The Western Australian Power Dilemma

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ABSTRACT

From 1984 gas-fired power generation had been gradually increasing its share of the electricity market in Western Australia (WA) starting at 1% and rising to about 50% by 2008. Had it continued on this trajectory, the WA power system would have made great advances in terms of cost and environmental efficiencies given the looming commencement of the Carbon Pollution Reduction Scheme in Australia from 2011. However, more recently the cost of natural gas has increased from \$3/GJ to \$7/GJ following the sudden collapse of the East Spar gas field in the North West Shelf. In this article, we analyse the impact of the gas price increase and demonstrate that despite being the most environmentally efficient conventional technology, Natural Gas Combined Cycle plant has been squeezed out of the market which in turn will increase forward electricity price risks to WA consumers through greater exposure to CO₂ pricing in the long run.

Keywords: Levelised Costs, Optimal Plant Mix, Power Generation, Carbon Price.

JEL Codes: D24, L11, L94 and Q41.

1. INTRODUCTION

Over the course of 2005-2007, the economics of new entrant conventional thermal power generating applications in WA fundamentally changed. Gas-fired generation dominated the investment frontier for new plant on WA's South West Interconnected System (SWIS) from 2003 with the development of the 220MW Cockburn Natural Gas Combined Cycle (NGCC) plant and the 280MW Pinjarra Cogeneration plant. More recently, this was most aptly demonstrated when a tender for 300MW of new base load capacity was awarded to a Natural Gas Combined Cycle (NGCC) plant over two competing coal projects in 2005.

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Coal-fired capacity historically dominated the Australian base load power market and at the time of writing continues to provide about 82% of Australia's power supply, esaa (2008). However, natural gas had been progressively penetrating the WA power market from 1984. Starting with a 1% market share of power production, gas-fired generation had risen to 44% by 2007 (esaa, (2008)). The addition of the 300MW base load NGCC plant to the SWIS market in 2008 would invariably drive the market share of gas fired generation to 50% or more in 2009. But the 2009 gas market share result is likely to represent a long run peak because of the step-change in the domestic price of natural gas that occurred between 2005 and 2007. Over this period of time, the cost of landed gas in the SWIS increased from about \$3/GJ to \$7/GJ, as noted by Wilson (2007), CCI (2007) and Frontier Economics (2008) amongst others.

The purpose of this article is to examine the implications of this step-change using a partial equilibrium model of the power system in order to illustrate the variation in probable near-term investment patterns. This article is structured as follows. Section II provides an overview of the supply-demand balance in the SWIS. Section III outlines the new entrant plant cost assumptions used in this article. Section IV describes the 'levelised cost model' which calculates the long run marginal cost of generating technologies given local resource endowments. In Section V, a supply-side model is described that determines the optimal mix of plant for a given power system. Section VI presents a demand-side model which projects hourly electricity demand based on historical load duration curves. Drawing on the model outlined in Section IV, the results from the levelised cost modelling in Section VII are presented. In Section VIII, we present the results from the Optimal Plant Mix Model described in Sections IV and V and sensitivity analysis is reported in Section IX. Section X examines policy options for WA that work to redress some of the adverse findings presented in this article with conclusions following in Section XI.

II. DEMAND-SUPPLY BALANCE IN POWER GENERATION IN WA

The SWIS is experiencing strong electricity demand growth by OECD standards. For instance, for the period 2006-2011, peak demand is forecast to increase by more than 4.5% per annum while energy demand has been forecast to rise at more than 3.4% per annum. Peak consumption is being driven by rapidly rising disposable household wealth (i.e. increased penetration of air-conditioning units and electric appliances) and energy demand is being driven by increased industrial activity. Forecast peak demand for the SWIS is published by the Independent Market Operator in WA (IMOWA) - for example, see IMOWA (2008) and Appendix I of this article.

From a supply-side perspective, the SWIS largely followed the trend of the eastern seaboard in that it started the current decade in a state of relative oversupply with reserve plant margins of 28% or more (esaa (2002)) against the ideal benchmark of 18% defined by the IMOWA (IMOWA (2006)). However, by 2006 the SWIS had reverted to a state of undersupply and remained so during 2007. Newly constructed capacity would alleviate the system in 2008, but expected plant closures would ensure that by 2009 the system would once again be undersupplied.³ This pattern is illustrated in Table 1. The significance of the power system being undersupplied is that in the absence of substantial demand management, blackouts become predictable under extreme weather or multiple generator contingency conditions – and given the political economy of electricity supply, this represents a situation that few OECD Governments consider tenable.⁴

³ For example, it has been reported by IMOWA that Verve Energy (the state owned generator) closed 200MW of coal plant in 2007, and has earmarked 200MW of gas plant for closure in 2008 and a further 200MW of coal plant in 2009, see IMOWA (2006).

⁴ Demand management should not be overstated. In Australia, typically less than 1% of aggregate demand is responsive to a short term change in price.

Table 1. Demand/Supply balance for the SWIS 2002-2009

Demand/Supply		2002	2003	2004	2005	2006	2007	2008	2009
Maximum demand	(MW)	2,473	2,678	2,859	2,886	3,237	3,394	3,398	3,824
Reserve margin	(MW)	445	482	515	519	583	611	612	688
Total plant required	(MW)	2,900	3,200	3,400	3,400	3,800	4,000	4,000	4,500
Aggregate supply	(MW)	3,300	3,300	3,500	3,500	3,700	3,800	4,000	4,300
Over/Undersupplied	(MW)	400	100	100	100	-100	-200	0	-200

Source: Data from appendix 1

III. ENTRY COST ASSUMPTIONS FOR POWER GENERATION IN WA

Power station capacity is not simply added to a system based on lowest average cost. The reason for this is that electricity load on any given power system varies according to the time-of-day and between seasons (e.g. hot, cold and mild). Consequently, all power systems need a mix of plant, and for a given load curve there exists an optimal combination of base, intermediate and peak load plant that will minimise the cost of supply.

By definition, base load plant has the lowest overall average cost of production as measured by dollars per Megawatt Hour (\$/MWh). Base plant have low marginal running costs with high fixed costs and are therefore suited to high Annual Capacity Factor (ACF) running. Peak load plants have the reverse blend of costs, i.e. high marginal running costs with low fixed costs, and are most suited to low ACF or emergency production duties, and tend to set high prices when operating. Intermediate plant sits between base and peak load plant in terms of costs and production duties. Additionally, because electricity load is unpredictable and because power stations require periodic maintenance and are subject to unexpected outages, all power systems require a 'reserve plant margin'. The reserve plant margin is crafted so that the power system can withstand demand- or supply-side capacity shocks and continue to deliver power to consumers and, as noted earlier, is considered optimal for WA at 18%.⁵

The importance of the relative cost of entry of the various technologies is intuitively logical in that it determines the extent to which base plant operates vis-à-vis intermediate plant duties, and the extent to which power is provided by coal or gas technologies, at least in the case of the SWIS where, as with the rest of Australia, limited hydro resources exist and nuclear technologies are prohibited. While renewable sources can be added, biomass resources are limited and the small and isolated nature of the SWIS means that there are technical limits to the amount of 'intermittent' wind power that can be added given the requirement for power system stability.

Over the most recent two years, entry conditions have changed dramatically in the SWIS. At the start of 2005, the domestic price of natural gas was about \$2.20/GJ commodity with a haulage cost of approximately \$1.00/GJ, totalling \$3.20/GJ 'landed'. By 2007, the landed cost had risen to \$7/GJ. There were two reasons for this. First, an unexpected collapse of a key gas resource (East Spar field) severely impacted available supply. Second, the North West Shelf Joint Venturers who held the vast (remaining) gas supply resources were more focused on gas extraction for the purposes of seaborne LNG trade rather than the supply of domestic natural gas. The impact of the Varanus Island gas processing facility explosion off the North West Shelf in mid-2008 temporarily sent prices above \$10/GJ, although its restoration has led to prices falling back down to the \$7/GJ mark.

That the cost of gas has risen from \$3.20/GJ to \$7/GJ is very significant in the context of the SWIS.⁶ With indigenous (non-export quality⁷) thermal coal priced at \$1.75/GJ, as modelling

⁵ Joskow (2008) notes that reserve plant margins in the US generally lie within the 15-20% range.

⁶ Incumbent plant listed in Appendix I that signed long-term fuel contracts prior to 2005 would be shielded from the current rise in the cost of natural gas (or indeed the fall in the cost of non-export quality coal, which is thought to have fallen from \$2.50/GJ to about \$1.75/GJ). This obviously applies until existing contracts expire.

results later reveal, the step-change in the unit cost of gas has reversed what was otherwise the projected unwinding of a highly carbon intensive industry in WA by squeezing new NGCC plant out of the market. To make matters worse, in addition to the rising cost of natural gas, the resources boom in WA has depleted construction labour stocks, while the global demand for power generating applications has led to a tightening of turbine prices. Thus, over the past two years, the underlying cost of all power generating applications has risen dramatically due to the rising cost of capital components and in the case of gas turbines, the rising cost of fuel. These changes will drive very different outcomes in terms of future plant developments. However, in order to understand how these changes will impact on near-term plant investment patterns, it is first necessary to outline our methodological approach which encompasses the Levelised Cost of Plant and Optimal Plant Mix models.

Recent economic literature on optimal investment has drawn heavily from developments in Finance. The seminal academic reference for this work is Dixit and Pindyck (1994). In this material, two key aspects have been emphasized. First, investment decisions are irreversible in nature. Second, price and output movements (and uncertainty) are modelled as stochastic processes with almost universal recourse to continuous-time Geometric Brownian Motion (GBM) Models (Dixit and Pindyck (1994, Ch. 2-5)).

In this article, we do not employ the framework advocated in Dixit and Pindyck (1994).⁸ The reason for this is that first, we have doubts about whether the GBM model can adequately describe key characteristics including evident periodicity in both half-hourly load and spot price time series data (Foster, Hinich and Wild (2008)). In this context, we note that Dixit and Pindyck (1994) assume that the GBM model is an adequate model without justification of why this is the case.

Second, the vast capital cost of power generating applications (ranging between \$400m and \$1100m in the case of the SWIS) has meant that all new developments in WA since 2003 have been Project Financed with between 65-80% debt capital. Project Finance banks do not account for the value of real options associated with a power station when sizing the initial debt facility, but rather, focus on the expected 'base case' cash flows and examine sensitivities to test for any downside bias. Real options will assist credit approval from a qualitative perspective, but not quantitatively. The experience of the authors with equity financing is similar – the expected 'base case' must at least meet the expected cost of equity whereas real options represent the project's potential for delivering 'abnormal returns' and thus will tend to support a 'go' decision rather than provide the underlying basis for a given power station investment. This is because early-year cash flows are critical to the financial stability of project financed capital-intensive investments.

Third, while investment has irreversible features, firms in electricity markets do not have a 'monopoly on opportunity'. In a competitive market, if a firm does not move on an investment opportunity when an apparent positive NPV project arises, there is a risk that someone else will invest ahead of them, subsequently stranding the firm's investment opportunity for a (perhaps significant) future period of time. This can be very problematic for firms because of the substantial holding costs associated with a power station site, and more significantly, the cost of holding 'slots' in turbine manufacturing queues.⁹ This consideration typically mitigates the affect that irreversibility has on the decision to invest. Conversely, if all firms collectively delayed investment plans on the grounds of irreversibility, supply would fall short of requirements leading

⁷ An anonymous referee noted that this is important, as it de-links the absolute level and volatility of the price of local coal with export coal.

⁸ An investigation of the role of uncertainty within the context of a central planning framework is contained in Turvey and Anderson (1977), Ch 14.

⁹ Power generating equipment has lead construction times of 24-48 months (depending on the technology) and long manufacturing times for pre-fabricated components such as turbines, step-up transformers and so on. At the time of writing, delays of up to three years existed for some components due to high global demand for new power station facilities.

to blackouts. As noted earlier, given the political economy of electricity, this is untenable for governments and is likely to be met by a policy response – an undesirable and more than theoretical possibility that is particularly well understood by private sector market participants.

Finally, our emphasis is not strictly on the decision-making of an individual firm per se. Our focus, instead, is on the optimal plant mix for the system as a whole given demand projections, feasible cost/technology assumptions and a least cost solution that heuristically mirrors the ‘DC OPF’ solutions implemented by the wholesale electricity market operators in Australia, including NEMMCO (East Coast Australia) and IMOWA (Western Australia).¹⁰

In this article, as is the case in application, the effect of uncertainty in our analysis will be undertaken by performing scenario analysis in order to see how sensitive our main findings are to variations in key data that are viewed as being particularly uncertain in character. Two main variables will be considered to be uncertain. The first is the load forecast itself. This reflects the fact that these forecasts are notoriously ‘risky’ data sets. The second will be the gas price shock. On the other hand, the plant costs details (set out in Table 2 below) are themselves fairly predictable to the extent that they have historically risen over time. Nonetheless, we also present sensitivity analysis based upon variations in plant capital cost (\$/kW), cost of capital and inflation rate. These particular scenarios allow us to test the sensitivity of our key findings to variations in the underlying macroeconomic conditions confronting the electricity industry. For example, increases in the cost of capital will capture the tightening in debt and equity finance associated with the credit crisis while increases in the inflation rate will reflect the situation where the actual rate of inflation is at the top end of the Reserve Bank of Australia’s preferred inflation target range.

In order to derive levelised costs of new entrant plant and the optimal plant mix for a power system, a number of key cost and working assumptions need to be made. These important assumptions are illustrated in Table 2:

Table 2. Generation technology cost assumptions¹¹

Generation technology	Capital cost in 2005 (\$/kW)	Capital cost in 2008 (\$/kW)	Unit size (MW)	Variable O&M (\$/MWh)	Fixed O&M (\$M pa)	Useful life (Yrs)	Heat rate (kJ/kWh)	Fuel cost in 2005 (\$/GJ)	Fuel cost in 2008 (\$/GJ)	Auxiliary load (%)
SCpf	1,500	2,500	350	1.00	12.0	40	9,800	1.75	1.75	7.00
NGCC	1,100	1,550	300	2.50	4.5	30	7,800	3.20	7.00	1.00
OCGT	750	1,000	150	8.00	2.0	30	11,500	4.00	7.50	0.00
Cost of capital		11.00%	Annual Inflation		2.50%					

The parameters in Table 2 provide cost estimates of the key components of the three dominant generating technologies used in the SWIS, including Sub-Critical pulverized fuel (SCpf) for base load applications, Natural Gas Combined Cycle (NGCC) for base and intermediate load plant, and Open Cycle Gas Turbines (OCGT) for peak load duties. Two capital cost estimates and two fuel cost estimates have been provided, for 2005 and 2008 respectively.

The cost of capital on a weighted basis is assumed to be 11% (nominal, pre-tax) and long run inflation is assumed to prevail at the midpoint of the Reserve Bank of Australia’s official target range, at 2.5%. The basis upon which inflation is applied to all subsequent modelling is at full CPI against (non-finance) operating cost streams, and only $\frac{3}{4}$ CPI against revenue streams. This reflects real-world trends in power generation, and the CPI disconnect is logical given that

¹⁰ NEMMCO: National Electricity Market Management Company. IMOWA: Independent Market Operator of Western Australia.

¹¹ One reviewer noted that there was an insufficient spread between the cost of unity load factor gas for the NGCC plant and shaped-gas for the OCGT plant (e.g. \$3.20/GJ vs. \$4.00/GJ in 2005). But the capital cost of the OCGT includes the cost of a gas lateral pipeline in which unity load factor gas can be purchased and stored for subsequent release during peak periods.

financing costs, which form the dominant cost of power applications, tend to be fixed up-front. The time profile of the ‘inflation stream’ escalation rates are calculated as

$$\inf l(t)_R = \left\{ \left[1 + \left(\frac{2.5}{100} \right) \right] * \alpha_R \right\}^t, \text{ and } \inf l(t)_C = \left\{ \left[1 + \left(\frac{2.5}{100} \right) \right] * \alpha_C \right\}^t,$$

where subscripts ‘R’ and ‘C’ denote revenue and cost and we assume that $\alpha_R = 0.75$ and $\alpha_C = 1.0$. Variable ‘t’ is defined to represent a discrete time index starting in the first period of the projection horizon and containing ‘N’ time periods (*i.e.* $t = 1, \dots, N$) with parameter N corresponding to the useful life statistics outlined Table 2.¹²

IV. THE ‘LEVELISED COST’ OF ENTRY MODEL

We now outline the ‘levelised cost’ of new entrant plant. In broad terms this involves calculating the present value of the time profile of annualised plant costs deflated by the time profile of revenue accruing to the plant over its lifespan. We assume that the revenue stream is proportional to the output of each plant. The energy generated gives a measure of the output of each generation plant and can be represented as

$$ES(t)_j = US_j * ACF_j * 8.76 * ESF(t)_j \quad (1)$$

where $ES(t)_j$ is the energy generated by plant type ‘j’,¹³ US_j is the constant unit size for each type of plant described in Table 2, ACF_j is the constant annual capacity factor assumed for each plant, 8.76 is the number of hours in a year divided by 1000 and $ESF(t)_j$ is an energy scale factor for each type of plant.¹⁴

The revenue stream for each generator is calculated by applying the assumed revenue ‘inflation escalation rate’ to the output generated by each respective generator. This is given by

$$RS(t)_j = ES(t)_j * \inf l(t)_R, \quad (2)$$

where $RS(t)_j$ is the revenue stream of each generating plant ‘j’, $ES(t)_j$ is the energy generated by plant, and $\inf l(t)_R$ is the ‘inflation escalation rate’ applied to generator revenue defined in Section III.

In defining annualized plant costs, it is necessary to split them into marginal running costs and fixed costs. Aggregate marginal running costs can be categorized as fuel cost and variable operations and maintenance costs. Aggregate fixed operating cost can be split into operations, maintenance and depreciation cost components. In terms of the marginal running cost of power generating applications, the crucial component is the cost of fuel expressed in dollars per Gigajoule (\$/GJ) which is linked to the type of technology underpinning power generation. This can be expressed as

$$FC(t)_j = \left(\frac{HR_j * GFC_j}{1000} \right) * ES(t)_j * \inf l(t)_C, \quad (3)$$

¹² If a variable does not have ‘(t)’, then it is to be regarded as a constant parameter, like, for example, one of the static parameters cited in Table 2.

¹³ Subscript ‘j’ can take values $j = b, i, p$, where ‘b’ refers to base load (*SCpf* or *NGCC*) plant, ‘i’ refers to intermediate (*NGCC*) plant and ‘p’ refers to peak load (*OCGT*) plant.

¹⁴ The values assigned to these latter two variables will be outlined in Section VIII.

where $FC(t)_j$ is the fuel cost of generating plant 'j', HR_j is the constant heat rate of each type of generator listed in Table 2, GFC_j is the constant generator fuel cost for each generator in Table 2, $ES(t)_j$ is energy sent out as defined above and $\inf l(t)_C$ is the 'inflation escalation rate' applied to generator costs outlined in Section III.

Recall that generator Operations and Maintenance (O&M) costs comprise two components – fixed and variable costs. The variable O&M cost can be calculated as

$$VARC(t)_j^v = UVAR_j * ES(t)_j * \inf l(t)_C, \quad (4)$$

where $VARC(t)_j^v$ is the variable O&M cost of plant 'j', $UVAR_j$ is the constant unit variable O&M cost rate for each generator in Table 2, and where variables $ES(t)_j$ and $\inf l(t)_C$ were defined above.¹⁵ The fixed O&M cost can be calculated as

$$VARC(t)_j^f = FIXC_j * 1000 * \inf l(t)_C, \quad (5)$$

where $VARC(t)_j^f$ is the fixed O&M cost of plant 'j' and $FIXC_j$ is the constant fixed O&M cost for each generator listed in Table 2. The total O&M cost $VARC(t)_j$ for each generator is obtained by summing the fixed and variable O&M costs, giving

$$VARC(t)_j = VARC(t)_j^f + VARC(t)_j^v. \quad (6)$$

The other fixed cost component is the maintenance capital expenditure allowance allocated by generator 'j'. This expense item is given by

$$MCAP(t)_j = MCAPEX_j * CAPEX_j * \inf l(t)_C, \quad (7)$$

where $MCAP(t)_j$ is the nominal depreciation allowance for each plant 'j', $MCAPEX_j$ is the constant capital maintenance rate for each generator type and $CAPEX_j$ is the nominal amount of 'upfront' capital expenditure associated with establishing each type of generator.¹⁶ Variable $MCAPEX_j$ can be interpreted as giving the annual amount of capital expenditure (as a percentage of upfront capital expenditure $CAPEX_j$) that is required for ongoing capital maintenance to ensure that existing units continue to operate at 'top working order'. In this article, the following parameter settings were assumed for $MCAPEX_j$:

$$MCAPEX_b = 0.25\% ; MCAPEX_i = 0.05\% ; MCAPEX_p = 0.05\% .$$

Total Operating Costs by generator ($TGC(t)_j$) equals the sum of fuel costs $FC(t)_j$, total O&M costs $VARC(t)_j$ and maintenance capital expenditure $MCAP(t)_j$, giving

$$TGC(t)_j = FC(t)_j + VARC(t)_j + MCAP(t)_j. \quad (8)$$

¹⁵ In order to avoid the tedious duplication of terminology, any model variable or parameter appearing in equations which have already been defined in earlier parts of the article will not be subsequently re-defined in the explanation of later equations.

¹⁶ The capital stock employed, denoted $CAPEX_j$, can be calculated by multiplying the unit capital cost (\$/kW) variable by the unit size (MW) variable, both of which are documented in Table 2.

It should be noted that $TGC(t)_j$ does not incorporate returns on the capital stock employed at the marginal efficiency of capital, which has been defined in Table 2 as 11% (weighted average).¹⁷

The measure of real unit cost or long run marginal cost (including capital costs) is given by calculating the Present Value (PV) of the total cost stream $TCPV_j$ and deflating this by the present value of the revenue stream $TRPV_j$. This is then adjusted by the amount of power that is expected to be consumed internally, referred to as ‘auxiliary load’ and represented by an expense weighting factor AUX_j in Table 2.¹⁸ This gives

$$TCPV_j = PV(TGC(t)_j) + CAPEX_j, \quad (9)$$

$$TRPV_j = PV(RS(t)_j), \quad (10)$$

and with the long run marginal cost being calculated as

$$LRMC_j = TCPV_j / TRPV_j / (1 - AUX_j). \quad (11)$$

It should be recognized that the cost of debt and equity emerge from the PV calculation in (9) via the process of discounting the cash flows at a discount rate of 11% which represents the weighted average cost of debt and equity capital. Furthermore, the discount rate can also be interpreted as a pre-tax marginal efficiency of capital so we do not have to explicitly account for any implied tax liability – this is implied in the discounting process underpinning the PV calculation in (9). Therefore, the pre-tax cost of capital can be determined as the difference between the LRMC and the sum of operational costs which reflect fuel and aggregate O&M expenses. Conceptually, the ‘residual’ cost of capital would include debt and equity costs, implied tax liability and capital retirements relating to principal repayments on debt and the return of equity capital.

V. THE ‘OPTIMAL PLANT MIX’ MODEL

We now outline the ‘Optimal Plant Mix’ model. In broad terms this involves projecting the costs of various technologies for ACF’s ranging from 0% to 100%. Once these technology cost paths are calculated, the cross-over points can be determined which then provides the optimum level of base plant, intermediate plant, and peaking plant – effectively representing the efficient frontier of generation plant investment. This can then be compared against actual plant stocks with the variations highlighting which type of plant should be added to the power system.

Given this outline, it is evident that ‘levelised’ costs form an essential input into the modelling process and from the cost concepts outlined in Section IV, a series of summary ‘levelised’ static cost measures can be calculated. The first is average (unit) fixed and variable costs. Average unit variable cost is calculated as the sum of unit fuel and unit O&M variable costs and can be represented as

$$UVC_j = \left(\frac{(HR_j * GFC_j)}{1000} \right) + UVAR_j, \quad (12)$$

¹⁷ The 11% pre-tax marginal efficiency of capital is applied to ungeared cash flows, with the implication being that a power project would be financed with 65% debt and 35% equity. The equivalent post-tax weighted average cost of capital is approximately 8%.

¹⁸ SCpf plant typically consumes 7% of its nameplate capacity. Thus a 350MW unit will generate 350MW of power when operating at full load but will consume about 24.5MW in the process. Thus, the energy generated is 350MW, but the energy sent out (i.e. the sales component) is only 325.5MW. In equation (11) the ‘weighting’ given to power sent out is represented by the last ‘(1-AUXj)’ term which equates to 93 percent of total power produced in the case of SCpf plant assuming an auxiliary load factor of 7 percent.

where UVC_j is the average unit variable cost for plant 'j', HR_j is the constant heat rate of each generator, GFC_j is the constant fuel cost for each type of generator, and $UVAR_j$ is the constant unit variable O&M cost rate of each generator, all of which are listed in Table 2.

The average unit fixed cost is calculated as a residual - as the difference between the long run marginal cost and unit variable costs calculated immediately above. It therefore incorporates the fixed costs of O&M, ongoing capital expenditure, depreciation (i.e. the return of capital) and a return on capital at the marginal efficiency of capital. Moreover, because the marginal efficiency of capital is a pre-tax weighted average cost of capital, by implication, it also includes the implied corporate taxation costs liable to be paid by a profit seeking generator. This can be represented as

$$UFC_j = LRMC_j - UVC_j. \quad (13)$$

The next summary cost measure is annual fixed running cost (ARC_j^f).¹⁹ This cost measure represents the fixed costs that apply irrespective of whether the generation plant operates – that is, irrespective of whether the plant actually produces any power. It includes fixed O&M, depreciation charges and returns on capital deployed. Because this definition includes a normal profit as a part of the fixed cost structure, it represents the concepts identified in microeconomic theory as opposed to accounting theory, and is viewed as a lump sum cost defined in terms of (\$/pa).

The next series of summary measures are the quantile Distributions of Generator Output and Costs. We calculate the quantile distribution of generator output (GWh) defined over the quantile range established by the discrete index set $q_l : l = 0, \dots, 100$. The quantile distribution of generator output is calculated as

$$QGO_j^l = US_j * 8.76 * \left(\frac{l}{100} \right), \text{ for } l = 0, \dots, 100, \quad (14)$$

where QGO_j^l is the quantile value of generator output for generator 'j' and quantile 'l', US_j is constant unit size for each plant type listed in Table 2 and $\{l = 0, \dots, 100\}$ is the quantile index. The quantile distribution of generator costs (\$/pa) can similarly be defined over the quantile range $q_l : l = 0, \dots, 100$. The quantile distribution of generator cost by generator is given by

$$QGC_j^l = ARC_j^f + UVC_j * QGO_j^l, \text{ for } l = 0, \dots, 100, \quad (15)$$

where QGC_j^l is the quantile value of generator cost for generator 'j' and quantile 'l', ARC_j^f is annual fixed running costs and UVC_j , QGO_j^l and quantile index 'l' were defined above.

To calculate the annualised unit generator cost ($QUGC_j^l$), defined in terms of (\$/kW/a), we divide the total annual running cost (QGC_j^l) by the unit size of the plant (US_j) displayed in Table 2. For each generator 'j', this is given by

$$QUGC_j^l = \frac{QGC_j^l}{US_j}, \text{ for } l = 0, \dots, 100. \quad (16)$$

¹⁹ For each generator, annual fixed running costs can be calculated by multiplying average unit fixed costs by energy sent out.

To produce generator cross-over paths which form the efficient investment frontier for generation plant, we calculate cross-over points as the difference between the annualised unit generator cost ($QUGC_j^l$) for different types of generators. Specifically, the ‘base load-intermediate’ plant crossover path is given by

$$CO_{b,i}^l = QUGC_b^l - QUGC_i^l, \text{ for } l = 0, \dots, 100, \quad (17)$$

while the ‘intermediate-peak’ plant cross-over path can be calculated as

$$CO_{i,p}^l = QUGC_i^l - QUGC_p^l, \text{ for } l = 0, \dots, 100. \quad (18)$$

To calculate the extent to which base load plant is optimal, we implement the following decision rule (solving for $GOPT_b^l$ for each $l = 0, \dots, 100$):

$$\text{if } CO_{b,i}^l \begin{cases} = 0, & GOPT_b^l = \left(\frac{l}{100} \right) \\ \neq 0, & \begin{cases} \text{if } (CO_{b,i}^l > 0, \text{ and } CO_{b,i}^{l+1} < 0), \text{ then } GOPT_b^l = \left(\frac{l+1}{100} \right). \\ \text{else} & GOPT_b^l = 0 \end{cases} \end{cases} \quad (19)$$

To determine the overall optimality value in percentage terms for base load plant, we sum the $GOPT_b^l$ sequence over the quantile index values $l = 0, \dots, 100$, producing

$$GOPT_b = \sum_{l=0}^{100} GOPT_b^l. \quad (20)$$

Using the 2005 capital and fuel cost data contained in Table 2, a value of 94 percent was determined for variable $GOPT_b$. Using the 2008 capital and fuel cost data, a value of 37 percent was obtained for variable $GOPT_b$.²⁰

To calculate the extent to which intermediate plant is optimal, we implement the following decision rule (once again, solving for $GOPT_i^l$ for each index value $l = 0, \dots, 100$):

$$\text{if } CO_{i,p}^l \begin{cases} = 0, & GOPT_i^l = \left(\frac{l}{100} \right) \\ \neq 0, & \begin{cases} \text{if } (CO_{i,p}^l > 0, \text{ and } CO_{i,p}^{l+1} < 0), \text{ then } GOPT_i^l = \left(\frac{l+1}{100} \right). \\ \text{else} & GOPT_i^l = 0 \end{cases} \end{cases} \quad (21)$$

Once again, to determine the overall optimality value (in percentage terms) for intermediate plant, we sum the $GOPT_i^l$, over the index range $l = 0, \dots, 100$, yielding

$$GOPT_i = \sum_{l=0}^{100} GOPT_i^l. \quad (22)$$

²⁰ A result of 94% is important and requires additional interpretation. Few power plants are capable of operating at 94% ACF year-on-year due to planned and forced maintenance outages, which typically equate to 8% per annum. But more importantly, in the specific case of WA, because aggregate overnight electricity load falls to such low levels it is physically impossible for base plant to operate at high load factors without disrupting the operations of other plant (i.e. supply exceeds demand in the middle of the night). Thus since NGCC plant spans the range between 20% (see equation 21) and 94% (i.e. the maximum practical ACF), it is likely to be the technology of choice for base and intermediate duties.

Using the 2005 capital and fuel cost data contained in Table 2, a value of 20 percent was obtained for variable $GOPT_i$. Similarly, from the 2008 capital and fuel cost data, a value of 25 percent was determined for variable $GOPT_i$.

VI. CALCULATING THE LOAD DURATION CURVE FOR THE OPTIMAL PLANT MIX MODEL

The Optimal Plant Mix model requires a load duration curve to be provided. A load duration curve is a representation of hourly electricity load, typically for a given year, with the data ranked in descending order. In this article, a forecast load duration curve has been established by reference to the peak load point estimate reported in IMOWA (2008) which has been illustrated in Figure 1. Once the peak load point estimate has been set, a schedule of hourly load is determined by applying a block load factor and load scaling factor to an existing (historical) load duration schedule to extrapolate the projected schedule on the basis of expected changes in peak load demand characteristics in the future.

The load scaling factor can be calculated as

$$lsf = \frac{(tgwh_{pro} - yhrs * mload_{pro})}{(energy_{bas} - yhrs * mload_{bas})}, \quad (23)$$

where lsf is the load scaling factor, $tgwh_{pro}$ is the GWh energy level for the ‘projection’ period, $yhrs$ is the number of hours in a year, $mload_{pro}$ and $mload_{bas}$ are the maximum peak demand in the ‘projection’ and ‘base’ periods respectively, and $energy_{bas}$ is the actual energy produced in order to satisfy the load demand prevailing in the ‘base’ period. Variable $yhrs$ is calculated as $yhrs = (365 * 24) = 8760$.

In order to demonstrate how future load duration curves can be projected from existing historical curves, suppose that the ‘projection’ period corresponds to financial year 2007/08 (FY08), with the ‘base’ period corresponding to financial year 2003/04. A value of 3398 was set for variable $mload_{pro}$ in FY08 and a value for variable $tgwh_{pro}$ was set to 16442 in FY08, respectively. This information was sourced from IMOWA (2008). The historical values for $mload_{bas}$ and $energy_{bas}$ were determined to be 2859 and 13374, respectively. After these parameter values were substituted into (23), we obtained a value for lsf_{08} of 1.1886 for FY08.²¹

The block load factor can be determined from

$$blf = (mload_{pro} - mload_{bas} * lsf), \quad (24)$$

where blf is the block load factor and lsf is the load scaling factor calculated immediately above. Given the above parameter settings, we obtain a value for blf_{08} of (0.0623) for FY08.

The projected load duration curve for FY08 can be projected from the following relation

$$ldc_{pro}^l = blf_{08} + lsf_{08} * ldc_{bas}^l, \quad (25)$$

²¹ Load duration curves for FY09 and FY10 will also be needed to complete model projections for the period 2008/09-2009/10 cited in Appendix III with data for both variables $tgwh_{pro}$ and $mload_{pro}$ being sourced from IMOWA (2008).

where ldc_{pro}^l is the projected load duration curve for FY08 at the quantile percentage ' l ', ldc_{bas}^l is the actual (historical) load duration curve for FY04 at the quantile percentage ' l '. Variable ' blf ' is the block load factor defined in (24) and acts as an intercept term in (25) while variable ' lsf ' is the load scale factor defined in (23) and acts as a slope parameter in (25). Variable ' l ' represents a percentage quantile index counter defined over the index range $l = 0, \dots, 100$ and increments in steps of 0.0113 of a percent.

In this article, we calculate three load duration curves in order to test how sensitive our conclusions are to uncertainty surrounding future load demand projections. Specially, the uncertainty (variation) in demand reflects three different sets of assumptions about the projected maximum hourly peak demand estimate and projected GWh energy demand expected to be consumed in each year for which optimal plant mixes are to be calculated.

This data was obtained from IMOWA (2008). The specific demand forecasts correspond to those associated with the 10% , 50% and 90% 'Probability of Exceedence' (PoE10, PoE50 and PoE90 respectively) standards which reflect demand forecasts that have been constructed using different assumptions about prevailing weather conditions and economic growth scenarios (IMOWA (2008)). As with any power system forecast, our baseline demand configuration is associated with the PoE50 scenario associated with a standard or median weather forecast and a median level of economic growth and energy consumption that is expected to prevail in each year of the forecast horizon. In order to undertake sensitivity analysis, however, we also adopted peak demand and energy consumption configurations for extreme high (PoE10) and extreme low (PoE90) growth scenarios.²² The data associated with all three scenarios are listed in Appendix I, and clearly provide a superior and more realistic approach to assessing the effect of uncertainty upon results than assuming that load demand evolves according to a GBM process as would be commonly employed in models utilizing the Dixit and Pindyck (1994) methodology, for example.

VII. MODEL RESULTS: LEVELISED COST OF ENTRY IN THE BASE LOAD MARKET

Before analyzing the Optimal Plant Mix model results for WA, it is useful to review the key input into the model, i.e. the 'levelised' cost of entry. Table 3 presents the results for SCpf and NGCC plant operating in base load duty, in both 2005 dollars and in 2008 dollars.

Table 3. Levelised cost of entry for base load applications at 92% ACF

TABLE 3a - gas at \$7/GJ in 2008				TABLE 3b - gas at \$5/GJ in 2008			
Techology	2005	2008	Change	Techology	2005	2008	Change
SCpf	\$45.24	\$58.20	\$12.95	SCpf	\$45.24	\$58.20	\$6.48
NGCC	\$45.08	\$82.41	\$37.33	NGCC	\$45.08	\$65.70	\$15.82
Difference	\$0.16	-\$24.21		Difference	\$0.16	-\$7.50	

Note that at a 92% ACF, in 2005 NGCC plant was the lowest cost solution by \$0.16/MWh in Table 3a. If the plant technologies were required to operate at a lower ACF, this would advantage the NGCC plant even further because: (1) it has a lower capital commitment at only \$1100/kW compared to coal at \$1500/kW; and (2) it has higher relative marginal running costs and thus when it reduces output, it avoids a proportionately greater level of cost. However, the inverse is also true. At an ACF greater than 94%, the SCpf plant becomes the lowest cost producer. While an ACF of 100% is a theoretical maximum output level, a practical sustainable maximum ACF would be less than 94% per annum due to statutory maintenance outages, unexpected plant

²² See the notes to Appendix III about the optimal plant mix scenarios.

breakdowns, and indeed low overnight (off-peak) loads which are required to sustain continuous operation. This latter point is particularly relevant in the case of the SWIS where the load factor (circa 55-59%) is poor by Australian standards (circa 62-68%).

It is also evident from inspection of Table 3a that a rise in the cost of gas to \$7/GJ causes a fundamental shift in the long run unit cost structure when compared with the results arising in 2005. We also examined how sensitive results were to uncertainty about future natural gas prices beyond the high observed in 2007 and 2008. This consideration reflects uncertainty over whether the ‘gas price shock’ arising in 2007 was, in fact, a temporary or permanent event. To account for this possibility another scenario has been investigated whereby the gas price moves back partially towards the lower 2005 level to \$5/GJ. This should be interpreted as a lower bound on prevailing private sector gas price forecasts that exist at the time of writing.²³ Table 3b highlights that the shift in the long run unit cost structure of both plant types has partially turned around, but still remains reversed when compared against the 2005 unit cost structure.

VIII. MODEL RESULTS: OPTIMAL PLANT MIX

In this section, we present the results on Optimal Plant Mix as described in Section V, along with the load duration curve described in Section VI. Combined, these two models form the Boiteux (1949) and Berrie (1967) static partial equilibrium framework for solving the optimal plant mix for a given load curve. Here, we have described this as the Boiteux/Berrie model and is presented graphically in the first instance, in Figure 1:

²³ When we adopt a gas price of \$5/GJ the OCGT/NGCC optimal cross over is 28% and the NGCC/SCpf optimal cross over is 64%, compared with 25% and 37% at \$7/GJ as illustrated in Figure 2.

Figure 1: Boiteux/Berrie Static Partial Equilibrium for the 2008 WA load curve

The top panel of Figure 1 presents ‘running cost curves’, with the x-axis measuring the annual cost of production (\$/kW/a) and the y-axis representing the power station ACF. The manner in which to interpret the panel is that the y-axis intercept represents the annual fixed costs of production whereas the slope of the line represents the marginal running cost of the plant. To derive the data displayed in Figure 1, the following parameter settings associated with equation (1) were adopted:

$$ACF_b = 0.92; ACF_i = 0.92; ACF_p = 0.2.$$

$$ESF(t)_b = 1.0 \text{ if } t \leq 30; ESF(t)_b = 0.6 \text{ if } 30 > t \leq 39; \text{ and } ESF(t)_b = 0.3 \text{ if } t > 39.$$

$$ESF(t)_i = 1.0 \text{ if } t \leq 25; ESF(t)_i = 0.7 \text{ if } 26 > t \leq 29; \text{ and } ESF(t)_i = 0.49 \text{ if } t > 29.$$

$$ESF(t)_p = 1.0 \text{ if } t \leq 25; ESF(t)_p = 0.7 \text{ if } 26 > t \leq 29; \text{ and } ESF(t)_p = 0.49 \text{ if } t > 29.$$

In order to determine the optimal portfolio shares for different types of generating plant, the optimal amount of base load plant capacity is associated with the 94 percent ‘quantile’ of the projected FY08 load duration curve which corresponded to 1273MW. Note that the ‘94 percent’ value was determined from (20) above. Similarly, the optimal amount of intermediate plant capacity is determined from the 20 percent quantile of the projected load duration curve (yielding 2114MW) and then netting off the existing contribution of base load plant determined above producing $(2114-1273) = 842\text{MW}$. The ‘20 percent’ value was determined from equation (22).

The total (MW) plant requirement for the system as a whole is calculated from the maximum projected FY08 peak load demand (of 3398MW) and assumed 18% reserve margin producing a total projected plant requirement of $(3398 \times 1.18) = 4010\text{MW}$. The optimal level of peaking plant capacity is calculated as the difference between the total plant requirement and sum of optimal base and intermediate plant, yielding an optimal level of peak plant of $[4010 - (1273 + 842)] = 1896\text{MW}$.

To determine the final optimal portfolio compositions, we need to account for expected plant outages. We assume an outage rate of 10% for base load plant and 15% for intermediate plant, approximating availability statistics reported by esaa (2006). The new optimal portfolio shares (upon rounding to the nearest integer) were determined to be $(1273/0.9/100) \times 100 = 1400\text{MW}$ for base load plant and $(842/0.85/100) \times 100 = 1000\text{MW}$ for intermediate plant and with the total plant requirement being given by $(4010/100) \times 100 = 4000\text{MW}$. The revised optimal peak plant share is calculated as a residual giving $[4000 - (1400 + 1000)] = 1600\text{MW}$. Taking these values away from the actual portfolio shares determine whether the underlying portfolio balance for each type of plant is underweight or overweight. The results and comparison with actual plant stock are illustrated in Panel 1 of Table 4:

Table 4. Optimal plant mix for 2008 with differing gas prices

PANEL 1. 2005 Cost Structure: \$3.20/GJ				PANEL 2. 2008 Cost Structure: \$7/GJ				PANEL 3. Alternative Cost Structure: \$5/GJ			
	Optimal	Actual	Portfolio Balance		Optimal	Actual	Portfolio Balance		Optimal	Actual	Portfolio Balance
Baseload	1400	1900	500	Baseload	2200	1900	-300	Baseload	1800	1900	100
Intermed	1000	600	-400	Intermed	100	600	500	Intermed	500	600	100
Peaking	1600	1500	-100	Peaking	1700	1500	-200	Peaking	1700	1500	-200
Aggregate	4000	4000	0	Aggregate	4000	4000	0	Aggregate	4000	4000	0

Panels 2 and 3 present the results with differing gas prices, in Panel 2 at the ‘gas price shock’ level of \$7/GJ, and in Panel 3 at the lower long run bound of \$5/GJ. It follows from inspection of the entire Table that the power system as a whole was projected to be in balance during 2008. Viewing the supply-side from its structural portfolio components, on the basis of 2005 costs, base load applications would be significantly overweight (+500MW), while both intermediate and peak plant would be underweight (-400MW and -100MW, respectively). However, when the 2005 costs are substituted with the higher 2008 costs, the plant mix changes considerably. Note that the optimal amount of intermediate plant drops from 1000MW in Panel 1, to 100MW in Panel 2. This is best explained by contrasting the running cost curves in Figure 1 above and in Figure 2 below - note the fundamental change in the optimal plant mix and the virtual evaporation of NGCC plant as a new entrant class:

Figure 2: Optimal plant mix for WA using 2008 costs

The optimal portfolio shares for different types of generating plant change considerably with base load plant now associated with the 37 percent quantile compared to the 94 percent quantile in the previous case. Note that the total (MW) plant requirement for the system as a whole remains 4000MW. As noted in Panel 2 of Table 4, after adjusting for outages base plant rises to 2200MW, intermediate is rounded to 100MW, and peaking plant as the residual amounts to 1700MW.

A comparison of results in Panel 1 to Panel 2, which arises from using the 2008 cost stream in optimal plant calculations leads to a situation whereby the actual amount of plant required remains constant, but base load portfolio moves from 500MW overweight to 300MW underweight – a shift of 800MW. In Panel 3 where the gas price shock is assumed to revert to a lower long run price of \$5/GJ, base plant is virtually in balance (only 100MW overweight).

While these results may appear to be shifting a problem from one bucket to another, the implications for future capacity additions are far more significant. The structural change in costs has, *ceteris paribus*, effectively brought forward the requirement for new base plant by six years, from about 2014 to 2008. Why this is so problematic is illustrated below in Table 5. As noted at the outset of this paper, the 2005 position of the WA power generation industry was highly favourable by Australian standards because the inevitable pricing of CO₂ would have an adverse impact on thermal power applications, and in particular, coal-fired generators. Consequently, a power system with an inherent bias towards gas-fired generation such as WA in 2005 would transition more smoothly to a carbon constrained world than would say Victoria which has very high CO₂ emitting brown coal power stations.

The fundamental economics of base load power applications in WA changed from 2007 onwards, from being 'NGCC biased' to 'SCpf biased'. Using the CO₂ price from Simshauser and Doan (2009) of \$17.50/t, Table 5 presents the 'levelised' cost model results after incorporating the impact of emissions trading on generating technologies, using both the 2005 and 2008 cost streams:

Table 5. Levelised cost of entry for base load applications at 92% ACF with CO₂ at \$17.50/t

Technology	tCO ₂ / MWh	CO ₂ \$17.50	2005	2008	Change
SCpf	0.90	\$15.75	\$60.99	\$73.95	\$12.95
NGCC	0.40	\$7.00	\$52.08	\$89.41	\$37.33
Difference	0.50	\$8.75	\$8.91	-\$15.46	
2005 CO ₂ Breakeven Price:		\$0.00	NGCC Investment Frontier: 20%-94%		
2008 CO ₂ Breakeven Price:		\$48.42	NGCC Investment Frontier: 25%-37%		

Table 5 indicates that SCpf plant has an emissions intensity of 0.9t of CO₂ for each MWh produced (see column 2 of Table 5). NGCC plant on the other hand has an emissions intensity of 0.4t of CO₂/MWh. Note that this adds \$15.75 and \$7.00/MWh respectively (column 3) to the overall entry cost structure. Thus, using the 2005 cost scenario from Table 2, NGCC plant becomes even more competitive than without CO₂ pricing, undercutting coal by \$8.91/MWh (Column 4). Given the manifest uncertainty of the level of pricing of CO₂ in Australia, it is not difficult to see why in 2005 the WA power system was in a particularly favorable position - the dominant technology of choice for all base and intermediate generating applications would be low emitting NGCC plant – with or without CO₂ pricing.

However, using the new 2008 cost streams at \$7/GJ, the higher polluting coal plant becomes the dominant technology (see Column 5) – and it is not until CO₂ prices exceed \$48/t that NGCC plant regains its position as the dominant technology for base load energy in WA. Because of the particularly acute nature of the rise in the cost of natural gas, coal is likely to remain in this position for a considerable period of time unless gas prices do moderate to our lower bound of \$5/GJ, in which case the CO₂ break point would reduce very substantially, to \$15/t.

Thus is the dilemma for the WA power industry. To minimize the private cost of base load power applications in WA and span the ACF range from 37% to 100%, SCpf has become the dominant technology. Yet, a new 350MW unit will require an initial \$875m investment commitment, imminently, and from an environmental perspective, will lock in approximately 2.3Mt of CO₂ per annum or more than 70Mt over the 30-40 year useful life of the investment as opposed to an equivalent NGCC unit which would emit 1Mt per annum and less than 30Mt over the life of the investment. Why this is so problematic is that new base plant is required immediately and NGCC plant has been squeezed out of the market. If the price of gas were to eventually fall back to \$5/GJ, there would be no new NGCC plant available (even as intermediate plant given the small range of 25-37%) to drive fuel switching, and any new plant would take between 5-7 years to commission given development, equipment lead-order times and construction delays.

IX. SENSITIVITY OF RESULTS TO VARIATIONS IN MACROECONOMIC CONDITIONS, PEAK DEMAND AND ENERGY CONSUMPTION

We conducted sensitivity analysis to examine the sensitivity of our key findings to variations in macroeconomic conditions confronting the electricity industry. This involved varying assumed plant capital cost (+/- \$200/kW), the cost of capital (in the range +/- 200bps) and inflation (in the range -50bps to +150bps). These particular scenarios involved assessing the sensitivity of our results to cost of capital estimates in the range 9.0% to 13.0%, and to inflation rate estimates in the range 2.0% to 4.0%. The results from these scenarios are documented in Appendix II.

It is apparent from inspection of these results that the key findings in this article are not qualitatively affected by the variations in the capital cost, cost of capital and inflation assumptions considered. A number of broad conclusions can be made. First, increases in the (\$/kW) capital cost of plant tended to narrow the region of the investment frontier that was

optimal for NGCC plant while also making NGCC plant relatively less costly (in 2008 dollars) when compared to SCpf plant. The converse was the case for reductions in capital costs. Second, increases in the cost of capital favoured NGCC plant by making NGCC plant relatively less costly (in 2008 dollars) and by increasing the region of the investment frontier that was optimal for NGCC plant. The converse held for reductions in the cost of capital which favoured SCpf plant over NGCC plant. Finally, increases in the inflation rate favoured SCpf plant over NGCC plant by making NGCC plant relatively more costly (in 2008 dollars) and producing a narrowing in the region of the investment frontier over which NGCC plant was the optimal technology. The converse held for reductions in the inflation rate, favouring NGCC plant over SCpf plant.

For completeness, the optimal plant mix for each year from 2009-2010 using the 2005, 2008 and \$5/GJ cost data is documented in Appendix III. We performed simulations to assess how sensitive the baseline results cited in Section VIII are to variations in maximum peak demand and energy consumption by calculating three particular load duration trajectories that capture variations in underlying electricity demand reflecting different assumptions about weather conditions and economic growth scenarios.²⁴ Because each type of ‘growth’ scenario is assumed to involve a permanent variation in the peak demand point estimate, the total (MW) installed and reserve plant requirement for the system will also change (which is a deliberate departure from conventional power system planning analysis to capture the sensitivity of outcomes).

The results listed in Appendix III are recorded on a year-by-year basis beginning in 2009 and ending in 2010. The short time horizon reflects our primary interest in the near-term requirements for investment in existing thermal based generation technology in order to achieve system wide portfolio balance prior to the commencement of the carbon pollution reduction scheme and CO₂ pricing in 2010. For each year, three tables are listed under each other corresponding to Scenarios A (the ‘extreme high growth’ scenario), Scenario B (the baseline scenario) and Scenario C (the ‘extreme low growth’ scenario). For each scenario, three further cost scenarios are identified which appear column-wise (i.e. as panels) and correspond to cost scenario 1 (2005 cost structure \$3.20/GJ), cost scenario 2 (2008 cost scenario \$7/GJ) and cost scenario 3 (the alternative \$5/GJ).

A number of broad conclusions can be discerned from inspection of the tables in Appendix III. First, the degree of aggregate capacity undersupply is greatest for the high growth scenario and diminishes as the growth component tailors off. For all time periods and high growth scenarios (i.e. Scenario A), the overall system tends to be moderately or significantly undersupplied, peaking at -700MW in 2010. In contrast, for the low growth scenario (i.e. Scenario C) the overall system is marginally oversupplied in 2009 and in balance in 2010. For the baseline scenario (Scenario B), the overall system appears to be marginally undersupplied by -200MW in 2009 and -300MW in 2010. Clearly for planning purposes, participants in the SWIS would assume that the required new capacity for the system is around 700MW between now and 2010 in the absence of a material change in electricity load.

This later result points to a reasonably urgent need for additional investment in infrastructure by 2010, with the most likely candidate being coal-fired base load plant if the natural gas prices from 2007 onwards (i.e. of \$7/GJ) continue to prevail and even possibly in the face of future CO₂ pricing developments in the range \$30.00/t - \$40.00/t. At the time of writing (FY09), this certainly appears to be case with Griffin Energy having just committed a second 200MW coal development at Bluewaters (arriving in 2011), with plans announced for a further 2 x 200MW coal plant thereafter.

²⁴ See Section VI for more details and Table 1 and Appendix I for the peak demand and energy consumption data used in all the simulations reported in Appendix III.

X. POLICY OPTIONS FOR WA

From a policy perspective, the State Government who has responsibility for energy policy in WA has much to consider. Foremost will be energy security, and thus a strong renewables push by the WA Government to ensure it captures at least a proportionate share of the national 20% renewable target would seem inevitable if the response by the European Union (i.e. to sharply rising gas prices) is anything to go by. WA wind and biomass resources are certainly capable of matching the cost of a SCpf plant that incorporates \$30/t CO₂ pricing. But as noted earlier, renewable power applications have resource or system technical limitations. Ultimately, new conventional power applications capable of providing load-following power will be required.²⁵

The WA Power Industry has formed the Domestic Gas Alliance, called DomGas, and is pushing for regulations with the State and Federal Government which force natural gas developers to reserve 15% of all future production for domestic supply. In the opinion of the authors, given the vast reserves of gas in offshore-WA, this would seem to be a sensible policy option. However, a potential problem with the DomGas concept is that, while it forces supply to the domestic market, it does not guarantee that supply will be at a lower cost than is currently the case.

The only way in which to drive price down is to ensure that supply-stocks increase, and thus the Federal Government should turn its focus to the facilitation of exploration, and attach suitable conditions to that facilitation. This might include, for example, reviewing the conditions surrounding retention leases²⁶ as discussed by CCI (2007), reviewing the joint selling dispensations that currently exist (which was occurring at the time of writing via an ACCC inquiry), changing royalties and tax incentives associated with exploration and perhaps even considering the establishment of common infrastructure (e.g. underwater pipelines and storage) to reduce the cost of offshore gas processing.

If there is a genuine prospect of gas prices stabilising and possibly falling by 2011, then the WA Government (as owner of Verve Energy) could consider delaying the closure of the coal plant at Kwinana (see Appendix I) until after 2011.²⁷ From a dynamic efficiency perspective, maintaining inefficient coal plant for four more years in order to usher new low cost gas fired plant may greatly exceed the alternative scenario – new coal locked in for 40 years.

Alternate investments such as Carbon Capture and Storage (CCS) have the potential to moderate the CO₂ risk through retrofitting or in front-end design, although as Simshauser, Doan and Lacey (2007) observed, even after factoring aggressive experience cost curves and financing assumptions, such technology is unlikely to be commercially deployed prior to 2025 and certainly cannot obtain the requisite financing in the near term given current costs and technology risks. Lewis and Curien (2008) formed a similar view in the case of the EU, with the deployment of CCS considered unlikely prior to 2030 despite CO₂ having been priced in the EU15 since 2005.

²⁵ Interestingly, Western Power note that for each 200MW of wind capacity installed on the SWIS, a further 50MW of load-following (conventional) thermal capacity is required for stability reasons. See report "Provision of electricity generating capacity for 2007/08 in the South West Interconnected System" available at www.imowa.com.au (accessed Oct-08).

²⁶ CCI (2007) noted that retention leases are 'hoarded' by the large oil and gas players in WA. A proposal exists to increase the transparency of the five-year renewal process to reduce the incidence of hoarding.

²⁷ An anonymous referee noted that these policy options were easier in the case of the SWIS because it is dominated by state owned entities. Such policy options, however, would be more difficult to implement in the NEM because of the higher level of private ownership of generation assets.

XI. CONCLUSION

The purpose of this paper was to analyse the effects of the step change in the price of natural gas to the SWIS in WA. This research has found that there is an ongoing requirement for new capacity in WA given rapidly rising electricity load and looming plant closures. A formal framework for determining the ‘levelised’ cost of each technology was presented along with a model for determining the optimal mix of plant for a given power system.

A key finding in this article was that the sharp increase in the cost of gas between 2005 and 2007 has affected the likely near-term future plant investment pattern in WA in a very adverse manner given the looming prospect of CO₂ pricing. In particular, whereas cleaner NGCC plant would have dominated the investment frontier for all applications with or without CO₂ price uncertainty (i.e. NGCC for base and intermediate applications), the change in the price of natural gas has eliminated the near-term prospects for any new NGCC plant. Figure 2 demonstrated that NGCC plant has effectively been squeezed out of the market to a range between 25-37% or less than 100MW. Since more than 500MW of NGCC plant will be sunk by the end of 2008 (see Appendix I), the market will revert to a coal play. This eliminates any near-term fuel switching even if gas does fall back to \$5/GJ given development, equipment lead-order times and construction delays.

The irony of this scenario is that while the east coast of Australia will be rapidly building new base load gas plant to replace less environmentally efficient coal plant, WA will be doing the exact opposite. Such an outcome is not inconsistent with the Carbon Pollution Reduction Scheme in that its design is intended to enable the market to determine the least-cost path of emissions reduction. But given the inertia of the aggregate plant stock within an electricity grid, WA consumers will now increase their exposure to forward CO₂ prices as they lock in 10+ year electricity supply contracts with coal generators, reportedly with carbon pass-through clauses (which were required for debt financing). In the short term, WA consumers will be clearly better served through coal-fired investments since CO₂ prices are expected to begin at relatively low levels from 2010 (up to \$20/t). Over the long run however, it is hard to imagine CO₂ prices remaining at such levels and there are indeed many forecasts which point to CO₂ price outcomes well above \$50/t by 2020 such as Lewis and Curien (2008), who forecast €48/t or about \$82/t.

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APPENDIX I – DEMAND AND SUPPLY DATA

Forecast Peak Demand (MW) at PoE50, PoE10 and PoE90 and Expected, High and Low Energy Consumption (GWh) Projections

Year	Maximum Demand (MW)			Energy Consumed		
	50% PoE	10% PoE	90% PoE	Expected	High	Low
2008	3398	3392	3392	16442	16442	16442
2009	3824	4143	3577	17283	17072	16844
2010	3987	4338	3702	19020	18504	18103
2011	4415	4807	4100	21795	21066	20543
2012	4555	4991	4211	22453	21492	20835
2013	4689	5168	4318	23051	21851	21091
2014	4857	5382	4456	23972	22500	21603
2015	5003	5902	4551	24871	22940	21768
2016	5132	5870	4651	25640	23373	22041

SWIS supply-side data

Power Station	Owner	Technology	Fuel	Duty	IMOWA Capacity (MW)	Heat rate (kJ/kWh)	Assumed fuel cost (\$/GJ)	Variable O&M (\$/MWh)	SRMC (\$/MWh)	Emissions intensity (tCO2/MWh)	Open / Close
Collie	Verve	SubCr pf	Coal	Base	304	10,000	1.75	1.00	18.50	0.861	
Griffin Bluewaters I	Griffin Energy	SubCr pf	Coal	Base	215	10,500	1.75	1.00	19.38	0.861	open 09
Griffin Bluewaters II	Griffin Energy	SubCr pf	Coal	Base	215	10,500	1.75	1.00	19.38	0.861	open 11
NewGen Kwinana	NewGen Power	NGCC	Gas	Base	310	7,800	3.50	2.00	29.30	0.451	open 09
Muja D	Verve	SubCr pf	Coal	Base	400	10,500	2.50	3.10	29.35	0.861	
Cockburn	Verve	NGCC	Gas	Base	227	8,000	3.50	1.80	29.80	0.451	2003
WAPL Worsley BHP	Worsley\BHP	CoGen	Gas	Base	128	8,000	3.50	1.80	29.80	0.537	
Muja C	Verve	SubCr pf	Coal	Base	370	11,000	2.50	3.00	30.50	0.861	
Kwinana A	Verve	Steam	Coal	Intermed.	212	12,000	2.50	3.00	33.00	0.861	close 09
Tiwest CoGen	Verve	CoGen	Gas	Base	29	9,000	3.50	1.80	33.30	0.537	
Alinta 1 CoGen Pinjarra	Alinta	CoGen	Gas	Base	140	9,000	3.50	2.50	34.00	0.537	open 04
Alinta 2 CoGen Pinjarra	Alinta	CoGen	Gas	Base	140	9,000	3.50	2.50	34.00	0.537	open 07
Muja A&B	Verve	SubCr pf	Coal	Base	202	13,000	2.50	3.00	35.50	0.861	close 07
Int. Power BP CoGen	IP, BP	CoGen	Gas	Base	71	11,000	3.50	2.90	41.40	0.537	
Kwinana C GT	Verve	Steam	Gas	Intermed.	370	11,000	3.50	2.90	41.40	0.537	
Parkeston GT	Transalta	OCGT	Gas	Intermed.	61	11,500	3.50	3.00	43.25	0.537	
Alinta 3&4 GT Wagerup	Alinta	OCGT	Gas	Peak	351	11,500	3.50	3.00	43.25	0.537	open 08
NewGen Neerabup	NewGen Power	OCGT	Gas	Peak	330	11,500	3.50	2.00	42.25	0.537	open 10
Kwinana B GT	Verve	Steam	Gas	Peak	194	12,000	3.50	2.90	44.90	0.537	close 08
Pinjar C GT	Verve	OCGT	Gas	Peak	202	12,500	3.50	2.90	46.65	0.537	
Southwest Cogen	Origin\Verve	OCGT	Gas	Base	100	12,500	3.50	3.00	46.75	0.537	
Kemerton GT	Transfield	OCGT	Gas	Peak	260	11,500	3.50	9.00	49.25	0.537	
Mungarra GT	Verve	OCGT	Gas	Peak	87	13,500	3.50	2.90	50.15	0.537	
Pinjar AB GT	Verve	OCGT	Gas	Peak	193	13,500	3.50	2.90	50.15	0.537	
Kwinana GT	Verve	OCGT	Gas	Peak	17	15,500	3.50	2.90	57.15	0.537	
Geraldton GT	Verve	OCGT	Gas	Peak	17	15,500	3.50	9.00	63.25	0.537	
Pinjar D GT	Verve	OCGT	Oil	Peak	107	12,500	20.00	2.90	252.90	0.681	
Kalgoorlie GT	Verve	OCGT	Oil	Peak	48	14,500	20.00	2.90	292.90	0.681	
Southern Cross GT	Transalta	OCGT	Oil	Peak	19	14,500	20.00	9.00	299.00	0.681	

APPENDIX II – ‘MACROECONOMIC’ LEVELISED ENTRY COST SENSITIVITIES

Techology	Capital Cost	Cost of Capital	tCO ₂ / MWh	CO ₂ \$17.50	2005	2008	Change
SCpf	Base Case	Base Case	0.90	\$15.75	\$60.99	\$73.95	\$12.95
NGCC	Base Case	Base Case	0.40	\$7.00	\$52.08	\$89.41	\$37.33
Difference			0.50	\$8.75	\$8.91	-\$15.46	
			CO ₂ Breakeven Price:	\$48.42	NGCC Investment Frontier: 25%-37%		
Techology	Capital Cost	Cost of Capital	tCO ₂ / MWh	CO ₂ \$17.50	2005	2008	Change
SCpf	Up \$200/kW	Base Case	0.90	\$15.75	\$60.99	\$76.54	\$15.54
NGCC	Up \$200/kW	Base Case	0.40	\$7.00	\$52.08	\$91.89	\$39.81
Difference			0.50	\$8.75	\$8.91	-\$15.35	
			CO ₂ Breakeven Price:	\$48.20	NGCC Investment Frontier: 31%-37%		
Techology	Capital Cost	Cost of Capital	tCO ₂ / MWh	CO ₂ \$17.50	2005	2008	Change
SCpf	Down \$200/kW	Base Case	0.90	\$15.75	\$60.99	\$71.35	\$10.36
NGCC	Down \$200/kW	Base Case	0.40	\$7.00	\$52.08	\$86.92	\$34.84
Difference			0.50	\$8.75	\$8.91	-\$15.57	
			CO ₂ Breakeven Price:	\$48.64	NGCC Investment Frontier: 19%-36%		
Techology	Capital Cost	Cost of Capital	tCO ₂ / MWh	CO ₂ \$17.50	2005	2008	Change
SCpf	Base Case	Up 200bps	0.90	\$15.75	\$64.35	\$79.70	\$15.35
NGCC	Base Case	Up 200bps	0.40	\$7.00	\$54.26	\$92.38	\$38.12
Difference			0.50	\$8.75	\$10.09	-\$12.68	
			CO ₂ Breakeven Price:	\$42.86	NGCC Investment Frontier: 27%-43%		
Techology	Capital Cost	Cost of Capital	tCO ₂ / MWh	CO ₂ \$17.50	2005	2008	Change
SCpf	Base Case	Up 100bps	0.90	\$15.75	\$62.65	\$76.79	\$14.14
NGCC	Base Case	Up 100bps	0.40	\$7.00	\$53.15	\$90.87	\$37.71
Difference			0.50	\$8.75	\$9.50	-\$14.08	
			CO ₂ Breakeven Price:	\$45.66	NGCC Investment Frontier: 26%-40%		
Techology	Capital Cost	Cost of Capital	tCO ₂ / MWh	CO ₂ \$17.50	2005	2008	Change
SCpf	Base Case	Down 100bps	0.90	\$15.75	\$59.39	\$71.19	\$11.80
NGCC	Base Case	Down 100bps	0.40	\$7.00	\$51.05	\$88.00	\$36.96
Difference			0.50	\$8.75	\$8.35	-\$16.81	
			CO ₂ Breakeven Price:	\$51.13	NGCC Investment Frontier: 24%-34%		
Techology	Capital Cost	Cost of Capital	tCO ₂ / MWh	CO ₂ \$17.50	2005	2008	Change
SCpf	Base Case	Down 200bps	0.90	\$15.75	\$57.86	\$68.53	\$10.67
NGCC	Base Case	Down 200bps	0.40	\$7.00	\$50.05	\$86.66	\$36.61
Difference			0.50	\$8.75	\$7.80	-\$18.13	
			CO ₂ Breakeven Price:	\$53.76	NGCC Investment Frontier: 23%-31%		
Techology	"Capital Costs"	Inflation	tCO ₂ / MWh	CO ₂ \$17.50	2005	2008	Change
SCpf	Base Case	Up 150bps	0.90	\$15.75	\$60.21	\$71.78	\$11.57
NGCC	Base Case	Up 150bps	0.40	\$7.00	\$52.02	\$90.11	\$38.08
Difference			0.50	\$8.75	\$8.18	-\$18.33	
			CO ₂ Breakeven Price:	\$54.15	NGCC Investment Frontier: 27%-30%		
Techology	"Capital Costs"	Inflation	tCO ₂ / MWh	CO ₂ \$17.50	2005	2008	Change
SCpf	Base Case	Up 100bps	0.90	\$15.75	\$60.43	\$72.45	\$12.02
NGCC	Base Case	Up 100bps	0.40	\$7.00	\$52.01	\$89.82	\$37.80
Difference			0.50	\$8.75	\$8.41	-\$17.37	
			CO ₂ Breakeven Price:	\$52.23	NGCC Investment Frontier: 26%-32%		
Techology	"Capital Costs"	Inflation	tCO ₂ / MWh	CO ₂ \$17.50	2005	2008	Change
SCpf	Base Case	Up 50bps	0.90	\$15.75	\$60.69	\$73.17	\$12.48
NGCC	Base Case	Up 50bps	0.40	\$7.00	\$52.03	\$89.58	\$37.55
Difference			0.50	\$8.75	\$8.66	-\$16.41	
			CO ₂ Breakeven Price:	\$50.32	NGCC Investment Frontier: 26%-35%		
Techology	"Capital Costs"	Inflation	tCO ₂ / MWh	CO ₂ \$17.50	2005	2008	Change
SCpf	Base Case	Down 50bps	0.90	\$15.75	\$61.33	\$74.76	\$13.43
NGCC	Base Case	Down 50bps	0.40	\$7.00	\$52.16	\$89.28	\$37.12
Difference			0.50	\$8.75	\$9.17	-\$14.52	
			CO ₂ Breakeven Price:	\$46.53	NGCC Investment Frontier: 24%-39%		

APPENDIX III – OPTIMAL PLANT MIX

Optimal Plant Mix Scenarios:

- (A) Maximum Growth Scenario – 10% PoE Peak Demand, Fast Economic Growth, High Energy Production/Consumption;
- (B) Baseline Scenario - 50% PoE (Expected) Peak Demand, Expected Economic Growth and Expected Energy Production/Consumption; and
- (C) Minimum Growth Scenario – 90% PoE Peak Demand, Slow Economic Growth, Low Energy Production/Consumption.

2009 Optimal Plant Mix: Scenario A											
PANEL 1. 2005 Cost Structure: \$3.20/GJ				PANEL 2. 2008 Cost Structure: \$7/GJ				PANEL 3. Alternative Cost Structure: \$5/GJ			
	Optimal	Actual	Portfolio Balance		Optimal	Actual	Portfolio Balance		Optimal	Actual	Portfolio Balance
Baseload	1,700	2,400	700	Baseload	2700	2400	-300	Baseload	2200	2400	200
Intermed	1,200	600	-600	Intermed	100	600	500	Intermed	600	600	0
Peaking	2,000	1,300	-700	Peaking	2100	1300	-800	Peaking	2100	1300	-800
Aggregate	4900	4300	-600	Aggregate	4900	4300	-600	Aggregate	4900	4300	-600
2009 Optimal Plant Mix: Scenario B											
PANEL 1. 2005 Cost Structure: \$3.20/GJ				PANEL 2. 2008 Cost Structure: \$7/GJ				PANEL 3. Alternative Cost Structure: \$5/GJ			
	Optimal	Actual	Portfolio Balance		Optimal	Actual	Portfolio Balance		Optimal	Actual	Portfolio Balance
Baseload	1600	2400	800	Baseload	2500	2400	-100	Baseload	2000	2400	400
Intermed	1100	600	-500	Intermed	100	600	500	Intermed	600	600	0
Peaking	1800	1300	-500	Peaking	1900	1300	-600	Peaking	1900	1300	-600
Aggregate	4500	4300	-200	Aggregate	4500	4300	-200	Aggregate	4500	4300	-200
2009 Optimal Plant Mix: Scenario C											
PANEL 1. 2005 Cost Structure: \$3.20/GJ				PANEL 2. 2008 Cost Structure: \$7/GJ				PANEL 3. Alternative Cost Structure: \$5/GJ			
	Optimal	Actual	Portfolio Balance		Optimal	Actual	Portfolio Balance		Optimal	Actual	Portfolio Balance
Baseload	1500	2400	900	Baseload	2300	2400	100	Baseload	1900	2400	500
Intermed	1000	600	-400	Intermed	100	600	500	Intermed	500	600	100
Peaking	1700	1300	-400	Peaking	1800	1300	-500	Peaking	1800	1300	-500
Aggregate	4200	4300	100	Aggregate	4200	4300	100	Aggregate	4200	4300	100
2010 Optimal Plant Mix: Scenario A											
PANEL 1. 2005 Cost Structure: \$3.20/GJ				PANEL 2. 2008 Cost Structure: \$7/GJ				PANEL 3. Alternative Cost Structure: \$5/GJ			
	Optimal	Actual	Portfolio Balance		Optimal	Actual	Portfolio Balance		Optimal	Actual	Portfolio Balance
Baseload	1,800	2,400	600	Baseload	2800	2400	-400	Baseload	2300	2400	100
Intermed	1,300	400	-900	Intermed	100	400	300	Intermed	600	400	-200
Peaking	2,000	1,600	-400	Peaking	2200	1600	-600	Peaking	2200	1600	-600
Aggregate	5100	4400	-700	Aggregate	5100	4400	-700	Aggregate	5100	4400	-700
2010 Optimal Plant Mix: Scenario B											
PANEL 1. 2005 Cost Structure: \$3.20/GJ				PANEL 2. 2008 Cost Structure: \$7/GJ				PANEL 3. Alternative Cost Structure: \$5/GJ			
	Optimal	Actual	Portfolio Balance		Optimal	Actual	Portfolio Balance		Optimal	Actual	Portfolio Balance
Baseload	1700	2400	700	Baseload	2600	2400	-200	Baseload	2100	2400	300
Intermed	1200	400	-800	Intermed	100	400	300	Intermed	600	400	-200
Peaking	1800	1600	-200	Peaking	2000	1600	-400	Peaking	2000	1600	-400
Aggregate	4700	4400	-300	Aggregate	4700	4400	-300	Aggregate	4700	4400	-300
2010 Optimal Plant Mix: Scenario C											
PANEL 1. 2005 Cost Structure: \$3.20/GJ				PANEL 2. 2008 Cost Structure: \$7/GJ				PANEL 3. Alternative Cost Structure: \$5/GJ			
	Optimal	Actual	Portfolio Balance		Optimal	Actual	Portfolio Balance		Optimal	Actual	Portfolio Balance
Baseload	1500	2400	900	Baseload	2400	2400	0	Baseload	2000	2400	400
Intermed	1100	400	-700	Intermed	100	400	300	Intermed	500	400	-100
Peaking	1800	1600	-200	Peaking	1900	1600	-300	Peaking	1900	1600	-300
Aggregate	4400	4400	0	Aggregate	4400	4400	0	Aggregate	4400	4400	0