The hidden costs of wind generation in a thermal power system: what cost?

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Renewable generation in Australia is unambiguously more expensive than thermal plant. But economic logic dictates that producing electricity in a sustainable manner will come at a cost. The Federal Government claims the 20% Renewable Energy Target will lead to a 4% increase in household electricity bills. Critics of renewables cite additional 'hidden costs' arising from the intermittency of wind and the subsequent causation for 'backup plant' for system security. South Australia, where wind's market share now exceeds 17%, provides a valuable case study to analyse 'hidden costs'. The evidence is that hidden costs are trivial, and the government's claim appears accurate.

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1. Introduction

Energy policies of the State Governments and the Federal Government in Australia have three common thematics. First and foremost is 'energy security' which can be simply thought of as 'keeping the lights on'. To be sure, all other energy policy objective functions are subordinate to this overarching principle by a very long way. The reason for this should be obvious enough; voters have a tendency to react particularly badly to systemic energy shortages. Second is 'efficient resource allocation' which is targeted through measures aimed at optimising productive, allocative and dynamic efficiency. Primary drivers of this objective have been restructuring, deregulation and privatisation. The third policy thematic is 'environmental constraint' and is a relatively new addition. Power generation in Australia has historically consumed vast quantities of fresh water for cooling purposes, and is responsible for about 37.6% of the nations' annual CO₂ emissions (DCCEE, 2010). Latest statistics from the Energy Supply Association of Australia note that 84% of electricity produced in the National Electricity Market (NEM) comes from carbon-intensive coal-fired generation (esaa, 2010); this is of course directionally inconsistent with emerging environmental constraints.

From an energy policy perspective, there are a number of ways in which to reduce the market share of coal generator emissions in the plant mix, and many examples already exist in Australia's policy laboratories, the states, and at the national level. These include certificated schemes designed to alter the fuel mix or generator efficiency levels such as the 13% gas target in Queensland (QLD) and the greenhouse gas abatement scheme in New South Wales (NSW). The federal government proposed an emissions trading scheme, although this was defeated in the Senate in 2009. But the environmentally-focused energy policy setting which stands out above all others in Australia is the expanded 20% Renewable Energy Target. This policy is material in all respects and in the main enjoys bipartisan political support with few caveats, and builds on an earlier 2% Mandated Renewable Energy Target. However, to be sure, 20% is a large target and has its share of critics, primarily on the grounds of the so-called 'hidden costs' of renewables. In the NEM, renewable power is unambiguously more expensive than thermal power on a unit cost basis. But the primary source of criticism in relation to the 20% Renewable Energy Target is a

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presumption that large amounts of additional ‘backup plant’ will be required to deal with system stability and reliability implications of large-scale intermittent renewable generation, thus further compounding the apparent cost impact of renewables. This is an important topic; some of Australia’s most respected business journalists and industry executives have claimed the hidden costs of renewables to be substantial. Yet, while the so-called hidden costs of intermittent power sources have considerable intuitive logical appeal, claims thus far do not appear to be based on applied economic analysis of power system operations. Thus is the purpose of this article. Somewhat fortuitously, the NEM has a particularly useful case study to examine the transparent costs and the hidden cost impacts of renewables courtesy of the State of South Australia (SA). At the time of writing at the end of FY10, renewable power generation and in particular intermittent wind generation in SA had increased its energy market share to a surprisingly large 17.1%. This provides for a unique examination of the cost impact of a rapidly rising penetration of renewable energy within a thermal power system.

Fundamentally, the analysis which follows finds the total incremental cost impact of developing renewables to be about \$8/MWh, with the so called ‘hidden costs’ of intermittency to be trivial. The total cost impact represents a 4% increase on the average household’s current electricity bill of c.\$200/MWh, a result consistent with the Federal Government’s estimate.

This article is organised as follows; Section 2 presents the details and results of an economic model which produces estimates of the long run marginal cost of new entrant generating technologies in Australia. Sections 3 and 4 examine Biomass and Hot Fractured Rock Geothermal technologies to assess their potential to disrupt the dominant renewable energy position currently enjoyed by wind. Section 5 then reviews domestic and global investment trends in renewable plant capacity. Section 6 presents the long-range demand for renewable generating output and installed plant capacity in Australia. Section 7 then analyses the SA generating plant and fuel mix. Section 8 identifies the suspected source of the ‘hidden costs’ of wind while Section 9 then presents modelling results on resource adequacy in SA and in particular, contrasts the system plant stock to analyse the transparent costs and the so-called hidden costs of wind generation. Conclusions follow.

2. The long run marginal cost of power generation technologies

It is useful to start this analysis by examining the current Long Run Marginal Cost (LRMC) of generation plant in the NEM. A levelised cost model has been developed to produce LRMC estimates for multiple plant technologies, the form of which is set out below.

Power generation is one of the most capital-intensive industries in the world; for example, the International Energy Agency noted that approximately A\$27 Trillion would be invested in the energy sector (comprising coal, gas, oil, electricity) between 2010 and 2030 and of this, A\$11 Trillion would be directed into power stations alone (IEA, 2009). With this in mind, it should be obvious that in producing estimates of the LRMC of new generating equipment, among the most important exogenously set variables for each technology option is the ‘overnight capital cost’ of plant. The overnight capital cost of plant (i.e. the aggregate capitalized costs of a new power station) essentially comprise the main power island¹ and the balance of plant construction contracts, site acquisition, planning and permitting costs, pre-development costs, electricity grid connection, gas pipeline or fuel connection costs, project development fees, project management fees, aggregate commissioning costs (including fuel consumed if applicable) and project contingencies.² The overnight capital cost of plant for each plant type ‘j’ (*Capex_j*) can be given by:

$$Capex_j = [k_j \times 1000 \times us_j] \quad (1)$$

Where:

- k_j is the Greenfield overnight capital cost associated with generating plant technology ' j ' and is expressed in \$/kW;
- us_j is the installed capacity of the ' j -th' plant and is expressed in MW.

Given the presence of plant economies of scale both in terms of unit size and the number of generating units, the design of generation plant and associated capital costs often involves more than one power generating unit. As such, $Capex_j$ can be further allocated to joint units giving the following capital cost stream from plant j and unit i :

$$Capex_{j(i)}^i = (\psi O_{j(i)}^i \times Capex_j \times CPI_{(t)} \times \nu O_{j(i)}^i) \quad (2)$$

$\psi O_{j(i)}^i$ is the allocation of total capital expenditure associated with plant j given to unit i measured as a percentage, $Capex_j$ was defined in (1), $CPI_{(t)}$ denotes the inflation based escalation in power station capital costs and as noted in Table 1 is set a 2.5% for each future year, and $\nu O_{j(i)}^i$ depicts how the sunk capital costs associated with the construction of technology j are incurred over the investment horizon for each unit i . For example, if an Open Cycle Gas Turbine (OCGT) plant comprises '4 units' such that $i=4$ then each unit receives allocations of 25% of total $Capex_j$; that is $\psi O_j^i = 25\%$, for $i=1..4$ and each j in (2). How this capital expenditure is allocated to each unit within the investment horizon depends critically upon the last variable $\nu O_{j(i)}^i$ in (2). For example, with a Combined Cycle Gas Turbine (CCGT) plant, the capital is sunk over two successive years at the rate of 40% and 60%, respectively. For all other years in the investment horizon, $\nu O_{j(i)}^i = 0$. For large thermal plant such as Black Coal where initial capital expenditure occurs over four years or more due to the scale and complexity of the construction task, initial capital for each unit ' i ' will typically be staggered by 6-12 months, again driven by the magnitude and economics of construction mobilisation.

For thermal technologies, Fuel Costs FC_j are a crucial component of the overall cost structure. Fuel costs are driven by two key variables, the thermal efficiency of the plant given by its Heat Rate (HR_j) and the unit cost of raw fuel (UFC_j). Fuel Costs can be expressed as:

$$FC_{j(i)} = \left(\frac{(HR_j \times UFC_j)}{1000} \right) \times (us_j \times ACF_j \times 8760) \times CPI_{(t)} \quad (3)$$

where $FC_{j(i)}$ is the fuel cost of generating plant ' j '. HR_j is the constant heat rate of each generator expressed in kJ/kWh and UFC_j is the constant raw unit fuel cost for each generator in \$/GJ and when divided by 1000, produces the unit cost of fuel expressed in \$/MWh. The term us_j is installed capacity as defined above, ACF_j is the Annual Capacity Factor of plant ' j ' and 8760 is the number of hours in each year and when combined produces energy generated (MWh) per annum.

Each power project j faces two Operations & Maintenance ($O\&M$) cost streams during operating periods; Fixed Operations and Maintenance costs (FOM) and Variable Operations and Maintenance costs (VOM) which can be expressed as follows:

$$O \& M_{j(i)} = (us_j \times FOM_j \times CPI_{(t)}) + (VOM_j \times us_j \times ACF_j \times 8760 \times CPI_{(t)}) \quad (4)$$

For most plant, the mix of operations and maintenance costs is dominated by fixed costs. With coal plant for example, FOM_j represents 86% of $\sum O \& M_{j(i)}$. Even for CCGT plant, FOM_j

represents 57% of $\sum O \& M_{j(t)}$. Given these parameters, the levelised cost of any power project using technology j can be represented by:

$$PS_j = \left[\frac{PV \left(\sum_{i=1}^I Capex_j^i + FC_{j(t)} + O \& M_{j(t)} + (CW_j \times Capex_j \times CPI_{(t)}) \right)}{PV((us_j \times ACF_j \times 8760) \times \gamma CPI_{(t)})} \right] / (1 - x_j) \quad (5)$$

In (5) the cost and quantity streams are discounted at a hurdle rate of 12% which is considered appropriate for power projects given prevailing capital market conditions. The cost stream in (5) is represented by the initial investment capital $\sum_{i=1}^I Capex_j^i$ and incurred in accordance with (2), plant fuel costs $FC_{j(t)}$ are incurred in accordance with (3) and plant O&M costs ($O \& M_j$) are incurred in accordance with (4). In addition, ongoing structural modifications to the plant, otherwise known as capital works (CW_j) are also incurred and are set to a certain percentage of initial capital $Capex_j$ and is escalated at the full rate of inflation $CPI_{(t)}$.

The production stream arising from the plant given by plant capacity (us_j), Annual Capacity Factor (ACF_j) and the hours in each year, was outlined earlier. Unit volumes are then escalated at the envisaged terminal revenue escalation rate $\gamma CPI_{(t)}$ in which γ is set to 75%, thereby representing a discount to the headline inflation rate. The discounted cost and quantity streams are then divided by the net output ratio of each technology ($1 - x_j$). The variable x_j represents the auxillary load of technology 'j'. Each of the key operational variables required to produce the LRMC estimates is contained in Table 1.

Table 1: Key assumptions for producing LRMC estimates

Technology	Overnight Capital Cost k_j (\$/kW)	Installed Capacity us_j (MW)	Generating Units ψO_j^i (MW)	Unit Heat Rate HR_j (kJ/kWh)	Unit Fuel Cost UFC_j (\$/GJ)	Capacity Factor ACF_j (%)	Fixed O&M Cost FOM_j (\$/MW/a)	Variable O&M VOM_j (\$/MWh)	Capital Works CW_j (%)	Auxiliary Load x_j (%)	Carbon Intensity (t/MWh)
Black coal	2,200	1,000	2	9,000	1.00	92%	48,000	1.00	0.25%	7.00%	0.78
Brown coal	2,600	1,000	2	11,250	0.40	92%	55,000	1.30	0.25%	8.00%	1.05
CCGT	1,368	380	1	7,000	4.00	92%	31,000	3.00	0.05%	2.00%	0.39
OCGT	985	600	4	11,500	4.50	92%	13,000	8.00	0.05%	0.50%	0.59
Mini Hydro	3,000	10	1	-	-	50%	30,000	2.00	0.05%	0.00%	-
Nuclear	5,100	1,400	2	10,500	0.50	92%	84,000	5.00	0.05%	7.00%	0.02
Wind	2,900	100	50	-	-	35%	40,000	1.00	0.05%	2.00%	-
Biomass	3,000	50	1	10,500	1.50	50%	120,000	2.00	0.05%	7.00%	-
HFR Geothermal	6,600	50	1	10,000	0.50	92%	200,000	2.00	0.25%	15.00%	-
Solar PV	6,900	10	1	-	-	31%	62,000	-	0.05%	0.50%	-
Solar Thermal	4,600	10	1	-	-	23%	55,000	-	0.05%	0.50%	-
Wave	7,000	10	1	-	-	25%	120,000	2.00	0.05%	0.50%	-
Cost of Capital	12.0%			CPI	2.5%						

The relevant values for the allocation of capital $\psi O_j^i(t)$ during the construction period as described in (2) is listed in Table 2.

Table 2: Capital allocation assumptions for producing LRM estimates

Technology	Allocation of Initial Capital Expenditure (νO^i_j)				
	t-5	t-4	t-3	t-2	t-1
Black coal	-	10.0%	20.0%	35.0%	35.0%
Brown coal	-	10.0%	20.0%	35.0%	35.0%
CCGT	-	-	-	40.0%	60.0%
OCGT	-	-	-	-	100.0%
Nuclear	10.0%	20.0%	20.0%	25.0%	25.0%
Wind	-	-	-	20.0%	80.0%
Mini Hydro	-	-	20.0%	20.0%	60.0%
Biomass	-	-	30.0%	35.0%	35.0%
Geothermal	-	20.0%	20.0%	20.0%	40.0%
Solar PV	-	-	-	-	100.0%
Solar Thermal	-	-	40.0%	40.0%	20.0%
Wave	-	-	-	20.0%	80.0%

The results of computing (5) with the variables contained in Tables 1 and 2 is presented in Figure 1. These results yield a 12% economic return on the capital invested. Of course in any future year, LRM for each project 'j' is escalated at $\gamma CPI_{(t)}$. Figure 1 also incorporates the CO₂ intensity of each plant, which is measured on the right-hand-side (RHS) axis.

Figure 1: LRM of Generating Plant in the NEM (ex Carbon)

Note in Figure 1 that the base load thermal fleet including black coal, brown coal and CCGT plant ranges from \$53-57/MWh, with peaking OCGT at around \$78/MWh, although its carrying cost, a better financial measure reflecting its operational duty, is just \$13.50/MWh. Nuclear has an LRM of \$118/MWh. The remaining technologies in Figure 1 are all renewable and as noted at the outset, are unambiguously more expensive than thermal plant in the NEM (i.e. black coal, brown coal and CCGT plant). The lowest cost renewable technology is mini-hydro at about \$84/MWh, however, such resources are highly limited in Australia – at the time of writing there were just 7 sites with capacity totalling 158MW (esaa, 2010). The most economic renewable technology able to be delivered at scale is wind with a LRM of \$120/MWh. Next is Biomass at \$135/MWh, which essentially has the complexity of a typical steam cycle plant with the added difficulty of often disparate or seasonal fuel sources such as bagasse (i.e. fibre from crushed sugar cane). Next is Hot Fractured Rock (HFR) Geothermal which has a potential underlying LRM of \$120/MWh and an aggregate LRM of \$180/MWh (the importance of which is discussed in Section 4). Finally are Solar PV, Solar Thermal (central receiver) and Wave technologies, the cost of which quite literally exceeds the y-axis scale and runs between \$200-\$350/MWh.

So the most viable renewable technology in the NEM, given the resource constraints of min-hydro, is wind generation and as this article later reveals, global investment statistics support this view. While Biomass appears to be a close rival, its development history in the NEM has, in the main, been traumatic. The emerging technology with the greatest potential to disrupt the dominant position of wind in the NEM's renewable cost curve is HFR Geothermal; however, while the technology is noted for its distinct geographic disadvantages, often (but not always) being remote from the grid, it is the material technical hurdles that will present the greatest challenge. To fully understand these dynamics, it is worth analysing Biomass and HFR Geothermal, in Sections 3 and 4 respectively.

3. Biomass developments: 'capital punishment'

When renewable targets first emerged in the NEM policy arena, dominant thought in the energy industry was that Biomass Power Projects, and in particular, sugar mill cogeneration projects using bagasse as the feedstock, were likely to gain a large share of the investment in, and production of, renewable electricity. The theory was that the existing fleet of sugar mills in QLD and NSW had aging low pressure boilers and steam turbines; these could be economically upgraded to high pressure boilers and with the vast increase in steam production, upsize the aging turbines and generators thereby exporting the newly created surplus power to the grid. In the late-1990s there was about 16 sugar mills with approximately 230MW of installed capacity, and even with their low pressure boilers, were nonetheless exporting about 300GWh of renewable power to the grid annually (esaa, 2002). Industry forecasts indicated an increase in capacity from 230MW to about 600MW was possible, with grid exports rising from 300GWh to well over 2900GWh pa. At the time of writing, capacity had expanded to 378MW (esaa, 2010). So much for theory. The history of biomass projects and bagasse developments in particular in the NEM has been anguished at best, and the sugar mill cogeneration projects have with very few exceptions resulted in sizeable shareholder losses.

The first bagasse/biomass project in the NEM was QLD power generator Stanwell Corporation's development of the 30MW Rocky Point Sugar Mill. Its original LRMC was thought to be in the range of \$55-\$60/MWh. However, capital costs increased from the original plan of \$50 million to nearly \$60 million, and operational costs increased by an order of magnitude. While separate accounts for the plant are not publicly available, Stanwell (2006) noted in its *2006 Annual Report* that the Rocky Point Cogeneration plant was sold about four years after final commissioning for just \$5.1 million, and in the event, suffering a \$55 million loss on the investment.³ This is by no means an isolated incident.

In a similar vein to the Stanwell venture, NSW power generator Delta Electricity formed a 50/50 joint venture with the NSW Sugar Milling Co-Operative to develop 2 x 30MW Cogeneration plants. The original capital budget was \$150 million, but during construction actual costs blew out to \$220m. At the time of writing, the projects were up for sale and investment banking sources indicated to the author that the Cogen portfolio is unlikely to sell for more than the \$150m debt facility, with some suggesting it may sell for as low as \$100 million.⁴

If any project was likely to succeed it was the Pioneer Sugar Mill project. Sitting in the middle of a very large sugar catchment area, the project was originally developed jointly by Stanwell and sugar miller CSR as a 65MW plant at a projected capital cost of about \$120 million. Unsurprisingly, Stanwell's Rocky Point experience led to their withdrawal from the project. CSR nonetheless persevered and while it is no doubt producing its targeted energy output, CSR noted in their *2006 Annual Report* that the 68MW Pioneer Cogen Project was originally forecast to cost \$140 million, but had blown out to \$170 million by completion.⁵ Biomass is, therefore, unlikely to feature prominently in future investment patterns.⁶

4. HFR Geothermal: risk and opportunity

A primary advantage of HFR Geothermal is its potential to provide continuous, base load power at relatively low cost by renewable standards. Unlike all other technologies in Figure 1, the aggregate LRMC of HFR Geothermal incorporates two additional cost elements, i.e. a 'Radial Transmission Connection' cost and a 'Tech Deployment' charge. In the case of radial transmission connection, the more advanced HFR Geothermal resources tend to be quite remote from the main electricity grid. Companies such as Geodynamics and Petratherm for example are about 200 - 500kms away from the main system (although to be sure, others emerging HFR Geothermal developers such as Torrens Energy and Kuth are within 20kms).⁷ This means that the more remote HFR Geothermal plants deployed at scale will often face a \$15-20/MWh radial transmission connection cost in addition to the shallow transmission grid connection costs faced by all generation technologies (MMA, 2009). The 'Tech Deployment' cost element on the other hand represents an entirely different form of cost risk premia, which has been added to underlying production costs at \$40/MWh, albeit somewhat arbitrarily. But the reason for this becomes clear when the technology is analysed. A Binary HFR Geothermal Power Plant process diagram is illustrated in Figure 2.

Figure 2: Binary HFR Geothermal Power Plant

As Figure 2 highlights, Australian HFR Geothermal involves drilling a pair of wells; an injection well and a production well. Hot granite rocks approximately 4-5 kms below the surface are then 'fraced' so that the two wells can communicate. At this point, a naturally occurring ground water referred to as geofluid or brine (because it contains a considerable amount of naturally occurring minerals and chemicals) is circulated through the injector well where it heats up naturally on the 200-250°C hot granite rocks before returning to the surface via the production well. At surface level, the thermal energy contained in the brine is transferred via a heat exchanger to a secondary working fluid for use in a largely conventional Rankine cycle⁸ power plant. As a result, the brine does not in any way come in contact with the moving parts of the power plant to avoid the possibility of corrosion (DiPippo, 1998). The secondary working fluid is flashed to steam, which is used to drive the steam turbine power generator. Candidates for the secondary fluid include isobutane, isopentane and propane; the properties of these fluids make them ideal for such a task as they have a very low heat capacity and flash to vapour or steam at relatively low temperatures (Anderson, 1998).

HFR Geothermal is different from 'conventional geothermal' plants such as those found in locations such as New Zealand, The Philippines, Italy, Japan and the USA. Conventional geothermal is characterised by naturally forming hot water which is released from highly permeable rock at high temperatures, and fed directly into a steam turbine (i.e. there is no requirement for a secondary working fluid). As Yearsley (2009) has noted, by comparison there are a number of material technical challenges facing HFR Geothermal.

- While there is nothing spectacular in the drilling technology used, the cost of wells has been surprisingly large. Once drilling moves beyond 3km, the point at which very hard granite rock is first struck, drilling costs tend to rise sharply. Industry sources suggest that the capital cost is typically between \$10-20 million per well.
- As granite has a low permeability and porosity, large amounts of power will be consumed in the production process (i.e. non-trivial auxiliary power losses arise through the significant pumping load associated with circulating the brine).
- But perhaps most critically, with the low permeability and porosity of granite, brine flow rates from paired wells are a fraction of those associated with conventional geothermal resources such as those found in New Zealand.

It is useful to illustrate this later point by reference to available public data on proposed HFR Geothermal power projects. DiPippo (1998) has noted that, with the exception of cases in which the brine is hyper-saline, it is acceptable to use the properties of pure water in evaluating the resource to useful output, and the example which follows is therefore based on the properties of conventional steam.

Temperatures at HFR Geothermal sites in Australia vary but are generally in the range of 170°C to 250°C. Perhaps the best known resource, and noted for its favourable temperature, is the Innamincka resource being developed by Geodynamics Limited. Following pilot testing, their power plant inlet temperature is stated to be 240°C with a reinjection or outlet temperature of 95°C (refer Figure 2).⁹ The theoretical thermal energy delivered by the brine can be derived from an engineering concept known as enthalpy or h . By definition, enthalpy is the total useful energy in a given substance, which in this case is the primary working fluid or brine (Swanekamp, 1998). It is the difference in enthalpy at the inlet and outlet temperatures that are critical. Enthalpy h^{in} of 240°C derived from Steam Tables¹⁰ is 1037.6 kJ/kg and enthalpy h^{out} of 95°C is 398.09 kJ/kg. As a result, Δh is 639.51 kJ/kg (or 274.94 Btu/lb). When the density of water ρ is combined with Δh we can compute the theoretical thermal energy per litre of brine, as follows:

$$m = \frac{1000}{60 \times (\Delta h \times \rho) \div \wp} \quad (6)$$

Where:

Δh is, as noted above, the difference in enthalpy at 639.51 kJ/kg;

ρ = the density of water at 240°C, and is 0.8133 kg/litre;¹¹

$\wp$ = conversion factor from kJ to kWh, and is 3600;¹²

Constants of 1000 and 60 represent the conversion factors from kWh to MWh and minutes to hours respectively; and therefore

• m = the theoretical thermal energy or flow rate expressed as 'litres per minute per MegaWatt' equates to 115 *lpm/MWt*

Geodynamics (2008) have estimated that the cycle thermal efficiency η of a Binary HFR Geothermal power plant to be 12%.¹³ DiPippo (1998, 2004) observed that Binary Geothermal power plants tend to involve a number of small modular units clustered together to receive the primary working fluid from several production wells through a manifold, and that the cycle efficiency for these binary plants are consistently in the range of 10-15% irrespective of capacity factor.¹⁴ There tends to be only a small sacrifice in cycle efficiency from using smaller generating units, and the gains of doing so include higher generating system availability and utilisation. The one global example where a large 65MW binary plant unit was installed (at Heber, California) never actually ran at full capacity due to inadequate supplies of the primary

working fluid (DiPippo, 1998). Similarly, research undertaken by Doroodchi and Moghtaderi (2009) found the thermal efficiency for binary geothermal plant to range between 8-14%. They also found that if the cycle developed was supercritical, thermal efficiency could rise to as high as 18%. However, while the technical conclusions were clear enough, the cost was not clear and accordingly, for the purposes of this article η has been set to 12% in subsequent calculations.

From equation (6), it was determined that each MW of plant capacity would require a flow rate of 115 *lpm*. However, this presumes a cycle efficiency of 100%. This point is critical and represents the single largest technical hurdle facing the deployment HFR Geothermal power plants in Australia. A 50MW Binary HFR Geothermal plant such as that envisaged in Figure 2 would require the following brine flow rate at full load:

$$M^t = \frac{\dot{m} \times k \div 60}{\eta} \quad (7)$$

Where:

$\dot{m}$ = the theoretical thermal energy as defined in equation (6), at 115 *lpm*/MWt

η = the cycle efficiency of the plant and is assumed to be 12%

k = the installed capacity of the power plant, at 50MW

M^t = is the required flow rate of the brine, expressed in “litres per second”, and is calculated to be 801 lps.

To put this into perspective, current flow rates at the Innamincka resource are just 20 lps.¹⁵ Accordingly, at this rate a 50MW HFR Geothermal Binary Power Plant would require 40 production wells, and at a cost of \$20m per well pairing would involve an \$800 million investment in drilling alone, let alone the cost of the power plant.¹⁶ Assuming the cost of the power plant is in the order of \$2200/kW, the total investment required for 50MW would be about \$910 million or \$18,200/kW installed. Applying the framework set out in Section 2, this would result in an LRMC of \$322/MWh plus \$20/MWh for radial transmission connection. Conversely, to achieve the implied ‘underlying’ LRMC for HFR Geothermal in Figure 1 of \$120/MWh, flow rates at Innamincka would need to exceed 75 lps. And once the cost of radial transmission is taken into account at \$20/MWh, brine flow rates would need to exceed 85 lps in order to undercut wind generation.¹⁷

Another HFR Geothermal company, Petrathern, expects to achieve brine flow rates of 75 lps although their resource at Paralana in SA has a lower inlet temperature of 200°C. Solving for equations (6) and (7) sequentially with this lower inlet temperature gives a result of 1061 lps.¹⁸ While this is 31% higher than the Geodynamics estimate of 801 lps, if flow rates are in fact 75 lps then it would require only 14 wells at a total project cost of \$390 million or \$7800/kW using the same assumptions of \$2200/kW for the power plant and \$20 million for each well pairing. To undercut wind generation, flow rates would need to increase to 110 lps or the cycle efficiency of the plant would need to reach about 17% (compared to 12% above).^{19,20}

Time, money and good engineering may lead to the necessary technological breakthrough. In Australia, coal seam gas was transformed from an uneconomic resource to one of the nation’s most economic via technological innovation (e.g. by horizontal drilling and under-reamed completions). It seems that the parallel breakthrough for HFR Geothermal may come in the form of ‘multi-zonal fracing’ to drive increases in brine flow rates. HFR Geothermal therefore remains in the ‘Research, Development & Deployment’ phase and will need the requisite R&D funding to match the challenge if it is to meet the potential LRMC benchmark outlined in Figure 1.

5. Investment in renewable power generation technologies

Wind is currently the most economic renewable energy technology in Australia (given resource endowments), and so any credible forecast of new capacity will necessarily involve a high penetration of wind turbine generators. A quantitative analysis of investment in renewable generating capacity in Table 1 confirms this to be the case. Australia's renewable fleet is dominated by wind capacity, representing as they do 69% of aggregate plant investment (excluding hydro).

Table 3: Australia's fleet of non-hydro renewable generation by fuel

Fuel Source	Installed Capacity (MW)	Market Share (%)
Wind	1,714.1	69%
Biomass	566.2	23%
Landfill Gas	207.0	8%
Solar	8.4	0%
Wave	0.5	0%
Geothermal	0.1	0%
Total	2,496.3	100%

Source: esaa (2010).

This bias towards investment in wind generation is not confined to Australia. As Figure 3 illustrates, wind dominates the global investment market for new renewable capacity. Between 2004 and 2009, aggregate global investment in new utility-scale renewable generating plant capacity was just over 378,000MW with wind representing 55 percent (210,000MW) of the total. In any given year, wind investments represent between 51-65 percent of all new global renewable energy capacity. The categories in Figure 3 of solar, biofuels and 'other'²¹, each have an approximately 15% (56,000MW) share of the global market for new capacity. It is also worth noting the slowdown in aggregate renewable energy investments in 2009 arising from the global financial and economic crisis; although growth in wind investments continued, even in 2009.

Figure 3: Global investment in non-hydro renewable generation technologies (2004-2009)

Source: PEW, 2010.

6. The demand for renewable energy generation in Australia and the investment task

The requirement for new renewable generating capacity in the NEM is substantial. As new plant forecasts presented later in this section reveal, approximately 9,500MW of renewable capacity

seems predictable between 2009 and 2020. The reason that this is predictable is that the primary demand for renewable energy in Australia exists as a result of government policy and associated legislation.

Supply is in turn facilitated via the establishment of a competitive ‘certificated market’ (as distinct from the substantially less efficient ‘Feed-in Tariff’ arrangements). In 2009, legislation was passed by the Federal Government which enforces a 20% Renewable Energy Target (RET) by 2020 upon liable entities, viz. energy retailers. Each year energy retailers are obliged to procure a certain percentage of their aggregate power purchases from renewable resources. Renewable generators have a right to create ‘Renewable Energy Certificates’ or RECs for each MWh produced. Retailers purchase RECs and submit them annually to a regulator as evidence that they have acquitted their RET liability (i.e. in the certificated market). The price at which RECs trade in the over-the-counter markets ‘trend towards’ the cost differential between the benchmark thermal plant (i.e. CCGT) and the benchmark renewable plant (i.e. wind) at the long end of the forward curve. This framework and the associated legislation builds on the earlier 2% Mandated Renewable Energy Target or MRET legislated in 2000 and implemented in 2002. The most practical way in which to examine the regulated demand for renewable energy is via Figure 4, which sets out Australia’s baseline renewable generation, the 2% MRET and the 20% RET.

Figure 4: Renewable energy production and targets in Australia

Source: Roam, AGL Energy Ltd.

In Figure 4, note that there is a pre-1997 renewable energy ‘baseline’ production level, represented by the dashed flat line at the 15,000GWh pa mark. This is the historic average annual renewable energy output from renewable power producers that existed prior to the MRET policy being first ‘announced’ in 1997. Most of the baseline renewable energy production is from conventional utility-scale hydroelectric schemes located in the Snowy Mountains, Victorian Alps, Far North Queensland and Tasmania. As Table 4 notes, this has typically been about 15,000GWh per annum, albeit declining more recently due to drought impacts. And as noted earlier, a 300GWh pa contribution was made from baseline bagasse cogeneration production from the QLD and NSW cane fields, amongst others.

Table 4: Historic hydroelectric production (2001 to 2009)

Year	Hydro Output (GWh)
2001	16,185
2002	15,362
2003	15,820
2004	15,399
2005	15,280
2006	16,141
2007	13,726
2008	11,800
2009	11,480
Average	14,577
Std Dev.	1,816

Source: esaa (2010)

Next in Figure 4 is the original 9,500GWh target associated with the MRET, given by the solid grey line. Note that it rises from the baseline commencing 2002 (when the policy was legislated) and rose to 9,500GWh above the baseline by 2010. Plant qualifying towards this target included all renewable generating technologies committed after 1997, and incremental output from the pre-1997 renewable fleet if they produced above historic baseline output levels. In the case of the latter, often this was achieved through efficiency improvements such as rewinding generators, replacing turbine blades or recoating penstocks, for example. In other cases, serendipitous weather conditions simply produced higher than seasonal average production.

Actual renewable generation output is also illustrated in Figure 4, given by the diamond-shaped markers. Note that the MRET was a policy met with considerable success, with the regulated target demand being met in all years. The final line in Figure 4 is the new RET demand, which represents an additional 45,000GWh by 2020 over and above the baseline, rising from 2009 – the point at which the legislation was passed.

The magnitude of this target is substantial. The existing fleet of renewable generators including large-scale hydroelectric schemes was built up over a 60 year period, yet produces only 25% of the total renewable generation requirement of 60,000GWh. What's more, there is no prospect for future large-scale hydro plant in Australia as all the prime sites for this technology have long been exhausted. The implications for incremental investment in renewable generation to FY20 are illustrated in Figure 5.

Source: Simshauser (2010), AGL Energy Ltd.

The four separate bar series in Figure 5 require explanation. The first bar series show the results of simulation modelling²² undertaken in FY06, which forecast the requirement for new plant capacity in the NEM over the period between FY09 and FY20. This FY06 analysis found that 5500MW of new base load CCGT plant was thought to be required along with 4500MW of peaking plant and only 1200MW of new renewable capacity. Driving these outcomes was a presumption of an Emissions Trading Scheme (ETS) and the original 2% MRET. The next bar series in Figure 5 was a forecast undertaken at the start of FY09, with the key change being the introduction of the 20% RET. Note the material increase in renewable capacity to 9500MW, with the primary casualty being CCGT plant - reducing from 5500MW to just 2800MW. OCGT plant was forecast to increase from 4500MW to 5500MW, driven in part by the reduction in need for base load plant, and in part by the intermittency of renewable resources.

The third bar series provides an update on projects that have since been built in the NEM over the FY09 to FY11f period. A surprisingly large percentage of CCGT plant has been built, driven by a short burst of highly favourable market conditions that existed throughout 2007 and 2008 in both electricity market prices and (expected) ETS policy settings.²³ The final series in Figure 5 provides a current outlook for investment in the NEM following new investments to FY11f, changed demand impacts of the global financial and economic crisis of FY09, and refinements to the 20% RET.²⁴

7. South Australian plant and fuel mix

Given the forecast requirement for new renewable generating capacity illustrated in Figure 5, an issue that challenged policy makers, system planners, developers and financiers alike was how the existing grid would cope with a surge in new intermittent plant. It is often the case that some of the best renewable resources are located remotely from the existing power transmission grid, but not exclusively so and SA is a particularly useful case study in this regard.

Just seven years ago SA had a pure thermal power system, comprising as it did two fuels; brown coal which provided 37.7% of the market (primarily base and intermediate) and natural gas which provided the remaining 62.3% of the market in base, intermediate and peaking plant types. This is illustrated in Table 5. CCGT plant in SA undertakes primarily base and intermediate duties, whereas Gas (steam) undertakes intermediate and peaking duties. OCGT plant tends to be limited to peak operations only. Note that there was no wind generating capacity at all.

Table 5: Plant mix and fuel use in South Australia in 2003

Technology	Capacity (MW)	Energy (GWh)	Share (%)
Brown Coal	760	3,836	37.7
CCGT	660	3,480	34.2
Gas (Steam)	1,280	2,186	21.5
OCGT	646	679	6.7
Wind	-	-	-
Total	3,346	10,182	100.0

Source: esaa (2004), AGL²⁵

Since 2004, the growth in SA's renewable plant stock has been rapid; as Table 6 illustrates, wind generation now produces 17.1% of market output and has done so under the existing market rules and without much fanfare, despite the original concerns of system planners, policy makers and financiers. In the main, all fuel types have expanded their production levels relative to 2004, but market shares for the two base load technologies, viz. brown coal and CCGT plant, have declined in relative terms. This is an important comparative observation and modelling produced later in this article provides a theoretical framework which illustrates why such an outcome is predictable.

Table 6: Plant mix and fuel use in South Australia in 2009

Technology	Capacity (MW)	Energy (GWh)	Share (%)
Brown Coal	760	4,575	32.7
CCGT	663	4,310	30.8
Gas (Steam)	1,280	2,374	17.0
OCGT	768	336	2.4
Wind	869	2,393	17.1
Total	4,340	13,989	100.0

Source: esaa (2010), AGL

Table 6 notes that 869MW of wind capacity has been added to the SA power system since 2004. Table 7 provides a detailed breakdown of the wind portfolio, including the owner, year of commissioning, installed capacity, energy output and the all important Annual Capacity Factor (ACF) of each facility for FY10.

Table 7: Wind Projects in South Australia

Wind Farm	Plant Owner	Year	Capacity (MW)	Energy (GWh)	ACF (%)
Starfish Hill	TSI	2003	34.5	88	29.1
Cathedral Rocks	Tas Hydro	2005	66.0	186	32.2
Canunda	IP Aust	2005	46.0	118	29.3
Lake Bonney 1	Infigen	2005	80.5	175	24.8
Mt Millar	Meridian	2005	70.0	179	29.2
Wattle Point	AGL	2005	90.8	262	33.0
Hallett 1	AGL	2008	94.5	336	40.6
Lake Bonney 2	Infigen	2008	160.0	274	19.5
Snowtown	Trust Power	2008	99.0	361	41.6
Clements Gap	Pac Hydro	2009	57.0	165	33.0
Hallett 2	AGL	2009	71.0	250	40.2
Fleet Total			869.3	2,393	31.4

Pavlak (2010, p.54) noted in the case of the US, ‘good, fairly windy sites result in an average capacity of 20 percent’. Perhaps the most important statistic from Table 7 is therefore the fleet average ACF of 31.4%, with some sites exceeding 40%. If the Lake Bonney projects were excluded, which were disrupted by transmission substation work during FY10, the fleet-wide ACF rises to 35.3%. This is a favourable fleet-wide ACF and reflects the high quality SA wind resource.

8. Defining the source of wind generation’s hidden costs

Dominant thought on intermittent power resources such as wind (and solar) is that because the output is variable and unlikely to be well correlated with energy demand, they have a negative effect on power system security. To see why this arises, consider Figure 6 which presents a sample of half-hourly ‘gross’ energy demand and ‘net’ energy demand (after deducting wind output) data in SA. Also included is the installed capacity of wind generation and wind power output.²⁶ This graph captures some of the perceived system security issues associated with introducing wind energy into a predominantly thermal system.²⁷

Note on 2 January 2010 at 5am (Event A) in Figure 6 that during the overnight demand trough, gross system load is only 1,093MW. The 870MW of installed wind capacity is producing 560MW (64% utilisation) and is essentially servicing 51% of gross system demand at this point in time, leaving net load of 533MW for thermal plant to service. This is in fact problematic for thermal plant. Both brown coal and CCGT plant have technical limitations on turn-down rates when operating base load. For example, the primary base load power plant in SA, Northern Power Station, comprises 2 x 265MW subcritical coal-fired generating units. When these units are on-line, they must run at no less than 40-50% of nameplate capacity in order to operate within a stable envelope. This is a technical limitation common to all steam cycle plants with large boilers. Assuming the two units were operational at the time, Northern Power Station alone accounts for about half of the 533MW of residual load. In a simple back of the envelope calculation, total Brown Coal and CCGT plant from Table 6 amounts to 1423MW; the implied minimum load of this base load fleet (at 40% of nameplate capacity) amounts to 570MW, which is more than the residual load.

Figure 6: SA Load and wind production from 1 January to 14 January 2010

Source: AEMO.

Fortunately, SA has 450MW of interstate transmission export capability to neighbouring Victoria (VIC) and clearly on such days, the minimum technical loads of the thermal fleet would be satisfactorily accommodated via exporting their power to the neighbouring region (although with low or even negative spot price outcomes). If more and more wind capacity was added, electricity prices could be expected to turn severely negative indicating that offloading of thermal plant may be required. However, an increased incidence of negative prices will find a natural saturation point. Firstly, rising negative price events will inevitably limit the economics of new wind projects. Secondly, additional transmission interconnection capacity is likely, thus enabling higher interstate transfers to the balance of the NEM. Thirdly, CCGT and Gas (steam) plant are more than capable of two-shifting. Fourthly, older, higher polluting inflexible coal plant should close (i.e. an outcome which is consistent with the environmental objective function of energy policy). And finally, virtually all wind farms built after 2007 are 'scheduled' or 'semi-scheduled' by the power exchange; meaning that all newly developed plant incorporate control system equipment that enables wind turbine generators to turn-down their output (i.e. essentially applying 'the brakes' to the turbines). Ultimately though, the minimum load issue is simply a market issue. Exactly the same risk exists whether new wind generators, new HFR Geothermal generators or even new CCGT plant is commissioned (i.e. with carbon pricing). As such, this cannot be considered a hidden cost associated with wind.

The remaining so-called hidden costs of wind relate to system security and the requirement for adequate 'operational reserves' and 'planning reserves'. The basis for this can be observed in Figure 6, and specifically the Events (B), (C) and (D).

In terms of wind's reliable supply contribution to peak demand, note in Figure 6 that on 10 January at 5:30pm (Event B) that the daily peak demand of 2930MW is associated with very little wind production. The entire 869MW wind fleet is producing just 36MW during this period which at first glance tends to support the view that intermittent plant cannot be relied upon to any great degree. Wind turbines have a cut-off wind velocity and shut down when wind drops below a certain level (Pavlak, 2010). However, note also on 11 January (see Events C and D) when temperatures rose very significantly to produce the maximum demand event of the year at 3311MW gross, the very weather conditions driving demand (hot dry winds) also led to virtual record wind farm output of 618MW (71% capacity utilisation), thus reducing the 'net' system load on that day to just 2700MW.

In the NEM, wind generating capacity is often said to make about an 8% capacity contribution to system security during peak demand with a 0.95 level of confidence (see for example AMEO, 2009 at Appendix B, B.6.6). In other words, for each 1000MW of wind capacity installed, about 80MW might be relied upon during extreme peak demand periods for planning purposes. To see how this might be determined, Table 8 presents a statistical analysis of wind output relative to FY10 peak demand in SA.

Table 8: Analysis of SA energy demand and wind output

SA Wind Portfolio	Top 5% of Load	Top 10% of Load	Top 15% of Load	Top 20% of Load	Total Load
Min Demand (MW)	3,146	2,980	2,815	2,649	983
Max Demand (MW)	3,311	3,311	3,311	3,311	3,311
No. of Half-Hours	18	61	169	280	17,520
Correlation Wind/Demand	0.78	0.68	0.51	0.35	-0.07
Min Wind Output (MW)	94	18	18	8	0
Max Wind Output (MW)	629	629	629	629	765
Avg Wind Output (MW)	448	291	210	195	273
95th Percentile Output (MW)	135	57	33	30	22
Wind Capacity Factor (%)	51.5	33.4	24.2	22.5	31.6
95th Percentile "Reliability" (%)	15.5	6.5	3.8	3.4	2.6

The first column of results analyses the top 5% of gross maximum demand events in SA, which range between 3146MW and 3311MW. The top 5% of demand events span 18 half-hour intervals spread across the year; 17 intervals occurred during 1Q2010 with the remaining 1 event occurring in 4Q2009. The correlation between wind production and energy demand in the top 5% of demand events is surprisingly high at 0.78. Note however as the analysis is expanded to the top 10%, 15% and 20% of demand events, this relationship begins to break down. And when analysed across the year as presented in the final column of Table 8, a mild negative correlation exists between wind output and system demand. But for the purposes of system security in a grid with a poor load factor, it is the top demand events that require especially detailed consideration (Turvey, 1968).

During the top 5% of demand events, minimum wind output was 94MW and maximum output was 629MW with an average output from the 869MW wind portfolio of 448MW. This is an implied capacity factor of 51.1% during those 18 half-hour intervals. More relevant to 'dominant thought' however is at a 0.95 confidence limit. If 95th percentile output was used to calculate a so-called *wind reliability factor for system security purposes*, it would imply that the SA wind generating portfolio could be thought of as making a 6.5% contribution (i.e. 0.95 confidence limit result in the Top 10% load events in Table 8), which is broadly consistent with the AEMO (2009) finding of 8%.

Taking this type of analysis to its logical (or perhaps illogical) conclusion, one would expect that with 870MW of installed wind capacity in SA, only 57MW is so-called *reliable capacity*, and therefore the system would need an additional 813MW of fast-start gas turbine capacity to ensure system reliability. This is the apparent conclusion that one might reasonably draw from this style of analysis.

9. The tyranny of dominant thought: the hidden costs of wind

The analysis that follows indicates that the hidden cost concept, when quantified, is trivial by comparison to thermal industry rhetoric.²⁸ The source of hidden costs can be condensed into three key concepts; the increased cost of transmission, the increased cost of voltage support and the increased cost of power system reserves.

9.1 Transmission

It was noted in Section 8 that increased interstate transmission capacity would enable a higher incidence of wind development in SA. The existing interstate transmission interconnection between SA and VIC will inevitably be expanded, and the general industry view is by an additional 400MW.²⁹ Prima facie, this might be thought of as a 'hidden cost' of the RET and in turn, wind generation. However, such logic is too convenient. As Roam (2010) demonstrated, if the SA power system was not being built-out with wind, it would be reliant on lower cost economic power transfers from neighbouring VIC where marginal running costs of the thermal fleet are considerably lower. In short, transmission augmentation between SA and VIC would occur regardless, although for different reasons and directional flows, and therefore cannot be considered a hidden cost of wind generation. Roam (2010) nonetheless quantified the impact of this 400MW augmentation using the current regulated cost of capital and found the annualised cost to be c.\$16 million pa or \$0.06/MWh. Accordingly, if augmented interconnect capacity was to be ascribed to the RET and thought of as a 'hidden cost', it would amount \$0.06/MWh.

Localised, or shallow transmission connection costs between a favourable wind resource and the main grid is of course a cost borne as part of any wind development and therefore forms a part of the \$120/MWh LRMC, just as they are for any thermal plant. This of itself is a transparent cost as distinct from a hidden cost.

9.2 Network Control Ancillary Services - voltage stability

In order to keep a geographically diverse grid operating in a stable manner, voltage support is required and the dispatch costs of this reactive power support currently costs about \$0.25/MWh, and is recovered from customers.³⁰ Reactive power is provided/absorbed by conventional generators or if there is no local generator, by network operators installing devices known as Static VAR Compensators (SVC). Australia's thermal generation fleet has been an important (free) source of reactive power, but if new plant capacity has a bias towards wind generation rather than thermal plant, new sources of reactive power may need to be supplied.³¹ A study by Müller et al. (2005) analysed the system stability of a 45,000MW power system (i.e. the same size as the NEM) with 5,000MW of wind congested in one particular region. They noted that fixed-speed induction wind generators have a highly negative impact on dynamic voltage, the implication being that SVCs would need to be added. However, modern wind generators, viz. variable speed wind generators (i.e. doubly-fed induction generators) equipped with low-voltage ride-through capability and reactive current boosting and fast voltage control actually made improvements to transient system stability. With very few exceptions, most wind generators developed in the NEM have been fixed-speed induction generators. But even if all wind future developments from FY10 continue to deploy fixed-speed induction technology, before connecting to the grid, the wind generator would be required by AEMO, the network operator or the SA Energy Regulator³² to pay for the installation of SVCs. Such costs form part of the overall project economics, and therefore need to be incorporated into the investment decision of the wind project and form part of the transparent LRMC of wind generation. Accordingly, the hidden cost of voltage support from wind generation is zero.

9.3 Operating, Contingency & Planning Reserves

If there is such a concept as the 'hidden cost' of wind generation, it is thought to be most acute in relation to the burden that intermittent technologies place on system reserves. But as the title of this Section 9.3 indicates, there are in fact three classes of reserves and each requires separate analysis.

To begin with, it is worth clearly defining what 'system reserve' actually means. Because electricity cannot be stored, there is a continuous (quite literally, a second-by-second) requirement for supply and demand to be matched. To achieve this, reserves are broken down

into three distinct classes; (1) real-time operating or ‘regulation reserves’; (2) near-real-time ‘contingency reserves’; and (3) longer term ‘planning reserves’ otherwise known as the power system’s reserve plant margin. As Rochlin (2010) noted, all of these forms of reserve are vital requirements to run a safe and reliable power system.

The NEM market operator, AEMO, operates 8 organised Frequency Control Ancillary Service (FCAS) markets which cover (1) regulation reserves and (2) contingency reserves. The system’s reserve plant margin is left entirely to the market, that is, the NEM is an energy-only market and there is no specific institutional arrangement for reserve plant.³³

9.4 Regulation reserves

At any moment in time on the power system, loads of various sizes are switching on and off, substantially more so than implied by the half-hour granularity of data used to construct the load curve in Figure 6. In consequence, the aggregate fleet of generators must respond to changes instantaneously and in order to do so, AEMO uses fast-response generators in Automatic Governor Control (AGC) mode to ‘raise’ and ‘lower’ power plant output, thus maintaining the power system at 50 hertz. AGC ‘raise services’ and ‘lower services’ are therefore providing operational or ‘regulation reserves’.

At one level, the intermittency of wind might appear to resemble demand variability; therefore as more wind capacity is added to a grid, the requirement for regulation reserves might be expected to increase because more generating capacity will be required to provide this real-time load-following service. Diversification of wind farm locations would, on the other hand, reduce this. However, detailed power system analysis undertaken by ESIPC (2005) found that the general inertia of wind turbines meant that they are in some respects less disruptive than conventional generators and loads.

Regardless, regulation reserves represent an especially small fraction of total Ancillary Service costs. For example, over the two year period between FY09 and FY10, the total value of energy traded in the 45000MW NEM was \$19.721 billion, with total ancillary service costs comprising \$377m or 1.9% of this. The cost of regulation reserves was minute, at just \$10.3 million over the two year period, representing less than 0.06% of the roughly \$10 billion of energy traded annually in the NEM, and equates to about \$0.03/MWh. And as an aside, generators pay for about 30% of regulation services in any event and thus customers currently pay about \$0.02/MWh.

Roam (2010, p.22) noted that as wind capacity expands, the requirement for regulation services may rise in the absence of wind diversity, but regardless, the cost per megawatt of wind for any additional regulation service would remain relatively constant in the future. Accordingly, if there is an additional ‘hidden cost’ of regulation services, it will be no more than \$0.03/MWh.

9.5 Contingency reserves

The remaining six spot markets for Frequency Control Ancillary Services in the NEM provide ‘contingency reserves’. These reserve services are provided by generators that are synchronised to the grid but not producing at full output. In doing so, they act as a form of storage to respond to material changes in demand or supply by raising or lowering output over 6 second, 60 second and 5 minute timeframes for both raise and lower services (that is, two distinct raise/lower products over the three timeframes).³⁴

The easiest way in which to consider the requirement for contingency reserves is in the context of a sudden ‘forced outage’ of a large 660MW generating unit that was producing at full load. When this occurs, system frequency and voltage immediately begin to drop. At this point, all

remaining generators increase their output although this extra output comes from kinetic energy rather than from additional fuel. As this supply source is depleted, frequency and voltage drop causing load to draw less power and the system then rebalances, albeit at a frequency lower than 50 hertz after a matter of seconds. At this point, the 6 second, 60 second and 5 minute 'contingency raise services' are dispatched to restore system frequency.³⁵

While wind generators may well increase the absolute quantity of regulation reserves as discussed in Section 9.4, they are most unlikely to increase the requirement for contingency reserves. The demand for contingency reserves is primarily driven by the sudden loss of large generators or individual loads (such as a 280MW aluminium potline). Such sizeable MW losses are clearly 'large' system disturbances. Wind farms on the other hand tend to comprise a large cluster of very small turbines. For example, in SA, wind farms range from 23-55 individual machines with the rated capacity of turbines ranging from 1.5MW to 3MW, with an average configuration of 40 x 2MW (esaa, 2010). It is entirely unlikely that a cluster of wind turbines operating at a high capacity factor would trip off-line simultaneously. Any shift in the plant availability or production duties of these smaller units is therefore captured by operational reserves (i.e. regulation reserves per Section 9.4). Accordingly, there are no 'hidden costs' of wind generators in relation to contingency reserves.

9.6 Planning reserves

In addition to the instantaneous and fast-response services of regulation and contingency reserves, there are also longer term 'planning reserves' or system reserve plant margin, which is essentially generating plant providing the resources to respond to meet forecast demand given unexpected changes in weather, economic conditions and plant outages. This is where the overwhelming majority of the 'hidden cost' of wind is thought to be, and the reason for this view should be apparent from Figure 8. Recall that AEMO (2009) analysis of wind in the NEM indicated that 8% of wind in SA could be relied upon at a 0.95 confidence limit, which in this case translates to 70MW of the 870MW portfolio.

Fortunately, our market institutions in the NEM utilise vastly more sophisticated objective functions than a 0.95 confidence limit to determine reliability. Crucially, the NEM's measure of reliability of supply is not constrained to delivering 100% of demand during a peak event. The NEM's reliability objective function is *no more than 1GWh lost for every 50,000GWh served*, or no more than 0.002% of unserved load. This reliability criteria has been examined by NEM's market institutions on several occasions, and has been retained on every occasion because of its suitability and balance between consumer welfare, economic efficiency and power system effectiveness. Accordingly, if there is a lost load event during a high demand period, this is not in any way inconsistent with the operation of the NEM's stated reliability criteria.

The implications of this are important. Assessing wind output at a 0.95 confidence limit is in many respects quite academic because it is inconsistent with the analysis and treatment of power system reliability in the NEM. Accordingly, the manner in which the reliability of wind is calculated in Table 8 for example is interesting at best, and very misleading at worst.

The better view in assessing the wind portfolio's output on system reliability and its consequent causation for additional 'backup' fast-start gas turbine plant capacity is by following Bushnell's (2010) static and dynamic partial equilibrium analysis. The static analysis involves the construction of gross and net aggregate load duration curves.³⁶ The net load duration curve is essentially the remaining load after output from the wind portfolio is deducted. At this point, either static plant investment cost curves or dynamic system simulation modelling can then be utilised to analyse the effect on the plant stock with- and without the wind portfolio. In this article, both analyses are used; the benefit of the static analysis is that it elegantly displays the

quintessential results of the computationally heavy and data intensive dynamic, partial-equilibrium power system simulation modelling. The results of the static partial equilibrium analysis, presented in Figure 7, is based on the seminal works of Boiteux (1949), Berrie (1967), Turvey (1968), and Crew and Kleindorfer (1975).^{37,38} The dynamic power system analysis undertakes the same exercise in a conceptual sense, but obviously achieves a level of accuracy that is simply not possible using static modelling methods. The dynamic results are presented in Tables 9 and 10.

To begin with, note that the static analysis in Figure 7 comprises two distinct graphs; the top graph presents the running cost curves of the thermal technologies able to be developed in SA. The primary cost inputs have been drawn from Table 1 although unit fuel costs have been modified for SA conditions (i.e. black coal railed from NSW at 2.50/GJ and gas at \$4.50/GJ) and carbon has been priced, or shadow priced, at about \$32/t and is drawn from Treasury Modelling. Three cost curves are therefore produced for each of base load Super Critical pulverised fuel (SCpf), base load CCGT plant and peaking OCGT plant. From inspection of the top graph in Figure 7, it is immediately apparent that SCpf plant is uneconomic at any level of output given the shadow price of carbon. OCGT plant on the other hand has the lowest cost in \$/kW/a for any Annual Capacity Factor to 30%. Thereafter, CCGT plant dominates the efficient frontier for generation plant investments.

Figure 7: Gross and net SA load duration curve for FY10

The bottom graph in Figure 7 presents two load duration curves. The higher load duration curve is gross system load³⁹, while the lower load duration curve is net of wind power output.⁴⁰ Note that the investment cross-over points from the top graph are transposed down to the load duration curves. Importantly, the gross peak demand and net peak demand periods are not time-related. That is, gross maximum demand of 3,311MW occurred at 1pm on 11 January 2010 whereas net maximum demand of 3,077MW occurred at 4pm on 9 February 2010 at which time the wind portfolio was running at a 10.8% utilisation rate and producing 94MW, and thus gross maximum demand at that time was 3,170MW (i.e. 3,077MW+94MW).

Using the gross load duration curve, the ideal plant mix comprises 1800MW of base load CCGT plant and 1920MW of OCGT peaking plant. Under this scenario, there is no wind generation. When the net load duration curve is used, only 1500MW of base load CCGT plant is required with no change to the fleet of OCGT plant. As a result, an entire CCGT plant of 300MW is avoided. The impact of this becomes clearer with results from dynamic power system modelling, as illustrated in Tables 9 and 10. The system optimal results have been produced by a model called NEMESYS, which is a dynamic, partial equilibrium model of the power system with half-hourly resolution and price formation based on a uniform, first price auction consistent with the NEM design. As with Bushnell's (2010) approach, the NEMESYS model assumes perfect

competition and essentially free entry to install any combination of capacity that satisfies differentiable equilibrium conditions with wind output being exogenous to the equilibrium investment model, having been implemented by the RET.⁴¹ However unlike Bushnell (2010), in this analysis the lumpiness of capacity is a constraint; firms may chose either a 300MW CCGT base load plant or a 160MW OCGT plant based on conventional ‘E Frame’ gas turbine technology; a technology widely available from the main plant manufacturers including GE, Mitsubishi Heavy Industries, Siemens, Alstom and so on. Table 9 presents results from the ‘no wind’ scenario.

Table 9: Dynamic power system modelling for SA – ‘no wind’

Plant type	Modelled (MW)	Production (MWh)	ACF (MW)	Fixed Costs (\$)	Running Costs (\$)	CO2 Costs (\$)	Total Costs (\$)
CCGT	1,800	12,830,525	81%	411,456,178	404,161,522	164,069,057	979,686,757
OCGT	1,920	1,584,276	9%	310,478,551	118,424,657	29,319,234	458,222,443
Wind	0	0	0%	0	0	0	0
Total Plant	3,720	14,414,801	44%	721,934,730	522,586,179	193,388,291	1,437,909,199
System Average Cost:		99.75 /MWh	Gas Demand:		108.0 PJ/a		
LRMC Base plant:		75.65 /MWh	CO2 Emissions:		6.1 Mtpa		

As implied by Figure 7, the least cost plant mix is found to be 1800MW of CCGT plant and 1920MW of OCGT plant, which produces about 14,400GWh. This fleet incurs system-wide annual costs of \$1.438 billion, with fixed capital and operating costs comprising about 50% of the total. This produces a system average cost of \$99.75/MWh with 108.0PJ of gas consumed and 6.1Mt of CO₂ emissions. Table 10 presents results from the ‘869MW wind portfolio’ scenario.

Table 10: Dynamic power system modelling for SA – ‘869MW wind portfolio’

Plant type	Modelled (MW)	Production (MWh)	ACF (MW)	Fixed Costs (\$)	Running Costs (\$)	CO2 Costs (\$)	Total Costs (\$)
CCGT	1,500	10,355,434	79%	342,880,149	326,196,185	132,419,088	801,495,422
OCGT	1,920	1,667,034	10%	310,478,551	124,610,805	30,850,783	465,940,139
Wind	869	2,393,317	31%	287,198,047	0	0	287,198,047
Total Plant	4,289	14,415,786	38%	940,556,747	450,806,989	163,269,871	1,554,633,608
System Average Cost:		107.84 /MWh	Gas Demand:		91.7 PJ/a		
LRMC Base plant:		75.65 /MWh	CO2 Emissions:		5.1 Mtpa		

The comparative results in Tables 9 and 10 reveal important information. Recall from Section 8 that NEM analysis of wind farms indicates an 8% level of capacity utilisation at a 0.95 level of confidence. Prima facie, this implies that only 8% or 70MW of the 869MW wind portfolio could be relied upon. Given plant choices of 300MW for CCGT and 160MW for OCGT, it would be hard to justify substituting any thermal plant whatsoever if only 70MW was considered reliable. However, with the proper treatment of planning reserves using the NEM’s reliability criteria, an entirely different outcome emerges.

The most important outcome from Table 10 is that a full 300MW base load CCGT plant is avoided with the implication being that at least 300MW or 35% of the 869MW wind portfolio has been contributed to planning reserves, dramatically higher than a 0.95 confidence limit implies. This finding is not unique. MMA (2010) and Roam (2010)⁴² had undertaken similar studies of the impact of wind in Australian power systems, and found that the *useful contribution* of wind capacity for planning purposes was consistently much closer to the average ACF of a wind portfolio, and substantially higher than that implied by a 0.95 confidence limit around half-hourly production.

To be sure, the wind scenario in Table 10 is unambiguously more expensive than the no-wind scenario in Table 9; System Average Cost is \$107.84/MWh, some \$8.10/MWh higher than the ‘no wind’ scenario and as noted earlier, if the hidden costs of transmission augmentation at \$0.06/MWh and regulation reserves of \$0.03/MWh are added, then the total cost impact is \$8.19/MWh. Since customer bills are currently running at \$200-\$210/MWh, this represents an increase of about 4%. To put this into perspective, electricity accounts would increase at a rate equivalent to 1.5 years worth of Consumer Price Indexing. The total result of \$8.19/MWh is a ‘total cost impact’. An aggregated breakdown of the costs and the benefits of wind in the SA system is provided in Table 11.

Table 11: Analysis of the Transparent and hidden costs and benefits of wind in SA

	Total Cost (\$)	Unit Cost (\$/MWh)	Driver
Transparent Costs of Wind			
Additional unit cost of wind generation	195,186,435	13.54	LRMC
Hidden Costs of the Wind			
Additional Reserve Plant (OCGT)	92,011,612	6.38	+569 MW
Additional Transmission Interconnection		0.06	SA-VIC
Additional Regulation Reserve		0.03	
Total Transparent & Hidden Costs	287,198,047	20.01	
Hidden Benefits of the Wind			
Avoided CCGT Base Plant (Capital Costs)	68,576,030	4.76	-300 MW
Avoided GT Running Costs (Fuel Costs)	71,779,189	4.98	-16.4 PJ/a
Avoided CO2 Costs at \$32/t	30,118,420	2.09	-1.0 Mtpa
Total Hidden Benefits	170,473,639	11.83	
Net hidden cost/benefit	78,462,026	+5.35	(benefit)
Total Additional Cost of Wind	116,724,409	8.19	

The difference in Total Costs between Tables 9 and 10 relating to the wholesale market amounts to \$287,198,047, and when the other hidden costs of transmission and regulation reserve are added, amounts to \$20.01/MWh. Clearly, in the wind scenario presented in Table 10, there is more installed plant capacity (i.e. 4289MW in Table 10 vs. 3720MW in Table 9) and therefore there is implied ‘back-up’ capacity, worth \$92 million or \$6.38/MWh as noted in Table 11.⁴³ By definition, the remaining cost is the differential between wind farms producing at \$120/MWh, and the marginal running and carbon costs and of the gas turbine fleet, albeit for 17.1% of the market.

What is not well understood well by the broader industry is the hidden benefits of introducing wind. In the first instance, the wind portfolio avoids a \$450m investment in a 300MW CCGT requirement that would otherwise be considered necessary using confidence intervals of minimum output at peak demand events, which in cost terms, avoids \$68.6 million pa or \$4.76/MWh. Fuel consumed also reduces significantly, from 108PJ/a to 91.7PJ/a, a reduction of 16.4PJ/a and reduced marginal running costs of \$71.8 million or \$4.98/MWh. Finally, in this study where carbon has a price, about 1Mtpa of CO₂ emissions are avoided representing a reduction of \$30.2 million or \$2.10/MWh. Accordingly, there is not a hidden cost of wind, but a hidden net-benefit amounting to \$5.35/MWh (i.e. total hidden costs of \$6.47 less total hidden benefits of 11.83/MWh). And when applied against the transparent cost of \$13.54/MWh results in a total cost of wind of \$8.19/MWh.

A simple rule of thumb will of course achieve 95% accuracy when predicting this result; take the LRMC of wind at \$120 less the cost of a CCGT at \$75, multiplied by the market share of wind of 17.1% to arrive at a cost impact of \$7.70/MWh, which is within 5% of the wholesale cost impact.

10. Concluding remarks

Australia's 20% RET is likely to see the introduction of more than 9000MW of new renewable generating capacity between now and 2020. Analysis in this article indicates that, given current technology costs in Australia, wind is likely to continue to dominate forward investment plans. Two rival technologies, Biomass and HFR Geothermal, have the potential to match wind as an economic entrant; but Biomass developments remain problematic from a capital cost perspective, and HFR Geothermal requires sizeable increases in the flow rates of the primary working fluids. In the interim, this leaves the industry with wind generators as the 'renewable workhorse'.

The purpose of this article was to analyse the transparent and so-called hidden costs of wind generation in a thermal power system, given claims by well respected business journalists and industry executives that LRMC of this technology greatly understates its true cost. The SA region of the NEM provides an interesting and an important case study, because wind generation has gone from a zero market share in FY03 to a 17.1% market share in FY10.

There were a number of important findings in this article. First, the cost of transmission and voltage support was found to be negligible, with the former at \$0.06/MWh and the latter essentially being absorbed within the LRMC of wind investments. The area where the hidden costs of wind are thought to be most acute is in power system reserves. Yet a detailed analysis of regulation reserves found that the cost is likely to be trivial (i.e. \$0.03/MWh), and that the remaining Frequency Control Ancillary Service markets are most unlikely to be affected at all. Planning reserves will be affected, but by an order of magnitude lower than industry rhetoric suggests. While the transparent cost of wind was found to be \$13.54/MWh, representing the cost differential between new wind generators and the marginal running costs (including carbon) of the gas turbine fleet, the so-called hidden costs of incremental fast-start gas turbine plant were actually found to be outweighed by 'hidden benefits'. These hidden benefits eliminated the hidden costs and led to a surplus of \$5.35/MWh, driven primarily by the reduction in base load CCGT plant, reduced gas consumption and avoided CO₂ emissions.

A simple rule of thumb, which takes the difference between the LRMC of a CCGT plant and wind plant, multiplied by the market share of wind, returned a result of about \$7.70/MWh. Comprehensive dynamic, partial equilibrium modelling found a result of \$8.19/MWh. If there is a hidden cost, it is about \$0.49/MWh – which when compared against an electricity bill of \$200/MWh, must be considered trivial. And the total cost of \$8.19/MWh equates to an increase of about 4%, which translates to about 1.5 years of Consumer Price Indexing of the end-use tariff.

One issue that will clearly require more research is future connection costs – our understanding of these are limited. One could reasonably expect that the cost of connecting the final 1000MW of renewable energy capacity under the RET will involve more distant renewable resources. Although, establishing the counterfactual will be equally important; any thermal resource alternative will not involve costless transmission connection. Had the power system been planned originally with carbon constraints in mind, the transmission system would presumably look entirely different; viewed in this light, whether we should blame the last 1000MW of renewables for imposing a connection premium then becomes as much an ethical issue as an economic issue.

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¹ The Power Island is defined as the core components of a generation plant (i.e. boiler, turbine, generator) whereas the Balance of Plant comprises auxiliary equipment (e.g. feed-heating, fuel processing, cooling systems and so on). In some cases the Power Island and Balance of Plant contracts are combined to form an Engineering, Procurement and Construction or EPC Wrap.

² In some cases, interest costs capitalised (IDC) during construction are also included. However, in this analysis IDC is excluded and instead captured by the discounting of cash flows over the construction period.

³ Stanwell’s loss on sale of \$1.5m in its 2006 accounts was preceded by asset write-downs of \$10.7m in 2005, \$18.2m in 2003 and by \$18.9m in 2002. For details see <http://www.stanwell.com>

⁴ For further details on the sale process, see *Australian Financial Review*, Street Talk column, 4 May 2010.

⁵ For further details see CSR (2006) at page 15.

⁶ More recently, Mackay Sugar committed to develop a 36MW CoGen at a cost of \$120m at \$3300/kW installed. For further details see <http://new.mkysugar.com.au/investors/announcements.aspx>.

⁷ For details, see www.geodynamics.com.au, www.petratherm.com.au, www.torrensenenergy.com and www.kuth.com.au.

⁸ A Rankine cycle is the simplest of steam cycles involving the straight expansion of steam and a single stage of external heat addition (Swanekamp, 1998).

⁹ See Geodynamics (2008) at page 6.

¹⁰ See steam tables at http://www.efunda.com/materials/water/steamtable_sat.cfm for enthalpy at various temperatures.

¹¹ The density of water at 240°C is 813.37 kg/m³ per http://www.efunda.com/materials/water/steamtable_sat.cfm. Converting this to kg/l returns 0.813365kg/l. See http://www.efunda.com/units/convert_units.cfm?From=190&mrn=813%2E36521725#ConvInto or <http://www.spiraxsarco.com/resources/steam-tables/saturated-water.asp> for details.

¹² Converting kJ to kWh is given by 3600kJ = 1KWh. See <http://www.onlineconversion.com/energy.htm>.

¹³ See Geodynamics (2008) at page 7.

¹⁴ The Kalina version of the binary plant (as distinct from the Rankine cycle) is thought to lead to substantial increases in power output – in the order of a 30-50% increase (Kalina cycles use a secondary working fluid comprised of water and ammonia, and the process involves pre-heating this fluid). However, DiPippo (2004) demonstrated that the cycle efficiency of Kalina plants only achieved a 0.6 percentage point improvement in cycle efficiency. See DiPippo (2004) at p.579-584.

¹⁵ See Geodynamics (2009) at page 12.

¹⁶ Industry sources seem to indicate that Geodynamics and Panax are aiming for an injection-to-production well ratio of 4:5 while Petrathern are aiming for a 1:2 ratio. Industry sources also suggest that drilling costs can drop by as much as 40% over an 8-well program.

¹⁷ If the capital cost of each well pairing was reduced from \$20m to \$15m, then the installed cost would reduce to \$14,200/kW and an LRMC of \$260/MWh. At this capital cost, brine flow rates of 61 lps would undercut wind generation.

¹⁸ Enthalpy h^{in} of 200°C is 852.27kJ/kg and therefore Δh equates to 454.18 kJ/kg. Density ρ is 0.864655.

¹⁹ Similarly, if the capital cost of each well pairing was reduced to \$15m, then the installed capital cost would be \$6400/kW and an LRMC of \$128/MWh, which is almost parity with wind generation.

²⁰ Another geothermal company, Torrens Energy, is expecting to achieve inlet temperatures of about 220°C based on modelling following drilling to depths of 1km (see http://www.torrensenenergy.com/announcements/100217_parachilna.pdf for details). Solving for equations (6) and (7) with an assumed 75 lps flow rate results in a requirement for only 12 well pairings, and at \$20m per pairing equates to a total Overnight Capital Cost of \$5800/kW (considerably less than the benchmark listed in Table 1). Such a project, if successful, would have an aggregate LRMC of \$110/MWh noting its very close proximity to the national grid.

²¹ ‘Other’ incorporates technologies such as biomass, mini-hydro, wave and geothermal.

²² Investment scenarios were modelled using a dynamic, partial equilibrium model of the NEM.

²³ Plant built includes Tallawarra (400MW), Condamine (140MW), Darling Downs (630MW), Yarrow CoGen (160MW) and Tamar CCGT (210MW) totalling 1540MW.

²⁴ In particular, the 20% RET was annexed into small-scale and utility scale targets. The utility or large-scale target (LRET) comprises a fixed target of 41,000GWh and hence an increase in renewable plant installed is now expected.

²⁵ Source data from esaa (2004) was for energy generated. This data has been adjusted for auxiliary losses at the rate of 7% for brown coal, 5% for CCGT and Gas (Steam) and 0.5% for OCGT plant.

²⁶ It is difficult to meaningfully display continuous half-hourly data beyond a short window, and so a two-week period was selected at the height of the hot SA summer in FY10.

²⁷ Introducing wind generation into predominantly hydroelectric systems is generally thought to be desirable rather than problematic due to (1) limitations of hydro resources, and (2) the fast start and inertia of hydro plant.

²⁸ As an aside, at the time of writing the author is the Chairman of Australia’s largest brown coal power station, the 2000MW Loy Yang Power Station and adjacent coal mine.

²⁹ See Roam (2010) for a detailed analysis.

³⁰ See AEMO at http://www.nemweb.com.au/REPORTS/CURRENT/Ancillary_Services_Payments/. Total reactive power over the period between FY08 to FY10 was \$96 million on aggregate load served of 383TWh, i.e. \$0.25/MWh.

³¹ My colleague Chrys Chandraraj also noted that inertia provided by thermal plant would also decrease under the RET and therefore over time may also need to be replaced.

³² While the minimum access standard in the NEM does not require new capacity to supply or absorb reactive power, this would only apply in an area where it is not actually required. AGL Energy’s experience in SA was that even in this scenario, the SA Regulator stepped in and made it a state licensing requirement. The cost of the SVC equipment for a 100MW wind farm is c.\$7m and comprises about 2.4% of the investment cost.

³³ This is not entirely correct. AEMO does have an ‘emergency’ capability to call for capacity under system stress. It first notifies the market of expected shortages, and then if the problem is not solved by participants, attempts to contract for reserves (typically Demand Response). AEMO has intervened twice since market start, but in the event the contracted reserves were not required.

³⁴ Over FY09-FY10, 6-second contingency reserve has averaged \$0.13/MWh for raise and \$0.02/MWh for lower services. 60-second contingency reserve has averaged \$0.16/MWh for raise and \$0.02/MWh for lower services, and 5-minute contingency reserve has averaged \$0.18/MWh for raise and \$0.01/MWh for lower services. Aggregate customer charges (for ‘lower services’) are therefore \$0.05/MWh.

³⁵ In the event that contingency raise services are unable to restore system frequency, load shedding occurs. See Stoft (2002) for further details.

³⁶ A load duration curve plots equilibrium demand in ascending order, using hourly or half-hourly data spanning a year.

³⁷ Joskow (1975) noted that these theoretical models regarding the optimal pricing of non-storable commodities with periodic demand can generally be divided into three analytical approaches. (1) The American Approach focuses on peak prices being set at marginal running costs plus marginal capacity costs with a focus on shifting peak loads (Crew and Kleindorfer, 1975). (2) The British Approach has a heavy focus on specifying the optimal mix of supply-side technologies (Berrie, 1967; Turvey, 1968). (3) The French Approach is fundamentally a combination of both the American and British Approaches where peak demand can be shifted and supplied by an optimal mix of different technologies (Boiteux, 1949).

³⁸ See also Stoft (2002) or Simshauser (2006) amongst others for applied examples in the context of thermal power systems.

³⁹ In order to construct this curve, output from ‘embedded’ or non-despatched wind projects is added back to the official NEM wholesale market data. Peak demand registers 3,311MW (per Table 8) and energy demand is 14,474GWh which results in a system load factor of just 38.3%.³⁹ SA’s power system load factor is the ‘peakiest’ market in Australia.

⁴⁰ Peak demand in this instance has been reduced from 3,311MW to 3,080MW, and residual energy demand is 12,082GWh meaning a system load factor of 34.4%. The top 5% of demand events in this load duration curve occurs in 23 half-hourly periods (as opposed to 18), but the dispersion of events is more broadly spread, with only 65% of events occurring in 1Q2010 (vs. 94%) and 35% of events occurring in 4Q2009 (vs. 6%).

⁴¹ The model specifications which produced the results in Tables 9 & 10 have been detailed in Simshauser (2008) and accordingly will not be reproduced here.

⁴² See in particular Roam (2010) at page 32 for details.

⁴³ Of course, in the case of SA where the system balance is close to optimal, this backup capacity is actually a sunk cost. Currently SA has about 1950MW of base and intermediate plant, and about 1700MW of peaking plant.