ACIL ALLEN CONSULTING

REPORT TO
AUSTRALIAN ENERGY MARKET OPERATOR

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FUEL AND TECHNOLOGY COST REVIEW

FINAL REPORT

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1 Introduction and background

The Australian Energy Market Operator's (AEMO) planning functions rely on an underlying set of input assumptions that characterise the behaviour of existing generation assets, and the economics/location of future investment and retirement decisions. The dataset includes projections of fuel and technology costs for both existing and emerging generation technologies. The dataset also encompasses the technical operating parameters of these units. For emerging technologies the dataset specifies location incentives/limits, construction lead-times, and earliest commercial viability dates.

The data is used by AEMO to conduct market simulation studies for medium and long-term planning purposes; in particular the analysis underlying the annual National Transmission Network Development Plan (NTNDP). Emissions factor data provided/validated through this review will also be used operationally in calculation of the Carbon Dioxide Equivalent Intensity Index (CDEII).

ACIL Allen Consulting (ACIL Allen) have been engaged by AEMO to undertake an update of the technology costs, fuel costs and technical parameters contained within the NTNDP assumptions database. To assist with this review ACIL Allen has engaged GHD as a sub-contractor to provide expert advice and estimates on new entrant technology costs, engineering and technical matters.

This engagement requires the delivery of the analysis, recommendations for updates and reports in stages:

- The first stage of the assignment involves the review and update of Emission factors which are used in the calculation of the CDEII. ACIL Allen has provided its assessment and recommendations of updates to fuel emission factors in a separate report.
- The second stage of the assignment was the delivery of the proposed methodology for updating the remaining data items, which is included as Chapter 3 in this report. Included in this chapter are the definitions and methodology employed in the estimation of the generation cost data.

This report is one of the key deliverables of this assignment and summarises the approach and methodology used and the key results for existing generators and new entrant technologies. It is structured as follows:

- Chapter 2 provides the scope of data elements
- Chapter 3 gives an overview of the methodology and definitions used
- Chapters 4 to 7 summarise the results and provide commentary for existing plant, new entrant plant, gas prices and coal prices respectively.

A detailed dataset is provided separately as an attachment to this report, in spreadsheet format.

2 Data deliverables

2.1 Format of data

At the completion of the assignment, the data is to be provided in the template attached to the RFP:

- on a sent-out basis using metric units
- presented in real 2014-15 Australian dollars covering the period 2014-15 to 2044-45
- exclusive of GST
- maintaining formulas in calculated fields as much as possible.

2.2 Scope of inputs – existing generators

AEMO require data elements as shown in Table 1 on a unit basis for all scheduled and semi-scheduled market generators. Thermal efficiency and emission factors are also required for all non-scheduled market generators.

Table 1 **Existing generator data elements required**

Technical parameters
Validation of the pre-populated dataset provided by AEMO
Minimum Stable Generation (% of installed capacity)
Cold/Warm/Hot Start Notification Times (hours)
Cold/Warm/Hot Minimum Sync Times (hours)
No load fuel consumption (GJ/hour)
Auxiliary load (% of as-generated energy)
Ramp Rates (MW sent-out/hour, during standard operation and start up)
Pumping efficiency values for the pumped hydro units (energy required for pumping expressed as a % of energy sent-out)
Thermal de-rate factors for hot climate operations (% of installed sent-out capacity)
Maintenance rate (days/year)
Full & Partial forced outage rates (on a running hours basis).
Efficiency and emission factors
Thermal Efficiency (%, HHV, sent-out and as generated)
Scope 1 Emission Factor (kg CO2e/GJ fuel)[1]
Scope 3 Emission Factor (kg CO2e/GJ fuel)[2]
Cost elements
Fixed Operating Cost ($/MW sent-out /year)
Variable Operating Cost ($/MWh sent-out)
No Load Cost ($/MW sent-out)
Cold start-up cost ($ per cold-start offline >40 hours)
Warm start-up cost ($ per warm-start — offline between 5 and 40 hours)
Hot start-up cost ($ per hot-start — offline <5 hours)

[1] This data element was previously termed Combustion Emission Factor

[2] The data element was previously termed Fugitive Emission Factor

Retirement / Refurbishment cost ($)
Fuel cost by year ($/GJ)

In discussions with AEMO, it was decided to remove “Minimum on/off times” from the original scope (although ACIL Allen and GHD will attempt to estimate these values as part of the industry survey). In addition, it was agreed that some of the ‘new’ data items such as cold/warm/hot start notification times and costs would be undertaken by technology rather than producing estimates for individual existing stations.

2.3 Scope of inputs – new entrants

The scope of work requires nominating the most likely generation technologies to be commercially viable over the next 30-year period for each scenario. The RFP and template include the technologies listed in Table 2.

Table 2 **Indicative Technology list to be examined**

Technology
Wind (onshore)
Biomass (with variety of fuel sources and locations)
Solar Thermal (including Compact Linear Fresnel, Parabolic Trough. Central Receiver. all with/without 6 hour storage)
Solar Photovoltaic (including Fixed Flat Plate, Single Axis Tracking and Dual Axis Tracking)
Wave/Ocean
Pumped Hydro storage
Large scale Battery storage
Integrated Solar (e.g. Kogan Creek Solar Boost - with detailed output characteristics)
Closed Cycle Gas Turbines (± Carbon Capture & Storage)
Open Cycle Gas Turbines
Super Critical Black Coal (± Carbon Capture & Storage)
Super Critical Brown Coal (± Carbon Capture & Storage)

In discussions with AEMO, it was decided to not undertake cost and parameter reviews for geothermal, coal gasification and nuclear technologies.

The new entrant generator data elements are specified in Table 3. Where appropriate, these should be specified for technology and region. In cases where parameters are impacted by learning rates, the parameter should be specified separately for each year representing a unit constructed in that year.

Table 3 **New entrant generator data elements required**

Technical parameters
First year assumed commercially viable (for commissioning, not construction start)
Assumed economic life (years)
Fugitive Emissions (kg CO2elGJ fuel)
Combustion Emissions (kg CO2elGJ fuel)
Emissions Capture (% of total emissions)
Assumed unit size (MW, sent-out)
Minimum Stable Generation (% of installed capacity)
Cold/Warm/Hot Start Notification Times (hours)

Cold/Warm/Hot Minimum Sync Times (hours)
No load fuel consumption (GJ/hour)
Auxiliary load (% of as—generated energy)
Ramp Rates (MW/h, during standard operation)
Thermal Efficiency (% as-generated and as sent-out, by year of construction)
Heat rate degradation curves
Pumping efficiency values for the pumped hydro units
Thermal de-rate factors for hot climate operations (% of installed sent-out capacity)
Maintenance rate (days/year)
Full & Partial forced outage rates (on a running hours basis)
Cost parameters
Fixed Operating Cost ($/MW sent-out/year)
Variable Operating Cost ($/MWh sent-out)
No Load Cost ($/MW sent-out)
Cold start-up cost ($ per cold-start offline >40 hours)
Warm start-up cost ($ per warm-start — offline between 5 and 40 hours)
Hot start-up cost ($ per hot-start - offline <5 hours)
CO_2 Transport & Storage Costs by zone ($/tonne)
Fuel cost by year and by zone ($/GJ)
Capital cost by year ($/MW sent-out)
Build limits
Project lead time between construction approval and commissioning
The maximum build achievable in each zone (MW sent-out)
The maximum build rate (MW sent-out/year)

The following elements were excluded from the original scope for data item requirements on AEMO's advice:

- Minimum on/off times
- Retirement and refurbishment costs for new technologies
- Contribution to peak demand for intermittent technologies.

3 Methodology and definitions

3.1 Consideration of AEMO planning scenarios

A number of the data items in the template, particularly the cost items, will vary as a function of the three planning scenarios developed by AEMO. Therefore, a description will be required about the way each data item varies across the scenarios. In the following chapters while defining each data item and the methodology applied for its estimation an indication is given as to whether it is static across the scenarios or varies with each scenario and the approach considered for determining the variation.

3.1.1 The scenarios

The three scenarios are based on information contained in AEMO's report titled, *2014 Planning and Forecasting Scenarios*, dated 11 February 2014. AEMO commissioned Independent Economics to produce the report titled, *Economic and Energy Market Forecasts,* 9 March, which provides more detail on each scenario.

Three scenarios have been defined as part of the study and are referred to as the:

- Medium centralised energy demand (Medium scenario)
- High centralised energy demand (High scenario)
- Low centralised energy demand (Low scenario).

Presented below are the key parameters from the scenario definitions which are relevant when projecting the generation technology and fuel costs of the NEM.

Table 4 **Scenario definitions - Key parameters for technology and fuel costs**

SCENARIO DRIVERS	Low centralised energy demand	Medium centralised energy demand	High centralised energy demand
Energy consumption			
Domestic energy consumption from centralised source	Low	Medium	High
Economic and demographic			
Economic activity - Australian	Low	Medium	High
Energy-intensive industrial sectors	Reduced output from industrial sectors	Continue at current levels	Increased output from industrial sectors
Population growth	Low levels of economic activity and low demand for Australia's resources reduces requirements for additional skilled labour and hence immigration levels are low	Central estimated growth	Stronger growth to support higher economic activity
Economic activity - Global	US remains weak; EU member state defaults cause new credit freeze; slows Chinese growth	Global recovery continues	Strong growth in India and China; increased growth in western Europe and the USA
Greenhouse policy			
International action on global warming	NA	NA	NA
Carbon	Implementation of Direct Action policy in the short to medium term; coupled with safeguarding emissions reduction with a wider effect and higher strength phased in from 2017	Implementation of Direct Action policy in the short to medium term; coupled with safeguarding emissions reduction with a wider effect and moderate strength phased in from 2020	Implementation of Direct Action policy
Renewable Energy Target	Current legislation	Current legislation	Current legislation
SRES	Current legislation	Current legislation	Current legislation
Domestic gas			
Production	Domestic gas production more difficult than in medium scenario; Australia has lower international competitiveness	Central estimate – consistent with current growth in production	Domestic gas production higher than in medium scenario; Australia has higher international competitiveness
Global LNG market	Global LNG demand is weak	Central estimate – consistent with current growth in production	Global LNG demand is strong
Penetration of gas as transport fuel	Low penetration	Central estimated	High penetration
Technology and development			
Research and development	Government and industry investment in development of new technologies is well funded and coordinated internationally. New low-emission technologies move rapidly down their learning curve	Low, moving to moderate	Investment in new technologies is constrained and slow
Distributed generation penetration (solar, cogen and trigen)	High	Moderate	Low

Source: AEMO

The Independent Economics report and associated spreadsheet (provided by AEMO) provide additional detail on each of the scenarios. ACIL Allen has extracted the relevant details and presents them in summary form below.

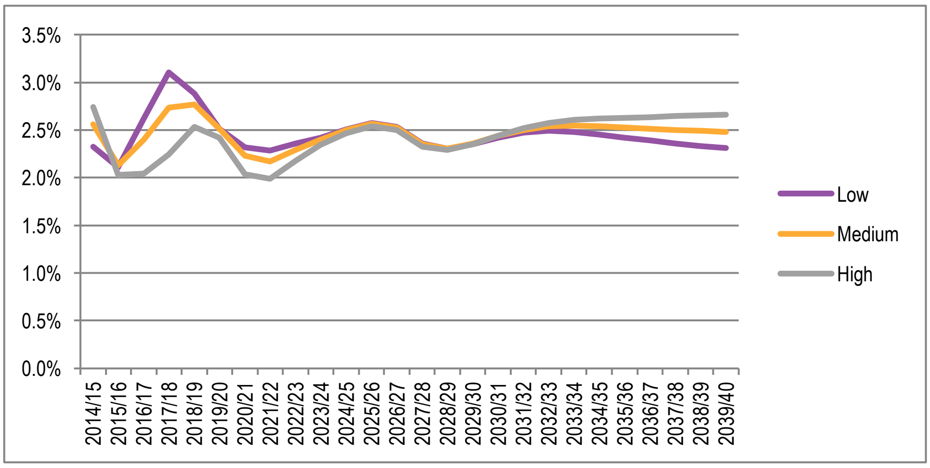
Table 5 **Scenario definitions - Key parameters for technology and fuel costs**

SCENARIO DRIVERS	Low centralised energy demand	Medium centralised energy demand	High centralised energy demand
Macro			
World commodity prices and terms of trade – shorter term	Terms of trade fall to reach 2005-06 levels	All three scenarios allow for a further decline in commodity prices from current levels; terms of trade fall to reach 2006-07 levels	Terms of trade fall to reach 2007-08 levels
World commodity prices – longer term (per cent deviation from Medium scenario)	-14%	0%	16%
Exchange rate		Adjusts in line with the change in commodity prices for all three scenarios	
Net overseas migration ('000 people)	200	240	280
Long-run unemployment rate	6.2%	5.2%	4.2%
Productivity growth (per cent)	1.25	1.5	1.75

Source: Independent Economics

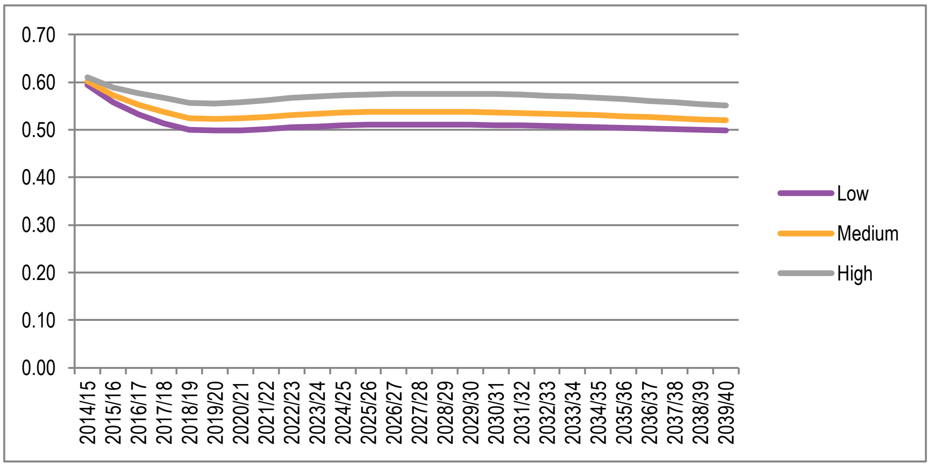
Figure 1 to Figure 8 summarise a range of macro input variables which were taken from the economic modelling and used as inputs into the cost projections.

Figure 1 **Domestic inflation**



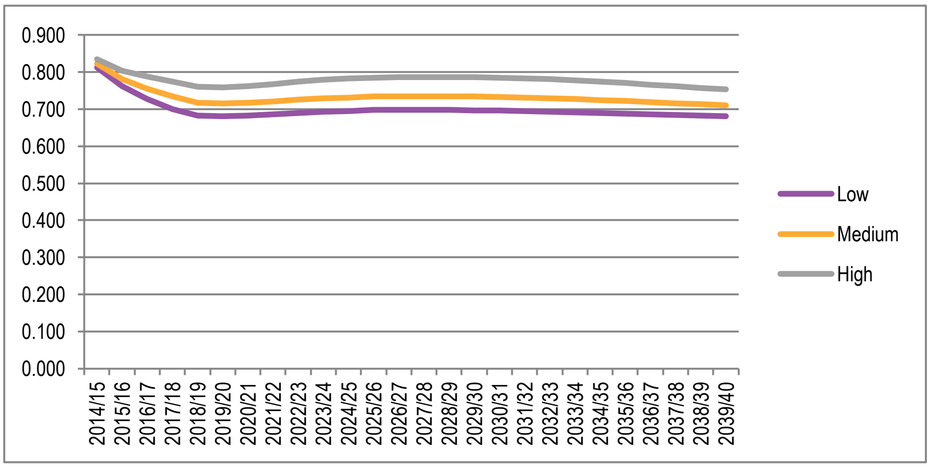
Source: AEMO

Figure 2 **Exchange rate – Euro/$A**



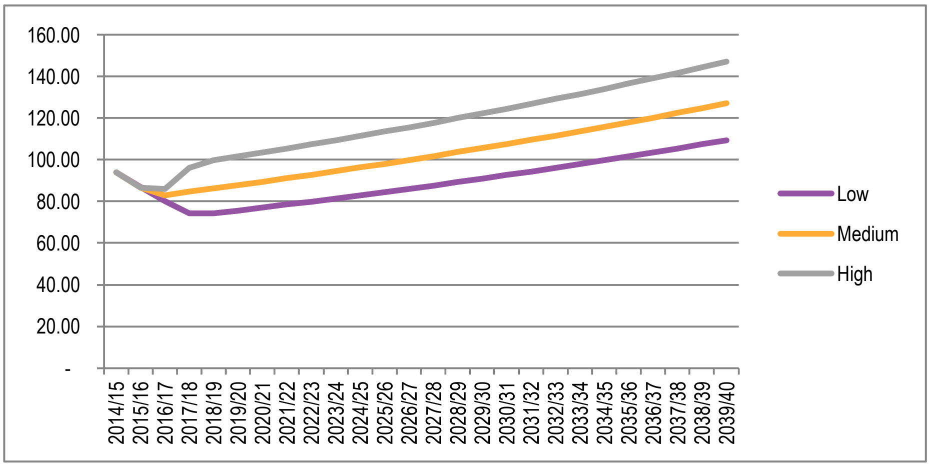
Source: AEMO

Figure 3 **Exchange rate – US$/$A**



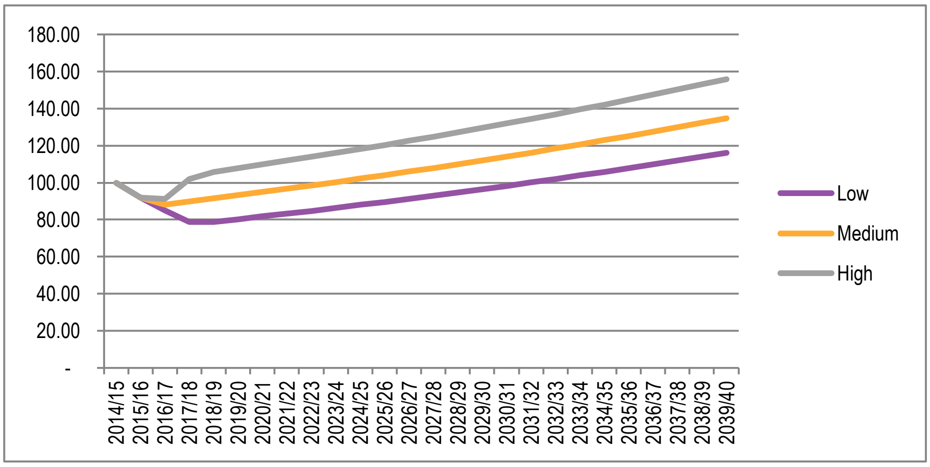
Source: AEMO

Figure 4 **Export coal price (US$/tonne, nominal)**



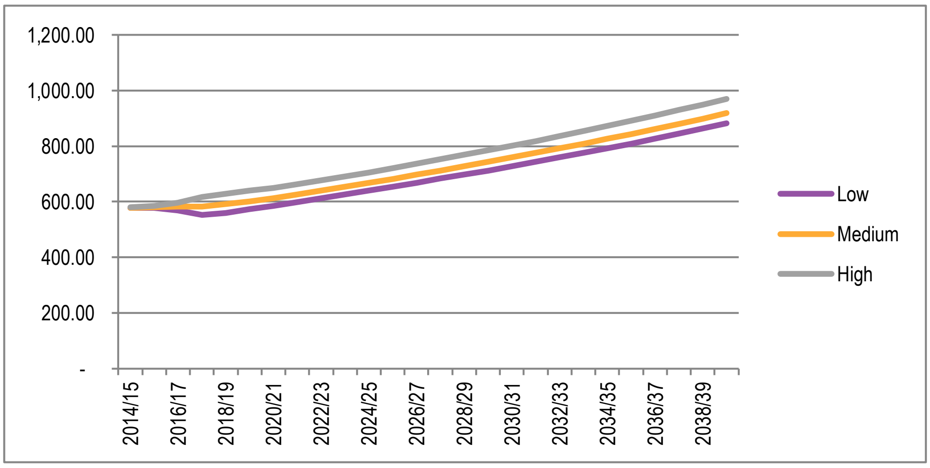
Source: AEMO

Figure 5 **Oil price (US$/bbl, nominal)**



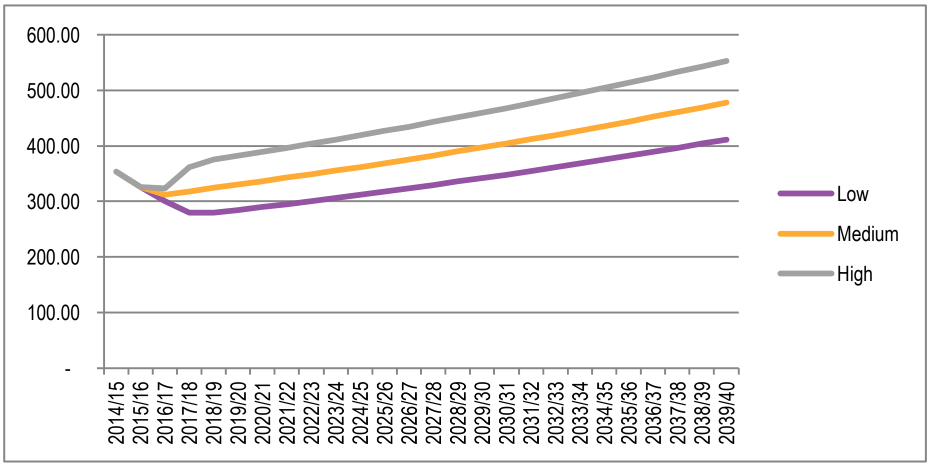
Source: AEMO

Figure 6 **LNG price (US$/tonne, nominal)**



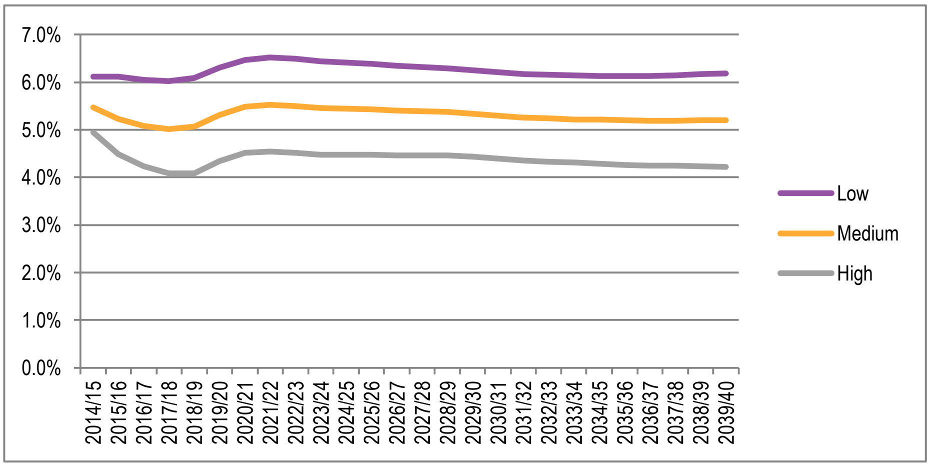
Source: AEMO

Figure 7 **Steel price (US$/tonne, nominal)**



Source: AEMO

Figure 8 **Australian unemployment rate**



Source: AEMO

3.1.2 Scenario definitions - key parameters

Taking the above summaries, presented in the table below are the key parameters which will influence the estimates of the data items, and a high level proposed treatment of these parameters for the three scenarios.

Table 6 **Scenario definitions - Key parameters for NEM modelling**

Scenario parameters	Data items affected	Low centralised energy demand	Medium centralised energy demand	High centralised energy demand
Macro				
AUD exchange rate	Capital costs; export coal and LNG netback prices	As per Figure 2 and Figure 3	As per Figure 2 and Figure 3	As per Figure 2 and Figure 3
Inflation		As per Figure 1	As per Figure 1	As per Figure 1
Carbon policy				
International action on greenhouse emissions	Demand for energy; learning rate for emerging technologies	Global agreement reached earlier and/or recovery in European permit prices by 2017	Global agreement reached by 2020 and/or recovery in European permit prices by 2020	Global agreement not reached until post 2030 and/or recovery in European permit prices by 2030
Fuel prices				
Oil prices	Export LNG netback prices; cost of liquid fuels	As per Figure 5	As per Figure 5	As per Figure 5
International coal price	Export coal netback prices	As per Figure 4	As per Figure 4	As per Figure 4
East coast gas supply / production costs	Gas supply cost curve	ACIL Allen Reference case supply curve with low development in unconventional reserves (out of the Cooper Basin)	ACIL Allen Reference case supply curve with moderate development in unconventional reserves (out of the Cooper Basin)	ACIL Allen Reference case supply curve with reasonable development in unconventional reserves (out of the Cooper Basin)
Other commodity prices				
Steel prices	Capital costs and O&M	As per Figure 7	As per Figure 7	As per Figure 7
Technology and development				
Research and development	Learning curve for emerging technologies	Government and industry investment in development of new technologies is well funded and coordinated internationally. New low-emission technologies move rapidly down their learning curve	Low, moving to moderate	Investment in new technologies is constrained and slow
Productivity growth (per cent)	Learning curve for emerging technologies	1.25	1.5	1.75
Demography				
Net overseas migration ('000 people)	Labour costs – capital costs and O&M	200	240	280
Long-run unemployment rate	Labour costs	As per Figure 8	As per Figure 8	As per Figure 8

Source: ACIL Allen and GHD, with AEMO data

3.2 Definitions and methodology - Existing generator costs and parameters

3.2.1 Overview of methodology

The approach adopted is a staged process which focuses on updates to the existing dataset rather than starting from scratch.

An initial review of the data set was undertaken to assess each item and identify any obvious changes required. These changes were initially based on in-house information and market intelligence, acknowledging the need for transparency and a preference to rely on publicly available data. Where possible use of publicly available data was made, including aggregate data – this often involved a degree of "forensic analysis" of indirectly observable data (such as aggregate emissions or aggregate auxiliary loads).

After the initial review the dataset was reviewed for internal consistency by grouping stations by technology and fuel type in order to identify any outliers. Provided an outlier can be explained, it remained in the dataset, otherwise a change was proposed.

The proposed dataset after the initial review was presented in comparison with the original dataset for initial feedback from AEMO.

The proposed changes were then tested within industry by way of a focused survey.

3.2.2 Industry survey

The proposed dataset was tested for reasonableness by surveying responses from industry participants.

A "traditional" mail out or web based survey were not followed as in that case the response rate was likely to be very low. Rather, contacts within the industry, in particular generators were followed up directly to obtain feedback. Between the ACIL Allen and GHD team a list of contacts was developed based on previous work undertaken for each of the generators, and a team member was identified who is better placed to contact the potential participant.

Each survey participant was sent the proposed data set (and the existing data set) together with a cover letter explaining the process before personal contact was made.

Upon completion of the survey the team compiled a list of proposed changes to the dataset, citing reasons at a high level and prepared a high level summary of the degree of agreement. This was then presented to AEMO for feedback.

Given the potential confidential nature of the feedback, only a very high level summary is provided in this report.

The industry survey was limited to the list of scheduled and semi-scheduled stations.

3.2.3 Individual data items

The following definitions were included in the survey cover letter.

Minimum stable load

Minimum stable load (or MinGen) is a measure of the lower bound that the generator unit can be dispatched at any instant while maintaining a stable combustion process. Minimum stable loads vary across each generator as a function of technology, fuel type and location.

The usual way of expressing the station minimum stable load is in percentage form and when applied to the gross capacity.

Minimum On/Off Times

Minimum time, in hours, a given unit can be dispatched or turned-off within the simulation modelling.

Cold/Warm/Hot Start Notification and Minimum Sync Times

Notification time is a measure of time in hours required to mobilise the appropriate resources for a unit start up or first firing.

Minimum Sync time is the synchronisation time in hours required from first firing to synchronise the unit to the national electricity grid and being ready to accept load.

Auxiliary load

Auxiliary load is an electricity load used within a power station as part of the electricity generation process – that is, it is an electricity load used in the making of electricity (also called a parasitic load). The usual way of expressing the station auxiliaries is in percentage form and when applied to the gross capacity of the station provides a measure of the net capacity or sent-out capacity of the station.

Station auxiliaries also impact the sent-out or net thermal efficiency of the station, and therefore the station's SRMC.

Ramp Rates

Ramp rate refers to a change in generation output over a given unit of time, and describes the ability of a generating unit to change its output. Technically, ramp rates are usually expressed in MW per minute, but given the ramp rates are likely to be used in modelling the market at an hourly resolution, AEMO require them to be estimated in MW per hour. AEMO also require a ramp up and a ramp down rate.

Thermal efficiency

Thermal efficiency is presented on a HHV sent-out basis (in GJ/MWh).

Pumping efficiency

Pumping efficiency for the pumped storage hydro units is a measure of the energy required to pump a given volume of water from the lower reservoir to the upper reservoir compared with the energy generated when that same volume of water is released from the upper reservoir via the turbines to the lower reservoir.

Thermal de-rate factors for hot climate operations

Thermal de-rate factors are a measure of a station's maximum available capacity during periods of high ambient temperature relative to its maximum available capacity during normal ambient conditions.

AEMO has provided the following temperature cut-offs which are consistent with the generators' survey:

- Queensland - 37°C
- NSW - 42°C
- Victoria - 41°C
- South Australia - 43°C
- Tasmania – 1.2°C.

Note that Tasmania is more affected by winter temperature than summer and the de-rate factor is therefore related to temperatures at 1.2 °C

Planned and Maintenance Outage rate

The planned and maintenance outage rate defines the amount of time each generator unit is off-line for planned or maintenance outages in a given year. A planned outage (full or partial) is an outage that has been anticipated well in advance, even if the timing plan has changed.

Maintenance Outages are not forced or planned outages. A maintenance outage refers to an outage that has not been anticipated well in advance, but could have been deferred or the unit being maintained recalled had there been a commercial driver to do so[3].

In reality, the rate varies year by year, normally in the form of a planned maintenance cycle – consisting of major and minor maintenance periods. However, a single/static value is required by AEMO and therefore will be an average rate across the remaining life of each asset. The value is to be expressed in days per year.

Full & Partial forced outage rates (on a running hours basis)

Full and partial forced outage rates represent the percent of time within a year the plant is unavailable due to circumstances other than a planned and maintenance event. Forced outages are not planned or maintenance outages. In principle, "forced outages" represent the risk that a unit's capacity will be affected by limitations beyond a generator's control. An outage (including full outage, partial outage or a failed start) is considered "forced" if the outage cannot reasonably be delayed beyond 48 hours[4].

It will be important to properly account (or discount) unusual events such coal supply constraints when assessing the forced outage rates.

Fixed Operating Cost

Fixed O&M costs ($/MW/year) represent the costs of operation and maintenance that do not vary with output, such as wages and salaries, insurances, other overheads and periodic maintenance. For stations that are vertically integrated with their fuel supply, fixed O&M costs can also include fixed costs associated with the coal mine/gas field.

Variable Operating Cost

The additional operating and maintenance costs for an increment of electrical output depend on a number of factors, including the size of the increment in generation, the way in which wear and tear on the generation units is accrued between scheduled maintenance (hours running or a specific number of start-stop cycles) and whether operation is as a base load or peaking facility. Generally, variable O&M is a relatively small portion of the overall SRMC for fossil fuel fired power plants.

For coal, variable O&M includes additional consumables such as water, chemicals and energy used in auxiliaries including incremental running costs for coal and ash handling etc.

For gas, in addition to consumables and additional operating costs, an allowance is also included for major maintenance. The reason for including an allowance for major maintenance in the variable O&M for gas turbines is because this maintenance is not periodic, as it is for coal plant, but rather is generally determined by hours of operation and often in addition is related to the number of specific events such as starts, stops, trips etc.

The OCGT peaking plant will have higher variable O&M per MWh than a CCGT base or intermediate load plant for following reasons:

— The OCGT plants will have more number of start/stops and part load operation than CCGT plants and

[3] See AEMO's GUIDEBOOK FOR FORCED OUTAGE DATA RECORDING: DEFINITIONS AND ASSUMPTIONS http://www.aemo.com.au/Electricity/Policies-and-Procedures/Reserve-Management/Forced-Outage-Data-Working-Group

[4] Ibid

— The output from gas turbine is about two third of the CCGT plant output. The steam turbine maintenance costs are generally lower as compared to gas turbine maintenance costs.

The variable O&M value is usually expressed in sent-out terms to account for internal usage by the station (see below) rather than in 'as generated' terms.

No load fuel consumption

No load fuel consumption is the quantity of primary and secondary fuel being consumed when the unit is synchronised to the grid but not despatching any load to the grid other than generation of the house load or the plant auxiliary load to be expressed as GJ/hour for each type of fuel such as primary and secondary fuel either independently or together.

No Load Cost

For no load costs ($/MW), estimates will be developed based on technology, fuel and specific application. The No Load Cost is the cost of not running a station for an extended period of time (the operation at Gladstone which generally results in the operation of five out six units is a current example). This approach still requires maintenance but is much less costly than the fixed maintenance (FOM) needed for a unit which is running.

No Load Cost is not to be confused with No load fuel consumption which relates to shorter term fuel costs associated with the unit being synchronised to the grid but not despatching load.

Start-up costs

The start-up costs will include plant maintenance cost, the fuel cost and any other identifiable cost related to the plant start-up.

Retirement / Rehabilitation cost

This cost shall include the cost of end of life plant remediation and site rehabilitation. These costs are often plant and technology specific and are significantly influenced by local statutory rules and regulations and the provisions under the development approval.

Fuel costs

The study approach in providing updated fuel cost estimates is reported separately in Chapter 3.5.

3.3 Definitions and methodology - New entrant costs and parameters

3.3.1 Overview of methodology

Similar to the data items for the existing generators, this study proposed approach is a staged process which focuses on updates to the existing dataset rather than starting from scratch.

To review and develop current costs for respective generation technologies, a variety of cost estimating methodologies were employed including:

— Compilation of data available in the public domain,

— Benchmarking against recent project costs (where available)

- New coal fired power, CCGT/OCGT and biomass cost estimates based on Thermoflow software GTPro, GTMaster, SteamPro, SteamMaster and PEACE. This software models plant performance and provides Engineering, Procurement and Construction (EPC) and total project cost data.
  - Industry suppliers regularly update performance and costing information to Thermoflow
  - Cost factors are built into the software for modelling to Australian conditions such as foreign exchange, materials and labour cost
- Development of cost and performance adjustment factors for application to new plant sourced from Asian continent reflecting Australia's increasing comfort with equipment from these sources and its maturing delivery standards.
- Future trends – based on OEM information, industry analysis papers and GHD internal data
- Renewables – direct experience in projects, surveys of vendors' products, access to industry association papers and public domain material.

3.3.2 Scope of Estimate

All estimates are based on a complete power plant facility on a generic site.

An EPC contracting strategy has been assumed where the EPC scope is conducted by a main contractor with multiple subcontracts working under the main contractor. This standard contracting strategy provides a high degree of certainty of costs for the facility but traditionally attracts risk premiums built into the EPC price.

No site specific conditions have been considered in the estimates.

Labour costs are based on 2014/15 Australian Rates and productivities in a competitive bidding environment.

Direct Cost Estimates

Estimated direct costs for new generation facilities include costs for all major plant, materials, minor equipment and labour involved in the development of the power plant to commercial operation.

Indirect Cost Estimates

Estimated indirect costs for new generation include all owner's costs to cover expenses leading up to commencing construction and anything not covered under an EPC contract during construction. Specific development cost items which have been estimated or assumed are listed below:

- Concept/Feasibility Studies and Project Development
- Site acquisition
- Legal fees
- Project support team
- Development approvals
- Duties and taxes
- Operator training
- Commissioning and testing (including fuel).

Exclusions

The following items are excluded from the direct and indirect capital costs:

- Costs of electricity network augmentation required to connect the generator to the NEM
- Escalation throughout the period-of-performance
- All taxes
- Site specific considerations including but not limited to: seismic zone, accessibility, local regulatory requirements, excessive rock, piles, lay down space, etc.
- For CCS cases, the cost associated for CO2 injection wells, pipelines to deliver the CO2 from the power plant to the storage facility and all administration supervision and control costs for the facility
- Import tariffs that may be charged for importing equipment to Australia or shipping charges for this equipment, and
- Interest during construction and financing costs.

3.3.3 Forward Curve Assumptions

Forward cost curves are based on AEMO's Economic and Energy Market Forecasts 2014 report by Independent Economics.

Exchange Rate

The exchange rate assumptions from the scenario definitions will be adopted.

Productivity Rate

One of the key assumptions used in the development of economic scenarios in AEMO's Economic and Energy Market Forecasts 2014 report by Independent Economics is productivity growth.

The medium scenario's productivity growth rate of 1.5% matches average growth over the last 20 years.

Commodity Variation

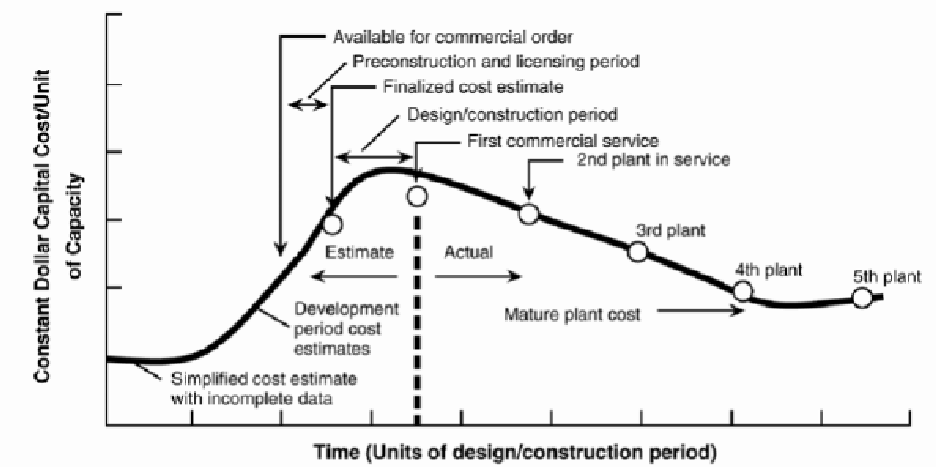
Another of the key assumptions used in the development of economic scenarios in AEMO's Economic and Energy Market Forecasts 2014 report by Independent Economics is commodity variation.

Technological Improvement

Pricing trends due to technological improvements over the next 30 years are likely to be one of the most significant factors for cost estimation.

Generally, assumptions have been made based on the expected trend for each technology following a typical Grubb curve shown in Figure 9. Each technology is assumed at a specific point of the curve according to the level of maturity for that technology.

Figure 9 **Typical Grubb Curve**



Source: GHD – taken from EPRI (2010)

3.3.4 Build limits

Build limits include:

- project lead time (by technology)
- maximum build achievable (by technology and zone)
- maximum build rate (by technology)

The analysis will build on the assumptions of the 2012 WorleyParsons report which defined the regional annual build limit as the physical ability to deliver a project as opposed to the ability to establish a commercial case to progress a project.

The principal influencing factors which impact the annual build capacity across all technologies (in addition to some individual technology specific factors) will include:

- The ability to source plant and equipment
- The ability to source sufficient general and specialised labour to construct the plant
- The ability to source necessary specialised equipment for construction of the plant
- The ability to source sufficient fuel feedstock to supply the planned plant
- The ability to source water
- The availability of sufficient electricity network infrastructure to export planned generation capacity
- Permitting constraints.

Individual issues which apply to specific technologies, e.g. availability of carbon storage reservoirs for CCS and acceptable penetration of variable (non-scheduled) generation into the network shall be considered.

Ability to Source Plant and Equipment

The majority of specialised components for all of the generation categories are manufactured internationally for Australian projects. This is expected to continue to be the case for the forecast period. The demand for equipment in Australia is unlikely to comprise a significant proportion of the manufacturing capacity, thus variation in Australian demand in isolation is unlikely to have a significant impact on the supply of plant and equipment.

Significant variation in international demand for specific technology may have an impact on the supply to Australia, however, such future constraints are difficult to forecast.

Therefore, it is assumed that constraints on the ability to source specialised plant and equipment are unlikely to contribute significantly to regional annual build limits.

Ability to Source Labour

Although the Australian market is currently experiencing a slowing level of economic activity in the resources sector, skilled labour constraints continue to be considered present in the Australian economy. This constraint is particularly accentuated in the mineral rich and more remote parts of the country. Such skilled labour shortages are often cyclic and dependent on the general growth patterns in the broader global economy.

The impact of a slowing global economy on the capital cost for delivery of projects has been considered; new projects are expected to maintain a higher cost to deliver, though not necessarily causing a constraint on the annual build limit.

Ability to Source Specialised Construction Equipment

The delivery of some large scale generation projects may require the use of specialised construction equipment.

It is not considered that constraints around sourcing specialised equipment will impact the regional annual build, but rather, as with the discussion on labour, may have an impact on the cost to deliver the projects.

Ability to Supply Fuel Feedstock

This analysis assumes the planned development of new generation capacity is based on the availability of sufficient and viable fuel supply. Constraints in infrastructure to supply the fuel to the generation plant may impact on the ability to deliver a project, however, solutions to fuel supply constraints are assumed to be incorporated into the development of a new generation project.

Ability to Source Water

Regional availability of water, both now and into the future, is likely to impact on the annual build limits for particular technology types. Where water is currently in short supply, or may become scarcer, it is likely that the application of wet cooled thermal generation technologies may be limited and air cooling would be preferable.

Availability of Electricity Network Infrastructure

One of the primary constraints on development of projects in a region is the availability of sufficient network capacity to effectively deliver the generation to the load taking into account the time required to plan, approve and build new powerlines. As with the impact of fuel supply, solutions to network constraints are assumed to be incorporated into the development of a new generation project, and thus not considered a separate factor limiting the regional annual build limit.

Permitting Constraints

Constraints on permitting for new build generation capacity can result from a number of factors including social acceptance of development, policy and legislative requirements and a capacity to process approvals. Such constraints can have a significant impact on the timeframe to deliver a project, and thus the annual build will be limited by the ability to clear necessary permitting steps in development.

Necessary permitting will also be influenced by government policy, both at a State and Federal level. While the ability to deliver projects and associated approval timeframes can be estimated under present policy settings, future changes to policy can have an impact on the delivery time and the annual build limits.

Technology Specific Constraints

In addition to the principal factors impacting the annual build limit as outlined above, there are a number of factors specific to technologies that will impact the ability to deliver projects in a specific region.

These will include:

- CCS: The availability to access appropriate storage structures at an economic cost.
- Wind: Ability to access land with an appropriate wind resource in a specific region. This can be influenced by both the topography and the division of land and population density.
- Wind/Solar: penetration of non-scheduled and semi-scheduled generation into the network. There are a number of studies suggesting that at penetration levels above 25 to 30%, the cost to integrate additional non-scheduled variable generation into the network, can increase. The extent to which this will be a regional constraint will depend on the future connection infrastructure and systems operational regimes.

3.4 Emission factors

This section outlines the approach in estimating the emission factors for each scheduled, semi-scheduled and non-scheduled generator in the NEM.

3.4.1 Measurement of emissions

Greenhouse gas emissions are measured in carbon dioxide equivalence (CO_2-e). These are comprised of the following emissions to the atmosphere:

- carbon dioxide (CO_2)
- methane (CH_4)
- nitrous oxide (N_2O), or
- perfluorocarbons specified in the NGER Regulations and that are attributable to aluminium production.

The equivalence measure allows the global warming potential of each greenhouse gas to be standardised relative to carbon dioxide.

3.4.2 Emission factors and intensities

In the context of an electricity generator an ***Emission factor*** relates the amount of greenhouse gas emitted per unit of fuel consumed (expressed in units of CO_2-e per unit of fuel consumed).

When combined with the power stations' thermal efficiency, one can calculate the ***Emissions intensity*** of the station, expressed in unit of CO_2-e per unit of electricity produced (either sent-out or as generated).

For the purpose of this work, we have been tasked with providing estimates of stations emission factors and thermal efficiencies separately. This allows AEMO to calculate emission intensity values for each power station.

Note that these definitions align with the NGA Factors workbook which provides estimates of Emission factors for various fuel types in kg CO_2-e/GJ.

In contrast, AEMO in its procedure for calculation of the Carbon Dioxide Equivalent Intensity Index[5] refer to Emission factors as being both defined on a per GJ and on a per MWh basis.

3.4.3 Emissions scope

In the language of carbon accounting, for example as set out in the Australian Government's National Greenhouse Accounts (NGA) Factors publications, there are a number of different emission 'scopes'. These are defined in Box 1.

Box 1 **Types of emission factors**

Firstly, it is important to note that an emission factor is activity-specific. The activity determines the emission factor used. The scope that emissions are reported under is determined by whether the activity is within the organisation's boundary (direct—scope 1) or outside it (indirect—scope 2 and scope 3).

Direct (or point-source) emission factors give the kilograms of carbon dioxide equivalent (CO_2-e) emitted per unit of activity at the point of emission release (i.e. fuel use, energy use, manufacturing process activity, mining activity, on-site waste disposal, etc.). These factors are used to calculate scope 1 emissions.

Indirect emission factors are used to calculate scope 2 emissions from the generation of the electricity purchased and consumed by an organisation as kilograms of CO_2-e per unit of electricity consumed. Scope 2 emissions are physically produced by the burning of fuels (coal, natural gas, etc.) at the power station.

Various emission factors can be used to calculate scope 3 emissions. For ease of use, this workbook reports specific 'scope 3' emission factors for organisations that:

a) burn fossil fuels: to estimate their indirect emissions attributable to the extraction, production and transport of those fuels; or
b) consume purchased electricity: to estimate their indirect emissions from the extraction, production and transport of fuel burned at generation and the indirect emissions attributable to the electricity lost in delivery in the transmission and distribution network.

Source: Department of Industry, Innovation, Climate Change, Science, Research and Tertiary Education, Australian National Greenhouse Accounts: National Greenhouse Accounts Factors, July 2013, p7

In simple terms for electricity generators:

- Scope 1 emissions relate to emissions associated with combustion of fuels on-site or other emissions associated with the power station facility
- Scope 2 emissions relate to indirect emissions from any electricity purchased from the grid
- Scope 3 relate to indirect emissions associated with the extraction, production and transport of fuel to the power station.

It should be recognised that this definition does cause an issue for renewable generators which do not consume fossil fuel in generating electricity, despite some of these entities

[5] AEMO, Carbon Dioxide Equivalent Intensity Index Procedure, August 2013

reporting scope 1 emissions under the NGER scheme. For renewable plant an Emission factor of zero will be set, despite them possibly having a non-zero Emission intensity value.[6]

3.4.4 AEMO carbon dioxide intensity index

The following is an extract from AEMO's procedure for calculating the Carbon Dioxide Equivalent Intensity Index (CDEII).

The calculation requires 2 discrete sets of data:

1. The total Sent Out Energy (MWh) generated from each generator; and
2. The carbon dioxide equivalent emissions per unit of electricity (t CO2-e /MWh) generated by each generator (generator specific Emission Factor).

The following formula is used to convert the Emissions Factor for an individual generator from t CO2-e/GJ to t CO2-e /MWh:

$$EF_i = \left(\frac{3.6}{TE_i}\right) \times \frac{ef_i}{(1 - A_i)}$$

Where:

EF = Emission Factor for individual generator (t CO2-e /MWh)

i = Generator with available energy data & Emission Factor

TE = Thermal Efficiency (MWh(Gen)/MWh(Fuel))

ef = Emission Factor for individual generator (t CO2-e /GJ)

A = Auxiliaries (% value)

3.6 = Conversion factor (1 MWh = 3.6 GJ).

The following formula is used to calculate the carbon dioxide equivalent emissions (CDE) for an individual generator:

$$CDE_i = EF_i \times E_i$$

Where:

CDE = Carbon Dioxide Equivalent emissions (t CO2-e) from a generating unit

EF = Emission Factor for individual generator (t CO2-e /MWh)

E = Sent Out Energy (MWh) generated from a generating unit

i = Generator with available energy data & Emission Factor.

The Carbon Dioxide Equivalent Intensity Index (CDEII) for the NEM is then calculated by:

$$CDEII = \frac{\sum_i CDE_i}{\sum_i E_i}$$

Where:

CDEII = Carbon Dioxide Equivalent Intensity Index for the NEM (t CO2-e /MWh).

3.4.5 NGER reporting

In 2007 Australia introduced a single, national framework for corporations to report on greenhouse gas emissions, energy use and energy production. That framework, known as the National Greenhouse and Energy Reporting (NGER) Scheme, operates under the National Greenhouse and Energy Reporting Act 2007. The Clean Energy Regulator administers the NGER Scheme and the Department of the Environment is responsible for NGER-related policy development and review.

[6] In most cases, the actual Emission intensity values for renewable generators are very close to zero in any case.

Under the NGER Scheme, companies which meet the threshold criteria[7] are required to report annually 'Scope 1' emissions, 'Scope 2' emissions, energy production and energy consumption.

The *National Greenhouse and Energy Reporting Regulations 2008* define 'Scope 1' and 'Scope 2' emissions as follows:

> 'Scope 1' emission of greenhouse gas, in relation to a facility, means the release of greenhouse gas into the atmosphere as a direct result of an activity or series of activities (including ancillary activities) that constitute the facility.
>
> 'Scope 2' emission of greenhouse gas, in relation to a facility, means the release of greenhouse gas into the atmosphere as a direct result of one or more activities that generate electricity, heating, cooling or steam that is consumed by the facility but that do not form part of the facility.

For electricity generators, 'Scope 1' emissions generally relate to greenhouse gas emissions associated with combustion of fuel in the electricity generation process. 'Scope 2' emissions would also accrue due to any purchased electricity sourced from the grid or from heat/steam acquired from an external source which is then used to generate electricity by the facility.

It is important to note that under the *Clean Energy Act 2011*, liability for covered emissions only include 'Scope 1' emissions under the carbon pricing mechanism. Entities are not liable for 'Scope 2' emissions.

For the reporting year 2012-13, the Clean Energy Regulator has for the first time made public reported energy production and scope 1 & 2 emission values at facility level.[8] Information reported by designated generation facilities is published for facilities where the principal activity is electricity generation and where the facility is not part of a vertically-integrated production process. Facilities generating electricity for their own use or as a secondary activity do not have their emissions and electricity production data published.

3.4.6 Approach in estimating emission factors

The proposed approach in estimating emission factors for this exercise is as follows:

1. Review CER data for NEM market generators (scheduled, semi-scheduled and non-scheduled generators)
2. Verify the basis of the Electricity Production (GJ) value in the CER data (i.e. whether it's sent-out or as generated). This should be obtainable from the NGERs Act and/or reporting guidelines for companies published by the CER
3. From this data, calculate Emission intensity values for each generator based on Scope 1 emissions only on a tonnes CO_2-e/MWh sent-out basis
4. Calculate Emission intensity values from existing AEMO NTNDP input assumptions (using the emission factors termed 'Combustion' only as the CER values do not contain Scope 3 components)
5. Calculate Emission intensity values from current ACIL Allen internal database values
6. Undertake a comparison of the actual CER values obtained against existing NTNDP and ACIL Allen estimates and between like for like plant.
7. Consider the plants running regime and other operational parameters (such as coal quality) through 2012-13 a decide whether this represents its typical running state

[7] The threshold criteria at facility level are currently set at 25 kt CO_2-e or more of greenhouse gases; production of 100 TJ or more of energy, or consumption of 100 TJ or more of energy. Corporate facility thresholds also apply for aggregate volumes of 50 kt CO_2-e or more of greenhouse gases; production of 200 TJ or more of energy or consumption of 200 TJ or more of energy.

[8] See http://www.cleanenergyregulator.gov.au/National-Greenhouse-and-Energy-Reporting/published-information/greenhouse-and-energy-information/Greenhouse-and-Energy-information-2012-2013/Pages/default.aspx

8. Settle on any appropriate adjustments to existing values and clearly state the rationale for the proposed change.

This will result in a recommended Emissions intensity value (Scope 1 only) for each generator (in tonnes CO_2-e/MWh either sent-out or as-generated depending upon result of Step 2 above).

To this an estimate of the Scope 3 emission intensity values (to be estimated separately based on non-CER data) may be added to yield a Scope 1 & 3 Emission intensity value which corresponds with the current values used in the CDEII. Scope 3 values will principally be sourced from the NGA factors workbook (July 2013)[9].

This approach essentially involves estimating the final Emission intensity figure, rather than its component parts which make up the calculation. This allows to modify thermal efficiencies, emission factors (and auxiliary use factors if relevant) at a later stage in the project, with the overall constraint being that the Emission intensity value matches those set in this early stage.

It is noted that AEMO's emission factors as used in the CDEII use the sum of 'Combustion' emission factors and 'Fugitive' emission factors in the calculation of the index. It is proposed to amend the terms used as follows:

- Replace 'Combustion' emission factor with 'Scope 1' emission factor. This is a more correct term as liability for emissions from a facility can relate to more than combustion of fossil fuels in the generation process (e.g. wind farms report a small amount of scope 1 emissions presumably due to vehicle use or other ancillary operations associated with the farm)
- Replace 'Fugitive' emission factor with 'Scope 3' emission factor. This is also a more correct term as Fugitive emissions solely relate to unintended leakages. The term 'Scope 3' emissions on the other hand, include all emissions associated with the extraction, production and transport of fuels to the power station which is the intended purpose of the measure.

Whilst inclusion of the Scope 3 emission factors is useful when conducting market modelling (it saves amending fuel price series each time the carbon price changes), in ACIL Allen's opinion, it is not a useful measure for estimating emissions from the electricity sector. Scope 3 emissions occur elsewhere throughout Australia and potentially even overseas when imported fuels are used (e.g. diesel). It also overstates the direct carbon emission liability for generators as they are only liable to pay for Scope 1 emissions. However considerations of modification to the CDEII are outside our scope of work and are mentioned here only for discussion purposes.

3.5 Fuel costs

ACIL Allen maintains a database of existing fuel supply contracts (in terms of volumes, terms and prices) based on publicly available information. This database has been used as a starting point for estimating fuel costs.

Projections of fuel costs beyond existing contracts is developed by using in house gas and coal models, taking into account the different scenario definitions.

[9] Department of Industry, Innovation, Climate Change, Science, Research and Tertiary Education, Australian National Greenhouse Accounts: National Greenhouse Accounts Factors, July 2013

A number of parameters are required to ensure proper description of each scenario in these models, and AEMO is provided with these key assumptions to ensure these are internally consistent with each scenario definition.

The marginal fuel cost to a station is dependent on a number of factors including:

- Contractual arrangements including pricing, indexation, tenure and take or pay provisions
- Mine/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.

Each of these factors is taken into account in evaluating the fuel cost component. The factors are discussed below.

3.5.1 Contractual prices versus opportunity cost

Where the power station is dependent on a third party to supply fuel under contract then the cost of incremental fuel within the AEMO dataset has historically been the average contract price on a delivered basis.

In some cases this is still the relevant value; however the divergence between legacy contract prices and current market prices has grown significantly for both coal and gas. In some cases generators no longer consider prices under existing contracts to be their marginal cost of fuel, but rather look to the opportunity cost of the commodity. This is illustrated by the recent decision by Stanwell to sell contracted gas to other users rather than utilise it at Swanbank E. If the gas or coal has a higher value elsewhere and on-sale is feasible then this should represent the marginal fuel cost.

ACIL Allen will examine the fuel supply situation for each station individually and make a judgement about whether legacy contract prices or opportunity value is the more appropriate value. The may vary across the scenario definitions if the spread in commodity prices is large.

3.5.2 Vertically integrated fuel supply

Stations which are fully vertically integrated with their fuel supply have lower fuel costs as a small increment in fuel use is unlikely to require additional capital and maintenance and hence this incremental fuel does not include these costs. Most brown coal stations in Victoria fall into this category (incremental fuel costs are reduced to marginal diesel and electricity costs from mining another tonne of coal).

For station owners who also own the associated coal mine and deposit but use contract miners, the marginal fuel cost will be dependent on the contractual arrangements with the contract miner and may not reflect the marginal cost if mining activities were carried out in-house. For stations such as these, the estimated mining contractor costs are used as the marginal cost of fuel.

Importantly, most vertically integrated fuel/power station developments do not have ready access to export markets/alternative buyers and therefore the true economic opportunity cost of fuel generally is the incremental cost of production. For those that could conceivably access alternative markets, an opportunity cost value will be considered.

3.5.3 Projecting prices for new long-term contracts

The following section outlines the proposed approach in projecting fuel prices for new long-term contracts. Coal, natural gas and liquid fuels are discussed separately.

Black coal – NSW and Queensland

New long-term coal prices for particular deposits depend upon the cost of mining and preparation (if required), whether the coal is of suitable quality and can access export markets. Other factors include ownership/vertical integration (for mine mouth developments) and transportation costs.

Analysis of coal prices relies principally upon estimates of costs of production and transport (if relevant) to the station in question. This analysis is undertaken on a deposit-by-deposit basis and takes into consideration the coal resources available.

Where coal is exportable, the netback price available for the coal producer becomes a factor in considering prices potentially available for power generation. However, given the stability offered from domestic contracts, which offer long-terms at fixed prices, we assume that domestic coal receive a 20% discount over the export parity value of the Run-of-Mine (ROM) coal. ACIL Allen will incorporate the projected thermal coal export price from the economic modelling of the three scenarios.

Hence the projected coal prices for new contracts for each NEM zone will be one of three values:

- 80% of the export parity value of the ROM coal where it is greater than the ROM coal mining cost. This generally applies to deposits which are higher quality coal and/or are generally closer to the export terminals.
- ROM coal mining costs where 80% of the export parity value of the ROM coal is less than the mining costs and the coal is delivered to a mine-mouth power station. This usually applies to deposits which are relatively inferior in quality and/or some distance from export terminals while being relatively close to major transmission links (Felton, New Acland, Ulan etc).
- ROM coal mining costs plus transport costs to a power station site remote from the mine but closer to transmission infrastructure and where 80% export parity value of the ROM coal is again less than the mining costs but where the deposit is greater than 100 km from the transmission system (Wandoan, Alpha, Pentland).

The delivered prices can switch from one basis to another as export prices and ROM coal mining costs are projected to vary. This is particularly the case where export prices are projected to fall in real terms while mining costs are projected to remain constant in real terms.

Victorian brown coal

Extensive deposits of brown coal occur in the tertiary sedimentary basins of Latrobe Valley coalfield which contains some of the thickest brown coal seams in the world. The coal is up to 330 m thick and is made up of 4 main seams, separated by thin sand and clay beds. The total brown coal resource in the Latrobe Valley is estimated to be 394,000 million tonnes, with an estimated useable brown coal reserve of 50,000 million tonnes.

Anglesea's brown coal reserves are estimated at around 120 million tonnes. Average coal thickness is 27 metres. The coal is a high quality brown coal, with a heat value of just over 15 MJ/kg.

Mine mouth dedicated coalmines supply all the power stations. The coalmines are owned by the same entities that own the power stations with two exceptions. The exceptions are the Loy Yang B power station, where the mine, which is in close proximity to the power station, is owned and operated by Loy Yang Power, the owners and operators of the Loy Yang A power station and Energy Brix which is supplied by Morwell mine.

The marginal price of coal for the Victorian power stations is generally taken as the cash costs for mining the coal.

South Australia black coal

The only currently producing coalfield in South Australia is near Leigh Creek based on low-grade sub-bituminous black coal. The mining operation involves drilling, blasting and removal of overburden and coal by shovels and trucks. After mining, the crushed coal is railed to the Port Augusta power stations. Due to the steeply dipping seams, it is likely that economic recovery of coal will be limited to between 70 and 100 Mt at depths of 150–200 m.

The Leigh Creek mine is about 250kms from the Northern power station. A long-term freight contract is in place with Pacific National. The marginal cost of coal in South Australia is taken as the cash costs for mining the coal. and transport. The life of the Leigh Creek mine is constantly under review and its future will depend on the cost of mining and transport.

Natural gas

Long-term price projections for natural gas will be provided as output from our proprietary gas market model – *GasMark Global Australia (GMG Australia)*. *GMG Australia* incorporates a complete input database containing data and assumptions for every gas producing field, transmission pipeline and major load/demand centre in Australia. It is used by ACIL Allen internally, and is also licensed to a number of external gas market participants.

GMG Australia provides price projections for each defined node on the Eastern Australian gas grid, which are mapped to each of the 16 NEM zones.

The availability of gas to support generation in each NEM zone 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.[10]

ACIL Allen will align key assumptions from each economic scenario (including the number of East coast LNG trains developed) in the gas market modelling to ensure consistency with the AEMO scenarios.

Other fuels

The price for liquid fuels will be based on the global oil/liquid fuel product price, converted to Australian dollars per GJ. As transportation costs for liquid fuels are a relatively small proportion of the total cost, these will be ignored and a single price for liquid fuel will be provided for all NEM zones.

[10] The planning and development of additional pipeline capacity is generally shorter than the station itself and therefore does not impact upon the lead-time for gas plant development.

4 Results – Existing generators

ACIL Allen and GHD undertook an assessment of the 2012 NTNDP data set by drawing upon industry experience as well as utilising AEMO operational data. This assessment resulted in a number of minor suggested amendments to the data set. These amendments were then tested with industry via the industry survey which was sent to 29 participants. Nineteen of the participants acknowledged receipt of the survey, and 13 sets of responses/feedback were received – representing over 50 percent of the capacity of the current generation fleet in the NEM.

The majority of the responses indicated that the proposed data set was reasonable for its purpose. Of those that suggested further changes, the key areas across all technologies were:

- Ramp rates
- Start-up notification times
- Minimum generation loads.

Not surprisingly, given the expansion of the wind farm fleet since the previous NTNDP data set, wind farm proponents provided feedback which suggested changes to:

- Auxiliary load
- Maintenance days
- Variable O&M costs.

Probably the most contentious data item was the forced outage for peaking plant, with most respondents suggesting a forced outage rate of less than five percent compared with the previous estimate of about 25 percent. However, there may have been some misinterpretation with regard to the rate being expressed as a percent of hours run, as opposed to a percent of hours in a given year. ACIL Allen followed up this matter with some respondents and there was reasonable sentiment that 25 percent was too high. Although it may be the case that some of the older peaking plant experience higher outage rates it seems unreasonable to assume all plant have this degree of outage rate. Given the modelling simulations are to be undertaken at an hourly resolution, rather than at five minutes, the conclusion was reached that an outage rate of about five percent would be more appropriate. Further, this assumption aligns better with the assumption adopted for new entrant peaking plant.

5 Results - New entrants

5.1 Introduction

GHD was engaged as a sub-consultant to assist in undertaking a review of AEMO's planning input assumptions which characterise the behaviours of existing generation assets and the economics/location of future investment or retirement decisions.

Specifically GHD has undertaken a review of the engineering elements, in particular the generator technical parameters and capital cost estimates for new entrant generation and forecasted technology improvements. This data was subject to a review in late 2013 by WorleyParsons, a full study into all of the data was not undertaken but it was reviewed for its suitability and currency.

Where the data was found not to be aligned with recent industry data in the public domain or sourced from internal databases, the data has been amended in line with referenced sources or appropriate justification.

When undertaking the review of the different technologies, GHD assumed a generic set of conditions to establish base case cost and performance estimates. These cost and performance estimates may vary significantly depending on the size and location of the proposed installation for a particular technology and fuel.

Using the three planning scenarios developed by AEMO the amended dataset has been projected for both the High Scenario and the Low Scenario. The Medium Scenario parameters and definitions were used in the review of the original dataset and form the assumed base case.

This report should be read in conjunction to the previously submitted Fuel and Technology Cost Review – Methodology Report with respect to the provided data and definition of all terminology.

5.2 Supercritical Pulverised Coal (PC) Technology

Currently close to 40% of world's electricity is produced from coal and this figure is likely to remain the same or reduce marginally in the future. However the actual consumption of coal for electricity production is forecast to increase significantly due to the development in China and India. The abundance of coal and its price maintains coal as the most competitive fuel for base load power generation. The introduction of emission restrictions and penalties promote the use of carbon capture and storage technologies (CCS) and may make coal fired generation relatively more expensive. However a limited availability of alternative fuels and growing global demand will keep coal as a competitive fuel for future power generation.

Over the years, significant effort has been expended in improving the thermal efficiency of coal fired power stations, including; regenerative feed heating system, steam reheat system, increasing main steam pressure and temperatures etc. However, the introduction of supercritical technology remains the most significant step change so far.

Supercritical technology has been in use since the 1950s but initial difficulties hindered further development of this technology. In the 1980s, manufactures in Japan and Europe took a great initiative to bring this technology to an acceptable level and its application is now well established. A thermodynamic cycle is considered supercritical when the boiler temperature and pressure exceed 374°C and 22.12 MPa respectively. At this point, no additional energy is required for the liquid-vapour transformation and the water is at its critical point. Operating at the higher temperature and pressure results in a significant cycle efficiency gain.

Several supercritical circulating fluidised bed combustion (CFBC) coal units have been installed internationally in the 400-450 MW size range. CFBC boilers are suitable where low-grade coals are available and also provide flexibility for multi-fuel burning capabilities including the co-firing of biomass.

Supercritical technology is considered to have achieved maturity; however there is a constant effort to further improve efficiency. The following are current technology improvement focus areas for the industry:

- Further increase of steam pressure and temperature (advanced supercritical, ultra supercritical)
- Development of appropriate materials to cope with increased steam temperature
- Retrofit options for existing sub-critical plants with supercritical technology
- Incorporation of CCS technologies for existing and future plants.

Coal-fired power continues to be the base load generation technology within the National Electricity Market (NEM). New entrant coal-fired generation into the NEM is likely to be supercritical and utilise carbon capture and storage (CCS) as the technology matures, is widely demonstrated at utility scale, and proven to be economical.

Four coal based technology options were reviewed against AEMO's current new entrant planning data:

1. Supercritical pulverised black coal with carbon capture and storage
2. Supercritical pulverised black coal without carbon capture and storage
3. Supercritical pulverised brown coal with carbon capture and storage
4. Supercritical pulverised brown coal without carbon capture and storage

Pulverised coal-fired power plants were based on a conventional boiler with single reheat supercritical steam turbine generator, wet natural draft cooling tower and air quality control equipment (particulate control). Cases were modelled with and without CCS technology installed. The steam generator was assumed to include low NOx burners and the plant to have a total generated (gross) capacity of 750 MW.

Post combustion carbon capture technology commonly comprises a process which involves absorption of CO2 in chemical solvents such as amines. Traditionally carbon capture utilising solvents yields a CO2 capture efficiency of 90%. Use of CCS technology causes a significant increase to the total parasitic load of any plant, reducing electrical efficiency.

Thermoflow software version 23 was used to model and derive the performance parameters of the pulverised coal and CCS technologies, including capital costs. Thermoflow utilises several cost factors which may be adjusted from defaults for a more accurate representation of costs in different countries or regions. These cost factors are provided in Table 7.

Table 7 **Thermoflow Cost Factors (Coal)**

Cost Factor	Thermoflow Default (Australia)	Adjusted Factor	Comment
Specialised equipment	1.3	1.0	Adjusted for Asian sourced equipment
Other equipment	1.3	1.3	No change
Commodities	1.3	1.3	No change
Labour	2.025	3.0	Adjusted for high domestic labour rates

Source: GHD

The cost factor for Specialised Equipment (boilers, steam turbines, feedwater heaters etc.) and Labour were altered from Thermoflow's default settings, to reflect the softening attitude of the Australian market to source power generation equipment from Asian countries such as China and India and to reflect Australia's high labour rates.

Supercritical pulverised coal technology is considered to be mature and therefore not expected to experience dramatic cost or efficiency improvements in the future. CCS technology however is likely to experience both cost and efficiency improvements (via a reduction of auxiliary loads) as number of installed units grows around the world.

Table 8 **Black Coal with Carbon Capture and Storage**

Technology Description	Pulverised Coal Supercritical with CCS
Fuel Type	Bituminous Coal
Capital Costs, A$/kW sent-out	$5,388
Local Equipment/Construction Costs (includes commodities)	36%
International Equipment Costs	35%
Labour Costs	29%
Construction Profile % of Capital Cost	Year 1 – 35% Year 2 – 35% Year 3 – 20% Year 4 – 10%
First Year Assumed Commercially Viable	2024
Typical new entrant size (Generated MW)	750 MW
Economic Life (years)	50
Lead time for development (years)	8
Minimum stable generation level (% capacity)	40%
Thermal Efficiency (sent out – HHV)	31.24%
Auxiliary Load (%)	18.5%
FOM ($/MW/year) for 2014	$73,200
VOM ($/MWh sent out) 2014	$9.0
Percentage of emissions captured (%)	90%
Emissions rate per kgCO_2e/MWhr (generated)	85 kgCO_2e/MWh

Source: GHD

Table 9 Black Coal without Carbon Capture and Storage

Technology Description	Pulverised Coal Supercritical without CCS
Fuel Type	Bituminous Coal
Capital Costs, A$/kW sent-out	$2,880
Local Equipment/Construction Costs (includes commodities)	31%
International Equipment Costs	39%
Labour Costs	30%
Construction Profile % of Capital Cost	Year 1 – 35% Year 2 – 35% Year 3 – 20% Year 4 – 10%
First Year Assumed Commercially Viable	2014
Typical new entrant size (Generated MW)	750 MW
Economic Life (years)	50
Lead time for development (years)	6
Minimum stable generation level (% capacity)	40%
Thermal Efficiency (sent out – HHV)	41.5%
Auxiliary Load (%)	7.1%
FOM ($/MW/year) for 2014	$50,500
VOM ($/MWh sent out) 2014	$4.00
Percentage of emissions captured (%)	0%
Emissions rate per kgCO_2e/MWhr (generated)	743 kgCO_2e/MWh

Source: GHD

Table 10 Brown Coal with Carbon Capture and Storage

Technology Description	Pulverised Coal Supercritical with CCS
Fuel Type	Brown Coal – Latrobe Valley
Capital Costs, A$/kW sent-out	$8,277
Local Equipment/Construction Costs (includes commodities)	36%
International Equipment Costs	35%
Labour Costs	29%
Construction Profile % of Capital Cost	Year 1 – 35% Year 2 – 35% Year 3 – 20% Year 4 – 10%
First Year Assumed Commercially Viable	2024
Typical new entrant size (Generated MW)	750
Economic Life	50
Lead time for development (years)	8
Minimum stable generation level (% capacity)	40%
Thermal Efficiency (sent out – HHV)	20.8%
Auxiliary Load (%)	24.3%
FOM ($/MW/year) for 2014	$96,500
VOM ($/MWh sent out) 2014	$11.0
Percentage of emissions captured (%)	90%
Emissions rate per kgCO_2e/MWh	87 kgCO_2e/MWh

Source: GHD

Table 11 **Brown Coal without Carbon Capture and Storage**

Technology Description	Pulverised Coal Supercritical without CCS
Fuel Type	Brown Coal – Latrobe Valley
Capital Costs, A$/kW sent-out	$4,386
Local Equipment/Construction Costs (includes commodities)	33%
International Equipment Costs	38%
Labour Costs	29%
Construction Profile % of Capital Cost	Year 1 – 35% Year 2 – 35% Year 3 – 20% Year 4 – 10%
First Year Assumed Commercially Viable	2014
Typical new entrant size (Generated MW)	750
Economic Life	50
Lead time for development (years)	6
Minimum stable generation level (% capacity)	40%
Thermal Efficiency (sent out – HHV)	28.9%
Auxiliary Load (%)	9.6%
FOM ($/MW/year) for 2014	$65,500
VOM ($/MWh sent out) 2014	$5.0
Percentage of emissions captured (%)	90%
Emissions rate per kgCO_2e/MWh	1126 kgCO_2e/MWh

Source: GHD

5.3 Biomass Technology

Power generation from biomass most commonly involves direct firing in a boiler. Sugar cane waste sourced from sugar mills is a common fuel source in Australia however the outlook for new entrant generation firing sugar cane biomass is limited. Waste products from agricultural processing facilities such as nut processing and also green waste are possible.

Biomass supply is seasonal, generally only having the required fuel resource during harvesting. Typically a biomass power generation facility will source alternative biomass fuels in non-milling season or accumulate and store bagasse during milling season to slack season.

The size of the plant is directly related to the available biomass resource, typical installations in Australia range between 5 – 30 MW. A typical new entrant size of 18 MW, comprised of a high pressure boiler and condensing steam turbine generator operating year-round, has been modelled for cost and performance estimation.

A capital cost of $5,200/kW has been estimated utilising Thermoflow 23.0 software, as well as recent reference projects. This value is consistent with the values used in the AETA 2013 update for biomass technologies ($4000/kW for a 32 MW sugar cane waste power plant and $5000/kW for a 18 MW other biomass plant).

The process of direct firing biomass is considered to be a mature technology and therefore is not expected to experience any dramatic cost or efficiency improvements in the future.

Table 12 **Biomass Technology**

Technology Description	Biomass
Fuel Type	Bagasse (agriculture by-product)
Capital Costs, A$/kW sent-out	$5,200
Local Equipment/Construction Costs (includes commodities)	55%
International Equipment Costs	27%
Labour Costs	18%
Construction Profile % of Capital Cost	Year 1 – 50% Year 2 – 50%
First Year Assumed Commercially Viable	2014
Typical new entrant size (Generated MW)	18 MW
Economic Life	30 years
Lead time for development (years)	4 years
Minimum stable generation level (% capacity)	40%
Thermal Efficiency (sent out – HHV)	29.5%
Auxiliary Load (%)	8%
FOM ($/MW/year) for 2014	$125,000
VOM ($/MWh sent out) 2014	$8.0
Percentage of emissions captured (%)	0%
Emissions rate per $kgCO_2e$/MWh	1114 $kgCO_2e$/MWh

Source: GHD

5.4 Gas Turbine Technology

Gas turbines are commonly used in power generation application as peaking stations due to their quick start up capability. However with significant efficiency increases owing to advances in technology and the emergence of combined cycle technology, gas turbine power stations have become popular for provision of base load generation. Gas turbines were initially produced as jet engines for aircraft. Once their potential for power generation purposes was realised, the design evolved into large land-based units referred to as heavy-duty industrial units. Gas turbines designed for aircraft may also be packaged for power generation purposes and are referred to as aero-derivative units.

Gas turbines can be run in several configurations including simple cycle (OCGT), combined cycle (CCGT), cogeneration and combined heat and power (CHP).

Combined cycle gas turbine (CCGT) utilises a combination of the gas turbine, a heat recovery steam generator (HRSG) and a steam turbine-generator system to produce power. Utilisation of the heat from the exhaust gasses to produce steam and drive a steam turbine greatly increases the efficiency of the system. CCS systems can also be installed and can achieve a CO_2 capture efficiency of greater than 90%.

Various classes of industrial gas turbine are currently available for the supply of utility scale power generation including the classic E class and more recent F, G and H classes.

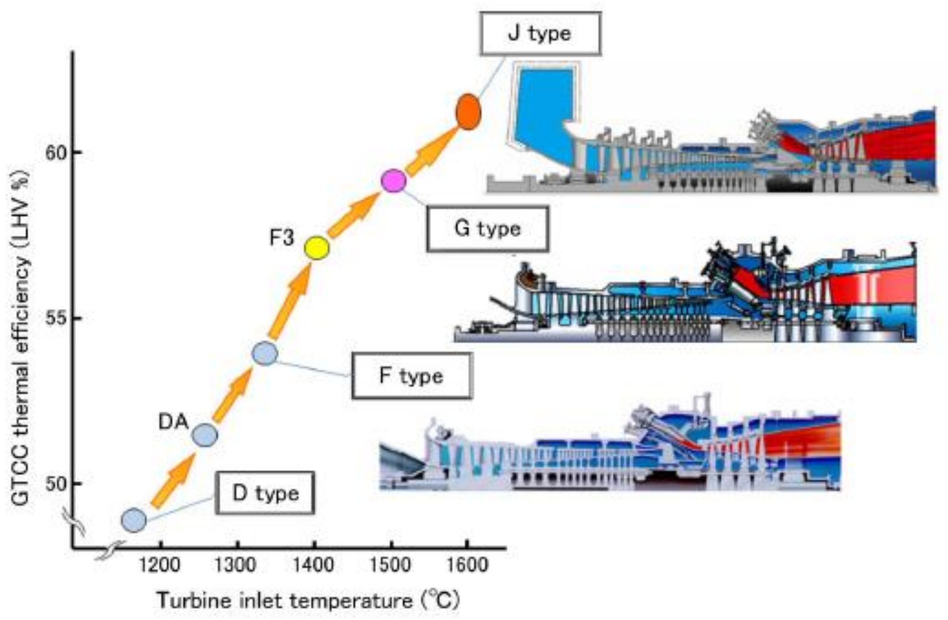
E class gas turbines were the dominantly used gas turbine for power generation in the 1980s and still hold a large share of the industry today. E class turbines can be run in both simple and combined cycle.

F class turbines emerged in the 1990s and are still the most popular gas turbine for power generation application

G and H class turbines are the most recent generation of gas turbines and provide the highest power capacity and efficiency (due to high turbine inlet temperature ceilings). These power and efficiency increases are due to the introduction of improved aerodynamic design, heat transfer design and new materials. G and H class turbines create inseparable thermodynamic and physical link between a CCGT's primary (GT) and secondary (ST) power generation systems. H class turbines are designed to achieve gross LHV efficiencies greater than 60% in combined cycle mode.

Looking forward, gas turbine manufacturers (OEMs) such as Mitsubishi Heavy Industries (MHI), Siemens and GE continue to develop larger and more efficient gas turbines such as J class. MHI's J class turbine, which is approaching commercial operation, has achieved a turbine inlet temperature of 1600°C and CCGT thermal efficiency of 61.5%. A graphical illustration of the development of MHI's gas turbine classes is shown in Figure 10.

Figure 10 **Development of gas turbine models**



Note: Development of 1600°C C-Class High-efficiency Gas Turbine for Power Generation Applying J-Type Technology, 2013, Mitsubishi Heavy Industries Technical Review Vol. 50 No. 3, Available: www.mhi.co.jp/technology/review/pdf/e503/e503001.pdf

Source: GHD

While G and H class turbines have been commercially available for a number of years, they are yet to fully break into markets as commonly installed units. For this study, single Siemens SGT5 4000F, F class units were modelled for each configuration with a three pressure reheat HRSG.

Three gas turbine based technology options were reviewed against AEMO's current new entrant planning data as follows:

1. Combined cycle gas turbine (CCGT) with CCS
2. Combined cycle gas turbine (CCGT) without CCS
3. Open cycle gas turbine (OCGT) without CCS

Thermoflow software version 23 was used to model and derive the performance parameters of the gas turbine installations and CCS technologies, including capital costs. Thermoflow utilises several cost factors which may be adjusted from defaults for a more accurate representation of costs. These cost factors are provided in Table 13.

Table 13 **Thermoflow Cost Factors (Gas Turbine)**

Cost Factor	Thermoflow Default (Australia)	Adjusted Factor	Comment
Specialised equipment	1.3	1.3	No change
Other equipment	1.3	1.3	No change
Commodities	1.3	1.3	No change
Labour	2.025	3.0	Adjusted for high domestic labour rates

Source: GHD

The cost factors for Specialised Equipment, Other Equipment, Commodities and Labour were adjusted using the default Australian values provided by Thermoflow with the exception of Labour which was adjusted to reflect Australian labour rates as per the models for coal fired plants.

Table 14 **Combined Cycle Gas Turbine with CCS**

Technology Description	CCGT with CCS
Fuel Type	Natural Gas
Capital Costs, A$/kW sent-out	$2,940
Local Equipment/Construction Costs (includes commodities)	14%
International Equipment Costs	67%
Labour Costs	19%
Construction Profile % of Capital Cost	Year 1 – 60% Year 2 – 40%
First Year Assumed Commercially Viable	2024
Typical new entrant size (Generated MW)	363 MW
Economic Life (years)	40
Lead time for development (years)	4
Minimum stable generation level (% capacity)	0%
Thermal Efficiency (sent out – HHV)	44.1%
Auxiliary Load (%)	10%
FOM ($/MW/year) for 2014	$17,000
VOM ($/MWh sent out) 2014	$12.0
Percentage of emissions captured (%)	85%
Emissions rate per $kgCO_2e/MWh$	54 $kgCO_2e/MWh$

Source: GHD

Table 15 **Combined Cycle Gas Turbine without CCS**

Technology Description	CCGT without CCS
Fuel Type	Natural Gas
Capital Costs, A$/kW sent-out AC	$1,092
Local Equipment/Construction Costs (includes commodities)	18%
International Equipment Costs	56%
Labour Costs	26%
Construction Profile % of Capital Cost	Year 1 – 60% Year 2 – 40%
First Year Assumed Commercially Viable	2014
Typical new entrant size (Generated/Sent-out, MW)	390 MW
Economic Life	40 years
Lead time for development (years)	4 years
Minimum stable generation level (% capacity)	0%
Thermal Efficiency (sent out – HHV)	50.6%
Auxiliary Load (%)	3%
FOM ($/MW/year) for 2014	$10,000
VOM ($/MWh sent out) 2014	$7.0
Percentage of emissions captured (%)	0%
Emissions rate per $kgCO_2e/MWh$	349 $kgCO_2e/MWh$

Source: GHD

Table 16 **Open Cycle Gas Turbine**

Technology Description	OCGT without CCS
Fuel Type	Natural Gas
Capital Costs, A$/kW sent-out	$725
Local Equipment/Construction Costs (includes commodities)	10%
International Equipment Costs	79%
Labour Costs	11%
Construction Profile % of Capital Cost	Year 1 – 100%
First Year Assumed Commercially Viable	2014
Typical new entrant size (Generated MW)	530 MW
Economic Life	30 years
Lead time for development (years)	2 years
Minimum stable generation level (% capacity)	0%
Thermal Efficiency (sent out – HHV)	34.6%
Auxiliary Load (%)	2.2%
FOM ($/MW/year) for 2014	$4,000
VOM ($/MWh sent out) 2014	$10.0
Percentage of emissions captured (%)	0%
Emissions rate per $kgCO_2e/MWh$	515 $kgCO_2e/MWh$

Source: GHD

5.5 Solar Photovoltaic Technologies

Solar photovoltaic (PV) systems convert sunlight directly into electricity and are one of the fastest growing renewable energy technologies today. Currently there are two main variations of PV cells at different levels of commercial maturity:

- Wafer-based crystalline silicon (c-Si) (single or multi-crystalline) and,
- Thin-film PV technologies including amorphous and micromorph silicon, Cadmium-Telluride and Copper-Indium-Selenide (CIS) and Copper-Indium-Gallium-Diselenide (CIGS)

PV cells, traditionally made with crystalline silicon, have put PV manufacturers in competition with electronics manufacturers for highly purified silicon wafers. More recent thin film technologies for PV cells that require just a fraction of the material needed for silicon crystal PV cells have provided alternative PV installation options to project developers. However, for a given MW installed PV capacity, thin film arrays tend to require[11] more land area than single or multi crystalline PV modules. There are industry reports that indicate thin film's financial advantages of cheap manufacturing are not being realised as much as initial industry expectations[12].

Additional PV cell technologies exist such as concentrating PV and organic PV which are currently in the demonstration phase or not widely commercialised and therefore have not been considered in this report.

A solar PV farm consists of a group of PV cells along with requisite balance of system (BOS) such as auxiliary components including the inverter, controls etc. that are bundled into a PV array module.

This report has considered the installed cost of the established crystalline silicon technology at a utility scale of 100 MW.

Operation and maintenance costs for PV systems are typically limited to fixed costs only as no fuels or consumables associated with PV generation. Fixed operating costs associated with general maintenance, cleaning and ancillary running costs are common to all PV installations.

Capacity factors for solar PV installation vary depending on the available solar resource (i.e. location), ranging from 10% to 20% for fixed tilt systems. A PV system can be fitted with a tracking device which tracks the sun's path, boosting the energy capture and hence capacity factor.

Tracking systems can significantly raise the electricity generation levels of an installation, however the additional expense is rarely justified economically and should be assessed on a case by case basis.

Capital Cost Basis

Costs of new solar PV systems have been decreasing rapidly due to the continuing maturation of the technology and market pressures from increasingly number of new

[11] Pre-feasibility study for a solar power precinct, 2010 AECOM, Available: http://www.environment.nsw.gov.au/resources/climatechange/PreFeasibilityStudy.pdf.

[12] Overview – Renewable Power Generation Costs in 2012, IRENA, 2013, Available:

http://www.irena.org/DocumentDownloads/Publications/Overview_Renewable%20Power%20Generation%20Costs%20in%202012.pdf manufacturing entrants particularly in China. These have led to overcapacity in the supply chain from both European and Asian manufacturers. System costs are made up of a combination of PV module process and BOS costs. BOS costs including installation are largely dependent on the nature of the installation and the site location. As utility scale PV installations become more common it is expected that BOS costs will fall as best practice techniques are adopted.

Identifying current costs for rapidly evolving technology is challenging, published cost figures and estimates quickly become outdated and projected costs can be quite speculative. Accepting the lag in in reported costs and the uncertainty in future costs, the estimated capital cost of installation represents an understanding of present day costs. These costs are compiled from various sources available in the public domain and shown relative to the system's DC nameplate rating.

Operation and Maintenance Costs

It is common practice to express the O&M costs for PV systems in fixed O&M (FOM) costs only, as there are negligible variable O&M (VOM) costs due to the generation being dependant on solar resource and the simplicity of operating the systems.

For a solar PV farm, the following costs are considered in FOM:

- Asset management and administrative expenses including insurances
- Planned and unplanned maintenance
- PV module washing and weed abatement
- Spare parts and repairs including inverter replacement reserves

The expected FOM for a 100 MW solar PV farm (fixed) is estimated to be $25,000[13] per MW per year.

Single Axis Tracking

A single axis solar tracking (SAT) PV system rotates on one axis moving back and forth in a single direction to change the orientation throughout the day to follow the suns path to maximise energy capture. The tracking system minimises the angle of incidence (the angle that a ray of light makes with a line perpendicular to the surface) between the incoming light and the panel, which increases the amount of energy the PV system generates. A typical regional single axis tracking PV system can expect an increased capacity factor relative to a fixed flat plate installation by a ratio of 1.28 (Solar Choice, 2010). Single axis systems offer lower cost and higher reliability compared with dual-axis systems since there are fewer components that require maintenance over the life of the system.

Operation and Maintenance Costs

The expected FOM for a 100 MW solar PV farm (with a single axis tracking system) is estimated to be $30,000[14] per MW per year.

5.5.2 Dual Axis Tracking

A dual axis solar tracking (DAT) PV system rotates on two axes, enabling the PV modules to accurately track the sun. Dual axis types include tip-tilt and azimuth-altitude. A typical

[13] Australian Energy Technology, Assessment 2013 Model Update – Dec 2013 (www.bree.gov.au)

[14] Australian Energy Technology, Assessment 2013 Model Update – Dec 2013 (www.bree.gov.au)

regional dual axis tracking PV system can expect an increased capacity factor relative to a fixed flat plate installation by a ratio of 1.35 (Solar Choice, 2010).They are more complicated to maintain and set up than a single-axis tracker.

Operation and Maintenance Costs

The expected FOM for a 100 MW solar PV farm (with a dual axis tracking system) is estimated to be $39,000[15] per MW per year.

Table 17 **PV Fixed Flat Plate/ Single Axis Tracking/ Dual Axis Tracking**

Technology Description	PV Fixed Flat Plate/ Single Axis Tracking/ Dual Axis Tracking
Fuel Type	Solar
Capital Costs, A$/kW sent-out AC	$2,350 – Fixed axis tracking $2,900 – Single axis tracking $3,800 – Dual axis tracking
Local Equipment/Construction Costs (includes commodities)	15%
International Equipment Costs	70%
Labour Costs	15%
Construction Profile % of Capital Cost	Year 1: 80% Year 2: 20%
First Year Assumed Commercially Viable	2014
Typical new entrant size (Generated MW)	100 MW was assumed for this report. However, any size can be considered.
Economic Life	Typical design life is 25 years. There are no examples of solar farms that have gone beyond this period. However, solar farms operational life can be extended beyond their design life by either refurbishing the main components or repowering to newer and larger PV modules.
Lead time for development (years)	Development time for a typical solar farm project is 2 to 4 years from site identification to commencing construction.
Minimum stable generation level (% capacity)	Non despatchable. Generation level is dependent on solar resource. No energy storage is included in this analysis
Thermal Efficiency (sent out – HHV)	N/A
Capacity Factor Ratio (AC Output, rural installation basis)[16]	FFP = 1 SAT = 1.28 DAT = 1.35
Auxiliary Load (%)	0%
FOM ($/MW/year) for 2014	$25,000/MW AC/year – Fixed flat plate $30,000/MW AC/year – Single axis tracking $39,000/MW AC/year – Dual axis tracking
VOM ($/MWh sent out) 2014	Included in FOM.
Percentage of emissions captured (%)	N/A
Emissions rate per kg CO2e/MWh	N/A

Source: GHD

[15] Australian Energy Technology, Assessment 2013 Model Update – Dec 2013 (www.bree.gov.au)

[16] Solar Trackers, 2010, Solar Choice, Available: http://www.solarchoice.net.au/blog/solar-trackers/

5.6 Solar Thermal Technologies

Solar thermal energy systems, known as Concentrating Solar Power (CSP), harness the sun's heat to generate electricity. Reflectors (mirrors) concentrate the sun's energy onto a thermal receiver. Fluids (such as water, oil or molten salt) or a gas passes through the receiver where the concentrated solar energy heats it to very high temperatures (from 350°C to over 1,000°C) depending on the system. This heating medium is used to heat water to create super-heated steam, which in turn drives a steam turbine connected to a generator.

There are typically four types of CSP design:

1. Compact Linear Fresnel design (CLFR), which uses modular flat reflectors to focus the sun's heat onto elevated receivers containing water; the concentrated sunlight boils the water in the tubes, generating high-pressure steam for direct use in power generation and industrial steam applications.
2. Central receiver or 'power tower' design, where many tracking mirrors reflect the sun onto a thermal receiver sitting at the top of a tower. Power towers can drive steam turbine or Brayton cycle (air turbine) systems connected to generators.
3. Parabolic trough design, where a series of large dish-shaped troughs reflects the sun's rays onto an inline receiver tube running along the centre of the trough arrays. The receiver tube can contain water, oil or molten salts, and drive a steam turbine connected to a generator.
4. Parabolic dish, which focuses the sun's rays onto a thermal receiver located at the focal point of the parabola.

CSP systems have not had the same explosive growth as solar PV. In 2000-2011, total growth was just over 3 TWh (+20% annually), reaching an estimated 4 TWh in 2011, from over 2 TWh in 2010. Though it is projected to grow significantly through 2017, to more than 30 TWh. Competition from lower-cost solar PV is challenging deployment, with some projects in the United States having converted from CSP to solar PV[17]. However, the suitability of CSP for integration with a fossil fuel plant and storage can enhance its value through dispatchability, which may lead to increased market penetration. Commercial capacity has been concentrated in a few areas, largely Spain and the United States, but numerous projects are being developed in the Middle East and North Africa, as well as in Australia, India, China and South Africa.

5.6.1 Compact Linear Fresnel

AREVA's CLFR technology was selected for the CSP solar flagship project in 2010. The project was based on using direct steam generation in the solar absorbers. The plant consisted of two 125 MW facilities. No energy storage was provided with this system.

[17] Tracking Clean Energy Progress, IEA Report 2013

Figure 11 **CLFR pilot plant at Kogan Creek**

Source: GHD

Operation and Maintenance Costs

The expected FOM and VOM for a 100 MW CLF system are estimated to be $64,000[18] per MW and 15.20/MWh per year, respectively.

[18] Australian Energy Technology, Assessment 2013 Model Update – Dec 2013 (www.bree.gov.au)

Table 18 **Compact Linear Fresnel Technology – Direct Stream Generation – No Storage**

Technology Description	Compact Linear Fresnel Technology – Direct Stream Generation – No Storage
Fuel Type	Solar
Capital Costs, A$/kW	$4,500
Local Equipment/Construction Costs (includes commodities)	25%
International Equipment Costs	55%
Labour Costs	20%
Construction Profile % of Capital Cost	Year 1 – 50% Year 2 – 30% Year 3 – 20%
First Year Assumed Commercially Viable	2016
Typical new entrant size (Generated MW)	100 MW
Economic Life	Typical design life is 25 years. There are no examples of CFLR plants that have gone beyond this period. However, similar to conventional power plants, their operational life can be extended beyond their design life by regular refurbishing of the main components or repowering.
Lead time for development (years)	4 years
Minimum stable generation level (% capacity)	10% - output is dependent on solar resource
Thermal Efficiency (sent out – HHV)	N/A
Auxiliary Load (%)	8%
FOM ($/MW/year) for 2014	$64,000[19] (without storage)
VOM ($/MWh sent out) 2014	$15.20
Percentage of emissions captured (%)	0%
Emissions rate per kgCO_2e/MWh	0

Source: GHD

5.6.2 Central Receiver (with Thermal Storage)

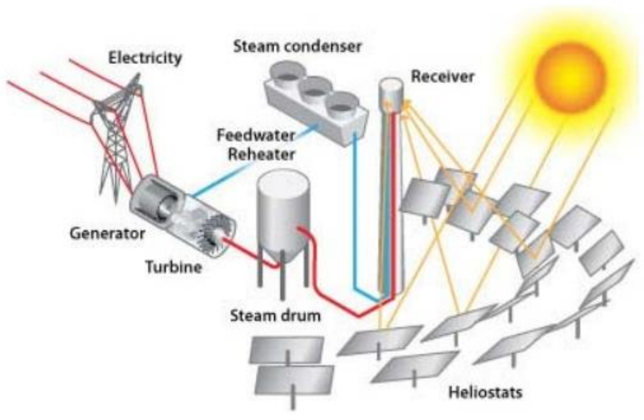
A CSP Central Receiver system, also called power towers, consists of a series of large mirrors or lenses placed around the tower, called heliostats. Typically, the central receiver systems have three main components: ground heliostats (mirrors, lenses, or reflectors), a tower, and a central receiver at the top of the tower. The function of the heliostats is to capture solar radiation from the sun and re-direct it to a central receiver. A heliostat typically rotates along two axes, east and west, and north and south, tracking the sun as it moves throughout the day and the year. Each individual heliostat is guided by a computer controlled system which follows the sun and optimises total energy output. Electricity is generated when the concentrated light is converted into heat, which drives a steam turbine connected to an electrical generator.

The first commercial solar tower system was built by Abengoa Solar of Spain at the Solucar Platform in the Spanish province of Seville. It began operation in March, 2007 and continues to this day[20].

[19] Australian Energy Technology, Assessment 2013 Model Update – Dec 2013 (www.bree.gov.au)

[20] Image source: http://solarcellcentral.com/csp_page.html

Figure 12 **Schematics of a CSP tower system**



Note: http://mcensustainableenergy.pbworks.com/w/page/32181014/
Source: GHD

Figure 13 **CSP tower systems (PS10 & PS20), Seville - Spain (10 & 20MW)**

Source: US Department of Energy

Operation and Maintenance Costs

The operating costs of CSP plants are low compared to fossil fuel-fired power plants, but are still significant. The replacement of receivers and mirrors, due to glass breakage, are a significant component of the O&M costs. The cost of mirror washing, including water costs, is significant. Plant insurance and general asset management are also important expenses.

The expected FOM and VOM for a 100 MW CSP tower system are estimated to be $71,300[21] per MW and 5.70/MWh per year, respectively.

21 Australian Energy Technology, Assessment 2013 Model Update – Dec 2013 (www.bree.gov.au)

Table 19 **Central Receiver with 6 hours thermal storage**

Technology Description	Central Receiver with 6 hours thermal storage
Fuel Type	N/A
Capital Costs, A$/kW	$6,700
Local Equipment/Construction Costs (includes commodities)	20%
International Equipment Costs	55%
Labour Costs	25%
Construction Profile % of Capital Cost	Year 1 – 50% Year 2 – 30% Year 3 – 20%
First Year Assumed Commercially Viable	2016 – There are currently no central receiver solar thermal plants under development in Australia.
Typical new entrant size (Generated MW)	100 MW
Economic Life	Typical design life is 25 years. There are no examples of CFLR plants that have gone beyond this period. However, similar to conventional power plants, their operational life can be extended beyond their design life by regular refurbishing of the main components or repowering.
Lead time for development (years)	4 years
Minimum stable generation level (% capacity)	10% - output is dependent on solar resource
Thermal Efficiency (sent out – HHV)	N/A
Auxiliary Load (%)	10%
FOM ($/MW/year) for 2014	$71,300
VOM ($/MWh sent out) 2014	$5.70
Percentage of emissions captured (%)	0%
Emissions rate per kgCO_2e/MWh	0

Source: GHD

5.6.3 Parabolic Trough (with Thermal Storage)

The parabolic trough is a relatively mature power generation technology with extensive operational history that could be deployed for large-scale installation. This technology was first commercialised in 1980s. It has improved on costs and efficiency significantly. Currently, there are several hundreds of MWs in operation in countries such as Spain, United States, Morocco, Algeria, Egypt, South Africa, India, Mexico and Chile. Parabolic trough is the most developed technology among all types of solar thermal power plants.

Parabolic trough technology uses a curved, mirrored trough which reflects the direct solar radiation onto a glass tube containing a fluid (a receiver, absorber or collector) running the length of the trough and positioned at the focal point of the reflectors. The trough is parabolic along one axis and linear in the orthogonal axis. Troughs are positioned on a single axis tracking system to tilt east to west so that the direct radiation remains focused on the receiver. A heat transfer fluid inside the receiver is used to heat steam in a standard steam turbine generator arrangement.

Figure 14 **A typical parabolic trough system**

Note: Image source: http://www.csp-world.com/resources/technology
Source: GHD

Operation and Maintenance Costs

The operating costs of CSP plants are low compared to fossil fuel-fired power plants, but are still significant. The replacement of receivers and mirrors, due to glass breakage, are a significant component of the O&M costs. The cost of mirror washing, including water costs, is also significant. Plant insurance and general asset management are also important expenses.

The expected FOM and VOM for a 100 MW CSP parabolic trough system are estimated to be $72,400[22] per MW and 11.40/MWh per year, respectively.

[22] Australian Energy Technology, Assessment 2013 Model Update – Dec 2013 (www.bree.gov.au)

Table 20 **Parabolic Trough with 6 hours**

Technology Description	Parabolic Trough with 6 hours thermal storage
Fuel Type	N/A
Capital Costs, A$/kW sent-out	$9,100
Local Equipment/Construction Costs (includes commodities)	20%
International Equipment Costs	55%
Labour Costs	25%
Construction Profile % of Capital Cost	Year 1 – 50% Year 2 – 30% Year 3 – 20%
First Year Assumed Commercially Viable	2016
Typical new entrant size (Generated MW)	100 MW
Economic Life	25 years
Lead time for development (years)	4 years
Minimum stable generation level (% capacity)	10% - output is dependent on solar resource
Thermal Efficiency (sent out – HHV)	N/A
Auxiliary Load (%)	10%
FOM ($/MW/year) for 2014	$72,400
VOM ($/MWh sent out) 2014	$11.40
Percentage of emissions captured (%)	0%
Emissions rate per kgCO_2e/MWh	0

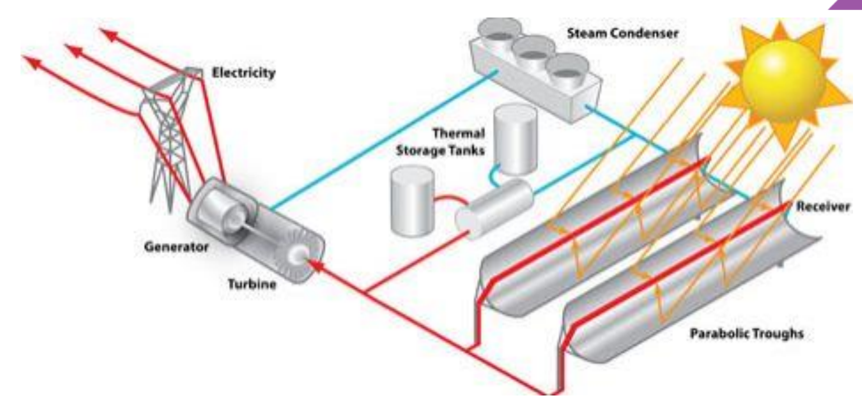
Source: GHD

5.6.4 Thermal Storage

Parabolic trough and central receiver systems with thermal energy storage typically use a two-tank, indirect, molten-salt system. The system uses different heat transfer fluids for the receiver and for storage, and therefore it requires a heat exchanger. Advances in thermal storage technologies could further improve the uptake of CSP by increasing capacity factors and enabling systems to take advantage of peak electricity prices. CSP plant capacity factors extend from 20-28% for plants with no storage to 30 -50% for plants with 6-7.5 hours of storage[23]. However, the storage system and additional mirrors increases the installed cost per kW. For instance, adding a six hour storage option would typically double the CAPEX, or even higher. The cost of installed generation varies greatly depending on the location, ownership, the values of key financing terms, available financial incentives, and other factors.

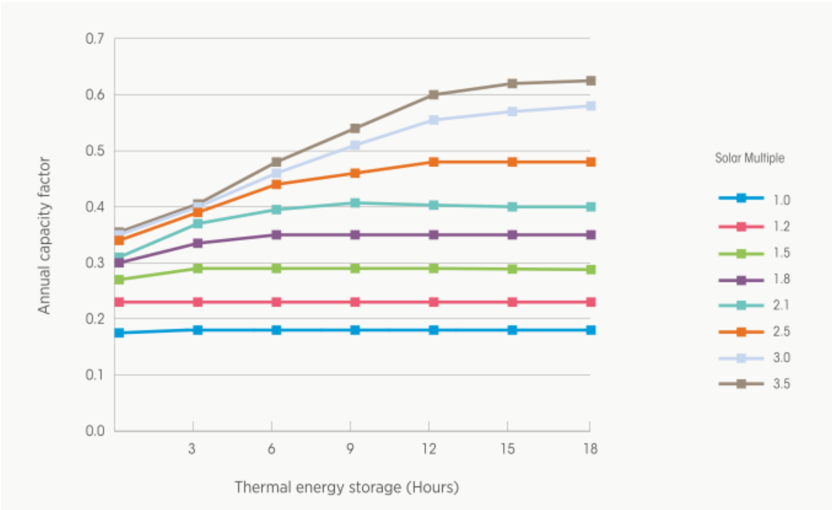
[23] www1.eere.energy.gov - Concentrating Solar Power: Technologies, Cost, and Performance report – May 2010

Figure 15 **Schematics of CSP with thermal storage**



Note: Image source: NREL
Source: US Department of Energy

Figure 16 **Annual capacity factor for a 100 MW parabolic trough plant as a function of solar field size and size of thermal energy storage**



Note: Data Source: Cost Analysis of Concentrating Solar Power Report – IRENA, June 2012.
Source: GHD

5.6.5 Potential Improvements in CSP Technologies

Currently, the installed costs of CSP systems are high compared to wind or solar PV. For the purpose of this report, a range of information and studies has been reviewed and analysed to establish a rule of thumb for cost estimation of CSP systems in Australia based on system size and thermal storage capacity. Whilst there is a high level of uncertainty with this, it is apparent that current installed costs per MW are as high as 100% of other renewable systems.

However, the potential for cost reduction going forward is very high. Reviewing experience in related industries suggests the most likely result is that cost reduces by around 15% for every doubling of installed capacity globally. On this basis, and assuming a 20 - 30% per year projected global growth rate, convergence between cost and value in the Australian market is likely to occur not later than 2030 and possibly as soon as 2018, with energy market price increases due to carbon prices or otherwise also influencing this (ASI[24]).

The key areas where cost reductions could to be achieved are given by ARENA[25] as:

- The solar field: mass production and cheaper components, as well as improvements in design, can help to reduce costs.
- The heat transfer fluid: new heat transfer fluids and those capable of higher temperatures will help to improve storage possibilities and reduce costs. Direct steam generation is also a possibility, but requires further research.
- The storage system: This is closely tied to the heat transfer fluid, as higher temperatures, notably from solar towers, will reduce the cost of thermal energy storage.
- The power block: There is still room for cost reductions, although these will be more modest than for the other components.
- The balance of costs, including project development costs.

5.6.6 Integrated Solar Combined Cycle

Integrated solar combined cycle generation integrates solar thermal technology into conventional combined cycle gas turbine plant, working effectively to boost the steam cycle plant to optimise for fuel use and equipment utilisation.

A similar technology is the Kogan Creek Solar Boost project being installed by CS Energy and AREVA. It involves utilising CLF array to heat steam to CS Energy's 750 megawatt coal-fired Kogan Creek Power Station in South West Queensland. The system will augment the Kogan Creek Power Station's steam generation and will produce 44 MW of electricity during peak solar conditions[26]. This system is similar to an integrated solar combined cycle in that it supplements the steam cycle to offset fuel consumption (see Figure 17).

The plant considered for this exercise assumes a nominal 500 MW plant including a solar field sized at a multiple of 1.2 with no thermal storage. The thermal efficiency of this plant is dependent on the capacity factor achieved due to the available solar resource. Assuming an average capacity factor of 23% over the year and a thermal efficiency of 50.6% for the base case CCGT (without integrated solar), the average thermal efficiency would increase to 53.7%. If the solar component were operated at full output, a thermal efficiency of around 64.1% could be achieved.

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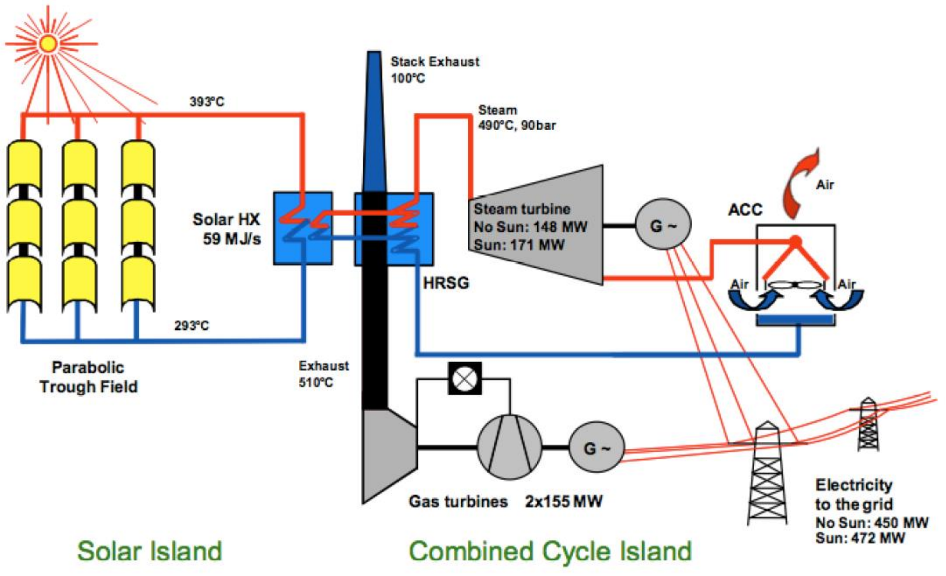
[24] ASI - Realising the potential of Concentrating Solar Power in Australia, May 2012

[25] Data Source: Cost Analysis of Concentrating Solar Power Report – ARENA, June 2012

[26] Kogan Creek Solar Boost Project, 2014, CS Energy, Available: http://kogansolarboost.com.au/

Figure 17 **Example ISCC Plant**



Note: Implementation Completion and Results Report for an Integrated Solar Combined Cycle Power Project, 2013, Sustainable Development Department – The World Bank, Available: http://www-wds.worldbank.org/external/default/WDSContentServer/WDSP/IB/2013/07/11/000356161_20130711123250/Rendered/PDF/ICR26930ICR0Mo00Box377354B00PUBLIC0.pdf
Source: GHD

Several ISCC demonstration plants have been installed since 2009 in the Middle East and North Africa region. The solar component of the plants is generally relatively small i.e. less that 10% of the total installed capacity.

Table 21 **Integrated Solar Combined Cycle**

Technology Description	Integrated Solar Combined Cycle
Fuel Type	Natural Gas/Solar
Capital Costs, A$/kW sent-out	$2,150
Local Equipment/Construction Costs (includes commodities)	18%
International Equipment Costs	56%
Labour Costs	26%
Construction Profile % of Capital Cost	Year 1 – 60% Year 2 – 40%
First Year Assumed Commercially Viable	2015
Typical new entrant size (Generated MW)	500 MW
Economic Life	40 years
Lead time for development (years)	5 years
Minimum stable generation level (% capacity)	40% - output is dependent on solar resource
Thermal Efficiency (sent out – HHV)	53.7% (Ave), 64.1% (max)
Auxiliary Load (%)	5%
FOM ($/MW/year) for 2014	$15,000
VOM ($/MWh sent out) 2014	$10.0
Percentage of emissions captured (%)	0%
Emissions rate per kgCO_2e/MWh	Dependant of capacity factor achieved

Source: GHD

5.7 Wind Technology

Wind power has become one of the mainstream electricity generation sources, and is considered to be a mature technology among other renewable technologies. It enjoyed the highest average cumulative growth of 25-30% for 15 consecutive years from late 1990s to early 2000s. The total installed wind energy capacity worldwide reached 319 GW by the end of 2013, which contributes close to 4% to the global electricity demand. China installed 16 GW in 2013 and has a total installed capacity of over 91 GW. Asia had the same installed capacity in 2013 as Europe (119 GW) and is expected to overtake Europe in 2014 as largest wind continent (WWEA[27]).

The amount of installed wind power in Australia has doubled in the past five years. The total installed wind power capacity in Australia by June 2013 was 3,059 MW, 13th position internationally. China has the first ranking in the world (WWEA).

Wind turbines directly convert the kinetic energy of the wind into electricity. The wind turns the blades that spin a shaft, which is connected (directly or indirectly via a gearbox) to a generator that generates electricity. The power generation of wind turbines is determined by the capacity of the turbine (in kW or MW), the wind resource, height of the turbine and the diameter of the rotors. Three bladed horizontal axis wind turbines have become the accepted configuration in most wind power installations. Wind turbine drive train is typically of two types: direct drive with ring or annular generators (i.e. without a gearbox) and transmission driven drive train which connects the rotors to a generator. In modern wind turbines, each blade is pitch-adjusted and controlled by a central computer to extract the optimum amount of energy from the wind and protect the turbine from extreme wind speeds. Wind turbines are deigned to operate to wind speeds of up to 90 km/hr; they shut down automatically until wind speeds return within turbine's operations range.

Large scale utility wind farms in Australia typically utilise machines in the 2 to 3 MW range with hub heights of 80 to 100 m above ground level and rotor diameters of 70 to 120 m. Wind farms are arrays of 50 to 250 turbines. Wind farm sizes in Australia have steadily grown. 100 MW is considered to be a typical size for the purpose of this report.

5.7.1 Wind Resource

Australia has one of the richest wind resources in the world. Australian wind regime is dominated by sea breezes and coastal weather systems. For most sites, wind speed is strongest in mid to later afternoon and weakest at night. Winter months are the windiest time at most Australian wind sites.

The strength and characteristics of the wind resource have significant impacts on the delivered cost of electricity generation from a wind turbine. There are a number of factors such as wind speed distribution characteristics, turbulence intensity, wind shear profile (i.e. change of wind speed with height) and diurnal / seasonal wind patterns that influence the strength and quality of the wind resource.

For the purpose of modelling a baseline 100 MW wind farm, an average wind resource that represents most Australian wind farms and produces a capacity factor of 35% have been assumed. It is noted that earlier wind farms in Australia have capacity factors of 30% or lower. However, newer turbines with improved production and higher reliability rates are expected to support an average 35% capacity factor, or higher.

[27] World Wind Energy Association – 2013 Half-Year Report

5.7.2 Typical New Entrant Size

For the purpose of this report, a typical wind farm size of 100 MW has been considered as an average new wind farm. The trend for larger wind farm projects has continued in Australia. Wind farm sizes tend to be limited by a number of factors such as:

- Availability of electrical network capacity (i.e. limitation of upgrade and augmentation costs associated in connecting a larger wind farm)
- Wind farm land availability – larger wind farms require large areas of rural land. Signing in all landowners and satisfying all planning requirements by local regulatory authorities can constrain wind farm sizes.
- Suitable site conditions – favourable wind resource, local topography, site access, ease of transportation, and wind farm constructability often dictate the size of wind farms.
- Off-take agreements – obtaining commercially viable off-take agreements for suitable long-term periods (i.e. 10 to 15 years).

MacArthur Wind farm with an installed capacity of 420 MW is the largest operational wind farm in Australia. There are several 500+ MW wind farm projects that are under consideration in NSW, QLD and WA. It is expected that 100+ MW wind farms will become more common over the forecast period with an ongoing trend towards deployment of fewer but larger capacity wind turbines.

5.7.3 Capital Costs Trend

The costs for onshore wind energy experienced significant reductions between 1980 and the early 2000s with notable increases in turbine performance. However, beginning in about 2003 and continuing through the latter half of the past decade, wind power capital costs increased, mainly due to rising commodity and raw materials prices, increased labour costs, improved manufacturer profitability, and turbine up-scaling – thus pushing wind energy’s costs upward in spite of continued performance improvements. More recently, wind turbine prices and therefore project capital costs have declined, but still have not returned to the historical lows observed earlier in the 2000s – however performance improvements have been maintained. Continued cost reductions are expected through to 2030, but the anticipated magnitude and pattern of these reductions varies widely and will ultimately be determined by a variety of technical and non-technical factors.

From mid 2000s, the wind turbine industry has heavily focused in up-scaling of wind turbines, primarily driven by demands from offshore wind sector. However, efforts to increase wind turbine reliability did not follow the same pace. Wind turbine suppliers in recent years have focused their attention to increase wind turbine reliability and lowering OPEX costs away from up-scaling efforts.

Looking into the future, the cost of wind power is expected to continue to fall, at least on a global basis and within fixed wind resource classes. Performance improvements associated with continued turbine up-scaling, use of stronger but lighter structural materials and design advancements are anticipated that could overall lower capital costs (IEA[28]). The magnitude of future cost reductions is nevertheless highly uncertain. It is noted that predictions of the future cost of onshore wind power that have been done to date have often been the result of an iterative process that incorporates some combination of historical trends, learning curve analysis, expert elicitation, and engineering modelling.

[28] IEA Wind Task 26 report - The Past and Future Cost of Wind Energy

A large number of technological and market-based drivers are expected to determine whether lowering cost projections are ultimately realised. Possible technical drivers include:

- More reliable drivetrain technology
- Improved manufacturing efficiency
- Cost effective O&M strategies
- Advancements in power electronics and power conversion
- More accurate predictions for energy yield assessments
- Advances in new rotor and tower designs by using lighter but stronger materials at lower costs and more robust high lifting.

Adding to these technical drivers, future environmental and planning policies by local and federal regulatory authorities such as turbine noise emission guidelines will play an important role in the cost of installed wind power plants.

5.7.4 Wind farm development and operational life

Wind farms have an operating life of 20 years or longer. However, there are currently no wind farms in Australia that have been continuously in service for that long. Wind turbines in Crookwell wind farm in NSW, Denham wind farm in WA, and Thursday Island in QLD are among the oldest operational machines in Australia.

Development time for a typical wind farm project is in the order of four to seven years from site identification to commissioning (i.e. commercial operation).

5.7.5 CAPEX Profile Assumptions (FY 2014 to FY 2040)

The following assumptions are made in preparing the CAPEX profile for construction of a 100 MW wind farm project in Australia.

- The expected cost in 2014 is taken to be AUD 2,550 per installed kW. This is based on GHD's in-house database of recent constructed wind farm projects in Australia.
- Wind turbines account for the largest single component of the cost of installed generation, typically about 72%.
- There expected to be reasonable reduction in costs from 2014 to 2020 (11.5%) driven by increased competition among turbine manufacturers to capture re-emerging Australian wind market, consolidation of new Asian and mainstream turbine suppliers, increased economies of scale, and advances in lighter, stronger and more durable core materials used in turbine rotors, drivetrain, and towers.
- It is expected that there would be a period of very limited to nil reduction in costs from 2021-2024. Most grade one wind farm sites (with high wind resource and favourable planning conditions) have been used up by project developers by then and sites with lower wind resource in more challenging geographies would be available for construction. This means that wind turbines with larger rotor diameter compared with generator size will have to be utilised, and hence the increased levelised cost of energy will negate the cost reduction factors mentioned above.
- From 2025 to 2040, it is expected that costs would continue to drop however the rate and period of this cost reduction is uncertain.

The above assumptions are in agreement with ARENA's[29] findings that state "wind turbines are projected to be 15% cheaper in 2020 than in 2011 and 28% cheaper in 2040".

Chinese Wind Turbine Suppliers

Among key drivers in lowering the costs for wind power in Australia are expected to be new entrants into the wind turbine suppliers market such as Chinese OEMs. Chinese and Asian turbine suppliers such as Goldwind and Suzlon are strongly presented in the Australian market and have already contributed to lower the capital cost of wind farms. However, since they are not yet fully recognised by the mainstream lenders and financiers for project financing, there expected to be another three to five years before they establish themselves as the dominant players in Australia. With close geographical and trade relationships between Australia and China, the influence of Chinese wind turbines in contributing to lower the costs should not be underestimated.

5.7.6 Operation and Maintenance Costs

Operation and maintenance (O&M) costs make up a sizeable share of the total annual costs of a wind farm. For a new wind farm, O&M costs can easily constitute up to 25% of the total cost per kWh for over the design life of the wind farm (ARENA, 2012). In recent years, wind farm O&M costs have been attracting greater attention by project developers and financiers, as manufacturers attempt to lower these costs significantly by developing new turbine designs that require fewer regular service visits and less turbine downtime. Wind farm O&M costs are separated into fixed and variable parts and typically related to:

- Planned and unplanned maintenance
- Repairs and midlife refurbishments
- Insurances
- Spare parts, and
- Administration and asset management costs.

Cost components such as insurances and planned maintenance (fixed costs) are relatively easy to estimate. However, costs related to unplanned maintenance and spare parts are much more difficult to predict. And although all cost components tend to increase as the turbine gets older, costs for repair and spare parts are particularly influenced by turbine age; starting low and increasing over time.

Due to dramatic changes in wind turbine technology and turbine sizes during the past two decades and relative infancy of the wind industry, as well as unavailability of reliable wind farm operational costs, it is difficult to extrapolate historical O&M costs into future. Nevertheless, there have been several recent studies that have produced beneficial results. These investigations indicate that annual average O&M costs have declined substantially since 1980. In the United States, data for completed projects suggest that total O&M costs (fixed and variable) have declined from around USD 33/MWh for 24 projects that were completed in the 1980s to USD 22/MWh for 27 projects installed in the 1990s and to USD 10/MWh for the 65 projects installed in the 2000s (ARENA, 2012).

In Australia, the total O&M costs are generally higher than the US and European costs due to smaller size of wind industry and unavailability of third party independent O&M service providers. The expected FOM costs is estimated to be AUD 45,000 per MW annually and

[29] RENEWABLE ENERGY TECHNOLOGIES: COST ANALYSIS SERIES, ARENA Volume 1: Power Sector, Issue 5/5 Report – June 2012.

VOM is estimated at AUD 13/MWh over the wind farm design life for a 100 MW size wind farm. It has also been observed that the average length of full-service O&M contracts for Australian wind farms has increased from 2 years for earlier projects to 5-10 years for current projects. Average availability guarantees will remain at 96%-97%. The decreasing cost and increasing contract length suggest that turbine reliability is improving.

Table 22 **Wind**

Technology Description	Wind
Fuel Type	N/A
Capital Costs, A$/kW	$2,550
Local Equipment/Construction Costs (includes commodities)	13%
International Equipment Costs	72%
Labour Costs	15%
Construction Profile % of Capital Cost	Year 1: 80% Year 2: 20%
First Year Assumed Commercially Viable	2014
Typical new entrant size	100 MW was assumed for this report. However, any size can be considered. There are several 500 MW+ wind farms that are in development stage across Australia
Economic Life	Typical design life is 20-25 years. There are no examples of wind farms that have gone beyond this period in Australia. However, wind farms are anticipated to have an operational life of greater than their design life by either refurbishing the main components or repowering to newer and larger turbines.
Lead time for development (years)	Development time for a typical wind farm project is 4 to 7 years from site identification to commissioning.
Minimum stable generation level (% capacity)	1% - 3%, depending on turbine type and size
Thermal Efficiency (sent out – HHV)	N/A
Thermal Efficiency (sent out – HHV) learning rate (% improvement per annum)	N/A
Capacity Factor	35%
Auxiliary Load (%)	1%. Auxiliary loads are very low for wind farms and the net capacity factor typically accounts for them.
FOM ($/MW/year) for 2014	$45,000
VOM ($/MWh sent out) 2014	$13.0
Percentage of emissions captured (%)	N/A
Emissions rate per kg CO2e/MWh	N/A

Source: GHD

5.8 Wave/Ocean Technology

Wave/ocean energy technologies harness the energy of ocean waves or tidal flows and convert them into electricity. Wave/ocean technologies are under development for near-shore, off-shore and far off-shore application. Wave/ocean energy technology is still considered immature and commercial production of systems at a material scale does not yet exist. Several prototype technology systems were investigated including point absorbers, terminator devices, oscillating water columns, attenuators, overtopping devices and surging devices. The costs are based on a commercial deployment of a wave reaction point absorber system and does not reflect the current pricing for development scale projects.

Table 23 **Wave/Ocean**

Technology Description	Wave/Ocean
Fuel Type	N/A
Capital Costs, A$/kW sent-out	$5,900
Local Equipment/Construction Costs (includes commodities)	30
International Equipment Costs	40
Labour Costs	30
Construction Profile % of Capital Cost	Year 1: 60% Year 2: 40%
First Year Assumed Commercially Viable	2020
Typical new entrant size	20 MW
Economic Life	20 years
Lead time for development (years)	6
Minimum stable generation level (% capacity)	0%
Thermal Efficiency (sent out – HHV)	N/A
Auxiliary Load (%)	0.5%
FOM ($/MW/year) for 2014	$40,000
VOM ($/MWh sent out) 2014	$20.0
Percentage of emissions captured (%)	N/A
Emissions rate per kg CO2e/MWh	N/A

Source: GHD

5.9 Storage Technologies

5.9.1 Large Scale Battery Storage

Battery storage on a large scale is an increasingly attractive solution to complement the emergence of intermittent renewable energy sources such as solar PV, wind and tidal energy. Large installations of battery storage can match the total generation to total load with precision on a second by second basis. Power from batteries can be dispatched almost instantaneously and effectively produces no emissions once the energy is stored.

Several types of batteries are used for large scale energy storage, all consisting of electrochemical cells although no one type is suitable for all applications. Technologies which have been demonstrated at MW-scale and have a growing supply chain include advanced lead-acid batteries flow batteries and lithium-ion batteries.[30]

Lead acid batteries are a well-established technology with multiple installations on the grid for back-up power supply. However they suffer a limited life cycle when regularly cycled over a substantial rate of change state (ROC), degrading rapidly. Recent advances in materials and electrolytes have seen increases in cycle life and performance.

Flow batteries have low energy densities although they can be charged and discharged over almost the entire range of their nameplate capacity.

NREL's Cost and Performance Data for Power Generation Technologies (Black & Veatch 2012)[31] estimates a sodium sulphide installation with an assumed net capacity of 7.2 MW with 8.1 hours of storage at a cycle efficiency of approximately 75% and gives a capital cost of US $3,990/kW in 2012 and US $3,890/kW in 2015 dollars. In view of both of these figures

[30] Energy Storage, AEMO 100% Renewable Energy Study, 2012, CSIRO, Available: http://www.climatechange.gov.au/sites/climatechange/files/files/reducing-carbon/APPENDIX8-CSIRO-energy-storage.pdf

[31] Cost and Performance Data for Power Generation Technologies, NREL, 2012, Black and Veatch, Available: http://bv.com/docs/reports-studies/nrel-cost-report.pdf

and taking into consideration both the current exchange and labour rates in the Australian market, the figure of $4,500 per installed kW has been utilised for a similar Sodium Sulfide installation.

The cost of large scale battery storage is expected to reduce over time as the technology progresses along the maturity curve and larger scale installations become more common practice within major electricity networks.

Table 24 **Large Scale Battery Storage**

Technology Description	Large Scale Battery Storage
Fuel Type	N/A
Capital Costs, A$/kW sent-out	$4,500
Local Equipment/Construction Costs (includes commodities)	30%
International Equipment Costs	40%
Labour Costs	30%
Construction Profile % of Capital Cost	Year 1: 60% Year 2: 40%
First Year Assumed Commercially Viable	2016
Typical new entrant size	20 MW
Economic Life	10 years
Lead time for development (years)	3
Minimum stable generation level (% capacity)	0%
Thermal Efficiency (sent out – HHV)	N/A
Auxiliary Load (%)	0%
FOM ($/MW/year) for 2014	$30,000
VOM ($/MWh sent out) 2014	$6
Percentage of emissions captured (%)	N/A
Emissions rate per kg CO2e/MWh	N/A

Source: GHD

5.9.2 Pumped Hydro Storage

Pumped hydro storage is the most widespread and mature electrical storage technology at present. Pumped hydro is mainly utilised to smooth the peaks and valleys of the daily and weekly demand curves. Demand peaks are met by releasing water from an upper pond through a turbine to generate electricity. The upper pond is then replenished during the demand trough by pumping, thereby smoothing the demand curve.

With the emergence of intermittent renewable generation technologies such as wind and solar, pumped hydro storage is viewed as beneficial in storing surplus energy when the available renewable generation exceeds demand.

Australia currently has several operating pumped hydro storage installations which contribute to the NEM including:

- Tumut 3, 600 MW, Snowy Mountains
- Shoalhaven, 240 MW, southern NSW
- Wivenhoe, 500 MW, southern QLD.

Several additional promising sites were identified in ROAM's report Pumped Storage modelling for AEMO 100% Renewables Project, 2012[32].

This report nominated the following notional cost inputs for estimating installed costs:

Table 25 **Pumped Storage Input Costs**

Unit costs	Cost
Dam wall $ million/m^2	0.1
Pipe/tunnel $ million/m	0.5
Mechanical/Electrical $/kW	1000

Source: GHD

Considering these figures and a plant size of 500 MW, the report suggested a benchmark cost of $3,200/kW.

NREL's Cost and Performance Data for Power Generation Technologies (Black & Veatch 2012)[33] estimates a plant with an assumed net capacity of 500 MW with 10 hours of storage and gives a capital cost of US $2,230/kW.

In view of both of these figures and taking into consideration both the current exchange and labour rates in the Australian market, the figure of $3,200 per installed kW has been utilised.

A pumping efficiency (GWh consumed per GWh despatched) of 1.7 has been assumed. This value, although high, is based on experience with existing plants and is considered appropriate due to part load operation and varying head in operation.

Pumped hydro storage is considered a mature technology and no cost improvements are assumed over time.

[32] ROAM report on Pumped Storage modelling for AEMO 100% Renewables project, 2012, ROAM Consulting.

[33] Cost and Performance Data for Power Generation Technologies, NREL, 2012, Black and Veatch, Available: http://bv.com/docs/reports-studies/nrel-cost-report.pdf

Table 26 **Pumped Hydro Storage**

Technology Description	Pumped Hydro Storage
Fuel Type	N/A
Capital Costs, A$/kW sent-out	$3,200
Local Equipment/Construction Costs (includes commodities)	55%
International Equipment Costs	20%
Labour Costs	25%
Construction Profile % of Capital Cost	Year 1: 20 Year 2: 30% Year 3: 30% Year 4: 20%
First Year Assumed Commercially Viable	2014
Typical new entrant size	500 MW
Economic Life	50 years
Lead time for development (years)	8 years
Minimum stable generation level (% capacity)	0%
Thermal Efficiency (sent out – HHV)	N/A
Auxiliary Load (%)	1%
Pumping Efficiency (GWh pumped per GWh generated) – within 24 hours	1.7
Pumping Efficiency (GWh pumped per GWh generated) - annual	1.7
FOM ($/MW/year) for 2014	$5000
VOM ($/MWh sent out) 2014	$5.0
Percentage of emissions captured (%)	N/A
Emissions rate per kg CO2e/MWh	N/A

Source: GHD

6 Results – Gas prices

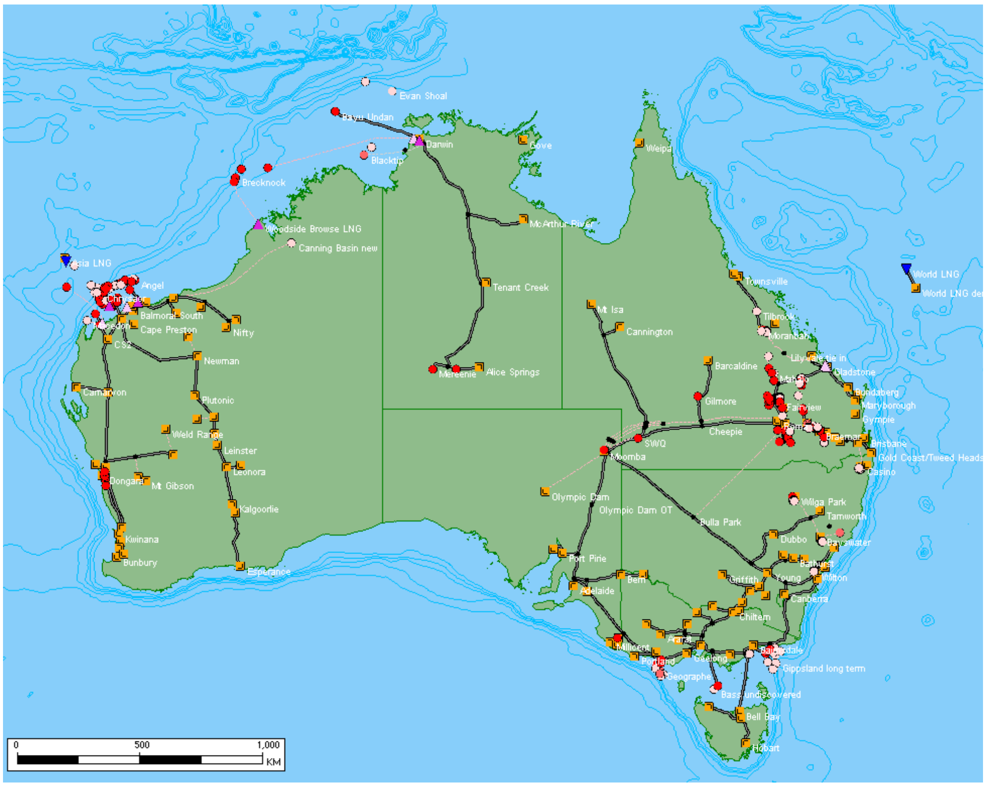
6.1 Approach

Long-term price projections for gas have been developed from the outputs of ACIL Allen'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 18. For the purposes of the NTNDP work, the modelling has focused on Eastern Australia only.

Figure 18 **Australian gas network representation**



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

ACIL Allen 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 within the NTNDP modelling. These are detailed below.

Table 27 **NTNDP zone and gas market nodes**

NTNDP Zone	Gas market node
NQ	Townsville
CQ	Gladstone
SEQ	Swanbank
SWQ	Braemar
NNS	Wilga Park
NCEN	Sydney
SWNSW	Wagga
CAN	Canberra
NVIC	Chiltern
CVIC	Ballarat
MEL	Melbourne
LV	Latrobe
TAS	Bell Bay
SESA	Ladbroke
ADE	Adelaide
NSA	Peterborough

Source: ACIL Allen

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.

Prices from GMG Australia can be interpreted as annual market clearing prices – similar to those that would apply within liquid spot markets. The NEM now has access to several spot gas markets: the Victorian spot market, the Short-term Trading Markets (STTMs) at Sydney, Adelaide and Brisbane and the recently opened Wallumbilla Gas Supply Hub. Whilst trading in these markets currently only comprises a very small proportion of gas supply, it is likely that these will develop over time and become pricing markers for domestic gas contracts.

Legacy gas contracts

Given the large divergence between prices within legacy gas supply contracts and current contract prices, we have chosen to use current price markers as being the representative cost for existing generators. Most generators no longer consider prices under existing contracts to be their marginal cost of fuel, but rather look to the opportunity cost of the commodity. This is illustrated by the recent decision by Stanwell to sell contracted gas to other users rather than utilise it at Swanbank E. If the gas has a higher value elsewhere and on-sale is feasible, then this should represent the marginal fuel cost. It is likely that a number of baseload/intermediate gas plant will switch to peaking roles over the next few years as anticipated wholesale gas price rises materialise.

For this reason, ACIL Allen has projected gas prices for each network node and used these values for all generators within that NTNDP zone, irrespective of existing gas supply contractual positions. A mark-up of $2/GJ (Real 2014-15 dollars) has been applied to peaking generators reflecting the fact that spot gas prices during periods when peakers are seeking to run will generally be higher than average annual values.

NTNDP scenarios

Within GMG Australia gas prices are set based on domestic gas-on-gas competition between producers, taking into account acreage and contracts for supply to export markets.

Adjustments between the NTNDP scenarios have been made for gas production costs and the degree to which prospective and contingent gas resources ultimately are firmed up into proven and probable gas reserves. The assumption changes between scenarios is summarised below.

Table 28 **NTNDP scenario assumptions**

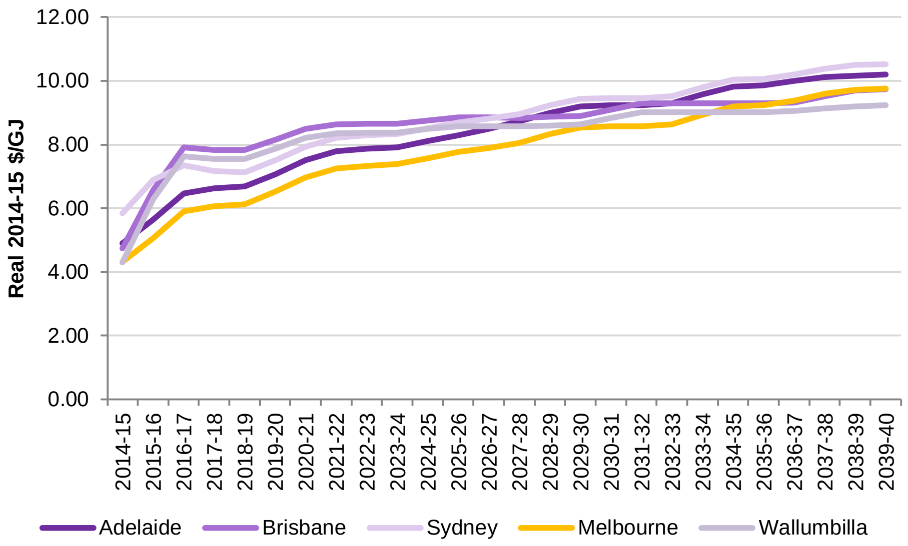
NTNDP scenario	Treatment within gas market modelling
High energy consumption from a centralised source	Lower production costs for unconventional gas (lower drilling and completion costs, higher well productivity and ultimate recovery); 8 LNG trains developed in QLD in the period to 2027
Medium energy consumption from a centralised source	ACIL Allen base case demand and supply assumptions; 6 LNG trains currently committed, no new LNG developments (committed 6 LNG trains only)
Low energy consumption from a centralised source	Increased production costs for unconventional gas (higher drilling and completion costs, lower well productivity and ultimate recovery); lower ultimate resource conversion to reserves; committed 6 LNG trains only

Source: ACIL Allen

6.2 Projection results

Medium energy consumption from a centralised source

Figure 19 **Projected gas prices for major load centres: Medium case**



Note: Delivered prices to city-gates
Source: ACIL Allen GMG Australia modelling

Figure 20 **Projected gas prices (real 2014-15 $/GJ) for existing gas plant: Medium case**

Type	Station	Region	Zone	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
CCGT	Condamine	QLD	SWQ	4.52	6.14	7.41	7.34	7.34	7.73	8.01	8.15	8.24	8.25	8.35	8.45	8.44	8.43	8.46	8.50
CCGT	Darling Downs	QLD	SWQ	4.52	6.14	7.41	7.34	7.34	7.73	8.01	8.15	8.24	8.25	8.35	8.45	8.44	8.43	8.46	8.50
CCGT	Osborne	SA	ADE	4.91	5.63	6.47	6.63	6.69	7.07	7.51	7.79	7.86	7.92	8.12	8.30	8.49	8.73	9.00	9.20
CCGT	Pelican Point	SA	ADE	4.91	5.63	6.47	6.63	6.69	7.07	7.51	7.79	7.86	7.92	8.12	8.30	8.49	8.73	9.00	9.20
CCGT	Swanbank E	QLD	SEQ	4.80	6.63	7.96	7.89	7.89	8.21	8.56	8.69	8.72	8.72	8.82	8.92	8.91	8.90	8.93	8.97
CCGT	Tallawarra	NSW	NCEN	5.84	6.89	7.34	7.17	7.13	7.51	7.94	8.22	8.29	8.34	8.52	8.69	8.81	8.96	9.23	9.43
CCGT	Tamar Valley CCGT	TAS	TAS	4.81	5.54	6.38	6.54	6.62	7.01	7.45	7.74	7.81	7.88	8.06	8.25	8.37	8.53	8.81	9.02
CCGT	Townsville	QLD	NQ	5.92	5.92	5.91	6.25	6.58	6.94	7.30	7.30	7.30	7.29	7.29	7.28	7.28	7.28	7.27	7.27
Cogen	Smithfield	NSW	NCEN	5.84	6.89	7.34	7.17	7.13	7.51	7.94	8.22	8.29	8.34	8.52	8.69	8.81	8.96	9.23	9.43
Cogen	Yarwun	QLD	CQ	5.23	7.14	8.20	7.92	7.93	8.25	8.60	8.74	8.78	8.78	8.89	8.99	8.99	8.98	9.02	9.06
OCGT	Bairnsdale	VIC	LV	5.90	6.63	7.47	7.64	7.71	8.10	8.54	8.83	8.91	8.97	9.15	9.34	9.47	9.63	9.90	10.11
OCGT	Barcaldine	QLD	CQ	7.23	9.14	10.20	9.92	9.93	10.25	10.60	10.74	10.78	10.78	10.89	10.99	10.99	10.98	11.02	11.06
OCGT	Bell Bay Three	TAS	TAS	6.81	7.54	8.38	8.54	8.62	9.01	9.45	9.74	9.81	9.88	10.06	10.25	10.37	10.53	10.81	11.02
OCGT	Braemar	QLD	SWQ	6.52	8.14	9.41	9.34	9.34	9.73	10.01	10.15	10.24	10.25	10.35	10.45	10.44	10.43	10.46	10.50
OCGT	Braemar 2	QLD	SWQ	6.52	8.14	9.41	9.34	9.34	9.73	10.01	10.15	10.24	10.25	10.35	10.45	10.44	10.43	10.46	10.50
OCGT	Colongra	NSW	NCEN	7.84	8.89	9.34	9.17	9.13	9.51	9.94	10.22	10.29	10.34	10.52	10.69	10.81	10.96	11.23	11.43
OCGT	Dry Creek	SA	ADE	6.91	7.63	8.47	8.63	8.69	9.07	9.51	9.79	9.86	9.92	10.12	10.30	10.49	10.73	11.00	11.20
OCGT	Hallett	SA	NSA	7.50	8.77	9.39	9.31	9.31	10.18	11.20	11.47	11.52	11.51	11.61	11.70	11.69	11.67	11.69	11.72
OCGT	Jeeralang	VIC	LV	5.90	6.63	7.47	7.64	7.71	8.10	8.54	8.83	8.91	8.97	9.15	9.34	9.47	9.63	9.90	10.11
OCGT	Ladbroke Grove	SA	SESA	7.09	7.81	8.64	8.80	8.87	9.25	9.68	9.96	10.03	10.09	10.29	10.47	10.65	10.89	11.16	11.37
OCGT	Laverton North	VIC	MEL	6.32	7.05	7.89	8.06	8.13	8.52	8.96	9.25	9.33	9.39	9.58	9.76	9.89	10.05	10.32	10.53
OCGT	Mintaro	SA	NSA	7.50	8.77	9.39	9.31	9.31	10.18	11.20	11.47	11.52	11.51	11.61	11.70	11.69	11.67	11.69	11.72
OCGT	Mortlake OCGT	VIC	MEL	6.32	7.05	7.89	8.06	8.13	8.52	8.96	9.25	9.33	9.39	9.58	9.76	9.89	10.05	10.32	10.53
OCGT	Newport	VIC	MEL	6.32	7.05	7.89	8.06	8.13	8.52	8.96	9.25	9.33	9.39	9.58	9.76	9.89	10.05	10.32	10.53
OCGT	Oakey	QLD	SWQ	6.52	8.14	9.41	9.34	9.34	9.73	10.01	10.15	10.24	10.25	10.35	10.45	10.44	10.43	10.46	10.50
OCGT	Quarantine	SA	ADE	6.91	7.63	8.47	8.63	8.69	9.07	9.51	9.79	9.86	9.92	10.12	10.30	10.49	10.73	11.00	11.20
OCGT	Roma	QLD	SWQ	6.52	8.14	9.41	9.34	9.34	9.73	10.01	10.15	10.24	10.25	10.35	10.45	10.44	10.43	10.46	10.50
OCGT	Somerton	VIC	MEL	6.32	7.05	7.89	8.06	8.13	8.52	8.96	9.25	9.33	9.39	9.58	9.76	9.89	10.05	10.32	10.53
OCGT	Tamar Valley OCGT	TAS	TAS	6.81	7.54	8.38	8.54	8.62	9.01	9.45	9.74	9.81	9.88	10.06	10.25	10.37	10.53	10.81	11.02
OCGT	Torrens Island	SA	ADE	6.91	7.63	8.47	8.63	8.69	9.07	9.51	9.79	9.86	9.92	10.12	10.30	10.49	10.73	11.00	11.20
OCGT	Uranquinty	NSW	SWNSW	7.62	8.38	9.22	9.38	9.45	9.83	10.27	10.56	10.63	10.69	10.87	11.06	11.18	11.33	11.61	11.81
OCGT	Valley Power	VIC	LV	5.90	6.63	7.47	7.64	7.71	8.10	8.54	8.83	8.91	8.97	9.15	9.34	9.47	9.63	9.90	10.11

Source: ACIL Allen GMG Australia modelling

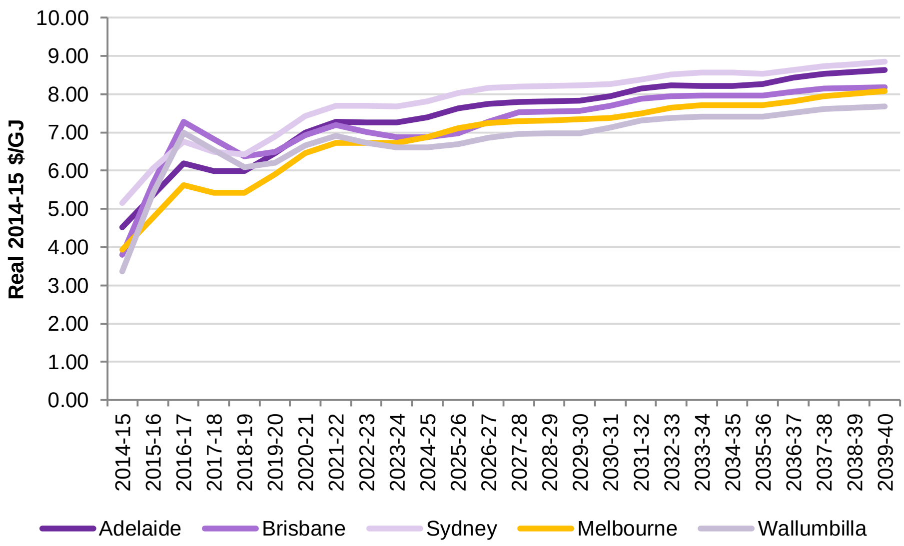
Figure 21 **Projected gas prices (real 2014-15 $/GJ) for new entrants: Medium case**

Technology	Zone	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
CCGT - Without CCS (ADE)	ADE	4.91	5.63	6.47	6.63	6.69	7.07	7.51	7.79	7.86	7.92	8.12	8.30	8.49	8.73	9.00	9.20
CCGT - Without CCS (CAN)	CAN	5.45	6.50	6.95	6.79	6.75	7.13	7.56	7.85	7.92	7.97	8.15	8.33	8.45	8.60	8.87	9.07
CCGT - Without CCS (CQ)	CQ	5.23	7.14	8.20	7.92	7.93	8.25	8.60	8.74	8.78	8.78	8.89	8.99	8.99	8.98	9.02	9.06
CCGT - Without CCS (CVIC)	CVIC	4.51	5.24	6.08	6.24	6.31	6.70	7.14	7.43	7.50	7.57	7.77	7.96	8.15	8.39	8.66	8.87
CCGT - Without CCS (LV)	LV	3.90	4.63	5.47	5.64	5.71	6.10	6.54	6.83	6.91	6.97	7.15	7.34	7.47	7.63	7.90	8.11
CCGT - Without CCS (MEL)	MEL	4.32	5.05	5.89	6.06	6.13	6.52	6.96	7.25	7.33	7.39	7.58	7.76	7.89	8.05	8.32	8.53
CCGT - Without CCS (NCEN)	NCEN	5.84	6.89	7.34	7.17	7.13	7.51	7.94	8.22	8.29	8.34	8.52	8.69	8.81	8.96	9.23	9.43
CCGT - Without CCS (NNS)	NNS	4.51	4.71	5.98	7.02	6.98	7.29	7.54	7.68	7.71	7.71	7.84	8.02	8.14	8.29	8.55	8.76
CCGT - Without CCS (NQ)	NQ	5.92	5.92	5.91	6.25	6.58	6.94	7.30	7.30	7.30	7.29	7.29	7.28	7.28	7.28	7.27	7.27
CCGT - Without CCS (NSA)	NSA	5.50	6.77	7.39	7.31	7.31	8.18	9.20	9.47	9.52	9.51	9.61	9.70	9.69	9.67	9.69	9.72
CCGT - Without CCS (NVIC)	NVIC	4.92	5.65	6.49	6.66	6.73	7.12	7.56	7.85	7.93	7.99	8.18	8.36	8.49	8.65	8.92	9.13
CCGT - Without CCS (SEQ)	SEQ	4.80	6.63	7.96	7.89	7.89	8.21	8.56	8.69	8.72	8.72	8.82	8.92	8.91	8.90	8.93	8.97
CCGT - Without CCS (SESA)	SESA	5.09	5.81	6.64	6.80	6.87	7.25	7.68	7.96	8.03	8.09	8.29	8.47	8.65	8.89	9.16	9.37
CCGT - Without CCS (SWNSW)	SWNSW	5.62	6.38	7.22	7.38	7.45	7.83	8.27	8.56	8.63	8.69	8.87	9.06	9.18	9.33	9.61	9.81
CCGT - Without CCS (SWQ)	SWQ	4.52	6.14	7.41	7.34	7.34	7.73	8.01	8.15	8.24	8.25	8.35	8.45	8.44	8.43	8.46	8.50
CCGT - Without CCS (TAS)	TAS	4.81	5.54	6.38	6.54	6.62	7.01	7.45	7.74	7.81	7.88	8.06	8.25	8.37	8.53	8.81	9.02
OCGT - Without CCS (ADE)	ADE	6.91	7.63	8.47	8.63	8.69	9.07	9.51	9.79	9.86	9.92	10.12	10.30	10.49	10.73	11.00	11.20
OCGT - Without CCS (CAN)	CAN	7.45	8.50	8.95	8.79	8.75	9.13	9.56	9.85	9.92	9.97	10.15	10.33	10.45	10.60	10.87	11.07
OCGT - Without CCS (CQ)	CQ	7.23	9.14	10.20	9.92	9.93	10.25	10.60	10.74	10.78	10.78	10.89	10.99	10.99	10.98	11.02	11.06
OCGT - Without CCS (CVIC)	CVIC	6.51	7.24	8.08	8.24	8.31	8.70	9.14	9.43	9.50	9.57	9.77	9.96	10.15	10.39	10.66	10.87
OCGT - Without CCS (LV)	LV	5.90	6.63	7.47	7.64	7.71	8.10	8.54	8.83	8.91	8.97	9.15	9.34	9.47	9.63	9.90	10.11
OCGT - Without CCS (MEL)	MEL	6.32	7.05	7.89	8.06	8.13	8.52	8.96	9.25	9.33	9.39	9.58	9.76	9.89	10.05	10.32	10.53
OCGT - Without CCS (NCEN)	NCEN	7.84	8.89	9.34	9.17	9.13	9.51	9.94	10.22	10.29	10.34	10.52	10.69	10.81	10.96	11.23	11.43
OCGT - Without CCS (NNS)	NNS	6.51	6.71	7.98	9.02	8.98	9.29	9.54	9.68	9.71	9.71	9.84	10.02	10.14	10.29	10.55	10.76
OCGT - Without CCS (NQ)	NQ	7.92	7.92	7.91	8.25	8.58	8.94	9.30	9.30	9.30	9.29	9.29	9.28	9.28	9.28	9.27	9.27
OCGT - Without CCS (NSA)	NSA	7.50	8.77	9.39	9.31	9.31	10.18	11.20	11.47	11.52	11.51	11.61	11.70	11.69	11.67	11.69	11.72
OCGT - Without CCS (NVIC)	NVIC	6.92	7.65	8.49	8.66	8.73	9.12	9.56	9.85	9.93	9.99	10.18	10.36	10.49	10.65	10.92	11.13
OCGT - Without CCS (SEQ)	SEQ	6.80	8.63	9.96	9.89	9.89	10.21	10.56	10.69	10.72	10.72	10.82	10.92	10.91	10.90	10.93	10.97
OCGT - Without CCS (SESA)	SESA	7.09	7.81	8.64	8.80	8.87	9.25	9.68	9.96	10.03	10.09	10.29	10.47	10.65	10.89	11.16	11.37
OCGT - Without CCS (SWNSW)	SWNSW	7.62	8.38	9.22	9.38	9.45	9.83	10.27	10.56	10.63	10.69	10.87	11.06	11.18	11.33	11.61	11.81
OCGT - Without CCS (SWQ)	SWQ	6.52	8.14	9.41	9.34	9.34	9.73	10.01	10.15	10.24	10.25	10.35	10.45	10.44	10.43	10.46	10.50
OCGT - Without CCS (TAS)	TAS	6.81	7.54	8.38	8.54	8.62	9.01	9.45	9.74	9.81	9.88	10.06	10.25	10.37	10.53	10.81	11.02

Source: ACIL Allen GMG Australia modelling

High energy consumption from a centralised source

Figure 22 **Projected gas prices for major load centres: High case**



Note: Delivered prices to city-gates

Source: ACIL Allen GMG Australia modelling

Figure 23 **Projected gas prices (real 2014-15 $/GJ) for existing gas plant: High case**

Type	Station	Region	Zone	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
CCGT	Condamine	QLD	SWQ	3.58	5.25	6.71	6.27	5.89	6.08	6.45	6.71	6.60	6.47	6.47	6.56	6.87	7.12	7.14	7.15
CCGT	Darling Downs	QLD	SWQ	3.58	5.25	6.71	6.27	5.89	6.08	6.45	6.71	6.60	6.47	6.47	6.56	6.87	7.12	7.14	7.15
CCGT	Osborne	SA	ADE	4.52	5.35	6.19	5.99	5.99	6.45	7.00	7.27	7.27	7.26	7.40	7.62	7.75	7.80	7.81	7.83
CCGT	Pelican Point	SA	ADE	4.52	5.35	6.19	5.99	5.99	6.45	7.00	7.27	7.27	7.26	7.40	7.62	7.75	7.80	7.81	7.83
CCGT	Swanbank E	QLD	SEQ	3.87	5.74	7.33	6.89	6.44	6.56	6.99	7.26	7.07	6.95	6.95	7.03	7.34	7.59	7.61	7.62
CCGT	Tallawarra	NSW	NCEN	5.16	6.05	6.76	6.50	6.42	6.89	7.43	7.70	7.69	7.68	7.81	8.04	8.17	8.21	8.22	8.24
CCGT	Tamar Valley CCGT	TAS	TAS	4.41	5.26	6.10	5.91	5.91	6.38	6.93	7.22	7.22	7.22	7.36	7.59	7.73	7.78	7.80	7.83
CCGT	Townsville	QLD	NQ	4.91	4.91	4.90	4.90	4.90	4.89	4.89	4.88	4.88	4.99	5.10	5.43	6.33	6.90	6.92	6.92
Cogen	Smithfield	NSW	NCEN	5.16	6.05	6.76	6.50	6.42	6.89	7.43	7.70	7.69	7.68	7.81	8.04	8.17	8.21	8.22	8.24
Cogen	Yarwun	QLD	CQ	4.29	6.25	7.56	6.92	6.48	6.60	7.04	7.31	7.13	7.01	7.02	7.10	7.27	7.37	7.40	7.41
OCGT	Bairnsdale	VIC	LV	5.51	6.35	7.20	7.00	7.01	7.48	8.03	8.31	8.31	8.31	8.45	8.69	8.82	8.87	8.90	8.92
OCGT	Barcaldine	QLD	CQ	6.29	8.25	9.56	8.92	8.48	8.60	9.04	9.31	9.13	9.01	9.02	9.10	9.27	9.37	9.40	9.41
OCGT	Bell Bay Three	TAS	TAS	6.41	7.26	8.10	7.91	7.91	8.38	8.93	9.22	9.22	9.22	9.36	9.59	9.73	9.78	9.80	9.83
OCGT	Braemar	QLD	SWQ	5.58	7.25	8.71	8.27	7.89	8.08	8.45	8.71	8.60	8.47	8.47	8.56	8.87	9.12	9.14	9.15
OCGT	Braemar 2	QLD	SWQ	5.58	7.25	8.71	8.27	7.89	8.08	8.45	8.71	8.60	8.47	8.47	8.56	8.87	9.12	9.14	9.15
OCGT	Colongra	NSW	NCEN	7.16	8.05	8.76	8.50	8.42	8.89	9.43	9.70	9.69	9.68	9.81	10.04	10.17	10.21	10.22	10.24
OCGT	Dry Creek	SA	ADE	6.52	7.35	8.19	7.99	7.99	8.45	9.00	9.27	9.27	9.26	9.40	9.62	9.75	9.80	9.81	9.83
OCGT	Hallett	SA	NSA	6.81	7.88	8.75	8.31	8.05	8.68	9.62	10.06	9.87	9.74	9.73	9.81	9.97	10.06	10.07	10.08
OCGT	Jeeralang	VIC	LV	5.51	6.35	7.20	7.00	7.01	7.48	8.03	8.31	8.31	8.31	8.45	8.69	8.82	8.87	8.90	8.92
OCGT	Ladbroke Grove	SA	SESA	6.69	7.53	8.37	8.17	8.16	8.63	9.17	9.44	9.44	9.43	9.57	9.79	9.92	9.96	9.98	10.00
OCGT	Laverton North	VIC	MEL	5.93	6.77	7.62	7.43	7.43	7.90	8.45	8.73	8.73	8.73	8.88	9.11	9.24	9.29	9.32	9.34
OCGT	Mintaro	SA	NSA	6.81	7.88	8.75	8.31	8.05	8.68	9.62	10.06	9.87	9.74	9.73	9.81	9.97	10.06	10.07	10.08
OCGT	Mortlake OCGT	VIC	MEL	5.93	6.77	7.62	7.43	7.43	7.90	8.45	8.73	8.73	8.73	8.88	9.11	9.24	9.29	9.32	9.34
OCGT	Newport	VIC	MEL	5.93	6.77	7.62	7.43	7.43	7.90	8.45	8.73	8.73	8.73	8.88	9.11	9.24	9.29	9.32	9.34
OCGT	Oakey	QLD	SWQ	5.58	7.25	8.71	8.27	7.89	8.08	8.45	8.71	8.60	8.47	8.47	8.56	8.87	9.12	9.14	9.15
OCGT	Quarantine	SA	ADE	6.52	7.35	8.19	7.99	7.99	8.45	9.00	9.27	9.27	9.26	9.40	9.62	9.75	9.80	9.81	9.83
OCGT	Roma	QLD	SWQ	5.58	7.25	8.71	8.27	7.89	8.08	8.45	8.71	8.60	8.47	8.47	8.56	8.87	9.12	9.14	9.15
OCGT	Somerton	VIC	MEL	5.93	6.77	7.62	7.43	7.43	7.90	8.45	8.73	8.73	8.73	8.88	9.11	9.24	9.29	9.32	9.34
OCGT	Tamar Valley OCGT	TAS	TAS	6.41	7.26	8.10	7.91	7.91	8.38	8.93	9.22	9.22	9.22	9.36	9.59	9.73	9.78	9.80	9.83
OCGT	Torrens Island	SA	ADE	6.52	7.35	8.19	7.99	7.99	8.45	9.00	9.27	9.27	9.26	9.40	9.62	9.75	9.80	9.81	9.83
OCGT	Uranquinty	NSW	SWNSW	7.23	8.10	8.94	8.70	8.65	9.16	9.76	10.04	10.03	10.03	10.17	10.39	10.52	10.58	10.60	10.62
OCGT	Valley Power	VIC	LV	5.51	6.35	7.20	7.00	7.01	7.48	8.03	8.31	8.31	8.31	8.45	8.69	8.82	8.87	8.90	8.92

Source: ACIL Allen GMG Australia modelling

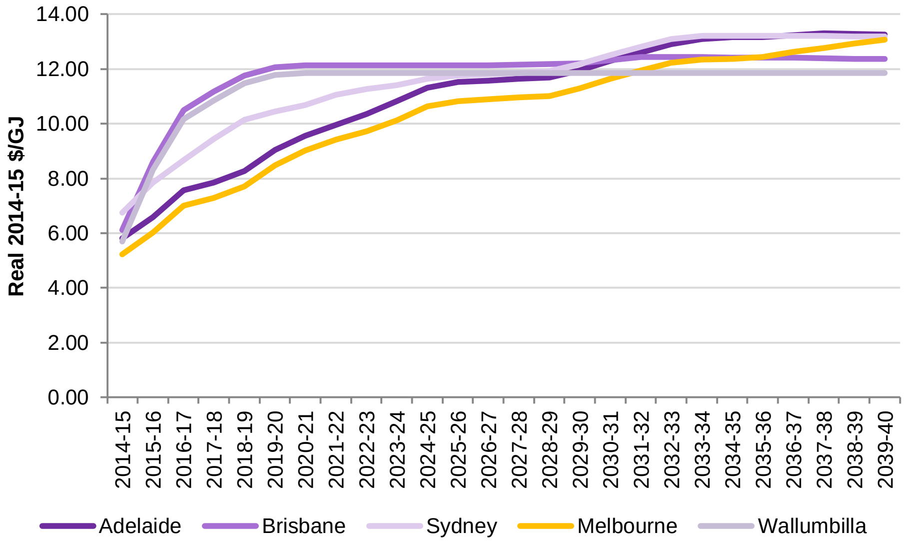
Figure 24 **Projected gas prices (real 2014-15 $/GJ) for new entrants: High case**

Technology	Zone	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
CCGT - Without CCS (ADE)	ADE	4.52	5.35	6.19	5.99	5.99	6.45	7.00	7.27	7.27	7.26	7.40	7.62	7.75	7.80	7.81	7.83
CCGT - Without CCS (CAN)	CAN	4.77	5.67	6.37	6.11	6.04	6.51	7.05	7.33	7.32	7.31	7.45	7.67	7.80	7.85	7.86	7.88
CCGT - Without CCS (CQ)	CQ	4.29	6.25	7.56	6.92	6.48	6.60	7.04	7.31	7.13	7.01	7.02	7.10	7.27	7.37	7.40	7.41
CCGT - Without CCS (CVIC)	CVIC	4.12	4.96	5.80	5.61	5.61	6.08	6.63	6.91	6.91	6.90	7.05	7.28	7.41	7.46	7.48	7.51
CCGT - Without CCS (LV)	LV	3.51	4.35	5.20	5.00	5.01	5.48	6.03	6.31	6.31	6.31	6.45	6.69	6.82	6.87	6.90	6.92
CCGT - Without CCS (MEL)	MEL	3.93	4.77	5.62	5.43	5.43	5.90	6.45	6.73	6.73	6.73	6.88	7.11	7.24	7.29	7.32	7.34
CCGT - Without CCS (NCEN)	NCEN	5.16	6.05	6.76	6.50	6.42	6.89	7.43	7.70	7.69	7.68	7.81	8.04	8.17	8.21	8.22	8.24
CCGT - Without CCS (NNS)	NNS	3.68	3.77	5.19	6.35	6.27	6.74	7.02	7.03	7.02	7.01	7.14	7.37	7.49	7.53	7.55	7.57
CCGT - Without CCS (NQ)	NQ	4.91	4.91	4.90	4.90	4.90	4.89	4.89	4.88	4.88	4.99	5.10	5.43	6.33	6.90	6.92	6.92
CCGT - Without CCS (NSA)	NSA	4.81	5.88	6.75	6.31	6.05	6.68	7.62	8.06	7.87	7.74	7.73	7.81	7.97	8.06	8.07	8.08
CCGT - Without CCS (NVIC)	NVIC	4.53	5.37	6.22	6.03	6.03	6.50	7.05	7.33	7.33	7.33	7.47	7.71	7.84	7.89	7.92	7.94
CCGT - Without CCS (SEQ)	SEQ	3.87	5.74	7.33	6.89	6.44	6.56	6.99	7.26	7.07	6.95	6.95	7.03	7.34	7.59	7.61	7.62
CCGT - Without CCS (SESA)	SESA	4.69	5.53	6.37	6.17	6.16	6.63	7.17	7.44	7.44	7.43	7.57	7.79	7.92	7.96	7.98	8.00
CCGT - Without CCS (SWNSW)	SWNSW	5.23	6.10	6.94	6.70	6.65	7.16	7.76	8.04	8.03	8.03	8.17	8.39	8.52	8.58	8.60	8.62
CCGT - Without CCS (SWQ)	SWQ	3.58	5.25	6.71	6.27	5.89	6.08	6.45	6.71	6.60	6.47	6.47	6.56	6.87	7.12	7.14	7.15
CCGT - Without CCS (TAS)	TAS	4.41	5.26	6.10	5.91	5.91	6.38	6.93	7.22	7.22	7.22	7.36	7.59	7.73	7.78	7.80	7.83
OCGT - Without CCS (ADE)	ADE	6.52	7.35	8.19	7.99	7.99	8.45	9.00	9.27	9.27	9.26	9.40	9.62	9.75	9.80	9.81	9.83
OCGT - Without CCS (CAN)	CAN	6.77	7.67	8.37	8.11	8.04	8.51	9.05	9.33	9.32	9.31	9.45	9.67	9.80	9.85	9.86	9.88
OCGT - Without CCS (CQ)	CQ	6.29	8.25	9.56	8.92	8.48	8.60	9.04	9.31	9.13	9.01	9.02	9.10	9.27	9.37	9.40	9.41
OCGT - Without CCS (CVIC)	CVIC	6.12	6.96	7.80	7.61	7.61	8.08	8.63	8.91	8.91	8.90	9.05	9.28	9.41	9.46	9.48	9.51
OCGT - Without CCS (LV)	LV	5.51	6.35	7.20	7.00	7.01	7.48	8.03	8.31	8.31	8.31	8.45	8.69	8.82	8.87	8.90	8.92
OCGT - Without CCS (MEL)	MEL	5.93	6.77	7.62	7.43	7.43	7.90	8.45	8.73	8.73	8.73	8.88	9.11	9.24	9.29	9.32	9.34
OCGT - Without CCS (NCEN)	NCEN	7.16	8.05	8.76	8.50	8.42	8.89	9.43	9.70	9.69	9.68	9.81	10.04	10.17	10.21	10.22	10.24
OCGT - Without CCS (NNS)	NNS	5.68	5.77	7.19	8.35	8.27	8.74	9.02	9.03	9.02	9.01	9.14	9.37	9.49	9.53	9.55	9.57
OCGT - Without CCS (NQ)	NQ	6.91	6.91	6.90	6.90	6.90	6.89	6.89	6.88	6.88	6.99	7.10	7.43	8.33	8.90	8.92	8.92
OCGT - Without CCS (NSA)	NSA	6.81	7.88	8.75	8.31	8.05	8.68	9.62	10.06	9.87	9.74	9.73	9.81	9.97	10.06	10.07	10.08
OCGT - Without CCS (NVIC)	NVIC	6.53	7.37	8.22	8.03	8.03	8.50	9.05	9.33	9.33	9.33	9.47	9.71	9.84	9.89	9.92	9.94
OCGT - Without CCS (SEQ)	SEQ	5.87	7.74	9.33	8.89	8.44	8.56	8.99	9.26	9.07	8.95	8.95	9.03	9.34	9.59	9.61	9.62
OCGT - Without CCS (SESA)	SESA	6.69	7.53	8.37	8.17	8.16	8.63	9.17	9.44	9.44	9.43	9.57	9.79	9.92	9.96	9.98	10.00
OCGT - Without CCS (SWNSW)	SWNSW	7.23	8.10	8.94	8.70	8.65	9.16	9.76	10.04	10.03	10.03	10.17	10.39	10.52	10.58	10.60	10.62
OCGT - Without CCS (SWQ)	SWQ	5.58	7.25	8.71	8.27	7.89	8.08	8.45	8.71	8.60	8.47	8.47	8.56	8.87	9.12	9.14	9.15
OCGT - Without CCS (TAS)	TAS	6.41	7.26	8.10	7.91	7.91	8.38	8.93	9.22	9.22	9.22	9.36	9.59	9.73	9.78	9.80	9.83

Source: ACIL Allen GMG Australia modelling

Low energy consumption from a centralised source

Figure 25 **Projected gas prices for major load centres: Low case**



Note: Delivered prices to city-gates

Source: ACIL Allen GMG Australia modelling

Figure 26 **Projected gas prices (real 2014-15 $/GJ) for existing gas plant: Low case**

Type	Station	Region	Zone	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
CCGT	Condamine	QLD	SWQ	5.90	8.17	10.00	10.70	11.30	11.58	11.59	11.66	11.73	11.73	11.73	11.73	11.73	11.75	11.78	11.80
CCGT	Darling Downs	QLD	SWQ	5.90	8.17	10.00	10.70	11.30	11.58	11.59	11.66	11.73	11.73	11.73	11.73	11.73	11.75	11.78	11.80
CCGT	Osborne	SA	ADE	5.81	6.59	7.57	7.86	8.28	9.03	9.56	9.95	10.34	10.83	11.32	11.52	11.58	11.63	11.69	11.95
CCGT	Pelican Point	SA	ADE	5.81	6.59	7.57	7.86	8.28	9.03	9.56	9.95	10.34	10.83	11.32	11.52	11.58	11.63	11.69	11.95
CCGT	Swanbank E	QLD	SEQ	6.19	8.57	10.37	11.05	11.65	12.04	12.21	12.21	12.20	12.20	12.20	12.20	12.20	12.22	12.25	12.26
CCGT	Tallawarra	NSW	NCEN	6.75	7.85	8.67	9.43	10.14	10.44	10.68	11.05	11.26	11.40	11.65	11.76	11.81	11.86	11.92	12.18
CCGT	Tamar Valley CCGT	TAS	TAS	5.71	6.49	7.48	7.78	8.20	8.96	9.49	9.90	10.20	10.61	11.11	11.31	11.38	11.44	11.50	11.77
CCGT	Townsville	QLD	NQ	6.93	6.93	6.92	8.88	11.00	11.15	11.14	11.34	11.53	11.53	11.52	11.52	11.52	11.53	11.56	11.57
Cogen	Smithfield	NSW	NCEN	6.75	7.85	8.67	9.43	10.14	10.44	10.68	11.05	11.26	11.40	11.65	11.76	11.81	11.86	11.92	12.18
Cogen	Yarwun	QLD	CQ	6.61	9.16	10.96	11.54	11.96	12.17	12.25	12.26	12.26	12.27	12.27	12.28	12.28	12.28	12.29	12.29
OCGT	Bairnsdale	VIC	LV	6.80	7.59	8.58	8.87	9.30	10.06	10.59	10.99	11.30	11.70	12.21	12.41	12.47	12.53	12.59	12.86
OCGT	Barcaldine	QLD	CQ	8.61	11.16	12.96	13.54	13.96	14.17	14.25	14.26	14.26	14.27	14.27	14.28	14.28	14.28	14.29	14.29
OCGT	Bell Bay Three	TAS	TAS	7.71	8.49	9.48	9.78	10.20	10.96	11.49	11.90	12.20	12.61	13.11	13.31	13.38	13.44	13.50	13.77
OCGT	Braemar	QLD	SWQ	7.90	10.17	12.00	12.70	13.30	13.58	13.59	13.66	13.73	13.73	13.73	13.73	13.73	13.75	13.78	13.80
OCGT	Braemar 2	QLD	SWQ	7.90	10.17	12.00	12.70	13.30	13.58	13.59	13.66	13.73	13.73	13.73	13.73	13.73	13.75	13.78	13.80
OCGT	Colongra	NSW	NCEN	8.75	9.85	10.67	11.43	12.14	12.44	12.68	13.05	13.26	13.40	13.65	13.76	13.81	13.86	13.92	14.18
OCGT	Dry Creek	SA	ADE	7.81	8.59	9.57	9.86	10.28	11.03	11.56	11.95	12.34	12.83	13.32	13.52	13.58	13.63	13.69	13.95
OCGT	Hallett	SA	NSA	8.40	10.31	11.94	12.62	13.33	13.71	13.94	14.30	14.51	14.64	14.88	14.98	14.98	14.97	14.96	14.96
OCGT	Jeeralang	VIC	LV	6.80	7.59	8.58	8.87	9.30	10.06	10.59	10.99	11.30	11.70	12.21	12.41	12.47	12.53	12.59	12.86
OCGT	Ladbroke Grove	SA	SESA	7.99	8.77	9.75	10.03	10.45	11.21	11.73	12.13	12.51	13.00	13.49	13.69	13.75	13.80	13.85	14.11
OCGT	Laverton North	VIC	MEL	7.23	8.01	9.00	9.29	9.72	10.48	11.01	11.41	11.72	12.12	12.63	12.83	12.89	12.95	13.01	13.28
OCGT	Mintaro	SA	NSA	8.40	10.31	11.94	12.62	13.33	13.71	13.94	14.30	14.51	14.64	14.88	14.98	14.98	14.97	14.96	14.96
OCGT	Mortlake OCGT	VIC	MEL	7.23	8.01	9.00	9.29	9.72	10.48	11.01	11.41	11.72	12.12	12.63	12.83	12.89	12.95	13.01	13.28
OCGT	Newport	VIC	MEL	7.23	8.01	9.00	9.29	9.72	10.48	11.01	11.41	11.72	12.12	12.63	12.83	12.89	12.95	13.01	13.28
OCGT	Oakey	QLD	SWQ	7.90	10.17	12.00	12.70	13.30	13.58	13.59	13.66	13.73	13.73	13.73	13.73	13.73	13.75	13.78	13.80
OCGT	Quarantine	SA	ADE	7.81	8.59	9.57	9.86	10.28	11.03	11.56	11.95	12.34	12.83	13.32	13.52	13.58	13.63	13.69	13.95
OCGT	Roma	QLD	SWQ	7.90	10.17	12.00	12.70	13.30	13.58	13.59	13.66	13.73	13.73	13.73	13.73	13.73	13.75	13.78	13.80
OCGT	Somerton	VIC	MEL	7.23	8.01	9.00	9.29	9.72	10.48	11.01	11.41	11.72	12.12	12.63	12.83	12.89	12.95	13.01	13.28
OCGT	Tamar Valley OCGT	TAS	TAS	7.71	8.49	9.48	9.78	10.20	10.96	11.49	11.90	12.20	12.61	13.11	13.31	13.38	13.44	13.50	13.77
OCGT	Torrens Island	SA	ADE	7.81	8.59	9.57	9.86	10.28	11.03	11.56	11.95	12.34	12.83	13.32	13.52	13.58	13.63	13.69	13.95
OCGT	Uranquinty	NSW	SWNSW	8.53	9.34	10.32	11.00	11.72	12.11	12.35	12.72	13.02	13.42	13.92	14.12	14.18	14.24	14.30	14.56
OCGT	Valley Power	VIC	LV	6.80	7.59	8.58	8.87	9.30	10.06	10.59	10.99	11.30	11.70	12.21	12.41	12.47	12.53	12.59	12.86

Source: ACIL Allen GMG Australia modelling

Figure 27 **Projected gas prices (real 2014-15 $/GJ) for new entrants: Low case**

Technology	Zone	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
CCGT - Without CCS (ADE)	ADE	5.81	6.59	7.57	7.86	8.28	9.03	9.56	9.95	10.34	10.83	11.32	11.52	11.58	11.63	11.69	11.95
CCGT - Without CCS (CAN)	CAN	6.36	7.46	8.28	9.05	9.76	10.06	10.30	10.68	10.89	11.03	11.28	11.39	11.45	11.50	11.56	11.82
CCGT - Without CCS (CQ)	CQ	6.61	9.16	10.96	11.54	11.96	12.17	12.25	12.26	12.26	12.27	12.27	12.28	12.28	12.28	12.29	12.29
CCGT - Without CCS (CVIC)	CVIC	5.41	6.20	7.19	7.48	7.90	8.66	9.19	9.59	9.98	10.47	10.97	11.18	11.24	11.30	11.35	11.62
CCGT - Without CCS (LV)	LV	4.80	5.59	6.58	6.87	7.30	8.06	8.59	8.99	9.30	9.70	10.21	10.41	10.47	10.53	10.59	10.86
CCGT - Without CCS (MEL)	MEL	5.23	6.01	7.00	7.29	7.72	8.48	9.01	9.41	9.72	10.12	10.63	10.83	10.89	10.95	11.01	11.28
CCGT - Without CCS (NCEN)	NCEN	6.75	7.85	8.67	9.43	10.14	10.44	10.68	11.05	11.26	11.40	11.65	11.76	11.81	11.86	11.92	12.18
CCGT - Without CCS (NNS)	NNS	5.48	5.65	7.22	9.69	10.81	11.11	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.19	11.24	11.50
CCGT - Without CCS (NQ)	NQ	6.93	6.93	6.92	8.88	11.00	11.15	11.14	11.34	11.53	11.53	11.52	11.52	11.52	11.53	11.56	11.57
CCGT - Without CCS (NSA)	NSA	6.40	8.31	9.94	10.62	11.33	11.71	11.94	12.30	12.51	12.64	12.88	12.98	12.98	12.97	12.96	12.96
CCGT - Without CCS (NVIC)	NVIC	5.83	6.61	7.60	8.28	9.00	9.39	9.64	10.01	10.32	10.72	11.23	11.43	11.49	11.55	11.61	11.88
CCGT - Without CCS (SEQ)	SEQ	6.19	8.57	10.37	11.05	11.65	12.04	12.21	12.21	12.20	12.20	12.20	12.20	12.20	12.22	12.25	12.26
CCGT - Without CCS (SESA)	SESA	5.99	6.77	7.75	8.03	8.45	9.21	9.73	10.13	10.51	11.00	11.49	11.69	11.75	11.80	11.85	12.11
CCGT - Without CCS (SWNSW)	SWNSW	6.53	7.34	8.32	9.00	9.72	10.11	10.35	10.72	11.02	11.42	11.92	12.12	12.18	12.24	12.30	12.56
CCGT - Without CCS (SWQ)	SWQ	5.90	8.17	10.00	10.70	11.30	11.58	11.59	11.66	11.73	11.73	11.73	11.73	11.73	11.75	11.78	11.80
CCGT - Without CCS (TAS)	TAS	5.71	6.49	7.48	7.78	8.20	8.96	9.49	9.90	10.20	10.61	11.11	11.31	11.38	11.44	11.50	11.77
OCGT - Without CCS (ADE)	ADE	7.81	8.59	9.57	9.86	10.28	11.03	11.56	11.95	12.34	12.83	13.32	13.52	13.58	13.63	13.69	13.95
OCGT - Without CCS (CAN)	CAN	8.36	9.46	10.28	11.05	11.76	12.06	12.30	12.68	12.89	13.03	13.28	13.39	13.45	13.50	13.56	13.82
OCGT - Without CCS (CQ)	CQ	8.61	11.16	12.96	13.54	13.96	14.17	14.25	14.26	14.26	14.27	14.27	14.28	14.28	14.28	14.29	14.29
OCGT - Without CCS (CVIC)	CVIC	7.41	8.20	9.19	9.48	9.90	10.66	11.19	11.59	11.98	12.47	12.97	13.18	13.24	13.30	13.35	13.62
OCGT - Without CCS (LV)	LV	6.80	7.59	8.58	8.87	9.30	10.06	10.59	10.99	11.30	11.70	12.21	12.41	12.47	12.53	12.59	12.86
OCGT - Without CCS (MEL)	MEL	7.23	8.01	9.00	9.29	9.72	10.48	11.01	11.41	11.72	12.12	12.63	12.83	12.89	12.95	13.01	13.28
OCGT - Without CCS (NCEN)	NCEN	8.75	9.85	10.67	11.43	12.14	12.44	12.68	13.05	13.26	13.40	13.65	13.76	13.81	13.86	13.92	14.18
OCGT - Without CCS (NNS)	NNS	7.48	7.65	9.22	11.69	12.81	13.11	13.19	13.19	13.19	13.19	13.19	13.19	13.19	13.19	13.24	13.50
OCGT - Without CCS (NQ)	NQ	8.93	8.93	8.92	10.88	13.00	13.15	13.14	13.34	13.53	13.53	13.52	13.52	13.52	13.53	13.56	13.57
OCGT - Without CCS (NSA)	NSA	8.40	10.31	11.94	12.62	13.33	13.71	13.94	14.30	14.51	14.64	14.88	14.98	14.98	14.97	14.96	14.96
OCGT - Without CCS (NVIC)	NVIC	7.83	8.61	9.60	10.28	11.00	11.39	11.64	12.01	12.32	12.72	13.23	13.43	13.49	13.55	13.61	13.88
OCGT - Without CCS (SEQ)	SEQ	8.19	10.57	12.37	13.05	13.65	14.04	14.21	14.21	14.20	14.20	14.20	14.20	14.20	14.22	14.25	14.26
OCGT - Without CCS (SESA)	SESA	7.99	8.77	9.75	10.03	10.45	11.21	11.73	12.13	12.51	13.00	13.49	13.69	13.75	13.80	13.85	14.11
OCGT - Without CCS (SWNSW)	SWNSW	8.53	9.34	10.32	11.00	11.72	12.11	12.35	12.72	13.02	13.42	13.92	14.12	14.18	14.24	14.30	14.56
OCGT - Without CCS (SWQ)	SWQ	7.90	10.17	12.00	12.70	13.30	13.58	13.59	13.66	13.73	13.73	13.73	13.73	13.73	13.75	13.78	13.80
OCGT - Without CCS (TAS)	TAS	7.71	8.49	9.48	9.78	10.20	10.96	11.49	11.90	12.20	12.61	13.11	13.31	13.38	13.44	13.50	13.77

Source: ACIL Allen GMG Australia modelling

7 Results – Coal prices

7.1 Approach

7.1.1 Existing power stations

For existing stations:

- the price for coal supplied from integrated mine mouth operations is the marginal price of supplying coal (for ex-mine operations fixed costs are not generally included in the coal price)
- the price for coal supplied by third parties is taken as the contract price
- where a power station is supplied by more than one contract, the price is taken as the tonnage weighted average of the contract prices.

For power stations with multiple coal contracts consideration was given to using the price of the marginal coal contract or alternatively the opportunity cost of the coal supply, as the coal price to the power station, but these approaches were not suitable for AEMO purposes.

In arriving at the coal price projections for each existing power station ACIL Allen has considered:

- existing contractual and other supply arrangements
- source and cost of new/replacement coal supply sources in the future taking into account, export prices and mining and transport costs.

The price for new coal contracts is taken as the maximum of the production cost and 90% of export parity value. The 90% of export parity estimate by ACIL Allen is based on recent domestic coal contract prices and presumably relates to the lower price and exchange rate and other risks for the producer when supplying domestic coal versus exporting.

7.1.2 New power stations

For new stations ACIL Allen undertook and analysis of known coal deposits in the 17 zones and selected those zones where adequate coal resources were available to support at least 1000 MW of future coal fired generation. Only seven of the 17 zones were judged as having adequate coal resources and they were NQ, CQ and SWQ in Queensland NCEN, NNS and SWNSW in New South Wales and LV in Victoria.

The price of black coal in each zone in Queensland and New South Wales was based on the deposit found to have the lowest delivered cost to a power station located close to the transmission network in that zone. For each black coal deposit the delivered price of coal was taken as the maximum of the cost of production and export parity value.

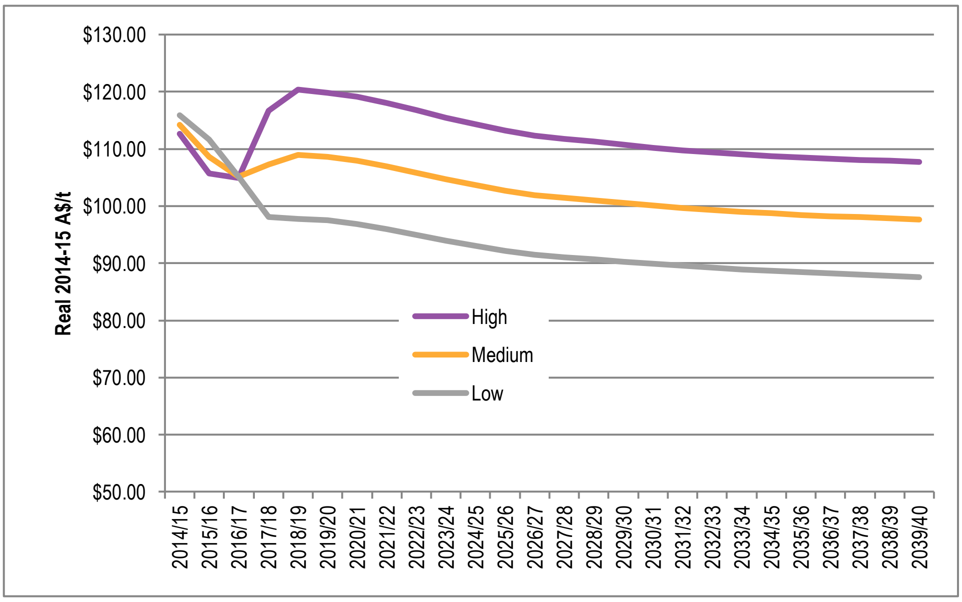
For Victoria the delivered price of brown coal is assumed at the cash cost of production.

7.2 Export coal prices

The Free on Board (FOB) price for thermal coal is an important consideration in the price formation for all new coal contracts in New South Wales and for some in Queensland. The projection of these prices underlies the projected future export parity value of the Run of Mine (ROM) coal at each location which is an important consideration in setting the likely delivered price into local power stations.

Figure 28 shows the assumed export prices in real 2014/15 A$/t for each of the three planning scenarios. The figures in real 2014-15 A$/t prices have been calculated by applying the US$/$A exchange rate and the Australian CPI to in nominal US$/t forecast of FOB coal prices as supplied by AEMO.

Figure 28 **Assumed export coal prices (Real 2014-15 A$/t)**

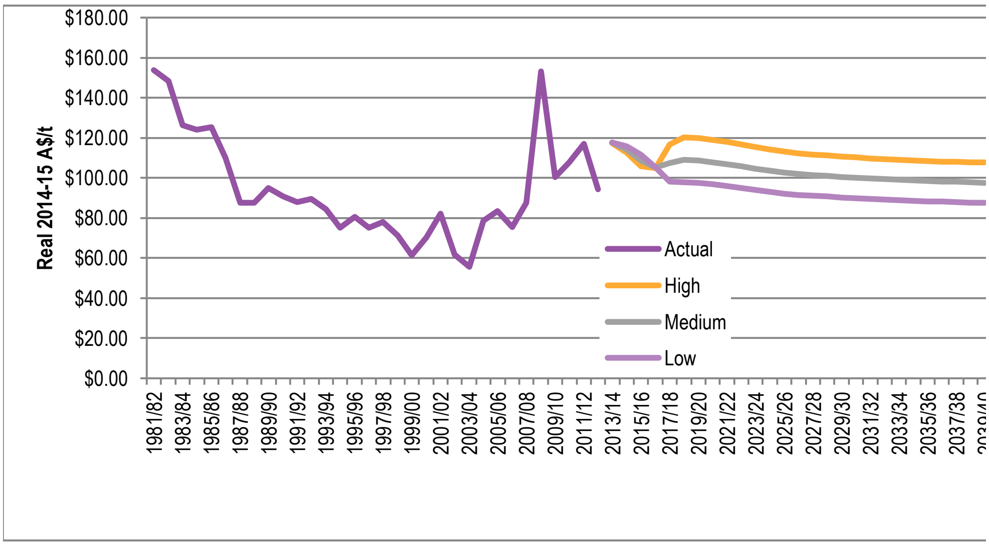


Source: *AEMO*

Figure 28 shows for the median scenario that, after the initial period to 2019/20 where the real 2014/15 A$/t price recovers to around A$110/t, the real FOB coal price is forecast to gradually decline to around A$98/t by 2039/40. Post 2019/20, the real A$/t FOB coal price in the high scenario is forecast to be A$10.00/t higher than the median scenario while the low scenario is forecast to be A$10.00/t lower.

The graph below plots the historic prices against the forecast prices for the three scenarios.

Figure 29 **Assumed export coal prices in comparison with historic prices**



Source: *ACIL Allen analysis with AEMO forecast*

7.3 Price of coal into existing power stations

New South Wales

In New South Wales 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 coal prices from early 2004 and carry contract prices which are generally well below the export parity value being experienced in today's export market.

There are a number of strategies which local power stations are likely to employ to keep prices of new tonnage lower than export parity price including:

- acquisition of undeveloped resources and employing a contract miner to produce the coal. (there are many unallocated resources available in New South Wales for this purpose)
- offering firm long term contracts to potential new developments in order to achieve discounted prices by lowering the market and infrastructure risks associated new developments
- accepting lower value high ash coal, oxidised coal and washery rejects and middlings.

We expect these purchase strategies to result in reductions of around 10% on the export parity price of coal.

Figure 30 summarises the projected delivered coal prices into the major NSW power stations. It shows significant increases in price in all three scenarios for Delta Coastal in 2021/22, Eraring in 2022-23 and Macquarie Generation in 2026-27 when all existing contracts have expired and prices follow 90% of the export parity price. The price to Delta Western is 90% of the export parity price form 2014-15 as there are no existing contracts. In the long term the price to the western stations is lowest and to the coastal stations the highest because of the noticeably higher transport cost reduce the export parity value of coal into the western stations. The price to Macquarie Generation in the longer term is only slightly higher than in the west because the transport cost differential is eroded by the fact that the lower quality open cut mine coal going to Macquarie Generation has lower washery yields for export than the western longwall mines. Coal to Redbank is assumed to be continued low quality washery tailings.

Figure 30 **Projected coal price (real 2014-15 $/GJ) into NSW existing stations**

Source: ACIL Allen analysis volume weighted prices

Table 29 **Coal prices into existing power stations in NSW (Real 2014-15 $/GJ) – High scenario**

	2014/ 15	2015/ 16	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26	2026/ 27	2027/ 28	2028/ 29	2029/ 30
MacGen	$1.62	$1.65	$1.71	$1.90	$2.03	$2.10	$2.14	$2.14	$2.13	$2.12	$2.14	$2.30	$2.91	$2.90	$2.88	$2.87
Eraring Energy	$2.84	$2.93	$2.62	$2.63	$2.67	$2.67	$2.61	$3.51	$3.47	$3.43	$3.40	$3.36	$3.33	$3.32	$3.30	$3.28
Delta Coastal	$2.69	$2.59	$2.58	$2.77	$2.85	$2.83	$2.80	$2.81	$3.47	$3.43	$3.40	$3.36	$3.33	$3.32	$3.30	$3.28
Delta Western	$2.90	$2.68	$2.65	$3.03	$3.14	$3.12	$3.10	$3.07	$3.03	$2.99	$2.95	$2.91	$2.89	$2.87	$2.85	$2.84
Redbank	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12

Source: ACIL Allen analysis using forecast of thermal coal export prices supplied by AEMO

Table 30 **Coal prices into existing power stations in NSW (Real 2014-15 $/GJ) – Medium scenario**

	2014/ 15	2015/ 16	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26	2026/ 27	2027/ 28	2028/ 29	2029/ 30
MacGen	$1.63	$1.67	$1.70	$1.82	$1.92	$1.97	$2.01	$2.01	$2.00	$1.99	$2.01	$2.13	$2.62	$2.61	$2.60	$2.59
Eraring Energy	$2.84	$2.92	$2.61	$2.60	$2.61	$2.60	$2.56	$3.17	$3.14	$3.11	$3.07	$3.04	$3.01	$3.00	$2.98	$2.97
Delta Coastal	$2.71	$2.64	$2.59	$2.63	$2.67	$2.65	$2.62	$2.63	$3.14	$3.11	$3.07	$3.04	$3.01	$3.00	$2.98	$2.97
Delta Western	$2.95	$2.78	$2.68	$2.75	$2.79	$2.77	$2.75	$2.72	$2.69	$2.66	$2.63	$2.59	$2.56	$2.55	$2.54	$2.52
Redbank	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12

Source: ACIL Allen analysis using forecast of thermal coal export prices supplied by AEMO

Table 31 **Coal prices into existing power stations in NSW (Real 2014-15 $/GJ) – Low scenario**

	2014/ 15	2015/ 16	2016/ 17	2017/ 18	2018/ 19	2019/ 20	2020/ 21	2021/ 22	2022/ 23	2023/ 24	2024/ 25	2025/ 26	2026/ 27	2027/ 28	2028/ 29	2029/ 30
MacGen	$1.64	$1.68	$1.70	$1.74	$1.81	$1.85	$1.88	$1.87	$1.87	$1.86	$1.87	$1.97	$2.32	$2.31	$2.30	$2.29
Eraring Energy	$2.84	$2.92	$2.61	$2.57	$2.56	$2.56	$2.53	$2.82	$2.79	$2.76	$2.73	$2.70	$2.68	$2.66	$2.65	$2.64
Delta Coastal	$2.73	$2.68	$2.58	$2.47	$2.48	$2.47	$2.44	$2.44	$2.79	$2.76	$2.73	$2.70	$2.68	$2.66	$2.65	$2.64
Delta Western	$3.00	$2.87	$2.66	$2.44	$2.43	$2.42	$2.40	$2.37	$2.34	$2.31	$2.28	$2.25	$2.23	$2.22	$2.20	$2.19
Redbank	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12	$1.12

Source: ACIL Allen analysis using forecast of thermal coal export prices supplied by AEMO

Existing power stations Queensland

In Queensland there are four types of coal supply arrangement:

- mine mouth - own mine: Tarong, Tarong North, Kogan Creek, Millmerran
- mine mouth - captive third party mine: Callide B, Callide Power (i.e. Callide C)
- transported from captive third party mine: Stanwell
- transported from third party mine: Gladstone.

Power stations in Queensland relying on their own mine mouth coal supply are least likely to be affected by export prices and it has been assumed that they will offer marginal fuel costs into the market. However they will be affected by changes in mining costs which have increased in recent years.

Power stations with a mine mouth operation with a third party supplier are likely to be under pressure to accept higher prices more in line with export parity particularly with price reviews and contract renewal. Costs at the Meandu mine supplying Tarong the Tarong North power stations have increased substantially in recent years as the mine has moved to deeper lower quality coal seams.

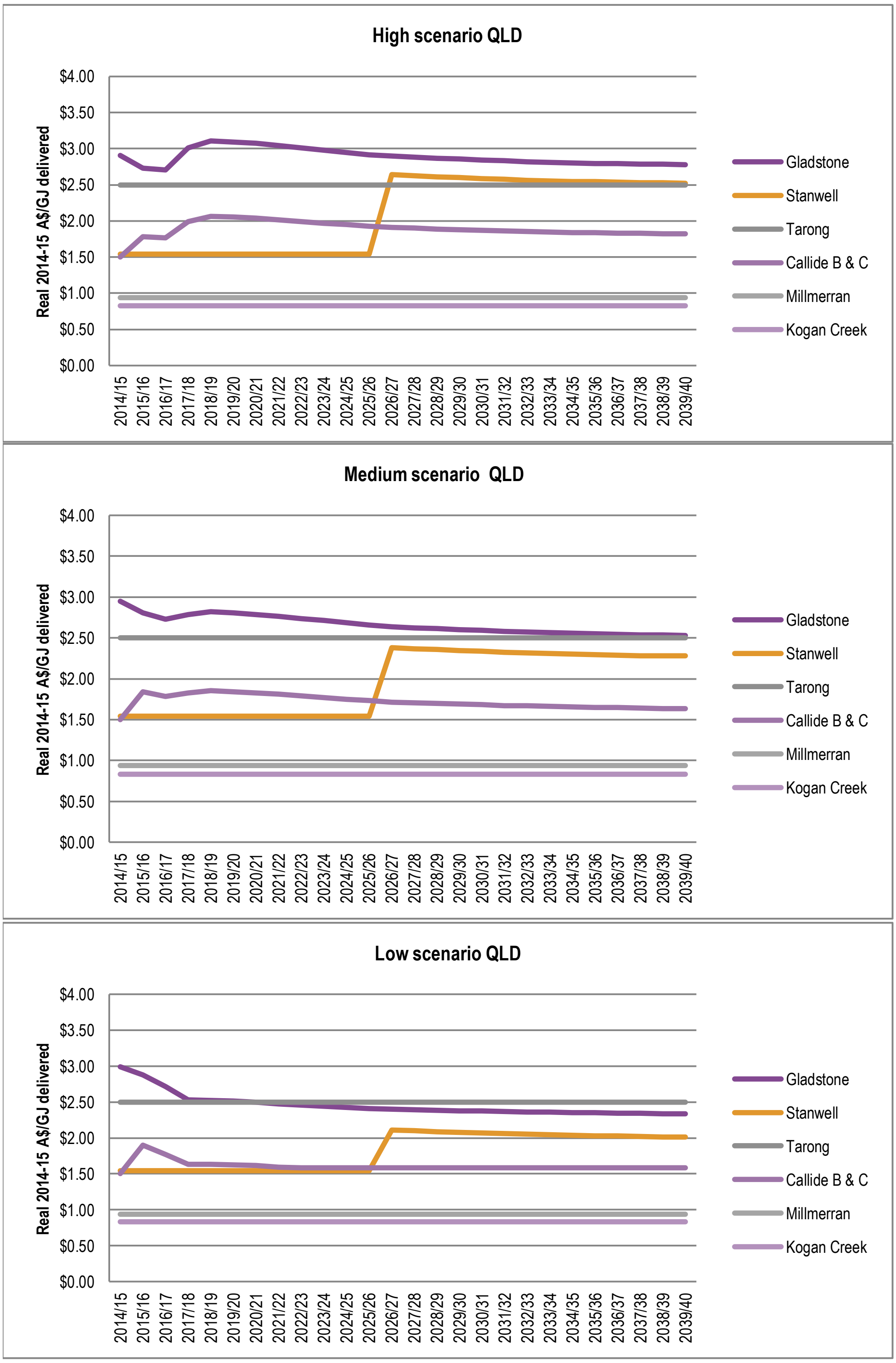
In 2004 Stanwell entered a 16 year arrangement with the Curragh mine which is not linked to export prices. We have assumed that Stanwell will move to a 65% export parity arrangement when the current arrangement expires in 2026-27.

Gladstone which relies on transported coal from third party mines is most exposed to pass through of export prices. Callide Boundary Hill mine is lowest cost potential supplier of coal into Gladstone as this coal has poor yield for export. It is assumed that Gladstone will move to an arrangement where half its future coal supply will be prices at 90% of export parity and half from the lower cost Callide mine.

Figure 31 shows the forecast coal prices into Queensland stations under the three scenarios. The low cost mine mouth operations at Millmerran and Kogan Creek remain the lowest cost based on the assumption that mining costs will escalate with general inflation of $1.0/GJ or less in real 2014/15 prices. In the longer term Gladstone and Stanwell have the highest costs being exposed to export parity pricing to varying degrees.

Comparing Figure 30 with Figure 31 shows that domestic coal prices at the higher end where domestic prices are exposed to the export coal price are similar in Queensland and NSW. However there is a significant volume of coal from captive mines in Queensland which has noticeably lower prices.

Figure 31 **Projected coal price (real 2014-15 $/GJ) into QLD existing stations**



Source: ACIL Allen analysis

Table 32 **Coal prices into existing power stations in Qld (Real 2014-15 $/GJ) – High scenario**

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Gladstone	$2.91	$2.73	$2.71	$3.01	$3.10	$3.09	$3.07	$3.04	$3.01	$2.98	$2.95	$2.92	$2.90	$2.88	$2.87	$2.86
Stanwell	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$2.64	$2.63	$2.61	$2.60
Tarong	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50
Callide B & C	$1.50	$1.78	$1.77	$1.99	$2.06	$2.05	$2.04	$2.02	$1.99	$1.97	$1.95	$1.93	$1.91	$1.90	$1.89	$1.88
Millmerran	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94
Kogan Creek	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83

Source: ACIL Allen analysis using forecast of thermal coal export prices supplied by AEMO

Table 33 **Coal prices into existing power stations in Qld (Real 2014-15 $/GJ) – Medium scenario**

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Gladstone	$2.95	$2.81	$2.73	$2.79	$2.82	$2.80	$2.79	$2.76	$2.74	$2.71	$2.69	$2.66	$2.63	$2.62	$2.61	$2.60
Stanwell	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$2.38	$2.37	$2.36	$2.35
Tarong	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50
Callide B & C	$1.50	$1.84	$1.78	$1.82	$1.85	$1.84	$1.83	$1.81	$1.79	$1.77	$1.75	$1.73	$1.71	$1.70	$1.70	$1.69
Millmerran	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94
Kogan Creek	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83

Source: ACIL Allen analysis using forecast of thermal coal export prices supplied by AEMO

Table 34 **Coal prices into existing power stations in Qld (Real 2014-15 $/GJ) – Low scenario**

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Gladstone	$2.99	$2.88	$2.71	$2.53	$2.52	$2.52	$2.50	$2.48	$2.45	$2.44	$2.42	$2.41	$2.40	$2.39	$2.39	$2.38
Stanwell	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$2.11	$2.10	$2.09	$2.08
Tarong	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50
Callide B & C	$1.50	$1.90	$1.77	$1.64	$1.63	$1.63	$1.61	$1.60	$1.58	$1.58	$1.58	$1.58	$1.58	$1.58	$1.58	$1.58
Millmerran	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94	$0.94
Kogan Creek	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83	$0.83

Source: ACIL Allen analysis using forecast of thermal coal export prices supplied by AEMO

Victorian brown coal and South Australian black coal

Coal mined for power generation in Victoria and South Australia is not suitable for export and hence removed from fluctuations in export prices.

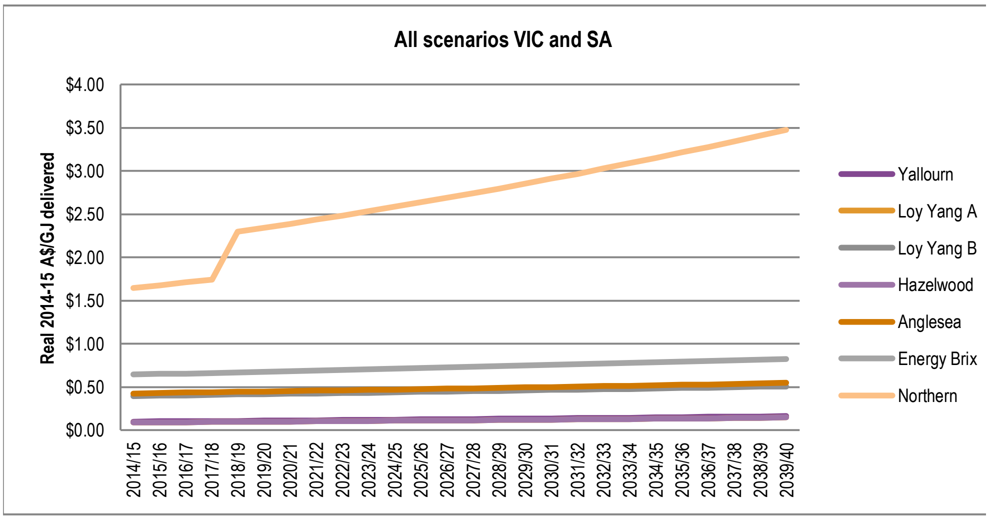
Extensive deposits of brown coal occur in the tertiary sedimentary basins of Latrobe Valley coalfield which contains some of the thickest brown coal seams in the world.

Mine mouth dedicated coalmines supply all the power stations. The coalmines are owned by the same entities that own the power stations with two exceptions. The exceptions are the Loy Yang B power station, where the mine, which is in close proximity to the power station, is owned and operated by Loy Yang Power, the owners and operators of the Loy Yang A power station and Energy Brix which is supplied by Morwell mine.

The marginal price of coal for the Victorian power stations is generally taken as the marginal cash costs of mining the coal.

The only currently producing coalfield in South Australia is at Leigh Creek based on low-grade sub-bituminous coal. The mining operation involves drilling, blasting and removal of overburden and coal by shovels and trucks. After mining, the crushed coal is railed to the Port Augusta power stations. The Leigh Creek mine is about 250 km from the power stations. A long-term rail haulage contract is in place with Pacific National.

Figure 32 **Projected coal price (real 2014-15 $/GJ) into VIC and SA existing stations**



Source: ACIL Allen analysis

Table 35 **Coal prices into existing power stations in Victoria and SA (Real 2014-15 $/GJ) – All scenarios**

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Yallourn	$0.10	$0.10	$0.10	$0.11	$0.11	$0.11	$0.11	$0.11	$0.12	$0.12	$0.12	$0.12	$0.13	$0.13	$0.13	$0.13
Loy Yang A	$0.09	$0.09	$0.09	$0.09	$0.10	$0.10	$0.10	$0.10	$0.10	$0.11	$0.11	$0.11	$0.11	$0.12	$0.12	$0.12
Loy Yang B	$0.40	$0.40	$0.40	$0.41	$0.41	$0.42	$0.42	$0.42	$0.43	$0.43	$0.44	$0.44	$0.45	$0.45	$0.45	$0.46
Hazelwood	$0.09	$0.09	$0.09	$0.09	$0.10	$0.10	$0.10	$0.10	$0.10	$0.11	$0.11	$0.11	$0.11	$0.12	$0.12	$0.12
Anglesea	$0.43	$0.43	$0.43	$0.44	$0.44	$0.45	$0.45	$0.46	$0.46	$0.47	$0.47	$0.47	$0.48	$0.48	$0.49	$0.49
Energy Brix	$0.64	$0.65	$0.66	$0.66	$0.67	$0.68	$0.68	$0.69	$0.70	$0.70	$0.71	$0.72	$0.72	$0.73	$0.74	$0.75
Northern	$1.64	$1.68	$1.71	$1.74	$2.29	$2.34	$2.39	$2.43	$2.48	$2.53	$2.58	$2.63	$2.69	$2.74	$2.80	$2.85

Source: ACIL Allen analysis using forecast of thermal coal export prices supplied by AEMO

7.4 Price of coal into new power stations by zone

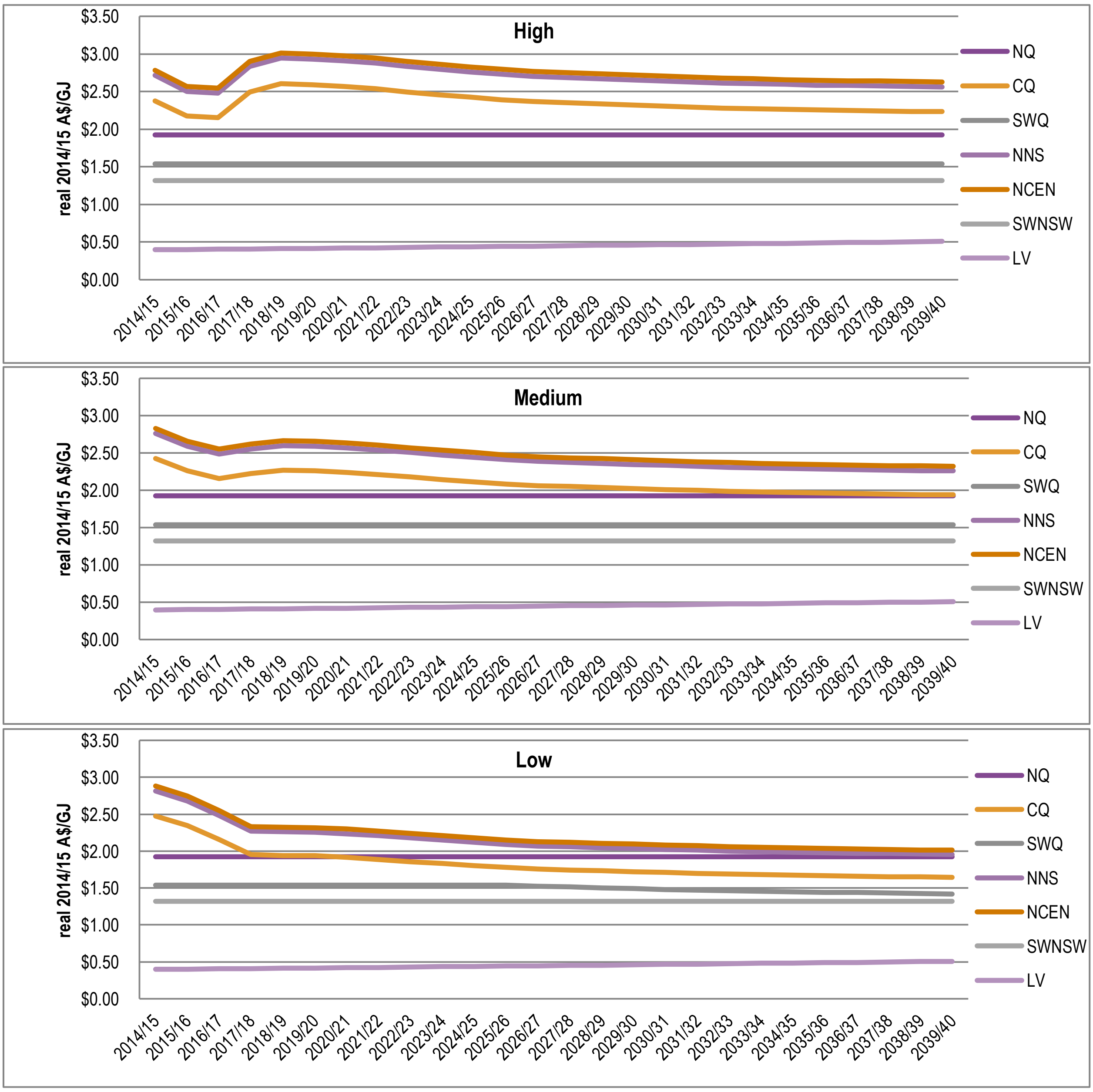
For new stations ACIL Allen undertook and analysis of known coal deposits in the 17 zones and selected those zones where adequate coal resources were available to support at least 2000 MW of future coal fired generation. Only seven of the 17 zones were judged as having adequate coal resources and they were NQ, CQ and SWQ in Queensland NCEN, NNS and SWNSW in New South Wales and LV in Victoria.

The price of black coal in each zone in Queensland and New South Wales was based on the deposit found to have the lowest delivered cost to a power station located close to the transmission network in that zone. For each black coal deposit the delivered price of coal was taken as the maximum of the cost of production and export parity value.

For Victoria the delivered price of brown coal is assumed at the cash cost of production which is forecast to increase at between 1 and 2 percent.

The real coal prices forecast in each of the seven zones are shown in Figure 33. Costs variation between the zones is due to the quality of the available deposits and whether access to export markets is expected to be available. The influence of export markets is evident in the prices in CQ, NNS and NCEN. The prices in other zones are linked to mining costs.

Figure 33 **Coal prices into new power stations by zone (Real 2014-15 $/GJ)**



Source: ACIL Allen analysis using forecast of thermal coal export prices supplied by AEMO

Table 36 **Coal prices into new power stations by zone (Real 2014-15 $/GJ) – High scenario**

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
NQ	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92
CQ	$2.38	$2.18	$2.15	$2.50	$2.60	$2.59	$2.57	$2.54	$2.50	$2.46	$2.43	$2.39	$2.37	$2.35	$2.34	$2.32
SWQ	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54
NNS	$2.71	$2.50	$2.48	$2.84	$2.95	$2.93	$2.91	$2.88	$2.84	$2.80	$2.76	$2.73	$2.70	$2.69	$2.67	$2.66
NCEN	$2.78	$2.57	$2.54	$2.90	$3.02	$3.00	$2.98	$2.95	$2.91	$2.87	$2.83	$2.80	$2.77	$2.75	$2.74	$2.72
SWNSW	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32
LV	$0.40	$0.40	$0.40	$0.41	$0.41	$0.42	$0.42	$0.42	$0.43	$0.43	$0.44	$0.44	$0.45	$0.45	$0.45	$0.46

Source: ACIL Allen analysis using forecast of thermal coal export prices supplied by AEMO

Table 37 **Coal prices into new power stations by zone (Real 2014-15 $/GJ) – Medium scenario**

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
NQ	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92
CQ	$2.42	$2.26	$2.16	$2.22	$2.27	$2.26	$2.24	$2.21	$2.18	$2.15	$2.11	$2.09	$2.06	$2.05	$2.04	$2.02
SWQ	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54
NNS	$2.76	$2.59	$2.49	$2.55	$2.60	$2.59	$2.57	$2.54	$2.51	$2.47	$2.44	$2.41	$2.39	$2.37	$2.36	$2.35
NCEN	$2.83	$2.66	$2.55	$2.62	$2.67	$2.66	$2.64	$2.61	$2.57	$2.54	$2.51	$2.47	$2.45	$2.44	$2.42	$2.41
SWNSW	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32
LV	$0.40	$0.40	$0.40	$0.41	$0.41	$0.42	$0.42	$0.42	$0.43	$0.43	$0.44	$0.44	$0.45	$0.45	$0.45	$0.46

Source: ACIL Allen analysis using forecast of thermal coal export prices supplied by AEMO

Table 38 **Coal prices into new power stations by zone (Real 2014-15 $/GJ) – Low scenario**

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
NQ	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92	$1.92
CQ	$2.47	$2.35	$2.16	$1.95	$1.94	$1.94	$1.92	$1.89	$1.86	$1.83	$1.80	$1.78	$1.76	$1.75	$1.73	$1.72
SWQ	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.54	$1.52	$1.51	$1.50	$1.49
NNS	$2.81	$2.68	$2.48	$2.27	$2.26	$2.26	$2.24	$2.21	$2.18	$2.15	$2.12	$2.09	$2.07	$2.06	$2.05	$2.04
NCEN	$2.88	$2.75	$2.55	$2.33	$2.32	$2.32	$2.30	$2.27	$2.24	$2.21	$2.18	$2.15	$2.13	$2.12	$2.11	$2.10
SWNSW	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32	$1.32
LV	$0.40	$0.40	$0.40	$0.41	$0.41	$0.42	$0.42	$0.42	$0.43	$0.43	$0.44	$0.44	$0.45	$0.45	$0.45	$0.46

Source: ACIL Allen analysis using forecast of thermal coal export prices supplied by AEMO