LRMC trend-lines. The solid LRMC line was produced by our PF Model (perfect world scenario) while the second dotted line, LRMC less GECs, reduces our LRMC estimate by the traded price of GECs in Queensland (since CCGT plant qualifies for GECs). For most of the last decade, the strike price of traded contracts is demonstrably below our LRMC. The forward market experienced an upwards shock due to drought conditions in Queensland in 2007. Hedges remained elevated after the passing of the drought because the cost of new power project development had increased sharply as Simshauser, Molyneux and Shepherd (2010) explain. But strike prices of base load swaps eventually reduced to pre-drought levels, and below. Absent this severe drought, we believe the tough market conditions of 2005 and 2006 would have prevailed for considerably longer.

Figure 3: **Calendar year base load hedge prices vs. LRMC**



As noted in Section 4, the PF Models' real world scenario uses live market data and simulated production levels from the HHP Sub-Model to produce Revenue and Fuel Costs. The overall project cash flow result is illustrated in Figure 4 and in many respects is the most important finding of this article. Notice that we have clearly marked the 'missing money' as the top box of the cost stack. To be sure, during periods of structural oversupply, one would expect sub-optimal equity returns. But the inverse is also true. And in this instance, as Figure 5 later reveals, the market imbalances oscillate, yet not a single year were returns to equity holders adequate.

It is immediately apparent from inspection of Figure 4 that the plant is on the brink of financial collapse in 2005, 2006 and in 2007. The DSCR for these years were 0.29, 0.33 and 1.05 respectively. Recall from Table 1 that debt was sized at 1.8 times but that crucially, an actual DSCR below 1.10 is a "default event", i.e. plant owners must either inject new capital to restore the liquidity ratios, or alternatively, hand the asset over to the project banks who will then proceed with a "workout".

From 2008-2010 the DSCR results are in the 1.50-1.60 range. However, in 2011 (and in 2012, although not visible) the ratio falls to 1.29, which is below the 1.35 "lockup event" threshold noted in Table 1. Under "lockup", equity owners are unable to receive the distributions or returns to equity flagged in Figure 4, rather, any profits otherwise earmarked to equity holders would be applied to outstanding debt into the future until ratios have been restored.

In Figure 4, we have also layered-in the average unit energy price (comprising spot, forward and GEC prices, measured on the RHS y-axis). In 2005, the average spot price was $25 and the GEC price was $12 and so production output from the HHP Model was 2728GWh or an 80.3% ACF. This is slightly lower than our perfect world result of 2900GWh (85% ACF). Hedge revenues amounted to $20.4M and energy revenues totalled $72.4M which resulted in a decrease of $55M in aggregate revenues from our perfect world scenario. The apparent reduction in total revenues during 2009-2011 is driven by a combination of lower prices and correspondingly lower output levels. Note in particular that Fuel Costs had fallen considerably from 2008 to 2011.

Figure 4: **Actual cash flows for a 400MW CCGT plant in Queensland**

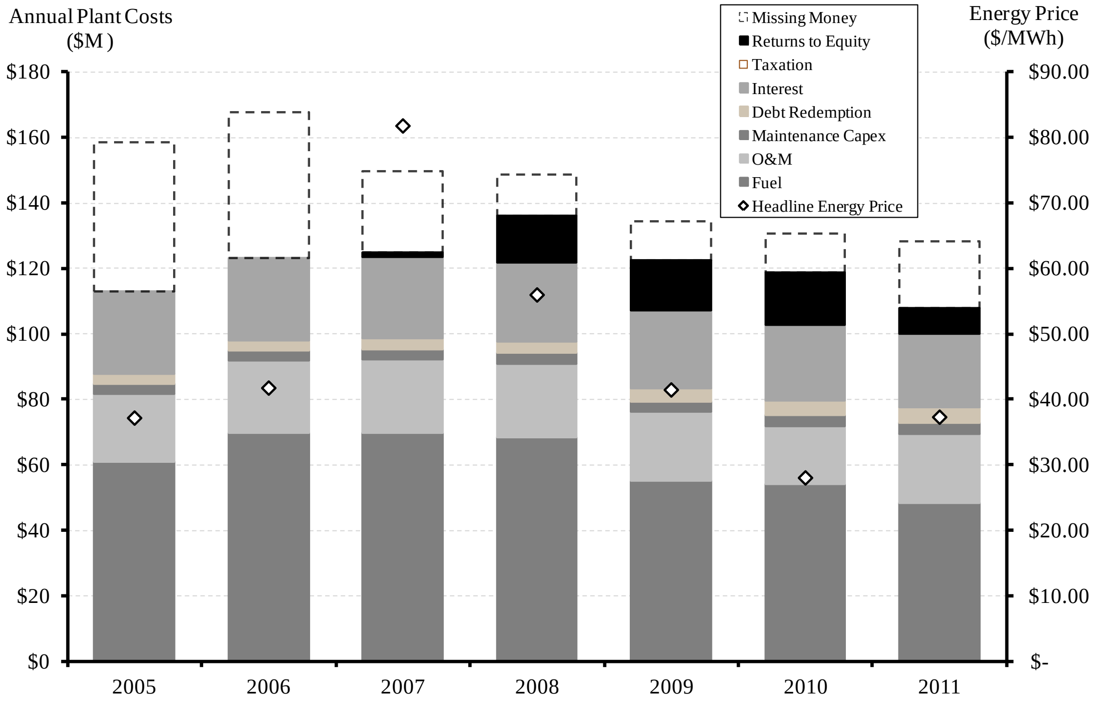
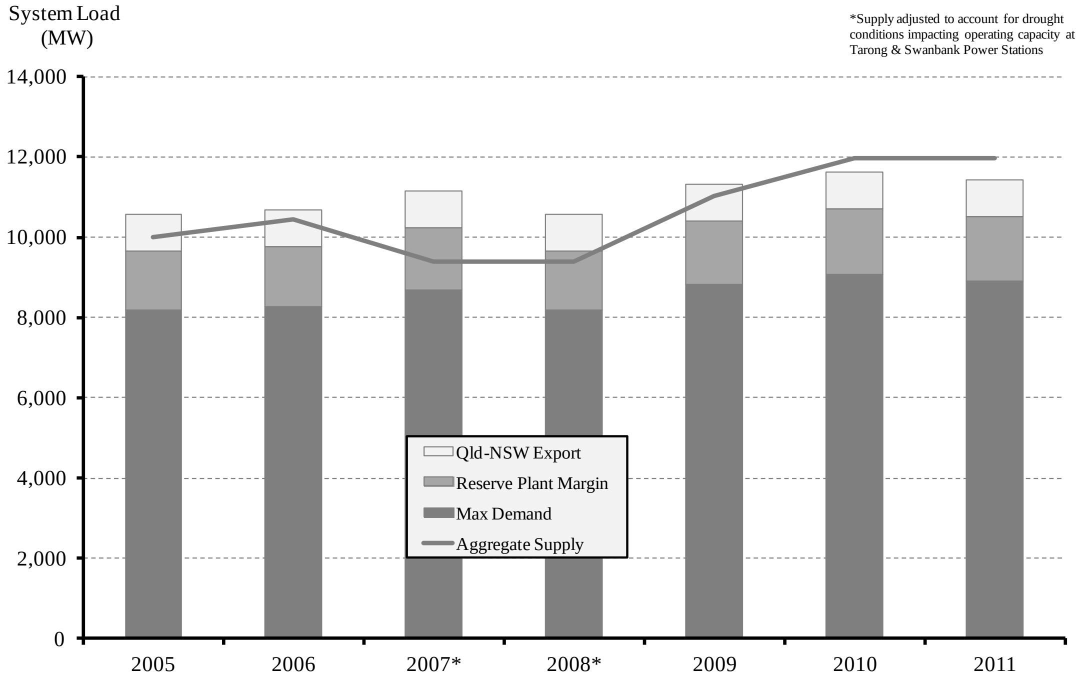


Figure 4 also highlights the role of the hedge portfolio in managing price risk. The average price in the hedge portfolio was lagging the energy spot market and this helped prevent the plant from defaulting again in 2010 and 2011. Total difference payments on hedge contracts from 2005 to 2011 inclusive, came to $66.6M, the equivalent of $9.5M per annum. This increased the unit price received by an average of $3.55/MWh over this period. While not enough to avoid the project failing, the role of a hedge portfolio is clearly important.

In our perfect world scenario, we analysed the expected running cash yield to equity (i.e. cash returns divided by initial equity injection). We found the expected result to average 13.2% over the first seven years of operation. In our real world scenario, we found the running cash yield to average just 1.1%. This is hardly an inspiring risk-adjusted cash yield to equity investors. Holding the proposed gearing level of 64% constant, an optimal entry year was sought for the plant to commence operations. There was no year between 2005 and 2011 that allowed the project to be a feasible investment on the basis of adequate returns to equity. At this juncture, it is worth examining the level of existing capacity in the market at that time relative to what was required. As Figure 5 illustrates, the market was not excessively over-supplied at any time during this period. On the contrary, during 2007 and 2008, aggregate supply fell short of optimal levels given reliability of supply constraints.

Figure 5: **Supply-demand in Queensland from 2005 - 2011**



Data Sources: esaa, AEMO, AGL Energy Ltd.

On this basis, Propositions I and II are accepted.

6. Policy Implications and Concluding Remarks

A key finding of this article is that from 2005 until 2011, a project financed CCGT Merchant Power Plant is not a feasible investment in Queensland's energy market given the current wholesale market price cap of $12,900/MWh. Specifically, a plant which represents the industry benchmark for base or semi-base LRMC is barely able to remain solvent, let alone return a normal profit stream to equity holders. The "canonical business model" of the deregulated energy industry to which Finon (2008) referred appears to be a broken model. It would seem that competitive energy pools turned out to be much tougher markets for stand-alone generators than its blueprint designers first thought.

Yet the theory of spot electricity markets and power simulation modelling has shown that Resource Adequacy can be met in energy pools. However, the mechanism by which this is achieved is by setting a very high market price cap and by implication, patiently waiting for extreme weather events and supply-side outages, or artificially inflating aggregate demand through various power system ancillary services and spinning reserve requirements to achieve suitable net revenues over time.

Economic theory tells us that a power project with a positive NPV should be built. But the economic theory of spot electricity markets and power system modelling assumes away critically important business constraints. A stand-alone power station may well be an NPV positive project, but if it posts losses in three years out of five, this is a problem, and our modelling clearly demonstrates this. Cash flow timing is important and in this instance provides a prime example of the collision between elegant economic theory and the harsh realities of real-world, applied corporate finance. Debt facilities require ongoing quarterly repayments, and cannot be rescheduled to meet intense weather patterns, when spot market price spikes are most likely. We observed that running cash yields of stand-alone power projects are important to both banking syndicates and equity investors.

Yet in spite of the findings of this article, the NEM has delivered more than 11,000MW of new plant to the system and a further 2000+MW of renewable plant, and in all years, the NEM's reliability criteria of maintaining system shortfalls to less than 0.002% has been satisfied (Simshauser, 2010). How then, has this been achieved?

In Australia, potential cracks in the Merchant Power Producer model were flagged at least as far back as 2006 by the Energy Reform Implementation Group (ERIG, 2006), which was set up by Federal and State governments to develop implementation strategies for additional energy market reforms. A central conclusion drawn from ERIG's extensive work was that while investments in stand-alone merchant plant were becoming more difficult than less, the market in Australia, and energy-only markets in the US, UK, New Zealand and other countries had found a way to overcome this apparently intractable result – through industrial organisation. We noted at the outset of this article that the NEM's blueprint design initially dissected the four State-based Electricity Commissions into 20 independent generators and 16 franchise retailers. The market now looks very different, with only 11 independent generators[xvii] – four of which have non-franchise retail businesses, three large vertically integrated franchise retailer/generators[xviii] and 5-6 independent retailers (ESAA, 2011).

ERIG (2006) predicted that vertically integrated entities would undertake a significant degree of investment or underwrite project financed new entrants through writing PPAs – a prediction that has been proven entirely correct from 2006-2012. The issue here is that vertically integrated firms combine two countercyclical markets simultaneously, the wholesale energy market and the retail energy market. Since default retail electricity tariff caps (i.e. the regulated *'price-to-beat'*) have historically been set by reference to (or equivalent to) the whole of industry LRMC, firms that span the merchant supply chain are able to 'balance the books' throughout the energy commodity business cycle. For example, recall from Figure 2 that spot prices spiked severely in 2007 and from Figure 3 that hedge prices similarly spiked in 2007 and 2008. Price movements of this nature represent adverse outcomes for retail businesses, and beneficial outcomes for generation businesses. The inverse is also true. And so integrated firms can facilitate project financed new entrant plant by signing long-term Power Purchase Agreements (PPA) with Independent Power Producers (IPP)[xix], or by financing their own new plant on-balance sheet – provided the integrated firm has a substantial franchise customer base, an investment grade credit rating, and that default tariff caps (as distinct from competitive market offers) are set by reference to LRMC as currently occurs in the deregulated Victorian market, and in the regulated NSW and SA markets.[xx]

In considering the investment signals facing participants in the NEM, ERIG (2006, p.60) made a number of important observations: (1) the industry had responded to market signals and risks inherent within the NEM design through industrial organisation, that is, vertical integration; (2) while policymakers often expressed concerns over integration, it represented ‘an inevitable and largely benign development’ and as a trend was well advanced in the UK, USA, New Zealand and other energy-only markets around the world; and (3) industrial reorganisation offers material risk management and (quite considerable) cost of capital advantages.[xxi]

ERIG (2006) concluded that policymakers should not be concerned by vertical integration in the NEM per se, as this represents the market at work. As the authors are employees of an integrated entity, we are clearly conflicted in providing truly independent policy advice on such matters. However, in practical terms, it would seem logical that policymakers should focus on ensuring that conditions are conducive for several vertically integrated entities so as to stimulate competition amongst the NEM competitors. Policy settings should also ensure that second tier retailers are not crowded out of retail market, and that vertical entities do not face constraints in writing PPAs so they can underwrite the participation of project financed Independent Power Producers (as distinct from Merchant Power Producers) in the generation sector, rather than building all of their own future plant requirements. In this way, the market should be able to ensure reliable energy supplies, with prices set at levels considered to be long run competitive, and therefore socially optimal.

Given a comparatively stable customer base and crucially, default retail tariff caps that broadly reflect the higher of market or sustainable long run costs (albeit, with progressively widening retail tariff discounts when system overcapacity exists), integrated firms appear to be capable of absorbing supply-side price risks within their combined wholesale/retail books – risks that are evidently entirely too large for Merchant Power Producers to absorb as stand-alone businesses.

The obvious question at this point is why an integrated firm would write a PPA at LRMC to facilitate a project financed entrant when it could purchase from the spot and forward markets at lower rates outside periods of system stress. It should be obvious that given demand uncertainty and construction lags, ill-timed PPAs or plant investments would result in spot and short term markets deviating to excessive levels such as those seen in 2007, that is, critically adverse for large retailers, especially if they find themselves with inadequate countercyclical generating equipment, and more importantly, an inadequate volume of (high-priced) hedge contracts. The only reason that integrated firms may baulk at timely investments in plant or underwriting PPAs is under conditions of intrusive retail price regulation – where default tariff caps or the ‘price-to-beat’ conflict with sustainable long run industry costs, i.e. by reference to volatile short run market dynamics observable in Figures 2 and 3. Doing so by regulatory instruments will unwind the very risk management benefits that vertical merchant integration presently delivers. It should also be obvious that there will be limits to the price differential (i.e. between PPAs and short run dynamic market prices) that such entities can reasonably withstand – something regulators should remain ever mindful of.

Ironically, as we were completing this article, the regulator in the Queensland region of the NEM had shifted its approach to regulating default tariff caps away from long run marginal cost to short run dynamic prices. In light of the key findings and quantitative evidence of our research, we believe such policy developments will have an adverse impact on Resource Adequacy, and if sustained, may cast considerable doubt over the ability of integrated utilities in those regions to navigate timely commitments. This issue should be of concern to policymakers given governments have now exited the market for investment in new plant capacity. At a minimum, we believe that integrated entities would be unable to make commitments with the same conviction that is evidently present in the Victorian and NSW regions, where more than $5.4 billion has been invested in existing and new merchant generating equipment over the past two financial years, and in South Australia, where more than $2 billion has been invested in new renewable energy capacity – bearing in mind that project financed renewable energy projects are also reliant on PPAs, albeit comprising both energy and renewable energy certificates.[xxii]

The key issue here for policymakers is that firms inevitably respond to the incentives that regulation establishes. If this were not the case, regulation would not exist in the first place. In our view, regulation which enforces a short-run dynamic approach to default tariff determinations has the unambiguous effect of interrupting the existence of countercyclical merchant businesses within the NEM. It also appears to us that it runs a clear risk of reopening the debate on whether an energy-only market (i.e. when combined with intrusive price regulation) can actually deliver Resource Adequacy. One alternative is to raise, quite significantly, the wholesale market price cap. We noted earlier that the NEM's current wholesale price cap is $12,900/MWh is well short of the estimate required to be remunerative in Simshauser (2008) of $24,500/MWh, given current reliability standards. Yet we noted earlier that raising the price cap to such a high level brings with it tangential financial risks of insolvency. As a result, the majority of NEM market participants, including those with inherently long positions, have historically *not* been supportive of such a dramatic step (AEMC, 2009). From a reliability perspective, it is also not clear that the pattern of spot prices during the 'ideal commitment period' would alter sufficiently to telegraph the requirement for new plant in a timely manner in any event – experience in the NEM at least tends to result in prices rising very steeply just prior to physical requirement, which given construction lags, would be suboptimal as the literature on Resource Adequacy highlights.

Another alternative is a market redesign, involving the introduction of generator capacity payments. On two prior occasions, NEM institutions have canvassed the concept of generator capacity payments, but rejected it on both occasions due to Resource Adequacy being met, which in large part was due to (1) government investments in plant (which has now ceased) and (2) the presence of PPAs written by investment-grade, integrated utilities to facilitate project financed new entrants, along with their own investments on-balance sheet. If default tariff caps are set on the basis of purely short run dynamics in Queensland as Merchant Power Producer model was fundamentally stylised on, it is not obvious to the authors that PPAs for conventional (or renewable) plant are credible instruments because they would essentially be marked-to-market annually by a regulator using imperfect information. And ironically, facilitating entry by writing PPAs would simply send wholesale prices down in the post-entry environment – with default tariff caps subsequently regulated down as a result.

Given the political economy of energy pricing, if regulators switch to a market approach during market overcapacity, it is not inconceivable (and to industry, seems almost predictable) that a switch back to an LRMC cap will occur during periods of under-capacity. Such an outcome would represent an episode of *inverse* ersatz capitalism, socialising profits and privatising losses. The finance and energy sectors have a documented history of pricing policy risk into the cost of capital of future investment decisions as Simshauser & Nelson (2012) observed.

Finally, and although not the intention of this article, our conclusions are reflected in the Queensland Government's state-owned generators, after having privatised its retail supply businesses in 2007. The portfolio generators own 16 Merchant Power Plants which account for about 57% of Queensland's generation capacity. Last financial year, the combined financial results of the generators produced asset returns of 5.1%. Given an aggregate asset base of $6.3 billion, corporate gearing of about 52% and an assumed interest cost of 7.5%, this translates to an equivalent equity return of about 1.7% - a result consistent with the findings of this article that equity returns of Merchant Power Plants are sub-optimal.[xxiii] This raises the issue of whether public ownership of merchant plants makes economic sense given the drag they place on State Government balance sheets and therefore, taxpayers. The better view, we believe, is to privatise government generators in competitive processes because presumably, vertically integrated firms will be able to value the plants as part of an integrated portfolio in a way that is no longer possible by government owners – subject to retail market regulatory conditions. Another alternative is to establish PPA and trading rights for those generators, as the New South Wales Government did with its fleet of power stations in 2011. Either way, proceeds from any privatisation (or synthetic privatisation through offering PPAs) and the reduction in total government debt should comfortably exceed the present value of future dividends from these businesses.

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Footnotes

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[i] A PPA is a long-dated fixed-price contract written by a Retail Supplier with an investment grade credit rating.

[ii] Under this scenario, the long-run marginal cost can be found by solving for the headline energy price which allows this “ideal project” (from a unit production cost and scale efficiency perspective) to meet all its debt and equity obligations at optimal gearing levels. We are specifically focused on the long run marginal cost of a base load plant.

[iii] The rival technology to the CCGT plant in Queensland was the Supercritical pulverised fuel (SCpf) black coal power plant. Prior to 2005, SCpf plant was generally considered to have a lower overall cost (ex-carbon). Three SCpf plants were built in Queensland between 2002 and 2007. However, this followed a 2-3 year development period and a 42-month construction period, and thus the origins of these SCpf plant developments can all be traced back to the late1990s, when the impact of carbon pricing was assumed to be benign (see for example Simshauser, 2009). Conversely, between 2002 and 2010, six gas-fired generators with 2400MW of aggregate capacity were built in Queensland, following the implementation of Queensland’s Gas Electricity Certificate scheme, which essentially facilitated a differential subsidy to gas plants. Furthermore, considering the carbon footprint of SCpf plant (0.9t/MWh) is more than double that of an efficient CCGT (0.4t/MWh), and increasing uncertainty over carbon pricing at the time of writing, we believe the CCGT plant better reflects the relevant benchmark technology.

[iv] By assuming that an operating company acquires the plant already built, it enables the analysis to focus on the financial stability of such investments by removing the complexities of construction-related risks and financings.

[v] Note that this should be distinguished from residential electricity tariffs, which in Queensland are currently rising faster than CPI due to extensive network capital investments in response to rising peak demand.

[vi] The unit fuel cost in \$/MWh is a product of fuel cost in \$/GJ and heat rate of the plant measured by GJ/MWh.

[vii] We assume transmission losses of 5%.

[viii] The exact result is 2889GWh on a sent out basis. Energy sent out is a function of plant capacity factor less auxiliary load.

[ix] In practical terms, a 12-year facility set within a 27-year semi-permanent structure essentially means that the loan facility is scheduled to be repaid over 27 years, not 12 years. As such, a large refinancing exercise will be required at the end of the tranche 2 12-year facility.

[x] Typically in project financings, models are built with quarterly periods, however to simplify the analysis and the results, this PF Model was built around annual cash flows. With an annual model, the complexity of intra-year cash flow timing is removed which makes analysing the ability of the project to meet its various obligations more straightforward (but with a loss of granularity). To verify the PF Model findings, the Levelised Cost of Electricity Model as documented in Simshauser (2011) was utilised with the results converging to within +/-1.5%.

[xi] In Queensland, a Gas Electricity Certificate (GEC) scheme was implemented in 2005. Under this scheme, retailers are obliged to purchase 15% of their electricity

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from gas-fired sources. Qualifying gas-fired generators are able to create 1 GEC for each MWh produced. The penalty price for retailers failing to procure sufficient GECs in any one year is $15/GEC, and so clearing prices over the last seven years have fluctuated between $2.47 and $16.10 (and averaged $9.77/GEC), based on prevailing supply and demand of GECs.

[xii] Of course, plant typically experiences outages for weeks at a time rather than sporadic half-hour intervals. But given the random nature of unplanned outages, this approach should ensure no bias is necessarily given either way to periods where spot prices deviate significantly from the average, both higher and lower - noting that our reference plant (400MW) is small relative to the size of the Queensland region (c.11,000MW) and the broader National Electricity Market (c.50,000MW) and should not therefore impact greatly on clearing prices during outages in any event.

[xiii] Plants are able to vary the load anywhere between minimum load and full capacity, and while there are time-delays in moving from minimum to maximum load, the half-hourly production model assumes this is largely done instantaneously.

[xiv] The HHP Model calculated spot and GEC revenues along with variables costs based on the randomly assigned outages which occur during operations. Spot prices were drawn from AEMO and GEC prices from ICAP. Half-hourly spot revenues, GEC revenues and hedge ‘difference payments’ against spot price are calculated by the HHP Model and fed into the PF Model. Swap prices were taken using live ICAP market data with quantities and timing consistent with that set out in Table 2.

[xv] Note that seaborne gas prices in the Asia-Pacific region are materially higher than those prices currently prevailing in the domestic US market.

[xvi] Simshauser (2008) also noted that the market price cap would need to be raised to about $24,500/MWh in order to drive remunerative price levels. Of course, such a high price cap introduces a new risk – systemic stability.

[xvii] This excludes small/boutique generators below 200MW of capacity.

[xviii] There are also two small (government owned) vertically integrated franchise retailer/generators, one in QUEENSLAND and one in TAS.

[xix] In this article, we distinguish Merchant Power Producers from IPPs. We assume the latter holds a PPA to mitigate wholesale price risk, and by implication, risks to equity returns.

[xx] An investment grade credit rating is essential for writing PPA for new entrants. The issue here is that project financiers will assess the credit quality of the PPA counterparty before providing debt facilities. See Simshauser (2010) for further details on the relationship between credit ratings, PPAs and project finance.

[xxi] See ERIG (2006, pp 60-67) for a detailed analysis of the manner in which investment markets view VI firms vs. Merchant Power Producers.

[xxii] Victorian investments include $820 million in Mortlake and $3.1 billion in Loy Yang A, and NSW investments include the Gentrader contracts associated with Delta West ($540 million) and Eraring ($960 million). South Australia includes various wind farms from 2008, and we have assumed a capital cost for all new capacity at $2750/kW.

[xxiii] To produce these results, we took the published Annual Financial Accounts of the three state-owned generators and reversed-out a series of one-off charges against profits (i.e. asset impairment charges, onerous contract charges and other accounting entries relating to derivatives). Our intention was to identify the underlying

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operating earnings of the firm and had the effect of significantly increasing the apparent profitability of the firms in 2011.