Preparation of energy market modelling data for the Energy White Paper

Supply assumptions report

Prepared for AEMO/DRET

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1 Introduction

ACIL Tasman has been engaged by the Australian Energy Market Operator (AEMO) and the Department of Resources, Energy and Tourism (DRET) to prepare energy market modelling data for the Energy White Paper scenarios. Specifically ACIL Tasman is to take the scenarios defined in the MMA/Strategis report – *Future Developments in the Stationary Energy Sector: Scenarios for the Stationary Energy Sector*, 2030 (October, 2009)(the scenarios report) and develop a set of well defined and detailed input data and assumptions, suitable for use in the modelling of the scenarios.

1.1 Purpose

The purpose of our engagement is to develop sets of supply input assumptions that are suitable be used by the long term market model of IES and Roam Consulting. Therefore, ACIL Tasman is mindful that the data needs to be well defined and in a format suitable for IES and Roam Consulting.

1.2 Process

This report presents the final input assumptions used in the scenario modelling and represents a culmination of a number of steps. Our engagement commenced in October 2009 and during the past six months we have consulted with industry and participated in a number of stakeholder reference group workshops to converge to a set of robust and defendable input assumptions.

The stakeholder reference group workshops were held in Melbourne on 29 January 2010, 2 March 2010 and 30 April 2010. Prior to these workshops a separate teleconference was held in December 2009 with the stake holder reference group to review our proposed fuel supply costs. ACIL Tasman has considered and addressed all feedback received from each of the meetings.

In May 2010, ACIL Tasman presented a report (the May report) summarising the final supply input assumptions adopted for each of the five scenarios to 2030. In August 2010, ACIL Tasman was requested to extend the assumptions to 2050. This current report takes the May report and includes an additional chapter (Chapter 8) describing the process used to extrapolate the assumptions to 2050.

2 Scope and coverage

Data sets are required for the following regions / areas:

- All 5 NEM regions,
- The SWIS in Western Australia,
- The NWIS in Western Australia
- The Darwin / Katherine interconnected system in Northern Territory, and
- The Mt Isa 'off grid' system.

The data sets are required for existing generators as well as new entrant generator costs and resource availability.

3 Existing power stations

For the existing generator fleet we are providing data for power stations of at least one MW in aggregate capacity. At present these total about 57,300MW. There are too numerous stations with a capacity of less than one MW to include for the purpose of this study. Stations with a capacity of less than one MW total less than 100MW in aggregate (that is, less than 0.1% of the national fleet) and will be immaterial in the modelling, and in any case are included in aggregate by offsetting the demand.

We are providing data for stations connected to the main transmission grid in each region as well as embedded generation.

The data inputs are provided in the table below. Also described in the table is the intended use of the input.

Table 1 **Inputs for existing power stations**

Input variable	Purpose
Station Name	Station Identifier
Plant type	Useful for summary statistics
Fuel type	To determine which plant are renewable and subject to MRET etc
Location	For model topology
Market	For model topology
Grid / Off-grid	For model topology
NEM-Scheduled	For model topology
NTS Zone	For model topology
State	For model topology
Commission Date	To give a sense of the age distribution of the power station fleet and to allow the modelers to appropriately include new stations which are committed or under construction
Retirement Year	To allow the modelers to include committed retirements of existing stations – this variable is used for three stations only in the NEM
Thermal efficiency HHV (%) sent-out	To determine the cost of fuel in $ per MWh of output and to determine the CO2-e emissions per MWh of output
Auxiliaries (%)	The percentage of electricity produced by the station consumed within the station
MLF	Marginal Loss Factor - to account for transmission losses between the station's output and the load centre
FOM ($/MW/year) for 2009-10	Fixed O&M costs - used in determining the net revenue position of the station
FOM escalation rate (% of CPI)	Fixed O&M cost escalator - to properly account for inflation of the FOM costs relative to the CPI
VOM ($/MWh sent-out) for 2009-10	Variable O&M costs - used in determining the net revenue position of the station as well as the short run marginal cost
VOM escalation rate (% of CPI)	Variable O&M cost escalator - to properly account for inflation of the VOM costs relative to the CPI
Fuel cost profile	Link to the projected fuel costs for the station - which are used to determine the net revenue position of the station as well as the short run marginal cost
Combustion emission factor (kg CO2-e/GJ of fuel)	Measure of emissions produced during combustion of the fuel
Fugitive emission factor (kg CO2-e/GJ of fuel)	Measure of emissions produced during production of the fuel - is added to the combustion emissions factor and combined with the thermal efficiency to give a measure of total emissions per MWh of output
Percentage of emissions captured (%)	Measure of the proportion of emissions produced by the station that are captured for transport and storage
Min Gen (% of capacity) (constraint on output per "hour")	The minimum stable generation that the station can produce at any instant if operating (expressed as a proportion of capacity)
Capacity (MW) (Year ending June)	The capacity of the station is provided on an annual basis which allows the representation of changes in capacity, for example, due to drought or other factors
Max_Capacity Factor (constraint at annual level) (Year ending June)	The capacity factor is the amount of generation produced by the station (in GWh) for a year divided by (the capacity of the station (in MW) multiplied by the number of hours in the year). The maximum capacity factor is used to constrain the output of a station on an annual basis by taking into account the availability of the station and other factors such has hydrological in-flows (for a hydro plant) or wind inputs (for wind farms).
Min_Capacity Factor (constraint at annual level) (Year ending June)	The minimum capacity factor is most likely not required for this exercise - but it can be used to place an annual lower limit on station production to account for certain fixed arrangements - such as run-of-river conditions for certain hydro plant or particular contract conditions that require the station to operate regardless of whether the station is competitive
Fuel Cost (Real 2009-10 $/GJ)	A projection of annual fuel costs used to determine the net revenue of the station and the short run marginal cost
Forced outage rate (%)	The percentage of time the station is assumed to be unavailable due to forced outages in a year - used to determine the maximum capacity factor.
Planned outage rate (%)	The percentage of time the station is assumed to be unavailable due to planned maintenance in a year - used to determine the maximum capacity factor.

It is worth noting that the request for proposal from AEMO listed the inclusion of station retirement and repatriation costs as part of the input data.

ACIL Tasman has not collected or provided such data – given it is likely to be unique for each station. We think these costs are relatively small (but not necessarily insignificant) compared with the fuel, and variable and fixed operating costs in terms of making a decision to close the station down (either due to station age or due to the impacts of a carbon price). Further, the retirement and repatriation costs could be partly offset by any residual value of the station (such as selling the turbines, scrap metal and land value).

3.1 Format

The input data is provided in spreadsheet format. There is a separate spreadsheet for each scenario. A template spreadsheet containing the format of inputs was sent to IES and ROAM Consulting for consideration. Both IES and ROAM indicated their comfort with the proposed format.

3.2 Data sources

We have made use of our internal generator databases as much as possible for this exercise. These databases have been developed over the past decade and benefit from regular updates and feedback from numerous clients who have firsthand experience in particular power stations.

The majority of our past work has been focused on or involved the principle stations in the NEM, SWIS and DKIS – and we are comfortable using our own databases for these particular stations. However, there are some gaps in our databases – these are more of a geographic nature – such as information on stations in the Mt Isa and NWIS regions and embedded generators. During our engagement we identified these gaps and sought the data inputs from a number of credible sources.

The table below summarises the sources of data for each data input and region.

Table 2 **Sources of data inputs for existing power stations**

Input variable	East coast – NEM	East coast - non-NEM	SWIS
Station Name	AEMO list of registered participants in the NEM (November 2009)	Electricity Gas Australia 2009 - esaa (August 2009), Geoscience Australia online interactive maps (November 2009), and ACIL Tasman Generator Database	IMO facility list in the SWIS (November 2009)
Plant type	ACIL Tasman Generator Database	See above	ACIL Tasman Generator Database
Fuel type	ACIL Tasman Generator Database	See above	ACIL Tasman Generator Database
Location	ACIL Tasman Generator Database / AEMO	See above	ACIL Tasman Generator Database / IMO
Market	AEMO list of registered participants in the NEM (November 2009)	See above	IMO facility list in the SWIS (November 2009)
Grid / Off-grid	AEMO list of registered participants in the NEM (November 2009)	See above	IMO facility list in the SWIS (November 2009)
NEM-Scheduled	AEMO list of registered participants in the NEM (November 2009)	NA	NA
NTS Zone	ACIL Tasman Generator Database	NA	NA
State	ACIL Tasman Generator Database	Electricity Gas Australia 2009 - esaa (August 2009),Geoscience Australia online interactive maps (November 2009), and ACIL Tasman Generator Database	ACIL Tasman Generator Database
Commission Date	ACIL Tasman Generator Database	See above and ACIL Tasman assumptions	ACIL Tasman Generator Database
Retirement Year	ACIL Tasman Generator Database	See above and ACIL Tasman assumptions	ACIL Tasman Generator Database
Thermal efficiency HHV (%) sent-out	ACIL Tasman Generator Database	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database
Auxiliaries (%)	ACIL Tasman Generator Database	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database
MLF	List of Regional Boundaries and Marginal Loss Factors for the 2009/10 Financial Year, NEMMCO (April 2009)	To be done	To be done
FOM ($/MW/year) for 2009-10	ACIL Tasman Generator Database	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database
FOM escalation rate (% of CPI)	ACIL Tasman Generator Database	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database
VOM ($/MWh sent-out) for 2009-10	ACIL Tasman Generator Database	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database
VOM escalation rate (% of CPI)	ACIL Tasman Generator Database	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database
Fuel cost profile	ACIL Tasman Generator Database	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database
Combustion emission factor (kg CO2-e/GJ of fuel)	National Greenhouse Accounts (NGA) Factors - Updating and replacing the AGO Factors and Methods Workbook, Department of Climate Change (February, 2008)	National Greenhouse Accounts (NGA) Factors - Updating and replacing the AGO Factors and Methods Workbook, Department of Climate Change (February, 2008)	National Greenhouse Accounts (NGA) Factors - Updating and replacing the AGO Factors and Methods Workbook, Department of Climate Change (February, 2008)
Fugitive emission factor (kg CO2-e/GJ of fuel)	See above	See above	See above
Percentage of emissions captured (%)	ACIL Tasman Generator Database	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database
Min Gen (% of capacity) (constraint on output per "hour")	ACIL Tasman Generator Database	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database
Capacity (MW) (Year ending June)	ACIL Tasman Generator Database	Electricity Gas Australia 2009 - esaa (August 2009),Geoscience Australia online interactive maps (November 2009), and ACIL Tasman Generator Database	ACIL Tasman Generator Database
Max_Capacity Factor (constraint at annual level) (Year ending June)	ACIL Tasman Generator Database	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database
Min_Capacity Factor (constraint at annual level) (Year ending June)	ACIL Tasman Generator Database	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database
Fuel Cost (Real 2009-10 $/GJ)	ACIL Tasman projection	ACIL Tasman projection	ACIL Tasman projection
Forced outage rate (%)	ACIL Tasman Generator Database	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database
Planned outage rate (%)	ACIL Tasman Generator Database	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database

Data source: ACIL Tasman

Table 3 **Sources of data inputs for existing power stations - continued**

Input variable	DKIS	Mt Isa	NWIS
Station Name	Power and Water Corporation, and Annual Power System Review - Northern Territory Utilities Commission (March 2009), and , Geoscience Australia online interactive maps (November 2009)	Queensland Department of Mines and Energy, Queensland Department of Infrastructure and Planning, Providing a circuit breaker to meet North West Queensland's future electricity needs - Sims Review report (May 2009), North West Queensland Energy Delivery Options - ROAM Consulting report to the Sims Review (February 2009), CS Energy and Geoscience Australia online interactive maps (November 2009)	Electricity Gas Australia 2009 - esaa (August 2009), Geoscience Australia online interactive maps (November 2009)
Plant type	See above and ACIL Tasman Generator Database	See above	See above
Fuel type	See above and ACIL Tasman Generator Database	See above	See above
Location	See above and ACIL Tasman Generator Database	See above	See above
Market	See above	See above	See above
Grid / Off-grid	See above	See above	See above
NEM-Scheduled	NA	NA	NA
NTS Zone	NA	NA	NA
State	Power and Water Corporation, and Annual Power System Review - Northern Territory Utilities Commission (March 2009)	See above	See above
Commission Date	See above and ACIL Tasman Generator Database	See above and ACIL Tasman assumptions	See above and ACIL Tasman assumptions
Retirement Year	See above and ACIL Tasman Generator Database	See above and ACIL Tasman assumptions	See above and ACIL Tasman assumptions
Thermal efficiency HHV (%) sent-out	ACIL Tasman Generator Database and ACIL Tasman assumptions	See above and ACIL Tasman assumptions	See above and ACIL Tasman assumptions
Auxiliaries (%)	ACIL Tasman Generator Database and ACIL Tasman assumptions	See above and ACIL Tasman assumptions	See above and ACIL Tasman assumptions
MLF	To be done	To be done	To be done
FOM ($/MW/year) for 2009-10	ACIL Tasman Generator Database and ACIL Tasman assumptions	See above and ACIL Tasman assumptions	See above and ACIL Tasman assumptions
FOM escalation rate (% of CPI)	ACIL Tasman Generator Database and ACIL Tasman assumptions	See above and ACIL Tasman assumptions	See above and ACIL Tasman assumptions
VOM ($/MWh sent-out) for 2009-10	ACIL Tasman Generator Database and ACIL Tasman assumptions	See above and ACIL Tasman assumptions	See above and ACIL Tasman assumptions
VOM escalation rate (% of CPI)	ACIL Tasman Generator Database and ACIL Tasman assumptions	See above and ACIL Tasman assumptions	See above and ACIL Tasman assumptions
Fuel cost profile	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database and ACIL Tasman assumptions
Combustion emission factor (kg CO2-e/GJ of fuel)	National Greenhouse Accounts (NGA) Factors - Updating and replacing the AGO Factors and Methods Workbook, Department of Climate Change (February, 2008)	National Greenhouse Accounts (NGA) Factors - Updating and replacing the AGO Factors and Methods Workbook, Department of Climate Change (February, 2008)	National Greenhouse Accounts (NGA) Factors - Updating and replacing the AGO Factors and Methods Workbook, Department of Climate Change (February, 2008)
Fugitive emission factor (kg CO2-e/GJ of fuel)	See above	See above	See above
Percentage of emissions captured (%)	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database and ACIL Tasman assumptions
Min Gen (% of capacity) (constraint on output per "hour")	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database and ACIL Tasman assumptions
Capacity (MW) (Year ending June)	Power and Water Corporation, and Annual Power System Review - Northern Territory Utilities Commission (March 2009) and ACIL Tasman Generator Database	Queensland Department of Mines and Energy, Queensland Department of Infrastructure and Planning, Providing a circuit breaker to meet North West Queensland's future electricity needs - Sims Review report (May 2009), North West Queensland Energy Delivery Options - ROAM Consulting report to the Sims Review (February 2009), CS Energy and Geoscience Australia online interactive maps (November 2009)	ERA, Geoscience Australia online interactive maps (November 2009)
Max_Capacity Factor (constraint at annual level) (Year ending June)	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database and ACIL Tasman assumptions
Min_Capacity Factor (constraint at annual level) (Year ending June)	See above	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database and ACIL Tasman assumptions
Fuel Cost (Real 2009-10 $/GJ)	ACIL Tasman projection	ACIL Tasman projection	ACIL Tasman projection
Forced outage rate (%)	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database and ACIL Tasman assumptions
Planned outage rate (%)	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database and ACIL Tasman assumptions	ACIL Tasman Generator Database and ACIL Tasman assumptions

Data source: ACIL Tasman

4 New entrant technology included in the study

4.1 Introduction

The data for new entrants covers the same inputs as for existing plant (see Table 1) as well as additional inputs describing the capital costs and any improvement in costs and other inputs (such as thermal efficiency) as a result of various technologies maturing throughout the projection period.

Data for new entrant technology costs and performance are derived from EPRI provided data with amendments to reflect local conditions agreed following stakeholder reference group consultation. These are provided for technologies as detailed in Table 1.

Table 4 **Technologies examined by EPRI study**

Technology Type	Size, MWe (sent out basis)
Non-Renewable	
Integrated Gasification Combined Cycle (IGCC)	
Black coal	700-800 MW
Black coal, with CCS (85-90%)	600-700 MW
Pulverized Coal (PC)	
Brown coal, no NOx/SO2 controls	750 MW
Brown coal, with CCS (90%) & NOx/SO2 controls as reqd	750 MW
Black coal, no NOx/SO2 controls	750 MW
Black coal, with CCS (90%) & NOx/SO2 controls as reqd	750 MW
Oxy-combustion with black coal	750 MW
Combustion Turbine Combined Cycle (CTCC)	
Without CCS	600-800 MW
With CCS	600-800 MW
Simple Cycle Combustion Turbine (CT)	
Heavy Duty	160-190 MW
Nuclear	
Generation III/III+ (with seawater cooling)	1100-1600 MW
Renewable	
Solar Thermal	
Parabolic trough w/6 hours storage (also w/o storage)	200-300 MWe
Central receiver w/6 hours storage (also w/o storage)	200-300 MWe
Solar Photovoltaic (PV)	
Utility scale centralized PV, fixed flat plate PV	1x5 MWe, 10x5 MWe
Utility scale centralized PV, single axis tracking PV	1x5 MWe, 10x5 MWe
Utility scale centralized PV, two axis tracking	1x5 MWe, 10x5 MWe
On-shore wind	
On-shore wind (class 3, 4, 5, & 6)	25x2 MW, 100x2 MW, 250x2 MW
Geothermal	
Enhanced Geothermal System (EGS)	50 MW
Hot Sedimentary Aquifers (HAS)	50 MW

Data source: EPRI

EPRI have not provided Grubb curves but rather a capital cost for 2015 and 2030. ACIL Tasman has assumed a linear trend between these two pints of time to derive a Grubb curve. We recognise that the curves are unlikely to be linear in reality but given the uncertainty of the shape it was agreed to use the linear function. Some of these curves needed adjustment to match scenario definitions (for example, Scenario 1 involves "faster than expected" development of CCS and geothermal technologies) – and this is discussed further below.

Resource availability is also required for each technology – particularly for renewable technologies such as wind and geothermal. In these cases we have derived resource estimates by using existing data and consulting with the stakeholder reference group.

4.2 Scenario independent assumptions

The two tables below summarise the new entrant input assumptions which do not change across the different scenarios. These assumptions are largely drawn from the EPRI data. Capital costs do vary by scenario and are reported separately in Chapter 6.

Table 5 **Scenario independent new entrant assumptions**

Technology	Fuel Type	Min_Capacity Factor (constraint at annual level)	Min Gen (% of capacity) (constraint on output per "hour")	Auxiliary load (%)	FOM ($/MW/year) for 2009-10	VOM ($/MWh sent-out) for 2009-10	Percentage of emissions captured (%)
IGCC - Black coal	Black coal	0%	50%	17.6%	73,000	12.80	0%
IGCC - Black coal with CCS	Black coal	0%	50%	23.5%	104,000	20.00	89%
Supercritical PC - Brown coal	Brown coal	0%	50%	10.3%	41,000	5.10	0%
Supercritical PC - Brown coal with CCS	Brown coal	0%	50%	23.9%	67,000	16.40	90%
Supercritical PC - Black coal	Black coal	0%	50%	9.8%	33,000	4.60	0%
Supercritical PC - Black coal with CCS	Black coal	0%	50%	23.3%	55,000	15.70	90%
Supercritical PC - Black coal oxy-combustion CCS	Black coal	0%	50%	31.6%	60,068	9.07	90%
CCGT - Without CCS	Natural Gas	0%	40%	2.9%	14,000	2.00	0%
CCGT - With CCS	Natural Gas	0%	40%	15.4%	25,000	4.24	90%
OCGT - Without CCS	Natural Gas	0%	0%	1.0%	9,000	2.50	0%
Solar Thermal - Parabolic Trough w 6hrs Storage	Solar	0%	0%	10.0%	73,000	0.00	0%
Solar Thermal - Parabolic Trough w/out Storage	Solar	0%	0%	10.0%	55,000	0.00	0%
Solar Thermal - Central Receiver w 6hrs Storage	Solar	0%	0%	10.0%	73,000	0.00	0%
Solar Thermal - Central Receiver w/out Storage	Solar	0%	0%	10.0%	55,000	0.00	0%
Photovoltaic - PV Fixed Flat Plate	Solar	0%	0%	0.0%	38,000	0.00	0%
Photovoltaic - PV Single Axis Tracking	Solar	0%	0%	0.0%	47,000	0.00	0%
Photovoltaic - PV Two Axis Tracking	Solar	0%	0%	0.0%	76,000	0.00	0%
Wind - Small scale (50 MW)	Wind	0%	0%	0.0%	42,000	0.00	0%
Wind - Medium scale (200 MW)	Wind	0%	0%	0.0%	39,000	0.00	0%
Wind - Large scale (500 MW)	Wind	0%	0%	0.0%	37,000	0.00	0%
Geothermal - Enhanced Geothermal System (EGS)	Geothermal	0%	0%	15.0%	187,500	0.00	0%
Geothermal - Hot Sedimentary Aquifers (HSA)	Geothermal	0%	0%	15.0%	125,000	0.00	0%
Biomass	Biomass	0%	0%	0.0%	40,000	2.25	0%
Nuclear	Nuclear	0%	50%	7.0%	147,000	6.10	0%

Data source: ACIL Tasman analysis of EPRI

Table 6 **Assumed thermal efficiency of new entrants (%, HHV sent-out)**

Technology	2010	2015	2020	2025	2030
IGCC - Black coal	39%	39%	41%	43%	45%
IGCC - Black coal with CCS	29%	29%	31%	33%	36%
Supercritical PC - Brown coal	35%	35%	39%	43%	47%
Supercritical PC - Brown coal with CCS	25%	25%	30%	34%	38%
Supercritical PC - Black coal	38%	38%	41%	45%	48%
Supercritical PC - Black coal with CCS	28%	28%	32%	35%	38%
Supercritical PC - Black coal oxy-combustion CCS	30%	30%	33%	36%	39%
CCGT - Without CCS	50%	50%	52%	55%	58%
CCGT - With CCS	41%	41%	44%	47%	49%
OCGT - Without CCS	33%	33%	35%	38%	40%
Solar Thermal - Parabolic Trough w 6hrs Storage	NA	NA	NA	NA	NA
Solar Thermal - Parabolic Trough w/out Storage	NA	NA	NA	NA	NA
Solar Thermal - Central Receiver w 6hrs Storage	NA	NA	NA	NA	NA
Solar Thermal - Central Receiver w/out Storage	NA	NA	NA	NA	NA
Photovoltaic - PV Fixed Flat Plate	NA	NA	NA	NA	NA
Photovoltaic - PV Single Axis Tracking	NA	NA	NA	NA	NA
Photovoltaic - PV Two Axis Tracking	NA	NA	NA	NA	NA
Wind - Small scale (50 MW)	NA	NA	NA	NA	NA
Wind - Medium scale (200 MW)	NA	NA	NA	NA	NA
Wind - Large scale (500 MW)	NA	NA	NA	NA	NA
Geothermal - Enhanced Geothermal System (EGS)	NA	NA	NA	NA	NA
Geothermal - Hot Sedimentary Aquifers (HSA)	NA	NA	NA	NA	NA
Biomass	30%	30%	30%	30%	30%
Nuclear	33%	33%	33%	33%	33%

Data source: ACIL Tasman analysis of EPRI

4.3 Resource and build constraints for renewable technologies

4.3.1 Introduction

A requirement for the modelling of the scenarios is a robust set of limits or constraints regarding resource availability. Exclusion of this information may well result in the models finding a solution which includes an unrealistic generator plant mix. This section summarises the resource constraints assumed for renewable technologies. Resource constraints for coal and gas are covered off in later sections of this report.

It is worth noting that resource availability is the same for each scenario.

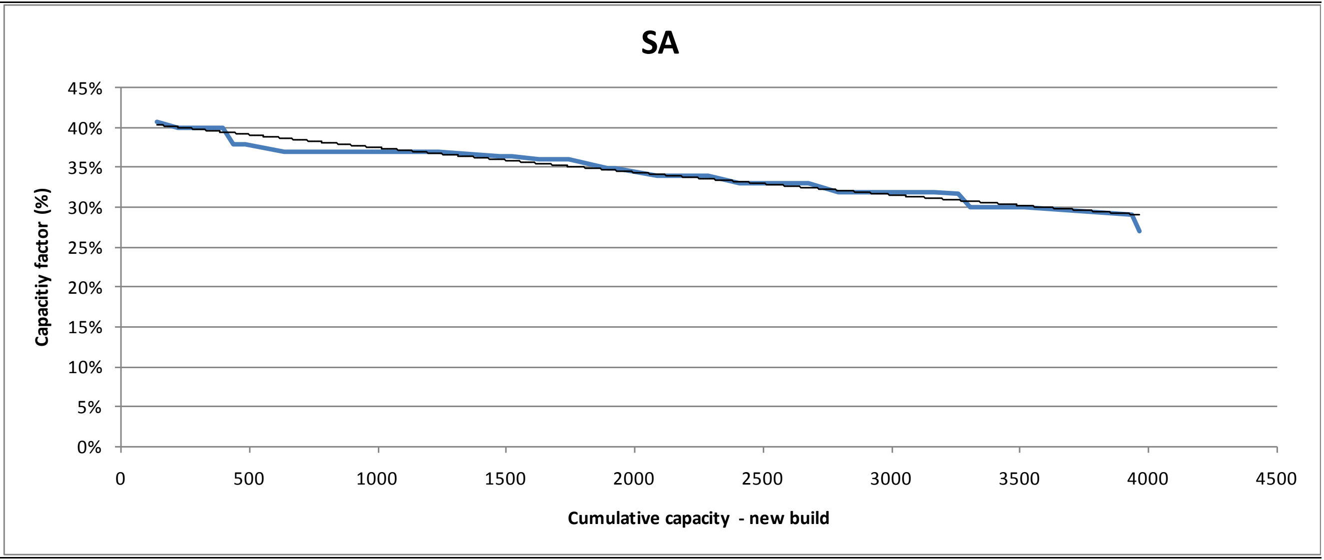
4.3.2 Wind

Although it is possible to develop a reasonable list of actual proposed wind farm projects, we need to consider the possibility of extending this list by estimating the potential for further wind farm projects beyond those already identified – particularly since the study extends to 2030. The following lists the methodology used to estimate the potential wind resource in each region.

ACIL Tasman compiled a list of proposed wind farms for each region in Australia. This list includes the capacity and likely capacity factor of the proposed projects.

For each region, this list was sorted from highest capacity factor to lowest capacity factor and the corresponding capacity and capacity factor was plotted - with cumulative capacity along the X-axis and capacity factor along the Y-axis. The graph below provides an example for South Australia – a similar trend is evident for other states.

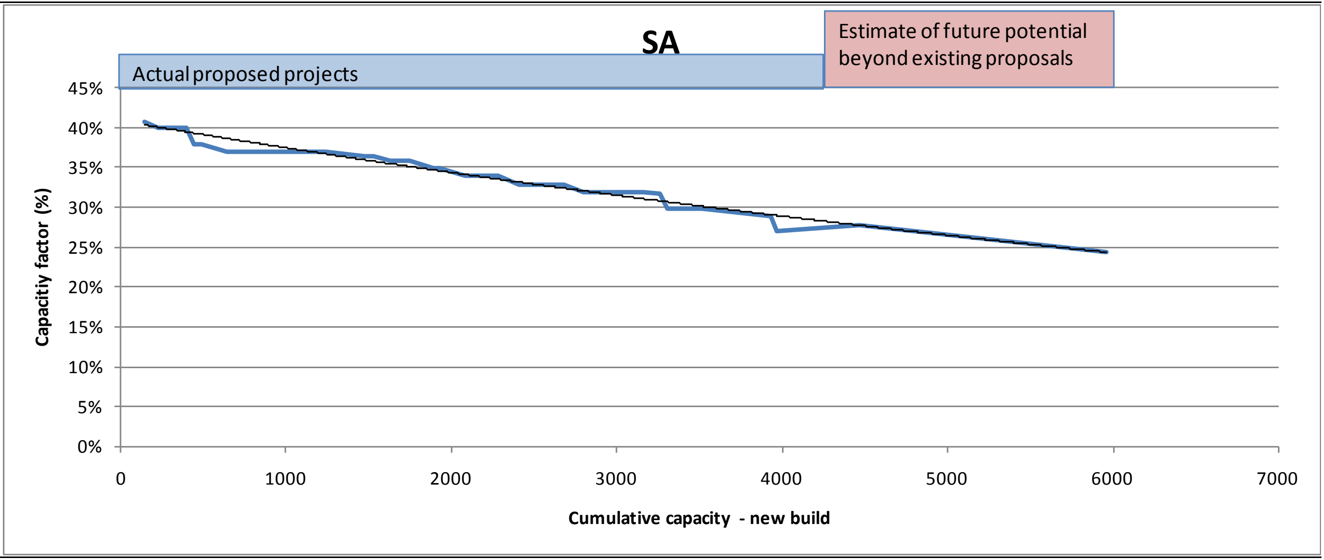
Figure 1 **Cumulative capacity of identified proposed wind farms versus capacity factor – South Australia**



Data source: ACIL Tasman analysis of data from various sources

We have then extrapolated a line of reasonable fit on the graph to the point at which the capacity factor hits 25% to provide a broad estimate of additional wind capacity beyond the existing proposals. The graph below provides an example for South Australia.

Figure 2 **Cumulative capacity of identified proposed and potential wind farms versus capacity factor – South Australia**



Data source: ACIL Tasman analysis of data from various sources

The important assumption here is that project proponents of the existing proposals have attempted to identify and develop the best sites first (simply using capacity factor as the measure) and therefore the best sites have already been identified. And therefore the remaining potential sites are assumed to have a lower capacity factor equal to or less than the capacity factor of already identified sites. The extrapolation takes no account of transmission costs or whether the observed trends have been impacted by factors other than resource quality (for example cost effective access to existing networks). Detailed analysis of wind maps and network access would be required in order to derive more precise resource estimates.

We have then taken this estimate of potential resource (which is at the state level) and split it up into the zones using proportions derived by the existing proposals. For example, in SA, 60% of the proposed wind farm capacity is in NSA and 40% is in SESA. We have then used these proportions to assign the additional resource.

If we notice a discernible difference between the projected capacity factors of the proposed developments between each of the zones then we make an adjustment accordingly.

ACIL Tasman readily admits this is a simplistic approach but we wanted to include the potential future resource and not just the proposed developments that currently exist (since the study is modelling out to 2030) without undertaking detailed studies of unidentified potential sites using wind mapping etc. We are being guided to some extent by behaviour of project proponents to estimate where the unidentified resources are and we assume they have already undertaken detailed analyses of potential sites etc.

The resulting assumptions for additional wind farm capacity is summarised below.

Table 7 **Assumed locational potential wind resource constraints – additional wind farm capacity by capacity factor**

			Capacity (MW)				Capacity factor			
State	Zone	% allocation within state	Tranche 1	Tranche 2	Tranche 3	Tranche 4	Tranche 1	Tranche 2	Tranche 3	Tranche 4
QLD	NQ	50%	266	266	266	266	33%	29%	29%	25%
QLD	CQ	0%	0	0	0	0	34%	30%	30%	26%
QLD	SEQ	50%	266	266	266	266	35%	31%	31%	27%
QLD	SWQ	0%	0	0	0	0	34%	30%	30%	26%
NSW	NNSW	16%	313	313	313	313	33%	31%	30%	27%
NSW	NCEN	16%	313	313	313	313	33%	31%	30%	27%
NSW	SWNSW	26%	509	509	509	509	34%	32%	31%	28%
NSW	CAN	41%	802	802	802	802	33%	31%	30%	27%
VIC	NVIC	0%	0	0	0	0	36%	33%	31%	29%
VIC	LV	5%	82	82	82	82	36%	33%	31%	29%
VIC	MEL	50%	818	818	818	818	36%	33%	31%	29%
VIC	CVIC	45%	736	736	736	736	36%	33%	31%	29%
SA	NSA	60%	895	895	895	895	38%	35%	32%	28%
SA	ADE	0%	0	0	0	0	38%	35%	32%	28%
SA	SESA	40%	596	596	596	596	38%	35%	32%	28%
TAS	TAS	100%	787	787	787	787	40%	38%	33%	26%
WA	SWIS	100%	306	306	306	306	43%	38%	33%	27%
NT	DKIS	0%	0	0	0	0	0%	0%	0%	0%
QLD	Mt Isa	0%	0	0	0	0	0%	0%	0%	0%
WA	NWIS	0%	0	0	0	0	0%	0%	0%	0%

Data source: ACIL Tasman analysis

4.3.3 Geothermal

The resource potential for geothermal is to some degree uncertain at this stage given that at present there exist no large scale geothermal power stations. The Australian Geothermal Energy Association (AGEA) participates in the stakeholder reference group and ACIL Tasman has consulted with AGEA to develop a set of estimates of geothermal resource potential by zone.

The potential for geothermal has been constrained– with up to 6,200MW of Enhanced Geothermal System (EGS) technology and up to 4,650MW of Hot Sedimentary Aquifers (HSA) technology available by 2030.

Entry of EGS is constrained to 450MW per year and entry of HSA is constrained to 350MW per year.

Table 8 **Assumed locational potential geothermal resource constraints (MW) – by 2030**

	QLD_NQ	QLD_CQ	QLD_SEQ	QLD_SWQ	NSW_NNSW	NSW_NCEN	NSW_SWNSW	NSW_CAN	VIC_NVIC	VIC_LV	VIC_MEL	VIC_CVIC	SA_NSA	SA_ADE	SA_SESA	TAS_TAS	WA_SWIS	NT_DKIS	QLD_Mt Isa	WA_NWIS
EGS	500	0	0	500	0	500	0	0	500	0	0	0	2,500	0	0	750	200	500	0	250
HSA	0	0	0	0	0	0	0	0	0	750	0	1,000	750	0	1,000	0	500	0	500	150

Data source: ACIL Tasman analysis of EGEA data

4.3.4 Biomass

ACIL Tasman identified about 1,000MW of currently operating biomass projects and 1,200MW of actual proposed biomass projects nationally. In consultation with ROAM Consulting, and the stakeholder reference group we have assumed the potential for biomass by zone by 2030 to be capped at 1,400MW nationally as shown in the table below. The zonal differences are based on the distribution of proposed biomass projects.

Entry of Biomass is constrained to 100MW per year on a national basis.

Table 9 **Assumed locational potential biomass resource constraints – by 2030**

Zone	Capacity (MW)
QLD_NQ	400
QLD_CQ	0
QLD_SEQ	0
QLD_SWQ	0
NSW_NNSW	100
NSW_NCEN	100
NSW_SWNSW	0
NSW_CAN	100
VIC_NVIC	0
VIC_LV	0
VIC_MEL	0
VIC_CVIC	0
SA_NSA	0
SA_ADE	0
SA_SESA	300
TAS_TAS	300
WA_SWIS	100
NT_DKIS	0

QLD_Mt Isa	0
WA_NWIS	0

Data source: ACIL Tasman analysis of various sources and consultation with ROAM Consulting and Stakeholder Reference Group

4.3.5 Solar Thermal and Photovoltaic

The resource potential for solar thermal and photovoltaic is uncertain at this stage. Availability has been assumed to be limited by a judgement about the rate at which projects can be undertaken.

It was agreed to assume solar thermal and photovoltaic capacity can enter the market at a rate of 200MW per year each, if commercially viable.

EPRI provided assumed capacity factors for different ranges of direct normal insolation (DNI). ACIL Tasman then mapped these values to each of the zones using a map of average daily solar exposure from the Bureau of Meteorology to give the assumed zonal capacity factor assumptions as shown in Table 10.

Table 10 **Assumed locational capacity factors for Solar Thermal and Photovoltaic technology**

Zone	Solar Thermal - Parabolic Trough w 6hrs Storage	Solar Thermal - Parabolic Trough w/out Storage	Solar Thermal - Central Receiver w 6hrs Storage	Solar Thermal - Central Receiver w/out Storage	Photovoltaic - PV Fixed Flat Plate	Photovoltaic - PV Single Axis Tracking	Photovoltaic - PV Two Axis Tracking
QLD_NQ	46%	28%	47%	29%	22%	28%	36%
QLD_CQ	46%	28%	47%	29%	22%	28%	36%
QLD_SEQ	39%	24%	39%	24%	19%	24%	30%
QLD_SWQ	39%	24%	39%	24%	19%	24%	30%
NSW_NNSW	39%	24%	39%	24%	19%	24%	30%
NSW_NCEN	39%	24%	39%	24%	19%	24%	30%
NSW_SWNSW	39%	24%	39%	24%	19%	24%	30%
NSW_CAN	33%	20%	33%	20%	16%	20%	25%
VIC_NVIC	33%	20%	33%	20%	16%	20%	25%
VIC_LV	27%	17%	27%	16%	13%	17%	21%
VIC_MEL	27%	17%	27%	16%	13%	17%	21%
VIC_CVIC	33%	20%	33%	20%	16%	20%	25%
SA_NSA	39%	24%	39%	24%	19%	24%	30%
SA_ADE	39%	24%	39%	24%	19%	24%	30%
SA_SESA	33%	20%	33%	20%	16%	20%	25%
TAS_TAS	27%	17%	27%	16%	13%	17%	21%
WA_SWIS	39%	24%	39%	24%	19%	24%	30%
NT_DKIS	46%	28%	47%	29%	22%	28%	36%
QLD_Mt Isa	46%	28%	47%	29%	22%	28%	36%
WA_NWIS	46%	28%	47%	29%	22%	28%	36%

Data source: ACIL Tasman analysis of EPRI data and BOM data

5 Emissions factors

The table below summarises the emissions factors assumed by state and fuel type.

Table 11 **Emission factors (kg CO2-e/GJ of fuel) – by state and fuel type**

	Combustion							Fugitive						
Fuel	QLD	NSW	VIC	SA	TAS	WA	NT	QLD	NSW	VIC	SA	TAS	WA	NT
Brown coal	NA	NA	93.2	NA	NA	NA	NA	NA	NA	0.3	NA	NA	NA	NA
Black coal	91.1	89.3	NA	NA	NA	93.1	NA	2.0	8.7	NA	NA	NA	2.3	NA
Natural gas	51.3	51.3	51.3	51.3	51.3	51.3	51.3	5.4	14.2	5.8	18.6	5.8	7	5.7
Solar Thermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0
Photovoltaic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0
Biomass	1.8	1.8	1.8	1.8	1.8	1.8	1.8	0.0	0.0	0.0	0.0	0.0	0	0

Data source: National Greenhouse Accounts (NGA) Factors - Updating and replacing the AGO Factors and Methods Workbook, Department of Climate Change, February, 2008.

6 Defining the scenarios – translating the narrative into numbers

6.1 Introduction

The three tables below summarise the key variations made to the input assumptions. We have listed the variations suggested from the MMA/Strategis report and then our interpretation and implementation of these variations by major input. More detailed discussion is provided in the sections following these tables.

Table 12 **Scenario interpretation and construction**

Input		Parameter	Scenario 1 "Fast rate of change"	Scenario 2 "An uncertain world"	Scenario 3 "A decentralised world"	Scenario 4 "Oil shock and adaptation"	Scenario 5 "Slow rate of change"
Carbon prices	MMA / Strategis Partners	carbon price sensitivities	High and Medium	Low and no carbon price	High and Medium	Medium and Low	Low and no carbon price
	ACIL Tasman	carbon price sensitivities	AU $0 -$100/t (high) and AU $0 - $85/t (medium)	AU $0 -$60/t (low) and AU $0/t (zero)	AU $0 -$100/t (high) and AU $0 - $85/t (medium)	AU $0 -$85/t (medium) and AU $0 - $60/t (low)	AU $0 -$60/t (low) and AU $0/t (zero)
Fuel costs	MMA / Strategis Partners	International oil price	Medium	Medium	Medium	High	Medium
		Domestic LNG production	High	Low	Medium	High	Low
		Competition in domestic markets	Medium	High	High	Low	Medium
	ACIL Tasman	International oil price	IEA Reference case: $115/bbl by 2030	IEA Reference case: $115/bbl by 2030	IEA Reference case: $115/bbl by 2030	IEA High case: $150/bbl by 2030	IEA Reference case: $115/bbl by 2030
		Domestic LNG production	Aggregate LNG exports peaking at 91Mtpa by 2020	Aggregate LNG exports peaking at 46.6Mtpa by 2020	Aggregate LNG exports peaking at 71.2Mtpa by 2020	Aggregate LNG exports peaking at 91Mtpa by 2020	Aggregate LNG exports peaking at 46.6Mtpa by 2020
		Competition in domestic markets	Normal level of competition between gas and coal producers to supply domestic users	Coal and gas producers aggressively compete against one another for supply to domestic loads	Coal and gas producers aggressively compete against one another for supply to domestic loads	Limited competition as a result of consolidation amongst coal/gas producers	Normal level of competition between gas and coal producers to supply domestic users

Data source: MMA/Strategis and ACIL Tasman

Table 13 **Scenario interpretation and construction - continued**

Input		Parameter	Scenario 1 "Fast rate of change"	Scenario 2 "An uncertain world"	Scenario 3 "A decentralised world"	Scenario 4 "Oil shock and adaptation"	Scenario 5 "Slow rate of change"
Technology costs	MMA / Strategis Partners	Exchange rate	High	High	Medium	Medium	Low
		Commodity costs	High	High	Medium	Medium	Low
		Learning curves/Grubb curves for new centralised supply technologies	Faster than expected for CCS and geothermal	Slower than expected for CCS and geothermal due to uncertainty	Slower than expected for CCS and geothermal	Slower than expected for CCS. Faster than expected for geothermal	As expected
		Capital costs for centralised new entrants	Higher than average due to high commodity costs	Higher than average due to high commodity costs	Higher than expected for CCS and geothermal	Higher than expected for CCS, average for other technologies	Lower than average due to low commodity costs
		Fixed operation and maintenance costs for new entrants	Average	Average	Average	Average	Average
		WACC	Low risk premium	High risk premium created by uncertainty	Average	Average	High due to shortage of access to capital
		Capital costs and benefits for distributed generation (eg cogeneration and tri-generation)	Higher than average due to high commodity costs	Higher than average due to high commodity costs	Below average	Higher than expected	Lower than average due to low commodity costs
		Costs for small-scale renewables	Average	Above average	Lower than expected	Higher than expected	Average
	ACIL Tasman	Exchange rate	US$0.85/AUD	US$0.85/AUD	US$0.75/AUD	US$0.75/AUD	US$0.60/AUD
		Commodity costs	High	High	Medium	Medium	Low
		Learning curves/Grubb curves for new centralised supply technologies	Faster than expected for CCS and geothermal	Slower than expected for CCS and geothermal due to uncertainty	Slower than expected for CCS and geothermal	Slower than expected for CCS. Faster than expected for geothermal	As expected
		Capital costs for centralised new entrants	As per ACIL Tasman/EPRI data + 10%	As per ACIL Tasman/EPRI data + 10%	As per ACIL Tasman/EPRI data. CCS and Geothermal + 10%	As per ACIL Tasman/EPRI data. CCS and Solar PV + 10%	As per ACIL Tasman/EPRI data - 10%
		Fixed operation and maintenance costs for new entrants	As per ACIL Tasman/EPRI data	As per ACIL Tasman/EPRI data	As per ACIL Tasman/EPRI data	As per ACIL Tasman/EPRI data	As per ACIL Tasman/EPRI data
		WACC (Pre-tax real)	8.78%	11.37%	9.79%	9.79%	11.37%
		Capital costs and benefits for distributed generation (eg cogeneration and tri-generation)			Not considering distributed generation as part of the supply mix - accounted for in demand forecast		
		Costs for small-scale renewables			EPRI data includes small scale wind		

Data source: MMA/Strategis and ACIL Tasman

Table 14 **Scenario interpretation and construction - continued**

Input		Parameter	Scenario 1 "Fast rate of change"	Scenario 2 "An uncertain world"	Scenario 3 "A decentralised world"	Scenario 4 "Oil shock and adaptation"	Scenario 5 "Slow rate of change"
Other parameters	MMA / Strategis Partners	Summer de-ratings for generators and transmission lines	Below average	Below average	Below average	Below average	Below average
		Availability of new and existing plant	Lower than expected for existing coal plant (less maintenance)	As expected	As expected	As expected	As expected
		Unavoidable costs of incumbents	Higher than expected	As expected – though uncertainty increases appetite to wait and see (slower rate of retirement)	As expected	As expected	Lower than expected
		Water availability for hydro power stations and thermal plants	Moderate	Moderate/low	Moderate	Low	High
	ACIL Tasman	Summer de-ratings for generators and transmission lines	AEMO assumptions	AEMO assumptions	AEMO assumptions	AEMO assumptions	AEMO assumptions
		Availability of new and existing plant	ACIL Tasman assumptions from 2009 IRPC cost report for existing plant. Existing coal availability 3% lower. No change for new plant	ACIL Tasman assumptions from 2009 IRPC cost report for existing plant. No change for new plant	ACIL Tasman assumptions from 2009 IRPC cost report for existing plant. No change for new plant	ACIL Tasman assumptions from 2009 IRPC cost report for existing plant. No change for new plant	ACIL Tasman assumptions from 2009 IRPC cost report for existing plant. No change for new plant
		Unavoidable costs of incumbents	FOM costs constant across scenarios	FOM costs constant across scenarios	FOM costs constant across scenarios	FOM costs constant across scenarios	FOM costs constant across scenarios
		Water availability for hydro power stations and thermal plants	Dartmouth to recover over three years to full output in 2012. Eildon to have 20% reduced output in 2010 recovering to full output in 2012. Snowy reduced to about 3,800GWh in 2009 and recovering by 2012. Hydro Tasmania output is about 20% lower than normal in 2009 and recovering to full output in 2012.	Scenario 2 treated with a long term drought throughout projection period. Production levels capped at about 80% of "normal" long terms levels.	Same as Scenario 1	Scenario 4 treated with severe two-year droughts occurring every six years throughout projection period. Production levels capped at about 65% of "normal" long terms levels during these drought periods and returning to normal levels for other periods.	Same as Scenario 1
		New Entrant Wind Farm resource limit in built up areas (SEQ, NCEN, MEL, ADE)	Average	50% reduction compared with other scenarios	Same as Scenario 1	Same as Scenario 1	Same as Scenario 1

Data source: MMA/Strategis and ACIL Tasman

6.2 Carbon prices

Emissions prices were derived from the Treasury modelling included in the report, *Australia's Low Pollution Future,* as shown below. These prices were incorporated into the first round of modelling by IES and ROAM. Following the completion of that initial modelling, the Australian Government announced that it would delay the implementation of the Carbon Pollution Reduction Scheme until after the end of the current commitment period under the Kyoto Protocol (which ends in 2012), and only when there is greater clarity on the actions of other major economies including the US, China and India. Accordingly, later modelling assumed that a price on carbon would not be introduced until 1 July 2014, which assumes a short delay between a policy decision, the passage of legislation and implementation. In later modelling therefore, the carbon price trajectories below were retained, with the carbon price set at zero prior to 1 July 2014.

Table 15 **Carbon prices used in modelling (Real 2009/2010 AUD$/tonne CO2)**

	No carbon price	Low	Medium	High
2010-11	$0.00	$0.00	$0.00	$0.00
2011-12	$0.00	$10.00	$10.00	$10.00
2012-13	$0.00	$26.47	$36.69	$46.44
2013-14	$0.00	$28.44	$39.59	$49.46
2014-15	$0.00	$30.42	$42.26	$52.71
2015-16	$0.00	$32.39	$46.21	$55.61
2016-17	$0.00	$34.25	$48.64	$58.40
2017-18	$0.00	$35.87	$50.97	$61.18
2018-19	$0.00	$37.50	$53.40	$63.97
2019-20	$0.00	$39.24	$55.73	$66.75
2020-21	$0.00	$40.87	$57.93	$69.66
2021-22	$0.00	$42.72	$61.07	$72.67
2022-23	$0.00	$44.46	$63.16	$75.35
2023-24	$0.00	$46.32	$65.59	$78.25
2024-25	$0.00	$48.18	$68.26	$81.27
2025-26	$0.00	$49.69	$70.47	$84.40
2026-27	$0.00	$51.78	$73.26	$87.42
2027-28	$0.00	$53.75	$75.81	$90.79
2028-29	$0.00	$55.96	$78.71	$94.27
2029-30	$0.00	$58.05	$81.38	$97.52

Note: Later modelling assumed a carbon price of zero in all scenarios for 2011-12, 2012-13 and 2013-14.

Data source: ACIL Tasman analysis of *Australia's Low Pollution Future, Australian Government*, December 2008

6.3 International oil and LNG prices

International oil and LNG prices were taken from the International Energy Agency's report, *World Energy Outlook 2009*. The scenarios require a mid case and high case which were provided in the IEA report as shown in Table 16. These projections were then converted to Australian dollars using the corresponding exchange rate for the given scenario as shown in Table 17.

Oil prices are used to adjust the price of diesel for existing peaking plant. International LNG prices are used in the GasMark modelling to project domestic gas prices for each scenario (see Section 7.1 for details of GasMark).

Table 16 **International oil and LNG prices used in modelling (Real 2009/2010 US$)**

	Reference Case		High Case	
	Oil	Japan LNG	Oil	Japan LNG
	US$/bbl	US$/mmbtu	US$/bbl	US$/mmbtu
2009-10	$97.95	$12.93	$105.05	$13.90
2010-11	$96.39	$12.82	$107.04	$14.27
2011-12	$94.83	$12.71	$109.02	$14.65
2012-13	$93.26	$12.60	$111.01	$15.03
2013-14	$91.70	$12.49	$113.00	$15.40
2014-15	$90.14	$12.39	$114.98	$15.78
2015-16	$92.91	$12.77	$119.03	$16.34
2016-17	$95.68	$13.15	$123.07	$16.90
2017-18	$98.45	$13.53	$127.11	$17.46
2018-19	$101.23	$13.92	$131.16	$18.01
2019-20	$104.00	$14.30	$135.20	$18.57
2020-21	$105.56	$14.52	$137.28	$18.88
2021-22	$107.12	$14.75	$139.36	$19.18
2022-23	$108.68	$14.97	$141.44	$19.48
2023-24	$110.24	$15.20	$143.52	$19.78
2024-25	$111.80	$15.42	$145.60	$20.08
2025-26	$113.36	$15.64	$147.68	$20.37
2026-27	$114.92	$15.86	$149.76	$20.66
2027-28	$116.48	$16.07	$151.84	$20.95
2028-29	$118.04	$16.29	$153.92	$21.24
2029-30	$119.60	$16.50	$156.00	$21.53

Data source: ACIL Tasman analysis of *World Energy Outlook 2009*, IEA, December 2008, p600-661

Table 17 **Landed LNG prices Japan (Real 2009-10 AUD$/GJ)**

	Scenario 1 and 2			Scenario 3			Scenario 4			Scenario 5		
	US$/GJ	US/AUD	A$/GJ	US$/GJ	US/AUD	A$/GJ	US$/GJ	US/AUD	A$/GJ	US$/GJ	US/AUD	A$/GJ
2010	$13.63	0.85	$16.03	$13.63	0.75	$18.17	$14.65	0.75	$19.53	$13.63	0.6	$22.71
2011	$13.51	0.85	$15.90	$13.51	0.75	$18.02	$15.04	0.75	$20.06	$13.51	0.6	$22.52
2012	$13.40	0.85	$15.76	$13.40	0.75	$17.86	$15.44	0.75	$20.59	$13.40	0.6	$22.33
2013	$13.28	0.85	$15.63	$13.28	0.75	$17.71	$15.84	0.75	$21.12	$13.28	0.6	$22.14
2014	$13.17	0.85	$15.49	$13.17	0.75	$17.56	$16.23	0.75	$21.64	$13.17	0.6	$21.95
2015	$13.06	0.85	$15.36	$13.06	0.75	$17.41	$16.63	0.75	$22.17	$13.06	0.6	$21.76
2016	$13.46	0.85	$15.83	$13.46	0.75	$17.94	$17.22	0.75	$22.96	$13.46	0.6	$22.43
2017	$13.86	0.85	$16.31	$13.86	0.75	$18.48	$17.81	0.75	$23.74	$13.86	0.6	$23.10
2018	$14.27	0.85	$16.78	$14.27	0.75	$19.02	$18.40	0.75	$24.53	$14.27	0.6	$23.78
2019	$14.67	0.85	$17.26	$14.67	0.75	$19.56	$18.99	0.75	$25.32	$14.67	0.6	$24.45
2020	$15.07	0.85	$17.73	$15.07	0.75	$20.10	$19.58	0.75	$26.10	$15.07	0.6	$25.12
2021	$15.31	0.85	$18.01	$15.31	0.75	$20.41	$19.90	0.75	$26.53	$15.31	0.6	$25.51
2022	$15.55	0.85	$18.29	$15.55	0.75	$20.73	$20.21	0.75	$26.95	$15.55	0.6	$25.91
2023	$15.78	0.85	$18.57	$15.78	0.75	$21.04	$20.53	0.75	$27.37	$15.78	0.6	$26.30
2024	$16.02	0.85	$18.85	$16.02	0.75	$21.36	$20.85	0.75	$27.80	$16.02	0.6	$26.70
2025	$16.26	0.85	$19.12	$16.26	0.75	$21.67	$21.17	0.75	$28.22	$16.26	0.6	$27.09
2026	$16.48	0.85	$19.39	$16.48	0.75	$21.98	$21.47	0.75	$28.63	$16.48	0.6	$27.47
2027	$16.71	0.85	$19.66	$16.71	0.75	$22.28	$21.78	0.75	$29.04	$16.71	0.6	$27.85
2028	$16.94	0.85	$19.93	$16.94	0.75	$22.59	$22.08	0.75	$29.44	$16.94	0.6	$28.23
2029	$17.17	0.85	$20.20	$17.17	0.75	$22.89	$22.39	0.75	$29.85	$17.17	0.6	$28.61
2030	$17.40	0.85	$20.47	$17.40	0.75	$23.19	$22.69	0.75	$30.25	$17.40	0.6	$28.99

Data source: ACIL Tasman analysis of *World Energy Outlook 2009*, IEA, December 2008, p600-661

6.4 Technology capital costs

The capital costs of each technology covered in the study are derived from the data provided by EPRI with amendments as agreed by the Stakeholder Reference Group on 23 December 2009 and 30 April 2009 and are shown in Table 18 below. Two capital cost values are shown – one for 2015 and one for 2030, which allow the study to account for the real reduction in capital costs due to the uptake of and learning within the technology.

Table 18 **Assumed capital costs (Real 2009-10 AUD$/kW) – central estimates**

Technology	Capital costs in 2015 ($/kW installed)	Capital costs in 2030 ($/kW installed)
IGCC - Brown coal	$5,025	$2,934
IGCC - Brown coal with CCS	$6,262	$3,374
IGCC - Black coal	$4,201	$3,232
IGCC - Black coal with CCS	$5,233	$3,726
Supercritical PC - Brown coal	$3,571	$3,214
Supercritical PC - Brown coal with CCS	$5,600	$4,638
Supercritical PC - Black coal	$2,676	$2,408
Supercritical PC - Black coal with CCS	$4,492	$3,677
Supercritical PC - Black coal oxy-combustion CCS	$4,299	$3,422
CCGT - Without CCS	$1,368	$1,170
CCGT - With CCS	$2,359	$1,757
OCGT - Without CCS	$985	$872
Solar Thermal - Parabolic Trough w 6hrs Storage	$7,875	$5,513
Solar Thermal - Parabolic Trough w/out Storage	$5,109	$3,321
Solar Thermal - Central Receiver w 6hrs Storage	$5,827	$3,788
Solar Thermal - Central Receiver w/out Storage	$4,103	$2,462
Photovoltaic - PV Fixed Flat Plate	$4,650	$3,255
Photovoltaic - PV Single Axis Tracking	$5,100	$3,570
Photovoltaic - PV Two Axis Tracking	$5,650	$3,955
Wind - Small scale (50 MW)	$3,178	$2,543
Wind - Medium scale (200 MW)	$2,886	$2,308
Wind - Large scale (500 MW)	$2,744	$2,195
Geothermal - Enhanced Geothermal System (EGS)	$6,899	$6,507
Geothermal - Hot Sedimentary Aquifers (HSA)	$6,600	$5,715
Nuclear	$5,283	$4,486

Note: Capital costs exclude transmission costs. CCS capital costs exclude cost of transportation and storage of captured CO2.

Data source: EPRI new entrant cost data with amendments agreed by Stakeholder Reference Group (as at 23 December 2009 and 30 April 2010)

6.4.1 Learning rate

It is worth noting that although costs are presented for each technology in 2015 and 2030, some of the technologies are assumed to have their cost curves altered in some of the scenarios. The rows in Table 19 assist in modifying the rate of learning for CCS and geothermal technologies. For example, in Scenario 1 the rate of learning is faster than expected for CCS and geothermal, and so it is assumed then that the 2030 capital cost shown above in Table 18 is actually reached by 2025 – in effect compressing the learning curve on the time continuum from the central case of 2015 to 2030, to 2015 to 2025.

Table 19 **Changes in Grubb curves for CCS and geothermal technology**

Year 2030 capital cost level reached			
	Faster than expected	As expected	Slower than expected
Carbon capture and storage equipped plant	2025	2030	2035
Geothermal technologies	2025	2030	2035

Data source: ACIL Tasman in consultation with Stakeholder Reference Group

6.4.2 Deviation from the central cost estimates

The capital costs estimates provided by EPRI and agreed by the Stakeholder Reference Group are central estimates with a confidence interval of +/- 30%. A number of the scenarios are designed to test deviations from these central estimates due to:

- Higher or lower underlying commodity prices (flowing through to the estimates); or
- Expectations regarding the estimates not being met due to uncertainty (for example, the cost of CCS turns out to be cheaper than expected for a given commodity price).

In regard to commodity prices we have assumed a high/low commodity price results in a 10% increase/decrease in technology capital costs, all other things equal. We have chosen the 10% increase/decrease in capital costs for the following reasons:

- We assume that the spread in commodity costs can be characterised by a 20% increase/decrease. With the exception of the short lived spike in commodity prices in 2008, price fluctuations have typically been between -20% and +20%.
- We assume that commodity prices impact about 50% of the capital cost of a new project.

In regard to the uncertainty around the capital cost estimates provided, we note that EPRI suggest the upper and lower limit of +/- 30%. We assume these to be the extreme bounds, which suggest that +/- 10% will cover a reasonable range of the uncertainty. In fact if we can assume a normal distribution with extreme of +/- 30%, then a range of +/- 10% roughly covers one standard deviation on either side of the central estimate – this does not seem unreasonable.

6.4.3 Other changes made to the central estimates of capital costs

Capital cost scale factor for smaller scale plant

New entrants are typically smaller in the SWIS, NWIS, DKIS and Mt Isa due to the smaller size of the system demand. Smaller new entrants are usually subject to a scale factor with regard to capital costs. In this study we have assumed the following scale factors for smaller scale plant:

- 15% premium for smaller scale coal fired plant (SWIS, NWIS);
- 10% premium for smaller scale CCGTs (SWIS, NWIS);
- 30% premium for very small scale CCGTs (DKIS, Mt Isa).

Capital cost scale factor for geothermal plant

Given the variability in the location of the potential geothermal projects it was decided to account for any reasonable variation in project costs by location – similar to accounting for different capacity factors for wind in different locations. The central estimates agreed by the Stakeholder Reference Group were preserved overall but on a locational basis were varied by an assumed discount/premium as provided by the AGEA (as shown in the table below). The weighted average of these discounts/premiums (using the locational resource potential as the weights) equals one – thus preserving on average the central capital cost estimates.

Table 20 **Assumed locational premium/discount for geothermal capital costs**

	QLD_NQ	QLD_CQ	QLD_SEQ	QLD_SWQ	NSW_NNSW	NSW_NCEN	NSW_SWNSW	NSW_CAN	VIC_NVIC	VIC_LV	VIC_MEL	VIC_CVIC	SA_NSA	SA_ADE	SA_SESA	TAS_TAS	WA_SWIS	NT_DKIS	QLD_Mt Isa	WA_NWIS
EGS	1.06			1.01		1.07			1.20				0.87			1.06	1.15	1.09		1.11
HSA										0.97		0.91	0.97		0.89		1.17		1.17	1.24

Data source: ACIL Tasman analysis of EGEA data

6.5 CO2 field establishment, transport, storage and monitoring costs

The Department of Resources, Energy and Tourism provided ACIL Tasman with estimates of CO2 transport and storage costs by location as presented below. The costs are taken from *The Costs of CO2 Transport and Injection in Australia* (CO2Tech, September 2009).

These costs are increased by 10% in Scenario 1 to Scenario 4 and reduced by 10% in Scenario 5.

Table 21 **Transport and storage costs (Real 2009/10 AUD/tonne CO_2)**

Generation location	Storage Location	Cost (AUD/tCO2)
Latrobe Valley	Gippsland	$7
North NSW	Surat	$82
South NSW	Gippsland	$34
South QLD	Surat	$19
South QLD	Eromanga	$45
North QLD	Galilee	$80
North QLD	Eromanga	$45
SWIS	Off-shore SWIS	$21

Data source: DRET

Table 22 **Annual injection rate constraint**

Storage Location	Max Basin injection rate (Mtpa)
Gippsland	400
Surat	50
Eromanga	30
Galilee	12
Darling	8
Denison	5
Off-shore SWIS	8.4

Data source: DRET

6.6 Other modifications of input data for the scenarios

6.6.1 Hydro stations

Hydro inflows are accounted for in the inputs by capping the annual production of each hydro station. For most scenarios the annual production will be capped at the long term average in the following manner:

- The recent drought conditions mean that Dartmouth will have zero output through 2009 and recover over three years to full output in 2012. Similarly Eildon will have reduced capacity of 60 MW until October 2009 and have a 20% reduced output in 2010 recovering gradually to full output in 2012.
- Water inflows at Snowy Hydro have been substantially below the long term average. Water levels in Eucumbene Dam, the Snowy Mountain Scheme's major long term storage, currently stand at about 22 percent of capacity. Recovery of the storage would take several years of above average inflow. Snowy Hydro is cycling water through the Tumut 3 power station (utilising water during the day for power generation and pumping it back to the source at night), so that the limited water resources are used efficiently. We have assumed in the base case that generation from Snowy hydro plant is reduced to about 3,800GWh in 2009 and recovering gradually to 4,600 GWh by 2012.
- Water storage levels at Hydro Tasmania were at about 25 percent at the beginning of 2009. Low water storage levels have resulted in Hydro

Tasmania importing power through Basslink to meet existing demand. We assume that the generation from hydro plant in Tasmania is about 20% lower than normal in 2009 and recovering gradually to full output in 2012 which will result in a continuation of the strong imports of energy from Victoria in the early years of the projection.

Scenarios 2, 5 and 5 will require modification to the hydro production levels:

- Scenario 2 assumes "by 2030, hydro availability is limited due to prolonged drought..." (MMA/Strategis report, page 9).
- Scenario 4 assumes "...droughts occur more frequently and are more severe than previously anticipated." (MMA/Strategis report, page 13).
- Scenario 5 assumes "there are also fewer periods of drought than initially anticipated." (MMA/Strategis report, page 15).

Scenario 2:

- We have treated Scenario 2 with a long term drought throughout the projection period.
- The production levels of the existing hydro plant will be capped at about 80% of "normal" long terms levels – similar to those levels experienced with the recent drought.

Scenario 4:

- We have treated Scenario 4 with two-year droughts occurring every six years throughout the projection period.
- The production levels of the existing hydro plant will be capped at about 65% of "normal" long terms levels during these drought periods and returning to normal levels for the other periods.

Scenario 5:

- We have treated Scenario 5 with no droughts throughout the projection period.
- The production levels of the existing hydro plant will be treated the same of the other non-drought scenarios.

6.6.2 New entrant wind farms

Scenario 2 contains the following description from the MMA/Strategic report: "*wind Farms are tolerated, but local community resistance has begun selection of more remote sites*."

We have reduced the resource limit of new entrant wind farms in SEQ, NCEN, MEL and ADE by 50% to reflect this feature.

7 Fuel costs

7.1 Natural gas

7.1.1 Introduction

Gas prices are a key input into long-term electricity modelling exercises as gas is one of the key fuels for new entrants in light of the anticipated introduction of a carbon price.

This section discusses ACIL Tasman's approach in estimating gas costs for existing and new entrant plant within EWP modelling process.

7.1.2 Gas costs for existing stations

The fuel cost for existing stations is dependent on a number of factors including:

- Contractual arrangements including pricing, indexation, tenure and take or pay provisions
- Gas field and power station ownership arrangements
- Availability of fuel through spot purchases or valuation on an opportunity cost basis
- Projected prices for new long-term contracts.

As virtually all existing gas plant rely upon long-term gas sales agreements, prices are estimated as the average contract price on a delivered basis. However, as details of contractual arrangements are almost never publicly available, contract prices, volumes and tenures are required to be estimated.

As these existing contracts expire, gas costs for the station transition to reflect the projected 'market' price for gas at that location (i.e. the same price which applies to new entrant plant – discussed in the following section). This will occur at different times for each station, depending upon their contractual positions.

Gas price estimated for existing NEM stations are consistent with estimates provided within the ACIL Tasman report completed for the Inter-Regional Planning Committee in 2009.[1] Costs for stations outside the NEM (i.e. Western Australia, Mt Isa and Northern Territory) are ACIL Tasman estimates based on extensive gas industry experience in these regions.

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[1] ACIL Tasman, Fuel resource, new entry and generation costs in the NEM, April 2009.

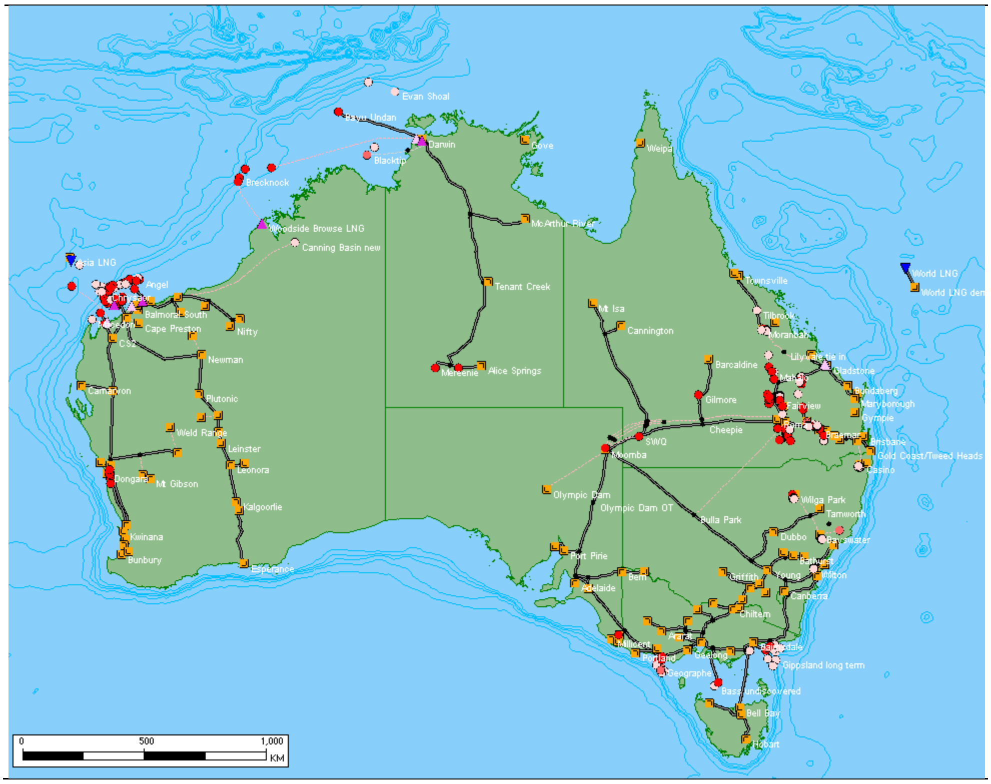
7.1.3 Gas costs for new entrants

Long-term price projections for gas have been developed from the outputs of ACIL Tasman's proprietary gas market model – *GMG Australia* (GasMark Global Australia). The input database within GMG Australia is the most comprehensive in Australia and comprises of:

- Over 180 individual gas fields and producing Basins
- 270 individual and aggregated load/demand points, mapped to around 120 market locations around Australia
- Over 300 pipelines/pipeline segments with actual regulated or estimated commercial tariff settings.

The geographic representation of the Australian gas network as modelled within this project is shown in Figure 3.

Figure 3 **Australian gas network representation**



Note: Global demand for Australian LNG is represented by notional offshore receiving terminals and demand points.

Data source: GMG Australia

ACIL Tasman has utilised its internal Base Case supply and demand assumptions for this work. The inputs contain assumptions regarding:

- field reserves, production capability and costs
- gas demand and the price tolerance and elasticity of this demand

- pipeline capacities and tariffs (as well as capability for future augmentations)
- LNG plants: capacity, liquefaction tolling and shipping costs.

GMG Australia provides price projections on a nodal basis for each defined node on the Australian gas grid. Specific nodes are selected to represent each of the 16 NEM zones and other regions within the EWP modelling.

The availability of gas to support generation in each region is determined by a number of factors, namely:

- The reserves and production capability of various fields (locally and in an aggregate sense throughout Eastern Australia)
- Existing transmission capacity into the zone (if the zone does not have indigenous gas resources)
- The potential for new or additional transmission capacity.

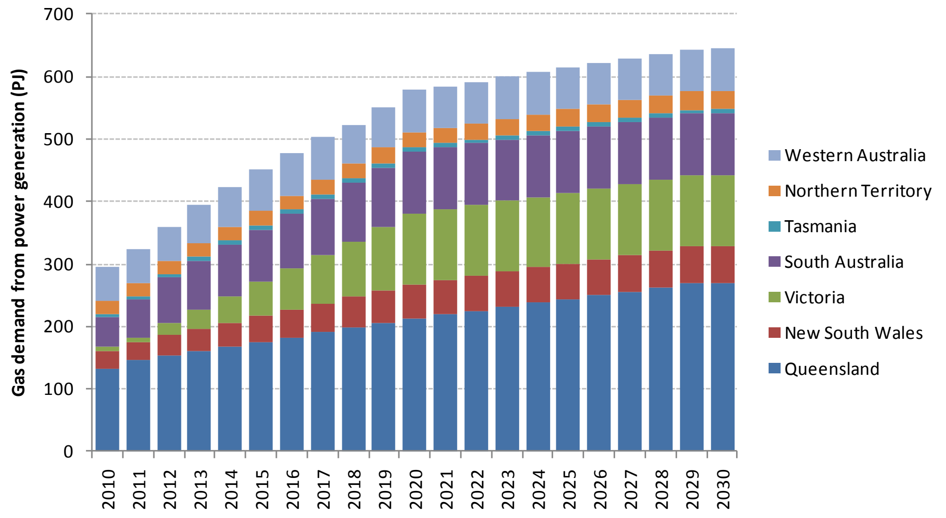
Gas demand from power generation

Owing to the sequential nature of the EWP process, gas prices are required as input to the modelling process, and hence need to be developed prior to the modelling being undertaken. ACIL Tasman therefore, has been required to make its own starting assumptions in relation to gas demand from power generation.

These assumptions have been sourced from ACIL Tasman's own internal electricity market modelling for the NEM and SWIS markets and assumptions regarding growth in gas used for power generation in remote systems.

In aggregate gas demand from power generation is assumed to increase from just under 300 PJ in aggregate in 2010, to around 650 PJ by 2030. Growth in gas demand slows in the last 10 years (relative to the first 10 years) as a result of carbon capture and storage technology being deployed within the electricity market scenario used to derive these figures.

Figure 4 **Gas demand from power generation assumed**



Note: Aggregate gas demand for power generation. Includes grid connected plants only (i.e. excludes remote mining loads).

Data source: ACIL Tasman analysis

7.1.4 Treatment of EWP scenarios

Table 23 details the key parameters that were used in the development of the EWP scenarios.

Table 23 **Key parameters used in projecting gas prices under the EWP scenarios**

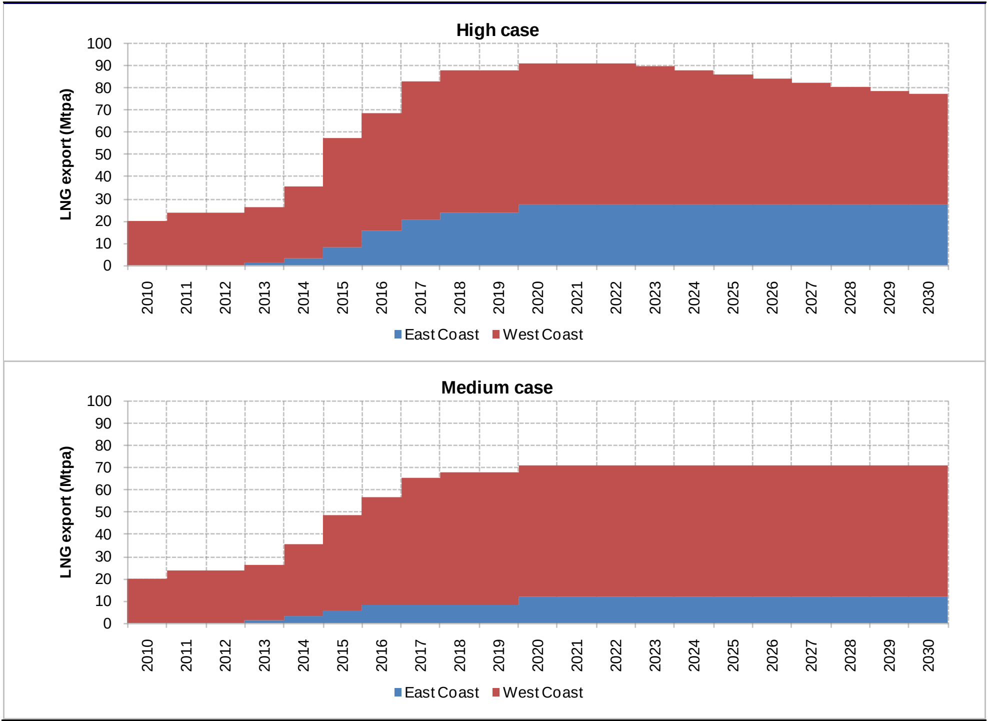
Scenario	Scenario 1 "Fast rate of change"	Scenario 2 "An uncertain world"	Scenario 3 "A decentralised world"	Scenario 4 "Oil shock and adaptation"	Scenario 5 "Slow rate of change"
Exchange rate (US$/A$)	0.85	0.85	0.85	0.75	0.6
International oil price	IEA Reference case: US$115/bbl by 2030	IEA Reference case: US$115/bbl by 2030	IEA Reference case: US$115/bbl by 2030	IEA High case: US$150/bbl by 2030	IEA Reference case: US$115/bbl by 2030
International LNG price	IEA Reference case: US$15.87/mmbtu by 2030	IEA Reference case: US$15.87/mmbtu by 2030	IEA Reference case: US$15.87/mmbtu by 2030	IEA High case: US$20.70/mmbtu by 2030	IEA Low case: US$11.05/mmbtu by 2030
Domestic LNG production	Aggregate LNG exports peaking at 91Mtpa by 2020	Aggregate LNG exports peaking at 46.6Mtpa by 2020	Aggregate LNG exports peaking at 71.2Mtpa by 2020	Aggregate LNG exports peaking at 91Mtpa by 2020	Aggregate LNG exports peaking at 46.6Mtpa by 2020
Competition in domestic markets	Normal level of competition between gas and coal producers to supply domestic users	Coal and gas producers aggressively compete against one another for supply to domestic loads	Coal and gas producers aggressively compete against one another for supply to domestic loads	Limited competition as a result of consolidation amongst coal/gas producers	Normal level of competition between gas and coal producers to supply domestic users
Commodity costs	High	High	Medium	Medium	Low

Data source: ACIL Tasman

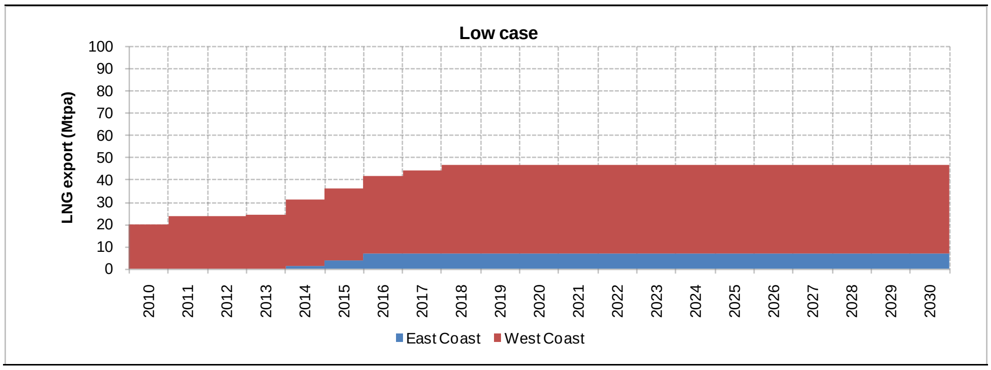
International oil and LNG prices have been derived from the International Energy Agency's 2009 World Energy Outlook report. The prices are sourced from the Reference, High and Low price sensitivities.[2] The LNG price has been treated as the landed price into Japan and once shipping and liquefaction costs are deducted, is assumed to represent the prices received by Australian LNG producers.

The scenarios encompass three different levels of aggregate LNG export for Australia – low (46.6 Mtpa), medium (71.2 Mtpa) and high (91 Mtpa). The overall level of LNG export and the split between East and West coast LNG projects are shown in Figure 5. The Low case sees only the current committed Western Australian projects proceeding, and 7 Mtpa (2x 3Mtpa trains) is assumed to occur in Queensland. By comparison, the High case reflects a situation where virtually all proposed LNG projects proceed by 2020. The sheer number of projects proceeding results in the overall level of LNG export declining from around 2020 onwards as a result of declining gas availability to backfill existing LNG plants in Western Australia.

Figure 5 **Australian LNG export scenarios**



[2] IEA, *World Energy Outlook 2009*, p600-661



Data source: ACIL Tasman

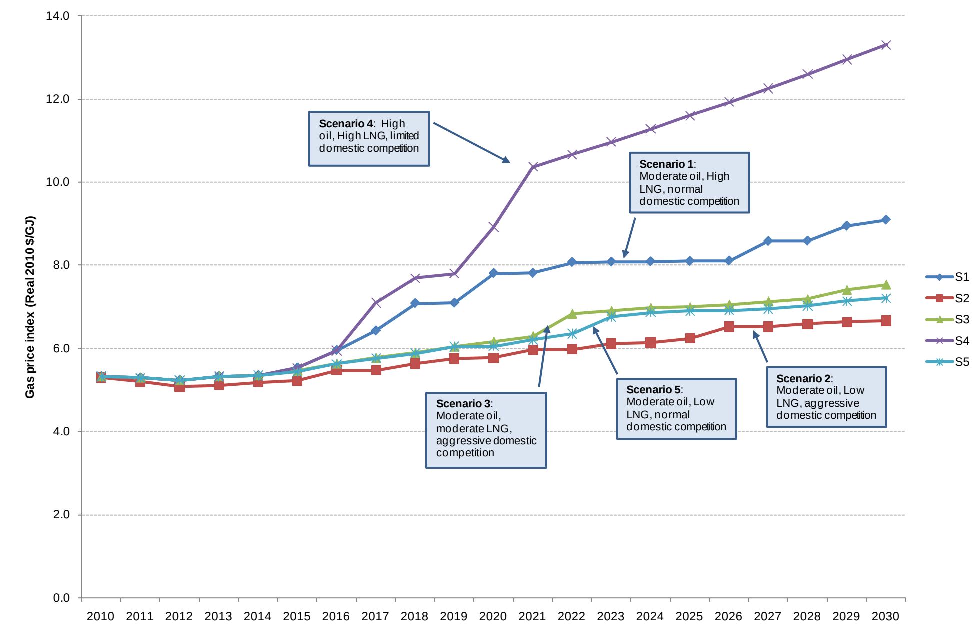
The level of competition amongst producers for supply to the domestic market has been adjusted through the inclusion of DOMGAS components to LNG projects and/or adjusting producer price expectations for domestic gas sales.

Commodity costs have been factored into production costs for fields. High commodity price environments are likely to increase demand for drill rigs and skilled labour, thereby increasing field development and ongoing operation and maintenance costs.

7.1.5 Gas price projections

Figure 6 and Figure 7 shows the resulting gas prices from the modelling of the EWP scenarios for the East Coast and West Coast respectively.

Figure 6 **East Coast gas price index under the EWP scenarios**



Note: Index comprised of a weighted average of projected Brisbane, Sydney, Melbourne, Adelaide city-gate prices
Data source: ACIL Tasman GMG Australia

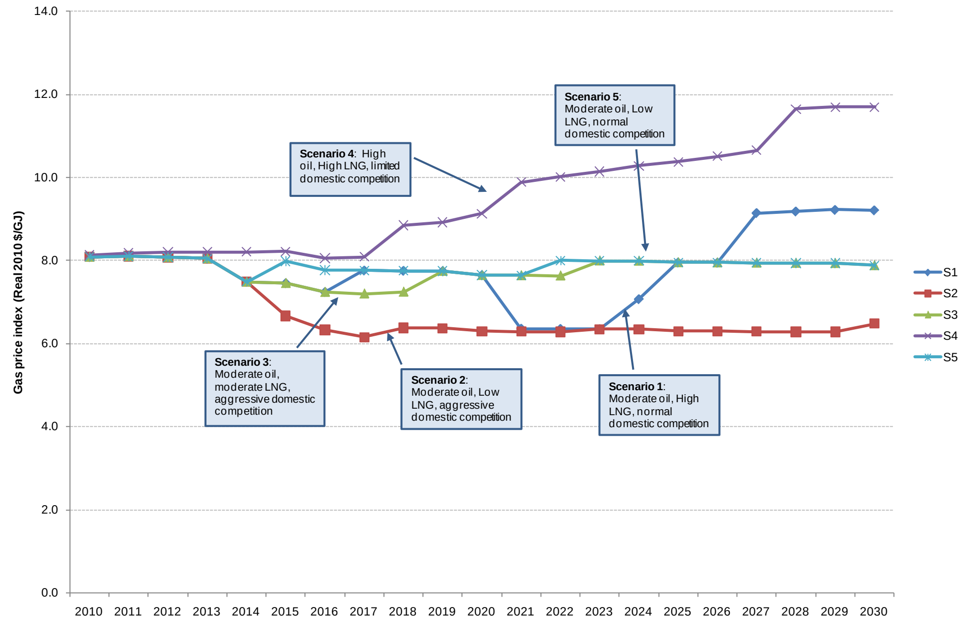
Price outcomes for Eastern Australian are most sensitive to the level of LNG export – particularly at "high" levels. Scenario 4 sees the highest prices with the index reaching a 'LNG parity' level from 2021 onwards. In contrast, Scenario 2 which includes a low level of LNG export coupled with aggressive domestic competition results in the lowest prices, with the price index only increasing slightly in real terms over the period.

The level of domestic competition only has a large bearing on outcomes under the 'high' LNG cases. This is a feature of the East coast gas market, which is characterised by a relatively diverse supply mix – particularly with the development of CSG resources in Queensland and potentially in NSW.

The Western Australian gas market is fundamentally quite different to that of Eastern Australia, with the supply composition highly concentrated from a small number of large offshore projects. New sources of supply for the domestic market are likely to be sourced from DOMGAS legs of large LNG projects. Unlike the East Coast where the level of LNG development is inversely related to the amount of gas available for domestic consumption, in the West it likely to be the development of an LNG project which results in a new DOMGAS stream becoming available.

Figure 7 shows the West Coast gas price index under the various EWP scenarios. The results show that it is the level of domestic competition, rather than the level of LNG development which is the main driver of price outcomes. While the primary driver may differ, the outcomes are broadly similar to the East Coast, with Scenario 4 resulting in the highest price outcomes, while Scenario 2 results in the lowest prices.

Figure 7 **West Coast gas price index under the EWP scenarios**



Note: Index represents projected Perth city-gate prices

Data source: ACIL Tasman GMG Australia

Table 24 and Table 25 tabulate the price index results for the East Coast and West Coast respectively.

Table 24 **East Coast gas price index (Real 2010 $/GJ)**

	Scenario 1 "Fast rate of change"	Scenario 2 "An uncertain world"	Scenario 3 "A decentralised world"	Scenario 4 "Oil shock and adaptation"	Scenario 5 "Slow rate of change"
2010	5.3	5.3	5.3	5.3	5.3
2011	5.3	5.2	5.3	5.3	5.3
2012	5.2	5.1	5.2	5.2	5.2
2013	5.3	5.1	5.3	5.3	5.3
2014	5.3	5.2	5.3	5.3	5.3
2015	5.5	5.2	5.5	5.5	5.4
2016	5.9	5.5	5.6	5.9	5.6
2017	6.4	5.5	5.8	7.1	5.8
2018	7.1	5.6	5.9	7.7	5.9
2019	7.1	5.8	6.0	7.8	6.0
2020	7.8	5.8	6.2	8.9	6.0
2021	7.8	6.0	6.3	10.4	6.2
2022	8.1	6.0	6.8	10.7	6.4
2023	8.1	6.1	6.9	11.0	6.8
2024	8.1	6.1	7.0	11.3	6.9
2025	8.1	6.2	7.0	11.6	6.9
2026	8.1	6.5	7.1	11.9	6.9
2027	8.6	6.5	7.1	12.3	7.0
2028	8.6	6.6	7.2	12.6	7.0
2029	8.9	6.6	7.4	12.9	7.1
2030	9.1	6.7	7.5	13.3	7.2

Note: Index comprised of a weighted average of projected Brisbane, Sydney, Melbourne, Adelaide city-gate prices

Data source: ACIL Tasman GMG Australia

Table 25 **West Coast gas price index (Real 2010 $/GJ)**

	Scenario 1 "Fast rate of change"	Scenario 2 "An uncertain world"	Scenario 3 "A decentralised world"	Scenario 4 "Oil shock and adaptation"	Scenario 5 "Slow rate of change"
2010	8.1	8.1	8.1	8.1	8.1
2011	8.1	8.1	8.1	8.2	8.1
2012	8.1	8.1	8.1	8.2	8.1
2013	8.0	8.0	8.0	8.2	8.0
2014	7.5	7.5	7.5	8.2	7.5
2015	7.5	6.7	7.5	8.2	8.0
2016	7.2	6.3	7.2	8.1	7.8
2017	7.8	6.2	7.2	8.1	7.8
2018	7.8	6.4	7.2	8.8	7.8
2019	7.7	6.4	7.7	8.9	7.7
2020	7.6	6.3	7.6	9.1	7.6
2021	6.4	6.3	7.6	9.9	7.6
2022	6.4	6.3	7.6	10.0	8.0
2023	6.3	6.3	8.0	10.1	8.0
2024	7.1	6.3	8.0	10.3	8.0
2025	8.0	6.3	8.0	10.4	8.0
2026	7.9	6.3	7.9	10.5	7.9
2027	9.1	6.3	7.9	10.7	7.9
2028	9.2	6.3	7.9	11.6	7.9
2029	9.2	6.3	7.9	11.7	7.9
2030	9.2	6.5	7.9	11.7	7.9

Note: Index represents projected Perth city-gate prices

Data source: ACIL Tasman GMG Australia

7.1.6 Gas price sensitivities

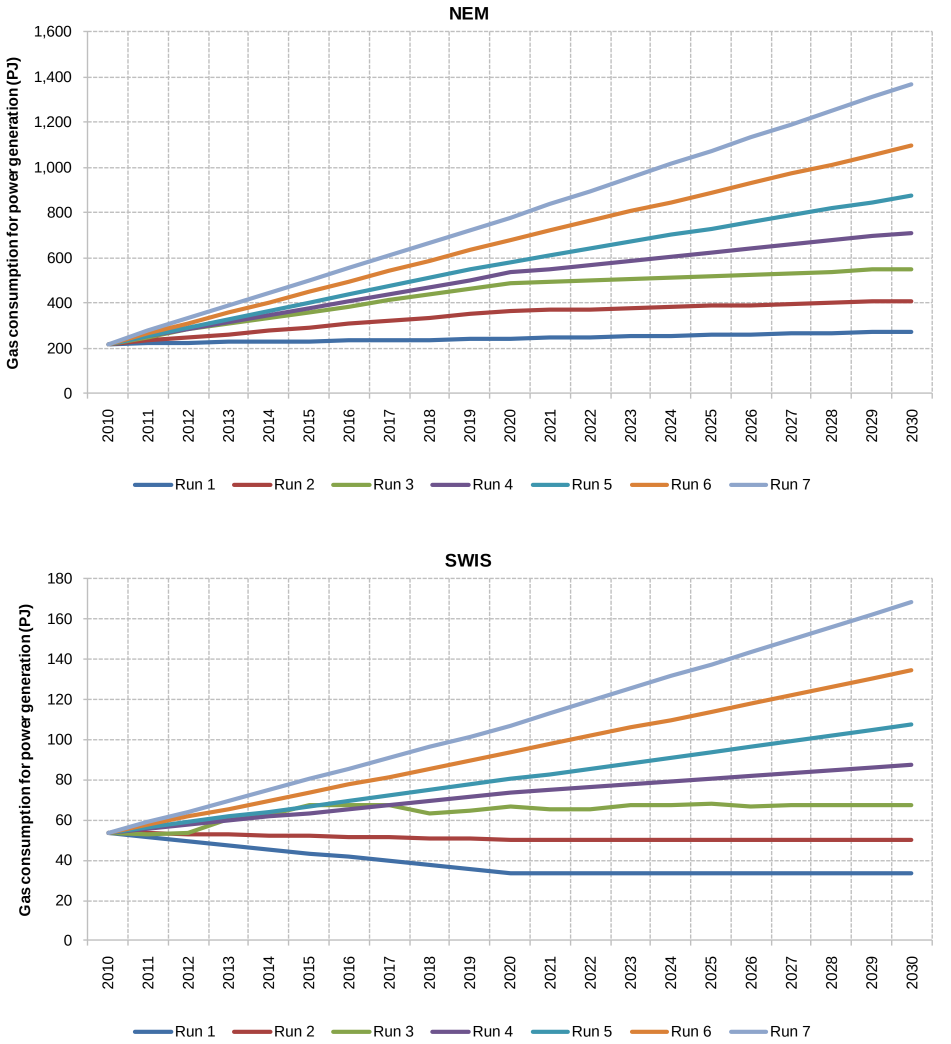
From initial model runs undertaken by Roam and IES, it was clear that outcomes from the electricity models, in terms of gas consumption, could potentially be quite inconsistent with the initial assumptions used in the gas modelling.

For this reason it was decided that a series of gas price curves be developed for each EWP scenario. These curves provide gas price points at various levels of gas consumption. The electricity modellers then incorporate these curves to achieve a greater level of consistency between gas consumption outcomes and gas price inputs.

To develop these curves the following process was used:

- Notional hubs were selected for both NEM and SWIS gas networks. The selected hubs were Moomba and Perth respectively.
- A number of alternate gas demand traces were constructed around the original demand profile (shown in Figure 4). Six new demand series were constructed: two of these with lower gas demand and four series with higher gas demands. These alternate traces are shown in Figure 8. For both the NEM and SWIS Run 3

Figure 8 **Alternate demand traces examined for NEM and SWIS**



Note: Non-power generation demand held constant. Run 3 represents the initial demand trace.

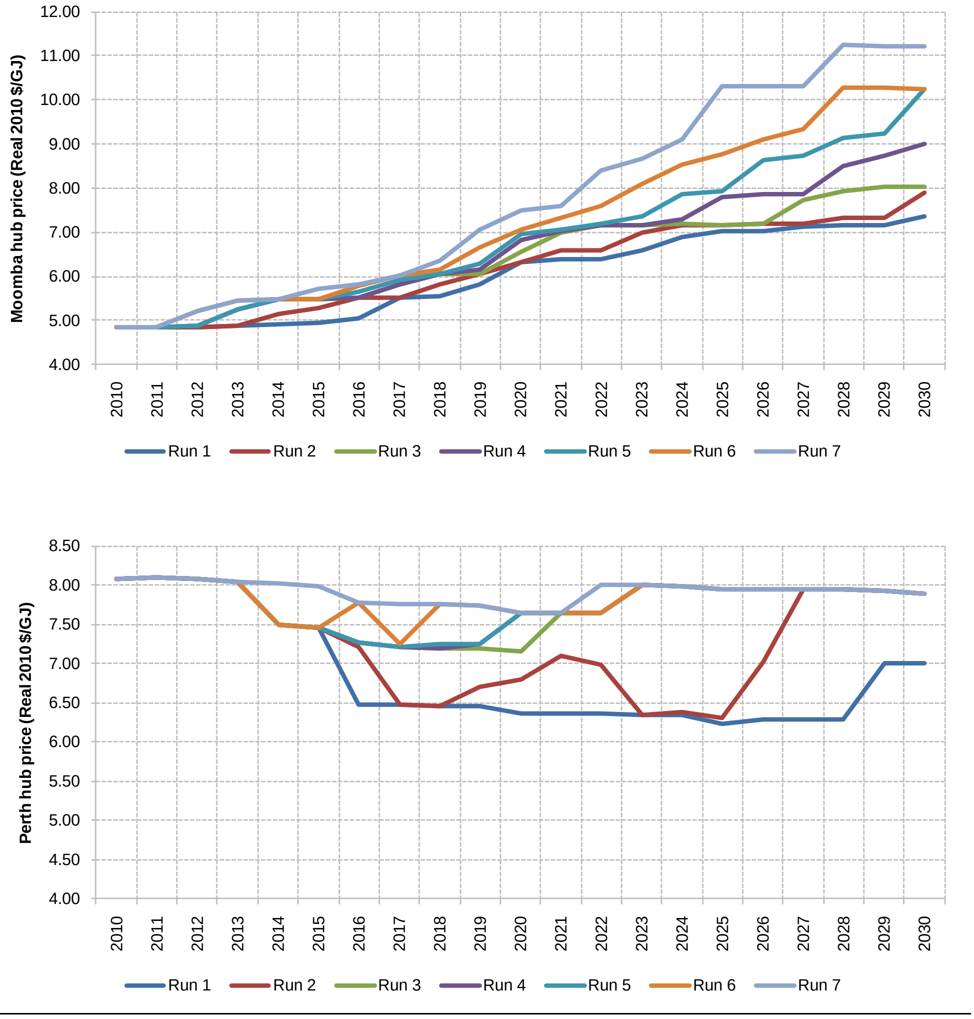
Data source: ACIL Tasman

- For the NEM, the changes in demand were pro-rated between the States in accordance with the original demand series (shown in Figure 4). For the SWIS, all changes were assumed to occur at Perth.
- These alternate demand traces were then run through GasMark to obtain new gas price series for each notional hub (i.e. modelling each alternate demand trace provides only two price series – Moomba and Perth).
- Prices for EWP zones are determined from the application of the cost differentials between the zones and the hub from the original scenario.

This process was repeated for each of the scenarios. Figure 9 provides the hub price outcomes for the NEM and SWIS under each of the alternate demand traces for Scenario 3. Price trajectories for Moomba tend to vary considerably with power generation demand with price outcomes in 2030 of around $8/GJ under Run 3 (~550 PJ/a of power generation demand), up to above $11/GJ under Run 7 (~1,400 PJ/a of power generation demand).

SWIS gas prices tend to move considerably less, and are characterised by step changes at certain demand points. This is a result of the lumpy nature of offshore conventional gas projects relative to small CSG projects in Eastern Australia.

Figure 9 **Moomba (top) and Perth (bottom) hub price outcomes for Scenario 3**



Note: Non-power generation demand held constant. Run 3 represents the initial demand trace.

Data source: ACIL Tasman GasMark modelling

The impact of the alternate demand series varied considerably between the scenarios. Scenarios where the demand-supply balance was relatively tight to begin with resulted in prices that were much more sensitive to changes in power generation demand levels than in scenarios where there was ample supply capacity.

Hub price outcomes and transportation differentials for each scenario are included in the spreadsheet datasets which accompany this report.

7.2 Coal

7.2.1 Background to coal prices

ACIL Tasman regularly undertakes assessment of the likely future cost of coal into domestic power stations.

The projected coal prices for existing and new coal fired power stations is provided in Appendix A.

In arriving at these coal price projections for each power station (each generation portfolio in NSW) ACIL Taman considered:

- existing contractual and other supply arrangements
- mine / power station ownership arrangements
- source and cost of new/replacement coal supply sources in the future taking into account:
  - nature and ownership of nearby coal reserves and mines
  - potential for development of new resources
  - future export prices
  - mining costs
  - transport costs

Table 26 summarises the types of coal supply arrangements currently in place and the methodology used by ACIL Tasman in projecting coal prices for the various types of arrangements in place.

Table 26 **Method for projection coal prices in the NEM**

Coal supply arrangement	Stations affected	Price setting mechanism
Existing NSW black coal - third party contracts	All existing stations in NSW	Existing contracts assumed to run full term at contracted prices with new contract prices at either a predetermined percentage of export parity prices or based on efficient mining costs – whichever is highest.
New NSW black coal - captive mine	Any new stations in NSW	Coal prices at either a predetermined percentage of export parity prices or based on efficient mining costs – whichever is highest.
Existing Qld Black coal - own mine	Tarong, Millmerran, Kogan Creek	Coal price is the marginal cost of production using an efficient mining contractor.
Existing Qld Black coal - captive mine	Callide, Stanwell, Collinsville	Coal prices at either a predetermined percentage of export parity prices or based on efficient mining costs – whichever is highest.
Existing Qld Black coal - third party contracts	Gladstone	Existing contracts assumed to run full term at contracted prices with new contract prices at either a predetermined percentage of export parity prices or based on efficient mining costs – whichever is highest.
New Qld black coal - captive mine	Any new stations in Qld	Prices set at around 80% of the export parity price to reflect the expected cost of contract mining.
Vic brown coal - own mine	Loy Yang A, Hazelwood, Yallourn	Price set at marginal cost of production currently less than $0.10/GJ
Vic brown coal - third party mine	Energy Brix, Anglesea, Loy Yang B	Prices set to reflect efficient mining costs currently less than $0.60/GJ
New IGCC using coal from third party	Any new IGCC	Prices set to reflect efficient mining costs currently less than $0.60/GJ
SA black coal - own mine	Northern, Thomas Playford	Marginal price including cost mining, handling and railing coal 250km

Data source: ACIL Tasman analysis of various sources

New South Wales

In NSW all coal is supplied to the power stations by third party coal mines under a variety of contractual arrangements with varying terms, prices and transport arrangements. These contracts vary from relatively short term (1 to 2 years) to very long term (20 years or more). Generally these contracts were written before the surge in export prices from early 2004 and carry contract prices which are generally well below the export parity value being experienced in today's buoyant market.

New tonnage however will need to be sourced in a setting of very high export coal prices and reduced quality requirements by overseas buyers. There are a number of strategies which local power stations will employ to keep prices of new tonnage lower than export parity and these include:

- gaining access to undeveloped resources and employing a contract miner to produce the coal. (there are many unallocated resources available in NSW for this purpose)
- offering firm contracts to potential new developments in order to achieve discounted prices by lowering the market and infrastructure risks associated new developments
- entering into long term contractual with mines aimed at achieving cost related pricing
- offering to take non-exportable high ash coal, oxidised coal and washery rejects and middlings.

We expect these purchase strategies to result in domestic coal prices being a percentage lower than the export parity price of coal at each location. The size of the percentage reduction depends on a number of factors including the level of competition between alternative energy suppliers particularly gas.

The cost of mining does not generally affect the likely level of discounting, but on an individual mine basis the discounted export parity price may be lower than mining costs. However, if the discounted export parity price is less than efficient mining costs then we have taken the mining costs as the price.

Queensland

In Queensland there are four types of coal supply arrangement:

1. mine mouth - own mine: Tarong, Kogan Creek, Millmerran
2. mine mouth - captive third party mine: Callide B, Callide Power, Collinsville
3. transported from captive third party mine: Stanwell
4. transported from third party mine: Gladstone, Swanbank B

Power stations in Queensland relying on their own mine mouth coal supply (Type 1 above) are unlikely to be affected by export prices and we have assumed that they will offer marginal fuel costs into the market which are currently less than A$1.00/GJ. We expect that these black coal stations with very low marginal fuel costs should be able to maintain dispatch when a carbon price is applied. However they will be affected by mining cost increases which have increased rapidly in recent years in response to strong demand and high oil and tyre prices.

Power stations with a mine mouth operation with a third party supplier (Type 2 above) are likely to be under pressure to accept higher prices more in line with export parity particularly with price reviews and contract renewal.

In 2004 Stanwell entered a 16 year arrangement with the Curragh mine which is not linked to export prices. We expect that Stanwell will be actively seeking advantageous alternative arrangements when these current arrangements expire. The existing arrangements were achieved by providing the miner access to additional coal resources and this approach may be able to be applied again. However, if Stanwell Corporation was exposed to full export parity pricing then the dispatch of both Stanwell and Gladstone power stations would be noticeably affected particularly under a when a carbon price is applied.

Gladstone and Swanbank which rely on transported coal from third party mines are at greatest risk of pass through of export prices. However Gladstone has a long term arrangement with Rolleston to take lower quality coal. Swanbank is likely to continue on similar arrangements beyond the current three year contract as the export infrastructure in the Brisbane region is at capacity, with rail capacity being the main bottleneck and is unlikely to be resolved.

Victoria

All power stations in Victoria are mine mouth stations where the mine is either owned by the power station or by a third party supplier.

In the cases where the coal mine is owned by the power station the coal cost in the model is assumed at the marginal cost of production, which includes power consumption, state royalties and any run time maintenance. This is usually less than $0.10/GJ, currently placing these brown coal stations at the bottom of the cost curve.

For stations which are supplied by third party coal producers the price currently averages around $4.50/t or around $0.50/GJ.

These prices are cost based and not affected by export price changes. They are escalated at around 80% of CPI.

South Australia

The Northern and Thomas Playford power stations are supplied by the Leigh Creek coal mine requiring a 250km haul. The mine and railway are owned by the power station but haulage is performed by a third party haulier. The coal price in the modelling therefore is the marginal mining cost plus haulage.

Western Australia

All of the existing coal fired stations in WA are based on the Collie coal resource. The power stations supplied out of this resource are

Verve power stations Collie and Muja B and C supplied under a long term contract by Wesfarmers from Premier mine

Griffin Energy power station Bluewaters supplied from Griffin's Ewington mine under transfer pricing arrangement.

The two possible new coal fired power station sites are Collie and Enneaba north of Perth

7.2.2 Coal prices under five scenarios

Five key drivers of domestic coal prices which have been used to differentiate between the five scenarios and these are:

- exchange rates
- discount on export parity price
- mining cost increase
- real growth in export thermal coal prices
- increase in prices in existing coal contracts

Quantitative assumptions for each of these have been made based on the more generalised description of the five scenarios developed for the study. These are summarised in Table 27.

Table 27 **Key assumptions underlying the domestic coal price forecast in each of the five scenarios**

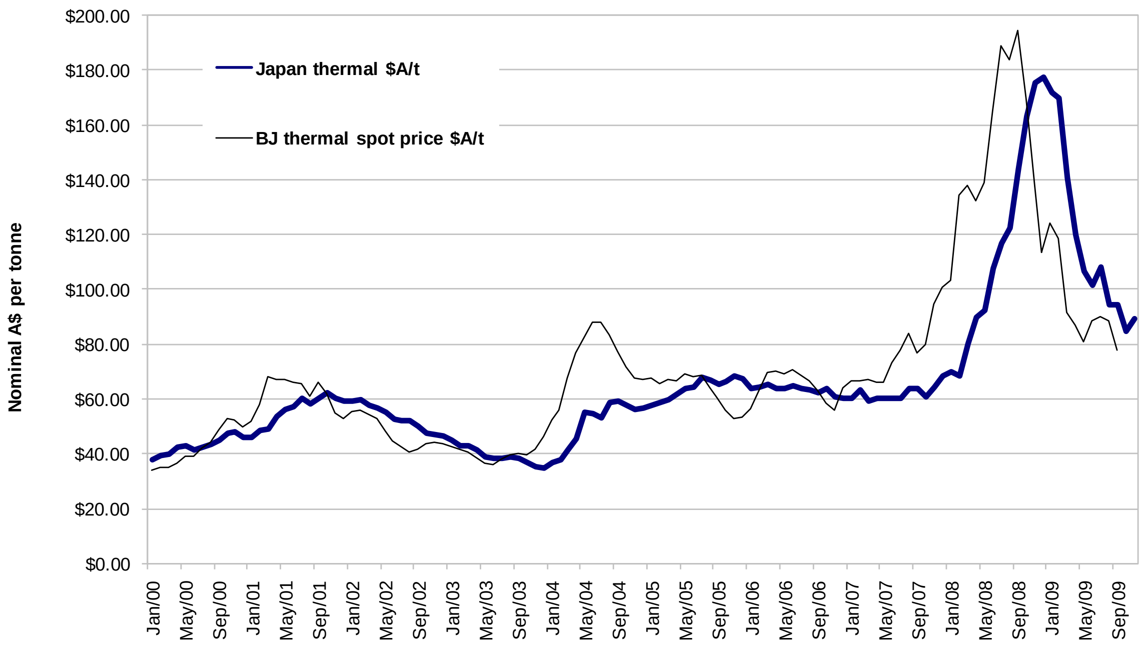
Parameter	Scenario 1 "Fast rate of change"	Scenario 2 "An uncertain world"	Scenario 3 "A decentralised world"	Scenario 4 "Oil shock and adaptation"	Scenario 5 "Slow rate of change"
Exchange rate (US$/A$)	0.85	0.85	0.85	0.75	0.60
Discount on net backed export parity	20%	25%	30%	10%	15%
Mining cost increases (% of CPI)	100%	100%	90%	90%	80%
Real growth in export thermal coal prices (US$)	-1.00%	0.00%	-0.01%	1.00%	-0.50%
Increase in existing contracts (% of CPI)	100%	90%	90%	100%	100%

Projected export thermal coal FOB prices

The FOB price for thermal coal is an important consideration in the price formation for new coal fired generation in Qld and NSW. It is the projection of these prices which underlies the future export parity value of the ROM coal at each location which in some cases sets the delivered price into local power stations using that coal.

Thermal coal spot and contract prices have subsided markedly in the past twelve months as shown in Figure 10.

Figure 10 **Spot and contract FOB prices for thermal coal exports (nominal A$/t)**



Data source: Australian Coal Report

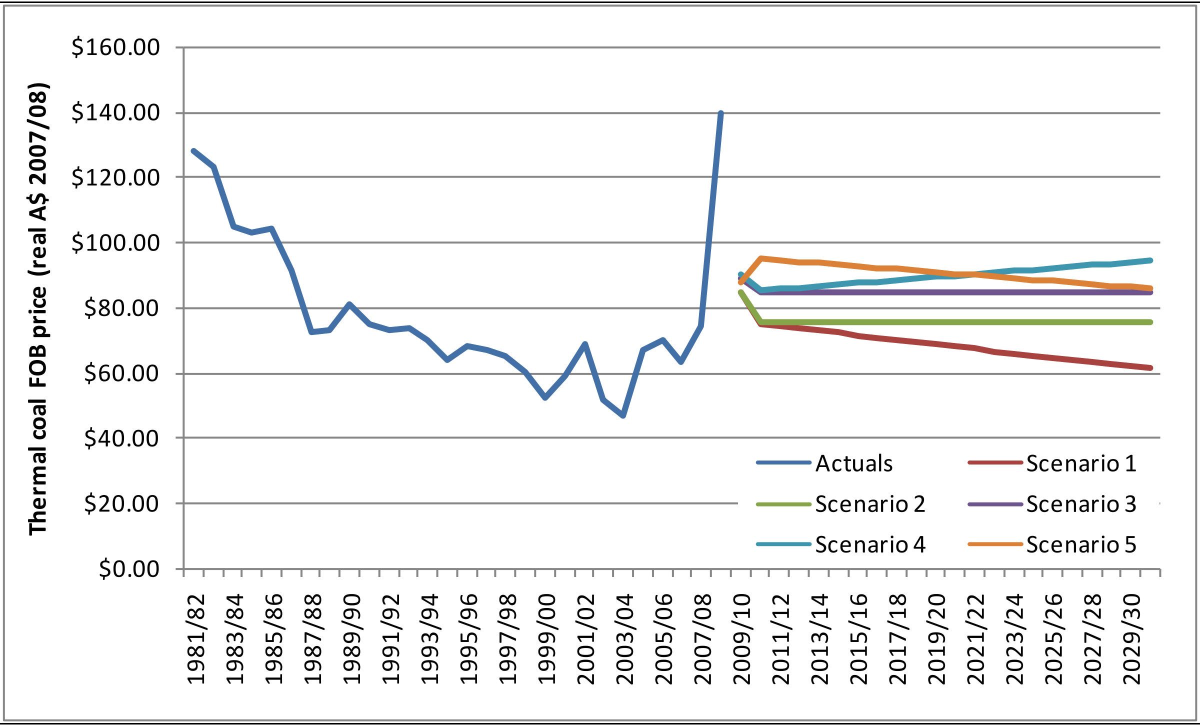
Projecting thermal coal export prices, particularly in the current volatile world economic environment is necessarily subject to a great deal of uncertainty. The future price trend is dependent on many factors including *inter alia*:

- Demand and supply balance in the coal market;
- World economic growth;
- Cost of coal of production;
- Price and availability of substitutes such as oil and gas;
- Technology changes in coal usage;
- Environmental policies potentially affecting coal usage; and
- Increasing low cost production, including that from Australia, China and Indonesia.

ACIL Tasman expects that the past trends of static or gradually declining real prices in A$ are likely to continue in most of the five scenarios except for Scenario 4 which is characterised by much higher oil (energy) prices.

The ACIL Tasman expectation of annual coal prices in real terms is illustrated in Figure 11. The two main drivers are exchange rate and assumed real annual change in the FOB price (see Table 27).

Figure 11 **Forecast of average annual export thermal coal prices (A$/tonne FOB in nominal and real 2007/08 prices)**



Data source: AT analysis based on in-house information

Projected coal prices into existing power stations

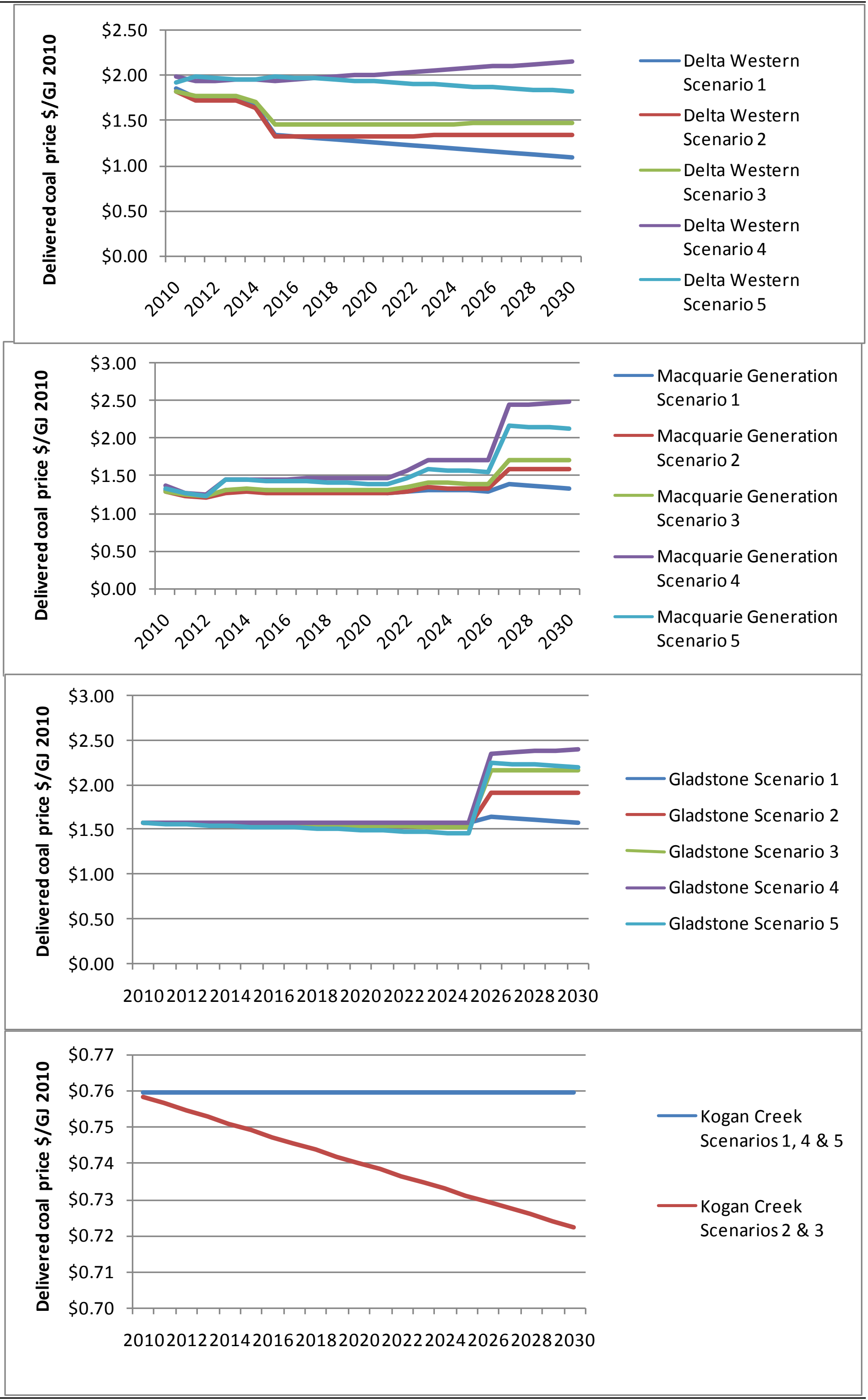
The projected price of coal into existing power stations is a function of the extent and price of existing contracts and the price for replacement contracts. Some stations have guaranteed coal supply for the life of the station. These stations include all brown coal fired stations in Victoria, all black coal stations in SA[3] and WA and selected stations in Queensland such as Millmerran and Kogan Creek. Other black coal stations in Queensland and all stations in NSW are not fully contracted for the station life and will be faced with negotiating replacement coal supply arrangements as existing contracts expire.

For these stations we have assumed that the replacement contracts will be at a price which is the greater of a discounted export parity price or the efficient production costs. The estimated delivered coal prices to selected existing stations are shown in Figure 12. The main variation between the scenarios is

[3] The Leigh Creek coal is not lignite but is classified under the ASTM system as Sub-bituminous A rank coal which would normally be considered a black coal

due to the variation in export prices between the Scenarios. For Kogan Creek however the difference between the scenarios is related to differences in the escalation of the coal supply contract price in the five scenarios.

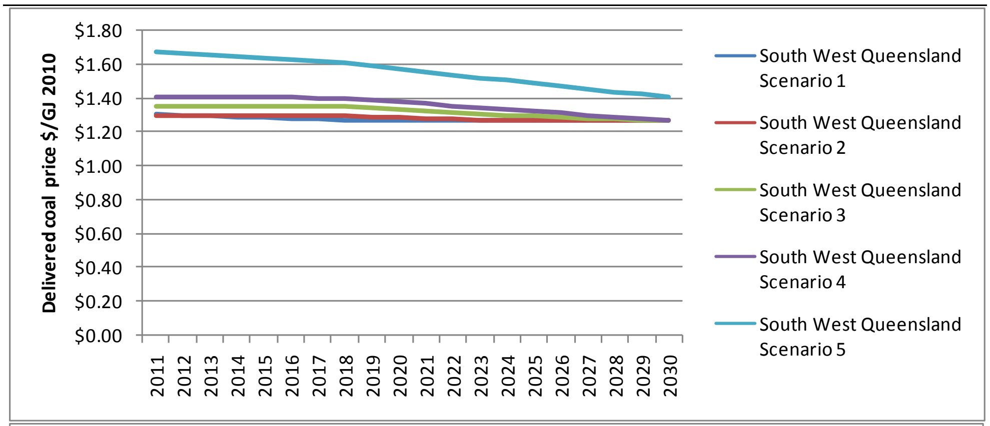
Figure 12 **Projected delivered coal prices into selected existing stations under the five scenarios**

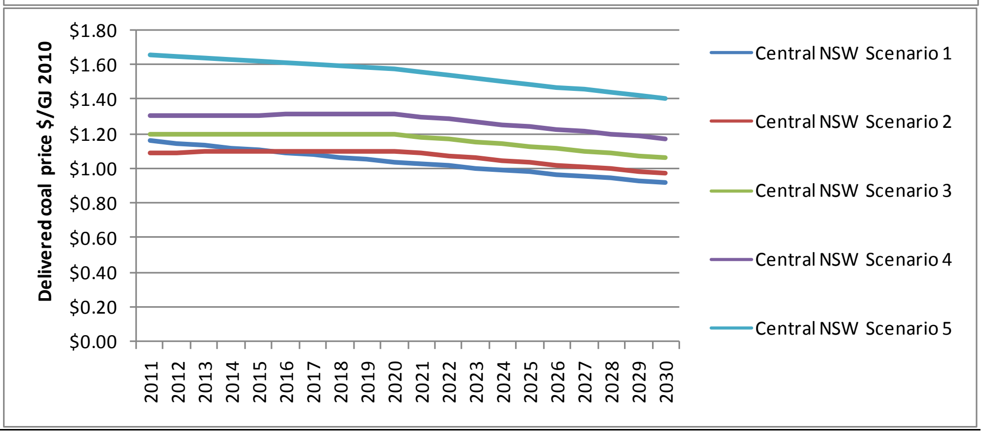


Projected coal prices into new coal fired power stations

The price of coal delivered to new power stations assumes that all new stations would be mine-mouth. Again as with replacement contracts for existing stations we have assumed that the delivered coal prices will be the greater of a discounted export parity price or the efficient production costs. The estimated delivered coal prices to new stations in selected areas in each of the five scenarios are shown in Figure 13. The higher delivered coal prices in Scenario 5 are associated with higher export parity prices at the various locations.

Figure 13 **Projected delivered coal prices into selected existing stations under the five scenarios**





8 Extrapolation of the input assumptions to 2050

8.1 Introduction

ACIL Tasman was requested by AEMO/DRET to extend the supply inputs from 2030 out to 2050. Although the focus of the modelling remained on the projected outcomes by 2030, concern was raised in the stakeholder reference group of the impact of end-effects on the modelled outcomes. In particular, the concern was that modelling to 2030 without consideration of changes in input assumptions between 2030 and 2050 (given investment decisions in power generation is a long term consideration) may unduly influence the projected outcomes at 2030.

For example, the learning curve of an emerging technology beyond 2030 may result in that technology being part of the least cost solution in 2030, whereas ignoring the input assumptions beyond 2030 result in that technology not being part of the plant mix. Also, changes in fuel costs beyond 2030 may impact investment decisions in 2030.

8.2 Process

A number of considerations and constraints were taken into account when deciding the approach to use in extending the supply inputs to 2050:

- There were to be no fundamental changes to the scenario definitions beyond 2030. Although the scenario narratives describe the state of the world in 2030 it is assumed that the narratives remain similar to 2050. For example, the extrapolation of the narratives to 2050 does not assume change in policies beyond those already described by 2030.
- The candidate set of generation technology remains the same beyond 2030 to that in 2030. There is no new technology not previously considered in the analysis introduced into the data set.
- ACIL Tasman was requested to use appropriate extrapolation techniques to extend the input assumptions to 2050 rather than undertake a detailed modelling and analysis of each individual input assumption. We agreed that this approach was sensible given the extent of unknowns beyond 2030 and the likely error in the estimates of the inputs – regardless of approach.
- The key inputs requiring extrapolation are capital cost and thermal efficiency of new investments (by technology) and fuel prices (by fuel type and location). Other cost inputs, such as variable and fixed O&M costs are escalated at some proportion of CPI.

- Renewable energy resource constraints remain unchanged between 2030 and 2050 – it is assumed that no new resources (of the candidate technology set) are discovered.

8.3 Capital costs

The approach used to extrapolate the capital costs of each technology in each scenario was to take the annualised reduction in real costs between 2026 and 2030 and apply a percentage of this reduction for each year between 2031 and 2050. The percentage of the reduction applied starts at 100% in 2031 and declines linearly to 5% by 2050.

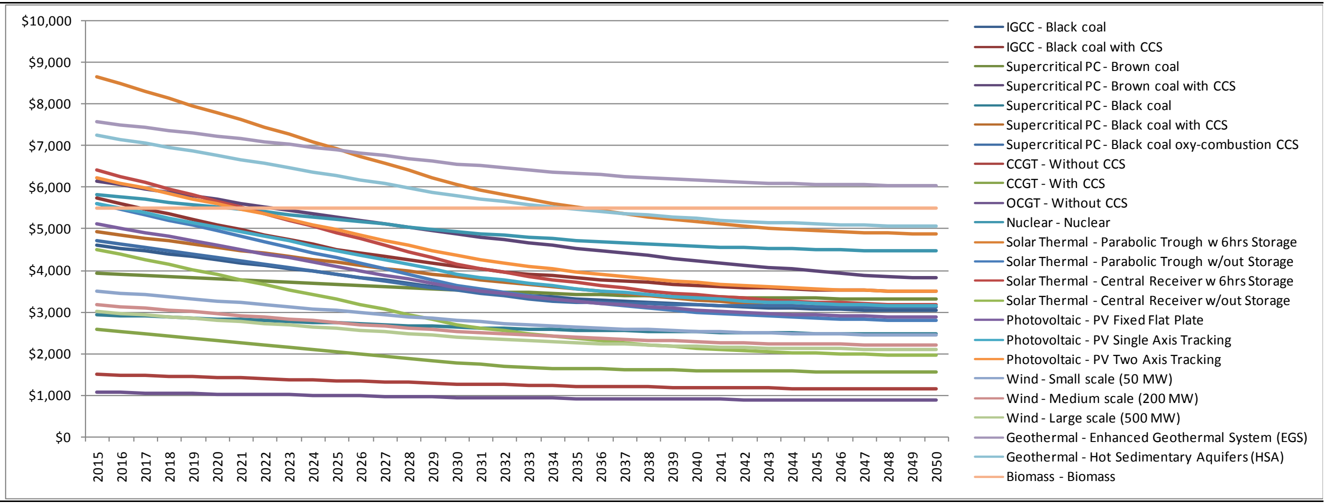
For example, if the annualised reduction between 2026 and 2030 is 4% (that is, the capital costs is declining 4% annually in real terms) then in 2031 the reduction is 4% (that is, 100% of 4%) and in 2050 the growth is 0.2% (that is, 5% of 4%).

This approach allows the information contained in the change in capital costs between 2026 and 2030 to be used out to 2050:

- If the decline in capital costs between 2026 and 2030 is relatively high (indicating the technology is in its learning phase) then the extrapolation will continue with the relatively higher decline.
- If the decline in capital costs between 2026 and 2030 is low or close to zero (indicating the technology is mature) then the extrapolation will continue with the relatively low or zero decline.
- If the scenario requires a delay in the learning curve then this delay is also continued in the extrapolation, and vice versa.
- Using a diminishing percentage of the annualised decline (from 100% in 2031 to 5% by 2050) is an attempt to reflect the point that by 2050 each of the candidate technologies will be mature, a hence real reductions in capital costs are likely to be quite small by that point in time.

The graph below shows the result of applying this approach to the capital costs for Scenario 1.

Figure 14 **Extrapolated capital costs (AUD$/kW, 2009/10$) – Scenario 1**



Data source: EPRI new entrant cost data with amendments agreed by Stakeholder Reference Group (as at 23 December 2009 and 30 April 2010) for 2015 to 2030 and ACIL Tasman extrapolation for 2031 to 2050.

8.4 Thermal efficiency

The approach used to extrapolate the thermal efficiency of each technology in each scenario is identical that the one used to extrapolate the capital costs – that is, we took the annualised improvement in thermal efficiency between 2026 and 2030 and applied a percentage of this improvement for each year between 2031 and 2050.

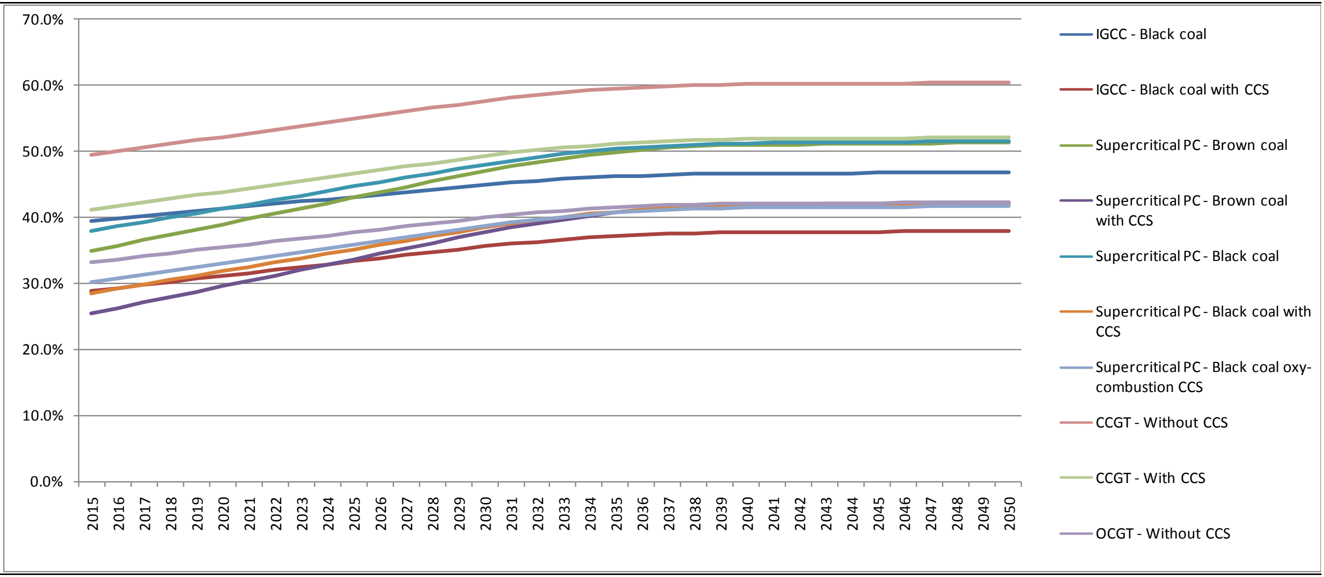
Similar to the approach applied to the capital costs, the percentage of the improvement applied starts at 100% in 2031 and declines to 5% by 2050. However, the percentage does not decline linearly from 100% in 2031 to 5% by 2050; instead we assume a more rapid decline in the percentage so that reaches 5% by 2041 and remains at 5% to 2050. This means that there is very little change in thermal efficiency beyond 2040.

Similar to the approach applied to the capital costs, this approach allows the information contained in the change in thermal efficiency between 20126 and 2030 to be used out to 2050.

Using a diminishing percentage of the annualised improvement (from 100% in 2031 to 5% by 2041 and flat at 5% thereafter) provides some control over the change in thermal efficiency so that for example it does not reach unrealistic levels for 2050.

The graph below shows the result of applying this approach to the thermal efficiency for Scenario 1.

Figure 15 **Extrapolated thermal efficiency (sent-out, HHV) – Scenario 1**



Data source: EPRI new entrant data with amendments agreed by Stakeholder Reference Group (as at 23 December 2009 and 30 April 2010) for 2015 to 2030 and ACIL Tasman extrapolation for 2031 to 2050.

8.5 Fuel prices

The approach used to extrapolate each fuel price series in each scenario is identical that the one used to extrapolate the capital costs – that is, we took the annualised change in fuel prices between 2026 and 2030 and applied a percentage of this change for each year between 2031 and 2050.

Similar to the approach applied to the capital costs, the percentage of the change applied starts at 100% in 2031 and declines to 2050. However, the percentage does not decline linearly from 100% in 2031 to 5% by 2050; instead we assume a linear decline in the percentage so that is reaches 25% by 2046 and remains at 25% to 2050. We chose 25% as the final percentage instead of 5% (as used in the capital costs and thermal efficiency extrapolation) because in general we do not assume a ceiling or floor for fuel prices – unlike the changes in capital costs and thermal efficiency which we assume asymptote very close to zero.

Similar to the approach applied to the capital costs, this approach allows the information contained in the change in fuel prices between 2026 and 2030 to be used out to 2050. We did need to make alterations to this approach in some cases. For example, if there was a step change in the prices for a particular fuel price series between 2026 and 2030, then continuing this step change to 2050 produces unrealistic results. Instead, in the cases of a step change we used the trend in other similar fuel price series or used a shorter period to estimate the rate of change (for example, we used the annualised rate of change between

2027 and 2030, instead of 2026 to 2030, if the step change occurred between 2026 and 2027).

In the case of the gas price curves, the extrapolation also had to consider the associated demand series so that the extrapolated prices for a lower demand trajectory did not cross-over with (and be greater than) the extrapolated prices from a higher demand trajectory.

Finally, in the case of the scenarios in which there is high demand for gas we assumed a limit on domestic gas prices of $12/GJ. In these scenarios the rapid growth in gas price prior to 2030 resulted in extrapolated gas prices reaching well above $12/GJ between 2031 and 2050 (even when using the declining percentage factor).

Modelling of extreme gas demand scenarios – even in the period to 2030 – resulted in the utilisation of all gas production capability currently assumed within our gas market model. This resulted in extremely high prices levels. However, exploration efforts in Australia are beginning to examine other non-conventional gas resources, such as shale gas and coal gasification. It has been demonstrated that these resources are potentially significant and are likely to become available in the longer-term if prices are sufficient to justify their development. While there remains significant uncertainty regarding the cost to develop such resources, based on experience in the US in relation to shale gas it is reasonable to assume that at prices of around $12/GJ, these additional resources will be able to be developed. Therefore we have essentially capped the gas price series at this level in real terms.

A Projected coal prices

A.1 Scenario 1

Table A1 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing NSW stations – Scenario 1**

Year ending June	Macquarie Generation	Eraring Energy	Delta Coastal	Delta Western	Redbank
2010	$1.31	$1.81	$1.85	$1.86	$1.01
2011	$1.24	$1.69	$1.70	$1.76	$1.01
2012	$1.23	$1.69	$1.70	$1.75	$1.01
2013	$1.31	$1.68	$1.68	$1.74	$1.01
2014	$1.31	$1.67	$1.67	$1.66	$1.01
2015	$1.30	$1.70	$1.66	$1.34	$1.01
2016	$1.29	$1.68	$1.65	$1.32	$1.01
2017	$1.29	$1.67	$1.64	$1.30	$1.01
2018	$1.29	$1.66	$1.63	$1.28	$1.01
2019	$1.28	$1.65	$1.62	$1.27	$1.01
2020	$1.28	$1.63	$1.61	$1.25	$1.01
2021	$1.27	$1.61	$1.61	$1.23	$1.01
2022	$1.29	$1.59	$1.59	$1.22	$1.01
2023	$1.31	$1.57	$1.57	$1.20	$1.01
2024	$1.31	$1.55	$1.55	$1.18	$1.01
2025	$1.30	$1.53	$1.53	$1.17	$1.01
2026	$1.29	$1.51	$1.51	$1.15	$1.01
2027	$1.38	$1.49	$1.49	$1.14	$1.01
2028	$1.37	$1.48	$1.48	$1.12	$1.01
2029	$1.35	$1.46	$1.46	$1.11	$1.01
2030	$1.33	$1.44	$1.44	$1.09	$1.01

Data source: ACIL Tasman modelling

Table A2 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing Qld stations – Scenario 1**

Year ending June	Gladstone	Stanwell	Tarong	Swanbank B	Callide B & C	Collinsville	Millmerran	Kogan Creek
2010	$1.58	$1.41	$1.02	$2.17	$1.34	$2.13	$0.86	$0.76
2011	$1.58	$1.41	$1.02	$1.92	$1.34	$2.13	$0.86	$0.76
2012	$1.58	$1.41	$1.02	$1.90	$1.34	$2.13	$0.86	$0.76
2013	$1.58	$1.41	$1.02	$1.88	$1.34	$2.13	$0.86	$0.76
2014	$1.58	$1.41	$1.02	$1.87	$1.34	$2.13	$0.86	$0.76
2015	$1.58	$1.41	$1.02	$1.85	$1.34	$2.13	$0.86	$0.76
2016	$1.58	$1.41	$1.02	$1.83	$1.34	$2.13	$0.86	$0.76
2017	$1.58	$1.41	$1.02	$1.81	$1.34	$2.13	$0.86	$0.76
2018	$1.58	$1.41	$1.02	$1.79	$1.34	$2.13	$0.86	$0.76
2019	$1.58	$1.41	$1.02	$1.77	$1.34	$2.13	$0.86	$0.76
2020	$1.58	$1.41	$1.02	$1.76	$1.34	$2.13	$0.86	$0.76
2021	$1.58	$1.41	$1.02	$1.74	$1.34	$2.13	$0.86	$0.76
2022	$1.58	$1.41	$1.02	$1.72	$1.34	$2.13	$0.86	$0.76
2023	$1.58	$1.41	$1.02	$1.70	$1.34	$2.13	$0.86	$0.76
2024	$1.58	$1.41	$1.02	$1.69	$1.34	$2.13	$0.86	$0.76
2025	$1.58	$1.41	$1.02	$1.67	$1.34	$2.13	$0.86	$0.76
2026	$1.65	$1.41	$1.02	$1.65	$1.34	$2.13	$0.86	$0.76
2027	$1.64	$1.41	$1.02	$1.64	$1.34	$2.13	$0.86	$0.76
2028	$1.62	$1.41	$1.02	$1.62	$1.34	$2.13	$0.86	$0.76
2029	$1.60	$1.41	$1.02	$1.60	$1.34	$2.13	$0.86	$0.76
2030	$1.59	$1.41	$1.02	$1.59	$1.34	$2.13	$0.86	$0.76

Data source: ACIL Tasman modelling

Table A3 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing Vic and SA stations – Scenario 1**

Year ending June	Victoria						South Australia	
	Yallourn	Loy Yang A	Loy Yang B	Hazelwood	Anglesea	Energy Brix	Northern	Thomas Playford
2010	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2011	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2012	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2013	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2014	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2015	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2016	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2017	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2018	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2019	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2020	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2021	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2022	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2023	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2024	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2025	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2026	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2027	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2028	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2029	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2030	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52

Data source: ACIL Tasman modelling

Table A4 **Projected coal prices (Real 2009-10 AUD$/GJ) for new stations – Scenario 1**

Year ending June	NQ	CQ	SWQ	NNS	NCEN	SWNSW	LV
2010	$1.71	$1.35	$1.32	$1.61	$1.36	$1.06	$0.57
2011	$1.71	$1.34	$1.31	$1.38	$1.17	$1.06	$0.57
2012	$1.71	$1.33	$1.30	$1.36	$1.15	$1.06	$0.57
2013	$1.70	$1.32	$1.30	$1.34	$1.14	$1.06	$0.57
2014	$1.70	$1.31	$1.29	$1.33	$1.12	$1.06	$0.56
2015	$1.70	$1.30	$1.29	$1.31	$1.11	$1.06	$0.56
2016	$1.70	$1.29	$1.28	$1.29	$1.10	$1.06	$0.56
2017	$1.70	$1.28	$1.28	$1.28	$1.08	$1.06	$0.56
2018	$1.70	$1.28	$1.27	$1.26	$1.07	$1.06	$0.56
2019	$1.70	$1.27	$1.27	$1.25	$1.05	$1.06	$0.56
2020	$1.70	$1.26	$1.27	$1.23	$1.04	$1.06	$0.56
2021	$1.69	$1.25	$1.27	$1.21	$1.03	$1.06	$0.55
2022	$1.69	$1.24	$1.27	$1.20	$1.02	$1.06	$0.55
2023	$1.69	$1.24	$1.27	$1.18	$1.00	$1.06	$0.55
2024	$1.69	$1.23	$1.27	$1.17	$0.99	$1.06	$0.55
2025	$1.69	$1.22	$1.27	$1.15	$0.98	$1.06	$0.55
2026	$1.69	$1.21	$1.27	$1.14	$0.97	$1.06	$0.55
2027	$1.69	$1.21	$1.27	$1.12	$0.95	$1.06	$0.55
2028	$1.69	$1.20	$1.27	$1.11	$0.94	$1.06	$0.55
2029	$1.68	$1.19	$1.27	$1.10	$0.93	$1.06	$0.54
2030	$1.68	$1.19	$1.27	$1.08	$0.92	$1.06	$0.54

Data source: ACIL Tasman modelling

A.2 Scenario 2

Table A5 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing NSW stations – Scenario 2**

Year ending June	Macquarie Generation	Eraring Energy	Delta Coastal	Delta Western	Redbank
2010	$1.30	$1.75	$1.78	$1.82	$1.01
2011	$1.23	$1.64	$1.64	$1.73	$1.01
2012	$1.22	$1.64	$1.64	$1.72	$1.01
2013	$1.29	$1.64	$1.64	$1.71	$1.00
2014	$1.29	$1.64	$1.64	$1.63	$1.00
2015	$1.28	$1.67	$1.64	$1.33	$1.00
2016	$1.28	$1.67	$1.64	$1.33	$1.00
2017	$1.28	$1.67	$1.64	$1.33	$0.99
2018	$1.28	$1.70	$1.63	$1.33	$0.99
2019	$1.27	$1.70	$1.63	$1.33	$0.99
2020	$1.27	$1.70	$1.63	$1.33	$0.99
2021	$1.27	$1.70	$1.70	$1.33	$0.98
2022	$1.30	$1.70	$1.70	$1.33	$0.98
2023	$1.35	$1.70	$1.70	$1.34	$0.98
2024	$1.34	$1.70	$1.70	$1.34	$0.98
2025	$1.34	$1.70	$1.70	$1.34	$0.97
2026	$1.34	$1.70	$1.70	$1.34	$0.97
2027	$1.59	$1.70	$1.70	$1.34	$0.97
2028	$1.59	$1.70	$1.70	$1.34	$0.97
2029	$1.59	$1.70	$1.70	$1.34	$0.96
2030	$1.59	$1.71	$1.71	$1.34	$0.96

Data source: ACIL Tasman modelling

Table A6 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing Qld stations – Scenario 2**

Year ending June	Gladstone	Stanwell	Tarong	Swanbank B	Callide B & C	Collinsville	Millmerran	Kogan Creek
2010	$1.58	$1.41	$1.02	$2.17	$1.33	$2.12	$0.86	$0.76
2011	$1.58	$1.41	$1.01	$1.92	$1.33	$2.12	$0.86	$0.76
2012	$1.57	$1.41	$1.01	$1.92	$1.33	$2.11	$0.86	$0.75
2013	$1.57	$1.40	$1.01	$1.92	$1.32	$2.11	$0.85	$0.75
2014	$1.57	$1.40	$1.01	$1.92	$1.32	$2.10	$0.85	$0.75
2015	$1.56	$1.40	$1.00	$1.92	$1.32	$2.10	$0.85	$0.75
2016	$1.56	$1.39	$1.00	$1.92	$1.31	$2.09	$0.85	$0.75
2017	$1.56	$1.39	$1.00	$1.92	$1.31	$2.09	$0.84	$0.75
2018	$1.55	$1.39	$1.00	$1.92	$1.31	$2.08	$0.84	$0.74
2019	$1.55	$1.38	$1.00	$1.92	$1.30	$2.08	$0.84	$0.74
2020	$1.54	$1.38	$0.99	$1.92	$1.30	$2.07	$0.84	$0.74
2021	$1.54	$1.38	$0.99	$1.92	$1.30	$2.07	$0.84	$0.74
2022	$1.54	$1.37	$0.99	$1.92	$1.30	$2.06	$0.83	$0.74
2023	$1.53	$1.37	$0.99	$1.92	$1.29	$2.06	$0.83	$0.73
2024	$1.53	$1.37	$0.98	$1.92	$1.29	$2.05	$0.83	$0.73
2025	$1.53	$1.36	$0.98	$1.92	$1.29	$2.05	$0.83	$0.73
2026	$1.92	$1.36	$0.98	$1.92	$1.28	$2.04	$0.83	$0.73
2027	$1.92	$1.36	$0.98	$1.92	$1.28	$2.04	$0.82	$0.73
2028	$1.92	$1.35	$0.97	$1.92	$1.28	$2.03	$0.82	$0.73
2029	$1.92	$1.35	$0.97	$1.92	$1.27	$2.03	$0.82	$0.72
2030	$1.92	$1.35	$0.97	$1.92	$1.27	$2.02	$0.82	$0.72

Data source: ACIL Tasman modelling

Table A7 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing Vic and SA stations – Scenario 2**

Year ending June	Victoria						South Australia	
	Yallourn	Loy Yang A	Loy Yang B	Hazelwood	Anglesea	Energy Brix	Northern	Thomas Playford
2010	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2011	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2012	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2013	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2014	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2015	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2016	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2017	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2018	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2019	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2020	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2021	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2022	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2023	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2024	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2025	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2026	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2027	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2028	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2029	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2030	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52

Data source: ACIL Tasman modelling

Table A8 **Projected coal prices (Real 2009-10 AUD$/GJ) for new stations – Scenario 2**

Year ending June	NQ	CQ	SWQ	NNS	NCEN	SWNSW	LV
2010	$1.71	$1.32	$1.29	$1.51	$1.27	$1.06	$0.57
2011	$1.71	$1.32	$1.29	$1.29	$1.09	$1.06	$0.57
2012	$1.71	$1.32	$1.29	$1.29	$1.09	$1.06	$0.57
2013	$1.70	$1.32	$1.29	$1.29	$1.09	$1.06	$0.57
2014	$1.70	$1.32	$1.29	$1.30	$1.10	$1.06	$0.56
2015	$1.70	$1.32	$1.29	$1.30	$1.10	$1.06	$0.56
2016	$1.70	$1.32	$1.29	$1.30	$1.10	$1.06	$0.56
2017	$1.70	$1.32	$1.29	$1.30	$1.10	$1.06	$0.56
2018	$1.70	$1.32	$1.29	$1.30	$1.10	$1.06	$0.56
2019	$1.70	$1.31	$1.29	$1.30	$1.10	$1.06	$0.56
2020	$1.70	$1.31	$1.28	$1.30	$1.10	$1.06	$0.56
2021	$1.69	$1.30	$1.28	$1.28	$1.09	$1.06	$0.55
2022	$1.69	$1.29	$1.28	$1.27	$1.07	$1.06	$0.55
2023	$1.69	$1.28	$1.27	$1.25	$1.06	$1.06	$0.55
2024	$1.69	$1.27	$1.27	$1.24	$1.05	$1.06	$0.55
2025	$1.69	$1.27	$1.27	$1.22	$1.03	$1.06	$0.55
2026	$1.69	$1.26	$1.27	$1.21	$1.02	$1.06	$0.55
2027	$1.69	$1.25	$1.27	$1.19	$1.01	$1.06	$0.55
2028	$1.69	$1.24	$1.27	$1.18	$1.00	$1.06	$0.55
2029	$1.68	$1.24	$1.27	$1.16	$0.98	$1.06	$0.54
2030	$1.68	$1.23	$1.27	$1.15	$0.97	$1.06	$0.54

Data source: ACIL Tasman modelling

A.3 Scenario 3

Table A9 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing NSW stations – Scenario 3**

Year ending June	Macquarie Generation	Eraring Energy	Delta Coastal	Delta Western	Redbank
2010	$1.29	$1.74	$1.77	$1.82	$1.01
2011	$1.24	$1.70	$1.71	$1.78	$1.01
2012	$1.22	$1.70	$1.72	$1.77	$1.01
2013	$1.31	$1.70	$1.71	$1.76	$1.00
2014	$1.32	$1.70	$1.71	$1.70	$1.00
2015	$1.31	$1.77	$1.71	$1.46	$1.00
2016	$1.31	$1.77	$1.71	$1.46	$1.00
2017	$1.31	$1.77	$1.71	$1.46	$0.99
2018	$1.31	$1.83	$1.70	$1.46	$0.99
2019	$1.30	$1.83	$1.70	$1.46	$0.99
2020	$1.30	$1.83	$1.70	$1.46	$0.99
2021	$1.30	$1.83	$1.83	$1.47	$0.98
2022	$1.34	$1.83	$1.83	$1.47	$0.98
2023	$1.40	$1.83	$1.83	$1.47	$0.98
2024	$1.40	$1.83	$1.83	$1.47	$0.98
2025	$1.40	$1.83	$1.83	$1.47	$0.97
2026	$1.39	$1.83	$1.83	$1.47	$0.97
2027	$1.72	$1.83	$1.83	$1.47	$0.97
2028	$1.72	$1.83	$1.83	$1.47	$0.97
2029	$1.72	$1.83	$1.83	$1.47	$0.96
2030	$1.72	$1.83	$1.83	$1.47	$0.96

Data source: ACIL Tasman modelling

Table A10 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing Qld stations – Scenario 3**

Year ending June	Gladstone	Stanwell	Tarong	Swanbank B	Callide B & C	Collinsville	Millmerran	Kogan Creek
2010	$1.58	$1.41	$1.02	$2.28	$1.33	$2.12	$0.86	$0.76
2011	$1.58	$1.41	$1.01	$2.17	$1.33	$2.12	$0.86	$0.76
2012	$1.57	$1.41	$1.01	$2.17	$1.33	$2.11	$0.86	$0.75
2013	$1.57	$1.40	$1.01	$2.17	$1.32	$2.11	$0.85	$0.75
2014	$1.57	$1.40	$1.01	$2.17	$1.32	$2.10	$0.85	$0.75
2015	$1.56	$1.40	$1.00	$2.17	$1.32	$2.10	$0.85	$0.75
2016	$1.56	$1.39	$1.00	$2.17	$1.31	$2.09	$0.85	$0.75
2017	$1.56	$1.39	$1.00	$2.17	$1.31	$2.09	$0.84	$0.75
2018	$1.55	$1.39	$1.00	$2.17	$1.31	$2.08	$0.84	$0.74
2019	$1.55	$1.38	$1.00	$2.17	$1.30	$2.08	$0.84	$0.74
2020	$1.54	$1.38	$0.99	$2.17	$1.30	$2.07	$0.84	$0.74
2021	$1.54	$1.38	$0.99	$2.17	$1.30	$2.07	$0.84	$0.74
2022	$1.54	$1.37	$0.99	$2.17	$1.30	$2.06	$0.83	$0.74
2023	$1.53	$1.37	$0.99	$2.17	$1.29	$2.06	$0.83	$0.73
2024	$1.53	$1.37	$0.98	$2.17	$1.29	$2.05	$0.83	$0.73
2025	$1.53	$1.36	$0.98	$2.17	$1.29	$2.05	$0.83	$0.73
2026	$2.17	$1.36	$0.98	$2.17	$1.28	$2.04	$0.83	$0.73
2027	$2.17	$1.36	$0.98	$2.17	$1.28	$2.04	$0.82	$0.73
2028	$2.17	$1.35	$0.97	$2.17	$1.28	$2.03	$0.82	$0.73
2029	$2.17	$1.35	$0.97	$2.17	$1.27	$2.03	$0.82	$0.72
2030	$2.17	$1.35	$0.97	$2.17	$1.27	$2.02	$0.82	$0.72

Data source: ACIL Tasman modelling

Table A11 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing Vic and SA stations – Scenario 3**

Year ending June	Victoria						South Australia	
	Yallourn	Loy Yang A	Loy Yang B	Hazelwood	Anglesea	Energy Brix	Northern	Thomas Playford
2010	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2011	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2012	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2013	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2014	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2015	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2016	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2017	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2018	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2019	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2020	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2021	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2022	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2023	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2024	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2025	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2026	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2027	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2028	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2029	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2030	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52

Data source: ACIL Tasman modelling

Table A12 **Projected coal prices (Real 2009-10 AUD$/GJ) for new stations – Scenario 3**

Year ending June	NQ	CQ	SWQ	NNS	NCEN	SWNSW	LV
2010	$1.71	$1.39	$1.36	$1.50	$1.26	$1.06	$0.57
2011	$1.71	$1.39	$1.36	$1.41	$1.19	$1.06	$0.57
2012	$1.71	$1.39	$1.36	$1.41	$1.19	$1.06	$0.57
2013	$1.70	$1.39	$1.36	$1.41	$1.19	$1.06	$0.57
2014	$1.70	$1.39	$1.36	$1.42	$1.19	$1.06	$0.56
2015	$1.70	$1.39	$1.36	$1.42	$1.19	$1.06	$0.56
2016	$1.70	$1.39	$1.36	$1.42	$1.19	$1.06	$0.56
2017	$1.70	$1.39	$1.36	$1.42	$1.19	$1.06	$0.56
2018	$1.70	$1.39	$1.36	$1.42	$1.19	$1.06	$0.56
2019	$1.70	$1.38	$1.35	$1.42	$1.20	$1.06	$0.56
2020	$1.70	$1.37	$1.34	$1.42	$1.20	$1.06	$0.56
2021	$1.69	$1.37	$1.33	$1.40	$1.18	$1.06	$0.55
2022	$1.69	$1.36	$1.32	$1.39	$1.17	$1.06	$0.55
2023	$1.69	$1.35	$1.31	$1.37	$1.15	$1.06	$0.55
2024	$1.69	$1.34	$1.31	$1.35	$1.14	$1.06	$0.55
2025	$1.69	$1.33	$1.30	$1.34	$1.13	$1.06	$0.55
2026	$1.69	$1.32	$1.29	$1.32	$1.11	$1.06	$0.55
2027	$1.69	$1.32	$1.29	$1.30	$1.10	$1.06	$0.55
2028	$1.69	$1.31	$1.28	$1.29	$1.09	$1.06	$0.55
2029	$1.68	$1.30	$1.28	$1.27	$1.07	$1.06	$0.54
2030	$1.68	$1.29	$1.27	$1.26	$1.06	$1.06	$0.54

Data source: ACIL Tasman modelling

A.4 Scenario 4

Table A13 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing NSW stations – Scenario 4**

Year ending June	Macquarie Generation	Eraring Energy	Delta Coastal	Delta Western	Redbank
2010	$1.37	$2.00	$2.08	$1.99	$1.01
2011	$1.27	$1.94	$2.00	$1.93	$1.01
2012	$1.25	$1.96	$2.01	$1.94	$1.01
2013	$1.44	$1.97	$2.02	$1.94	$1.01
2014	$1.45	$1.98	$2.01	$1.94	$1.01
2015	$1.45	$2.23	$2.02	$1.94	$1.01
2016	$1.45	$2.24	$2.04	$1.95	$1.01
2017	$1.47	$2.26	$2.05	$1.97	$1.01
2018	$1.46	$2.46	$2.05	$1.98	$1.01
2019	$1.46	$2.48	$2.06	$2.00	$1.01
2020	$1.47	$2.49	$2.07	$2.01	$1.01
2021	$1.47	$2.51	$2.51	$2.02	$1.01
2022	$1.56	$2.52	$2.52	$2.04	$1.01
2023	$1.71	$2.54	$2.54	$2.05	$1.01
2024	$1.71	$2.55	$2.55	$2.07	$1.01
2025	$1.71	$2.57	$2.57	$2.08	$1.01
2026	$1.71	$2.58	$2.58	$2.10	$1.01
2027	$2.44	$2.60	$2.60	$2.11	$1.01
2028	$2.46	$2.62	$2.62	$2.13	$1.01
2029	$2.48	$2.63	$2.63	$2.14	$1.01
2030	$2.49	$2.65	$2.65	$2.16	$1.01

Data source: ACIL Tasman modelling

Table A14 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing Qld stations – Scenario 4**

Year ending June	Gladstone	Stanwell	Tarong	Swanbank B	Callide B & C	Collinsville	Millmerran	Kogan Creek
2010	$1.58	$1.41	$1.02	$2.30	$1.34	$2.13	$0.86	$0.76
2011	$1.58	$1.41	$1.02	$2.18	$1.34	$2.13	$0.86	$0.76
2012	$1.58	$1.41	$1.02	$2.19	$1.34	$2.13	$0.86	$0.76
2013	$1.58	$1.41	$1.02	$2.20	$1.34	$2.13	$0.86	$0.76
2014	$1.58	$1.41	$1.02	$2.21	$1.34	$2.13	$0.86	$0.76
2015	$1.58	$1.41	$1.02	$2.22	$1.34	$2.13	$0.86	$0.76
2016	$1.58	$1.41	$1.02	$2.23	$1.34	$2.13	$0.86	$0.76
2017	$1.58	$1.41	$1.02	$2.25	$1.34	$2.13	$0.86	$0.76
2018	$1.58	$1.41	$1.02	$2.26	$1.34	$2.13	$0.86	$0.76
2019	$1.58	$1.41	$1.02	$2.27	$1.34	$2.13	$0.86	$0.76
2020	$1.58	$1.41	$1.02	$2.28	$1.34	$2.13	$0.86	$0.76
2021	$1.58	$1.41	$1.02	$2.29	$1.34	$2.13	$0.86	$0.76
2022	$1.58	$1.41	$1.02	$2.30	$1.34	$2.13	$0.86	$0.76
2023	$1.58	$1.41	$1.02	$2.31	$1.34	$2.13	$0.86	$0.76
2024	$1.58	$1.41	$1.02	$2.33	$1.34	$2.13	$0.86	$0.76
2025	$1.58	$1.41	$1.02	$2.34	$1.34	$2.13	$0.86	$0.76
2026	$2.35	$1.41	$1.02	$2.35	$1.34	$2.13	$0.86	$0.76
2027	$2.36	$1.41	$1.02	$2.36	$1.34	$2.13	$0.86	$0.76
2028	$2.37	$1.41	$1.02	$2.37	$1.34	$2.13	$0.86	$0.76
2029	$2.38	$1.41	$1.02	$2.38	$1.34	$2.13	$0.86	$0.76
2030	$2.40	$1.41	$1.02	$2.40	$1.34	$2.13	$0.86	$0.76

Data source: ACIL Tasman modelling

Table A15 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing Vic and SA stations – Scenario 4**

Year ending June	Victoria						South Australia	
	Yallourn	Loy Yang A	Loy Yang B	Hazelwood	Anglesea	Energy Brix	Northern	Thomas Playford
2010	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2011	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2012	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2013	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2014	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2015	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2016	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2017	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2018	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2019	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2020	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2021	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2022	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2023	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2024	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2025	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2026	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2027	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2028	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2029	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2030	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52

Data source: ACIL Tasman modelling

Table A16 **Projected coal prices (Real 2009-10 AUD$/GJ) for new stations – Scenario 4**

Year ending June	NQ	CQ	SWQ	NNS	NCEN	SWNSW	LV
2010	$1.70	$1.42	$1.40	$1.81	$1.53	$1.06	$0.57
2011	$1.70	$1.42	$1.40	$1.55	$1.31	$1.05	$0.57
2012	$1.70	$1.42	$1.40	$1.55	$1.31	$1.05	$0.57
2013	$1.69	$1.42	$1.40	$1.55	$1.31	$1.05	$0.57
2014	$1.69	$1.42	$1.40	$1.56	$1.32	$1.04	$0.56
2015	$1.68	$1.42	$1.40	$1.56	$1.32	$1.04	$0.56
2016	$1.68	$1.42	$1.40	$1.56	$1.32	$1.04	$0.56
2017	$1.67	$1.42	$1.40	$1.56	$1.32	$1.04	$0.56
2018	$1.67	$1.41	$1.40	$1.56	$1.32	$1.03	$0.56
2019	$1.67	$1.40	$1.39	$1.56	$1.32	$1.03	$0.56
2020	$1.66	$1.39	$1.38	$1.56	$1.32	$1.03	$0.56
2021	$1.66	$1.38	$1.36	$1.54	$1.31	$1.03	$0.55
2022	$1.65	$1.37	$1.35	$1.53	$1.29	$1.02	$0.55
2023	$1.65	$1.36	$1.34	$1.51	$1.27	$1.02	$0.55
2024	$1.65	$1.35	$1.33	$1.49	$1.26	$1.02	$0.55
2025	$1.64	$1.34	$1.32	$1.47	$1.24	$1.02	$0.55
2026	$1.64	$1.33	$1.31	$1.45	$1.23	$1.01	$0.55
2027	$1.63	$1.32	$1.30	$1.43	$1.21	$1.01	$0.55
2028	$1.63	$1.31	$1.29	$1.42	$1.20	$1.01	$0.55
2029	$1.63	$1.30	$1.28	$1.40	$1.19	$1.01	$0.54
2030	$1.62	$1.29	$1.27	$1.38	$1.17	$1.00	$0.54

Data source: ACIL Tasman modelling

A.5 Scenario 5

Table A17 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing NSW stations – Scenario 5**

Year ending June	Macquarie Generation	Eraring Energy	Delta Coastal	Delta Western	Redbank
2010	$1.35	$1.94	$2.01	$1.95	$1.01
2011	$1.30	$2.17	$2.27	$2.11	$1.01
2012	$1.26	$2.19	$2.28	$2.11	$1.01
2013	$1.54	$2.19	$2.26	$2.11	$1.01
2014	$1.55	$2.18	$2.24	$2.15	$1.01
2015	$1.54	$2.54	$2.24	$2.32	$1.01
2016	$1.53	$2.53	$2.24	$2.30	$1.01
2017	$1.55	$2.52	$2.23	$2.29	$1.01
2018	$1.53	$2.77	$2.22	$2.28	$1.01
2019	$1.52	$2.76	$2.21	$2.26	$1.01
2020	$1.53	$2.74	$2.20	$2.25	$1.01
2021	$1.52	$2.73	$2.73	$2.24	$1.01
2022	$1.62	$2.71	$2.71	$2.23	$1.01
2023	$1.77	$2.70	$2.70	$2.21	$1.01
2024	$1.76	$2.68	$2.68	$2.20	$1.01
2025	$1.75	$2.67	$2.67	$2.19	$1.01
2026	$1.74	$2.66	$2.66	$2.18	$1.01
2027	$2.49	$2.64	$2.64	$2.16	$1.01
2028	$2.47	$2.63	$2.63	$2.15	$1.01
2029	$2.46	$2.61	$2.61	$2.14	$1.01
2030	$2.45	$2.60	$2.60	$2.13	$1.01

Data source: ACIL Tasman modelling

Table A18 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing Qld stations – Scenario 5**

Year ending June	Gladstone	Stanwell	Tarong	Swanbank B	Callide B & C	Collinsville	Millmerran	Kogan Creek
2010	$1.58	$1.41	$1.02	$2.31	$1.34	$2.13	$0.86	$0.76
2011	$1.58	$1.41	$1.02	$2.72	$1.34	$2.13	$0.86	$0.76
2012	$1.58	$1.41	$1.02	$2.71	$1.34	$2.13	$0.86	$0.76
2013	$1.58	$1.41	$1.02	$2.70	$1.34	$2.13	$0.86	$0.76
2014	$1.58	$1.41	$1.02	$2.68	$1.34	$2.13	$0.86	$0.76
2015	$1.58	$1.41	$1.02	$2.67	$1.34	$2.13	$0.86	$0.76
2016	$1.58	$1.41	$1.02	$2.66	$1.34	$2.13	$0.86	$0.76
2017	$1.58	$1.41	$1.02	$2.64	$1.34	$2.13	$0.86	$0.76
2018	$1.58	$1.41	$1.02	$2.63	$1.34	$2.13	$0.86	$0.76
2019	$1.58	$1.41	$1.02	$2.62	$1.34	$2.13	$0.86	$0.76
2020	$1.58	$1.41	$1.02	$2.60	$1.34	$2.13	$0.86	$0.76
2021	$1.58	$1.41	$1.02	$2.59	$1.34	$2.13	$0.86	$0.76
2022	$1.58	$1.41	$1.02	$2.58	$1.34	$2.13	$0.86	$0.76
2023	$1.58	$1.41	$1.02	$2.57	$1.34	$2.13	$0.86	$0.76
2024	$1.58	$1.41	$1.02	$2.55	$1.34	$2.13	$0.86	$0.76
2025	$1.58	$1.41	$1.02	$2.54	$1.34	$2.13	$0.86	$0.76
2026	$2.53	$1.41	$1.02	$2.53	$1.34	$2.13	$0.86	$0.76
2027	$2.51	$1.41	$1.02	$2.51	$1.34	$2.13	$0.86	$0.76
2028	$2.50	$1.41	$1.02	$2.50	$1.34	$2.13	$0.86	$0.76
2029	$2.49	$1.41	$1.02	$2.49	$1.34	$2.13	$0.86	$0.76
2030	$2.48	$1.41	$1.02	$2.48	$1.34	$2.13	$0.86	$0.76

Data source: ACIL Tasman modelling

Table A19 **Projected coal prices (Real 2009-10 AUD$/GJ) for existing Vic and SA stations – Scenario 5**

Year ending June	Victoria						South Australia	
	Yallourn	Loy Yang A	Loy Yang B	Hazelwood	Anglesea	Energy Brix	Northern	Thomas Playford
2010	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2011	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2012	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2013	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2014	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2015	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2016	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2017	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2018	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2019	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2020	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2021	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2022	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2023	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2024	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2025	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2026	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2027	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2028	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2029	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52
2030	$0.09	$0.08	$0.37	$0.08	$0.39	$0.59	$1.52	$1.52

Data source: ACIL Tasman modelling

Table A20 **Projected coal prices (Real 2009-10 AUD$/GJ) for new stations – Scenario 5**

Year ending June	NQ	CQ	SWQ	NNS	NCEN	SWNSW	LV
2010	$1.86	$1.68	$1.69	$1.77	$1.50	$1.06	$0.57
2011	$1.85	$1.67	$1.68	$1.97	$1.66	$1.05	$0.57
2012	$1.84	$1.66	$1.67	$1.96	$1.65	$1.04	$0.57
2013	$1.83	$1.65	$1.66	$1.95	$1.64	$1.04	$0.57
2014	$1.82	$1.64	$1.65	$1.94	$1.63	$1.03	$0.56
2015	$1.81	$1.63	$1.64	$1.92	$1.62	$1.03	$0.56
2016	$1.80	$1.62	$1.63	$1.91	$1.61	$1.02	$0.56
2017	$1.79	$1.61	$1.62	$1.90	$1.60	$1.02	$0.56
2018	$1.78	$1.60	$1.61	$1.89	$1.59	$1.01	$0.56
2019	$1.76	$1.58	$1.59	$1.88	$1.59	$1.01	$0.56
2020	$1.73	$1.56	$1.58	$1.87	$1.58	$1.00	$0.56
2021	$1.71	$1.54	$1.56	$1.85	$1.56	$1.00	$0.55
2022	$1.69	$1.52	$1.54	$1.83	$1.54	$0.99	$0.55
2023	$1.67	$1.50	$1.52	$1.81	$1.52	$0.99	$0.55
2024	$1.65	$1.49	$1.51	$1.79	$1.51	$0.99	$0.55
2025	$1.63	$1.47	$1.49	$1.77	$1.49	$0.98	$0.55
2026	$1.61	$1.46	$1.48	$1.75	$1.47	$0.98	$0.55
2027	$1.59	$1.45	$1.46	$1.73	$1.46	$0.97	$0.55
2028	$1.58	$1.44	$1.44	$1.71	$1.44	$0.97	$0.55
2029	$1.57	$1.42	$1.43	$1.69	$1.42	$0.96	$0.54
2030	$1.56	$1.41	$1.41	$1.67	$1.41	$0.96	$0.54

Data source: ACIL Tasman modelling