GHD

AEMO

AEMO costs and technical parameter review

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GHD has prepared the preliminary estimates set out in this report using information reasonably available to the GHD employee(s) who prepared this report; and based on assumptions and judgments made by GHD.

The data has been prepared for the purpose of providing an updated dataset for AEMO's long term planning functions and must not be used for any other purpose.

1. Introduction

1.1 Background

The Australian Energy Market Operator (AEMO) is responsible for operating the National Electricity Market (NEM) electricity grid in Eastern and South-Eastern Australia, and the Wholesale Electricity Market (WEM) power system in Western Australia.

AEMO's planning functions utilise an underlying set of input assumptions that describe the behaviour of existing generation assets, and the economics/location of future investment and retirement decisions.

The dataset includes estimates of current technology costs and generator performance characteristics for both existing generators and for new entrants to the market. The dataset also encompasses the technical operating parameters of these units.

AEMO has engaged GHD to undertake a review and update of the existing dataset and to populate new entrant costs and technical parameters across a selection of generation and storage technologies.

1.2 Purpose of this report

The primary purpose of this exercise is the development of an updated dataset for AEMO to use in the execution of their planning functions.

This report supports this dataset and provides an overview of the scope, methodology and assumptions used in its development, along with a list of definitions for terms used in the dataset.

The results of this exercise are also included, along with key discussion points for the various technologies as required.

1.3 Structure of this report

This report is structured as follows:

Section 2 – Scope: Provides an overview of the dataset to be produced, including lists of included generators, technologies, and parameters to be included in the dataset,

Section 3 – Methodology and definitions: Details the approach taken to populate each area of the dataset, along with a comprehensive list of definitions of the parameters included in the dataset,

Section 4 – Results – existing generators: Details the specific process and findings pertaining to the review and update of existing generator parameters,

Section 5 – Results – new entrants: Details the specific process and findings pertaining to the update of new entrant parameters, including the assumptions and methodology used to populate the data for each technology,

Section 6 – Regional cost factors: Provides a set of regional cost factors that can be used in conjunction with the new entrant costs for regionalisation.

1.4 Acronyms and abbreviations

A list of acronyms and abbreviations used in this report is presented in Table 1.

Table 1 Acronyms and abbreviations

Acronym/abbreviation	Meaning
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AUD	Australian dollar
CAPEX	Capital expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CPI	Consumer Price Index
DNSP	Distribution network service provider
EPC	Engineer procure and construct
FOM	Fixed Operation and Maintenance
GE	General Electric
GHD	GHD Pty Ltd
GJ	Gigajoule
GST	Goods and services tax
GT	Gas Turbine
HDPE	High Density Polyethylene
HHV	Higher heating value
MCR	Maximum Continuous Rating
MW	Megawatt
MWh	Megawatt-hour
NDT	Non-destructive testing
NEM	National Electricity Market
NSW	New South Wales
NT	Northern Territory
OCGT	Open Cycle Gas Turbine
OEM	Original equipment manufacturer
OPEX	Operational expenditure
PC	Pulverised Coal
PV	Photovoltaic
QLD	Queensland
SA	South Australia
SAT	Single Axis Tracking
SRMC	Short run marginal cost
SWIS	South West Interconnected System
USD	US dollar
VIC	Victoria
VOM	Variable Operation and Maintenance
WA	Western Australia

Acronym/abbreviation	Meaning
WEM	Wholesale Electricity Market
WF	Wind Farm
XLPE	Cross Linked Polyethylene

2. Scope

2.1 Overview

This section details the scope of this exercise with respect to the following aspects:

- The extent and format of the dataset to be produced
- The existing generators considered in the dataset
- The technical and cost parameters considered for existing generators, including those pertaining to refurbishment and retirement
- The generation and storage technologies considered as potential new entrants to the market
- The technical and cost parameters considered for the new entrant technologies, including those pertaining to capital cost for generation and for storage

2.2 Existing data

A portion of this exercise is based on updating or revising the existing dataset.

In this context, the following approach has been taken:

- Existing data updated or revised only when better, more current information was available
- New parameters added where required, and old parameters removed (or ignored) as appropriate
- New(er) technologies or configurations added to reflect the current cross-section of new entrant technologies

2.3 Format of data

Unless otherwise stated, the costs and data presented in this report and in the dataset are consistent with the following:

- All costs are provided in real 2018-19 $AUD
- All costs are exclusive of GST
- Generation and plant capacity is specified on an as-generated basis, with auxiliary assumptions listed

2.4 Existing generator list and parameters

The list of existing generators included in the NEM is provided in Table 2.

Table 2 List of existing generators

Station name	Generation type	Fuel type
Bayswater	Steam turbine	Black Coal
Callide B	Steam turbine	Black Coal
Callide Power Plant	Steam turbine	Black Coal
Eraring	Steam turbine	Black Coal
Gladstone	Steam turbine	Black Coal
Kogan Creek	Steam turbine	Black Coal
Liddell	Steam turbine	Black Coal

Station name	Generation type	Fuel type
Millmerran	Steam turbine	Black Coal
Mt Piper	Steam turbine	Black Coal
Stanwell	Steam turbine	Black Coal
Tarong	Steam turbine	Black Coal
Tarong North	Steam turbine	Black Coal
Vales Point B	Steam turbine	Black Coal
Loy Yang A	Steam turbine	Brown Coal
Loy Yang B	Steam turbine	Brown Coal
Yallourn	Steam turbine	Brown Coal
Angaston	OCGT	Distillate
Hunter Valley	OCGT	Distillate
Mackay	OCGT	Distillate
Mt Stuart	OCGT	Distillate
Port Lincoln	OCGT	Distillate
Snuggery	OCGT	Distillate
Lonsdale	Reciprocating Engine	Distillate
Port Stanvac 1	Reciprocating Engine	Distillate
Barron Gorge	Hydro	Hydro
Bastyan	Hydro	Hydro
Blowering	Hydro	Hydro
Catagunya	Hydro	Hydro
Cethana	Hydro	Hydro
Dartmouth	Hydro	Hydro
Devils Gate	Hydro	Hydro
Eildon	Hydro	Hydro
Fisher	Hydro	Hydro
Gordon	Hydro	Hydro
Guthega	Hydro	Hydro
Hume (NSW)	Hydro	Hydro
Hume (VIC)	Hydro	Hydro
John Butters	Hydro	Hydro
Kareeya	Hydro	Hydro
Lake Echo	Hydro	Hydro
Lemonthyme	Hydro	Hydro
Liapootah	Hydro	Hydro
Mackintosh	Hydro	Hydro
McKay Creek	Hydro	Hydro
Meadowbank	Hydro	Hydro
Murray 1	Hydro	Hydro
Murray 2	Hydro	Hydro
Poatina	Hydro	Hydro

Station name	Generation type	Fuel type
Reece	Hydro	Hydro
Shoalhaven	Hydro	Hydro
Tarraleah	Hydro	Hydro
Trevallyn	Hydro	Hydro
Tribute	Hydro	Hydro
Tumut 1	Hydro	Hydro
Tumut 2	Hydro	Hydro
Tumut 3	Hydro	Hydro
Tungatinah	Hydro	Hydro
Wayatinah	Hydro	Hydro
West Kiewa	Hydro	Hydro
Wilmot	Hydro	Hydro
Wivenhoe	Hydro	Hydro
Condamine	CCGT	Natural gas
Darling Downs	CCGT	Natural gas
Osborne	CCGT	Natural gas
Pelican Point	CCGT	Natural gas
Swanbank E	CCGT	Natural gas
Tallawarra	CCGT	Natural gas
Tamar Valley CCGT	CCGT	Natural gas
Townsville	CCGT	Natural gas
Smithfield	Cogen	Natural gas
Yarwun Cogen	Cogen	Natural gas
Bairnsdale	OCGT	Natural gas
Barcaldine	OCGT	Natural gas
Bell Bay Three	OCGT	Natural gas
Braemar	OCGT	Natural gas
Braemar 2	OCGT	Natural gas
Colongra GT	OCGT	Natural gas
Dry Creek	OCGT	Natural gas
Hallett	OCGT	Natural gas
Jeeralang A	OCGT	Natural gas
Jeeralang B	OCGT	Natural gas
Ladbroke Grove	OCGT	Natural gas
Laverton North	OCGT	Natural gas
Mintaro	OCGT	Natural gas
Mortlake	OCGT	Natural gas
Oakey	OCGT	Natural gas
Quarantine	OCGT	Natural gas
Roma	OCGT	Natural gas
Somerton	OCGT	Natural gas

Station name	Generation type	Fuel type
Tamar Valley OCGT	OCGT	Natural gas
Uranquinty	OCGT	Natural gas
Valley Power	OCGT	Natural gas
Barker Inlet Power Station	Reciprocating Engine	Natural Gas
Newport	Steam turbine	Natural gas
Torrens Island A	Steam turbine	Natural gas
Torrens Island B	Steam turbine	Natural gas
Broken Hill Solar Plant	Solar	Solar
Gullen Range Solar Farm	Solar	Solar
Moree Solar Farm	Solar	Solar
Nyngan Solar Plant	Solar	Solar
Ararat	Wind	Wind
Bald Hills p1	Wind	Wind
Boco Rock Wind Farm	Wind	Wind
Canunda	Wind	Wind
Capital Wind Farm	Wind	Wind
Cathedral Rocks	Wind	Wind
Challicum Hills	Wind	Wind
Clements Gap Wind Farm	Wind	Wind
Crowlands Wind Farm	Wind	Wind
Cullerin Range Wind Farm	Wind	Wind
Gullen Range	Wind	Wind
Gunning	Wind	Wind
Hallett 1 Wind Farm	Wind	Wind
Hallett 2 Wind Farm	Wind	Wind
Hallett 4 Wind Farm	Wind	Wind
Hallett 5 Wind Farm	Wind	Wind
Hornsdale Wind Farm Stage 1	Wind	Wind
Hornsdale Wind Farm Stage 2	Wind	Wind
Hornsdale Wind Farm Stage 3	Wind	Wind
Lake Bonney 1 Wind Farm	Wind	Wind
Lake Bonney 2 Wind Farm	Wind	Wind
Lake Bonney 3 Wind Farm	Wind	Wind
Macarthur	Wind	Wind
Mortons Lane WF	Wind	Wind
Mt Mercer	Wind	Wind
Mt Millar	Wind	Wind
Musselroe Wind Farm	Wind	Wind
Oaklands Hill	Wind	Wind
Portland Wind Farm	Wind	Wind
Snowtown 2 North	Wind	Wind

Station name	Generation type	Fuel type
Snowtown 2 South	Wind	Wind
Snowtown Wind Farm	Wind	Wind
Starfish Hill	Wind	Wind
Taralga Wind Farm	Wind	Wind
Waterloo	Wind	Wind
Wattle Point	Wind	Wind
Waubra	Wind	Wind
White Rock Wind Farm	Wind	Wind
Woodlawn Wind Farm	Wind	Wind
Woolnorth Studland Bay / Bluff Point	Wind	Wind
Yambuk	Wind	Wind
Hornsdale Power Reserve Unit 1	Batteries	

In addition, AEMO requested that GHD includes details of connected plant in Western Australia's SWIS network and in the Northern Territory's Darwin/Katherine, Alice Springs and Tennant Creek systems. These power stations are shown in Table 3 below.

Table 3 SWIS and NT existing generators

Station name	Generation type	Fuel type
Channel Island	OCGT/CCGT	Natural Gas/Distillate
Weddell	OCGT	Natural Gas
Katherine	OCGT	Natural Gas/Distillate
LMS Generation	Reciprocating	Landfill gas
Pine Creek	OCGT/CCGT	Natural Gas
Owen Springs	OCGT/Reciprocating	Natural Gas/Distillate
Brewer	Reciprocating	Natural gas
Crown Plaza Alice Springs	Solar	Solar
Tennant Creek	Reciprocating /OCGT	Natural Gas/Distillate
Yulara	Reciprocating	
Kings Canyon	Reciprocating /Solar	Distillate
Albany Wind Farm	Wind	Wind
Alcoa Wagerup	Reciprocating	Natural Gas
Atlas	Reciprocating	landfill gas
Bluewaters	Steam turbine	Bituminous coal
Bridgetown Biomass	Steam turbine	biomass
Bremer Bay Wind Farm	wind	wind
Clean Tech Biogas	Reciprocating	landfill gas
Cockburn	CCGT	Natural Gas
Collgar Wind Farm	wind	wind
Collie G1	Steam turbine	bituminous
Denmark Wind Farm	wind	wind
Emu Downs Wind Farm	wind	wind
Goldfields	Reciprocating	Gas/Distillate

Station name	Generation type	Fuel type
Gosnells Landfill Gas	Reciprocating	landfill gas
Grasmere Wind Farm		wind
Greenough River Solar Farm	solar	solar
Henderson Landfill Gas	Reciprocating	landfill gas
Kalamunda	Reciprocating	Distillate
Kalbarri Wind Farm		wind
Karakin Wind Farm		wind
Kemerton 1	OCGT	Gas/Distillate
Kemerton 2	OCGT	Gas/Distillate
NewGen Kwinana	CCGT	Gas
Kwinana EG1	OCGT	Natural Gas
Kwinana Gas Turbine	OCGT	Gas/Distillate
Merredin Gas Turbine	OCGT	Distillate
Mount Barker Wind Farm		wind
Muja	Steam turbine	Bituminous coal
Mumbida Wind Farm		wind
Mungarra Gas Turbine	OCGT	Natural Gas
Neerabup Gas Turbine	OCGT	Natural Gas
Pinjar Gas Turbine	OCGT	Gas/Distillate
Pinjarra	OCGT	Natural Gas
Red Hill Landfill Gas and Power	Reciprocating	landfill gas
Rockingham	Reciprocating	landfill gas
South Cardup	Reciprocating	landfill gas
Tamala Park	Reciprocating	landfill gas
Tesla Geraldton	Reciprocating	Distillate
Tesla Kemerton	Reciprocating	Distillate
Tesla Northam	Reciprocating	Distillate
Tesla Picton	Reciprocating	Distillate
Tiwest	OCGT	Natural Gas
Wagerup Gas Turbine	OCGT	Gas/Distillate
Walkaway Wind Farm		Wind
West Hills Wind Farm		Wind
West Kalgoorlie	OCGT	Distillate
Southern Cross	Reciprocating	Distillate

The parameters considered for the existing generators are listed in Table 4.

Table 4 Existing generator parameters

Item
General Details
Station name
Unit name
Commissioning Date

Item
Technical Details
Installed capacity (MW)
Min Stable Generation (% of installed capacity)
Auxiliary load (% of installed capacity)
Ramp Up Rate (MW/h) - standard operation
Ramp Down Rate (MW/h) - standard operation
Heat rate at maximum operation (GJ/MWh)
Thermal Efficiency (%, HHV sent-out)
Maintenance Frequency (no of maintenance events per year)
Average Planned Maintenance (no of days/year)
Storage Details
Hydro units: Pumping Efficiency (MWh pumped per MWh generated) - within 24 hours
Pump load (MW)
Cost Detail
Fixed Operating Cost ($/kW/year)
Variable Op Cost ($/MWh sent-out)
Cold Start-up Time (h)
Warm Start-up Time (h)
Hot Start-up Time (h)
Cold Start-up Costs ($/MW)
Warm Start-up Costs ($/MW)
Hot Start-up Costs ($/MW)

The parameters considered for the impact of refurbishment of existing generators are listed in Table 5.

Table 5 Existing generator refurbishment and retirement parameters

Item
Refurbishment Costs
Technology
Generation Type
Fuel Type
Region
Cost ($)
Duration of refurbishment (weeks)
Impact to plant parameters due to refurbishment
Thermal Efficiency ($, HHV sent-out)
Variable Operation and Maintenance Cost (VOM) ($/MWh)
Fixed Operation and Maintenance Cost (FOM) ($ per annum)
Fugitive Emissions (kg CO_{2e}/GJ)
Combustion Emissions (tonnes CO_{2e}/GJ)
Retirement Costs
Retirement Cost ($)

2.5 New entrant technologies and parameters

The new entrant technologies included in the dataset are listed in Table 6.

Table 6 New entrant technologies

Technology	Generation Type	Fuel Type
CCGT - With CCS	Thermal	Natural Gas
CCGT - Without CCS	Thermal	Natural Gas
OCGT - Without CCS	Thermal	Natural Gas
Reciprocating Engine	Thermal	Natural Gas/Diesel
Supercritical PC - Black coal with CCS	Thermal	Black Coal
Supercritical PC - Black coal without CCS	Thermal	Black Coal
Supercritical PC - Brown coal with CCS	Thermal	Brown Coal
Supercritical PC - Brown coal without CCS	Thermal	Brown Coal
Ultra Supercritical PC - Black coal with CCS	Thermal	Black Coal
Ultra Supercritical PC - Black coal with CCS	Thermal	Black Coal
Advanced Ultra Supercritical PC - Black coal with CCS	Thermal	Black Coal
Advanced Ultra Supercritical PC - Black coal with CCS	Thermal	Black Coal
Synchronous Condenser	Other	N/A
Battery Storage	Storage	N/A
Large Scale Battery Storage	Storage	N/A
Diabatic Compressed Air Storage	Storage	N/A
Biomass - Electricity only	Renewable	Wood waste (clean) RDF (contaminated)
Biomass - Cogeneration	Renewable	Wood waste (clean) RDF (contaminated)
Nuclear	Thermal	
Pumped Hydro Storage	Storage	N/A
Solar PV - Single axis tracking	Renewable	N/A
Solar Thermal Central Receiver with storage	Renewable	N/A
Solar Thermal Central Receiver without storage	Renewable	N/A
Wind – onshore	Renewable	N/A
Wind – offshore	Renewable	N/A

The parameters considered (where relevant for the technology) are listed in Table 7. Details have been included where GHD has relevant in-house knowledge or relevant information is available in the public domain. Definitions for these parameters are provided in Section 3.2.1.

Table 7 New entrant parameters

Item
General Details
Fuel Type
First Year Assumed Commercially Viable for construction
Assumed unit size (MW)

Item
Seasonal Ratings: Summer (MW)
Seasonal Ratings: Not summer (MW)
Economic Life (yrs)
Technical Life (yrs)
Lead time for Project development (Years) / Construction time (weeks)
Technical Details
Min Stable Generation (% of installed capacity)
Auxiliary load (% of installed capacity)
Auxiliary load for Generators operating in Synchronous Condenser mode (% of installed capacity)
Forced outage rate (full forced outages)
Frequency of full forced outage per annum
Full outage Mean time to repair (h)
Partial Forced outage rate (partial forced outages)
Frequency of partial forced outages
Partial Outage derating factor (% lost during partial outage)
Partial outage Mean time to repair (h)
Equivalent forced outage rate (%)
Minimum Load required for Synchronous Condensers (MW)
Ramp Up Rate (MW/h) - standard operation
Ramp Down Rate (MW/h) - standard operation
Heat rate at minimum operation (GJ/MWh)
Heat rate at maximum operation (GJ/MWh)
Thermal Efficiency (%, HHV sent-out)
Maintenance Frequency (no of times per year)
Average Maintenance rate (no of days/year)
Storage Details
Hydro units: Pumping Efficiency (MWh pumped per MWh generated) - within 24 hours
Pump load (MW)
Battery storage: Charge efficiency
Battery storage: Discharge efficiency
Battery Storage: Allowable max State of Charge (%)
Battery Storage: Allowable min State of Charge (%)
Battery Storage: maximum number of Cycles
Battery storage: Depth of Discharge (DoD)
Cost Details
Fixed Operating Cost ($/MW/year)
Variable Op Cost ($/MWh sent-out)
Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)
Cost to operate in Synchronous condenser mode($/MWh as gen)
Cold Start-up Notification Time (h)
Warm Start-up Notification Time (h)

Item
Hot Start-up Notification Time (h)
Cold Start-up Costs ($/MW as gen)
Warm Start-up Costs ($/MW as gen)
Hot Start-up Costs ($/MW as gen)
Emissions Details
Combustion Emissions (kg CO_{2e}/GJ of fuel)
Fugitive Emissions (kg CO_{2e}/GJ of fuel)

The capital cost items considered for each new entrant are listed in Table 8

Table 8 New entrant capital cost items

Item
General Costs
Equipment costs
Fuel connection costs
Cost of land and development
Installation costs
Carbon Capture and Storage Costs
CCS costs (separate from the generation plant)
CCS storage costs (separate from CCS capture costs)
CCS transportation cost
Energy Storage Costs
Cost of energy storage ($/MWh)
Cost of storage capacity ($/MW)

3. Methodology and definitions

3.1 Methodology

The dataset has been populated and updated with as much granularity as possible within the time and budget available and with an understanding that the data will support long-term modelling undertaken by AEMO. In this context, the data has been curated to reflect long-term averages and typical figures that aim to reflect the impact that the existing or new entrant generation unit will have on the network.

The approach taken for each segment of data is discussed below.

3.1.1 Existing generators costs and technical parameters

Our initial review of the technical and cost parameters for existing generators has drawn on our knowledge of relevant public material and data sources to which GHD subscribes backed up by our internal databases and relevant specialist experience. The data has been adjusted on an as-needs basis, and only where we are confident in an updated or adjusted figure in preference to the existing data.

The assessment of refurbishment of existing generators has been undertaken on an as-needed basis, with only those technologies that are appropriate for life-extension type works being considered. This is discussed in detail in Section 4.2.

3.1.2 New entrant costs and technical parameters

The list of new entrant parameters and costs have been developed broadly according to the following approach. Where the methodology or assumptions differ for a given technology, this is noted under the corresponding technology in Section 5.

- Nominal configuration and type selected for the technology so as to reflect a typical new entrant to the Australian market
- Key operating and technical parameters selected
- Technical parameter data entered based on available information and typical performance characteristics for a new entrant
- Cost estimates developed based on a complete facility on a generic site.

The following assumptions have been made for the purpose of estimating capital cost:

- An engineer procure and construct (EPC) contracting strategy has been assumed, as is typical for large power projects
- No site specific conditions or constraints have been considered in the estimates
- No allowance has been made for electricity network extension works required for connection.

3.1.3 Escalation rates

Capital costs and fixed and variable operating costs have been sourced from GHD’s in-house knowledge or from the public domain. Available data has, in most cases, insufficient granularity to apply complex escalation formulae based on detailed cost breakdowns covering a range of material, energy and labour costs. Instead, costs have been escalated using appropriate producer price indices relevant to the country of origin of the goods. For Australian sourced goods the PPI used are as per Australian Bureau of Statistics Data Set 6427.0.

3.1.4 Exchange rates

Exchange rates have been applied on an as-needs basis using 2018 exchange rates current at the time of writing this report. Typically, main power plant components are imported and priced in US dollars. We have converted these costs to Australian dollars. An exchange rate of 1.35 AUD/USD has been used in these scenarios.

The following indicative portions of the costs presented in the dataset are considered to be influenced by exchange rates:

- Equipment costs: 90%
- Fuel connection costs: 50%
- Cost of land and development: 0%
- Installation costs: 10%
- Carbon capture equipment costs: 90%
- O&M costs: 25%

3.1.5 WACC rates

GHD has conducted a desktop survey of publicly available information on the weighted average cost of capital (WACC) typically applying to energy generation projects for various technologies. The cost of capital information includes cost of debt, cost of equity, debt/equity ratio (gearing), and the overall weighted average cost of capital (WACC). The WACC marks the required rate of return of an energy generation project.

We note that public information is very limited on cost of capital. Developers and project financiers use this for expected cash flow and project profitability analysis. The parameters, especially the company-risk-specific equity beta coefficient, can be commercially sensitive.

From the information available we have developed the typical range of cost of capital and its parameters) by technology group:

- For renewable technologies (solar, wind etc.), we observe a 4.5%~5.5% cost of debt (mid-point 5%), a 7%~12% cost of equity (mid-point 10%), and a debt-equity ratio about 75:25, which generates a WACC around 6.2%.
- For base-load coal generation, we observe a 5.3% cost of debt, 13% for cost of equity, and a debt/equity ratio of 40:60, which generates a WACC around 10%. For the new high efficiency low emission (HELE) coal generation, we found a reference that generates comparable WACC rate to base-load coal generation.
- For semi-base combined cycle gas turbines (CCGT), we observe a 4.4% for cost of debt, an 11% for cost of equity, and a debt/equity ratio of 75:25, which generates a WACC around 6%, similar to the WACC of the renewable technologies.

On the basis that the interest rate in Australia remains low in the near future, the cost of debt is likely to remain at the current level.

Table 9 and Table 10 below tabulate the WACC estimates we have found, along with reference document information.

Table 9 WACC rate reference data

Technologies	Reference	Cost of debt	Cost of equity	Debt/Equity ratio	WACC
Coal (base)	Jacobs Finkel report 2017 – Without policy risk premium	5.3%	13%	40:60	9.9%
	Jacobs Finkel report 2017 – With policy risk premium	10.3%	18%	40:60	14.9%
High efficiency low emission coal (HELE)	Bloomberg New Energy Finance 2017	5.3%	18%[1]	40:60	12.9%
Combined Cycle gas Turbines (semi-base)	Jacobs Finkel report 2017 – Without policy risk premium	4.4%	11%	75:25	6.1%
	Jacobs Finkel report 2017 – With policy risk premium	6.4%	13%	75:25	8.1%
Renewables in general	**GHD summary of below**	**5%**	**10%**	**75:25**	**6.25%**
	Jacobs Finkel report 2017 – Without policy risk premium	4.4%	11%	75:25	6.1%
	Jacobs Finkel report 2017 – With policy risk premium	5.4%	12%	75:25	7.1%
Solar Photovoltaic	David Leitch, RenewEconomy 2016b, for Clare solar farm	4.8%	7%	33:67	6.27%
Wind (onshore or off-shore)	David Leitch, RenewEconomy 2016a				6%+
WACC for all technologies	**CO2CRC, CSIRO etc. 2015**	**8.0%**	**11.5%**	**70:30**	**9.05%**
	Simshauser 2014				12.1%

[1] We consider an 18% of cost of equity is too high and unlikely. When considering this estimate, we propose to adjust down the cost of equity, and in turn the overall cost of capital.

Table 10 WACC rate reference sources

Reference name	Source link and information
Jacobs Finkel report 2017	Jacobs Group, Report to the Independent Review into the Future Security of the National Electricity Market, June 2017. https://www.energy.gov.au/sites/g/files/net3411/f/independent-review-future-nem-emissions-mitigation-policies-2017.pdf
Bloomberg New Energy Finance 2017	Presentation at Australian Clean Energy Summit 2017, July 2017. http://www.cleanenergysummit.com.au/dam/clean-energy-summit/agenda/aces-2017-presentations/market-outlook-2017/Kobad-Bhavnagri/Kobad%20Bhavnagri.pdf
David Leitch, RenewEconomy 2016a	https://reneweconomy.com.au/the-ret-is-a-high-cost-way-to-procure-renewable-energy-50794/
David Leitch, RenewEconomy 2016b	https://reneweconomy.com.au/is-solar-power-really-cheaper-than-wind-in-australia-38550/
CO2CRC, CSIRO etc. 2015	http://www.co2crc.com.au/wp-content/uploads/2016/04/LCOE_Report_final_web.pdf
Simshauser 2014	AGL Applied Economic and Policy Research Working Paper No.39 - The cost of capital for power generation in atypical capital market conditions. http://aglblog.com.au/wp-content/uploads/2013/09/No.39-CAPM-in-Atypical-Markets.pdf

3.2 General basis and assumptions

This section details overarching assumptions and inputs that apply to all of the technologies and stations considered. Where a specific technology requires an assumption or value to vary from those listed here, it shall be specifically addressed in the relevant paragraph in Section 5.

These assumptions predominantly apply to new entrant technologies.

Design ambient conditions

For thermal plant the design ambient conditions used were:

- Dry Bulb Temperature – 25°C
- Elevation above sea level – 110 m
- Relative Humidity - 60%

These are based on ambient conditions given in the *Technical Guidelines: generator efficiency standards* published by the Australian Greenhouse Office, December 2006.

For seasonal ratings of new entry plant, the reference conditions for all thermal generation other than brown coal fired steam plant were selected as typical of the Hunter Valley, NSW while the reference conditions for brown coal fired steam plant were selected as typical of the Latrobe Valley, Victoria. Summer ratings have been based on the average monthly maximum temperatures for December, January and February while the non-summer ratings have been based on the average monthly maximum temperatures for the remainder of the year.

3.2.1 Estimating Class

The cost estimates in this report are typically either Estimating Class 5[2] estimates, order of magnitude, concept screening: -20% to +50%, or Estimating Class 4 estimates, study or feasibility: -15% to +30% depending on the level of definition of the generating plant. Estimating Class 5 estimates and Class 4 estimates are defined as follows[3]:

Table 11 Estimating classes

Estimating Class	Primary Characteristic	Secondary Characteristic		
	Maturity Level of Project Definition Deliverables Expressed as a % of complete definition	End Usage Typical purpose of estimate	Methodology Typical estimating method	Expected Accuracy Range Typical variation is low and high ranges
Class 5	0 to 2	Concept Screening	Capacity factored, parametric models, judgement or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1 to 15	Study of feasibility	Equipment factored or parametric models	L: -15% to -30% H: +30% to +50%

[2] As published by the AACE International
[3] Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries, AACE International, 2016

3.3 Definitions

This section provides a brief definition for all parameters listed in Section 2.

3.3.1 General details

Commissioning Date (existing generators)

The year in which the generating unit was commissioned.

Installed capacity (MW) (existing generators)

The nameplate capacity of the generating unit in MW at the generator terminals (i.e. gross generation).

Fuel Type

The type of fuel used in the generation plant, from one of the following:

- Black coal
- Brown coal
- Distillate (diesel)
- Hydro
- Natural gas
- Solar
- Wind
- Biomass (specific biomass fuel type to be specified as required)

First Year Assumed Commercially Viable for construction

For new entrant emerging technologies only; the year in which it is considered viable that a new entrant of the given technology type could begin construction at the nominated scale.

Assumed unit size (MW)

The nominal generating unit output capacity (in MW) as measured at the generator terminals (i.e. gross generation).

Seasonal Ratings: Summer (MW)

The generating unit output during summer conditions as defined in Section 3.2. This rating is as measured at the outlet terminals of the generator step up transformer (i.e. net generation).

Seasonal Ratings: Not summer (MW)

The generating unit output during not-summer conditions as defined in Section 3.2. This rating is as measured at the outlet terminals of the generator step up transformer (i.e. net generation).

Economic Life (yrs)

GHD has assumed that Economic Life refers to the Design Life of a plant.

Technical Life (yrs)

GHD has assumed that Technical Life of a plant is the elapsed time between first commercial operation and decommissioning.

Lead Time for Development / Construction Time

GHD has assumed that the Lead Time for Development refers to the time required to undertake feasibility studies and secure the necessary approvals to construct the project whereas the Construction Time refers to the tie from site access being granted to the plant achieving Commercial Operation.

3.3.2 Technical Details

Min Stable Generation (% of installed capacity)

The minimum load (as a percentage of the rated gross capacity of that unit) that the generating unit can operate in a stable manner (without combustion support in the case of coal or biomass fired units) for an extended period of time and then reliably ramp-up to full load while continuing to comply with its emissions licences.

Auxiliary load (% of installed capacity)

The percentage of rated generation output of a unit (as measured at the generator terminals) that is consumed by and within the station and not available for export to the grid. The auxiliary load is provided as a percentage of the rated output at full load.

The net output of the unit can be calculated as the rated output minus the auxiliary load.

Auxiliary load for Generators operating in Synchronous Condenser mode (% of installed capacity)

The percentage of the rated capacity of the generator that is consumed during the operation of the generator as a synchronous condenser.

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

Full and partial forced outage rates represent the percentage of time within a year the plant is unavailable due to circumstances other than a planned maintenance event. Forced outages are not planned 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

It is noted that for thermal plant, GHD has been unable to source any meaningful generic data for the following parameters, either in-house or in the public domain:

- Frequency of full forced outage per annum
- Full outage Mean time to repair (h)
- Frequency of partial forced outages
- Partial outage Mean time to repair (h)

Equivalent forced outage rate (%)

Equivalent forced outage rate is the sum of all full and partial forced outages/de-ratings by magnitude and duration (MWh) expressed as a percentage of the total possible full load generation (MWh).

Minimum Load required for Synchronous Condenser Mode (MW)

The minimum load (in MW) at which the synchronous condenser can operate continuously.

Ramp Up / Ramp Down Rates (MW/h) – standard operation

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 requires them to be estimated in MW per hour.

In thermal plants, the rate of temperature rise / fall in large, thick-walled pressure vessels or flame stability tends to limit ramp rates.

Where no information was available in-house or in the public domain, we have estimated ramp rates based on published data for similar plant configurations/sizes.

Heat rate at minimum operation (GJ/MWh)

Heat rate when operating at minimum operating load as previously defined.

Heat rate at maximum operation (GJ/MWh)

Heat rate when operating at maximum continuous load.

Thermal (Electrical) Efficiency (%, HHV sent-out)

Calculated using:

Net Thermal Efficiency (%) HHV = 3600 ÷ Net Heat Rate (kJ/kWh) HHV × 100

Maintenance Frequency (no of times per year)

Maintenance Frequency refers to the number of times a plant is shut down per year for planned or unplanned maintenance.

Average Planned Maintenance Rate (no of days/year)

Average Planned Maintenance Rate refers to the total number of days of planned maintenance per year.

3.3.3 Storage Details

Hydro units: Pumping Efficiency (MWh pumped per MWh generated)

This parameter is defined as the energy consumed by pumping and losses (in MWh) for every MWh that is produced by the pumped hydro generation plant.

Pump load (MW)

The rated pumping capacity (in MW) of the pumped hydro system.

Battery storage: Charge efficiency

The efficiency of the battery energy storage system (in %) when the battery is being charged.

Battery storage: Discharge efficiency

The efficiency of the battery energy storage system (in %) when the battery is being discharged.

Battery Storage: Allowable max State of Charge (%)

The maximum charge % of the battery system.

Battery Storage: Allowable min State of Charge (%)

The minimum charge % of the battery system.

Battery Storage: maximum number of Cycles

The maximum total number of cycles within a typical battery lifetime.

Battery storage: Depth of Discharge (DoD)

The percentage of the battery that can be discharged – i.e. the difference between the maximum allowable charge state and the minimum allowance charge state.

3.3.4 Cost Details

Fixed Operating Cost ($/MW Net/year)

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 fully mature technologies, fixed operating costs have not changed significantly in real terms since the previous AEMO review in 2014, hence in most cases the 2014 costs have simply been escalated to the present day equivalents.

Variable Operating Cost ($/MWh sent-out)

The additional operating and maintenance costs for an increment of electrical output depends 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 short run marginal cost (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, we have included an allowance 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 a greater number of start/stops and part load operation than CCGT plants and

The output from the gas turbine(s) 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 rather than in ‘as generated’ terms.

For fully mature technologies, non-fuel variable operating costs have not changed significantly in real terms since the previous AEMO review in 2014, hence in most cases the 2014 costs have simply been escalated to the present day equivalents.

Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)

The variable operating cost for carbon capture and storage is the additional cost of capturing and storage of CO_2 emissions from the flue gas stream of a thermal power station. Capture rates of 90% have been assumed in the costings.

Cost to operate in Synchronous condenser mode ($/MWh as gen)

The cost incurred (in $/MWh) to operate a generator in synchronous condenser mode.

Cold/Warm/Hot Starts

These terms are only applicable to thermal plant. For the purposes of this report the following definitions have been assumed:

- Cold Start – the plant has been offline for more than 40 hours (assumed to be at atmospheric pressure and temperature and de-energised. Plant may be in a state of preservation),
- Warm start – the plant has been offline for between 5 and 40 hours (has some remaining heat and ready to be returned to service),
- Hot start – the plant has been offline for less than 5 hours (may be in the process of shut-down to cold but can be returned to service quickly).

Each plant will have been designed for a defined number of hot, warm and cold starts and shutdowns. Deviations from this will accelerate aging of the asset and shorten its service life. No assessments have been made of the plants' historical start / stop history.

Start-up Notification Time (h)

Start-up notification time is the estimated time in hours to mobilise staff, carry out all necessary pre-start checks, start the unit, synchronise to the grid and load up to minimum stable load.

Start-up Costs ($/MW as gen)

Start-up costs are the costs incurred in starting a plant from its off-line state to it reaching minimum stable load. Costs will include labour, water, chemicals and fuel.

Retirement / Rehabilitation cost

These costs cover decommissioning, demolition, site rehabilitation and any on-going monitoring required. These costs are plant specific and are significantly influenced by local statutory rules and regulations and the provisions under the development approval. GHD has used in-house data to estimate costs on a $/MW based on different technologies.

3.3.5 Emissions Details

Combustion Emissions (kg CO_{2e}/GJ of fuel)

Combustion emissions are the quantity of CO_2 equivalent released by burning fuel at each station. Source: Emission Factors - Review of Emission Factors for Use in the CDEII, report to AEMO, ACIL Allen, 2014.

Fugitive Emissions (kg CO_{2e}/GJ of fuel)

Fugitive Emissions are the quantity of CO_2 equivalent released mining/extracting and delivering fuel to each station. Source: Emission Factors - Review of Emission Factors for Use in the CDEII, report to AEMO, ACIL Allen, 2014.

3.3.6 Existing Generator Refurbishment Details

Technology

Technology covers the types of refurbishment that could reasonably be expected to be undertaken to improve the performance or extend the life of an existing plant.

Generation Type

Generation type refers to the type of plant (e.g. coal fired boiler/steam turbine, gas fuelled open cycle gas turbine, wind turbine, solar etc.).

Fuel Type

Fuel type refers to the type of fuel (or source of energy) used by a particular plant.

Region

Region refers to the location of the plant. Other than relatively minor impacts from labour, commodity and transportation costs, refurbishment costs will not be region dependent.

Refurbishment cost ($)

Refurbishment cost is the cost of a particular refurbishment activity undertaken to improve the performance or extend the life of an existing plant.

Duration of refurbishment (weeks)

Duration of refurbishment is the time required between plant shutdown and return to commercial operation following a refurbishment activity and recommissioning.

Change in Thermal Efficiency ($, HHV sent-out)

The change in thermal efficiency as a result of a refurbishment activity on a percentage basis.

Variable Operation and Maintenance Cost (VOM) ($/MWh)

The change in variable operation and maintenance costs as a result of a refurbishment activity on a percentage basis.

Fixed Operation and Maintenance Cost (FOM) ($ per annum)

The change in fixed operation and maintenance costs as a result of a refurbishment activity on a percentage basis.

Fugitive Emissions (kg CO_{2e}/GJ)

The change in fugitive emissions as a result of a refurbishment activity on a percentage basis.

Combustion Emissions (tonnes CO_{2e}/GJ)

The change in combustion emissions as a result of a refurbishment activity on a percentage basis.

Retirement Cost ($)

These costs cover decommissioning, demolition, site rehabilitation and any on-going monitoring required. These costs are plant specific and are significantly influenced by local statutory rules and regulations and the provisions under the development approval.

We have used in-house data to estimate costs on a $/MW based on different technologies. Refurbishment may extend the life of a plant and allow retirement costs to be deferred.

3.3.7 New Entrant Capital Costs

Equipment costs

Equipment costs are the costs of design, procurement, manufacture and delivery to site of items of equipment. No new coal fired plants have been constructed in Australia since Kogan Creek

(2004-2007) so no recent Australian cost data is available. Similarly, there is limited cost data in the public domain on recent gas turbine plants.

For this reason, thermal plants new entrant costs have been estimated using Thermoflow 27 software. Thermoflow software comprises a range of proprietary software packages used to model performance and costs of thermal generating plants. The software is internationally recognised within the power industry. The plant data base is updated several times a year to include new plant models/technologies and reflect international cost trends. For the estimates, the modelled costs have been converted from USD to AUD at an exchange rate of 1:1.354349.

Fuel connection costs

Fuel connection cost are the costs of connecting a new plant to a fuel source. These costs will be specific to individual sites/plant capacities/fuel types. As a guide, based on in-house data, GHD estimates $100M AUD for 50 km of single track rail line as a fuel connection cost for coal fired plant and $70,000 AUD per 25 mm diameter per km (up to 50 km) for a pipeline supplying gas fired plant. Any brown coal plant has been assumed to be mine-mouth plant.

Cost of land and development

This covers the owner's purchase of land and environmental and technical studies required to secure the necessary permits to allow a plant to be constructed and connected to the grid. For thermal plant these costs have been estimated using Thermoflow 27 software and are non-site specific with respect to land values.

Installation costs

Installation costs cover the labour and consumables required to construct and commission the plant. For thermal plant these costs have been estimated using Thermoflow 27 software.

CCS Capture Costs

CCS capture costs cover the costs of a typical chemical absorption process including auxiliary power consumption, heat consumption (steam) and cooling loads. For thermal plant these costs have been estimated using Thermoflow 27 software.

CCS storage costs

CCS storage costs are the costs associated with storage and on-going monitoring of CO_2 in a stable geological formation. As no commercial scale storage facilities have been developed in Australia, these costs are indicative estimates compiled from a number of public domain sources including the International Energy Agency 2008, the Intergovernmental Panel on Climate Change 2005 and the Electric Power Research Institute 2015.

CCS transportation cost

CCS transportation costs are the costs associated with the transmission of captured CO_2 from a thermal power station to a stable geological formation in which it can be sequestered. As no commercial scale storage facilities have been developed in Australia, these costs are indicative estimates compiled from a number of public domain sources including the International Energy Agency 2008, the Intergovernmental Panel on Climate Change 2005 and the Electric Power Research Institute 2015, assuming a transportation distance in the order of 250 km.

Cost of energy storage ($/MWh)

The cost of the storage component of the energy storage system, as measured in $/MWh.

Cost of storage capacity ($/MW)

The cost of the charge/discharge component (e.g. inverters for battery storage systems) of a given energy storage system, as measured in $/MW).

4. Results – existing generators

4.1 Review of existing generator costs and parameters

The costs and technical parameters for the existing generators has been updated by exception based on the following information hierarchy:

- Published figures (public domain or subscription data source)
- GHD knowledge based on prior experience, where able to do so within confidentiality and probity limits
- Typical figures for the type of plant being considered drawn from e.g. engineering software, databases, project information, adjusted to account for the age and condition of the plant if possible
- Engineering judgement.

Where no information is available to update or critique existing data, the data are left as is. Where no data exists and no new information is available to populate the entry, the entry has been left blank.

4.2 Refurbishment

The design life of a power station is typically between 25 and 40 years. Over time, a number of mechanisms act together to degrade the performance/availability of a power station including:

- Erosion
- Corrosion
- Thermal fatigue
- Creep
- Obsolescence/unavailability of spares

In the current market, there is an increasing trend to extend the operating life of power stations beyond their original design life. In addition to normal maintenance, significant refurbishment may be necessary. In addition, it is likely that there will be increasing pressure on generators to reduce their CO_2 emissions.

In the following sections a number of options are discussed which may be applicable to particular technologies. Whether they are applicable to a particular power station will depend on the existing configuration of the plant and its condition. Costs have been estimated on a $/kW basis.

Refurbishment costs are based on:

- Generic plant type only (i.e. not specific generators)
- Not specific condition of existing generators
- Costs/technical parameters from modern equivalent assets

4.2.1 Coal Fired Plant

In coal fired plants in particular, high temperature, high pressure components such as boiler superheater and reheater headers and tubes, turbine casings and blading and high temperature steam pipes are subject to creep which is a time-dependent deformation at elevated temperature and constant stress that can eventually result in failure. Extending the life of a plant may require some of these components to be replaced to ensure they do not fail prior to the new planned closure date.

It is normal practice for owners of coal fired plant to undertake a preliminary remnant life assessment of their high temperature, high pressure components when their plant has operated for approximately half of its original design life and to use the results of this assessment to determine which components are most at risk. These components are then subjected to more detailed assessment to determine whether they will need to be replaced.

Whether a creep affected component will need to be replaced or not will depend on the material of its construction, the design operating pressure and temperature and whether it has been operated under conditions more severe than the design conditions.

In addition, if an ageing plant is to continue to provide reliable power, all of the plant systems will need to be assessed in detail and, in many cases, significant refurbishment or replacement of air heaters, ductwork, expansion joints, pumps, fans, cooling towers, heat exchangers, foundations, concrete structures, instruments and control systems will be required.

A decision to extend the life of a plant would best be made at least five years prior to the current planned closure date as it is likely that maintenance would be kept to a minimum for the last few years of planned operation and a later decision to extend the life of a plant will probably mean more work would be required to replace components that had been allowed to degrade.

The Press has reported Australia's Chief Scientist, Dr Alan Finkel's advice that refurbishment costs for an aging coal fired plant such as Liddell would be in the order of $250 - $300/kW for a 10 year life extension.

The Press also reports that Advisian, the consulting arm of Worley Parsons advised AGL that the cost to refurbish Liddell would be in the order of $450/kW. This cost covered boilers, turbines, electrical generators and distribution as well as refurbishment of balance of plant systems.

We concur with these numbers having independently assessed costs at least $120/kW to replace only a limited number of creep affected components in a typical boiler.

To enable high availability as well as safe operation from an aging plant, comprehensive refurbishment of all plant systems will be required.

Any refurbishment is likely to be a once-only undertaking as further work would likely require replacing the previously replaced components again as well as other components and costs would quickly escalate.

Refurbishment is not always successful. The Western Australian Government invested $310M in refurbishing Muja A/B before the project was abandoned due to time (18 months) and cost ($150M) blowouts when the plant was found to be far more corroded than originally envisaged.

The important issue to note is that a thorough understanding of the existing condition of all plant and equipment at a power station will be needed before an assessment regarding the feasibility of life extension at an acceptable cost can be made. Safety must remain a priority. Not replacing a pressure retaining component which subsequently fails in service could lead to multiple fatalities.

A number of powers stations have replaced or are considering replacing their existing steam turbines with new, more efficient units of higher output. This may be an option for other plants depending on their forecast remaining life. Costs and improvements in output and efficiency would need to be assessed on a case by case basis but it is unlikely that a turbine upgrade would be considered for a plant with less than 20 years forecast remaining life.

This is consistent with advice provided to Josh Frydenberg, the Minister for Environment and Energy in 2017 when GE Power Services proposed an audit of Australia's coal fired power stations to assess their suitability for turbine upgrades.

4.2.2 Gas Turbine Plant

Gas turbines are classified as either:

- Aero-derivatives or,
- Industrial or Frame units

The former are, as the name implies, derived from jet aircraft engines and are maintained on the basis of accumulated running hours regardless of the number of starts they have been subjected to. Aero-derivatives are maintained by completely replacing the power core on an exchange basis.

Industrial gas turbines are normally maintained in-situ based on equivalent operating hours which are made up of hours run plus additional factored hours for every start, trip and rapid load change (GE monitors starts and running hours separately and either can be the trigger for maintenance depending on the operating profile of a particular unit). The largest industrial gas turbines are several times the capacity of the largest aero-derivatives.

The design life of an industrial gas turbine is typically between 150,000 and 200,000 equivalent operating hours. This may be extended a single time by a further 50,000 equivalent operating hours if a complete NDT inspection of the rotor and blades is carried out by the original equipment manufacturer (OEM) or a qualified service provider.

Many gas turbine models are regularly upgraded by the OEMs throughout their production life and it may be possible to replace compressor and/or turbine blading with upgraded components to improve the output and/or efficiency of an existing gas turbine.

5. Results – new entrants

5.1 Gas turbines

Gas turbines are used in power generation in both Open Cycle (OCGT) and Combined Cycle (CCGT) configurations. OCGTs are commonly used in a peaking role because of their fast start capability. CCGTs are slower to start and less flexible in their operation and, hence, are typically used in base or shoulder load configuration.

Thermoflow software version 27 was used to model and derive the performance parameters of the OCGT, CCGT 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 12.

Table 12 Thermoflow Cost Factors (Gas Turbines)

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	2.025	No change

5.1.1 CCGT with CCS

Nominal new entrant details

- 2 x Siemens SGT5 – 2000E gas turbines and 1 x steam turbine
- Nominal capacity at reference conditions 484 MW Gross
- Evaporative cooler / low NO_x burners

Table 13 New entrant parameters – CCGT with CCS

Item	Value	Source / Basis
General Details		
Fuel Type	Gas	
First Year Assumed Commercially Viable for construction	2028	CCS unproven at a commercial scale. Assume Min 10 year development time.
Assumed unit size (MW)	484 Gross	Thermoflow GTPro Version 27
Seasonal Ratings: Summer (MW)	422 Net	Thermoflow GTPro Version 27
Seasonal Ratings: Not summer (MW)	437 Net	Thermoflow GTPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	30	GHD in-house data
Lead time for development (yrs) / Construction (weeks)	10 / 104	GHD in-house data
Technical Details		
Min Stable Generation (% of installed capacity)	30	Thermoflow GTPro Version 27
Auxiliary load (% of installed capacity)	9.72	Thermoflow GTPro Version 27
Forced outage rate (full forced outages) (%)	2	
Frequency of full forced outage per annum		
Full outage Mean time to repair (h)		
Partial Forced outage rate (partial forced outages) (%)	1	
Frequency of partial forced outages		
Partial Outage derating factor (% lost during partial outage)	40	GHD in-house data
Partial outage Mean time to repair (h)		
Equivalent forced outage rate (%)	3	Thermoflow GTPro Version 27
Ramp Up Rate (MW/h) - standard operation	370	Per Existing AEMO data for similar plant

Item	Value	Source / Basis
Ramp Down Rate (MW/h) - standard operation	370	Per Existing AEMO data for similar plant
Heat rate at minimum operation (GJ/MWh)	12.15	Thermoflow GTPro Version 27
Heat rate at maximum operation (GJ/MWh)	8.78	Thermoflow GTPro Version 27
Thermal Efficiency (%, HHV sent-out) at MCR	40.99	Thermoflow GTPro Version 27
Average Maintenance rate (no of days/year)	10	GHD in-house data
Cold Start-up Notification Time (h)	15	Per Existing AEMO data for similar plant
Warm Start-up Notification Time (h)	3	Per Existing AEMO data for similar plant
Hot Start-up Notification Time (h)	1	Per Existing AEMO data for similar plant
Cost Details		
Fixed Operating Cost ($/MW/year)	17,900	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Op Cost ($/MWh sent-out)	12.64	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)	1.92	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Cold Start-up Costs ($/MW as gen)	25	Per Existing AEMO data for similar plant
Warm Start-up Costs ($/MW as gen)	15	Per Existing AEMO data for similar plant
Hot Start-up Costs ($/MW as gen)	5	Per Existing AEMO data for similar plant
Emissions Details		Per Existing AEMO data for similar plant
Combustion Emissions (kg CO2-e/GJ of fuel)	6.36	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014
Fugitive Emissions (kg CO2-e/GJ of fuel)	3.9 – 13.5	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014

Table 14 New entrant capital cost – CCGT with CCS

Item	Value	Source / Basis
General Costs		
Equipment costs	$618,886,000	Thermoflow GTPro Version 27
Fuel connection costs	$70,000 per 25 mm diameter per km	GHD in-house data
Cost of land and development	$151,179,000	Thermoflow GTPro Version 27
Installation costs	$44,288,000	Thermoflow GTPro Version 27
Carbon Capture and Storage Costs		
CCS costs (separate from the generation plant)	$1,016,582,000	Thermoflow GTPro Version 27
CCS storage costs (separate from CCS capture costs) ($/t CO_2)	0.32 - 18.34	Compiled from data from the International Energy Agency 2008, the Intergovernmental Panel on Climate Change 2005 and the Electric Power Research Institute 2015
CCS transportation cost ($/t CO_2)	1.60 - 16.66	Compiled from data from the International Energy Agency 2008, the Intergovernmental Panel on Climate Change 2005 and the Electric Power Research Institute 2015

5.1.2 CCGT without CCS

Nominal new entrant details

- 2 x Siemens SGT5 – 2000E gas turbines
- Nominal capacity at reference conditions 519 MW Gross
- Evaporative cooler / low NO_x burners.

Table 15 New entrant capital cost – CCGT without CCS

Item	Value	Source / Basis
General Details		
Fuel Type	Gas	
First Year Assumed Commercially Viable for construction	2018	
Assumed unit size (MW)	519 Gross	Thermoflow GTPro Version 27
Seasonal Ratings: Summer (MW)	488 Net	Thermoflow GTPro Version 27
Seasonal Ratings: Not summer (MW)	506 Net	Thermoflow GTPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	30	GHD in-house data
Lead time for development (yrs) / Construction (weeks)	3 / 104	GHD in-house data
Technical Details		
Min Stable Generation (% of installed capacity)	30	Thermoflow GTPro Version 27
Auxiliary load (% of installed capacity)	2.5	Thermoflow GTPro Version 27
Forced outage rate (full forced outages) (%)	2	GHD in-house data
Frequency of full forced outage per annum		
Full outage Mean time to repair (h)		
Partial Forced outage rate (partial forced outages) (%)	1	GHD in-house data
Frequency of partial forced outages		
Partial Outage derating factor (% lost during partial outage)	40	GHD in-house data
Partial outage Mean time to repair (h)		
Equivalent forced outage rate (%)	3	Thermoflow GTPro Version 27
Ramp Up Rate (MW/h) - standard operation	370	Per Existing AEMO data for similar plant

Item	Value	Source / Basis
Ramp Down Rate (MW/h) - standard operation	370	Per Existing AEMO data for similar plant
Heat rate at minimum operation (GJ/MWh)	16.59	Thermoflow GTPro Version 27
Heat rate at maximum operation (GJ/MWh)	7.58	Thermoflow GTPro Version 27
Thermal Efficiency (%, HHV sent-out) at MCR	47.52	Thermoflow GTPro Version 27
Average Maintenance rate (no of days/year)	10	GHD in-house data
Cold Start-up Notification Time (h)	15	Per Existing AEMO data for similar plant
Warm Start-up Notification Time (h)	3	Per Existing AEMO data for similar plant
Hot Start-up Notification Time (h)	1	Per Existing AEMO data for similar plant
Cost Details		
Fixed Operating Cost ($/MW/year)	10,500	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Op Cost ($/MWh sent-out)	7.37	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)	N/A	
Cold Start-up Costs ($/MW as gen)	25	Per Existing AEMO data for similar plant
Warm Start-up Costs ($/MW as gen)	15	Per Existing AEMO data for similar plant
Hot Start-up Costs ($/MW as gen)	5	Per Existing AEMO data for similar plant
Emissions Details		Per Existing AEMO data for similar plant
Combustion Emissions (kg CO_{2e}/GJ of fuel)	52.10	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014
Fugitive Emissions (kg CO_{2e}/GJ of fuel)	3.9 – 13.5	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014

Table 16 New entrant capital cost – CCGT without CCS

Item	Value	Source / Basis
General Costs		
Equipment costs	$564,262,000	Thermoflow GTPro Version 27
Fuel connection costs	$70,000 per 25 mm diameter per km	GHD in-house data
Cost of land and development	$54,764,000	Thermoflow GTPro Version 27
Installation costs	$44,227,000	Thermoflow GTPro Version 27

5.1.3 OCGT without CCS

Nominal new entrant details

- 3 x Siemens SGT5-2000E gas turbines
- Nominal nameplate capacity 549 MW Gross
- Water injection / low NO_x burners / evaporative cooler / water injection

Table 17 New entrant parameters – OCGT without CCS

Item	Value	Source / Basis
General Details		
Fuel Type	Gas	
First Year Assumed Commercially Viable for construction	2018	
Assumed unit size (MW)	3 x 183 Gross	Thermoflow GTPro Version 27
Seasonal Ratings: Summer (MW)	3 x 170 Net	Thermoflow GTPro Version 27
Seasonal Ratings: Not summer (MW)	3 x 179 Net	Thermoflow GTPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	30	GHD in-house data
Lead time for development (yrs)	3	

Item	Value	Source / Basis
Construction (weeks)	52	GHD in-house data
Technical Details		
Min Stable Generation (% of installed capacity)	0	Thermoflow GTPro Version 27
Auxiliary load (% of installed capacity)	1.53	Thermoflow GTPro Version 27
Forced outage rate (full forced outages) (%)	1	GHD in-house data
Frequency of full forced outage per annum		
Full outage Mean time to repair (h)		
Partial Forced outage rate (partial forced outages) (%)	1	GHD in-house data
Frequency of partial forced outages		
Partial Outage derating factor (% lost during partial outage)	10	GHD in-house data
Partial outage Mean time to repair (h)		
Equivalent forced outage rate (%)	1.1	GHD in-house data
Ramp Up Rate (MW/h) - standard operation	500	Per Existing AEMO data for similar plant
Ramp Down Rate (MW/h) - standard operation	500	Per Existing AEMO data for similar plant
Heat rate at minimum operation (GJ/MWh)	37.5	Thermoflow GTPro Version 27
Heat rate at maximum operation (GJ/MWh)	11.75	Thermoflow GTPro Version 27
Thermal Efficiency (%, HHV sent-out)	30.64	Thermoflow GTPro Version 27
Average Maintenance rate (no of days/year)	4	GHD in-house data
Cold Start-up Notification Time (h)	6	Per Existing AEMO data for similar plant
Warm Start-up Notification Time (h)	1	Per Existing AEMO data for similar plant
Hot Start-up Notification Time (h)	1	Per Existing AEMO data for similar plant
Cost Details		
Fixed Operating Cost ($/MW/year)	4,200	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)

Item	Value	Source / Basis
Variable Op Cost ($/MWh sent-out)	10.53	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Cold Start-up Costs ($/MW as gen)	100	Per Existing AEMO data for similar plant
Warm Start-up Costs ($/MW as gen)	100	Per Existing AEMO data for similar plant
Hot Start-up Costs ($/MW as gen)	100	Per Existing AEMO data for similar plant
Emissions Details		
Combustion Emissions (kg CO_{2e}/GJ of fuel)	53.15	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014
Fugitive Emissions (kg CO_{2e}/GJ of fuel)	3.9 – 13.5	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014

Table 18 New entrant capital cost – OCGT without CCS

Item	Value	Source / Basis
General Costs		
Equipment costs	$421,147,000	
Fuel connection costs	$70,000 per 25 mm diameter per km	GHD in-house data
Cost of land and development	$40,538,000	
Installation costs	$29,274,000	

5.1.4 Fixed and variable operating and maintenance costs

As the output of a gas turbine is dependent on ambient temperature, pressure and humidity, the fixed operating costs ($/MW) and variable operating cost $/MWh$_{Net}$ will be vary with temperature, pressure and humidity. As a first approximation, fixed operating costs, for the referenced plant conditions of 25°C, 110 m above sea level and 60% relative humidity can be calculated as:

(Assumed unit size (MW)(100 – Auxiliary load %)/100) x Fixed Operating Costs ($/MW$_{Net}$/year)

Variable operating costs are already in the required units. If a total annual cost is required then the formulae to use is:

(Assumed unit size (MW)(100 – Auxiliary load %)/100) x Variable Operating Costs ($/MW$_{Net}$/year) x hours

This assumes that the unit is operating at full load.

5.2 Reciprocating engine generators

There are two basic categories of reciprocating engines used in power generation: spark ignition (SI), typically fuelled by natural gas, and compression ignition (CI), and typically fuelled by diesel or heavier fuel oils. CI engines can also be fuelled by natural gas with ignition provided by a small amount of diesel pilot fuel.

While liquid fuelled CI engines are commonly used to provide power for remote mines or communities not connected to an electricity grid, they are generally too expensive to operate to provide cost effective power to an interconnected grid. For this reason, it is likely that any new market entrant will be restricted to gas fuelled SI engines or gas fuelled CI engines using pilot ignition.

Gas fuelled reciprocating engines are faster starting and more efficient than gas turbines. Unlike industrial gas turbines, maintenance of gas fuelled reciprocating engines is not affected by multiple starts making them ideal for peak load operation.

Gas fuelled reciprocating engines are also able to operate at higher ambient temperatures (up to 38-40^{o}C) and altitudes (up to 1,000 metres above sea level) than gas turbines without de-rating.

Unit sizes are limited to around 20 MW meaning more generating sets are required for the same plant capacity compared to gas turbines and this will require a larger plant footprint and will incur additional capital costs.

Thermoflow software version 27 was used to model and derive the performance parameters of gas reciprocating engines, 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 19.

Table 19 Thermoflow Cost Factors (Gas Engines)

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	2.025	No change

Nominal new entrant details

- 12 x Wartsila 18V50SG reciprocating gas engines

- Nominal nameplate capacity 221 MW Gross

Table 20 New entrant parameters – Reciprocating engine generators

Item	Value	Source / Basis
General Details		
Fuel Type	Gas	
First Year Assumed Commercially Viable for construction	2018	
Assumed unit size (MW)	12 x 18.4 Gross	Thermoflow GTPro Version 27
Seasonal Ratings: Summer (MW)	12 x 18 Net	Thermoflow GTPro Version 27
Seasonal Ratings: Not summer (MW)	12 x 18 Net	Thermoflow GTPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	30	GHD in-house data
Lead time for development (yrs)	3	GHD in-house data
Construction (weeks)	52	GHD in-house data
Technical Details		
Min Stable Generation (% of installed capacity)	0	Thermoflow GTPro Version 27
Auxiliary load (% of installed capacity)	2.2	Thermoflow GTPro Version 27
Forced outage rate (full forced outages) (%)	1	GHD in-house data
Frequency of full forced outage per annum		
Full outage Mean time to repair (h)		
Partial Forced outage rate (partial forced outages) (%)	1	GHD in-house data
Frequency of partial forced outages		
Partial Outage derating factor (% lost during partial outage)	10	GHD in-house data
Partial outage Mean time to repair (h)		
Equivalent forced outage rate (%)	1.5	GHD in-house data

Item	Value	Source / Basis
Ramp Up Rate (MW/h) - standard operation	1,000	Per Existing AEMO data for similar plant
Ramp Down Rate (MW/h) - standard operation	1,000	Per Existing AEMO data for similar plant
Heat rate at minimum operation (GJ/MWh)	11.37	Thermoflow GTPro Version 27
Heat rate at maximum operation (GJ/MWh)	8.85	Thermoflow GTPro Version 27
Thermal Efficiency (%, HHV sent-out)	40.69	Thermoflow GTPro Version 27
Average Maintenance rate (no of days/year)	4	GHD in-house data
Cold Start-up Notification Time (h)	6	Per Existing AEMO data for similar plant
Warm Start-up Notification Time (h)	1	Per Existing AEMO data for similar plant
Hot Start-up Notification Time (h)	1	Per Existing AEMO data for similar plant
Cost Details		
Fixed Operating Cost ($/MW/year)	4,200	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Op Cost ($/MWh sent-out)	16.42	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Cold Start-up Costs ($/MW as gen)	100	Per Existing AEMO data for similar plant
Warm Start-up Costs ($/MW as gen)	100	Per Existing AEMO data for similar plant
Hot Start-up Costs ($/MW as gen)	100	Per Existing AEMO data for similar plant
Emissions Details		
Combustion Emissions (kg CO_{2e}/GJ of fuel)	53.53	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014
Fugitive Emissions (kg CO_{2e}/GJ of fuel)	3.9 – 13.5	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014

Table 21 New entrant capital cost – Reciprocating engine generators

Item	Value	Source / Basis
General Costs		
Equipment costs	$291,611,000	Thermoflow GTPro Version 27

Item	Value	Source / Basis
Fuel connection costs	$70,000 per 25 mm diameter per km	GHD in-house data
Cost of land and development	$28,325,000	Thermoflow GTPro Version 27
Installation costs	$23,110,000	Thermoflow GTPro Version 27

5.3 Coal

Supercritical technology has been in use since the 1950s but initial issues with poor availability hindered further development of this technology. In the 1980s, manufacturers in Japan and Europe took a great initiative to bring this technology to an acceptable level of availability 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 these higher temperatures and pressures results in a significant cycle efficiency gain because no energy is required to transform water from its liquid to vapour phases.

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 temperatures,
- Incorporation of CCS technologies for existing and future plants.

Coal-fired power continues to be the base load generation technology within the NEM. Any new entrant coal-fired generation into the NEM is likely to be supercritical and to utilise carbon capture and storage (CCS) if this technology proves technically and financially viable.

We reviewed six coal based technology options against AEMO’s current new entrant planning data, with an additional two cases considered for the use of brown coal. The full list of configurations considered is as follows:

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
5. Ultra Supercritical pulverised black coal with carbon capture and storage

6. Ultra Supercritical pulverised black coal without carbon capture and storage
7. Advanced Ultra Supercritical pulverised black coal with carbon capture and storage
8. Advanced Ultra Supercritical pulverised black coal without carbon capture and storage

Pulverised coal-fired power plants have been 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 have been modelled with and without CCS technology installed. The steam generator has been assumed to include low NO_x 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 CO_2 in chemical solvents such as amines. Traditionally carbon capture utilising solvents yields a CO_2 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 27 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 22.

Table 22 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	2.025	No change

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.

AEMO required a number of options to be considered as shown in Table 23.

Table 23 Steam temperatures and pressures for coal fired thermal plant

Cycle	Main Steam Pressure (MPa)	Main Steam Temperature (°C)	Reheat Steam Temperature (°C)	Carbon Capture and Storage (CCS)
Supercritical	22.8	568	568	Not Included
Supercritical	22.8	568	568	Included
Ultra- Supercritical	25.0	620	620	Not Included
Ultra- Supercritical	25.0	620	620	Included
Advanced Ultra-Supercritical	30.0	680	680	Not Included
Advanced Ultra-Supercritical	30.0	680	680	Included

It should be noted that there is no firm definition of Ultra-Supercritical or Advanced Ultra-Supercritical. GHD has used typical pressures and temperatures in its comparisons.

5.3.1 Supercritical PC – black coal with CCS

Table 24 New entrant parameters – Supercritical PC – black coal with CCS

Item	Value	Source / Basis
General Details		
Fuel Type	Black coal	
First Year Assumed Commercially Viable for construction	2028	CCS unproven on a commercial scale
Assumed unit size (MW)	750 Gross	
Seasonal Ratings: Summer (MW)	624 Net	Thermoflow SteamPro Version 27
Seasonal Ratings: Not summer (MW)	633 Net	Thermoflow SteamPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	50	GHD in-house data
Lead time for development (yrs)	10	GHD in-house data
Construction (weeks)	208	GHD in-house data
Technical Details		

Item	Value	Source / Basis
Min Stable Generation (% of installed capacity)	40	GHD in-house data
Auxiliary load (% of installed capacity)	15.94	Thermoflow SteamPro Version 27
Forced outage rate (full forced outages) (%)	2	GHD in-house data
Frequency of full forced outage per annum		
Full outage Mean time to repair (h)		
Partial Forced outage rate (partial forced outages) (%)	1	GHD in-house data
Frequency of partial forced outages		
Partial Outage derating factor (% lost during partial outage)	30	GHD in-house data
Partial outage Mean time to repair (h)		
Equivalent forced outage rate (%)	2.3	GHD in-house data
Ramp Up Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Ramp Down Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Heat rate at minimum operation (GJ/MWh)	13.1	Thermoflow SteamPro Version 27
Heat rate at maximum operation (GJ/MWh)	12.1	Thermoflow SteamPro Version 27
Thermal Efficiency (%, HHV sent-out)	30.05	Thermoflow SteamPro Version 27
Average Maintenance rate (no of days/year)	21	GHD in-house data
Cold Start-up Notification Time (h)	24	Per AEMO data for similar plant
Warm Start-up Notification Time (h)	4	Per AEMO data for similar plant
Hot Start-up Notification Time (h)	2	Per AEMO data for similar plant
Cost Details		
Fixed Operating Cost ($/MW/year)	77,100	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Op Cost ($/MWh sent-out)	9.48	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)

Item	Value	Source / Basis
Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)	4.13	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Cold Start-up Costs ($/MW as gen)	350	Per AEMO data for similar plant
Warm Start-up Costs ($/MW as gen)	120	Per AEMO data for similar plant
Hot Start-up Costs ($/MW as gen)	40	Per AEMO data for similar plant
Emissions Details		
Combustion Emissions (kg CO_{2e}/GJ of fuel)	6.19	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014
Fugitive Emissions (kg CO_{2e}/GJ of fuel)	2.3 – 9.2	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014

Table 25 New entrant capital cost – Supercritical PC – black coal with CCS

Item	Value	Source / Basis
General Costs		
Equipment costs	$2,128,252,000	Thermoflow SteamPro Version 27
Fuel connection costs	$100 M for 50 km of single track rail line	GHD in-house data
Cost of land and development	$751,102,000	Thermoflow SteamPro Version 27
Installation costs	$270,325,000	Thermoflow SteamPro Version 27
Carbon Capture and Storage Costs		
CCS costs (separate from the generation plant)	$1,356,930,000	Thermoflow SteamPro Version 27
CCS storage costs (separate from CCS capture costs)	$0.32 - $18.34	Compiled from data from the International Energy Agency 2008, the Intergovernmental Panel on Climate Change 2005 and the Electric Power Research Institute 2015
CCS transportation cost	$1.60 - $16.66	Compiled from data from the International Energy Agency 2008, the Intergovernmental Panel on Climate Change 2005 and the Electric Power Research Institute 2015

5.3.2 Supercritical PC – black coal without CCS

Table 26 New entrant parameters – Supercritical PC – black coal without CCS

Item	Value	Source / Basis
General Details		
Fuel Type	Black coal	
First Year Assumed Commercially Viable for construction	2018	
Assumed unit size (MW)	750 Gross	
Seasonal Ratings: Summer (MW)	711 Net	Thermoflow SteamPro Version 27
Seasonal Ratings: Not summer (MW)	722 Net	Thermoflow SteamPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	50	GHD in-house data
Lead time for development (yrs)	4	
Construction (weeks)	208	GHD in-house data
Technical Details		
Min Stable Generation (% of installed capacity)	40	GHD in-house data
Auxiliary load (% of installed capacity)	4	Thermoflow SteamPro Version 27
Forced outage rate (full forced outages) (%)	2	GHD in-house data
Frequency of full forced outage per annum		
Full outage Mean time to repair (h)		
Partial Forced outage rate (partial forced outages) (%)	1	GHD in-house data
Frequency of partial forced outages		
Partial Outage derating factor (% lost during partial outage)	30	GHD in-house data
Partial outage Mean time to repair (h)		

Item	Value	Source / Basis
Equivalent forced outage rate (%)	2.3	GHD in-house data
Ramp Up Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Ramp Down Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Heat rate at minimum operation (GJ/MWh)	10.0	Thermoflow SteamPro Version 27
Heat rate at maximum operation (GJ/MWh)	8.98	Thermoflow SteamPro Version 27
Thermal Efficiency (%, HHV sent-out)	40.11	Thermoflow SteamPro Version 27
Average Maintenance rate (no of days/year)	21	GHD in-house data
Cold Start-up Notification Time (h)	24	Per AEMO data for similar plant
Warm Start-up Notification Time (h)	4	Per AEMO data for similar plant
Hot Start-up Notification Time (h)	2	Per AEMO data for similar plant
Cost Details		
Fixed Operating Cost ($/MW/year)	53,200	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Op Cost ($/MWh sent-out)	4.21	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)	N/A	
Cold Start-up Costs ($/MW as gen)	350	Per AEMO data for similar plant
Warm Start-up Costs ($/MW as gen)	120	Per AEMO data for similar plant
Hot Start-up Costs ($/MW as gen)	40	Per AEMO data for similar plant
Emissions Details		
Combustion Emissions (kg CO_{2e}/GJ of fuel)	85.74	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014
Fugitive Emissions (kg CO_{2e}/GJ of fuel)	2.3 – 9.2	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014

Table 27 New entrant capital cost – Supercritical PC – black coal without CCS

Item	Value	Source / Basis
General Costs		
Equipment costs	$1,794,929,000	Thermoflow SteamPro Version 27
Fuel connection costs	$100 M for 50 km of single track rail line	GHD in-house data
Cost of land and development	$407,142,000	Thermoflow SteamPro Version 27
Installation costs	$240,778,000	Thermoflow SteamPro Version 27

5.3.3 Supercritical PC – brown coal with CCS

Table 28 New entrant parameters – Supercritical PC – brown coal with CCS

Item	Value	Source / Basis
General Details		
Fuel Type	Brown coal	
First Year Assumed Commercially Viable for construction	2028	CCS unproven on a commercial scale
Assumed unit size (MW)	750 Gross	
Seasonal Ratings: Summer (MW)	565.77 Net	Thermoflow SteamPro Version 27
Seasonal Ratings: Not summer (MW)	570.34 Net	Thermoflow SteamPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	50	GHD in-house data
Lead time for development (yrs)	10	
Construction (weeks)	208	GHD in-house data
Technical Details		

Item	Value	Source / Basis
Min Stable Generation (% of installed capacity)	40	GHD in-house data
Auxiliary load (% of installed capacity)	24.4	Thermoflow SteamPro Version 27
Forced outage rate (full forced outages) (%)	2	GHD in-house data
Frequency of full forced outage per annum		
Full outage Mean time to repair (h)		
Partial Forced outage rate (partial forced outages) (%)	1	GHD in-house data
Frequency of partial forced outages		
Partial Outage derating factor (% lost during partial outage)	30	GHD in-house data
Partial outage Mean time to repair (h)		
Equivalent forced outage rate (%)	2.3	GHD in-house data
Ramp Up Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Ramp Down Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Heat rate at minimum operation (GJ/MWh)	16.53	Thermoflow SteamPro Version 27
Heat rate at maximum operation (GJ/MWh)	14.95	Thermoflow SteamPro Version 27
Thermal Efficiency (%, HHV sent-out)	20.65	Thermoflow SteamPro Version 27
Average Maintenance rate (no of days/year)	21	GHD in-house data
Cold Start-up Notification Time (h)	48	Per AEMO data for similar plant
Warm Start-up Notification Time (h)	4	Per AEMO data for similar plant
Hot Start-up Notification Time (h)	2	Per AEMO data for similar plant
Cost Details		
Fixed Operating Cost ($/MW/year)	101,600	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)

Item	Value	Source / Basis
Variable Op Cost ($/MWh sent-out)	11.58	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)	4.67	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Cold Start-up Costs ($/MW as gen)	350	Per AEMO data for similar plant
Warm Start-up Costs ($/MW as gen)	120	Per AEMO data for similar plant
Hot Start-up Costs ($/MW as gen)	40	Per AEMO data for similar plant
Emissions Details		
Combustion Emissions (kg CO_{2e}/GJ of fuel)	5.36	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014
Fugitive Emissions (kg CO_{2e}/GJ of fuel)	0.4	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014

Table 29 New entrant capital cost – Supercritical PC – brown coal with CCS

Item	Value	Source / Basis
General Costs		
Equipment costs	$3,457,980,000	Thermoflow SteamPro Version 27
Fuel connection costs	Any brown coal plant is assumed to be mine mouth plant.	
Cost of land and development	$1,152,927,000	Thermoflow SteamPro Version 27
Installation costs	$506,042,000	Thermoflow SteamPro Version 27
Carbon Capture and Storage Costs		
CCS costs (separate from the generation plant)	$1,800,610,000	Thermoflow SteamPro Version 27
CCS storage costs (separate from CCS capture costs)	$0.32 - $18.34	Compiled from data from the International Energy Agency 2008, the Intergovernmental Panel on Climate Change 2005 and the Electric Power Research Institute 2015

Item	Value	Source / Basis
CCS transportation cost	$1.60 - $16.66	Compiled from data from the International Energy Agency 2008, the Intergovernmental Panel on Climate Change 2005 and the Electric Power Research Institute 2015

5.3.4 Supercritical PC – brown coal without CCS

Table 30 New entrant parameters – Supercritical PC – brown coal without CCS

Item	Value	Source / Basis
General Details		
Fuel Type	Brown coal	
First Year Assumed Commercially Viable for construction	2018	
Assumed unit size (MW)	750 Gross	
Seasonal Ratings: Summer (MW)	703.09 Net	Thermoflow SteamPro Version 27
Seasonal Ratings: Not summer (MW)	709.41 Net	Thermoflow SteamPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	50	GHD in-house data
Lead time for development (yrs)	4	GHD in-house data
Construction (weeks)	208	GHD in-house data
Technical Details		
Min Stable Generation (% of installed capacity)	40	GHD in-house data
Auxiliary load (% of installed capacity)	6.01	Thermoflow SteamPro Version 27
Forced outage rate (full forced outages) (%)	2	
Frequency of full forced outage per annum		
Full outage Mean time to repair (h)		
Partial Forced outage rate (partial forced outages) (%)	1	

Item	Value	Source / Basis
Frequency of partial forced outages		
Partial Outage derating factor (% lost during partial outage)	30	
Partial outage Mean time to repair (h)		
Equivalent forced outage rate (%)	2.3	GHD in-house data
Ramp Up Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Ramp Down Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Heat rate at minimum operation (GJ/MWh)	12.54	Thermoflow SteamPro Version 27
Heat rate at maximum operation (GJ/MWh)	11.34	Thermoflow SteamPro Version 27
Thermal Efficiency (%, HHV sent-out)	31.75	Thermoflow SteamPro Version 27
Average Maintenance rate (no of days/year)	21	GHD in-house data
Cold Start-up Notification Time (h)	48	Per AEMO data for similar plant
Warm Start-up Notification Time (h)	4	Per AEMO data for similar plant
Hot Start-up Notification Time (h)	2	Per AEMO data for similar plant
Cost Details		
Fixed Operating Cost ($/MW/year)	69,000	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Op Cost ($/MWh sent-out)	5.27	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)	N/A	
Cold Start-up Costs ($/MW as gen)	350	Per AEMO data for similar plant
Warm Start-up Costs ($/MW as gen)	120	Per AEMO data for similar plant
Hot Start-up Costs ($/MW as gen)	40	Per AEMO data for similar plant
Emissions Details		

Item	Value	Source / Basis
Combustion Emissions (kg CO_{2e}/GJ of fuel)	84.62	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014
Fugitive Emissions (kg CO_{2e}/GJ of fuel)	0.4	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014

Table 31 New entrant capital cost – Supercritical PC – brown coal without CCS

Item	Value	Source / Basis
General Costs		
Equipment costs	$2,737,347,000	Thermoflow SteamPro Version 27
Fuel connection costs	Any brown coal plant is assumed to be mine mouth plant.	
Cost of land and development	$628,399,000	Thermoflow SteamPro Version 27
Installation costs	$404,643,000	Thermoflow SteamPro Version 27

5.3.5 USC PC – black coal with CCS

Table 32 New entrant parameters –USC PC – black coal with CCS

Item	Value	Source / Basis
General Details		
Fuel Type	Black coal	
First Year Assumed Commercially Viable for construction	2028	CCS unproven on a commercial scale
Assumed unit size (MW)	750 Gross	
Seasonal Ratings: Summer (MW)	628.57 Net	Thermoflow SteamPro Version 27
Seasonal Ratings: Not summer (MW)	636.34 Net	Thermoflow SteamPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	50	GHD in-house data
Lead time for development (yrs)	10	GHD in-house data

Item	Value	Source / Basis
Construction (weeks)	208	GHD in-house data
Technical Details		
Min Stable Generation (% of installed capacity)	40	GHD in-house data
Auxiliary load (% of installed capacity)	15.37	Thermoflow SteamPro Version 27
Forced outage rate (full forced outages) (%)	2	GHD in-house data
Frequency of full forced outage per annum		
Full outage Mean time to repair (h)		
Partial Forced outage rate (partial forced outages) (%)	1	GHD in-house data
Frequency of partial forced outages		
Partial Outage derating factor (% lost during partial outage)	30	GHD in-house data
Partial outage Mean time to repair (h)		
Equivalent forced outage rate (%)	2.3	GHD in-house data
Ramp Up Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Ramp Down Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Heat rate at minimum operation (GJ/MWh)	12.98	Thermoflow SteamPro Version 27
Heat rate at maximum operation (GJ/MWh)	11.42	Thermoflow SteamPro Version 27
Thermal Efficiency (%, HHV sent-out)	31.39	Thermoflow SteamPro Version 27
Average Maintenance rate (no of days/year)	21	GHD in-house data
Cold Start-up Notification Time (h)	24	Per AEMO data for similar plant
Warm Start-up Notification Time (h)	4	Per AEMO data for similar plant
Hot Start-up Notification Time (h)	2	Per AEMO data for similar plant
Cost Details		

Item	Value	Source / Basis
Fixed Operating Cost ($/MW/year)	77,100	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Op Cost ($/MWh sent-out)	9.48	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)	4.13	
Cold Start-up Costs ($/MW as gen)	350	Per AEMO data for similar plant
Warm Start-up Costs ($/MW as gen)	120	Per AEMO data for similar plant
Hot Start-up Costs ($/MW as gen)	40	Per AEMO data for similar plant
Emissions Details		
Combustion Emissions (kg CO2-e/GJ of fuel)	6.27	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014
Fugitive Emissions (kg CO2-e/GJ of fuel)	2.3 - 9.2	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014

Table 33 New entrant capital cost – USC PC – black coal with CCS

Item	Value	Source / Basis
General Costs		
Equipment costs	$2,143,153,000	Thermoflow SteamPro Version 27
Fuel connection costs	$100 M for 50 km of single track rail line	GHD in-house data
Cost of land and development	$748,692,000	Thermoflow SteamPro Version 27
Installation costs	$276,818,000	Thermoflow SteamPro Version 27
Carbon Capture and Storage Costs		
CCS costs (separate from the generation plant)	$1,323,487,000	Thermoflow SteamPro Version 27
CCS storage costs (separate from CCS capture costs)	$0.32 - $18.34	Compiled from data from the International Energy Agency 2008, the Intergovernmental Panel on Climate Change 2005 and the Electric Power Research Institute 2015

Item	Value	Source / Basis
CCS transportation cost	$1.60 - $16.66	Compiled from data from the International Energy Agency 2008, the Intergovernmental Panel on Climate Change 2005 and the Electric Power Research Institute 2015

5.3.6 USC PC – black coal without CCS

Table 34 New entrant parameters – USC PC – black coal without CCS

Item	Value	Source / Basis
General Details		
Fuel Type	Black coal	
First Year Assumed Commercially Viable for construction	2018	
Assumed unit size (MW)	750 Gross	
Seasonal Ratings: Summer (MW)	714.08 Net	Thermoflow SteamPro Version 27
Seasonal Ratings: Not summer (MW)	724.07 Net	Thermoflow SteamPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	50	GHD in-house data
Lead time for development (yrs)	4	GHD in-house data
Construction (weeks)	208	GHD in-house data
Technical Details		
Min Stable Generation (% of installed capacity)	40	GHD in-house data
Auxiliary load (% of installed capacity)	3.77	Thermoflow SteamPro Version 27
Forced outage rate (full forced outages) (%)	2	GHD in-house data
Partial Forced outage rate (partial forced outages) (%)	1	GHD in-house data
Partial Outage derating factor (% lost during partial outage)	30	GHD in-house data

Item	Value	Source / Basis
Equivalent forced outage rate (%)	2.3	GHD in-house data
Ramp Up Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Ramp Down Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Heat rate at minimum operation (GJ/MWh)	9.84	Thermoflow SteamPro Version 27
Heat rate at maximum operation (GJ/MWh)	8.67	Thermoflow SteamPro Version 27
Thermal Efficiency (%, HHV sent-out)	41.54	Thermoflow SteamPro Version 27
Average Maintenance rate (no of days/year)	21	GHD in-house data
Cost Details		
Fixed Operating Cost ($/MW/year)	53,200	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Op Cost ($/MWh sent-out)	4.21	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)	N/A	
Cold Start-up Notification Time (h)	24	Per AEMO data for similar plant
Warm Start-up Notification Time (h)	4	Per AEMO data for similar plant
Hot Start-up Notification Time (h)	2	Per AEMO data for similar plant
Cold Start-up Costs ($/MW as gen)	350	Per AEMO data for similar plant
Warm Start-up Costs ($/MW as gen)	120	Per AEMO data for similar plant
Hot Start-up Costs ($/MW as gen)	40	Per AEMO data for similar plant
Emissions Details		
Combustion Emissions (kg CO_{2e}/GJ of fuel)	85.99	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014
Fugitive Emissions (kg CO_{2e}/GJ of fuel)	2.3 - 9.2	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014

Table 35 New entrant capital cost – USC PC – black coal without CCS

Item	Value	Source / Basis
General Costs		
Equipment costs	$1,861,012,000	Thermoflow SteamPro Version 27
Fuel connection costs	$100 M for 50 km of single track rail line	GHD in-house data
Cost of land and development	$420,706,000	Thermoflow SteamPro Version 27
Installation costs	$242,514,000	Thermoflow SteamPro Version 27

5.3.7 Advanced USC PC – black coal with CCS

Table 36 New entrant parameters – Advanced USC PC – black coal with CCS

Item	Value	Source / Basis
General Details		
Fuel Type	Black coal	
First Year Assumed Commercially Viable for construction	2028	CCS unproven on a commercial scale
Assumed unit size (MW)	750 Gross	
Seasonal Ratings: Summer (MW)	637.68 Net	Thermoflow SteamPro Version 27
Seasonal Ratings: Not summer (MW)	644.21 Net	Thermoflow SteamPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	50	GHD in-house data
Lead time for development (yrs)	10	
Construction (weeks)	208	GHD in-house data
Technical Details		
Min Stable Generation (% of installed capacity)	40	GHD in-house data
Auxiliary load (% of installed capacity)	14.27	Thermoflow SteamPro Version 27
Forced outage rate (full forced outages) (%)	2	GHD in-house data

Item	Value	Source / Basis
Partial Forced outage rate (partial forced outages) (%)	1	GHD in-house data
Partial Outage derating factor (% lost during partial outage)	30	GHD in-house data
Equivalent forced outage rate (%)	2.3	GHD in-house data
Ramp Up Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Ramp Down Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Heat rate at minimum operation (GJ/MWh)	12.30	Thermoflow SteamPro Version 27
Heat rate at maximum operation (GJ/MWh)	11.42	Thermoflow SteamPro Version 27
Thermal Efficiency (%, HHV sent-out)	33.10	Thermoflow SteamPro Version 27
Average Maintenance rate (no of days/year)	21	GHD in-house data
Cost Details		
Fixed Operating Cost ($/MW/year)	77,100	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Op Cost ($/MWh sent-out)	9.48	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)	4.13	
Cold Start-up Notification Time (h)	24	Per AEMO data for similar plant
Warm Start-up Notification Time (h)	4	Per AEMO data for similar plant
Hot Start-up Notification Time (h)	2	Per AEMO data for similar plant
Cold Start-up Costs ($/MW as gen)	350	Per AEMO data for similar plant
Warm Start-up Costs ($/MW as gen)	120	Per AEMO data for similar plant
Hot Start-up Costs ($/MW as gen)	40	Per AEMO data for similar plant
Emissions Details		

Item	Value	Source / Basis
Combustion Emissions (kg CO2-e/GJ of fuel)	6.44	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014
Fugitive Emissions (kg CO2-e/GJ of fuel)	2.3 - 9.2	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014

Table 37 New entrant capital cost – Advanced USC PC – black coal with CCS

Item	Value	Source / Basis
General Costs		
Equipment costs	$2,053,027,000	Thermoflow SteamPro Version 27
Fuel connection costs	$100 M for 50 km of single track rail line	GHD in-house data
Cost of land and development	$718,298,000	Thermoflow SteamPro Version 27
Installation costs	$254,058,000	Thermoflow SteamPro Version 27
Carbon Capture and Storage Costs		
CCS costs (separate from the generation plant)	$1,284,401,000	Thermoflow SteamPro Version 27
CCS storage costs (separate from CCS capture costs)	$0.32 - $18.34	Compiled from data from the International Energy Agency 2008, the Intergovernmental Panel on Climate Change 2005 and the Electric Power Research Institute 2015
CCS transportation cost	$1.60 - $16.66	Compiled from data from the International Energy Agency 2008, the Intergovernmental Panel on Climate Change 2005 and the Electric Power Research Institute 2015

5.3.8 Advanced USC PC – black coal without CCS

Table 38 New entrant parameters – Advanced USC PC – black coal without CCS

Item	Value	Source / Basis
General Details		
Fuel Type	Black coal	

Item	Value	Source / Basis
First Year Assumed Commercially Viable for construction	2018	
Assumed unit size (MW)	750 Gross	
Seasonal Ratings: Summer (MW)	714.66 Net	Thermoflow SteamPro Version 27
Seasonal Ratings: Not summer (MW)	724.07 Net	Thermoflow SteamPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	50	GHD in-house data
Lead time for development (yrs)	4	GHD in-house data
Construction (weeks)	208	GHD in-house data
Technical Details		
Min Stable Generation (% of installed capacity)	40	GHD in-house data
Auxiliary load (% of installed capacity)	3.7	Thermoflow SteamPro Version 27
Forced outage rate (full forced outages) (%)	2	GHD in-house data
Frequency of full forced outage per annum		
Full outage Mean time to repair (h)		
Partial Forced outage rate (partial forced outages) (%)	1	GHD in-house data
Partial Outage derating factor (% lost during partial outage)	30	GHD in-house data
Equivalent forced outage rate (%)	2.3	GHD in-house data
Ramp Up Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Ramp Down Rate (MW/h) - standard operation	230	Per AEMO data for similar plant
Heat rate at minimum operation (GJ/MWh)	9.33	Thermoflow SteamPro Version 27
Heat rate at maximum operation (GJ/MWh)	8.32	Thermoflow SteamPro Version 27
Thermal Efficiency (%, HHV sent-out)	43.27	Thermoflow SteamPro Version 27

Item	Value	Source / Basis
Average Maintenance rate (no of days/year)	21	GHD in-house data
Cold Start-up Notification Time (h)	24	Per AEMO data for similar plant
Warm Start-up Notification Time (h)	4	Per AEMO data for similar plant
Hot Start-up Notification Time (h)	2	Per AEMO data for similar plant
Cost Details		
Fixed Operating Cost ($/MW/year)	53,200	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Op Cost ($/MWh sent-out)	4.21	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI per Data Set 6427.0 i.e. x 109.2/103.7)
Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)	N/A	
Cold Start-up Costs ($/MW as gen)	350	Per AEMO data for similar plant
Warm Start-up Costs ($/MW as gen)	120	Per AEMO data for similar plant
Hot Start-up Costs ($/MW as gen)	40	Per AEMO data for similar plant
Emissions Details		
Combustion Emissions (kg CO_{2e}/GJ of fuel)	85.99	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014
Fugitive Emissions (kg CO_{2e}/GJ of fuel)	2.3 - 9.2	ACIL Allen report to AEMO: Emission Factors – Review of Emission Factors for Use in the CDEII, 2014

Table 39 New entrant capital cost – Advanced USC PC – black coal without CCS

Item	Value	Source / Basis
General Costs		
Equipment costs	$1,968,029,000	Thermoflow SteamPro Version 27
Fuel connection costs	$100 M for 50 km of single track rail line	GHD in-house data
Cost of land and development	$442,310,000	Thermoflow SteamPro Version 27
Installation costs	$243,516,000	Thermoflow SteamPro Version 27

Item	Value	Source / Basis
Carbon Capture and Storage Costs		
CCS costs (separate from the generation plant)	N/A	
CCS storage costs (separate from CCS capture costs)	N/A	
CCS transportation cost	N/A	

5.4 Synchronous condensers

A synchronous condenser is a synchronous generator or motor operating without a prime mover (no active power is generated). Traditionally, this technology has provided a source of dynamic reactive power to improve network stability and support voltage under varying load conditions and contingencies. Over the past 25 years, the technology was considered antiquated, being replaced by more dynamic reactive support technology. However, with the increasing trend in asynchronous generation, synchronous condensers have undergone a renaissance in the industry for supporting weak grids. Similar to a synchronous generator, the synchronous condenser has a high short circuit capacity and the rotating mass component of the condenser can provide critical inertia to the network.

Driven by new regulation in the NER, new generators are obligated to 'do no harm' to the level of system strength necessary, maintaining the security of the power system. Responsibility for system strength remediation is placed on the connecting generator. Recently, new asynchronous generators within Australia have been looking at connecting synchronous condensers at the connection point to improve the local grid strength.

Existing thermal plant can be repurposed as synchronous condensers, which is an appealing option for decommissioned power stations. Synchronous condensers consume little power except to compensate parasitic losses and hence have high efficiencies (losses vs VARS).

Nominal new entrant details

- Nominal nameplate capacity: ±100 MVAr overexcited
- Includes auxiliary start-up motor and associated connection plant (drives, LCC MCC, HV circuit breaker, transformer (11 / 220 kV) etc.)
- Assumed to be new unit not repurposing existing generator.

Table 40 New entrant parameters – Synchronous condensers

Item	Value	Source / Basis
First Year Assumed Commercially Viable for construction	2018	Mature technology

Item	Value	Source / Basis
Assumed unit size (MVAr)	±100	GHD sourced from vendor. As with a generator, synchronous condensers are available in a wide range of sizes.
Seasonal Ratings: Summer (MVAr)	±100	Assume sufficient heating/cooling to enable full capacity
Seasonal Ratings: Not summer (MVAr)	±100	Assume sufficient heating/cooling to enable full capacity
Technical Life (yrs)	40	GHD sourced.
Lead time for development (yrs)	1	GHD sourced. Correlated "*Victorian Reactive Power Support Planning and Forecasting"* AEMO
Construction time (weeks)	20	GHD sourced. Correlated "*Victorian Reactive Power Support Planning and Forecasting"* AEMO
<u>Technical Details</u>		
Partial forced outage (%)	0	Not applicable (unit has no partial redundancy)
Forced outage rate (full forced outages) (%)	<0.5	GHD sourced. "A*CS Dynamic Reactive Power"* Transpower.
Frequency of full forced outage per annum	<1	GHD estimate. Very low likelihood of forced outage.
Full outage Mean time to repair (h)	672	GHD estimate. Up to 3 months for severe failure such as pony motor with no spare
Ramp Up Rate (MW/h) - standard operation	~near instantaneous	Condensers reactive power output can change in order of seconds.
Ramp Down Rate (MW/h) - standard operation	~near instantaneous	Condensers reactive power output can change in order of seconds.
Heat rate at minimum operation (GJ/MWh)	0	
Heat rate at maximum operation (GJ/MWh)	0	
Thermal Efficiency (%, HHV sent-out)	97	GHD sourced and public domain. "*Synchronous condensers in mining projects"* ABB
Maintenance Frequency (no of times per year)	0.25	Public domain sourced. "*Cost implication and reactive power generating potential of the synchronous condenser"* CTU
Average Maintenance rate (no of days/year)	1	GHD estimate
Cold Start-up Notification Time (h)	0.16	Public domain sourced. "*Synchronous condenser systems"* GE.
Warm Start-up Notification Time (h)	0.16	Public domain sourced. "*Synchronous condenser systems"* GE.
Hot Start-up Notification Time (h)	~near instant	Public domain sourced. "*Synchronous condenser systems"* GE.

Item	Value	Source / Basis
Cost Details		
Fixed Operating Cost ($/MW/year)	800	Public domain sourced. "*Cost implication and reactive power generating potential of the synchronous condenser*" CTU.
Cold Start-up Costs ($/MW as gen)	0	
Warm Start-up Costs ($/MW as gen)	0	
Hot Start-up Costs ($/MW as gen)	0	

Table 41 New entrant capital cost – Synchronous condensers

Item	Value	Source / Basis
General Costs		
Equipment costs	$9,000,000	GHD sourced. Based on vendor quote minus installation costs.
Fuel connection costs	N/A	
Cost of land and development	N/A	
Installation costs	$1,000,000	GHD estimate. 10% of total cost.

5.5 Battery storage

5.5.1 Small scale battery storage

Batteries comprise electrochemical cells capable of storing and discharging energy and on a utility scale, numerous types of batteries can be used for energy storage. Each battery type varies in performance and capability and no single battery type will be best suited to all applications. Battery storage can be used for numerous applications that have the potential to accumulate multiple revenue/cost saving streams.

The battery storage market is still developing with numerous technologies competing however over the last 4 years Li-ion technology has obtained a large market share due to diverse capability of the technology and significant cost reductions driven largely by increased manufacturing for electric vehicles. Advanced lead acid batteries, high temperature batteries and flow batteries are still competing with Li-ion technology and both high temperature and flow batteries could have cost advantages for long storage applications when compared to Li-ion. Advanced lead acid batteries could find cost advantages in specific applications and have superior recyclability. The cost of utility scale battery storage is expected to continue to fall over time as the technology progresses further along the maturity curve, manufacturing volumes increase and utility scale installations become more common.

Nominal new entrant details

Nominal small scale battery storage plant is as follows:

- Li ion BESS, utilising battery with C1 capability
- Nominal nameplate capacity: 10 MW / 10 MWh
- Assumed battery is typical of commercial offerings and neither high end (more expensive with less degradation) or low end (lower cost/quality with higher degradation)

Table 42 New entrant parameters – Small scale battery storage

Item	Value	Source / Basis
General Details		
First Year Assumed Commercially Viable for construction	2018	MW scale installations now in operation in Australia
Assumed unit size (MW/MWh)	10 / 10	Assume C1 battery
Seasonal Ratings: Summer (MW)	10	Assume sufficient heating/cooling to enable full capacity
Seasonal Ratings: Not summer (MW)	10	Assume sufficient heating/cooling to enable full capacity
Economic Life (yrs)	10	Based on battery warranty to 80% of original capacity
Technical Life (yrs)	15	Expected inverter life- battery operates <80% capacity from year 10
Lead time for development (yrs)	1	GHD estimate
Construction time (weeks)	35	GHD estimate
Technical Details		
Min Stable Generation (% of installed capacity)	0	Capable of 0-100% operation
Auxiliary load (% of installed capacity)	4	GHD estimate - Assumes HVAC for battery and inverters
Forced outage rate (full forced outages) (%)	1.5	GHD estimate

Item	Value	Source / Basis
Frequency of full forced outage per annum	<2	GHD estimate
Full outage Mean time to repair (h)	48	GHD estimate
Partial Forced outage rate (partial forced outages) (%)	3.0	GHD estimate
Frequency of partial forced outages	<4	GHD estimate
Partial Outage derating factor (% lost during partial outage)	20	GHD estimate - Assumes loss of 2 MW block
Partial outage Mean time to repair (h)	96	GHD estimate
Equivalent forced outage rate (%)	2.1	GHD sourced
Ramp Up Rate (MW/s) - standard operation	10	GHD estimate – typical capability full output in 500 ms Note: ramp rate in MW/s
Ramp Down Rate (MW/s) - standard operation	10	GHD estimate – typical capability full output in 500 ms. Note ramp rate in MW/s
Maintenance Frequency (no of times per year)	2	GHD sourced
Average Maintenance rate (no of days/year)	4	GHD sourced
Cold Start-up Notification Time (h)	0	~ Instantaneous
Warm Start-up Notification Time (h)	0	~ Instantaneous
Hot Start-up Notification Time (h)	0	~ Instantaneous
Storage Details		
Battery storage: Charge efficiency (%)	90	GHD estimate

Item	Value	Source / Basis
Battery storage: Discharge efficiency (%)	90	GHD estimate
Battery Storage: Allowable max State of Charge (%)	90	GHD estimate
Battery Storage: Allowable min State of Charge (%)	10	GHD estimate
Battery Storage: maximum number of Cycles	6,000	GHD estimate - Typical across Li-ion battery types http://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf
Battery storage: Depth of Discharge (DoD) (%)	80	GHD estimate
Cost Details		
Fixed Operating Cost ($/MW/year)	8,000	GHD estimate based on 2017 and H1 2018 tender pricing. Small scale battery cost slightly higher than Large Scale due to higher proportion of fixed costs
Variable Op Cost ($/MWh sent-out)	0	Included in Fixed costs – assumes no “top-up” of battery capacity and cost for electricity to charge battery is not included
Cold Start-up Costs ($/MW as gen)	0	GHD estimate
Warm Start-up Costs ($/MW as gen)	0	GHD estimate
Hot Start-up Costs ($/MW as gen)	0	GHD estimate

Table 43 New entrant capital cost – Small scale battery storage

Item	Value	Source / Basis
General Costs		
Equipment costs	$9,500,000	GHD estimate based on 2017 and H1 2018 tender responses.
Fuel connection costs	$0	

Item	Value	Source / Basis
Cost of land and development	$978,000	GHD estimate land costs based on requirement of 150 m^2/MWh estimated for Li-Ion technology. Development costs based on 6% of project costs.
Installation costs	$3,500,000	GHD estimate based on H1 2018 tender responses for small scale storage.
Energy Storage Costs		
Cost of energy storage ($/MWh)	650,000	GHD estimate- based on 2018 tender capital cost pricing from Tier 1 battery supplier for 1.0 C battery with factor applied for large scale efficiencies. This does not include the cost of electricity to charge the battery and the charge/discharge efficiency.
Cost of storage capacity ($/MW)	300,000	GHD estimate- based on 2018 tender capital cost pricing from Tier 1 battery supplier for 1.0 C battery with factor applied for large scale efficiencies. This does not include the cost of electricity to charge the battery and the charge/discharge efficiency.

5.5.2 Large scale battery storage

Batteries comprise electrochemical cells capable of storing and discharging energy and on a utility scale, numerous types of batteries can be used for energy storage. Each battery type varies in performance and capability and no single battery type will be best suited to all applications. Battery storage can be used for numerous applications that have the potential to accumulate multiple revenue/cost saving streams.

The battery storage market is still developing with competing technologies. However, over the last four years Li-ion technology has obtained a large market share due to diverse capability of the technology and significant cost reductions driven largely by increased manufacturing for electric vehicles. Advanced lead acid batteries, high temperature batteries and flow batteries are still competing with Li-ion technology and both high temperature and flow batteries could have cost advantages for long storage applications when compared to Li-ion. Advanced lead acid batteries could find cost advantages in specific applications and have superior recyclability. The cost of utility scale battery storage is expected to continue to fall over time as the technology progresses further along the maturity curve, manufacturing volumes increase and utility scale installations become more common.

Large scale battery storage installations are now emerging in Australia and are expected to become more common in the future aiming to support intermittent renewable generation and also provide power quality correction, energy arbitrage and grid stability on a scale larger than small scale battery storage can provide.

Nominal new entrant details

Nominal large scale battery storage plant is as follows:

- Li ion BESS, utilising battery with C1 capability
- Nominal nameplate capacity: 100 MW / 100 MWh
- Assumed battery is typical of commercial offerings and neither high end (more expensive with less degradation) or low end (lower cost/quality with higher degradation)

Table 44 New entrant parameters – Large scale battery storage

Item	Value	Source / Basis
General Details		
First Year Assumed Commercially Viable for construction	2018	MW scale installations now in operation in Australia
Assumed unit size (MW/MWh)	100 / 100	Assume C1 battery
Seasonal Ratings: Summer (MW)	100	Assume sufficient heating/cooling to enable full capacity
Seasonal Ratings: Not summer (MW)	100	Assume sufficient heating/cooling to enable full capacity
Economic Life (yrs)	10	Based on battery warranty to 80% of original capacity
Technical Life (yrs)	15	Expected inverter life- battery operates <80% capacity from year 10
Lead time for development (yrs)	1	GHD estimate
Construction time (weeks)	45	GHD estimate
Technical Details		
Min Stable Generation (% of installed capacity)	0	Capable of 0-100% operation
Auxiliary load (% of installed capacity)	3	GHD estimate - Assumes some improvement over small scale
Forced outage rate (full forced outages) (%)	1.5	GHD estimate

Item	Value	Source / Basis
Frequency of full forced outage per annum	<2	GHD estimate
Full outage Mean time to repair (h)	48	GHD estimate
Partial Forced outage rate (partial forced outages) (%)	3.0	GHD estimate
Frequency of partial forced outages	<4	GHD estimate
Partial Outage derating factor (% lost during partial outage)	10	GHD estimate – assumes loss of up to 10 MW
Partial outage Mean time to repair (h)	96	GHD estimate
Equivalent forced outage rate (%)	1.8	GHD sourced
Ramp Up Rate (MW/s) - standard operation	100	GHD estimate – typical capability full output in 500 ms. Note: ramp rate is in MW/s
Ramp Down Rate (MW/s) - standard operation	100]	GHD estimate – typical capability full output in 500 ms. Note: ramp rate is in MW/s
Maintenance Frequency (no of times per year)	2	GHD sourced
Average Maintenance rate (no of days/year)	4	GHD sourced
Storage Details		
Battery storage: Charge efficiency (%)	90	GHD estimate
Battery storage: Discharge efficiency (%)	90	GHD estimate
Battery Storage: Allowable max State of Charge (%)	90	GHD estimate

Item	Value	Source / Basis
Battery Storage: Allowable min State of Charge (%)	10	GHD estimate
Battery Storage: maximum number of Cycles	6,000	GHD estimate - Typical across Li-ion battery types http://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf
Battery storage: Depth of Discharge (DoD)	80	GHD estimate
Cold Start-up Notification Time (h)	0	~ Instantaneous
Warm Start-up Notification Time (h)	0	~ Instantaneous
Hot Start-up Notification Time (h)	0	~ Instantaneous
Cost Details		
Fixed Operating Cost ($/MW/year)	7,500	GHD estimate based on 2017 and H1 2018 tender pricing. Small Scale Battery cost higher than Large Scale due to higher proportion of fixed costs.
Variable Op Cost ($/MWh sent-out)	0	Included in Fixed costs – assumes no “top-up” of battery capacity and cost for electricity to charge battery is not included
Cold Start-up Costs ($/MW as gen)	0	GHD estimate
Warm Start-up Costs ($/MW as gen)	0	GHD estimate
Hot Start-up Costs ($/MW as gen)	0	GHD estimate

Table 45 New entrant capital cost – Large scale battery storage

Item	Value	Source / Basis
General Costs		
Equipment costs	$90,000,000	GHD estimate based on 2017 and H1 2018 tender pricing
Fuel connection costs	$0	

Item	Value	Source / Basis
Cost of land and development	$7,644,000	GHD estimate land costs based on requirement of 150 m^2/MWh estimated for Li-Ion technology. Development costs based on 6% of project costs.
Installation costs	$29,750,000	GHD estimate based on H1 2018 tender responses noting Large scale installation could expect 15% cost efficiencies over small scale storage.
Energy Storage Costs		
Cost of energy storage ($/MWh)	600,000	GHD estimate- based on 2018 tender capital cost pricing from Tier 1 battery supplier for 1.0 C battery with factor applied for large scale efficiencies. This does not include the cost of electricity to charge the battery and the charge/discharge efficiency.
Cost of storage capacity ($/MW)	300,000	GHD estimate- based on 2018 tender capital cost pricing from Tier 1 battery supplier for 1.0 C battery with factor applied for large scale efficiencies. This does not include the cost of electricity to charge the battery and the charge/discharge efficiency.

5.6 Compressed air storage

Compressed air storage energy systems (CAES) store potential energy in the form of compressed gas. Typically, compressors driven by a renewable source are used to store high-pressure air within large reservoirs or naturally occurring underground formations. When required, the pressurized air is expanded in an expansion turbine driving a generator for power production.

Heat exchange is an important characteristic of CAES. Diabatic CAES is the mature industry technology that refers to extracting the heat during the compressing stage and dissipating it via intercoolers. Consequently, combustion of natural gas is then required to supplement the lost heat during the energy recovery process and drive the expansion process.

The major barrier of implementation is the reliance on favourable geography such as caverns. Furthermore, the technology suffers from lower efficiencies compared with other bulk storage alternatives. Currently only two large scale CAES plants are in operation across the world. Progressing research into other forms of CAES (adiabatic, isothermal) aim to increase the efficiency of the technology, however at this time they are experimental.

Table 46 New entrant parameters – Compressed air storage

Item	Value	Source / Basis
General Details		
Fuel Type	Natural Gas	Used during energy recovery process
First Year Assumed Commercially Viable for construction	2018	Mature technology, increasing development of heat recuperation techniques
Assumed unit size (MW/MWh)	320 / 15,360	Public domain sourced – Magnum CAES. "*Bulk Storage Study Report*" PacifiCorp
Seasonal Ratings: Summer (MW)	320	
Seasonal Ratings: Not summer (MW)	320	
Economic Life (yrs)	20	GHD estimate
Technical Life (yrs)	30	Public domain sourced "*Compressed Air Energy Storage"* Intech.
Lead time for development (yrs)	2	Public domain sourced. "*Compressed Air Energy Storage"* University of Durban-Westville.
Construction time (weeks)	104	
Technical Details		
Min Stable Generation (% of installed capacity)	10	Public domain sourced – Magnum CAES. "*Bulk Storage Study Report*" PacifiCorp
Equivalent forced outage rate (%)	3	Public domain sourced – Magnum CAES. "*Bulk Storage Study Report*" PacifiCorp
Ramp Up Rate (MW/h) - standard operation	180	Public domain sourced – Magnum CAES. "*Bulk Storage Study Report*" PacifiCorp
Ramp Down Rate (MW/h) - standard operation	32	Public domain sourced – Magnum CAES. "*Bulk Storage Study Report*" PacifiCorp
Heat rate at minimum operation (GJ/MWh)	0	Public domain sourced – Magnum CAES. "*Bulk Storage Study Report*" PacifiCorp
Heat rate at maximum operation (GJ/MWh)	4.4	Public domain sourced – Magnum CAES. "*Bulk Storage Study Report*" PacifiCorp

Item	Value	Source / Basis
Thermal Efficiency (%, HHV sent-out)	70	GHD sourced. Efficiency can vary drastically and given that fuel is used during discharge mode, is not an accurate representation.
Maintenance Frequency (no of times per year)	8	GHD estimate. Similar to simple combustion cycle engine
Cold Start-up Notification Time (h)	0.1	Public domain sourced – "*Handbook of Energy Storage for Transmission & Distribution Applications*" EPRI
Hot Start-up Notification Time (h)	~near instant	Public domain sourced – "*Handbook of Energy Storage for Transmission & Distribution Applications*" EPRI
Storage Details		
Rated energy capacity (MWh)	15,360	Public domain sourced – Magnum CAES. "*Bulk Storage Study Report*" PacifiCorp. 2 days storage.
Recharge rate (MWh/hour)	150	Public domain sourced – Magnum CAES. "*Bulk Storage Study Report*" PacifiCorp
Cost Details		
Fixed Operating Cost ($/MW/year)	18,900	Public domain sourced – Magnum CAES. "*Bulk Storage Study Report*" PacifiCorp
Variable Op Cost ($/MWh sent-out)	0	This does not include the cost of electricity to compress the air and the charge/discharge efficiency.
Emissions Details		
Combustion Emissions (kg CO_{2e}/GJ of fuel)	7.7	Public domain sourced – Magnum CAES. "*Bulk Storage Study Report*" PacifiCorp

Table 47 New entrant capital cost – Compressed air storage

Item	Value	Source / Basis
General Costs		
Equipment costs	$603,520,000	
Cost of land and development	$51,000,000	Public domain sourced – "*Handbook of Energy Storage for Transmission & Distribution Applications*" EPRI. Can vary drastically depending on geography.

Item	Value	Source / Basis
Installation costs	$135,000,000	Public domain sourced – "*Handbook of Energy Storage for Transmission & Distribution Applications*" EPRI. Can vary drastically depending on geography.
Energy Storage Costs		
Cost of energy storage ($/MWh)	32,000	Public domain sourced – "*Handbook of Energy Storage for Transmission & Distribution Applications*" EPRI. Escalated as per additional $1/KWh per hour over 10 hours storage.
Cost of storage capacity ($/MW)	350,000	Public domain sourced – "*Handbook of Energy Storage for Transmission & Distribution Applications*" EPRI.

5.7 Biomass

Combustion of biomass or products generated from biomass to generate steam and drive a steam turbine generator is a proven technology.

Saw mills, sugar mills, sewage treatment plants and the like which generate a large quantity of biomass or products generated from biomass as a waste stream often utilise that waste stream as a fuel to produce power and/or steam for use in process with any excess power exported to the grid.

Alternatively, purpose built waste to energy plants that import fuel can be constructed to produce power and/or steam for export to the grid or industrial consumers. Biomass fuels can comprise bagasse, wood chips, municipal waste, sewage etc. Solid fuel can be burnt directly in a boiler or converted to gaseous or liquid fuel. Municipal waste can be burnt directly or, if sent to landfill, can generate methane which can be used to fuel reciprocating engine or gas turbine driven generators. Sewage can be used to generate methane in biodigesters.

Thermoflow software version 27 was used to model and derive the performance parameters of a number of biomass alternatives, namely:

- Power generation using woodchips as fuel
- Power generation using refuse derived waste (RDF) as fuel
- Co-generation using woodchips as fuel
- Co-generation using RDF as fuel

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 22.

Table 48 Thermoflow Cost Factors (Biomass)

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

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.

Biomass technology is considered to be mature and therefore not expected to experience dramatic cost or efficiency improvements in the future.

5.7.1 Power generation – Woodchips

Nominal new entrant details

Table 49 New entrant parameters – Biomass – power generation only (Wood chip)

Item	Value	Source / Basis
General Details		
Fuel Type	Wood Chip	Typical fuel type
First Year Assumed Commercially Viable for construction	2018	
Assumed unit size (MW)	30	
Seasonal Ratings: Summer (MW)	28.5	Thermoflow SteamPro Version 27
Seasonal Ratings: Not summer (MW)	29.8	Thermoflow SteamPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	50	GHD in-house data
Lead time for development (yrs)	3	GHD in-house data
Construction time in (weeks)	104	GHD in-house data

Item	Value	Source / Basis
Technical Details		
Min Stable Generation (% of installed capacity)	40	GHD in-house data
Auxiliary load (% of installed capacity)	6.1	Thermoflow SteamPro Version 27
Forced outage rate (full forced outages) (%)	3	GHD in-house data
Frequency of full forced outage per annum		
Full outage Mean time to repair (h)		
Partial Forced outage rate (partial forced outages) (%)	2	GHD in-house data
Frequency of partial forced outages		
Partial Outage derating factor (% lost during partial outage)	30	GHD in-house data
Partial outage Mean time to repair (h)		
Equivalent forced outage rate (%)	3.6	GHD in-house data
Ramp Up Rate (MW/h) - standard operation	360	GHD in-house data
Ramp Down Rate (MW/h) - standard operation	360	GHD in-house data
Heat rate at minimum operation (GJ/MWh)	20.04	Thermoflow SteamPro Version 27
Heat rate at maximum operation (GJ/MWh)	13.39	Thermoflow SteamPro Version 27
Thermal Efficiency (%, HHV sent-out)	23.3	Thermoflow SteamPro Version 27
Maintenance Frequency (no of times per year)		
Average Maintenance rate (no of days/year)	30	GHD in-house data
Cold Start-up Notification Time (h)	24	
Warm Start-up Notification Time (h)	4	
Hot Start-up Notification Time (h)	2	
Cost Details		
Fixed Operating Cost ($/MW/year)	131,600	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI)

Item	Value	Source / Basis
Variable Op Cost ($/MWh sent-out)	8.42	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI)
Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)		
Cold Start-up Costs ($/MW as gen)	210	
Warm Start-up Costs ($/MW as gen)	105	
Hot Start-up Costs ($/MW as gen)	40	
Emissions Details		
Combustion Emissions (kg CO_{2e}/GJ of fuel)	100.9	Thermoflow SteamPro Version 27
Fugitive Emissions (kg CO_{2e}/GJ of fuel)		N/A

Table 50 New entrant capital cost – Biomass – power generation only (Wood chip)

Item	Value	Source / Basis
General Costs		
Equipment costs	$112,714,000	Thermoflow SteamPro Version 27
Fuel connection costs	Typically, given the scale of such plants, biomass would be delivered by road. A rail connection would cost in the order of $100M for 50 km of single track rail line	GHD in-house data
Cost of land and development	$62,976,000	Thermoflow SteamPro Version 27
Installation costs	$202,164,000	Thermoflow SteamPro Version 27
Carbon Capture and Storage Costs		
CCS costs (separate from the generation plant)	N/A	
CCS storage costs (separate from CCS capture costs)	N/A	

Item	Value	Source / Basis
CCS transportation cost	N/A	

5.7.2 Power generation – Refuse Derived Waste (RDF)

Nominal new entrant details

Table 51 New entrant parameters – Biomass – power generation only (RDF)

Item	Value	Source / Basis
General Details		
Fuel Type	RDF	Typical fuel type
First Year Assumed Commercially Viable for construction	2018	
Assumed unit size (MW)	30	
Seasonal Ratings: Summer (MW)	28.5	Thermoflow SteamPro Version 27
Seasonal Ratings: Not summer (MW)	29.8	Thermoflow SteamPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	50	GHD in-house data
Lead time for development (yrs)	3	GHD in-house data
Construction time in (weeks)	104	GHD in-house data
Technical Details		
Min Stable Generation (% of installed capacity)	40	GHD in-house data
Auxiliary load (% of installed capacity)	7.6	Thermoflow SteamPro Version 27
Forced outage rate (full forced outages) (%)	3	GHD in-house data
Frequency of full forced outage per annum		
Full outage Mean time to repair (h)		
Partial Forced outage rate (partial forced outages) (%)	2	GHD in-house data

Item	Value	Source / Basis
Frequency of partial forced outages		
Partial Outage derating factor (% lost during partial outage)	30	GHD in-house data
Partial outage Mean time to repair (h)		
Equivalent forced outage rate (%)	3.6	GHD in-house data
Ramp Up Rate (MW/h) - standard operation	360	GHD in-house data
Ramp Down Rate (MW/h) - standard operation	360	GHD in-house data
Heat rate at minimum operation (GJ/MWh)	20.75	Thermoflow SteamPro Version 27
Heat rate at maximum operation (GJ/MWh)	13.89	Thermoflow SteamPro Version 27
Thermal Efficiency (%, HHV sent-out)	22.32	Thermoflow SteamPro Version 27
Maintenance Frequency (no of times per year)		
Average Maintenance rate (no of days/year)	30	GHD in-house data
Cold Start-up Notification Time (h)	24	
Warm Start-up Notification Time (h)	4	
Hot Start-up Notification Time (h)	2	
Cost Details		
Fixed Operating Cost ($/MW/year)	131,600	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI)
Variable Op Cost ($/MWh sent-out)	8.42	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI)
Cold Start-up Costs ($/MW as gen)	210	
Warm Start-up Costs ($/MW as gen)	105	
Hot Start-up Costs ($/MW as gen)	40	
Emissions Details		
Combustion Emissions (kg CO2-e/GJ of fuel)	103.38	Thermoflow SteamPro Version 27
Fugitive Emissions (kg CO2-e/GJ of fuel)		N/A

Table 52 New entrant capital cost – Biomass – power generation only (RDF)

Item	Value	Source / Basis
General Costs		
Equipment costs	$149,774,000	Thermoflow SteamPro Version 27
Fuel connection costs	$100 M for 50 km of single track rail line	GHD in-house data. Typically, given the scale of such plants, biomass would be delivered by road. A rail connection would cost in the order of $100M for 50 km of single track rail line.
Cost of land and development	$88,061,000	Thermoflow SteamPro Version 27
Installation costs	$290,526,000	Thermoflow SteamPro Version 27
Carbon Capture and Storage Costs		
CCS costs (separate from the generation plant)	N/A	
CCS storage costs (separate from CCS capture costs)	N/A	
CCS transportation cost	N/A	

5.7.3 Cogeneration – Woodchips

Cogeneration has been modelled to show the scenario where the generation of electricity and useful heat is required. The useful heat is typically steam used for process heating. Industries such as chemical plants, pulp and paper mills, timber mills or other industries that require large amounts of process heat may adopt this form of technology. Thermoflow SteamPro Version 27 has been used to model a typical scenario based on a condensing turbine with a controlled extraction where 50% of the steam produced by the boiler is used for electricity generation and the remaining 50% is used for process purposes. This configuration allows electricity generation all year round, unlike a backpressure turbine that relies on a process such as sugar milling to utilise the exhaust steam so that it can operate.

Nominal new entrant details

Table 53 New entrant parameters – Biomass – cogeneration (Wood chip)

Item	Value	Source / Basis
General Details		

Item	Value	Source / Basis
Fuel Type	Wood chip	Typical fuel type
First Year Assumed Commercially Viable for construction	2018	
Assumed unit size (MW)	18	
Seasonal Ratings: Summer (MW)	16	Thermoflow SteamPro Version 27
Seasonal Ratings: Not summer (MW)	16.9	Thermoflow SteamPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	50	GHD in-house data
Lead time for development (yrs)	3	GHD in-house data
Construction time in (weeks)	104	GHD in-house data
Technical Details		
Min Stable Generation (% of installed capacity)	40	GHD in-house data
Auxiliary load (% of installed capacity)	11	Thermoflow SteamPro Version 27
Forced outage rate (full forced outages) (%)	3	GHD in-house data
Frequency of full forced outage per annum		
Full outage Mean time to repair (h)		
Partial Forced outage rate (partial forced outages) (%)	2	GHD in-house data
Frequency of partial forced outages		
Partial Outage derating factor (% lost during partial outage)	30	GHD in-house data
Partial outage Mean time to repair (h)		
Equivalent forced outage rate (%)	3.6	GHD in-house data
Ramp Up Rate (MW/h) - standard operation	360	GHD in-house data
Ramp Down Rate (MW/h) - standard operation	360	GHD in-house data
Heat rate at minimum operation (GJ/MWh)	N/A	Dependent on ratio of electricity to heat

Item	Value	Source / Basis
Heat rate at maximum operation (GJ/MWh)	N/A	Dependent on ratio of electricity to heat
Thermal Efficiency (%, HHV sent-out)	14.41	Thermoflow SteamPro Version 27
Maintenance Frequency (no of times per year)		
Average Maintenance rate (no of days/year)	30	GHD in-house data
Cold Start-up Notification Time (h)	24	
Warm Start-up Notification Time (h)	4	
Hot Start-up Notification Time (h)	2	
Cost Details		
Fixed Operating Cost ($/MW/year)	131,600	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI)
Variable Op Cost ($/MWh sent-out)	8.42	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI)
Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)		
Cold Start-up Costs ($/MW as gen)	210	
Warm Start-up Costs ($/MW as gen)	105	
Hot Start-up Costs ($/MW as gen)	40	
Emissions Details		
Combustion Emissions (kg CO_{2e}/GJ of fuel)	85.25	Thermoflow SteamPro Version 27
Fugitive Emissions (kg CO_{2e}/GJ of fuel)		N/A

Table 54 New entrant capital cost – Biomass – cogeneration (Wood chip)

Item	Value	Source / Basis
General Costs		
Equipment costs	$100,471,000	Thermoflow SteamPro Version 27
Fuel connection costs	$100 M for 50 km of single track rail line	GHD in-house data.

Item	Value	Source / Basis
		Typically, given the scale of such plants, biomass would be delivered by road. A rail connection would cost in the order of $100M for 50 km of single track rail line.
Cost of land and development	$59,740,000	Thermoflow SteamPro Version 27
Installation costs	$198,225,000	Thermoflow SteamPro Version 27
Carbon Capture and Storage Costs		
CCS costs (separate from the generation plant)	N/A	
CCS storage costs (separate from CCS capture costs)	N/A	
CCS transportation cost	N/A	

5.7.4 Cogeneration – RDF

Nominal new entrant details

Table 55 New entrant parameters – Biomass cogeneration (RDF)

Item	Value	Source / Basis
General Details		
Fuel Type	Wood chip	Typical fuel type
First Year Assumed Commercially Viable for construction	2018	
Assumed unit size (MW)	18	
Seasonal Ratings: Summer (MW)	16	Thermoflow SteamPro Version 27
Seasonal Ratings: Not summer (MW)	16.9	Thermoflow SteamPro Version 27
Economic Life (yrs)	25	GHD in-house data
Technical Life (yrs)	50	GHD in-house data
Lead time for development (yrs)	3	GHD in-house data

Item	Value	Source / Basis
Construction time in (weeks)	104	GHD in-house data
Technical Details		
Min Stable Generation (% of installed capacity)	40	GHD in-house data
Auxiliary load (% of installed capacity)	14.3	Thermoflow SteamPro Version 27
Forced outage rate (full forced outages) (%)	3	GHD in-house data
Partial Forced outage rate (partial forced outages) (%)	2	GHD in-house data
Partial Outage derating factor (% lost during partial outage)	30	GHD in-house data
Equivalent forced outage rate (%)	3.6	GHD in-house data
Ramp Up Rate (MW/h) - standard operation	360	GHD in-house data
Ramp Down Rate (MW/h) - standard operation	360	GHD in-house data
Heat rate at minimum operation (GJ/MWh)	N/A	Dependent on ratio of electricity to heat
Heat rate at maximum operation (GJ/MWh)	N/A	Dependent on ratio of electricity to heat
Thermal Efficiency (%, HHV sent-out)	13.61	Thermoflow SteamPro Version 27
Maintenance Frequency (no of times per year)		
Average Maintenance rate (no of days/year)	30	GHD in-house data
Cold Start-up Notification Time (h)	24	
Warm Start-up Notification Time (h)	4	
Hot Start-up Notification Time (h)	2	
Cost Details		
Fixed Operating Cost ($/MW/year)	131,600	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI)
Variable Op Cost ($/MWh sent-out)	8.42	ACIL Allen report for AEMO: Fuel and Technology Cost Review 2014 (escalated by PPI)
Variable Operating Cost for Carbon Capture and Storage (CCS) costs ($/MWh as gen)		

Item	Value	Source / Basis
Cold Start-up Costs ($/MW as gen)	210	
Warm Start-up Costs ($/MW as gen)	105	
Hot Start-up Costs ($/MW as gen)	40	
Emissions Details		
Combustion Emissions (kg CO2-e/GJ of fuel)	82.5	Thermoflow SteamPro Version 27
Fugitive Emissions (kg CO2-e/GJ of fuel)		N/A

Table 56 New entrant capital cost – Biomass cogeneration (RDF)

Item	Value	Source / Basis
General Costs		
Equipment costs	$137,273,000	Thermoflow SteamPro Version 27
Fuel connection costs	Typically, given the scale of such plants, biomass would be delivered by road. A rail connection would cost in the order of $100M for 50 km of single track rail line	GHD in-house data
Cost of land and development	$84,775,000	Thermoflow SteamPro Version 27
Installation costs	$286,601,000	Thermoflow SteamPro Version 27
Carbon Capture and Storage Costs		
CCS costs (separate from the generation plant)	N/A	
CCS storage costs (separate from CCS capture costs)	N/A	
CCS transportation cost	N/A	

5.8 Nuclear

Nuclear power has been around since the 1950s, with several evolutions in design leading up to the Gen III+ reactor's being built today. Currently there are about 450 nuclear power reactors operating in 30 countries, with a combined capacity of over 390 GW_e, providing approximately 11% of the world's electricity.

There are approximately 50 generation III+ designs currently being constructed around the world, particularly in China, India, UAE and Russia. Whilst Australia does have a single nuclear reactor for nuclear medicine production, Australia does not have any nuclear power reactors. Several attempts have been made in Australia since the 1950s to initiate the development of nuclear power. However, there has been fierce resistance to its development, and currently nuclear power plant construction is prohibited by the Commonwealth, in addition to some states having additional legislation prohibiting the same. Noting that this legislation must be repealed in order to begin the development of a nuclear power plant, it is highly likely that development of Gen III+ reactors will happen not happen before 2030 in Australia, and that Australia will seek to construct a Gen IV reactor which may address safety concerns of the public and have an economical business case. It is also highly likely that any first mover in this space will be a Small Modular Reactor (SMR) as these are likely to have suitability with respect to demand load and lower capital requirements.

Nominal new entrant details

The nominal plant that is considered for this new entrant:

- Generation IV Small Modular Reactor (SMR)
- Nominal nameplate capacity 300 MW, several being built around the world at this size in China, Russia and the UK.

Table 57 New entrant parameters – Nuclear

Item	Value	Source / Basis
General Details		
Fuel Type	Uranium	World Nuclear Association
First Year Assumed Commercially Viable for construction	2035	Australian Nuclear Energy Report 171 – Generation IV Nuclear Energy – Accession. Generation IV reactors are not expected to be constructed for at least 10 years, up to 40 years as of 2017.
Assumed unit size (MW)	300	World Nuclear Association - Largest Small Modular Reactor (SMR) size. Smaller sizes likely to be prohibitively expensive to generate a positive IRR.
Seasonal Ratings: Summer (MW)	300	Not influenced by season.
Seasonal Ratings: Not summer (MW)	300	Not influenced by season.
Economic Life (yrs)	60	World Nuclear Association
Technical Life (yrs)	60	World Nuclear Association
Lead time for development (yrs)	10	World Nuclear Association.

Item	Value	Source / Basis
		Moreira, J. M. L., & Carajilescov, P. (2011). Construction time of PWRs. In *2011 International Nuclear Atlantic Conference - INAC 2011*. https://doi.org/10.1016/j.enpol.2012.12.044
Construction time in weeks	260	World Nuclear Association. Moreira, J. M. L., & Carajilescov, P. (2011). Construction time of PWRs. In *2011 International Nuclear Atlantic Conference - INAC 2011*. https://doi.org/10.1016/j.enpol.2012.12.044
Technical Details		
Min Stable Generation (% of installed capacity)	50	J.D. Jenkins et al. (2018) The benefits of nuclear flexibility in power system operations with renewable energy. *Applied Energy 222 (2018) 872-884*
Auxiliary load (% of installed capacity)	5	I.Kuzle, D.Bosnjak, H Pandzic. Auxiliary System Load Schemes in Large Thermal and Nuclear Power Plants. *8th International Conference: Nuclear Option in Coun*
Forced outage rate (full forced outages) (%)	<0.8	World Nuclear Association
Frequency of full forced outage per annum	0.1	World Nuclear Association – 28.8 day repair, approximately 3 day downtime on average per annum.
Full outage Mean time to repair (h)	700	World Nuclear Association
Partial Forced outage rate (partial forced outages) (%)	4.8	World Nuclear Association
Frequency of partial forced outages per annum	1	World Nuclear Association
Partial Outage derating factor (% lost during partial outage)	100	World Nuclear Association
Partial outage Mean time to repair (h)	420	World Nuclear Association – Time spent refuelling and coincident maintenance works
Equivalent forced outage rate (%)	5.6	World Nuclear Association
Ramp Up Rate (MW/h) - standard operation	900	World Nuclear Association -5% ramp up rate per minute
Ramp Down Rate (MW/h) - standard operation	900	World Nuclear Association -5% ramp down rate per minute
Heat rate at minimum operation (GJ/MWh)	8	World Nuclear Association –Based on 45% thermal efficiency

Item	Value	Source / Basis
Heat rate at maximum operation (GJ/MWh)	8	World Nuclear Association - Based on 45% thermal efficiency
Thermal Efficiency (%, HHV sent-out)	45	World Nuclear Association
Maintenance Frequency (no of times per year)	1	
Average Maintenance rate (no of days/year)	17.5	World Nuclear Association
Cold Start-up Notification Time (h)	72	Would not shutdown reactor unless for forced outage, refuelling or maintenance, as this would reduce reactor life and impose unnecessary risk. Hence this is for start-up after re-fuelling
Warm Start-up Notification Time (h)	4	Same as above.
Hot Start-up Notification Time (h)	2	Same as above.
Cost Details		
Fixed Operating Cost ($/MW/year)	$200,000	World Nuclear Association
Variable Op Cost ($/MWh sent-out)	$20	World Nuclear Association
Cold Start-up Costs ($/MW as gen)	N/A	Same as above.
Warm Start-up Costs ($/MW as gen)	N/A	Same as above.
Hot Start-up Costs ($/MW as gen)	N/A	Same as above.
Emissions Details		
Combustion Emissions (kg CO_{2e}/GJ of fuel)	N/A	Fission Reaction
Fugitive Emissions (kg CO_{2e}/GJ of fuel)	N/A	

Table 58 New entrant capital cost – Nuclear

Item	Value	Source / Basis
General Costs		
Equipment costs	$2,880,000,000	World Nuclear Association – 60% of total costs, at $16,000/kW
Fuel connection costs	$0	No direct connection fuel source
Cost of land and development	$960,000,000	World Nuclear Association – 20% of total costs, at $16,000/kW
Installation costs	$960,000,000	World Nuclear Association – 20% of total costs, at $16,000/kW

5.9 Pumped hydro

General

Pumped hydro energy storage (PHES) is a form of energy storage using the potential energy between two reservoirs separated in elevation. A single electrical machine can function as either a motor, driving a pump, or a generator, being driven by a turbine. In most cases, the pump and turbine are the same item, operating in either the forward or reverse rotational direction, a so-called "reversible pump-turbine", but in most of the current installations in Australia, the pump and the turbine are mounted on the same shaft and rotate only in one direction. Given the specific geotechnical, topographical, and hydrogeological requirements of the reservoirs, PHES costs and arrangements are heavily location specific. Typical plant costs also tend to strongly reflect power rating unless the units are towards the "edges" of typical operating experience. Civil costs are driven by the size and complexity of structures: longer waterways, deep underground powerhouses with long access tunnels and shafts, high dams and embankments, large surge tanks and chambers. High head plants have smaller ponds but expensive tunnels and deeper set powerhouses, while low head plants will often have surface powerhouses, short waterways, and low but very long embankments to hold very large pond volumes.

Across eastern Australia, the Great Dividing Range provides a plethora of attractive greenfield sites, outside of National Parks and other sensitive regions. Even South Australia offers many smaller but attractive sites along the Flinders Ranges. Proximity to a water supply for filling, and a transmission line to minimise losses and maximise contributions to network regulation and strength are therefore crucial in site selection.

Most PHES across the world, except those opportunistically built on existing water supply or irrigation dams, have relatively limited run times, in the range of 4-8 hours. The recent ARENA-funded Cultana PHES study found little value derived from capacity above 6 hours. However, sites on existing reservoirs may be developed to provide very large quantities of stored energy, resulting in very low levelised costs of energy storage, albeit at relatively high costs per rated power. Interest in PHES has only recently re-emerged, after a hiatus of more than 30 years, and was initially focused on existing reservoirs. But that is now shifting towards very low capital cost projects limited to 4-8h of storage. There are sites that sit between these two groups, where it is hard to typify costs – for the purposes of this report these are not considered further, since they are less likely to be built. Instead two "families" of PHES are described below. It is noted that the parameters presented in Table 60 apply to the first category – 'Low capacity cost sites'.

Low capacity cost sites: $1-1.4 M/MW – 4-6 hours storage

These are typically characterised by:

- Green field sites
- Short waterways (1-2 km total)
- Head: 150-300 m avoiding excessively large machines on the one hand or very highly stressed materials on the other
- Power: 150-300 MW

- Simple arrangement: no surge tank or only on one waterway, surface powerhouse or underground with short access tunnel
- Low embankment (10 – 15 m high) on one pond, other pond formed naturally, 4-6 h storage

Low storage cost sites: $20,000/MWh – >150 hours storage

These are typically characterised by:

- Existing reservoir with greenfield upper storage
- Longer waterways (several kilometres)
- Head: >300 m including those >500 m
- Power: 500-2,000 MW
- Complex arrangements: headrace and tailrace surges tank, underground powerhouse
- Modest embankments given higher head, lower storage volumes

Costing approach and benchmarking

The two categories of projects have been costed using different metrics – $/MW for the ‘low capacity cost’ sites and $/MWh for the ‘low storage cost’ sites respectively – due to the different cost drivers for each.

A ‘low capacity cost’ project can be estimated at the given range of $1.0-1.4M/MW with a fixed storage duration of 6 hours. This is comparable to the suite of similar projects presented within HydroTas’s Battery of the Nation report at $1.1-$1.7M/MW.

The cost of a ‘low storage cost’ project is more heavily dictated by the civil costs required for the storage volumes and associated infrastructure. Given the unique nature of a project of this type, there are few examples against which to benchmark. The rate of $20,000/MWh is comparable to that reported for Snowy 2.0 ($14,000/MWh) and for similar projects from the Battery of the Nation report (in the order of $15,000/MWh).

Installation capacities

A high level indication of the amount of PHES (in MW) that may be installed in each state within each price range is presented in Table 59. These figures are based on GHD’s knowledge of the current status of the industry and the potential for PHES in Australia, and that no detailed investigation has been undertaken to determine or confirm these figures. The intended use of the figures below is to inform the AEMO modelling process with regards to the magnitude of new entrant capacity that may be available within each price range only.

It is considered that the projects that would be completed as part of the installed capacities listed below would follow the current practice of installing storage in the order of 6 hours. We have also provided in Table 59 estimates of large storage capacities in the states that are conducive to construction of large capacity pumped storage hydro plant.

Table 59 State based new entrant PHES capacities

State	Low (4-8 h) storage		Large Storage (150 h)	
	MW	MWh	MW	MWh
Victoria	300	1,800	N/A	N/A
New South Wales	10,000	60,000	2,000	300,000
Queensland	10,000	60,000	2,000	300,000
South Australia	500	3,000	N/A	N/A
Tasmania	500	3,000	200	30,000
Northern Territory	N/A	N/A	N/A	N/A
Western Australia	300	1,800	N/A	N/A

Table 60 New entrant parameters – Pumped hydro

Item	Value	Source / Basis
General Details		
Fuel Type	N/A	
First Year Assumed Commercially Viable for construction	2018	Mature technology, already viable
Assumed unit size (MW)	200	Station size ranges from 150 MW to 4,000 MW, with unit sizes typically driven by physical size rather than rating. Low head units are much larger than high head, with pipeline diameters above 10 m uncommon. Size of 200 MW selected to represent a typical new entrant size.
Seasonal Ratings: Summer (MW)	200	Not impacted by ambient conditions.
Seasonal Ratings: Not summer (MW)	200	Not impacted by ambient conditions.
Economic Life (yrs)	30	Most projects are costed on the basis of a 30 year economic life

Item	Value	Source / Basis
Technical Life (yrs)	50	Typically half-life refurbishment would be contemplated at 100,000 h, which corresponds to >50 yrs on a typical capacity factor. Civil works are designed for 200 yrs life.
Lead time for development (yrs)	2	Lead time for development typically 18-24 months for permitting and feasibility studies, reference design and contracting. Construction times typically 30-48 months
Construction time (weeks)	208	Lead time for development typically 18-24 months for permitting and feasibility studies, reference design and contracting. Construction times typically 30-48 months
Technical Details		
Min Stable Generation (% of installed capacity)	0	GHD estimate
Auxiliary load (% of installed capacity)	1	GHD estimate
Auxiliary load for Generators operating in Synchronous Condenser mode (% of installed capacity)	4	Depends on direction of rotation, but typically 3-5% of unit rating.
Forced outage rate (full forced outages)		Refer to 'Equivalent forced outage rate'
Frequency of full forced outage per annum		Refer to 'Equivalent forced outage rate'
Full outage Mean time to repair (h)		Refer to 'Equivalent forced outage rate'
Partial Forced outage rate (partial forced outages)		Refer to 'Equivalent forced outage rate'
Frequency of partial forced outages		Refer to 'Equivalent forced outage rate'
Partial Outage derating factor (% lost during partial outage)		Refer to 'Equivalent forced outage rate'
Partial outage Mean time to repair (h)		Refer to 'Equivalent forced outage rate'
Equivalent forced outage rate (%)	1	Extremely high availability, coupled with a capacity factor in the order of 20%, makes unforced outages very infrequent.
Ramp Up Rate (MW/h) - standard operation	20 MW / second	Typically of the order of 10 s for full load
Ramp Down Rate (MW/h) - standard operation	20 MW / second	Typically of the order of 10 s for full load

Item	Value	Source / Basis
Maintenance Frequency (no of times per year)	1	A typical annual runner inspection has been allowed for, comprising of a single day once per year in which the unit is electrically and hydraulically isolated for inspection.
Average Maintenance rate (no of days/year)	1	Refer above.
Storage Details		
Hydro units: Pumping Efficiency (MWh pumped per MWh generated) - within 24 hours (%)	75-80	Round trip efficiency.
Pump load (MW)	Approximately 240 MW	Approximately 1.2 times the turbine rating.
Cost Details		
Fixed Operating Cost ($/MW/year)	0.5% CAPEX	GHD estimate
Variable Op Cost ($/MWh sent-out)	Marginal	
Cost to operate in Synchronous condenser mode($/MWh as gen)	Marginal	

5.10 Solar PV – SAT

Solar photovoltaic (PV) systems allow electricity generation directly from sunlight. Today PV is one of the fastest growing electricity generation technologies and is expected to play a major role in the future global electricity generation mix. PV systems can be fixed tilt or tracking systems. Tracking systems are designated as either single axis (which can track the sun in one plane e.g. east to west) or dual axis (can track the sun in two planes e.g. east to west and north to south).

The majority of large scale PV installations proposed in Australia are expected to be single axis tracking (SAT) systems which can provide up to 25% more energy generation than fixed tilt systems with <15% additional capital cost. Currently, the incremental benefits of dual axis tracking systems does not warrant the increased capital and operating costs in typical large scale applications. The cost of manufacturing PV modules has reduced significantly in the last decade and the conversion efficiency continues to improve such that solar PV is expected to be one of the lowest cost forms of electricity generation in the short to medium term.

Nominal new entrant details

The nominal plant that is considered for this new entrant:

- Single axis tracking system
- Nominal nameplate capacity 100 MW AC
- 1500 V DC system with 5 MW power conversion stations

Table 61 New entrant parameters – Solar PV – SAT

Item	Value	Source / Basis
General Details		
First Year Assumed Commercially Viable for construction	2018	Already in operation throughout Australia
Assumed unit size (MW)	100	
Seasonal Ratings: Summer (MW)	100	GHD sourced^ – assume instantaneous rating at 100% capacity in local environmental conditions
Seasonal Ratings: Not summer (MW)	100	GHD sourced - – assume instantaneous rating at 100% capacity in local environmental conditions
Economic Life (yrs)	25	GHD estimate – based on module warranty
Technical Life (yrs)	30	GHD estimate
Lead time for development (yrs)	2	
Construction time (weeks)	50	GHD estimate
Technical Details		
Min Stable Generation (% of installed capacity)	0	GHD estimate – 0-100% possible based on irradiance
Auxiliary load (% of installed capacity)	2	GHD estimate including reticulation losses
Forced outage rate (full forced outages) (%)	0.4	GHD estimate
Frequency of full forced outage per annum	<1	GHD estimate
Full outage Mean time to repair (h)	36	GHD estimate
Partial Forced outage rate (partial forced outages) (%)	0.8	GHD estimate
Frequency of partial forced outages	<2	GHD estimate

Item	Value	Source / Basis
Partial Outage derating factor (% lost during partial outage)	10	GHD estimate
Partial outage Mean time to repair (h)	96	GHD estimate
Equivalent forced outage rate (%)	0.48	GHD sourced
Ramp Up Rate (MW/min) - standard operation	100	GHD estimate. Note ramp rate is in MW/min
Ramp Down Rate (MW/min) - standard operation	100	GHD estimate. Note ramp rate is in MW/min
Maintenance Frequency (no of times per year)	2	GHD sourced
Average Maintenance rate (no of days/year)	3	GHD sourced
Cost Details		
Fixed Operating Cost ($/MW/year)	14,440	GHD estimate based on large scale solar tenders awarded 2017 and/or received H1 2018. Estimate is based on first 5 years of operation thereafter annual costs expected to be 10% higher than years 1-5.
Variable Op Cost ($/MWh sent-out)	0	GHD estimate – included in Fixed operating
Cold Start-up Notification Time (h)	0	GHD sourced
Warm Start-up Notification Time (h)	0	GHD sourced
Hot Start-up Notification Time (h)	0	GHD sourced
Cold Start-up Costs ($/MW as gen)	0	GHD sourced
Warm Start-up Costs ($/MW as gen)	0	GHD sourced
Hot Start-up Costs ($/MW as gen)	0	GHD sourced

^ GHD sourced refers to data sourced from GHD database or from GHD experience/engineering knowledge

Table 62 New entrant capital cost – Solar PV – SAT

Item	Value	Source / Basis
General Costs		

Item	Value	Source / Basis
Equipment costs	$137,640,000	GHD estimate based on large scale solar tenders awarded and/or received H2 2017 and H1 2018. Estimate includes civils, erection equipment, balance of plant, buildings and facilities.
Fuel connection costs	0	
Cost of land and development	$9,447,000	GHD sourced land costs based on expectation of 2.6 Ha requirement per MW AC and indicative land price of $4500 / Ha. Development cost is estimated at 6% of project budget.
Installation costs	$10,360,000	GHD estimate based on value of labour required for erection estimated at 7% of total CAPEX.

5.11 Solar thermal – central receiver

Central Receivers, or Power Towers, use ground-based mirrors (called heliostats) to focus solar radiation onto a receiver mounted high on a central tower. The mirrors rotate and track the sun's position throughout the day to maintain a stationary image of the sun on the receiver. The concentrated sun light heats molten salt flowing through the receiver where it is used to generate electricity through a conventional steam generator. Molten salt retains heat efficiently, so it can be stored for days before being converted into electricity. That means electricity can be produced on cloudy days or even several hours after sunset with the application of molten salt storage.

Solar thermal systems are typically high cost, which promotes greater uptake in solar PV systems and other renewable technologies than solar thermal. Solar thermal systems with storage do have a distinct advantage of being able to provide dispatchable energy, which is very attractive for remote areas. Agencies such as ARENA encourage the growth of the solar thermal market and offer funding incentives for research and demonstration plants. This ongoing development will eventually lead to reduction in costs, specifically in balance of plant items and overall levelised costs of electricity (the largest cost reduction is expected to be in the heliostat field).

5.11.1 Central receiver with storage

Nominal new entrant details

- One central receiver with surrounding heliostat field utilising molten salt technology
- 1 x steam turbine and dry cooling system
- Nominal nameplate capacity 150 MW

- With 8 hours storage

The central receiver system described below has been sized with a 'solar multiple' of 2.4, meaning that the heliostat field and receiver are capable of producing 240% of the thermal energy required to operate the steam turbine generator at full output. The additional energy is stored in the molten salt storage system for use at another time.

The incorporation of energy storage provides the plant with increased operational flexibility. For example, if the plant is running at full capacity, any of the following may be achieved:

- Generate at full output, while also storing energy at a rate of 140% of nameplate capacity (i.e. at a rate sufficient to fill the 8 hours storage in 5.7 hours),
- Do not generate, but store energy at a rate of 240% of nameplate capacity (i.e. at a rate sufficient to fill the 8 hours storage in 3.3 hours), or
- Use stored energy to output at full capacity for 8 hours without sunlight (assuming full storage).

Additional storage can be added at the rate provided in

Table 64. This incremental costs allows for increased tank size and heat storage medium, but does not allow for an increase in the heliostat field or receiver capacity (i.e. the solar multiple remains constant at 2.4). Increasing storage volume without increasing the solar multiple will provide additional operational flexibility, but is likely to have minimal impact on the plant capacity factor.

Table 63 New entrant parameters – Solar thermal – central receiver with storage

Item	Value	Source / Basis
General Details		
First Year Assumed Commercially Viable for construction	2020	
Assumed unit size (MW)	150	Comparable size for future development.
Seasonal Ratings: Summer (MW)	150	
Seasonal Ratings: Not summer (MW)	150	
Economic Life (yrs)	25	Based on industry.
Technical Life (yrs)	40	GHD sourced, Based on refurbishment potential.
Lead time for development (yrs)	3	
Construction time (weeks)	125	Based on estimates for Solar Reserve Aurora project and GHD estimate.

Item	Value	Source / Basis
Technical Details		
Min Stable Generation (% of installed capacity)	20	
Auxiliary load (% of installed capacity)	10	
Forced outage rate (full forced outages) (%)	4	*"Estimating the Performance and Economic Value of Multiple Concentrating Solar Power Technologies in a Production Cost Model" NREL*
Frequency of full forced outage per annum	<2	GHD sourced
Full outage Mean time to repair (h)	10	GHD sourced
Partial Forced outage rate (partial forced outages)		
Frequency of partial forced outages		
Partial Outage derating factor (% lost during partial outage)		
Partial outage Mean time to repair (h)		
Equivalent forced outage rate (%)	8	*"Concentrating Solar Power Gen3 Demonstration Roadmap"* Mark Mehos, Craig Turchi ,et al.
Ramp Up Rate (MW/h) - standard operation	500	GHD sourced
Ramp Down Rate (MW/h) - standard operation	500	GHD sourced
Thermal Efficiency (%)	41	NREL SAM
Maintenance Frequency (no of times per year)	2	*KJC Operating Company, "SEGS Acquaintance & Data Package", Boron, CA*
Average Maintenance rate (no of days/year)	8	GHD sourced
Cold Start-up Notification Time (h)	5	GHD sourced, *"Concentrating Solar Power Gen3 Demonstration Roadmap"* Mark Mehos, Craig Turchi ,et al.
Warm Start-up Notification Time (h)	2	GHD sourced, *"Concentrating Solar Power Gen3 Demonstration Roadmap"* Mark Mehos, Craig Turchi ,et al.
Hot Start-up Notification Time (h)	1	GHD sourced, *"Concentrating Solar Power Gen3 Demonstration Roadmap"* Mark Mehos, Craig Turchi ,et al.

Item	Value	Source / Basis
Cost Details		
Fixed Operating Cost ($/MW/year)	85,000	
Variable Op Cost ($/MWh sent-out)	5.4	
Cold Start-up Costs ($/MW as gen)	15	
Warm Start-up Costs ($/MW as gen)	8	GHD sourced
Hot Start-up Costs ($/MW as gen)	0	

Table 64 New entrant capital cost – Solar thermal – central receiver with storage

Item	Value	Source / Basis
General Costs		
Equipment costs	$877,500,000	GHD sourced and NREL SAM (based on 150 MW_e plant with storage)
Cost of land and development	$59,400,000	GHD sourced and NREL SAM (based on 150 MW_e plant with storage)
Installation costs	$114,750,000	GHD sourced and NREL SAM (based on 150 MW_e plant with storage)
Energy Storage Costs		
Cost of energy storage ($/MWh)	180,000	GHD sourced and NREL SAM (based on 150 MW_e plant with storage). This cost is divided between thermal storage costs of $80,000/MWh (molten salt tanks and system) and additional solar field costs of $100,000/MWh (additional heliostats and increase in receiver size). The additional solar field costs are required in order to provide the 'solar multiple' required to export power and store thermal energy at the same time (which results in an increase in annual electricity generation). If the additional energy capture capacity is not required, molten salt storage can be added at the cost of $80,000/MWh. This allows a disconnect between the time of energy capture (i.e. daylight hours)

Item	Value	Source / Basis
		and energy discharge, however it will not increase the overall annual electricity generation. (Note: all MWh are electrical as opposed to thermal, and are calculated using a conversion efficiency of 41%).
Cost of storage capacity ($/MW)	4,400,000	GHD sourced and NREL SAM (based on 150 MW_e plant with storage). This cost represents the rate (in $/MW) for a solar thermal plant with no energy storage capacity. This cost includes the power tower, power block, solar field, and all balance of plant required for a solar thermal power station with no storage capacity (i.e. with a 'solar multiple' of 1.0).

5.11.2 Central receiver without storage

Nominal new entrant details

- One central receiver with surrounding heliostat field utilising molten salt technology
- 1 x steam turbine and dry cooling system
- Nominal nameplate capacity 150 MW
- No molten salt storage

In the central receiver project described below, the heat generated from the receiver is directly fed to the steam circuit (via heat transfer fluid) to produce power in the steam turbine generator. With the absence of molten salt energy storage, the output of the plant is directly tied to the instantaneous heat generated from the concentrated sunlight. The heliostat field has been sized to provide sufficient heat to the receiver to produce the nameplate output under optimal sunlight conditions.

Table 65 New entrant parameters – Solar thermal – central receiver without storage

Item	Value	Source / Basis
General Details		

Item	Value	Source / Basis
First Year Assumed Commercially Viable for construction	2020	
Assumed unit size (MW)	150	
Seasonal Ratings: Summer (MW)	150	
Seasonal Ratings: Not summer (MW)	150	
Economic Life (yrs)	25	Based on industry
Technical Life (yrs)	40	GHD sourced, Based on refurbishment potential
Lead time for development (yrs)	3	Based on estimates for Solar Reserve Aurora project and GHD estimate.
Construction time (weeks)	125	Based on estimates for Solar Reserve Aurora project and GHD estimate.
Technical Details		
Min Stable Generation (% of installed capacity)	20	
Auxiliary load (% of installed capacity)	10	
Forced outage rate (full forced outages) (%)	4	*"Estimating the Performance and Economic Value of Multiple Concentrating Solar Power Technologies in a Production Cost Model" NREL*
Frequency of full forced outage per annum	<2	GHD sourced
Full outage Mean time to repair (h)	10	GHD sourced
Equivalent forced outage rate (%)	8	*"Concentrating Solar Power Gen3 Demonstration Roadmap"* Mark Mehos, Craig Turchi ,et al.
Ramp Up Rate (MW/h) - standard operation	500	GHD sourced
Ramp Down Rate (MW/h) - standard operation	500	GHD sourced
Thermal Efficiency (%)	41	NREL SAM
Maintenance Frequency (no of times per year)	2	GHD sourced
Average Maintenance rate (no of days/year)	8	KJC Operating Company, "SEGS Acquaintance & Data Package", Boron, CA

Item	Value	Source / Basis
Cold Start-up Notification Time (h)	5	GHD sourced, GHD sourced, *“Concentrating Solar Power Gen3 Demonstration Roadmap”* Mark Mehos, Craig Turchi ,et al.
Warm Start-up Notification Time (h)	2	GHD sourced, GHD sourced, *“Concentrating Solar Power Gen3 Demonstration Roadmap”* Mark Mehos, Craig Turchi ,et al.
Hot Start-up Notification Time (h)	1	GHD sourced, GHD sourced, *“Concentrating Solar Power Gen3 Demonstration Roadmap”* Mark Mehos, Craig Turchi ,et al.
Cost Details		
Fixed Operating Cost ($/MW/year)	85,000	GHD sourced and NREL SAM (based on 150 MW_e plant with storage)
Variable Op Cost ($/MWh sent-out)	4.7	GHD sourced and NREL SAM (based on 150 MW_e plant with storage)
Cold Start-up Costs ($/MW as gen)	15	GHD sourced
Warm Start-up Costs ($/MW as gen)	8	GHD sourced
Hot Start-up Costs ($/MW as gen)	0	GHD sourced

Table 66 New entrant capital cost – Solar thermal – central receiver without storage

Item	Value	Source / Basis
General Costs		
Equipment costs	$662,850,000	GHD sourced and NREL SAM (based on 150 MW_e plant without storage)
Cost of land and development	$36,450,000	GHD sourced and NREL SAM (based on 150 MW_e plant without storage)
Installation costs	$86,400,000	GHD sourced and NREL SAM (based on 150 MW_e plant without storage)

5.12 Wind

5.12.1 Onshore

- 100 MW Wind Farm, for both on-shore & off-shore
- Assume CAPEX includes cost to achieve network connection voltage (but no transmission)
- CAPEX based on large scale wind farm projects recently reached financial closed in Vic, Qld, WA, and SA States

Nominal new entrant details

- Assumed Size: 100 MW Wind Farm, for both on-shore & off-shore. Projects in the range 100-300 MW are typical.
- O&M Costs – the following assumptions are made for estimating typical wind farm O&M costs:
  - Wind farm installed capacity is 100 MW
  - Wind farm net annual capacity factor is 38%
  - The land lease costs are estimated at 2% of the revenue generation and assuming a fixed offtake price of $72/MWh
  - Wind farm is operated under an O&M contract (from the date of completion) with long-term availability warranty of 97% or higher for a period of 20-25 years. The fixed-fee portion of the O&M contract is expected to be about 75% of the total contract sum.
  - The fixed O&M costs are assumed to include planned maintenance for civil and electrical works, including substation planned maintenance.

The estimated O&M costs exclude costs related to project insurances, administration, servicing debts, network access charges, frequency control ancillary services, unplanned maintenance, allowance for major spare components (such as a generator, blade, step-up transformer, gearbox, etc.) and any relevant environmental monitoring activities.

Overall wind farm O&M costs have experienced a declining trend in the past few years as WTG sizes (i.e. MW output per WTG) have increased and reduced the number of turbines installed, which in turn has led to lower operating costs per MW. Furthermore, OEMs offering wind farm O&M contracts expanding to the design life of the project (i.e. 25 years) and more direct drive WTGs have resulted operating costs to drop (when averaged over the project life term).

The significant increase in uptake of solar PV projects in Australia and setting up of manufacturing facilities in China by main stream turbine OEMs as well as Chinese suppliers such as GoldWind moving into tier one OEMs have put downwind pressure on wind farm EPC costs, which in turn have led to wind farm Capex cost of less than $2,000 per kW.

Table 67 New entrant parameters – Wind – onshore

Item	Value	Source / Basis
General Details		
Fuel Type	N/A	
First Year Assumed Commercially Viable for construction	2018	
Assumed unit size (MW)	100	Typical wind farm size is 100-300 MW
Seasonal Ratings: Summer (MW)	100	GHD assumes the dominant seasonal rating is not applicable to a wind farm. The dominant seasonal pattern is attributed to wind seasonal patterns, which is site specific. Accordingly Instantaneous Rating is assumed at full capacity throughout the year.
Seasonal Ratings: Not summer (MW)	100	As for 'Seasonal ratings: Summer'.
Economic Life (yrs)	25	Economic life of 25 yrs based on typical wind farm projects that recently have been built. Actual technical life of facility could be expected to exceed 30 years for financial modelling purposes.
Technical Life (yrs)	30	As per comment for 'Economic Life'.
Lead time for development (yrs)	2	GHD in-house data
Construction time (weeks)	60	GHD in-house data
Technical Details		
Min Stable Generation (% of installed capacity)	0	
Auxiliary load (% of installed capacity)	2	Auxiliary loads are very low for wind farms – estimated at 0.1% per wind turbine. Including reticulation losses
Auxiliary load for Generators operating in Synchronous Condenser mode (% of installed capacity)	N/A	
Forced outage rate (full forced outages) (%)	3.5	Majority of wind farms being currently constructed in Australia have contractual warranted availability of 97% (or higher) for wind turbines for up to a 25 year period. Taking into account grid/substation availability, 96.5% and 95% annual availability is assumed for an on-shore and off-shore wind farm, respectively.

Item	Value	Source / Basis
Frequency of full forced outage per annum	N/A	All unplanned outage is included in the 3.5% forced outage rate.
Full outage mean time to repair (h)	300	All unplanned outage is included in the 3.5% forced outage rate.
Partial Forced outage rate (partial forced outages)	N/A	All unplanned outage is included in the 3.5% forced outage rate.
Frequency of partial forced outages	N/A	All unplanned outage is included in the 3.5% forced outage rate.
Partial Outage derating factor (% lost during partial outage)	N/A	All unplanned outage is included in the 3.5% forced outage rate.
Partial outage Mean time to repair (h)	N/A	All unplanned outage is included in the 3.5% forced outage rate.
Equivalent forced outage rate (%)	N/A	All unplanned outage is included in the 3.5% forced outage rate.
Maintenance Frequency (no of times per year)	2	
Average Maintenance rate (no of days/year)	13	It is assumed that the average maintenance rate is the same as wind farm annual availability.
Cost Details		
Fixed Operating Cost ($/MW/year)	36,020	Based on the O&M cost allowance discussed above.
Variable Op Cost ($/MWh sent-out)	2.67	Based on the O&M cost allowance discussed above.

New entrant capital cost

The onshore wind farm CAPEX cost estimate ($/MW) assumes:

- Wind farm is built under an Engineer, Procure, and Construct (EPC) contract Arrangement.
- Total project EPC costs are made of the sum of ‘Equipment costs’ plus ‘Installation costs’
- For an on-shore wind farm, the equipment costs (including turbine foundation materials) are 85% of the total EPC cost
- Civils works exclude any public road alterations/upgrades
- Electrical works include internal wind farm network, substation, and transformation to network connection voltage
- Inclusion of O&M buildings and wind farm workshop facilities
- Wind farm land requirement is minimum; all lands for development are leased

- Cost of land lease are accounted for in fixed O&M costs
- Wind farm development costs are estimated as 2-5% of the project CAPEX costs.

Table 68 New entrant capital cost – Wind – onshore

Item	Value	Source / Basis
General Costs		
Equipment costs	$165,750,000	GHD estimate based on recent experience.
Fuel connection costs	N/A	
Cost of land and development	$6,825,000	Based on an average of 3.5% of the project capital cost (i.e. equipment cost plus installation cost)
Installation costs	$29,250,000	GHD estimate based on recent experience.

5.12.2 Offshore

- 100 MW Wind Farm, for both on-shore & off-shore
- Assume CAPEX includes cost to achieve network connection voltage (but no transmission)
- CAPEX based on large scale wind farm projects recently reached financial closed in Vic, Qld, WA, and SA States

It is noted that there is no operational off-shore nor a mature developmental wind farm project in Australia. Off-shore estimated costs are based on overseas reference materials.

Nominal new entrant details

- Assumed Size: 100 MW Wind Farm, for both on-shore & off-shore. Projects in the range 100-300 MW are typical.
- O&M Costs – the following assumptions are made for estimating typical wind farm O&M costs:
  - Wind farm installed capacity is 100 MW
  - Wind farm net annual capacity factor is 38%
  - The land lease costs are estimated at 2% of the revenue generation and assuming a fixed offtake price of $72/MWh
  - Wind farm is operated under an O&M contract (from the date of completion) with long-term availability warranty of 97% or higher for a period of 20-25 years. The fixed-fee portion of the O&M contract is assumed to be about 100% of the total contract sum.

– The fixed O&M costs are assumed to include planned maintenance for civil and electrical works, including substation planned maintenance.

The estimated O&M costs exclude costs related to project insurances, administration, servicing debts, network access charges, frequency control ancillary services, unplanned maintenance, allowance for major spare components (such as a generator, blade, step-up transformer, gearbox, etc.) and any relevant environmental monitoring activities.

Table 69 New entrant parameters – Wind – offshore

Item	Value	Source / Basis
General Details		
Fuel Type	N/A	
First Year Assumed Commercially Viable for construction	2018	International data.
Assumed unit size (MW)	100	Typical wind farm size is 100-300 MW
Seasonal Ratings: Summer (MW)	100	GHD assumes the dominant seasonal rating is not applicable to a wind farm. The dominant seasonal pattern is attributed to wind seasonal patterns, which is site specific. Accordingly Instantaneous Rating is assumed at full capacity throughout the year.
Seasonal Ratings: Not summer (MW)	100	As for 'Seasonal ratings: Summer'
Economic Life (yrs)	30	GHD Soured Data
Technical Life (yrs)	25	GHD Soured Data
Lead time for development (yrs)	2	
Construction time (weeks)	80	
Technical Details		
Min Stable Generation (% of installed capacity)	0	
Auxiliary load (% of installed capacity)	2	
Forced outage rate (full forced outages) (%)	5	All unplanned outage is included in the 5% forced outage rate.
Frequency of full forced outage per annum		All unplanned outage is included in the 5% forced outage rate.
Full outage Mean time to repair (h)	450	All unplanned outage is included in the 5% forced outage rate.
Partial Forced outage rate (partial forced outages)		All unplanned outage is included in the 5% forced outage rate.

Item	Value	Source / Basis
Frequency of partial forced outages		All unplanned outage is included in the 5% forced outage rate.
Partial Outage derating factor (% lost during partial outage)		All unplanned outage is included in the 5% forced outage rate.
Partial outage Mean time to repair (h)		All unplanned outage is included in the 5% forced outage rate.
Equivalent forced outage rate (%)		All unplanned outage is included in the 5% forced outage rate.
Maintenance Frequency (no of times per year)	2	
Average Maintenance rate (no of days/year)	18	It is assumed that the average maintenance rate is the same as wind farm annual availability.
Cost Details		
Fixed Operating Cost ($/MW/year)	$108,060	Based on the O&M cost allowance discussed above.
Variable Op Cost ($/MWh sent-out)	N/A	Assumed to be included in fixed operating cost. While some variable costs will exist, these are not substantial compared to the fixed costs and are assumed to be included.

New entrant capital cost

The offshore wind farm CAPEX cost estimate ($/MW) assumes:

- Wind farm is built under an Engineer, Procure, and Construct (EPC) contract Arrangement
- Total project EPC costs are made of the sum of ‘Equipment costs’ plus ‘Installation costs’
- For an off-shore wind farm, the equipment costs (including turbine foundation materials) are 80% of the total EPC cost.
- Civils works exclude any public road alterations/upgrades
- Electrical works include internal wind farm network, substation, and transformation to network connection voltage
- Inclusion of O&M buildings and wind farm workshop facilities
- Wind farm land requirement is minimum; all lands for development are leased
- Cost of land are accounted for in fixed O&M costs
- Wind farm development costs are estimated as 2-5% of the project CAPEX costs.

Table 70 New entrant capital cost – Wind – offshore

Item	Value	Source / Basis
General Costs		
Equipment costs	$374,400,000	GHD estimate based on recent experience.
Fuel connection costs	N/A	
Cost of land and development	$16,380,000	Based on an average of 3.5% of the project capital cost (i.e. equipment cost plus installation cost)
Installation costs	$93,600,000	GHD estimate based on recent experience.

6. Regional cost factors

As part of this exercise, AEMO requested that the data be provided for a range of geographic regions across Australia, including Northern Territory and Western Australia. The intention of this is to provide an indication of the variation in project cost based on the shift in labour, equipment, and shipping/delivery cost between the selected regions.

To address this, a set of cost factors has been developed which can be used to convert the baseline cost estimate provided to a region-specific cost estimate.

The following methodology has been applied for this process:

- All cost data for new entrants supplied at a 'baseline' location, which was nominally selected as Melbourne, Victoria
- A set of regions developed for each state, based on nominal factors (such as distance from major population centre or port) that typically reflect higher construction costs
- Cost factors developed for each of the cost components included in the dataset, including:
  - Equipment costs
  - Installation costs
  - Fuel connection costs
  - Cost of land and development
  - O&M costs
- The cost for a given new entrant for a selected region can be calculated by applying the factors to the corresponding cost item.

The derivation of the regions and cost factors is presented below.

The table of cost factors is presented in Section 6.3.

6.1 Cost regions

The incremental cost of developing and executing a generation project in a given location is nominally based on factors such as:

- Transportation costs associated with distance from a major port,
- Labour rates and labour availability in remote locations,
- Increased cost of working in remote location due to lack of amenities and industry.

On this basis, cost regions were developed for each state using the following approach:

- Major ports and industrial centres identified (e.g. capital cities, major port cities),
- The surrounding areas considered (e.g. with regards to level of industry and population) and any publicly available cost factors (e.g. Rawlinsons Australian Construction Handbook 2018 (Rawlinsons)) used to determine the distances from a given major centre at which the cost delineation will be applied,
- A heat map produced for each state based on the above.

These maps are shown in Appendix A.

6.2 Derivation of regional cost factors

6.2.1 Equipment cost factors

The equipment cost factors for the nominal regions have been developed based on an incremental transport/shipping cost relative to delivery to a plant located near a major port.

On this basis, all major port locations have an equipment cost factor of 1.00. Regions further from a major port receive a factor ranging from 1.03 to 1.10, reflecting the scale of additional transportation required (i.e. level of remoteness).

6.2.2 Installation cost factors

Installation cost factors have been developed using a blend of labour and bulk material rates sourced from Rawlinsons. These rates are provided for each capital city, which allows a relative factor to be developed between these locations. This capital-based factor is then used in conjunction with state-based cost factor maps to apply additional cost increases due to remoteness.

The blended rate is based on the following typical installation cost composition:

- Labour: 50%
- Steel: 35%
- Concrete: 15%

This composition was developed based on a cost breakdown produced for a nominal thermal power plant. While this composition will change based on the type of plant, it is considered to be sufficiently representative of typical installation costs to be used for all technologies.

The rates used for each location are based on the following cost items from Rawlinsons:

- Labour: average electrical installation labour rate
- Steel: rate for universal steel beam
- Concrete: rate for concrete column or pier foundation, 25 MPa

The relative rate for each item was factored relative to a consistent location (nominally selected as Melbourne). The three relative rates were then included in the proportions listed above to develop the capital-based factors presented in Table 71.

Table 71 Capital-based installation cost factors

City	Factor relative to Melbourne
Melbourne	1.00
Adelaide	1.02
Brisbane	1.10
Perth	1.11
Sydney	1.18
Darwin	1.27
Hobart	1.07

The factor for remoteness within each state was developed based on a combination of the following:

- The state cost factor maps presented in Rawlinsons
- A qualitative assessment of the range of cost factors within each state that fall within a logical area for construction of the projects being considered
- The location remoteness and impact on construction costs based on previous project experience.

These state-based remoteness factors are presented in Table 72.

Table 72 State-based remoteness cost factors

State	Distance from major city/port		
	Low	Medium	High
Victoria	1.00	1.03	1.05
South Australia	1.00	1.15	1.30
Queensland	1.00	1.15	1.30
Western Australia	1.00	1.25	1.50
New South Wales	1.00	1.10	1.20
Northern Territory	1.00	1.25	1.50
Tasmania	1.00	1.10	1.20

The factors presented in the tables above are multiplied together to produce the construction cost factor for a given region relative to the baseline cost location of Melbourne (i.e. 'Victoria low cost'). These factors are included in Table 73.

6.2.3 Fuel connection costs

The varied nature of fuel connection infrastructure presents a challenge in applying regional cost factors. Notwithstanding, a factor has been developed, which is a 50:50 blend of the equipment cost factor and installation cost factor. This is considered to be representative of the type of work involved with fuel connection infrastructure.

6.2.4 Cost of land and development

The cost of land and development is considered to be a collation of typical owner's costs and a nominal allowance for land.

Both of these costs are heavily dependent on a number of factor's that do not necessarily align with geographical variance. For example, while land cost might typically reduce as the project location becomes more remote, the costs associated with land development, access, and community engagement may increase. Additionally, the land may be high value grazing or farming land which would counteract the remoteness factor.

Additionally, typical owner's costs are more dependent on the nature of the owner than rationality, and as such cannot be predicted using degree of remoteness. On this basis, the land and development cost factor for all regions is 1.00.

6.2.5 O&M costs

Regional cost factor's for O&M costs have been developed as a combination of equipment costs (based on the need for equipment sourced from overseas or from warehouses located near major industrial centres) and installation costs.

6.3 Table of regional cost factors

The list of regional cost factors is presented in Table 73.

Table 73 Regional cost factors

Region	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs	O&M costs
Vic low	1.00	1.00	1.00	1.00	1.00
Vic medium	1.03	1.03	1.00	1.03	1.03
Vic high	1.05	1.05	1.00	1.05	1.05
Qld low	1.00	1.05	1.00	1.10	1.07
Qld medium	1.05	1.16	1.00	1.27	1.20
Qld high	1.10	1.27	1.00	1.44	1.34
NSW low	1.00	1.09	1.00	1.18	1.13
NSW medium	1.05	1.17	1.00	1.30	1.22
NSW high	1.10	1.26	1.00	1.42	1.32
SA Low	1.00	1.01	1.00	1.02	1.01
SA medium	1.05	1.11	1.00	1.17	1.13
SA high	1.10	1.21	1.00	1.32	1.25
WA low	1.00	1.06	1.00	1.11	1.08
WA medium	1.05	1.22	1.00	1.39	1.29
WA high	1.10	1.38	1.00	1.67	1.50
NT low	1.00	1.13	1.00	1.27	1.19
NT medium	1.05	1.32	1.00	1.59	1.42
NT high	1.10	1.50	1.00	1.90	1.66
Tas low	1.00	1.04	1.00	1.07	1.05
Tas medium	1.05	1.11	1.00	1.18	1.14
Tas high	1.10	1.19	1.00	1.29	1.23

Appendices

Appendix A – Cost region maps

Paper Size ISO A4
0 90 180 270 360
Kilometers

Horizontal Datum: GDA 1994
Grid: GCS GDA 1994

N

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Costs and Technical Parameter Review

COST REGION MAPS
QUEENSLAND

Project No. 91-10715
Revision No. A
Date 17/ 08/ 2018

FIGURE 1

G:\91\10715\GIS\Maps\MXD\91-10715_001_Queensland_revA.mxd
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Data source: GA: populated places (2007); GHD: Buffer Distances (2018); Esri, Garmin, GEBCO, NOAA NGDC, and other contributors. Created by: acjackson

Paper Size ISO A4

0 75 150 225 300

Kilometers

Horizontal Datum: GDA 1994
Grid: GCS GDA 1994

N

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COST REGION MAPS
NEW SOUTH WALES

Project No. 91-10715
Revision No. A
Date 17/ 08/ 2018

FIGURE 2

G:\91\10715\GIS\Maps\MXD\91-10715_002_NewSouthWales_revA.mxd
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Paper Size ISO A4

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Kilometers

Horizontal Datum: GDA 1994
Grid: GCS GDA 1994

N

GHD

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COST REGION MAPS
VICTORIA

Project No. **91-10715**
Revision No. **A**
Date **17/ 08/ 2018**

FIGURE 7

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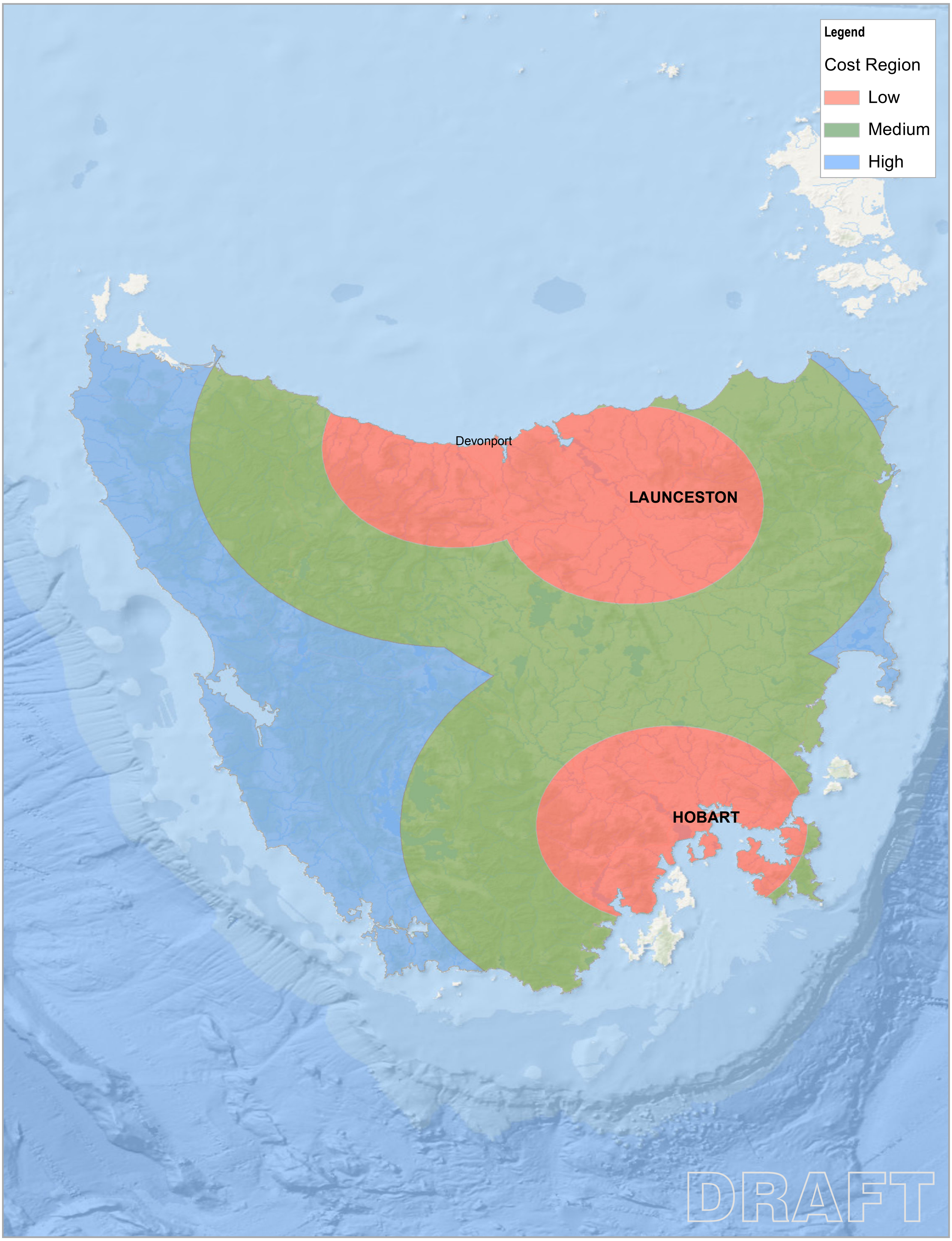

Paper Size ISO A4

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Kilometers

N

Horizontal Datum: GDA 1994
Grid: GCS GDA 1994

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COST REGION MAPS
TASMANIA

Project No.	**91-10715**
Revision No.	**A**
Date	**17/ 08/ 2018**

FIGURE 3

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Paper Size ISO A4

0 75 150 225 300

Kilometers

Horizontal Datum: GDA 1994
Grid: GCS GDA 1994

N

GHD

AEMO
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COST REGION MAPS
SOUTH AUSTRALIA

Project No. **91-10715**
Revision No. **A**
Date **17/ 08/ 2018**

FIGURE 5

G:\91\10715\GIS\Maps\MXD\91-10715_005_SouthAustralia_revA.mxd
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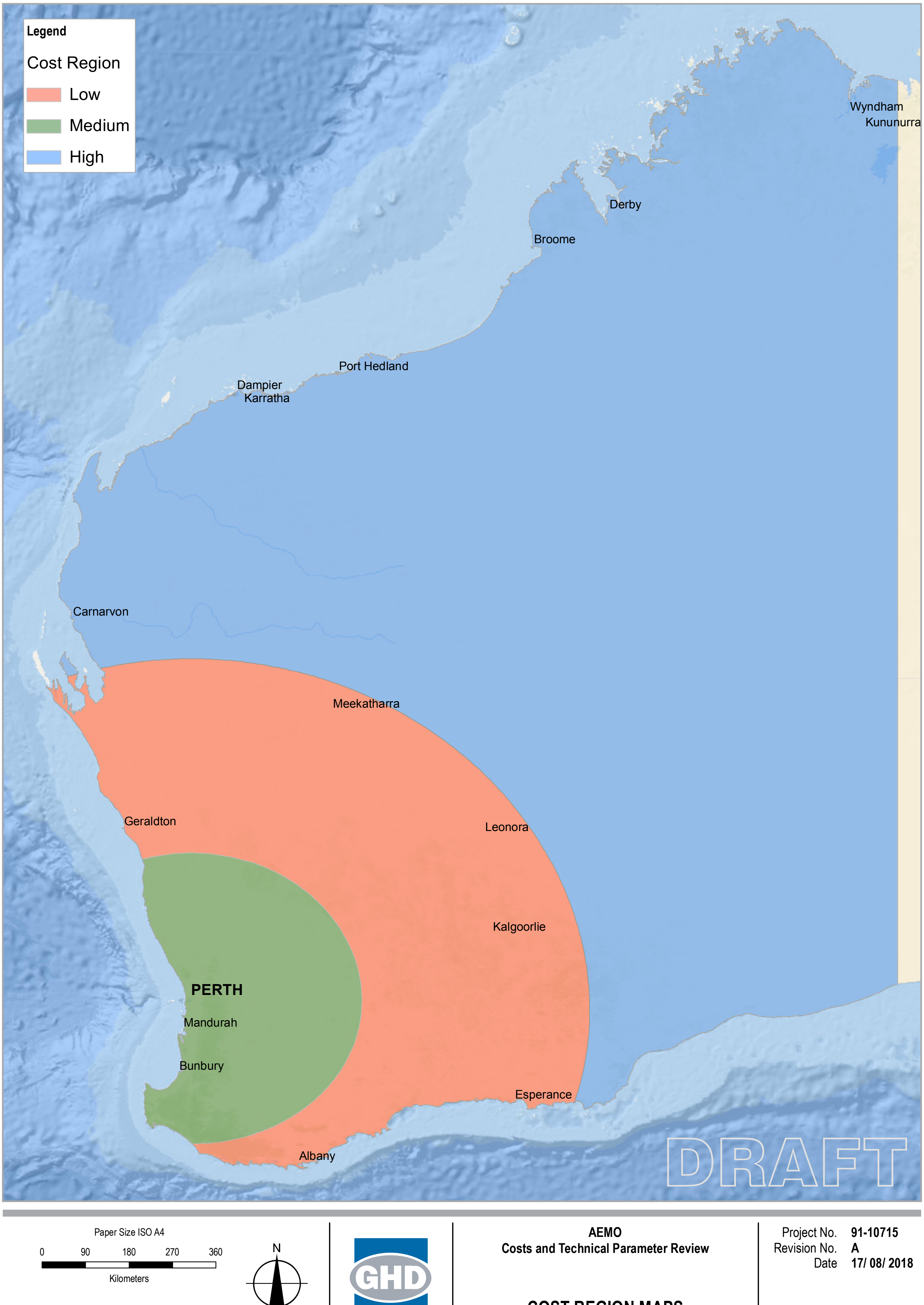

Horizontal Datum: GDA 1994
Grid: GCS GDA 1994

GHD

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COST REGION MAPS
WEST AUSTRALIA

Project No. 91-10715
Revision No. A
Date 17/ 08/ 2018

FIGURE 4

G:\91\10715\GIS\Maps\MXD\91-10715_004_WestAustraila_revA.mxd
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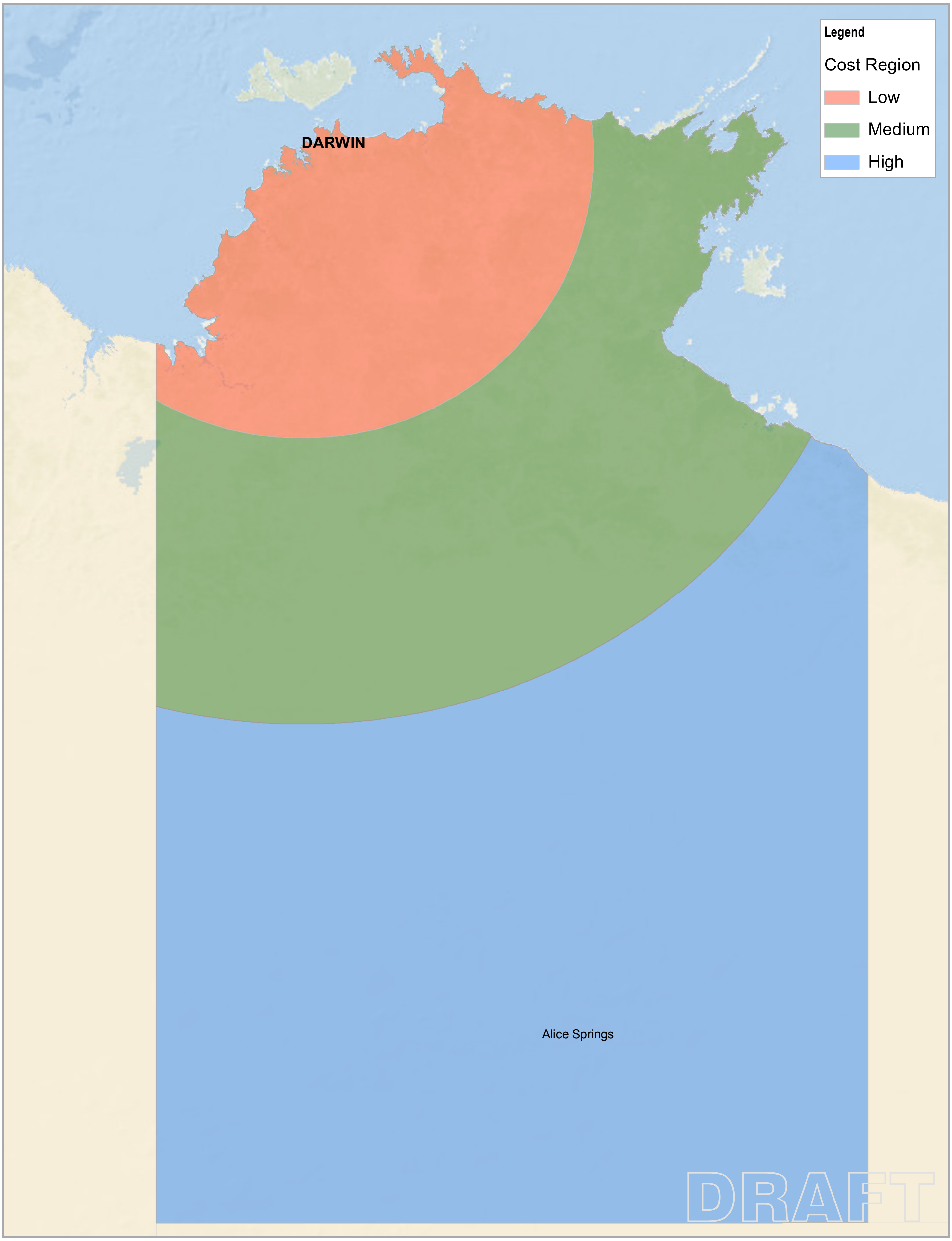

Paper Size ISO A4

0 70 140 210 280

Kilometers

N

Horizontal Datum: GDA 1994
Grid: GCS GDA 1994

GHD

AEMO
Costs and Technical Parameter Review

COST REGION MAPS
NORTHERN TERRITORY

Project No. **91-10715**
Revision No. **A**
Date **17/ 08/ 2018**

FIGURE 6

G:\91\10715\GIS\Maps\MXD\91-10715_006_NorthernTerritory_revA.mxd
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Data source: GA: populated places (2007); GHD: Buffer Distances (2018); Esri, Garmin, GEBCO, NOAA NGDC, and other contributors. Created by: acjackson

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Rev 3	DB/MT	S Hinchliffe		S Bond		19/09/2018
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