Is There an Optimal Entry Time for Carbon Capture and Storage? A Case Study for Australia's National Electricity Market

Liam Wagner* and John Foster
Energy Economics and Management Group,
School of Economics
The University of Queensland

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Abstract

This paper examines the economic competitiveness of implementing Carbon Capture and Storage (CCS) for deployment on the Australias National Electricity Market (NEM) against conventional base load electricity generation. By examining the Levelised Cost of Energy (LCOE) for sent out generation as a suitable hurdle for judging the future prospects of different technology types, we examine the likely mix of generation assets that could be invested in. After examining the LCOE it is shown that CCS enabled technologies will not be competitive in Australia until 2025, which is well beyond the first emissions reduction target for 2020.

JEL Classification: Q40; G12; C61;

Keywords: Levelised Cost of Energy; Electricity Generation; Emissions Reduction; Carbon Capture and Storage

1 Introduction

Much has been written about the potential for Carbon Capture and Storage (CCS) technologies and their ability to significantly reduce emissions and prolong the usage of coal as a primary energy source [Gibbins and Chalmers 2008]. CCS has recently assessed by

*Corresponding author email: L.Wagner@uq.edu.au

the Australian Energy Market Operator [AEMO 2011b], as a viable technological options for the abatement of carbon emissions released from the largest emitting sector in the Australian economy. While CCS could act as a huge contributor to abatement of carbon dioxide emissions, the feasible deployment of this technology as a bolt-on to coal fired electricity generation has been stated as not being available until 2015 at the earliest. Not being able to deploy this technology rapidly on a large scale could mean that it is left behind in the competitive search for low emissions electricity generation technologies as Australia moves toward renewables. In some jurisdictions, CCS readiness has been a requirement for installing new coal fired power stations to supply the electricity market (e.g. the UK) to ensure that emissions into the future do not exceed abatement targets.

Australia is one of the top users of coal per MWh for electricity generation in the developed world [CoA 2008, Garnaut 2008]. Furthermore, Australia has one of the highest emissions intensities in its energy sector at 1.01t-CO_2/MWh (in 2009). This has produced a need to find a way to continue to use the cheapest and most abundant fossil fuel resource, coal, while also reducing our emissions. While timing has been signaled as an issue in the possible deployment of CCS [Chalmers and Gibbins 2007], the true cost of deploying these new generation assets in Australia needs to be carefully assessed to establish its competitiveness as an investment option for the electricity supply industry. There a great number of factors the member of the electricity supply industry must consider when deciding to invest in a particular generation asset type [Thumann and Woodroof]. One of the difficulties in providing a prediction of the true cost of each technology type is in estimating its cost of production over its economic life and how this relates to future uncertainties in policy formation.

In this article we consider a range of combustive technology types suitable for deployment to supply electricity on the National Electricity Market (NEM), to achieve emissions reduction. The timing of such investments is crucial in obtaining a viable mix of generation options to adequately meet demand in each of the States connected to the NEM. Furthermore, the timing of deployment could have a number of effects on Australias ability to abate emissions especially, given the first landmark year for our abatement trajectory is less than a decade away.

Transforming the electricity supply industry (ESI), in Australia by facilitating a move to lower emissions by 5% with respect to 2000 levels by 2020 would mean reducing our emissions by 25% compared to the business as usual case. This dramatic cut is certainly a challenge that CCS could help meet if it could become economically viable within the initial planning horizon to 2020.

Our goal is to examine the implications of a variety of policy and market condition shifts that could significantly affect investment decisions in the electricity sector over the coming decade. The remainder of the article is structured as follows: Section 2 provides an analysis of policy and market issues facing the NEM. Section 3 describes our levelised cost model. In section 4 we present the results of the levelised cost methodology and the effects of shifting market conditions. Section 5 contains some concluding remarks.

2 Background

Structural change in electricity markets can be fairly costly given that generation assets are the most capital intensive contributors to economic activity [Stoft 2002]. Having said that, structural change has to occur if long term emissions intensity is to be reduced and the efficiency of electricity production increased.

Currently, the Australian government is developing an emissions trading scheme intended to dramatically reduce emissions from large carbon dioxide intensive activities in the economy. If this is to happen, the ESI will need to transform itself from one of the highest emitters per MWh of sent out energy. This transformation will require a significant shift from higher emitting brown and black coal-fired generation towards a range of technologies such as Super Critical Pulverized Fuel, gas and renewables.

A second policy-driven factor that will be decisive for the timing and affordability of investment in generation assets is the prospect of significant exports of natural gas on to the international market. The Gas Electricity Scheme (GES) was introduced in 1994 by the Queensland State Government to facilitate the exploration and use of coal seam methane (CSM). This scheme placed a target for the amount of electricity generated by gas in the State. This is currently set at 15%. The GES has been partly responsible for the current rush to export liquid natural gas on the eastern coast of Australia. This export trade could easily double the domestic price of natural gas in a short period of time and hamper investments in gas-fired electricity generation technologies

2.1 Emissions Trading

With growing community concern over the potential effects climate change, the Australian Government attempted to implement a cap on Green House Gas (GHG) emissions via a Carbon Pollution Reduction Scheme (CPRS)[1].

The latest version of this scheme involves a fixed carbon price for the first 2-3 years, before transitioning to a cap and trade scheme, with the auction of emissions permits to occur monthly. The current Government has made a minimum commitment to a 5% reduction (CPRS -5%) in emissions compared to 2000 levels (see figure 2.1). If the global community agrees to a more extensive emissions reduction target the government has proposed a two further targets of -15% and -25% (more commonly referred to as CPRS -15% and CPRS -25%). Here we only consider the -5% and -15% reduction pathways given the failure of

[1]Through out this paper all references to the Australian CPRS refer to legislation present to parliament known as *Carbon Pollution Reduction Scheme Bill No.2 2009. [DCC 2010]*

the recent UN Climate Change Conference 2009 (COP15), to reach a consensus.

The electricity supply industry has been identified as being a strongly affected by such a policy and it is recognised that it may require further transitional assistance to be brought into compliance in the long term with the proposed CPRS. The Electricity Sector Adjustment Scheme (ESAS) has been proposed to create an equalized emissions intensity factor for higher polluting generation technologies such as older black coal and brown coal fired assets. This equalized emissions intensity factor reduces coal-fired generators liability down to a maximum of 1.01t-CO_2/MWh [Lambie 2010]. The number of permits which would be allocated under the ESAS would be based on the name plate emissions intensity established at the start of the CPRS. This assistance has only been proposed for existing generation assets and therefore all technologies considered here are not eligible for assistance.

The rate at which the carbon price is passed through on to electricity prices is highly dependent on the generators emissions intensity that sets the price on the gross pool. This pass through rate has been established in the short run as being between 80-100% with changes to overall returns restricted only to higher emitters. Higher emitters, such as brown coal generators, would be unable able to pass through the full cost of their carbon liability when lower emitting technology types set the electricity price [Menezes et.al. 2009]. The recent annual AEMO NTNDP [AEMO 2011b], and recent projections by the Treasury [CoA 2008], have provided expected carbon price forecasts for CPRS-5 and CPRS-15 (see figure 2.2)

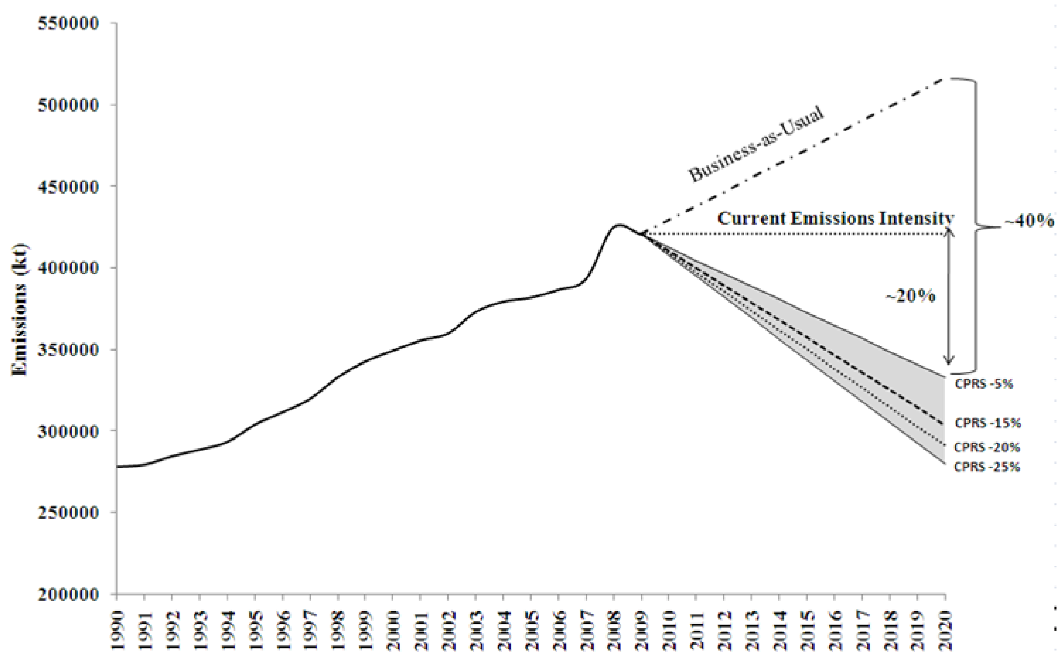

Figure 2.1: Carbon emissions abatement pathway [CoA 2008]

2.2 Liquefied Natural Gas Exports

With the prospect of exporting a significant proportion of Australias natural gas resources to China and Japan, the availability of affordable gas for use by the electricity sector is being put under pressure [Simshauser and Wild 2009]. The exports of Liquefied Natural Gas (LNG), from Gladstone on Queenslands central coast, could have a variety of consequences for Australias ability to generate low cost electricity from lower emitting technologies. The exports of LNG from Western Australia have already been observed to have had a detrimental effect on investments in gas fired electricity generation [Simshauser and Wild 2009]. Below in figure 2.2, we present four price forecasts based on AEMOs estimates for the Moomba hub under -5% and -15% emissions reduction scenarios and the EIA reference price for well head and average delivered price for natural gas to electricity users in the lower 48 states of the US [EIA 2011b].

While many have supported the view that natural gas prices will remain bullish at the Japanese hub to reach $12/GJ (which would result in the free-on-board net-back price at the Gladstone hub reaching $9/GJ) such as the forecasts presented by AEMO [AEMO 2011b]. The general view of the Energy Information Agency [EIA 2011a, EIA 2011b] is that well head prices in the US will remain low until well into 2020. With technical advances in recovery of shale gas in the lower 48 states of the US, well head prices are expected to be much lower than previously forecasted by the EIA and IEA [EIA 2011b, IEA 2009]. Production from the US shale fields combined with large supplies being made available from

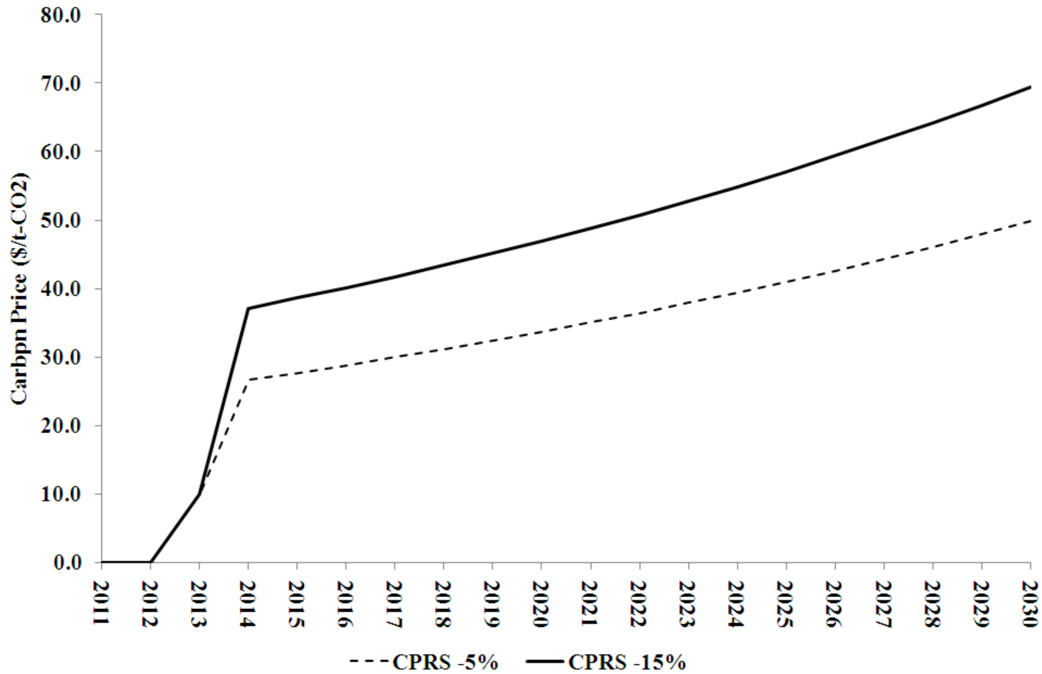

Figure 2.2: Carbon price forecasts: Based on estimates from AEMO NTNDP [AEMO 2011b]

Australia's coal seam gas fields, will significantly increase world availability. However, these conflicting views over price forecasts imposes a great deal on uncertainty for investors into the electricity supply industry in Australia. While fuel price risk still remains high with recent unrest amongst Middle East and North African states (MENA), and uncertainty over the future of oil supplies, we have made the assumption that natural gas contracts will be set for 20 years.

Rather than implement any of the forecasts, we have removed the long term price uncertainty by imposing a contracted price for each gas fired generation technology which assumes a significant premium above the prevailing spot price at the Moomba gas hub. In doing so we assume that gas fired generation investment will be associated with a long term gas delivery contract with at least a $2-3/GJ premium on top of long term forecasts of $6/GJ out to 2020. Furthermore the price of gas at $8/GJ more accurately represents the opportunity cost seen most recently in Western Australia [Simshauser and Wild 2009] with a mature export market.

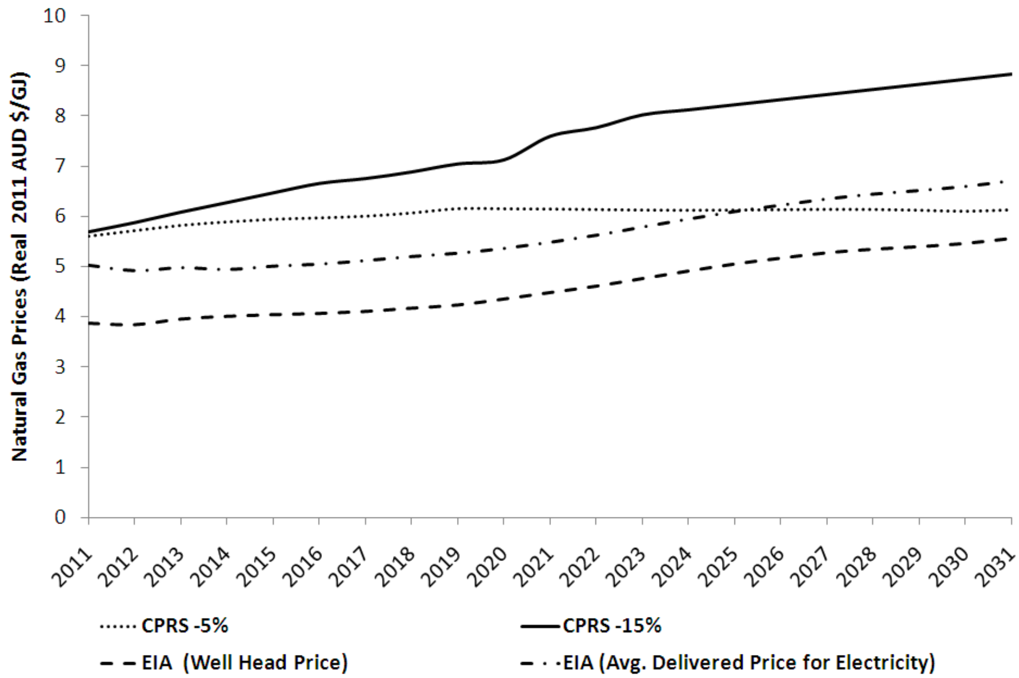

Figure 2.3: Natural Gas price forecasts: Based on estimates from AEMO NTNDP [AEMO 2011b] and EIA Annual Energy Outlook 2011 [EIA 2011b].

3 Establishing the Levelised Cost of Energy

An important goal is to ascertain what the true costs of different generating technologies are. This involves what is known in the literature as levelised cost analyses [Alonso et.al. 2006, Berrie 1967a, Berrie 1967b, Berrie 1967c]. Although we can draw upon this literature, it is necessary to derive costs that are specifically relevant to Australia to input into our modelling. In particular we have relied on a variety of Australian sources for information on generation costs [ACIL Tasman 2009, AEMC 2008, AER 2009].

To evaluate the likely optimal plant mix for a power system it is necessary to derive the levelised cost of new entrant plant. Before we can model this plant mix, the analytical framework and the assumptions made have to be discussed. In figure 3.1 we provide a schematic which outlines all of the assumptions for the cost of generation model.

3.1 Financial Modelling Assumptions

The following assumptions have been included in our levelised cost model for establishing the future viability of centralised and distributed generation projects. Time t is defined to be a discrete time period such that $t = 1 \ldots n$ where n corresponds to the economic life of the technology being considered. Each technology type is denoted by j. We shall now

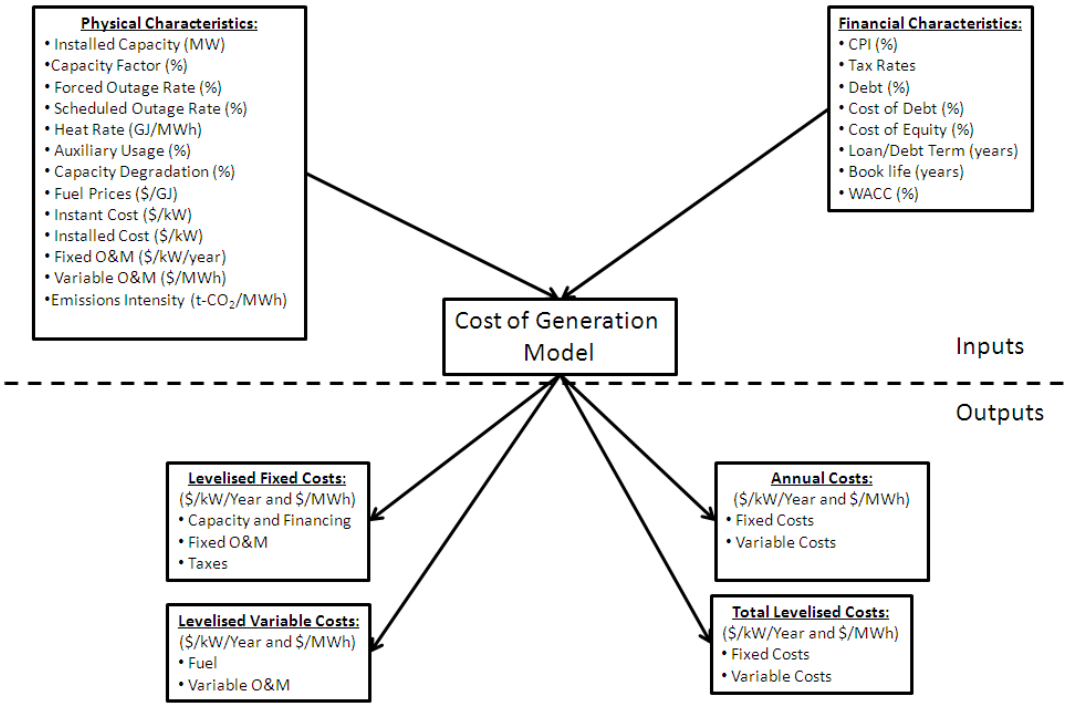

Figure 3.1: Flow Diagram of Cost of Generation Model (adapted from [**?**]).

move on to describe in detail our list of assumptions, as outlined in figure 3.1

The economic life (book life), of a particular technology j is expressed as $life_j$. Typical viable operating life span varies widely between manufacturer and technology types. Here we have implemented typical book life values described by [ACIL Tasman 2009, AEMO 2011b], as being generally acceptable industry standards.

The pass through rate of inflation (ρ), throughout this modelling will be considered to be $\rho_R = 75\%$ for revenue streams and $\rho_C = 100\%$ for non-finance related operating costs. The prevailing inflation rate is assumed to be 3% in accordance with the aforementioned cost stream pass through rate [Simshauser and Wild 2009].

$$CPI(t)_R = \left\{ \left[1 + \left(\frac{3}{100} \right) \right] * \rho_R \right\}^t \tag{1}$$

$$CPI(t)_C = \left\{ \left[1 + \left(\frac{3}{100} \right) \right] * \rho_C \right\}^t \tag{2}$$

When applying a discounted cash flow model of the kind used in the levelised cost of energy methodology, the effects of taxation rates must be accounted for. Currently in Australia corporate taxation is currently set at 30%. When taxation shields are implemented the effects of deductibility of interest payments and imputation credits have been calculated by a number of analysts [ACIL Tasman 2009, Allens 2004, NECG 2003], and the effective corporate tax rate is assumed to be 22.5%

The Weighted Average Cost of Capital (WACC), has been used for a significant number of regulatory decisions and has generally been determined as one of the hurdle rates for investment in capital infrastructure in Australia [IPART 2002]. Initially we must establish the cost of equity using the Capital Asset Pricing Model (CPAM), as used by a variety of regulators in Australia.

$$R_e = R_f + \beta_e(R_m - R_f), \tag{3}$$

where

- R_e = Return on Equity,
- R_f = Risk free rates as observed in the market,
- R_m = Market rate of return,
- β_e = Equity Beta.

One of the most common applications of the CAPM model is to establish the cost of equity, with the assumption that capital markets are completely independent [IPART 2002]. This assumption is not applied here - international prices of debt, based on the increasing debt basis point premium on BBB+ credit, are included to establish a more appropriate cost of capital [Allens 2004]. The recognition, by some regulators [IPART 2002], that ownership of electricity supply assets dictates all investment hurdle rates, highlights the need to act in a conservative manner when calculating the cost of capital. We assume that the cost of capital will be for private investment rather than any further development by government-owned corporations. International credit ratings data and lending premiums were sourced from [Reuters 2011]. All of the assumed values for the WACC calculations are presented in table 3.1 below.

We have used the post-tax real WACC in a similar way as proposed in [ACIL Tasman 2009] as a conservative proxy for investment decision hurdle rate for electricity market modelling. The post-tax WACC has been applied due to the effects of depreciation for capital intensive generation assets.

$$WACC_{Post-TaxNominal} = \frac{E}{V} \times R_e \left(\frac{(1 - T_e)}{(1 - T_e(1 - \Gamma))} \right) + \frac{D}{V} \times R_d(1 - T_e) = 9.93\% \tag{4}$$

The Fisher equation allows for the conversion of the WACC into real terms, which accounts for inflation effects over the economic life of the project.

$$WACC_{Post-TaxReal} = \left(\frac{1 + WACC_{Post-TaxNominal}}{(1 + CPI_C)} \right) - 1 = 6.72\% \tag{5}$$

Table 3.1: Components of the Weighted Average Cost of Capital (WACC)

Variable	**Description**	**Value**
V=D+E	Total enterprise value	100%
D	Debt	60%
E	Equity	40%
R_f	Risk free RoR	6.0%
MRP = (R_m-R_f)	Market risk premium	6.0%
R_{rm}	Market RoR	12.0%
T	Corporate tax rate	30%
T_e	Effective tax rate	22.5%
	Debt basis point premium	295
R_d	Cost of debt	8.95%
Γ	Gamma	0.50
β_a	Asset Beta	0.80
β_d	Debt Beta	0.16
β_e	Equity Beta	1.75
R_e	Required return on equity	16.5%
CPI	Inflation	3%

3.2 Plant Characteristics

The unit size (MW) of available generation installed capacity varies widely across different technology types j, which we will denote as $size_j$. The number of units to include within the optimal plant mix is calculated ed on an incremental integer basis, given that it is not usually possible to install fractions of a unit of any particular asset type. Within our model we consider uniform unit sizes within each technology type. Typical unit sizes have been sourced from [ACIL Tasman 2009, AEMO 2011a, AER 2009].

Each generation technology type has different modes of operation which dictate its typical energy output over time. More formally, the Capacity Factor CF_j is the ratio of total energy generated by a unit for a particular time scale to the maximum possible energy it could have produced if it was operated at its maximum capacity rating for that time period [Stoft 2002].

The Capacity Factor reflects a particular technology types ability to recover its long run marginal costs over a year. This behaviour also dictates its potential candidacy for inclusion in the optimal plant mix. Typical operating behaviour has been taken from [AEMO 2011a] historical data. The amount of energy which is expected to be sent out over an entire year is denoted $SO(t)j$, for each generating technology j and is calculated as follows:

$$SO(t)_j = \left(\frac{size_j * CF_j * 8760 * (1 - Aux_j)}{1000} \right). \quad (6)$$

The revenue stream version of the sent out energy calculation $SOR(t)_j$, is found by applying the assumed revenue inflation escalation rate to the output generated by each representative generation asset type. This is given by the following calculation:

$$SOR(t)_j = SO(t)_j * CPI(t)_R. \quad (7)$$

There are two types of outage patterns/rates which have been considered for inclusion in this levelised cost/optimal generation mix model, namely forced and scheduled outages. The first is the Forced Outage Rate (FOR), which mainly incorporates the likely timing and length of unexpected removal from service availability of a generating unit. Scheduled outages/patterns are typical for maintenance of plant to maintain optimal operation and long term viability. Typical acceptable standard outage rates have been incorporated from the IEEE standards [IEEE 2006], into the expected capacity factor CF_j for each technology type j.

For the electricity generation sector, heat rates HR_j are a direct indicator of the efficiency of energy production. The lower the heat rate the less fuel is required to generate power. Typically, heat rate improvements over time have facilitated the deployment of more fuel efficient and lower carbon emitting assets. Furthermore, some of the technology types considered in this modelling have evolving heat rates as better technology is developed (i.e. Ultra Super Critical black coal fired generation [ACIL Tasman 2009]).

The internal use of energy to enable a generation asset to operate normally is referred to as auxiliary usage Aux_j. Typically, generation technology types have improved their internal usage factors considerably over time [ACIL Tasman 2009]. However the imposition of carbon capture and storage [ACIL Tasman 2009], has had an appreciable effect on generator efficiency rates. This will play a significant role in whether this type of technology is suitable for the Australian electricity generation sector. Higher energy internal use rates are expected to have a detrimental effect on the probability of inclusion in the interior solution of screening curve analysis.

The ability of any electricity generation asset to maintain peak performance over time is also an internal optimisation constraint on future performance. The technical reliability of each electricity generation technology type is considered in our modelling framework and is explicitly associated with sent out energy over time [Stoft 2002]. While some have proposed the implementation of a degradation of sent out capacity over the final 3-5 years of the book life of the generation asset [Simshauser and Wild 2009], we have implemented an extra form of maintenance to avoid this potential distortion of the operational performance. Furthermore, many assets in the Australian electricity supply industry have lasted well beyond their initial expected book life. Examples are Hazelwood power station and other brown coal fired plants. To avoid the long term effects of capacity degradation, capital maintenance programs are performed via a variety of inspection on top of the usual O&M. These inspections and their associated costs have been implemented directly into the operations and maintenance costs [ACIL Tasman 2009, ESSA 2008].

$$CM_j = \left(\frac{CF_j * Capex_j * CPI_C}{life_j} \right) \tag{8}$$

Accessing cheap, reliable and abundant primary fuel supply sources is of extreme importance for central planners and GENCOs to not only to finance and develop a project but to also operate effectively. Fuel prices $FC(t)_j$ are examined explicitly by incorporating fuel prices forecasts from a variety of sources [ACIL Tasman 2009, EIA 2011a, IEA 2009]. Furthermore, primary fuel source pricing has a dramatic effect on the potential positioning of an assets bidding behaviour. Total fuel costs for each generator technology type $Fuel(t)_j$, are given via the following equation,

$$Fuel(t)_j = \left(\frac{HR_j * CF_j * FC(t)_j}{1000} \right) * SO(t)_j * CPI(t)_C. \tag{9}$$

The cost of deployment of each generation asset technology type $Capex_j$ (\$/kW), is explicitly included in the cost structure of our modelling. While installed cost can vary marginally for different locations, we have constructed this model from a central planning perspective and will rely on a generalized price for each technology type [ACIL Tasman 2009, Klein 2009]. Installed costs include all costs: the component cost, land cost, development cost, regulatory compliance costs, connection charges and environmental compliance costs [Klein 2009].

The Fixed Operations and Maintenance costs $FOM(t)_j$, are conceptually composed of costs incurred regardless of whether the station generates electricity. The costs included in this category are not always consistent from one assessment to the other but always include labour and the associated overhead costs. Other costs that are not consistently included are equipment (and leasing of equipment), regulatory compliance, and miscellaneous direct costs. We shall adopt these conventions as previously implemented by the Californian Energy Commission [Klein 2009] and the IEA [IEA 2009].

$$FOM(t+1)_j = FOM_t * CPI(t)_C. \tag{10}$$

Variable Operations and Maintenance $VOM(t)_j$, is a function of the generating assets operational behaviour and it is composed of scheduled outage and maintenance, including the three main inspection types, forced outage repairs, startup cost and the cost of water [ACIL Tasman 2009, AEMC 2008, IEEE 2006, Klein 2009]. The VOM is found by establishing the initial cost at construction VOC_j per MW, escalating by $CPI(t)_C$ and calculating the sent out energy $SO(t)_j$ and is defined as follows:

$$VOM(t)_j = VOC_j * SO(t)_j * CPI(t)_C. \tag{11}$$

The emissions intensity of any generation technology type EIF_j, will become of prime significance over the next ten years. With a carbon pollution reduction scheme on the horizon, higher emitting generation assets will struggle to have their power dispatched. The emissions intensity factor (see table 4.1 for a comparison of different technology types), has been explicitly included to account for future carbon liability under some sort of emissions reduction plan [Roth and Ambs 2004]. The emissions liability $CL_j = \{0, 1\}$, the carbon price $C(t)$, and the total cost of that liability $EL(t)_j$, for each generation technology type j, is defined as follows:

$$EL(t)_j = SO(t)_j * EIF_j * C(t) * CPI(t)_C * CL_j. \tag{12}$$

The consequences of Australia's renewable energy target will have on different generation asset types is also of importance when considering which plant types to invest in. Many of the assets which we have included in our modelling are eligible for payments under the renewable energy scheme. Accounting for these payments is performed via the following equation:

$$RE(t)_j = SO(t)_j * REC(t) * CPI(t)_R * REE_j \tag{13}$$

Where $REC(t)$ is the renewable energy certificate price in time t, and $REE_j = \{0, 1\}$, is the eligibility of a particular generation asset to be awarded those certificates.

The total costs associated with operations and maintenance $O\&M(t)_j$ and the total operational costs $TOC(t)_j$, associated with generation are follows:

$$O\&M(t)_j = VOM(t)_j + FOM(t)_j \tag{14}$$

$$TOC(t)_j = Fuel(t)_j + O\&M + CM(t)_j + EL(t)_j - RE(t)_j \tag{15}$$

To calculate the levelised cost of energy we have applied the following standard formula from [IEA 2009, Klein 2009, Roth and Ambs 2004],

$$\begin{aligned} LCE_j &= \left(\frac{\sum_{t=1}^{n} \left(\frac{Fuel(t)_t + OM(t)_j + CM(t)_j + EL(t)_j - RE(t)_j}{(1+WACC)^t} \right) + Capex_j}{\frac{\sum_{t=1}^{n} \left(\frac{Size_j * CF_j * 8760 * (1 - Aux_j)}{1000} \right) * CPI(t)_R}{(1+WACC)^t}} \right) \\ &= \left(\frac{\sum_{t=1}^{n} \left(\frac{TOC(t)_j}{(1+WACC)^t} \right) + Capex_j}{\frac{\left(\sum_{t=1}^{n} SO(t)_j \right) * CPI(t)_R}{(1+WACC)^t}} \right). \end{aligned} \tag{16}$$

Having established the levelised cost formula we shall move on to three scenarios to examine how the likelihood of investment options will change with respect to policy and fuel cost view points. In table 4.1 we provide a comprehensive list of assumptions of technological specifications for a variety of generation assets which have been considered for deployment in the NEM.

4 Analysis and Results

Establishing the optimal entry timing for a particular technology type revolves around a great number of externalities which have been included in our analysis of the LCOE. The development of analytical modelling frameworks that can model the NEM and capture price signals with as generation options are implemented will provide significant support to decision makers in the pursuit of emissions reduction via technological improvement and alternate investment prioritisation. We examine the LCOE of 10 technology types with respect to a range of scenarios which demonstrate that, in the medium term, there is a discrete set of base load generators that will be economically viable. The scenarios that we examine are as follows:

Scenario 1: Business-As-Usual. (BAU) case with no carbon trading: in which carbon pricing is not implemented.

Scenario 2: CPRS -5%. The CPRS is introduced in combination with the renewable energy target to reach an overall reduction of emissions by 5% below 2000 levels. The price of emissions permits is set to reach approximately \$33.7 t/CO2 in 2020.

Scenario 3: CPRS -15%. The introduction of the CPRS with a deeper emissions abatement pathway is implemented to achieve an overall reduction of emissions of 15% below 2000 levels. The emissions permit price is set to reach around \$46.9 t/CO2 in 2020 which will place more pressure to achieve further energy efficiency and lower emissions technology deployment across the NEM.

4.1 Technology Specification

The recent announcement of the annual NTNDP to be performed by AEMO [AEMO 2011b], has provided us with the most up to date information available on technology specifications for stakeholders in the ESI. We consider a subset of the ten main these technologies identified by NTNDP:

- IGCC - Black and Brown coal with and without CCS
- SCPC - Black and Brown coal with and without CCS
- SCPC - Black with oxy-combustion and CCS
- CCGT - without CCS

In table 4.1 we outline the standard components of the costs of each of these technology types. The associated technology characteristics are all in 2011 terms without externalities such as the cost of carbon or the benefits of the Gas Electricity Scheme (GES). We have not included the effects of the GES in this study as the term of its continued input is uncertain and because of the fact that is has only been implemented in one state of the NEM.

Table 4.1: Fossil fuel based electricity generation technology type specification

Generation technology	**Capex ($/kW)**	**Size (MW)**	**VOM ($/MWh)**	**FOM ($M pa)**	**Life (years)**	**Heat rate (GJ/MWh)**	**Fuel ($/GJ)**	**Aux. (%)**	**EIF (t/MWh)**	**CF (%)**	**Cap. Main.**	**CO_2 Capture**
IGCC - Brown	5702	700	15.1	63.00	40	12.4	$0.58	76%	1.16	87%	2.2%	0%
IGCC - Brown CCS	7694	600	25	84.00	40	15	$0.58	70%	0.15	87%	2.2%	90%
IGCC - Black	4744	700	12.8	51.10	40	8.78	$1.09	82%	0.78	87%	2.2%	0%
IGCC - Black CCS	6210	600	20	62.40	40	9.78	$1.09	77%	0.10	87%	2.2%	89%
SCPf - Brown	3751	750	5.1	30.75	40	11.61	$0.58	90%	1.08	93%	2.3%	0%
SCPf - Brown CCS	8041	750	16.4	50.25	40	18.7	$0.58	76%	0.17	93%	2.3%	90%
SCPf - Black	2706	750	4.6	24.75	40	8.86	$1.09	90%	0.79	93%	2.3%	0%
SCPf - Black CCS	4988	750	15.7	41.25	40	12.3	$1.09	77%	0.11	93%	2.3%	90%
SCPf - Black oxy-comb. CCS	5644	750	12.6	45.08	40	10.8	$1.09	68%	0.10	93%	2.3%	90%
CCGT	1114	700	2	9.80	30	7.32	$2.50	97%	0.38	92%	3.1%	0%

4.2 Scenario 1: Business as Usual

The incentives for investing in CCS technology for the energy supply industry in Australia are completely removed in this case. Gas fired generation is competitive as a base load generation option (via CCGT) up to a gas price of \$4/GJ. While this seems fairly low, long term gas prices over the next 10 years are likely to remain low in the southern Queensland area which is close to the CSM fields. While US well head prices are generally viewed as a good indicator of production in developed countries [IEA 2009], transport costs through the eastern states could add an extra \$1.5/GJ to gas used in Victoria and Tasmania, given their distance from the Moomba hub in central Australia.

Black and brown coal fired SCpf remains the dominant option for deployment under the BAU scenario (see figure 4.1 and table 4.2). Base load generation is most likely to be met by black coal in NSW and brown coal in lower Victoria and South Australia. While location was considered by the AEMO [AEMO 2011b], we have imposed the most cost efficient fuel prices for each regional area on the NEM. With black coal prices based on the Newcastle export hub price and brown coal prices based used for Victorian and South Australian assets.

Finally we considered a high gas price at \$8/GJ, which presents a large departure from the forecasts by AEMO and EIA [AEMO 2011b, EIA 2011b]. Securing a long term gas supply agreement at this premium would overcome market volatility concerns brought on by supply problems from MENA states. This case study shows that regardless of the fuel prices considered CCS is unlikely to be viable option until well after 2025.

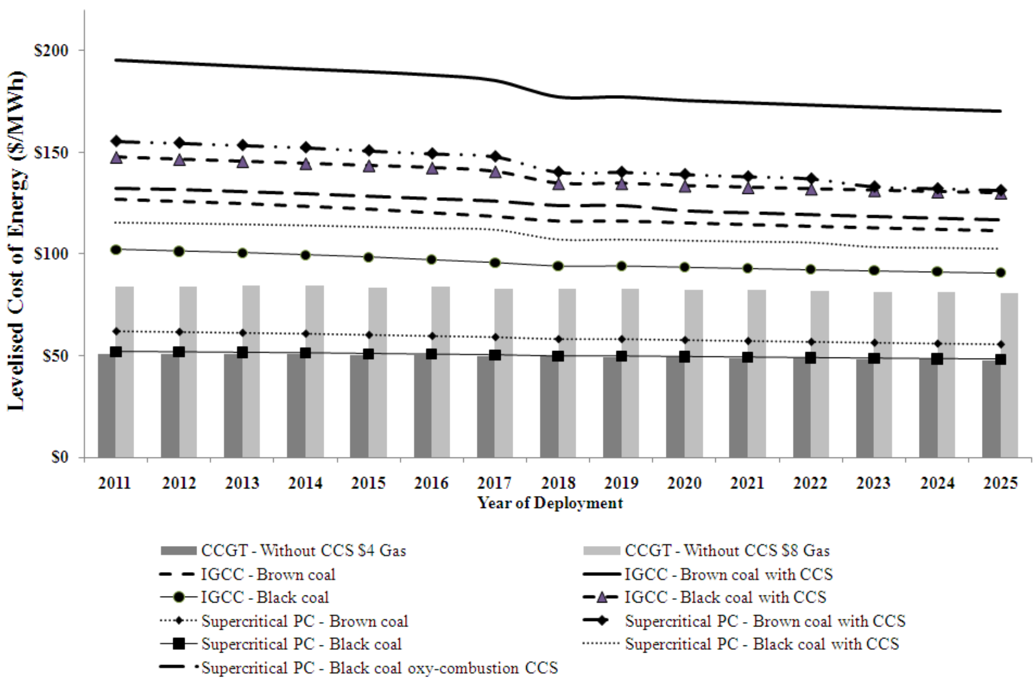

Figure 4.1: Levelised Cost of Energy for Scenario 1, Business-As-Usual

Table 4.2: Levelised Cost of Energy for Scenario 1, Business-As-Usual

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
IGCC - Brown coal	$127.03	$125.96	$124.93	$123.53	$122.14	$120.27	$118.49	$116.20	$116.20	$115.30	$114.44	$113.62	$112.83	$112.07	$111.36
IGCC - Brown coal CCS	$195.43	$193.91	$192.46	$191.07	$189.74	$188.14	$185.50	$177.46	$177.46	$175.74	$174.58	$173.47	$172.42	$171.42	$170.47
IGCC - Black coal	$102.10	$101.32	$100.57	$99.54	$98.50	$97.13	$95.82	$94.19	$94.19	$93.55	$92.95	$92.37	$91.82	$91.29	$90.79
IGCC - Black coal CCS	$147.54	$146.45	$145.41	$144.41	$143.39	$142.31	$140.46	$134.68	$134.68	$133.49	$132.70	$131.96	$131.25	$130.57	$129.93
SCpf - Brown coal	$61.85	$61.53	$61.11	$60.70	$60.15	$59.62	$59.11	$58.15	$58.15	$57.70	$57.26	$56.84	$56.44	$56.05	$55.67
SCpf - Brown coal CCS	$155.44	$154.58	$153.46	$152.38	$150.85	$149.38	$147.98	$140.39	$140.39	$139.27	$138.20	$137.17	$133.27	$132.36	$131.49
SCpf - Black coal	$51.95	$51.75	$51.52	$51.30	$50.95	$50.61	$50.29	$49.68	$49.68	$49.39	$49.12	$48.86	$48.60	$48.36	$48.13
SCpf - Black coal CCS	$115.68	$115.31	$114.79	$114.29	$113.52	$112.78	$112.08	$107.11	$107.11	$106.55	$106.02	$105.50	$103.29	$102.85	$102.43
SCpf - Black coal oxy-comb CCS	$132.39	$131.84	$130.80	$129.81	$128.56	$127.37	$126.21	$124.03	$124.03	$121.47	$120.50	$119.58	$118.69	$117.83	$117.01
CCGT $4 Gas	$50.69	$50.68	$50.68	$50.69	$50.13	$50.15	$49.52	$49.56	$49.28	$49.01	$48.75	$48.50	$48.26	$48.03	$47.81
CCGT $8 Gas	$83.77	$84.00	$84.25	$84.50	$83.62	$83.89	$82.83	$83.12	$82.76	$82.41	$82.07	$81.75	$81.44	$81.15	$80.86

4.3 Scenario 2: CPRS -5%

Given the current political landscape in Australia this is the most likely carbon abatement trajectory. The policies announced and proposed before Parliament [CoA 2008], have planned a minimum commitment of a 5% reduction of emissions compared to 2000 levels. The carbon price trajectory remains relatively low to 2020 ($ 33.7/t-CO_2). Given the low emissions intensity factor of CCGT without CCS as a base load generator compared to SC pf (Black and Brown), it is certainly the most competitive from an LCOE perspective (see figure 4.2 and table 4.3).

CCGT without CCS is the most competitive generation option with a delivered gas price of $8/GJ up to 2020. While a $10/GJ is still competitive for investment through to 2020, subject to the availability of a long term supply contract. Entry of SC pf black and brown coal with CCS is not competitive however until well after 2025. The possible entry of IGCC - Brown with CCS - while theoretically feasible after 2015, the current price on brown coal in lower Victoria is currently under inflationary pressure do to the recent export agreement for brown coal briquettes to Vietnam linking the fuel to international coal benchmark prices. Furthermore, IGCC is still only a demonstration technology in Australia and yet to be deployed on a commercial scale. Beyond 2021 the emissions abatement targets are more likely to be met by CCGT and USC pf black or brown. USC pf technology is still under development but its predecessor, SC pf, has been successfully deployed on to the NEM (i.e. Kogan Creek, 700 MW in Southern Queensland), as lower emitting and more thermally efficient generation type.

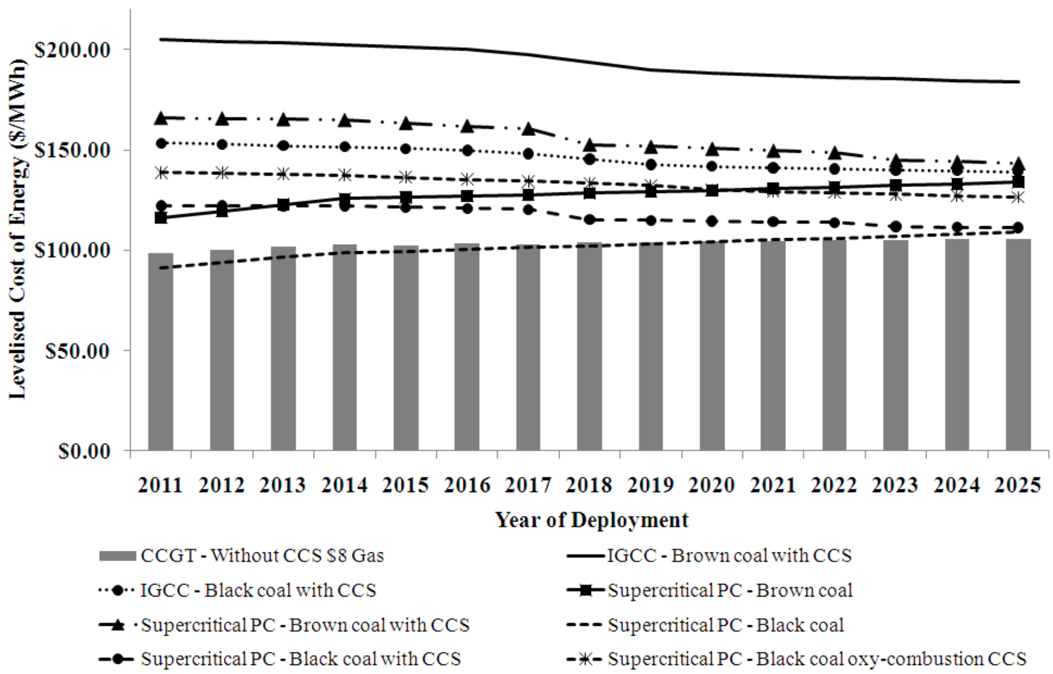

Figure 4.2: Levelised Cost of Energy for Scenario 2, CPRS-5%

Table 4.3: Levelised Cost of Energy for Scenario 2, CPRS -5%

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
IGCC - Brown coal	$195.6	$199.1	$202.9	$205.7	$206.9	$206.5	$206.2	$206.3	$206.9	$207.4	$208.1	$208.7	$209.4	$210.2	$210.9
IGCC - Brown coal CCS	$204.9	$204.0	$203.2	$202.4	$201.5	$200.0	$197.5	$193.5	$189.8	$188.2	$187.2	$186.3	$185.4	$184.5	$183.7
IGCC - Black coal	$144.9	$147.0	$149.2	$150.8	$151.5	$151.5	$151.6	$152.1	$152.9	$153.7	$154.5	$155.4	$156.3	$157.3	$158.2
IGCC - Black coal with CCS	$153.4	$152.7	$152.1	$151.5	$150.7	$149.8	$148.1	$145.4	$142.7	$141.7	$141.1	$140.6	$140.1	$139.6	$139.1
SC pf - Brown coal	$116.1	$119.4	$122.8	$125.7	$126.3	$127.0	$127.7	$128.4	$129.1	$129.9	$130.6	$131.4	$132.2	$133.0	$133.9
SC pf - Brown coal with CCS	$165.8	$165.6	$165.2	$164.8	$163.3	$161.9	$160.6	$152.7	$151.7	$150.7	$149.7	$148.8	$145.0	$144.3	$143.5
SC pf - Black Coal	$91.4	$93.9	$96.4	$98.6	$99.5	$100.4	$101.3	$102.2	$103.1	$104.1	$105.1	$106.1	$107.1	$108.1	$109.2
SC pf - Black coal CCS	$122.1	$122.2	$122.1	$122.0	$121.4	$120.9	$120.3	$115.3	$114.9	$114.5	$114.2	$113.8	$111.8	$111.5	$111.2
SC pf - Black coal oxy-comb CCS	$138.7	$138.6	$138.0	$137.4	$136.3	$135.3	$134.3	$133.4	$132.5	$130.1	$129.3	$128.5	$127.8	$127.1	$126.5
CCGT $8 Gas	$98.8	$100.2	$101.7	$103.0	$102.6	$103.6	$102.9	$103.9	$104.1	$104.4	$104.6	$104.9	$105.1	$105.4	$105.7

4.4 Scenario 3: CPRS -15%

While the probability of the introduction of a 15% reduction in emissions by 2020 would seem to be remote given the timing and the current political landscape, the aspirational target is still physically and technically possible. CCGT without CCS was found to be the most competitive up to a gas price of $8/GJ with entry of SC pf. Black coal is still viable during the planning horizon out to 2025 (see figure 4.3 and table 4.4). CCS based technologies are not viable for entry until long term gas prices reach $9/GJ with an associated high carbon price. So the likely forward deployment rate of SC pf with CCS must be significantly questioned, given its immaturity. The first industrial scale generator will not be ready for commissioning until 2015 [AEMO 2011b].

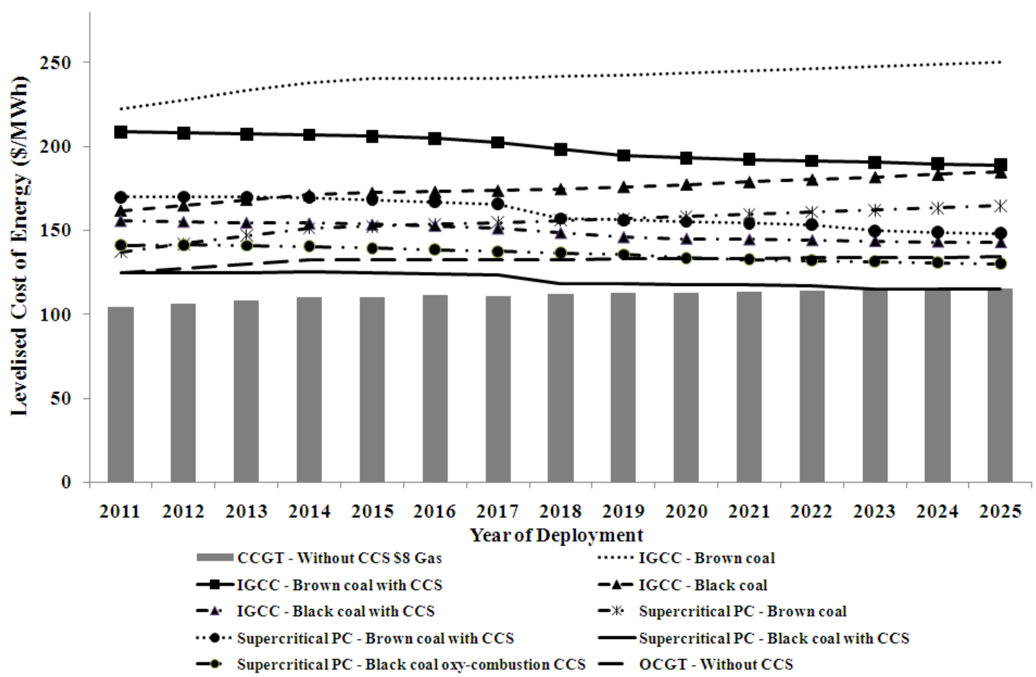

Figure 4.3: Levelised Cost of Energy for Scenario 3, CPRS-15%

Table 4.4: Levelised Cost of Energy for Scenario 3, CPRS -15%

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
IGCC - Brown coal	$222.4	$227.6	$233.3	$238.1	$240.3	$240.5	$240.7	$241.5	$242.6	$243.8	$245.0	$246.2	$247.5	$248.8	$250.1
IGCC - Brown coal CCS	$208.5	$207.9	$207.4	$206.8	$206.1	$204.7	$202.3	$198.3	$194.6	$193.1	$192.2	$191.3	$190.5	$189.7	$189.0
IGCC - Black coal	$161.6	$164.8	$168.2	$171.0	$172.4	$173.0	$173.6	$174.7	$176.0	$177.4	$178.8	$180.3	$181.8	$183.3	$184.8
IGCC - Black coal CCS	$155.7	$155.2	$154.7	$154.3	$153.6	$152.8	$151.2	$148.5	$145.9	$145.0	$144.5	$144.0	$143.5	$143.1	$142.8
SC pf - Brown coal	$137.3	$142.0	$146.8	$151.3	$152.4	$153.6	$154.7	$155.9	$157.1	$158.3	$159.6	$160.9	$162.1	$163.4	$164.7
SC pf - Brown coal with CCS	$169.8	$169.9	$169.8	$169.6	$168.2	$166.9	$165.6	$157.1	$156.1	$155.2	$154.3	$153.4	$149.7	$149.0	$148.3
SC pf - Black Coal	$106.8	$110.3	$113.9	$117.3	$118.6	$120.0	$121.4	$122.8	$124.2	$125.7	$127.2	$128.7	$130.2	$131.7	$133.2
SC pf - Black coal CCS	$124.7	$124.9	$125.0	$125.1	$124.5	$124.0	$123.6	$118.3	$118.0	$117.7	$117.4	$117.1	$115.1	$114.9	$114.7
SC pf - Black coal oxy-comb CCS	$141.2	$141.3	$140.8	$140.4	$139.4	$138.4	$137.5	$136.6	$135.8	$133.5	$132.8	$132.1	$131.4	$130.8	$130.2
CCGT $8 Gas	$104.6	$106.5	$108.5	$110.3	$110.0	$111.3	$110.8	$112.1	$112.6	$113.0	$113.5	$114.0	$114.5	$115.0	$115.5

5 Conclusion

The proposed deployment of Carbon Capture and Storage into the Australian Electricity Supply Industry has been met with much speculation by the coal-fired generators as a way to continue to use their cheap and abundant fuel sources. AEMO has signaled that the first CCS capable electricity generator will be installed during 2015. However, this will be too late to make a significant impact on the emissions intensity factor of delivered energy for the industry as a whole. The scenarios considered here show quite conclusively that, without a sufficiently high carbon price trajectory, CCS based technology will not be suitable for deployment till after 2025 in the case of scenario 3 and 2030 for scenario 2.

The deployment of CCS technology as a viable economic option for supplying electricity on to the NEM is seriously in doubt from a levelised cost of energy perspective, given the findings of this study. So stakeholders in the ESI should look elsewhere for a lower cost generation option that has an adequate capacity, given the target set, to reduce carbon dioxide emissions.

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