2020 Costs and Technical Parameter Review

Consultation Report

Australian Energy Market Operator (AEMO)

Reference: 510177

Revision: 3

2020-12-10

Document prepared by

Aurecon Australasia Pty Ltd
ABN 54 005 139 873
Ground Floor, 25 King Street
Bowen Hills QLD 4006
Locked Bag 331
Brisbane QLD 4001
Australia

T +61 7 3173 8000
F +61 7 3173 8001
E brisbane@aurecongroup.com
W aurecongroup.com

Document control						aurecon
Report title	Consultation Report					
Document code			**Project number**	510177		
File path	**2020 Cost and Technical Parameters Review Report_Rev 3.docx**					
Client	Australian Energy Market Operator (AEMO)					
Client contact	Andrew Turley		**Client reference**			
Rev	**Date**	**Revision details/status**	**Author**	**Reviewer**	**Verifier** (if required)	**Approver**
0	2020-09-18	Draft issue for review	SHM	PCG		PCG
1	2020-11-24	Second draft issue (for consultation)	SHM	PCG		PCG
2	2020-12-07	Updated BESS figures	SHM	PCG		PCG
3	2020-12-10	Minor edits	SHM	PCG		PCG
Current revision	**3**					

A person using Aurecon documents or data accepts the risk of:

a) *Using the documents or data in electronic form without requesting and checking them for accuracy against the original hard copy version.*

b) *Using the documents or data for any purpose not agreed to in writing by Aurecon.*

Approval			
Author signature		Approver signature	
Name	Shannon Moss	Name	Paul Godden
Title	Senior Power Generation Engineer	Title	Competency Leader – Power Generation

Contents

Appendices

Figures

Tables

1 Introduction

1.1 Background

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

AEMO's forecasting functions can influence the behaviour of existing generation assets and the economics and location of future investment and retirement decisions. These forecasts rely on various input assumptions. AEMO has engaged Aurecon to review and prepare an updated set of generation technology input data to be used in AEMO forecasting studies and to be published on the AEMO website.

The updated dataset includes current technology costs and technical operating parameters for both existing and emerging generation technologies, including those with minimal current local or international deployment.

The dataset is intended to be used by AEMO, and shared with industry, to conduct market simulation studies for medium and long-term forecasting purposes. This data will be then used in various AEMO forecasting publications.

1.2 Scope of study

The scope of this study was to prepare an updated set of costs and technical parameters for a concise list of new entrant generation (and storage) technologies, including the following:

- Onshore wind
- Offshore wind
- Large-scale solar photovoltaic (PV)
- Concentrated solar thermal (with 8 hours energy storage)
- Reciprocating engines
- Open-cycle gas turbine (OCGT)
- Combined-cycle gas turbine (CCGT) (with and without carbon capture and storage (CCS))
- Advanced Ultra Supercritical Pulverised Coal (with and without CCS)
- Biomass
- Electrolysers (PEM & Alkaline)
- Fuel cells
- Battery Energy Storage Systems (BESS) with 1 to 8 hours storage

The parameters to be updated or developed include the following:

- Performance – such as output, efficiencies, and capacity factors
- Timeframes – such as for development and operational life
- Technical and operational parameters – such as configuration, ramp rates, and minimum generation
- Costs – including for development, capital costs and O&M costs (both fixed and variable)

The updated dataset is provided in the accompanying Microsoft Excel spreadsheet (see Appendix A), the template for which was developed by AEMO. This report provides supporting information for the dataset and an overview of the scope, methodology, assumptions, and definition of terms used in the dataset and its development.

The intention is for the updated dataset to form a key input to the long-term capital cost curves in the 2020 GenCost publication to be prepared by CSIRO in conjunction with AEMO as well as other various AEMO forecasting publications such as the Integrated System Plan (ISP).

1.3 Abbreviations

Table 1-1 Acronyms / Abbreviations

Acronym	Definition
AEMO	Australian Energy Market Operator
AUD	Australian Dollar
BESS	Battery Energy Storage System
C&I	Commercial and Industrial
CAPEX	Capital Expenditure
CCGT	Combined-Cycle Gas Turbine
CCS	Carbon capture and storage
DNI	Direct Normal Irradiance
EPC	Engineer Procure and Construct
FFR	Fast Frequency Response
GJ	Gigajoule
GST	Goods and Services Tax
HHV	Higher Heating Value
LCOE	Levelised Cost Of Electricity
LHV	Lower Heating Value
MCR	Maximum Continuous Rating
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
OCGT	Open Cycle Gas Turbine
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
O&M	Operations and Maintenance
PEM	Proton Exchange Membrane
PV	Photovoltaic
SAT	Single-axis Tracking
WEM	Wholesale Electricity Market

2 Limitations

2.1 General

This report has been prepared by Aurecon on behalf of, and for the exclusive use of, AEMO. It is subject to - and issued in connection with the provisions of the agreement between Aurecon and AEMO.

Power generation conceptual design is not an exact science, and there are several variables that may affect the results. Bearing this in mind, the results provide reasonable guidance as to the ability of the power generation facility to perform adequately, rather than an exact analysis of all the parameters involved.

This report is not a certification, warranty, or guarantee. It is a report scoped in accordance with the instructions given by AEMO and limited by the agreed time allowed.

The findings, observations, and conclusions expressed by Aurecon in this report are not and should not be considered an opinion concerning the commercial feasibility of such a project.

This report is partly based on information provided to Aurecon by AEMO. This report is provided strictly on the basis that the information provided to Aurecon is accurate, complete and adequate, unless stated otherwise.

If AEMO or a third party should become aware of any inaccuracy in, or change to, any of the facts, findings or assumptions made either in this report or elsewhere, AEMO or a third party should inform Aurecon so that Aurecon can assess its significance and review its comments and recommendations.

2.2 Thermoflow Inc. Software

This report relies on outputs generated from Thermoflow Inc. software by personnel in Aurecon experienced in using this software. The provider of this software does not guarantee results obtained using this software, nor accept liability for any claimed damages arising out of use or misuse of its software. Aurecon's report is provided strictly on the basis that the outputs that have been generated are accurate, complete, and adequate. Aurecon takes no responsibility and disclaims all liability whatsoever for any loss or damage that AEMO may suffer resulting from any conclusions based on outputs generated by Aurecon using this software.

2.3 Costs and Budget

Aurecon has no control over the cost of labour, materials, equipment, or services furnished by others. Aurecon similarly has no control over Contractors' methods of determining prices, or over competitive bidding or market conditions. Any opinion or estimate of costs by Aurecon is made on the basis of Aurecon's experience and qualifications, and represents Aurecon's judgment as an experienced and qualified professional engineering organisation, familiar with the construction industry. However, Aurecon cannot and does not guarantee that proposals, bids, or actual construction costs will not vary from Aurecon's estimates.

3 Methodology and Definitions

3.1 Methodology

The dataset for the new entrant technologies has been developed and updated based on a hypothetical project selected as being representative for each examined technology, and which would or could be typically installed in the NEM as a market participant.

The size and configuration for each hypothetical project has been selected based on Aurecon's current experience with existing and recent / proposed new entrant power generation and storage projects in Australia, particularly in the NEM. The intent is that the technical and cost information developed for these hypothetical projects can be used as a basis by others with adjustment as needed for its specific purpose or project (i.e. scale on a $/MW basis, inflate to account for regional or remote cost factors, etc).

The performance figures and technical parameters have been based on actual project information where available, or vendor provided information.

The cost estimates have been developed based on collating information from the following sources:

- Aurecon's internal database of projects – recently constructed or under construction
- Recent bid information from EPC competitive tendering processes
- Industry publications and publicly available data

This cost data has been levelised or adjusted to account for differences in battery limits, scope, location factors, technical factors (where relevant), etc.

A representative cost has been selected for the hypothetical project from the data available, and cost certainty qualified based on the spread and quality of data available.

Recent trends for each technology have been reviewed and discussed throughout the report. These have been considered when selecting the hypothetical project, nominating technical parameters, and developing the cost estimates on a 2020 basis.

3.2 Assumptions and Basis

3.2.1 General

This section defines the basis used for the hypothetical projects and for determining the technical parameters and cost estimates.

3.2.2 Power generation / storage facility

Power generation or storage facility equipment and installation scope is based on the assumptions as described in the following table.

Table 3-1 Power generation / storage facility key assumptions

Item	Detail
Site	Greenfield site (clear, flat, no benching required), NEM installation, coastal location (within 200 km of coast)
Base ambient conditions:	▪ Dry Bulb Temperature: 25 °C, ▪ Elevation above sea level: 110 metres ▪ Relative Humidity: 60%
Fuel quality	▪ Gas: Standard pipeline quality natural gas (HHV to LHV ratio of 1.107) ▪ Diesel: No.2 diesel fuel
Water quality	▪ Towns water quality (i.e. potable) ▪ Demineralised water produced on site if required
Hydrogen quality	99.99+% v/v in compliance with ISO 14687-2:2014 and SAE J2719.
Grid connection voltage	220 – 275 kV (or lower for small scale options (i.e. electrolysers, etc))
Grid connection infrastructure	Step-up transformer included, switchyard / substation excluded
Energy Storage	▪ Concentrated solar thermal – 8 hrs thermal energy storage considered ▪ Electrolysers / fuel cells – Hydrogen compression, transport and storage excluded (relative costs provided separately) ▪ BESS – 1, 2, 4, and 8 hour energy storage options considered
Project delivery	EPC turn-key basis
O&M approach	▪ Thermal: Owner operates and maintains, but contracts for scheduled maintenance ▪ Renewables or storage: Owner appoints a third-party O&M provider

The assumed terminal points for the power generation or storage facility is described in the following table.

Table 3-2 Power generation / storage facility terminal points

No.	Terminal point	Terminal point location and details
1	Fuel supply (if relevant)	Gas: 30 – 40 bar supply pipeline at site boundary, dry and moisture free Diesel: Truck unloading facility located on site Coal: Train unloading facility located on site Biomass: Truck unloading facility located on site
2	Grid connection	HV side of generator step-up transformer
3	Raw / potable water	Site boundary (Water treatment plant included in project scope if demineralised water required)
4	Waste water	Site boundary
5	Road access	Site boundary
6	Hydrogen supply (if relevant)	Electrolyser: Outlet of package at delivery pressure (i.e. no additional compression) Fuel cell: 10 bar supply pipeline at package inlet

3.2.3 Fuel connection / transport

The fuel connection scope and costs are highly dependent on both location and site. As such, a single estimate for each hypothetical project is not practical. An indicative $/km cost has been nominated based on prior work and publicly available data.

The natural gas fuel connection scope assumptions are as follows:

- Distance from connection point to power station: <50 km
- Pipeline size and class: DN200, Class 600 (AS 2885)
- Scope: hot tap at connection, buried pipeline to power station, and fuel conditioning skid
- Fuel conditioning skid plant and equipment: Filtration, heating, metering, pressure let down, etc (excludes any fuel compression)

The coal fuel connection scope assumptions are as follows:

- Coal transport via rail (i.e. power station not located at the mine mouth)
- Distance from starting point to power station between 50 to 100 km
- Single track rail line dedicated for power station use
- Scope: Track rail line from mine to power station location delivered under a D&C contract. Excluding loading infrastructure at mine.

The biomass fuel connection scope assumptions are as follows:

- Biomass delivered to power station via road transport
- Existing road infrastructure used
- Unloading infrastructure included in power station cost
- No new transport infrastructure required hence no CAPEX associated with fuel supply (i.e. to be captured as an OPEX cost)

3.2.4 Natural gas compression and storage

Some natural gas power station projects require fuel gas compression depending on the pipeline pressure available and pressure requirements specified by the gas turbine manufacture. A separate cost has been provided for natural gas compression.

The natural gas compression scope assumptions are as follows:

- Type: Reciprocating compressor
- Supply pressure: 30 bar. Discharge pressure: 50 bar.
- Capacity: ~50 t/h
- Scope: Complete supply of compressor(s) and enclosures. Includes civil works. Excluding power supply.

Natural gas storage facilities are also used for increased fuel security and supply chain / demand management. A cost has been provided on the following basis.

- Storage: Underground storage facility in a depleted natural gas field.
- Scope: Third party contract for storage at the Iona underground storage facility. (Note that this is the only underground facility which is currently provides storage services to third parties in the East Coast Gas Market.)

3.2.5 Hydrogen compression, transport and storage

In addition to hydrogen production, hydrogen needs to be compressed (or liquified) and transported to the end user. The costs associated with compression (or liquification) and transport are considered separately in this report. When hydrogen is being produced from renewable sources considerable storage volumes are required to manage their intermittency, particularly where the end user requires a continuous supply or is being transported by road transport or sea going vessel.

The hydrogen compression scope assumptions are as follows:

- Type: Multi-stage diaphragm type
- Supply pressure: 30 bar (for PEM) or 1 bar (for Alkaline). Discharge pressure: 100 bar
- Capacity: Between 3,700 and 4,000 Nm^3/h (1 x 100% duty)
- Scope: Complete supply of compressor(s) and enclosures. Includes civil works. Excluding power supply (assumed co-located with the electrolyser plant).

The hydrogen transport scope assumptions are as follows:

- Type: Buried carbon steel pipeline (API 5L X42)
- Pressure: 100 bar
- Length: 50 to 250 km
- Diameter: DN50 (suitable for single 20 MW electrolyser)
- Scope: Full supply and installation of pipeline under D&C contract. Excludes compression and receiving stations at either end. Assumes single pipe run (not networked system).

The hydrogen storage scope assumptions are as follows:

- Type: High pressure steel cylinders (AS 1548 compliant)
- Pressure: 100 bar
- Size: 40ft ISO containers, 350kgH2 each (at 100 bar)
- Scope: Full supply and installation of storage tanks under D&C contract. Includes civils. Excludes additional compound infrastructure (assumes co-located with a wider facility).

3.2.6 Carbon capture and storage

Carbon capture and storage (CCS) refers to the process of removing the CO_2 from the flue gas / exhaust gas which is produced from traditional thermal power stations and typically released into the atmosphere. The most common form of CCS for power stations is a post combustion capture technology using a chemical absorption process with amines as the chemical solvent.

It has been assumed that in additional to the CCS chemical abortion and CO_2 removal and compression process a coal fired power station with CCS will also require selective catalytic reduction (SCR) for NO_x removal and a flue-gas desulfurization (FGD) plant for SO_x control. In Australia, depending on the coal quality and project location there may not be a specific requirement for the inclusion of SCR or an FGD with a new coal fired power station and as such these are not included in the non-CCS plant configuration. The post carbon capture absorption process typically has low NO_x and SO_x tolerances however and so these are included in the CCS plant configurations for coal fired power station.

For the CCGT with CCS plant configurations it has been assumed that SCR and FGD processes would not be required due to the low sulphur content of Australia’s natural gas and with the low NO_x levels achievable with the latest gas turbine dry low NO_x burner technology.

The downstream terminal point for the carbon capture process is assumed to be the outlet of the CO_2 compression plant at nominally 150 bar (no temporary storage assumed on site).

CO_2 transport costs are provided separately based on onshore transport via underground pipeline from the power station to the storage location. Costs are provided on a $/t$CO_2$/km basis.

CO_2 storage costs are provided separately and assumed to involve injecting the CO_2 into a depleted natural gas reservoir. Costs are provided on a $/t$CO_2$ basis.

3.2.7 Development and land costs

The development and land costs for a power generation or storage project typically include the following components:

- Legal and technical advisory costs
- Financing and insurance
- Project administration, grid connection studies, and agreements
- Permits and licences, approvals (development, environmental, etc)
- Land procurement and applications

The costs for project and land procurement are highly variable and project specific. An indicative estimate has been determined based on a percentage of CAPEX estimate for each technology from recent projects, and experience with development processes.

3.2.8 Financial assumptions

The following key assumptions have been made regarding the cost estimates:

- Prices in AUD, 2020 basis
- New plant (no second hand or refurbished equipment assumed)
- Competitive tender process for the plant and equipment
- Taxes and import / custom duties excluded
- Assumes foreign exchange rates of 0.7 AUD:USD and 0.6 AUD:EUR
- No contingency applied

It is important to note that without specific engagement with potential OEM suppliers and/or issuing a detailed EPC specification for tender, it is not possible to obtain a high accuracy estimate of the costs. The risk and profit components of EPC contracts can vary considerably from project to project and are dependent upon factors such as:

- Project location
- Cost of labour
- Cost of materials
- Market conditions
- Exchange rates

The accuracy / certainty of the cost estimates is targeted at +/- 30% based on the spread and quality of data available and our experience with the impact of the above factors.

3.3 Definitions

The following table provides definitions for each of the key terms used throughout this document and in the Excel-based dataset.

Table 3-3 Definition of key terms

Term	Definition
Summer rating conditions	DBT: 35°C
Base / design conditions	DBT: 25°C, RH: 60%, 110 m elevation
Not summer rating conditions	DBT: 15°C
Economic life (design life)	Typical design life of major components.
Technical life (operational life)	Typical elapsed time between first commercial operation and decommissioning for that technology (mid-life refurbishment typically required to achieve this Technical Life).
Development time	Time to undertake feasibility studies, procurement and contract negotiations, obtain permits and approvals (DA, EIA), secure land agreements, fuel supply and offtake agreements, and obtain financing. This period lasts up until financial close.
EPC total programme	Total time from granting of Notice to Proceed (NTP) to the EPC Contractor until Commercial Operation Date (COD).
Total lead time	Time from issue of NTP to the EPC contractor up to the delivery of all major equipment to site.
Construction time	Time from receipt of major equipment to site up to the commercial operation date (COD). *Note that for simplicity it has been assumed that the total EPC programme = lead time + construction time. In reality lead time and construction time will overlap which would result in a longer actual construction time to that stated.*
Minimum stable generation	The minimum load - *as a percentage of the rated gross capacity of that unit* - that the generator unit can operate at in a stable manner for an extended period of time without supplementary fuel oil or similar support, and reliably ramp-up to full load while continuing to comply with its emissions licences.
Gross output	Electrical output as measured at the generator terminals.
Auxiliary load	The percentage of rated generation output of each unit - *as measured at the generator terminals* - that is consumed by the station and not available for export to the grid. This includes cable and transformer losses. The auxiliary load is provided as a percentage of the rated output at full load.
Net output	Electrical output exported to the grid as measured at the HV side of the generator step-up transformer. The net output of the unit can be calculated as the rated gross output at the generator terminals minus the auxiliary load.
Planned maintenance	Where a unit or number of units are offline for schedule maintenance in accordance with the OEM recommendations.
Average planned maintenance rate	The average annual number of days per year over the Design Life that the power station (or part thereof) is off line for planned maintenance and unavailable to provide electricity generation. For configurations with multiple units the rate - *in number of days per year* - has been proportioned in relation to the units' contribution to the overall power station capacity.
Forced maintenance / outage	Full and partial forced outage represent the percent of time within a year the plant is unavailable due to circumstances other than a planned maintenance event. 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.

Term	Definition
Equivalent forced outage rate (EFOR)	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). *Note Specific formulas are as defined in IEEE Std. 762.*
Ramp up/down rate	The rate that an online generating unit can increase or decrease its generation output without affecting the stability of the unit i.e. while maintaining acceptable frequency and voltage control.
Heat rate	The ratio of thermal energy consumed in fuel over the electrical energy generated.
Efficiency	Calculated using: Efficiency (%) = 3600 / Heat Rate (kJ/kWh) x 100
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 maximum state of charge (%)	The maximum charge % of the battery system.
Battery storage: Allowable minimum 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 to which the battery can be discharged – i.e. the difference between the maximum allowable charge and minimum allowance charge states.
Total EPC cost	The EPC contract sum (exclusive of taxes).
Equipment cost	The component of the EPC contract sum that is primarily attributed to the supply of the major equipment. *Note that the total EPC cost has been split into "equipment cost" and "installation cost" for the purpose of this study, based on a typical proportion for that technology. Other EPC cost factors such as engineering, overhead, risk, profit, etc have been distributed evenly between the two.*
Installation cost	The component of the EPC contract sum that is primarily attributed to the site construction, installation, and commissioning works. *Note that the total EPC cost has been split into "equipment cost" and "installation cost" for the purpose of this study, based on a typical proportion for that technology. Other EPC cost factors such as engineering, overhead, risk, profit, etc have been distributed evenly between the two.*
Carbon Capture cost	The component of the EPC contract sum that is primarily attributed to the supply, construction, installation, and commissioning works for the Carbon Capture equipment and associated components.
Fixed operating cost ($/MW Net/year)	Fixed costs include; plant O&M staff, insurance, minor contract work, and miscellaneous fixed charges such as service contracts, overheads, and licences. For some technologies where operation and maintenance are holistically covered by O&M and/or LTMA type contracts, all of the Operating Costs have been classed as "fixed" for the purposes of this study.
Variable operating cost ($/MWh Net)	Variable costs include; spare parts, scheduled maintenance, and consumables (chemicals and oils). Variable costs exclude fuel consumption costs.
Total annual O&M Cost	Annual average O&M cost over the design life.

4 New Entrant Generation Development Candidates

4.1 Overview

The following sections provide the technical and cost parameters for each of the nominated new entrant technologies, along with a brief discussion of typical options and recent trends. The information in the respective tables has been used to populate the AEMO GenCost 2020 Excel spreadsheets, which are included in Appendix A.

4.2 Onshore wind

4.2.1 Overview

Wind energy - *along with solar PV* - is one of the leading types of new renewable power generation technologies installed, both globally and in Australia. The most common technology used is the three-bladed horizontal-axis wind turbines (HAWT), with the blades upwind of the tower. These turbines are typically classified by the design wind speed and turbulence intensity of the wind (i.e. Class IA to IIIC). Grid-connected wind turbines are considered a reliable and mature technology with many years of operational experience.

4.2.2 Typical options

Currently deployed utility-scale wind turbine sizes range from 1 to 4 MW with hub heights of 50 to 150 m and rotor diameters of 60 m to 140 m. New models proposed for future projects are approaching 6 MW capacity with rotors over 160 m in diameter.

Onshore wind developments are critically dependent on:

- Access to land
- Planning permissions / development consents
- Nearby grid transmission capacity

Depending on the above, modern onshore wind farms can range from 1 to over 150 turbines. Different OEMs and turbine models have slightly different power curves, with some more suited to a particular site wind resource than others. As such, selection of the optimal and lowest levelised cost of energy (LCOE) option is highly site-specific.

Modern projects are also increasingly being delivered with a co-located battery and or solar PV plant to reduce intermittency of generation.

4.2.3 Recent trends

The design wind range for wind turbines has changed over the last few decades. Early focus was on very windy sites for best economics e.g. Class I = 8.5m/s to 10m/s. Class I wind turbines now only represents a small fraction (10%) of total manufacturing worldwide. Currently large turbines are being used in medium (Class II) and low wind speed sites (Class III) to achieve net capacity factors that can exceed 40%.

Turbine outputs, hub heights, and rotor diameters are continually being increased. These increases are resulting in lower installed costs ($/MW) and improved annual capacity factors.

For projects that are currently planned and under construction, wind turbine sizes in the 4 – 6 MW range are being used. Project due for commencement in 2021/2022 are at the upper end of the range.

Wind farm sizes throughout Australia have historically been in the 50 to 150 MW capacity range. However, in recent years new wind farms - *planned and under construction* - are expanding to total capacities in the range of 200 to 1,000 MW.

Typical capacity factors at the connection point range from 30% to 50%. Capacity factors are linked to the wind resource and turbine model used, with the main factor being the size of the rotor relative to the rated power. With recent developments in turbine design, capacity factors have been increasing for the same wind resource profile. The most recent wind turbine projects on the NEM have reported capacity factors of approximately 40%.

In recent years the development and grid connection of new windfarm projects has become more challenging. Planning applications require that wind turbine maximum tip heights are nominated very early in the approvals process. The rate of new developments in wind turbine technology is currently so high that at the time of project execution the planning approvals need to be amended to enable the use of the latest and most economically viable technology. New requirements for grid connection approvals and Generator Performance Standards (GPS) have also been extending the time required for completion of the supporting studies. These factors have been extending the overall development timeframes for new windfarms in Australia.

4.2.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project upon which costing is based. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2020, given the above discussion on typical options and current trends.

Table 4-1 Configuration and performance

Item	Unit	Value	Comment
Configuration			
Technology / OEM		Vestas	Other options include Siemens, GE, Goldwind, etc
Make model		V150-4.2	Based on current new installations
Unit size (nominal)	MW	4.2	ISO / nameplate rating
Number of units		75	
Performance			
Total plant size (Gross)	MW	315	
Auxiliary power consumption	%	3%	Primarily includes electrical distribution losses from the turbines to the substation and typically included in the capacity factor build-up.
Total plant size (Net)	MW	305.6	25°C, 110 metres, 60%RH
Seasonal rating – Summer (Net)	MW	291	Derating above 30°C based on OEM datasheet.
Seasonal rating – Not Summer (Net)	MW	305.6	Accounting for temperature related factors only.
Annual Performance			
Average planned maintenance	Days / yr.	-	Included in EFOR below.
Equivalent forced outage rate	%	3%	Majority wind farms currently being constructed in Australia have contractual warranted availability of 97% (or higher) for wind turbines for up to a 25-year period.

Item	Unit	Value	Comment
Effective annual capacity factor (year 0)	%	40%	Dependent on wake losses, wind resource, and electrical losses. Based on gross capacity.
Annual generation	MWh / yr	1,070,647	Provided for reference.
Annual degradation over design life	%	0.1%	Assuming straight line degradation.

Table 4-2 Technical parameters and project timeline

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW/min	Resource dependent	
Ramp down rate	MW/min	Resource dependent	
Start-up time	Min	N/A	Always on. < 5 min after maintenance shutdown.
Min stable generation	% of installed capacity	Near 0	
Project timeline			
Time for development	Years	3 – 5	Includes pre-feasibility, design, approvals etc. For wind a key factor is the availability of wind resource data. Installing wind masts at the nominated hub height can add 12 months to detailed feasibility assessments, pushing the timeframe to the upper end of the scale. Obtaining development approvals and consents can also add considerable time to the overall development schedule. Conversely, if there are already long-term consents in place development time could be in the order of 2 years.
First year assumed commercially viable for construction	Year	2020	
EPC programme	Years	2	For NTP to COD.
▪ Total lead time	Years	1	Time from NTP to first turbine on site.
▪ Construction time	Weeks	52	Time from first turbine on site to last turbine commissioned.
Economic life (design life)	Years	20 – 25	Varies between manufactures.
Technical life (operational life)	Years	20 – 30	Includes life extension but not repowering.

4.2.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

Table 4-3 Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW	1,700	Based on Aurecon internal benchmarks
Total EPC cost	$	535,500,000	
▪ Equipment cost	$	374,850,000	70% of EPC cost – typical.
▪ Installation cost	$	160,650,000	30% of EPC cost – typical.
Other costs			
Cost of land and development	$	32,130,000	Assuming 6% of CAPEX.
Fuel connection costs	$	N/A	
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	25,000	Average annual cost over the design life.
Variable O&M Cost	$ / MWh (Net)	-	Included in the fixed component.
Total annual O&M Cost	$	7,875,000	Annual average cost over the design life.

4.3 Offshore wind

4.3.1 Overview

Offshore wind turbines are fundamentally the same as onshore wind turbines, however they have been designed to survive in the aggressive offshore environment and involve very different foundations.

Offshore wind developments can offer some advantages over onshore projects:

- Access to offshore wind resources which when compared to onshore resources are generally:
  - stronger
  - less turbulent
  - can have better temporal alignment with generic demand profiles (i.e. windier in the late afternoon than onshore)
- Reduced visual and noise pollution concerns, due to being out at sea
- An offshore development adjacent to a large demand centre (city) can avoid expensive overland transmission compared to some onshore projects
- Turbines are typically manufactured near cannels or ports and barged to site

A combination of the above factors permits the use of much larger wind turbines offshore which can improve project economics. Commonly cited challenges include:

- Proximity to onshore transmission infrastructure and associated costs
- Harsh conditions from marine operating environment

- Expensive operation and maintenance costs of offshore sites
- High balance of plant costs (foundations and electrical connections) which are the major cost for offshore sites where as for onshore projects the major costs are the turbines

It is also worth noting that development of an offshore project - *especially given the non-existent offshore wind market in Australia compared to Europe* - would be significantly more complicated and involved than an onshore project, which would impact project development timelines accordingly.

4.3.2 Typical options

Existing offshore wind turbines range in nameplate capacity from 3 MW to 9.5 MW, with correspondingly large rotor diameters but hub-heights in similar or slightly larger ranges than onshore equivalents. Aurecon notes however, that the market is trending towards much larger turbines (see section 4.3.3 below).

Offshore wind farms are typically larger in both turbine number and total output due to the following:

- Significant capital expenditure associated with the challenging nature of offshore construction and maintenance requires lager builds to drive down normalised capital and operational costs
- Reduced limitations arising from land parcel boundaries and associated complications

As such it is not uncommon to have offshore projects in development with 50-150 turbines and 400 MW+ capacity. Aurecon notes that globally there are multiple projects in the development pipeline with capacities in excess of 1,000 MW.

Contrary to the use of the term 'offshore' in the oil and gas industry, offshore wind turbines are currently limited to fjords, lakes and continental shelves with a depth upper limit of 50 – 60 m. Note that:

- Traditionally mounted wind turbines are mounted on a single monopile in water depths <30 m.
- More recently complex structures have been developed to reach deeper waters, including tripod style piled structures, which are suitable for depths of up to 60 – 80 m.

For depths over 60 – 80 m floating type structures have been used with a number or demonstration turbines installed or in planning. The first commercially operating wind farm using floating type structure, Hywind Scotland, was commissioned in late 2017[1] and so this is still considered to be in the early commercialisation stage.

4.3.3 Recent trends

In Europe the cost of offshore wind has been falling dramatically since 2015, from €4,360 / kW down to €2,450 / kW in 2018.[2] This reduction has been attributed to the following factors:

- Increased market efficiency through increased constructor competition and competitive auction processes for new projects
- Development of current generation of large turbines (6 – 10 MW)
- Increases in total installed capacity

Further investment efficiency gains are expected to be realised in the European market with the announcement of even larger turbines (such as Siemens Gamesa 14 MW, 222 m rotor diameter platform due for serial production in 2024).

It should be noted that these cost reductions have been realised off the back of a maturing European development and delivery market. Given that the current offshore development and delivery capability in Australia is virtually non-existent, Aurecon would recommend caution in assuming efficient translation of

[1] https://www.windpowerengineering.com/business-news-projects/worlds-first-floating-wind-farm-delivers-promising-results/
[2] David Weston, "Europe's offshore wind costs falling steeply", Wind Power Offshore, 11 February 2019 https://www.windpoweroffshore.com/article/1525362/europes-offshore-wind-costs-falling-steeply

European prices to Australian prices. Australian projects will need to factor in costs of shipping turbines and specialist installation equipment (for instance jack up cranes).

In Australia, there are no existing offshore wind projects, and only one which has secured a resource exploration licence (i.e. the Star of the South). As such, costs for offshore wind in Australia are expected to be closer to the international average, with increased costs for the first few market entrants.

4.3.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2020 given the above discussion on typical options and current trends.

Table 4-4 Configuration and performance

Item	Unit	Value	Comment
Configuration			
Technology / OEM		Vestas	
Make model		V164-9.5	
Unit size (nominal)	MW	9.5	Modern offshore turbines are very large compared to onshore variants.
Number of units		110	
Performance			
Total plant size (Gross)	MW	1,045	
Auxiliary power consumption	%	4%	Primarily includes electrical distribution losses from the turbines to the substation and typically included in the capacity factor build-up. Nominal allowance only. Dependant on distance from shore.
Total plant size (Net)	MW	1,003	
Seasonal Rating – Summer (Net)	MW	1,003	Derating occurs above 35°C.
Seasonal Rating – Not Summer (Net)	MW	1,003	
Annual Performance			
Average Planned Maintenance	Days / yr.	-	Included in EFOR below.
Equivalent forced outage rate	%	5%	Based on international benchmarks.
Effective annual capacity factor	%	45%	Based on international benchmarks.
Annual generation	MWh / yr.	3,953,826	Provided for reference.
Annual degradation over design life	%	0.1%	Assuming straight line degradation.

Table 4-5 Technical parameters and project timeline

Item	Unit	Value	Comment
Technical parameters			
Ramp up rate	MW/min	Resource dependent	
Ramp down rate	MW/min	Resource dependent	
Start-up time	Min	N/A	Always on. < 5 min after maintenance shutdown.
Min stable generation	% of installed capacity	Near 0	
Project timeline			
Time for development	Years	4 – 5	Typical for Europe.
First year assumed commercially viable for construction	Year	2020	
EPC programme	Years	5	For NTP to COD.
▪ Total lead time	Years	2	Time from NTP to first turbine on site.
▪ Construction time	Weeks	156	Time from first turbine on site to last turbine commissioned.
Economic life (design life)	Years	25	
Technical life (operational life)	Years	35	

4.3.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

Table 4-6 Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW	5,430	Based on US$3,800 / kW which was the 2019 global weighted-average installed costs for offshore wind[3].
Total EPC cost	$	5,674,350,000	
▪ Equipment cost	$	3,972,045,000	70% of EPC cost – typical.
▪ Installation cost	$	1,702,305,000	30% of EPC cost – typical.
Other costs			
Cost of land and development	$	113,487,000	Assuming 2% of CAPEX due to large project scale.
Fuel connection costs	$	N/A	

[3] IRENA (2020), Renewable Power Generation Costs in 2019, International Renewable Energy Agency, Abu Dhabi

Item	Unit	Value	Comment
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	157,680	Based on an indicative average of 25 Euro/MWh[4].
Variable O&M Cost	$ / MWh (Net)	-	Included in the fixed component.
Total annual O&M Cost	$	158,153,040	Annual average cost over the design life

4.4 Large-scale solar photovoltaic (PV)

4.4.1 Overview

Over the last decade, solar PV generation has emerged as a significant growth area globally. Improvements in solar PV technology and reduction in costs have led to the widespread uptake and increasing sizes of utility-scale solar PV systems.

In large-scale solar PV systems, several thousand solar PV modules are connected to an inverter, which converts the electricity generated from DC to AC. The outputs from each of the inverters in the solar farm are aggregated and exported to the network through the connection point.

The output of solar PV systems is highly dependent on the availability of solar resource. Generally, the solar resource in Australia improves as you move towards the north-west. As such, large-scale solar PV systems are typically constructed inland. They are usually located in close proximity to a major transmission line.

4.4.2 Typical options

At the utility-scale, solar PV plants typically fall into two categories: fixed-tilt or single-axis tracking. Other configurations such as dual-axis tracking, ground-mount, PEG, etc. may be used, but are uncommon and typically used for smaller installations. In fixed-tilt systems, panels are mounted on a static frame, which is generally tilted towards the north. In single-axis tracking systems, panels are mounted on a torque tube, which rotates around a north-south axis, allowing the panels to track the sun's movement from east to west throughout the day. Single-axis tracking systems have a higher capital cost than fixed-tilt systems. However, they generally have a lower LCOE, as they produce more energy throughout the day.

Panel (or module) design is another key area which affects overall plant capacity. Historically, mono-facial panels (i.e. generation on one side of the panel) have been implemented at solar farms. However, bi-facial panels, which also generate electricity on the rear of the panel, have become a viable option. In Australia most new solar farm projects being awarded are now using bi-facial panels.

4.4.3 Recent trends

The widespread deployment of solar PV systems globally has led to significant reduction in the cost of solar panels in recent years. Although the rate of solar panel cost reduction is slowing, investment in the sector is growing, with several large-scale (i.e. >200 MW) solar farms under development in Australia.

Solar farm sizes are also on the upward trend with some projects reaching financial close in 2020 being in the 200 to 400 MWac range. This relates primarily to their connection at higher grid voltages and hence larger installations being permitted.

Due to the relatively low cost of the solar PV modules, solar developers are increasingly installing more solar panel capacity than grid connection capacity (i.e. higher DC:AC ratio). Though some power generation is curtailed in the middle of the day, this allows a more consistent, flatter generation profile, with increased

[4] P.E. Morthorst, L. Kitzing, "Economics of building and operating offshore wind farms", Technical University of Denmark, Roskilde, 2016

generation in the early morning and late afternoon. More recently developers are also installing more inverter capacity than grid connection capacity to improve reactive power capabilities.

Single-axis tracking systems are becoming widely deployed, due to the increased energy capacity they offer over fixed-tilt systems in the early morning and late afternoon. This results in improved project economics.

Solar module capacities have been rising over recent years, with modules on utility-scale solar farms under construction typically around 400 W. Bi-facial panels are now offered as standard for utility projects, allowing greater power generation for the same overall footprint.

Many solar farms have experienced delays in the grid connection process. In order to meet power quality restrictions enforced under the Generator Performance Standards harmonic filters are generally required.

4.4.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2020, given the above discussion on typical options and current trends.

Table 4-7 Configuration and performance

Item	Unit	Value	Comment
Configuration			
Technology		Single Axis Tracking (SAT)	Based on recent trends.
Performance			
Plant DC Capacity	MW	240	
Plant AC Capacity	MW	200	
DC:AC Ratio		1.2	Typical range from 1.1 to 1.3
Auxiliary power consumption	%	2.9%	Primarily includes electrical distribution losses.
Total plant size (Net)	MW (AC)	194.2	
Seasonal Rating – Summer (Net)	MW (AC)	194.2	Degradation expected above 35°C. Expect approximately 10% de-rate at 50°C.
Seasonal Rating – Not Summer (Net)	MW (AC)	194.2	
Annual Performance			
Average Planned Maintenance	Days / yr.	-	Included in EFOR below.
Equivalent forced outage rate (EFOR)	%	1.50%	Based on 98.5% O&M availability.
Effective annual capacity factor	%	29%	AC basis, Highly dependent on location. Number based on a system installed in regional NSW.
Annual generation	MWh / yr.	493,345.7	Calculated from capacity factor above.
Annual degradation over design life	%	0.4%	On AC basis.

Table 4-8 Technical parameters and project timeline

Item	Unit	Value	Comment
		Technical parameters	
Ramp Up Rate	MW/min	Resource dependant	
Ramp Down Rate	MW/min	Resource dependant	
Start-up time	Min	N/A	
Min Stable Generation	% of installed capacity	Near 0	
		Project timeline	
Time for development	Years	2 – 3	
First Year Assumed Commercially Viable for construction	Year	2020	
EPC Programme	Years	1.5	18 months for NTP to COD.
▪ Total lead time	Years	1	Time from NTP to first inverter on site.
▪ Construction time	Weeks	26	Time from first inverter on site to COD.
Economic Life (Design Life)	Years	25	Typical given current PV module warranties
Technical Life (Operational Life)	Years	30	+40 if piles don't corrode and the spare parts remain available.

4.4.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

Table 4-9 Cost estimates

Item	Unit	Value	Comment
		CAPEX – EPC cost	
Relative cost	$ / W (DC)	1.075	
Total EPC cost	$	258,000,000	
▪ Equipment cost	$	180,600,000	60% of EPC cost – typical.
▪ Installation cost	$	77,400,000	40% of EPC cost – typical.
		Other costs	
Cost of land and development	$	15,480,000	Assuming 6% of CAPEX.
Fuel connection costs	$	N/A	
		OPEX – Annual	
Fixed O&M Cost	$ / MW (Net)	16,990	
Variable O&M Cost	$ / MWh (Net)	-	Included in the fixed component.
Total annual O&M Cost	$	3,398,000	Annual average cost over the design life

4.5 Concentrated solar thermal

4.5.1 Overview

Concentrated solar thermal technology in power generation applications generally refers to using mirrors to collect solar energy over a wide area and then concentrating the reflected energy onto a central receiver. The energy is then captured by a thermal fluid which is cycled through the receiver and either stored or used directly for power generation.

There are four primary types of concentrated solar thermal power plants available in the current market. These include:

- Solar Tower – Solar tower technologies use a ground-based field of sun-tracking mirrors or heliostats to focus sunlight onto a receiver mounted on top of a central tower. A heat transfer fluid is heated in the receiver, which is then used to generate steam. This steam is used in a conventional steam turbine generator to produce electricity. The heliostats use two-axis tracking systems to follow the sun.
- Parabolic Trough Collectors – Parabolic Trough systems consist of parabolic, trough-shaped solar collectors which concentrate the sun rays onto a tubular heat receiver placed at the focal line of the solar collector. A single-axis tracking system is used to orient both solar collectors and heat receivers toward the sun.
- Linear Fresnel Collectors – This technology uses long flat, or slightly curved, mirrors placed at different angles. These move independently on a single axis, to concentrate the sunlight on either side of a fixed receiver. The fixed receivers are mounted above the mirrors on towers.
- Parabolic Dish – This technology consists of a parabolic dish-shaped concentrator that reflects the solar direct radiation on to a receiver placed at the focal point of the dish. The dish-shaped concentrators are mounted on structures with two-axis tracking systems that follow the sun. The collected heat is used directly by a heat engine mounted on the receiver. Typical heat engine cycles deployed are Stirling or Brayton cycle (micro-turbine).

Parabolic trough collectors are by far the most mature technology and account for the largest number of installations globally. Solar tower projects are currently transitioning from pilot plants to commercial pants, with a number of large-scale solar tower commercial plants under construction or operation globally. Linear Fresnel and Parabolic dish systems are still in pilot or demonstration phase.

The key advantage of concentrated solar thermal, in comparison to solar PV and wind technologies, is its ability to incorporate thermal energy storage. This increases its capacity factor and could provide an option for dispatchable renewable power.

Solar thermal plants are however capital intensive, with cost drivers including storage volumes, the solar multiple, and the DNI of the location.

The O&M requirements of solar thermal plants are lower in comparison to fossil fuel plants however still significant, much of which relates to fixed labour costs. Key O&M costs include replacement of receiver elements and mirrors due to breakage, cost of field mirror cleaning (including water consumption), and plant insurance. O&M costs for the steam cycle and BOP (i.e. steam turbine, cooling system, electrical systems, etc) are similar to traditional thermal plant O&M costs.

4.5.2 Typical options

As mentioned above, the key differentiation of the concentrated solar thermal technologies as against solar PV or wind is the ability to integrate thermal energy storage. Although inclusion of thermal energy storage increases the installed cost of the plant, current trends show thermal energy storage is being included on most projects under construction and all projects under development[5].

[5] https://solarpaces.nrel.gov/by-status

Typical plant configuration under development are split between parabolic trough and solar tower with thermal storage. Utility-scale plants currently under development globally range from 50 MW to 395 MW with 4.5 hrs to 16 hrs storage[5].

Due to the nature of the solar tower technology, through concentrating the solar energy to a single focal point, this technology can produce the highest temperatures and hence offers improved steam cycle efficiencies over the parabolic trough alternatives and well as reduced thermal storage requirements.

4.5.3 Recent trends

Solar thermal capacity grew five-fold globally between 2009 and 2019 on the back of incentive schemes in key markets like Spain and the USA. Currently an estimated 6.3 GW of concentrated solar thermal projects have been installed globally[6]. As mentioned above, the trend is to have thermal storage integrated with the solar thermal plant. Molten salt is the current preferred heat transfer fluid for solar tower technology, while mineral oils continue to be preferred for parabolic trough technology. However, the use of molten salt is also increasing with parabolic troughs. Use of molten salt results in increased steam cycle efficiencies in comparison to mineral oils based on their ability to enable higher steam temperature generation.

Plant capacity factors have been increasing over time to above 50% with larger thermal storage capacities of over 8 hour storage.

In Australia, there is currently no utility-scale concentrated solar thermal project in commercial operation. The following utility-scale solar thermal projects have been previously proposed:

- Aurora Solar Energy Project – 150 MW solar tower with 8 hours molten salt energy storage. This was proposed by SolarReserve to be built in Port Augusta, South Australia (SA). The project entered into a power purchase agreement with the South Australia Government in 2017, but that agreement was terminated in early 2019 following the inability to achieve financial close.
- Vast Solar – Vast Solar is currently developing a 50 MW hybrid solar plant in Mt Isa which includes a 50 MW solar tower plant with 14 hours thermal energy storage[7]. The project is in development stage and follows Vast Solar's 1.1 MW Pilot Project in NSW.

Given the lack of projects in Australia, there is very little information on the cost of solar thermal projects for the region.

4.5.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2020, given the above discussion on typical options and current trends.

Table 4-10 Configuration and performance

Item	Unit	Value	Comment
Configuration			
Technology		Solar Tower with Thermal Energy Storage	Based on typical options, recent trends and more specifically the latest proposed CSP projects mentioned in Australia in Section 4.5.3.
Power block		1 x Steam Turbine, dry cooling system	

[6] IRENA (2020), Renewable Power Generation Costs in 2019, International Renewable Energy Agency, Abu Dhabi
[7] https://www.pv-magazine-australia.com/2020/07/21/vast-solar-eyes-600-million-solar-hybrid-plant-for-mount-isa/

Item	Unit	Value	Comment
Capacity	MW	150	Based on typical options, recent trends, and more specifically the latest commercial CSP project mentioned in Australia in Section 4.5.3, 150 MW with 8 hours thermal energy storage is selected.
Power cycle efficiency	%	41.2	Typical
Heat transfer fluid		Molten salt	Molten salt is the preferred heat transfer fluid for solar tower technology,
Solar Multiple		2.4	Ratio between solar receiver thermal size vs power block thermal size,
Storage	Hours	8	As mentioned in Section 4.5.2 almost all recent projects have a thermal energy storage component. 8 hours was chosen as typical and is also the value for the 150 MW Aurora plant.
Storage type		2 tank direct	
Storage description		Molten salt	
Performance			
Total plant size (Gross)	MW	150	25°C, 110 metres, 60%RH
Auxiliary power consumption	%	10%	
Total plant size (Net)	MW	135	25°C, 110 metres, 60%RH
Seasonal Rating – Summer (Net)	MW	135	
Seasonal Rating – Not Summer (Net)	MW	135	
Annual Performance			
Average Planned Maintenance	Days / yr.	7	Based on published figures[8].
Equivalent forced outage rate	%	3%	Based on published figures[8].
Effective annual capacity factor	%	50%	Based on published figures[9].
Annual generation	MWh / yr.	768,690	Provided for reference.
Annual degradation over design life	%	0.2%	Typical for subcritical steam cycle.

Table 4-11 Technical parameters and project timeline

Item	Unit	Value	Comment
Technical parameters			
Ramp Up Rate	MW/min	6	Based on 4% of turbine maximum output.
Ramp Down Rate	MW/min	6	Based on 4% of turbine maximum output.
Start-up time	Minutes	Hot: 60 - 120 Warm: 120 - 270 Cold: 200 - 480	Standard operation.

[8] Alinta, 2015. Port Augusta Solar Thermal Generation Feasibility Study
[9] https://itpthermal.files.wordpress.com/2019/02/itpt_csproadmap3.0.pdf

Item	Unit	Value	Comment
Min Stable Generation	% of installed capacity	20%	
Project timeline			
Time for development	Years	2 – 3	includes pre/feasibility, design, approvals etc.
First Year Assumed Commercially Viable for construction	Year	2020	
Total EPC programme	Years	3.5	42 months from NTP to COD.
▪ Total Lead Time	Years	1.75	Time from NTP to main equipment on site.
▪ Construction time	Weeks	91	Time from main equipment on site to COD.
Economic Life (Design Life)	Years	25	
Technical Life (Operational Life)	Years	40	

4.5.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

Table 4-12 Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW (net)	7,125	Very little project information in Australia relating to build cost for CSP plant. Estimate based on ITP report T0036, “Informing a CSP Roadmap for Australia.” Table 20.[10] A 15% margin as been applied to account for the first of a kind nature of such a project in Australia as recommended in ITP report.
Total EPC cost	$	962,000,000	
▪ Equipment cost	$	721,500,000	75% of EPC cost – typical.
▪ Construction cost	$	240,500,000	25% of EPC cost – typical.
Other costs			
Cost of land and development	$	38,480,000	Assuming 4% of CAPEX.
Fuel connection costs		N/A	
OPEX – Annual			
Fixed O&M Cost	$ / MW	142,500	2% of CAPEX (based on ITP report T0036, “Informing a CSP Roadmap for Australia.”[10]).
Variable O&M Cost	$ / MWh	-	Included in fixed component.
Total annual O&M Cost	$	19,240,000	Annual average cost over the design life

[10] https://itpthermal.files.wordpress.com/2019/02/itpt_csproadmap3.0.pdf

4.6 Reciprocating engines

4.6.1 Overview

Reciprocating engines are a widespread and well-known technology used in a variety of applications. They are typically categorised by speed, stroke, configuration, and ignition/fuel type.

For power generation applications, reciprocating engines are coupled to a generator on the same base frame. For grid scale applications, centralised installations are typically installed in a common powerhouse structure in a multi-unit configuration with separate cooling systems, air intake/filter, exhaust silencer, stack structure, etc.

Reciprocating engines utilise synchronous generators, which provide high fault current contribution and support the NEM system strength.

4.6.2 Typical options

For power generation applications, there are two general classifications of reciprocating engine - medium-speed and high-speed. Medium-speed engines operate at 500 – 750 rpm and typically range in output from 4 to 18 MW. High-speed engines operate at 1,000 – 1,500 rpm with a typical output below 4 MW.

Additionally, there are three general fuel classes for reciprocating engines. These are gaseous fuel, liquid fuel, and dual fuel. Gaseous fuel engines - *also known as spark ignition engines* - operate on the thermodynamic Otto cycle, and typically use natural gas as the fuel source. Liquid fuel engines operate based on the thermodynamic Diesel cycle, and typically use no. 2 diesel (or heavy fuel oil) as the fuel source. Duel fuel engines can operate on either gaseous or liquid fuel, however always rely on a small consumption of diesel as a pilot fuel.

4.6.3 Recent trends

Traditionally multi-unit reciprocating engine installations on the NEM have consisted of high-speed spark-ignition engines, fuelled from coal seam methane or waste gas where the fuel gas is not suited to gas turbines. Installed capacities of these power stations are in the <50 MW range. Historically, capacity factors have been dependant on fuel gas availability.

Given the high degree of uncertainty around medium to long-term market conditions, large-scale medium-speed reciprocating engine power stations are increasing in popularity for firming applications. This is driven by their favourable fuel efficiency merits, and high degree of flexibility in start times and turn-down. This provides a strong business case for a wide range of capacity factors.

AGL's Barker Inlet Power Station is currently the only large-scale medium-speed reciprocating engine power station in operation on the NEM which commenced commercial operation in 2019. Pacific Energy has also entered into an agreement to supply a similar power station to supply power to FMG's Solomon mine in Western Australia's Pilbara region[11].

Other large-scale medium-speed installations for the NEM which are in the early planning phase include the following. These however are yet to be progressed further:

- AGL's Barker Inlet Power Station (Stage 2 – 210 MW)
- AGL's Newcastle Power Station (250 MW)
- APA's Dandenong Power Project (Stage 1 – 220 MW, Stage 2 – 110 MW)

Equipment pricing is not expected to decrease materially in the near future however the EPC cost could come down over time with increased popularity and competition. Marginal performance improvements are also expected over time with ongoing technology developments.

[11] https://www.australianmining.com.au/news/fortescue-hands-solomon-energy-contract-to-pacific-energy/

4.6.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2020 given the above discussion on typical options and current trends.

Table 4-13 Configuration and performance

Item	Unit	Value	Comment
Configuration			
Technology / OEM		Wartsila	MAN Diesel and Rolls Royce Bergen (RRB) also offer comparable engine options.
Make model		18V50DF	Including SCR for NO_x emission control
Unit size (nominal)	MW	17.6	ISO / nameplate rating at generator terminals.
Number of units		12	
Performance			
Total plant size (Gross)	MW	211.2	25°C, 110 metres, 60%RH
Auxiliary power consumption	%	1%	Excludes intermittent auxiliary loads. Overall average consumption could be closer to 2.5%.
Total plant size (Net)	MW	209.1	25°C, 110 metres, 60%RH
Seasonal Rating – Summer (Net)	MW	209.1	Derating does not typically occur until temperatures over 38 – 40°C.
Seasonal Rating – Not Summer (Net)	MW	209.1	
Heat rate at minimum operation	(GJ/MWh) LHV Net	10.259	25°C, 110 metres, 60%RH. Assuming minimum operation on gaseous fuel.
Heat rate at maximum operation	(GJ/MWh) LHV Net	7.940	25°C, 110 metres, 60%RH
Thermal Efficiency at MCR	%, LHV Net	45.3%	25°C, 110 metres, 60%RH
Heat rate at minimum operation	(GJ/MWh) HHV Net	11,356	25°C, 110 metres, 60%RH
Heat rate at maximum operation	(GJ/MWh) HHV Net	8,790	25°C, 110 metres, 60%RH
Thermal Efficiency at MCR	%, HHV Net	40.9%	25°C, 110 metres, 60%RH
Annual Performance			
Average Planned Maintenance	Days / yr.	2.7	Based on each engine only running 2190 hours per year.
Equivalent forced outage rate	%	2%	
Annual capacity factor	%	25%	Typical for current planned firming generation dispatch.
Annual generation	MWh / yr.	457,903	Provided for reference based on assumed capacity factor.
Annual degradation over design life - output	%	0%	Assuming straight line degradation.
Annual degradation over design life – heat rate	%	0.05%	Assuming straight line degradation.

Table 4-14 Technical parameters and project timeline

Item	Unit	Value	Comment
Technical parameters			
Ramp Up Rate	MW/min	36	Station ramp rate (all units) under standard operation. Based on OEM data.
Ramp Down Rate	MW/min	36	Station ramp rate (all units) under standard operation. Based on OEM data.
Start-up time	Min	10	Standard operation. Based on OEM data. 5-minute fast start is available.
Min Stable Generation	% of installed capacity	40%	Can turn down to 10% on diesel operation. Based on OEM data.
Project timeline			
Time for development	Years	2	includes pre/feasibility, design, approvals, procurement, etc.
First Year Assumed Commercially Viable for construction	Year	2020	
EPC programme	Years	2	For NTP to COD.
▪ Total Lead Time	Years	1	12 months typical to engines on site.
▪ Construction time	Weeks	52	12 months assumed from engines to site to COD.
Economic Life (Design Life)	Years	25	Can be capacity factor dependant
Technical Life (Operational Life)	Years	40	

4.6.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

Table 4-15 Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW	1,350	Net basis
Total EPC cost	$	282,285,000	
▪ Equipment cost	$	169,371,000	60% of EPC cost – typical.
▪ Installation cost	$	112,914,000	40% of EPC cost – typical.
Other costs			
Cost of land and development	$	25,400,000	Assuming 9% of CAPEX.
Fuel connection costs	$M	$20M +$1.5M/km	

Item	Unit	Value	Comment
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	24,100	Based on Aurecon internal database.
Variable O&M Cost	$ / MWh (Net)	7.6	Based on Aurecon internal database.
Total annual O&M Cost	$	8,520,000	Annual average cost over the design life

4.7 Open Cycle Gas Turbine

4.7.1 Overview

Gas turbines are one of the most widely-used power generation technologies today. The technology is well proven, and is used in both open-cycle gas turbine (OCGT) and combined-cycle gas turbine (CCGT) configurations. Gas turbines are classified into two main categories - aero-derivatives and industrial turbines. Both of these find application in the power generation industry, although for baseload applications, industrial gas turbines are preferred. Conversely, for peaking applications, the areo-derivative is more suitable primarily due to its faster start up time. Within the industrial turbines class, gas turbines are further classified as E - class, F - class and H (G/J) - class turbines. This classification depends on their development generation and the associated advancement in size and efficiencies. Gas turbines can operate on both natural gas and liquid fuel.

Gas turbines utilise synchronous generators, which provide relatively high fault current contribution in comparison to other technologies and support the NEM network strength.

Gas turbines currently provide high rotating inertia to the NEM. The rotating inertia is a valuable feature that increases the NEM frequency stability.

4.7.2 Typical options

An OCGT plant consists of a gas turbine connected to an electrical generator via a shaft. A gearbox may be required depending on the rpm of the gas turbine and the grid frequency. The number of gas turbines deployed in an OCGT plant will depend mainly on the output and redundancy levels required. OCGT plants are typically used to meet peak demand. Both industrial and aero-derivative gas turbines can be used for peaking applications. However, aero-derivatives have some advantages that make them more suitable for peaking applications, including;

- Better start-up time
- Operational flexibility i.e. quick ramp up and load change capability
- No penalties on O&M for number of starts

Irrespective of the benefits of aero-gas turbines, industrial gas turbines have also been widely used in OCGT mode. Traditionally, E or D class machines are used in OCGT mode. Rarely are F or H class machines used in OCGT applications. There are however instances where F class machines used in OCGT configuration in Australia (i.e. Mortlake Power Station (operational) and Tallawara B Power Station (planned)). Ultimately, the choice of gas turbine will depend on the many factors including the operating regimes of the plant, size, and more importantly, life cycle cost.

4.7.3 Recent trends

The increased installation of renewables has created opportunities for capacity firming solutions, that are currently largely met by gas-fired power generation options. OCGT and reciprocating engines compete in this market.

With the exception of the recent 250 MW emergency power generation plant in South Australia, which included deployment of nine TM2500 aero-derivative gas turbines last year, the most recent OCGT installation on the NEM was Mortlake Power Station in 2011. This included two 283 MW F-Class gas turbines supplied by Siemens.

Recent gas turbine power projects proposed for deployment on the NEM are summarised below:

- 250 MW peaking/mid-merit OCGT in Newcastle. This project is currently under development. It is likely that if an OCGT solution, it would be multiple units of aero-derivative machines.
- 300 to 350 MW OCGT plant in Tallawara. It is understood that the developer of this project has specified an F class machine for this project, possibly to enable future conversion of the unit to combined-cycle mode.
- 200 to 280 MW Mortlake Power Station Expansion. This project is currently in planning phase with multiple units aero-derivative units being considered.

Overall, demand for gas turbines has been declining globally over the past few years, with a corresponding drop in prices. Gas turbine prices (supply only, ex-Works) for utility-scale power generation are expected to have declined by 20% in 2020-2021 relative to those seen in 2017-2018[12].

Gas turbine OEMs are also looking at improving the hydrogen fuel capabilities of its offered models. Most gas turbines have the ability to operate with a percentage of hydrogen in the fuel mix. Some are quite low (i.e. 10 - 15%) whilst others can accept very high percentages of hydrogen in the fuel (95%+). Currently very few gas turbines can operate on 100% hydrogen (mainly limited to small industrial gas turbines). This is expected to change dramatically over the next few years.

4.7.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical projects (one considering smaller aero-derivative units and one considering a single large industrial unit). The hypothetical projects have been selected based on what is envisaged as a plausible project for installation in the NEM in 2020, given the above discussion on typical options and current trends.

Table 4-16 Configuration and performance

Item	Unit	Small GTs	Large GT	Comment
Configuration				
Technology		Aero-derivative	Industrial (F-Class)	
Make model		LM 6000 PF SPRINT	GE 9F.03	Small GTs − Typical model used in Australia Large GT − Smallest F-Class unit available
Unit size (nominal)	MW	49	265	ISO / nameplate rating, GT Pro.
Number of units		5	1	
Performance				
Total plant size (Gross)	MW	257.2	244.3	25°C, 110 metres, 60%RH

[12] Gas Turbine World 2019 GTW Handbook

Item	Unit	Small GTs	Large GT	Comment
Auxiliary power consumption	%	1.7%	1.1%	Small GTs − Includes fuel compressor auxiliary power consumption Large GT − Assumes no fuel compression required
Total plant size (Net)	MW	252.9	241.7	25°C, 110 metres, 60%RH
Seasonal Rating – Summer (Net)	MW	235.3	226.4	35°C, 110 metres, 60%RH
Seasonal Rating – Not Summer (Net)	MW	267.2	258.2	15°C, 110 metres, 60%RH
Heat rate at minimum operation	(GJ/MWh) LHV Net	11.458	14.735	25°C, 110 metres, 60%RH. Assuming a Minimum Stable Generation as stated below.
Heat rate at maximum operation	(GJ/MWh) LHV Net	9.049	9.766	25°C, 110 metres, 60%RH
Thermal Efficiency at MCR	%, LHV Net	39.79%	36.86%	25°C, 110 metres, 60%RH
Heat rate at minimum operation	(GJ/MWh) HHV Net	12.684	16.312	Assuming LHV to HHV conversion ratio of 1.107.
Heat rate at maximum operation	(GJ/MWh) HHV Net	10.017	10.811	Assuming LHV to HHV conversion ratio of 1.107.
Thermal Efficiency at MCR	%, HHV Net	35.94%	33.30%	Assuming LHV to HHV conversion ratio of 1.107.
Annual Performance				
Average Planned Maintenance	Days / yr.	3	5	Assuming maintenance on all units completed concurrently
Equivalent forced outage rate	%	2%	2%	
Effective annual capacity factor (year 0)	%	20%	20%	Average capacity factor for similar GTs on the NEM.
Annual generation	MWh / yr.	443,117	423,502	
Annual degradation over design life - output	%	0.24%	0.1%	Assuming straight line degradation.
Annual degradation over design life – heat rate	%	0.16%	0.06%	Assuming straight line degradation.

Table 4-17 Technical parameters and project timeline

Item	Unit	Small GTs	Large GT	Comment
Technical parameters				
Ramp Up Rate	MW/min	250	22	Station ramp rate (all units simultaneously) under standard operation. Based on OEM data.
Ramp Down Rate	MW/min	250	22	Station ramp rate (all units simultaneously) under standard operation. Based on OEM data.
Start-up time	Min	5	25	Standard operation.

Item	Unit	Small GTs	Large GT	Comment
Min Stable Generation	% of installed capacity	50%	35%	Assuming Dry Low NO_x burner technology.
Project timeline				
Time for development	Years	2	2	includes pre/feasibility, design, approvals etc.
First Year Assumed Commercially Viable for construction	Year	2020	2020	
EPC programme	Years	2	2	For NTP to COD.
▪ Total Lead Time	Years	0.75	1	Time from NTP to gas turbine on site.
▪ Construction time	Weeks	65	58	Time from gas turbine on site to COD.
Economic Life (Design Life)	Years	25	25	Can be capacity factor dependant
Technical Life (Operational Life)	Years	40	40	

4.7.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

Table 4-18 Cost estimates

Item	Unit	Small GTs	Large GT	Comment
CAPEX – EPC cost				
Relative cost	$ / kW	1,250	750	Net basis
Total EPC cost	$	316,151,000	181,294,000	
▪ Equipment cost	$	221,306,000	126,906,000	70% of EPC cost – typical.
▪ Construction cost	$	94,845,000	54,388,000	30% of EPC cost – typical.
Other costs				
Cost of land and development	$	28,454,000	16,316,000	Assuming 9% of CAPEX.
Fuel connection costs	$M	$20M +$1.5M/km	$20M +$1.5M/km	Gas Transport (i.e. pipes/lines)
Gas compressors	$	$2,500,000	Not required	
Gas storage[13]		Fixed: $0.015 - $0.025 /GJ/Day Variable (injection): $0.014 - $0.093 /GJ Variable (withdraw): $0.041 - $0.093 /GJ		Gas storage refers to underground storage facility in a depleted natural gas field. Costs based on published prises for Iona underground gas facility.
Hydrogen Gas Turbines				
Cost impact (hydrogen vs natural gas)		Same as above for natural gas		It is not believed that there will be a material cost impact for the different fuels (considering the gas turbine and direct auxiliaries only)

[13] ACCC (2020), "Gas inquiry 2017–2025 Interim report", www.ACCC.gov.au

Item	Unit	Small GTs	Large GT	Comment
Current %hydrogen capabilities		85%	65%	Figures stated are for the gas turbine models stated above[14]. Some gas turbines are currently available with 100%hydrogen capabilities (i.e. GE Frame 6B, GE10).
First Year Assumed Commercially Viable for construction		2020	2020	For %hydrogen capability stated above. 100% hydrogen capabilities for the models listed above may not be readily available until 2025.
OPEX – Annual				
Fixed O&M Cost	$ / MW (Net)	12,600	10,200	Based on Aurecon internal database.
Variable O&M Cost	$ / MWh (Net)	4.1	2.4	Based on Aurecon internal database.
Total annual O&M Cost	$	5,003,000	3,482,000	Annual average cost over the design life

4.8 Combined-Cycle Gas Turbines

4.8.1 Overview

Over time, combined-cycle gas turbines (CCGT) have become the technology of choice for gas-fired base load and intermediate load power generation. Typically, they consist of 1 or more gas turbine generator sets (gas turbines plus the electric generator), dedicated heat recovery steam generators (HRSG), and a steam turbine generator set (steam turbine plus the electric generator).

Advancements in gas turbine technology have led to significant increase in CCGT efficiencies, with some gas CCGT plants, namely those with H-class gas turbines, offering efficiencies of above 60%.

4.8.2 Typical options

Both aero and industrial gas turbines are widely used for CCGT applications. However, traditionally industrial gas turbines are preferred. Popular CCGT configuration options include:

- 1-on-1 (1 x 1) option consisting of 1 gas turbine generator set, a dedicated HRSG, and a steam turbine generator set.
- 2-on-1 (2 x 1) option consisting of 2 gas turbine generator sets, 2 dedicated HRSGs, and a steam turbine generator set.

Other options have also been used e.g. 3 x 1 configuration, but they are not a typical offering unless on islanded grids.

4.8.3 Recent trends

The focus of all major gas turbine manufactures over the last couple of decades was to improve the thermal efficiency of the gas turbines. In recent years, OEMs have announced record high efficiencies in CCGT mode (over 60%). This quest for higher efficiencies, which is founded on the traditional operation of baseload power

[14] Dr. J Goldmeer, "Gas Turbines: Hydrogen Capability and Experience", A presentation to the DOE Hydrogen and Fuel Cell Technology Advisory Committee, 9 March 2020

plants, is expected to continue. Although higher efficiencies are important, with the expansion of intermittent renewable energy in all major markets, the need for CCGT to be flexible and operate on a cyclic pattern is becoming equally important. As such, OEMs are now focusing on making improvements to CCGT plant start-up times and ability to ramp-up/down rapidly.

Globally, the gas turbine market has declined in the last couple of years and is expected to continue that downward trend[15]. In addition, there are indications that operators are seeing less value in centralised CCGT plants[16].

In Australia, there has not been a CCGT plant constructed in the NEM region since the commissioning of Tallawara in 2009. Recent CCGT projects constructed in Australia include:

- South Hedland Power Plant – 2 x 1 CCGT with LM 6000 PF SPRINT

Aurecon is not aware of any CCGT plant under development in Australia. The choice of gas turbine class would be influenced by the project size. The demand in the NEM may not require a CCGT plant based on advanced high-efficiency gas turbines i.e. F or H class gas turbines. Unless the market demand conditions are known, with very little recent CCGT activities in NEM, selecting the plant configuration or gas turbine class is difficult. However, if a CCGT is to be developed in Australia / the NEM, given the prevalent high gas price, high efficiency gas turbines (F or H class) would probably be the preferred gas turbine class, depending on the project size (MW), cost, etc. Based on this assessment, Aurecon has selected a CCGT with an F class gas turbine, as it is believed a H class would be too large based on current NEM market requirements. F class gas turbines range from 265 – 450 MW in open-cycle, and from 400 – 685 MW in 1+1 combined-cycle configuration (at ISO conditions). H Class gas turbines however range from 445 – 595 MW in open-cycle, and from 660 – 840 MW in 1+1 combined-cycle configuration (at ISO conditions).

4.8.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2020, given the above discussion on typical options and current trends.

Table 4-19 Configuration and performance

Item	Unit	CCGT without CCS	CCGT with CCS	Comment
Configuration				
Technology		CCGT	CCGT	With mechanical draft cooling tower.
Carbon capture and storage		No	Yes	85% capture efficiency assumed
Make model		GE 9F.03	GE 9F.03	Smallest model available selected.
Unit size (nominal)	MW	409		ISO / nameplate rating.
Number of units		1 GT + 1 ST	1 GT + 1 ST	HP pressure – 165 bar HP temperature – 582°C Reheat temperature – 567°C
Performance				
Total plant size (Gross)	MW	380	353.4	25°C, 110 metres, 60%RH
Auxiliary power consumption	%	2.5%	8.9%	
Total plant size (Net)	MW	371	321.9	25°C, 110 metres, 60%RH
Seasonal Rating – Summer (Net)	MW	348	303.6	35°C, 110 metres, 60%RH

[15] https://www.power-technology.com/comment/global-gas-turbines-market-decline-6-83bn-2022/
[16] https://www.ge.com/power/transform/article.transform.articles.2018.jan.evolution-of-combined-cycle-pe#

Item	Unit	CCGT without CCS	CCGT with CCS	Comment
Seasonal Rating – Not Summer (Net)	MW	389	336.9	15°C, 110 metres, 60%RH
Heat rate at minimum operation	(GJ/MWh) LHV Net	7.472	8.680	25°C, 110 metres, 60%RH. Assuming a Minimum Stable Generation of 46% on gaseous fuel.
Heat rate at maximum operation	(GJ/MWh) LHV Net	6.385	7.355	
Thermal Efficiency at MCR	%, LHV Net	56.4%	53.74%	
Heat rate at minimum operation	(GJ/MWh) HHV Net	8.271	9.608	Assuming LHV to HHV conversion of 1.107.
Heat rate at maximum operation	(GJ/MWh) HHV Net	7.068	8.142	Assuming LHV to HHV conversion of 1.107.
Thermal Efficiency at MCR	%, HHV Net	50.9%	44.2%	Assuming LHV to HHV conversion of 1.107.
Annual Performance				
Average Planned Maintenance	Days / yr.	12.8	12.8	Based on 3.5% average planned outage rate over a full maintenance cycle.
Equivalent forced outage rate	%	3.5%	3.5%	
Effective annual capacity factor	%	60%	60%	
Annual generation	MWh / yr.	1,949,135	1,691,906	Provided for reference.
Annual degradation over design life - output	%	0.20%	0.20%	Assuming straight line degradation.
Annual degradation over design life – heat rate	%	0.12%	0.12%	Assuming straight line degradation.

Table 4-20 Technical parameters and project timeline

Item	Unit	CCGT without CCS	CCGT with CCS	Comment
Technical parameters				
Ramp Up Rate	MW/min	22	22	Standard operation.
Ramp Down Rate	MW/min	22	22	Standard operation.
Start-up time	Min	Cold: 145 Warm: 115 Hot: 30	Cold: 145 Warm: 115 Hot: 30	Standard operation.
Min Stable Generation	% of installed capacity	46%	46%	Differs between GT models. Equates to 35% GT load.
Project timeline				
Time for development	Years	2	3	includes pre/feasibility, design, approvals etc.
First Year Assumed Commercially Viable for construction	Year	2020	2020	

Item	Unit	CCGT without CCS	CCGT with CCS	Comment
EPC programme	Years	2.5	2.5	For NTP to COD.
▪ Total Lead Time	Years	1	1	Time from NTP to gas turbine on site.
▪ Construction time	Weeks	78	78	Time from gas turbine on site to COD.
Economic Life (Design Life)	Years	25	25	
Technical Life (Operational Life)	Years	40	40	

4.8.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

Table 4-21 Cost estimates

Item	Unit	CCGT without CCS	CCGT with CCS	Comment
CAPEX – EPC cost				
Relative cost	$ / kW	1,500	3,803	Net basis
Total EPC cost	$	556,500,000	1,224,300,000	
▪ Equipment cost	$	389,550,000	389,550,000	70% of EPC cost (without CCS)
▪ Construction cost	$	166,950,000	166,950,000	30% of EPC cost (without CCS)
▪ Carbon Capture cost	$	N/A	667,800,000	Equipment and installation
Other costs				
Cost of land and development		50,085,000	110,187,000	Assuming 9% of CAPEX.
Fuel connection costs (CAPEX)	$M	$20M +$1.5M/km	$20M +$1.5M/km	
Gas compressors		Not required	Not required	
Gas storage[17]		Fixed: $0.015 - $0.025 /GJ/Day Variable (injection): $0.014 - $0.093 /GJ Variable (withdraw): $0.041 - $0.093 /GJ		Gas storage refers to underground storage facility in a depleted natural gas field. Costs based on published prises for Iona underground gas facility.
CO_2 storage cost	$/t$CO_2$	N/A	$12 - 25 /t$CO_2$	Based on Rubin, E.S., et al (2015)[18] and adjusted to match report basis
CO_2 transport	$/t$CO_2$/km	N/A	$0.1/t$CO_2$/km	Based on Rubin, E.S., et al (2015)[18] and adjusted to match report basis
OPEX – Annual				
Fixed O&M Cost	$ / MW (Net)	10,900	16,350	Based on Aurecon internal database.
Variable O&M Cost	$ / MWh (Net)	3.7	7.2	Based on Aurecon internal database.

[17] ACCC (2020), "Gas inquiry 2017–2025 Interim report", www.ACCC.gov.au
[18] Rubin, E.S., et al., The cost of CO2 capture and storage. Int. J. Greenhouse Gas Control (2015), http://dx.doi.org/10.1016/j.ijggc.2015.05.018

Item	Unit	CCGT without CCS	CCGT with CCS	Comment
Total annual O&M Cost	$	11,255,700	17,470,170	Annual average cost over the design life

4.9 Advanced Ultra Supercritical Pulverised Coal

4.9.1 Overview

Coal fired power plants are currently the dominant source of electricity generation in Australia, providing 68.4% of electricity generation for the NEM in 2019/20[19]. In the NEM there are approximately 48 coal fired units installed across 16 power stations in QLD, NSW and VIC. The unit sizes range from 280 MW to 750 MW and use a range of coal types from low grade brown coal through to export grade black coal.

Coal fired (thermal) power plants operate by burning coal in a large industrial boiler to generate high pressure, high temperature steam. High pressure steam from the boiler is passed through the steam turbine generator where the steam is expanded to produce electricity. This process is based on the thermodynamic Rankine cycle.

Coal fired power plants are typically classified as sub critical and super critical (more recently ultra-super critical and advanced ultra-supercritical) plants depending on the steam temperature and pressure. Over time advancements in the construction materials have permitted higher steam pressures and temperatures leading to increased plant efficiencies and overall unit sizes.

4.9.2 Typical options

The coal fired power stations installed on the NEM utilise either subcritical or supercritical pulverised coal (PC) technology which is an established, well proven technology used for power generation throughout the world for many decades.

The latest supercritical coal fired units installed in Australia can produce supercritical steam conditions in the order of 24 MPa and 566°C and typically used with unit sizes above 400 MW. Internationally, more recent coal fired units have been installed with ever increasing steam temperature and pressure conditions. Current OEMs are offering supercritical units in line with the following:

- Ultra-supercritical, with main steam conditions in the order of 27 MPa and 600°C
- Advanced ultra-supercritical, with main steam conditions in the order of 33 MPa and 660°C

Ultra-supercritical coal fired units are typically installed with capacities of 1,000 MW each. An advanced ultra-supercritical power station with the above main steam conditions is yet to be constructed however are currently being offered by a number of OEMs.

4.9.3 Recent trends

The latest coal fired power station to be installed in Australia was Kogan Creek Power Station in Queensland which was commissioned in 2007. Since then there has been limited focus on further coal fired development in Australia until necessitated by existing coal fired unit retirement. More recently, alternative technologies have become more prevalent with a focus on adopting non-coal technologies for replacing lost capacity due to coal fired plant closures.

Internationally, particularly in Asia, there has been extensive development of new large coal fired power stations to provide for the growing demand for electricity. These plants are now commonly being installed

[19] https://www.aemo.com.au/-/media/Files/Electricity/NEM/National-Electricity-Market-Fact-Sheet.pdf

utilising ultra-supercritical steam conditions which offer improved plant efficiencies and reduced whole of life costs.

In Australia the only coal fired development in progress is understood to be the Collinsville coal fired power station proposed by Shine Energy. This project is in the early feasibility stage.

4.9.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2020, given the above discussion on typical options and current trends.

Table 4-22 Configuration and performance

Item	Unit	AUSC without CCS	AUSC with CCS	Comment
Configuration				
Technology		AUSC	AUSC	With natural draft cooling tower.
Carbon capture and storage		No	Yes	90% capture efficiency assumed. SCR and FGD included with CCS option.
Make model		Western OEM	Western OEM	Western includes Japanese or Korean OEMs
Unit size (nominal)	MW	1,000	1,000	ISO / nameplate rating.
Number of units		1	1	
Steam Pressures (Main / Reheat)	MPa	33 / 6.1	33 / 6.1	
Steam Temperatures (Main / Reheat)	°C	650 / 670	650 / 670	
Condenser pressure	kPa abs	6	6	
Performance				
Total plant size (Gross)	MW	1,000	1,000	25°C, 110 metres, 60%RH Standard size offered by OEMs. Impact of unit size on NEM not assessed.
Auxiliary power consumption	%	4%	17%	Assumes steam driven Boiler Feed Pump, natural draft cooling tower. Excludes intermittent station loads.
Total plant size (Net)	MW	940.3	827.0	25°C, 110 metres, 60%RH
Seasonal Rating – Summer (Net)	MW	939.5	811.9	35°C, 110 metres, 60%RH
Seasonal Rating – Not Summer (Net)	MW	966.0	832.3	15°C, 110 metres, 60%RH
Heat rate at minimum operation	(GJ/MWh) HHV Net	10.323	14.591	25°C, 110 metres, 60%RH.
Heat rate at maximum operation	(GJ/MWh) HHV Net	8.470	11.887	25°C, 110 metres, 60%RH.
Thermal Efficiency at MCR	%, HHV Net	42.5%	30.28%	25°C, 110 metres, 60%RH.

Item	Unit	AUSC without CCS	AUSC with CCS	Comment
Annual Performance				
Average Planned Maintenance	Days / yr.	10.5	10.5	Based on 14-day minor outage every 2 years and 28-day major outage every 4 years.
Equivalent forced outage rate	%	4%	4%	Indicative
Effective annual capacity factor	%	93%	93%	
Annual generation	MWh / yr.	7,780,194	6,737,404	Provided for reference.
Annual degradation over design life - output	%	0	0	Assuming straight line degradation.
Annual degradation over design life – heat rate	%	0.2%	0.2%	Assuming straight line degradation.

Table 4-23 Technical parameters and project timeline

Item	Unit	AUSC without CCS	AUSC with CCS	Comment
Technical parameters				
Ramp Up Rate	MW/min	30	30	Based on 3%/min standard operation
Ramp Down Rate	MW/min	30	30	Based on 3%/min standard operation
Start-up time	Min	Cold: 444 Warm: 264 Hot: 60	Cold: 444 Warm: 264 Hot: 60	Standard operation.
Min Stable Generation	% of installed capacity	30%	30%	Without oil support.
Project timeline				
Time for development	Years	3	3	includes pre/feasibility, design, approvals etc. (assuming no delay in development approvals)
First Year Assumed Commercially Viable for construction	Year	2020	2020	
EPC programme	Years	4	4	For NTP to COD.
▪ Total Lead Time	Years	2	2	Time from NTP to steam turbine on site.
▪ Construction time	Weeks	104	104	Time from steam turbine on site to COD.
Economic Life (Design Life)	Years	30	30	
Technical Life (Operational Life)	Years	50	50	

4.9.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

Table 4-24 Cost estimates

Item	Unit	AUSC without CCS	AUSC with CCS	Comment
CAPEX – EPC cost				
Relative cost	$ / kW	3,750	7,500	
Total EPC cost	$	3,600,000,000	6,300,000,000	
■ Equipment cost	$	1,440,000,000	1,440,000,000	40% of EPC cost (without CCS)
■ Construction cost	$	2,160,000,000	2,160,000,000	60% of EPC cost (without CCS)
■ Carbon Capture cost	$	N/A	2,700,000,000	Equipment and installation
Other costs				
Cost of land and development	$	720,000,000	1,260,000,000	Assuming 20% of CAPEX.
Fuel connection costs	$/km	2,000,000/km	2,000,000/km	Assuming single track rail line fuel supply arrangement in the order of 50 to 100km in length.
CO_2 storage cost	$/tCO_2$	N/A	$12 - 25 /tCO_2$	Based on Rubin, E.S., et al (2015)[20] and adjusted to match report basis
CO_2 transport	$/tCO_2/km$	N/A	$0.1/tCO_2/km$	Based on Rubin, E.S., et al (2015)[20] and adjusted to match report basis
OPEX – Annual				
Fixed O&M Cost	$ / MW (Net)	53,200	77,800	AEMO costs and technical parameter review, 2018
Variable O&M Cost	$ / MWh (Net)	4.21	7.95	AEMO costs and technical parameter review, 2018
Total annual O&M Cost	$	83,560,000	119,279,331	Annual average cost over the design life

4.10 Biomass

4.10.1 Overview

The use of biomass for electricity generation can take many different forms and cover a variety of technologies, some well proven and others still in the pilot phase. Broadly speaking biomass is considered to cover any organic matter or biological material that can be considered available on a renewable basis. This includes materials derived from animals and/or plants as well as waste streams from municipal or industrial sources.

4.10.2 Typical options

Producing electricity from biomass can be completed via the following process:

- Incineration: This involves the combustion of solid biomass in a steam generation boiler, typically grate or circulating fluidised bed (CFB) type. The steam is then used in a traditional steam turbine to generate

[20] Rubin, E.S., et al., The cost of CO2 capture and storage. Int. J. Greenhouse Gas Control (2015), http://dx.doi.org/10.1016/j.ijggc.2015.05.018

electricity. The solid biomass can typically be; forestry products (i.e. wood chips, sawdust, etc), harvest residues (i.e. sugar cane, bagasse, etc), municipal solid waste, or refuse-derived fuel (RDF).

- Anaerobic digestion: This is a biological process where biomass is feed into a reactor where microorganisms assist in the decomposition process. The off gas that is produced, called biogas, is a mixture of methane and carbon dioxide which can be combusted, with some clean up, in either a reciprocating engine or gas turbine to produce electricity.
- Gasification: This is a thermochemical process that transforms any carbon-based biomass into a gas by creating a chemical reaction without burning the material. This reaction combines those carbon-based materials with small amounts of air or oxygen to produce primarily a mixture of carbon monoxide and hydrogen. Additional treatment is required to remove any pollutants and or impurities. The gas produced is called "synthesis gas" or "syn gas". This gas is the consumed in either a reciprocating engine or gas turbine to produce electricity
- Biofuels: This is the process of refining liquid fuels from renewable biomass such as ethanol and biodiesel. Although possible to use in power generation, liquid biofuels are most commonly used in the transport industry.

4.10.3 Recent trends

In Australia the most common form of power generation from biomass is incineration / combustion in subcritical steam boilers. The biomass used as the primary feedstock is typically a bi product from the forestry industry such as wood waste from sawmills or harvest residues such as bagasse from the sugar cane industry. More recently municipal solid waste and RDF feedstocks are also being considered with two plants now operational in WA and a number considered in the NEM.

Currently the feedstocks used in power generation are bi products from other industries. This generally has the advantage of a low-cost fuel source however the quantities available are limited by the primary harvesting or manufacturing process. Harvesting a feedstock for the sole purpose of power generation has not yet been implemented for a project on the NEM.

Biomass power plants using incineration or combustion technologies are typically deployed with unit sizes in the range of 20 to 40 MW. Higher plant sizes are typical not viable due to the limitations in available feedstock within a practical transport distance from the plant.

4.10.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2020 given the above discussion on typical options and current trends.

Table 4-25 Configuration and performance

Item	Unit	Value	Comment
Configuration			
Technology		Sub-critical boiler	With mechanical draft cooling tower.
Fuel source		Woodchips	
Make model		Western OEM	
Unit size (nominal)	MW	30	
Number of units		1	
Steam Pressure	MPa	7	
Steam Temperature	°C	470	
Condenser pressure	kPa abs	7.5	

Item	Unit	Value	Comment
Performance			
Total plant size (Gross)	MW	30	25°C, 110 metres, 60%RH
Auxiliary power consumption	%	8.3%	
Total plant size (Net)	MW	27.5	25°C, 110 metres, 60%RH
Seasonal Rating – Summer (Net)	MW	26.8	35°C, 110 metres, 60%RH
Seasonal Rating – Not Summer (Net)	MW	28.0	15°C, 110 metres, 60%RH
Heat rate at minimum operation	(GJ/MWh) HHV Net	15.933	25°C, 110 metres, 60%RH
Heat rate at maximum operation	(GJ/MWh) HHV Net	12.596	25°C, 110 metres, 60%RH
Thermal Efficiency at MCR	%, HHV Net	28.58%	25°C, 110 metres, 60%RH
Annual Performance			
Average Planned Maintenance	Days / yr.	22.8	
Equivalent forced outage rate	%	4%	
Annual capacity factor	%	89.8%	
Annual generation	MWh / yr.	216,208	Provided for reference based on assumed capacity factor.
Annual degradation over design life - output	%	0	Assuming straight line degradation.
Annual degradation over design life – heat rate	%	0.2%	Assuming straight line degradation.

Table 4-26 Technical parameters and project timeline

Item	Unit	Value	Comment
Technical parameters			
Ramp Up Rate	MW/min	1.2	Based on 3%/min standard operation
Ramp Down Rate	MW/min	1.2	Based on 3%/min standard operation
Start-up time	Min	Cold: 420 Warm: 120 Hot: 60	Standard operation.
Min Stable Generation	% of installed capacity	40%	Without oil support
Project timeline			
Time for development	Years	3	includes pre/feasibility, design, approvals, procurement, etc.
First Year Assumed Commercially Viable for construction	Year	2020	
EPC programme	Years	3	For NTP to COD.

Item	Unit	Value	Comment
▪ Total Lead Time	Years	1.75	Time from NTP to steam turbine on site.
▪ Construction time	Weeks	65	Time from steam turbine on site to COD.
Economic Life (Design Life)	Years	30	
Technical Life (Operational Life)	Years	50	

4.10.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

Table 4-27 Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW	7,000	Net basis
Total EPC cost	$	192,500,000	
▪ Equipment cost	$	77,000,000	40% of EPC cost – typical.
▪ Installation cost	$	115,500,000	60% of EPC cost – typical.
Other costs			
Cost of land and development	$	38,500,000	Assuming 20% of CAPEX.
Fuel connection costs	$M	N/A	Typically, given the scale of the plant, the feedstock would be delivered by road. As such the fuel transport costs become an ongoing OPEX cost.
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	131,600	AEMO costs and technical parameter review, 2018
Variable O&M Cost	$ / MWh (Net)	8.42	AEMO costs and technical parameter review, 2018
Total annual O&M Cost	$	5,439,469	

4.11 Electrolysers

4.11.1 Overview

The interest in hydrogen as part of the energy mix has increased dramatically in the past few years, as hydrogen offers a potential pathway to a low carbon future when produced using renewable power generation sources. Once produced, hydrogen can then be stored and/or transported either via pipeline, for domestic use, or ocean-going vessel for international export. Currently hydrogen is seen as a potential zero emission transport fuel, alternative fuel for iron and steel production, or for potential blending with natural gas in existing gas pipelines.

4.11.2 Typical options

Hydrogen is typically produced either by electrolysis of water, or by a thermochemical process which uses fossil fuels. Currently, approximately 96% of hydrogen production is by thermochemical process, although renewable hydrogen – *using water electrolysis and electricity generated by renewable sources* - is gaining momentum.

For this report, the focus is the production of hydrogen through a zero-emission electrolysis process. For this there are two primary technology options, being:

- Alkaline electrolysis – a mature electrolyser technology based on submersed electrodes in liquid alkaline electrolyte solution. Has long been used in the production of chlorine where hydrogen is produced as a by-product.
- Proton Exchange Membrane (PEM) – a less mature electrolyser technology categorised by its solid polymer electrolyte which separate the electrodes.

Designs vary from supplier to supplier but in most cases electrolysers are made up from a number of individual cells or stacks of cells manifolded together for a combined output. The individual cell stacks range in size up to approximately 5MW, with over all units currently being marketed up to approximately 20MW. Beyond this plants would install multiples of standard units with a degrees of utility sharing being applied.

4.11.3 Recent trends

The debate continues between the relative benefits of the various technologies and indeed from individual supplier to supplier. Where large industrial scale applications are being proposed the capex cost advantage of low pressure systems are being maximised and this can be seen from both PEM and alkaline suppliers.

Several examples of grid services applications are being published globally. The 10 MW PEM electrolyser Shell are installing at their Rhineland Refinery[21] will provide grid stabilisation services and recent findings from E.ON show alkaline technology has potential for this also[22].

Globally the trend in electrolysis is to the larger scale with more and more projects being developed in the triple figure MW range.

For hydrogen production, PEM electrolysers have been growing in popularity relative to more traditional alkaline technology for the smaller scale projects. This is primarily due to the improved dynamic operation of the PEM-based technology, with improved responsiveness, and improved current densities. PEM also produces hydrogen at around 30 bar compared to atmospheric pressures achieved with Alkaline electrolysers which reduces the need for costly first stage compression.

Most proposed and planned hydrogen production projects in Australia are in the 10 – 100 MW range using either PEM or Alkaline electrolysers, most notably including:

- Neoen Hydrogen Superhub Project in Crystal Brook, South Australia – 50 MW electrolyser
- Hydrogen Supply Chain Demonstration Project, South Australia – 20 MW (4 x 5 MW units) electrolyser
- Stanwell Hydrogen Electrolysis Deployment Project – 10 MW electrolyser
- Yarra Pilbara Renewable Ammonia Feasibility Study – multi-megawatt scale electrolyser
- Feasibility Study for a Green Hydrogen and Ammonia Project (Queensland Nitrates) – 30 MW electrolyser

It is important to note that the choice made between PEM and Alkaline electrolyser technologies is project specific with both having a role to play in the current market. Generally speaking Alkaline electrolyser technology is lower in cost compared to PEM with both undergoing dramatic reductions in cost (on a $/MW basis) as projects and manufacturing is being increased in scale. Although PEM is seen as more responsive

[21] https://www.fch.europa.eu/news/launch-refhyne-worlds-largest-electrolysis-plant-rhineland-refinery

[22] https://www.eon.com/en/about-us/media/press-release/2020/2020-06-30-e-on-and-thyssenkrupp-bring-hydrogen-production-on-the-electricity-market.html

and/or flexible, recent improvements have been made with the latest Alkaline electrolyses which has closed the gap in some areas and offer improved benefits in others (such as reduced water consumption).

4.11.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM, given the above discussion on typical options and current trends.

Table 4-28 Electrolyser configuration and performance

Item	Unit	PEM	Alkaline	Comment
Configuration				
Technology		Proton Exchange Membrane	Alkaline	
Unit size (nominal)	MW	10	10	Selected based on the upper range of currently available single stack sizes.
Number of units		1	1	
Performance				
Total plant size	MW	10	10	
Auxiliary power consumption	%	100%	100%	
Seasonal Rating – Summer (Net)	MW	10	10	Derating not expected at 35°C. Will be dependent on cooling system design.
Seasonal Rating – Not Summer (Net)	MW	10	10	
Efficiency	%	65.7%	71.7%	HHV basis
Hydrogen Production	kWh/kg	60	55	Typical (whole package), excluding additional compression (shown below)
Output pressure	bar	~ 30 bar	Atmospheric	Siemens SILYZER 300 product (which is PEM) is atmospheric
Additional compression power	kW	235	985	Additional power required to compress hydrogen to 100bar
Life cycle design	hrs	80,000	80,000	Represents expected life of cells only. Cells can be refurbished or replaced within the unit to achieve plant life of around 25 years
Raw water consumption	L/kgH_2	20 - 30	15 - 20	Typical un-treated water consumption volumes, for hydrogen production only (excludes any cooling water make-up). Quantity of rejected water will vary according to original water quality. Typically PEM technology requires a high quality of water to enter the cells and as such more water is rejected in the purification step.

Item	Unit	PEM	Alkaline	Comment
Annual Performance				
Average Planned Maintenance	Days / yr.	15	15	Includes consideration for mid-life stack replacement on average annual basis.
Equivalent forced outage rate	%	3%	3%	
Annual degradation	%	1	1	Typical published value.

Table 4-29 Technical parameters and project timeline

Item	Unit	PEM	Alkaline	Comment
Technical parameters				
Ramp Up Rate	MW/min	105	60	PEM typically 10%/sec. Alkaline typically 5%/sec.
Ramp Down Rate	MW/min	105	60	PEM typically 10%/sec. Alkaline typically 5%/sec.
Start-up time	Min	Cold: 5 Warm: 0.5	Cold: 60 Warm: 1	Quoted start up time varies from vendor to vendor, however typically PEM technology advertises faster start-up particular in the cold start-up case
Min Stable Generation	% of installed capacity	10%	10%	Typical
Project timeline				
Time for development	Years	2	2	Includes pre/feasibility, design, approvals etc.
First Year Assumed Commercially Viable for construction	Year	2020	2020	Although theoretically viable at this size in 2020 it is questionable that a hydrogen offtake agreement could be secured for this volume and at a price that would result in a commercially viable project.
EPC programme	Years	2	2	For NTP to COD.
▪ Total Lead Time	Years	1.5	1.5	Time from NTP to main equipment on site.
▪ Construction time	Weeks	26	26	Time from main equipment on site to COD.
Economic Life (Design Life)	Years	10	10	Assumed time to membrane replacement based on 91.3% capacity factor. If powered purely by renewables capacity factors will be much lower.
Technical Life (Operational Life)	Years	25	25	Typical value.

4.11.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above, however the costs are representative of the technology type rather than the specific vendors and models as per above.

Table 4-30 Cost estimates

Item	Unit	PEM	Alkaline	Comment
CAPEX – EPC cost				
Relative cost	$ / kW	3,250	2,330	Full turn-key supply
Total EPC cost	$	32,500,000	23,300,000	
▪ Equipment cost	$	22,750,000	16,310,000	70% of EPC cost – typical.
▪ Construction cost	$	9,750,000	6,990,000	30% of EPC cost – typical.
Other costs				
Cost of land and development	$	2,600,000	1,864,000	Based on 8% of CAPEX.
Fuel connection costs	$	N/A	N/A	
Hydrogen compressor	$	2,200,000	5,200,000	Single 1 x 100% duty train
Hydrogen transport	$/km	$150,000/km	$150,000/km	DN50 buried pipeline (suitable for 1 x 10 MW unit)
Hydrogen storage	$/kg$H_2$	$2,350 /kg$H_2$	$2,350 /kg$H_2$	
OPEX – Annual				
Fixed O&M Cost	$ / MW (Net)	97,500	69,900	Based on 3% of CAPEX per annum. Note that this includes allowance for the 10 year overhaul. Excludes power consumption costs
Variable O&M Cost	$ / MWh (Net)	-		Included in fixed O&M component.
Total annual O&M Cost	$	975,000	699,000	Annual average cost over the design life. Excludes power and water consumption costs.

4.12 Hydrogen fuel cells

4.12.1 Overview

Hydrogen can be used for a variety of uses including natural gas blending and mobility applications. Fuel cells for stationary power generation are also being considered to provide a carbon emission free solution continuous electricity generation.

Currently only a small percentage of hydrogen-based projects involve fuel cells for stationary power generation applications and are currently limited to small off-grid installations supporting back-up power for homes, businesses, and hospitals.

4.12.2 Typical options

Below are some of the most commonly used fuel cells[23]:

- Proton Exchange Membrane Fuel Cell (PEMFC): PEMFCs use a polymer membrane for their electrolyte and a precious metal, typically platinum, for their catalyst. PEMFCs operate between 40% to 60% efficiency and are capable of handling large and sudden shifts in power output.
- Direct Methanol Fuel Cells (DMFCs): DMFCs also use a polymer membrane as an electrolyte and commonly a platinum catalyst as well. DMFCs draw hydrogen from liquid methanol instead of using hydrogen directly as a fuel.
- Alkaline Fuel Cell (AFC): AFCs use porous electrolytes saturated with an alkaline solution and have an alkaline membrane. AFCs have approximately 60% electrical efficiency.
- Phosphoric Acid Fuel Cell (PAFC): PAFCs use a liquid phosphoric acid and ceramic electrolyte and a platinum catalyst. They have similar efficiencies to those of PEMFCs. PAFCs are often seen in applications with a high energy demand, such as hospitals, schools, and manufacturing and processing centres.
- Solid Oxide Fuel Cell (SOFC): SOFCs operate at high temperatures and use a solid ceramic electrolyte instead of a liquid or membrane. SOFCs are used in large and small stationary power generation and small cogeneration facilities.

Stationery fuel cell stack sizes vary from <1 kW to 3 MW. Fuel cell installations can either be provided as standalone plants or installed in in combination with other power (e.g. Rooftop PV) or energy storage (e.g. Lithium battery) solutions.

4.12.3 Recent trends

For stationery fuel cells the uptake has been growing rapidly worldwide, with installed capacity reaching 1.6 GW in 2018. However, only a small portion (approximately 70 MW) is fuelled by hydrogen[24]. Some of the largest technology companies including Apple, Google, IBM, Verizon, AT&T, and Yahoo have all recently installed small scale (kW scale) stationery hydrogen fuel cells as a source of power for their operations. The world's largest fuel cell power plant commenced commercial operation in February 2019 in South Korea[25]. This 59 MW plant consists of 21 x 2.8 MW hydrogen fuel cells. However, hydrogen for this facility is produced from natural gas.

In Australia, stationary fuel cell plants that use hydrogen as fuel are generally small pilot-scale projects and/or installed in commercial buildings and data centres for both power and CHP applications, for example:

- Griffith University in Brisbane has a building which has been run with a 60 kW hydrogen fuel cell since 2013[26].

4.12.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM in 2020, given the above discussion on typical options and current trends.

Table 4-31 Fuel cell configuration and performance

Item	Unit	Value	Comment
Configuration			
Technology		PEM-FC	Technology offer for the demonstration plant in SA.

[23] http://www.fchea.org/fuelcells
[24] The Future of Hydrogen, Report prepared by the IEA for the G20, Japan, Seizing today's opportunities
[25] https://www.powermag.com/worlds-largest-fuel-cell-plant-opens-in-south-korea/
[26] https://new.gbca.org.au/showcase/projects/sir-samuel-griffith-centre/

Item	Unit	Value	Comment
Make model		Hydrogenics HyPM-XR120	Example.
Unit size (nominal)	MW	0.120	
Number of units		1	4 x XR30 modules.
Performance			
Total plant size (Gross)	MW	0.120	25°C, 110 metres, 60%RH
Auxiliary power consumption	%	10%	Assumption
Total plant size (Net)	MW	0.108	25°C, 110 metres, 60%RH
Seasonal Rating – Summer (Net)	MW	0.108	35°C, 110 metres, 60%RH
Seasonal Rating – Not Summer (Net)	MW	0.108	15°C, 110 metres, 60%RH
Heat rate at minimum operation	(GJ/MWh) HHV Net	14.180	Based on a fuel consumption of 0.08 kg/kWh (net)
Heat rate at maximum operation	(GJ/MWh) HHV Net	11.344	Based on a fuel consumption of 0.08 kg/kWh (net)
Thermal Efficiency at MCR	%, HHV Net	32%	25°C, 110 metres, 60%RH
Annual Performance			
Average Planned Maintenance	Days / yr.	-	Included in EFOR below.
Equivalent forced outage rate	%	2%	

Table 4-32 Technical parameters and project timeline

Item	Unit	Value	Comment
Technical parameters			
Ramp Up Rate	MW/min	2.1	Based on 0% to 100% in 7 secs as per OEM datasheet.[27]
Ramp Down Rate	MW/min	2.1	Based on 100% to 0% in 7 secs as per OEM datasheet.[27]
Start-up time	Min	Cold: 5 Warm: 0.5	Typical
Min Stable Generation	% of installed capacity	10%	Typical Continuous Minimum turndown
Project timeline			
Time for development	Years	< 1	includes pre/feasibility, design, approvals etc.
First Year Assumed Commercially Viable for construction	Year	2020	
EPC programme	Years	< 1	For NTP to COD.
▪ Total Lead Time	Years	0.75	Time from NTP to Fuel cell delivery to site.

[27] https://www.h2fc-fair.com/hm10/images/pdf/hydrogenics02.pdf

Item	Unit	Value	Comment
▪ Construction time	Weeks	13	Time from fuel cell on site to COD.
Economic Life (Design Life)	Years	8	Based on a capacity factor of 38% with a typical stack replacement frequency of 25,000 operating hours
Technical Life (Operational Life)	Years	20	

4.12.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

Table 4-33 Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW	7,000	Aurecon in-house database. Includes full turn-key supply for standalone installation including cooling systems and connection to electrical system at 11kV.
Total EPC cost	$	840,000	
▪ Equipment cost	$	672,000	80% of EPC cost – typical.
▪ Construction cost	$	168,000	20% of EPC cost – typical.
Other costs			
Cost of land and development		168,000	Assuming 20% of CAPEX due to small scale.
Fuel connection costs	$	Excluded	Pressure let-down equipment may be required depending on hydrogen supply pressure.
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	350,000	Based on 5% of CAPEX per year.[28]
Variable O&M Cost	$ / MWh (Net)	-	Included in the fixed O&M component.
Total annual O&M Cost	$	42,000	Annual average cost over the design life. Dependant of annual capacity factor. Excludes stack replacement.

4.13 Battery Energy Storage System (BESS)

4.13.1 Overview

A battery energy storage system (BESS) stores electricity from the network or collocated generation plant, for use as needed at a later point. The power is converted to low voltage in alternating current source, then converted to direct current source through four-quadrant inverters and then stored in batteries. The power can be regenerated back from the batteries to the high voltage AC network through the reverse path.

[28] Eichman J, Townsend A, Melaina M (2016), “Economic Assessment of Hydrogen Technologies Participating in California Electricity Markets”, National Renewable Energy Laboratory, NREL/TP-5400-65856

A BESS contains several primary components, including the battery system (with cells assembled into modules and racks), battery management system, bi-directional inverters, step-up transformer(s), plant control and monitoring system, HVAC / thermal management systems, and other balance of plant.

Approximately 10 to 20% of the energy supplied to the batteries during the charge operation is lost and not available when the battery discharge. These losses are mainly due to the BESS HVAC load and referred to as the round-trip efficiency losses.

4.13.2 Typical options

A BESS can be used for a wide range of network services, including energy market participation, load shifting, a range of market and non-market ancillary services (in particular FCAS services), and cost mitigation to avoid or reduce network upgrades, demand charges, fuel costs, and the FCAS 'causer pays' exposure of intermittent wind and solar generators. A BESS can also be used to protect the NEM interconnectors, with for example the Hornsdale Power Reserve BESS participating in the Special Integrated Protection Scheme (SIPS) of the SA-VIC Heywood interconnector. The modular nature of a BESS enables it to be sized in both power and energy to meet highly specific project requirements.

Batteries used for bulk energy shifting and arbitrage typically have greater than one hour of energy storage, whereas, batteries used primarily for network support services or renewable integration may have less than one hour of storage.

Lithium ion has become the dominant battery technology in recent years, primarily due to falling costs, developments in the range of cell chemistries for different applications, high power and energy density (small physical size), and high efficiency. Within the lithium ion battery class are a number of sub-categories of cell chemistries. Each of these has different performance, life, and cost characteristics which may be used for different purposes.

BESS units have a range of packaging approaches, including separate or combined battery and inverter enclosures, stand-alone buildings, or outdoor modular cabinet type arrangements.

4.13.3 Recent trends

Grid-connected batteries installed within the last couple of years range from residential systems, to the 150MW / 194MWh Hornsdale Power Reserve system. Generally, large-scale batteries have been installed with less than two hours energy storage. As battery prices continue to fall (circa -50% over last 3 years) and market price trends shift with increasing penetration of variable renewable energy, there may be some incentive to construct grid scale batteries with more storage. However, this has yet to be demonstrated.

Based on the AEMO 2020 Integrated System Plan (ISP) and other states specific projects such as the AEMO 2020 Victorian Government SIPS, the size of large BESS installation is likely to increase over the next few years, with projects possibly designed to provide energy storage in excess of 200-300 MW for an hour, to support the NEM system stability.

Battery energy storage systems have been installed by a range of companies, including generators, transmission and distribution operators, and C&I customers. Given the flexibility of operating regimes and modularity of systems, battery systems are being adopted to serve a wide range of challenges and customer bases.

Due to restrictions placed on generators in South Australia by the Office of the Technical Regulator, many generators are increasingly looking to install battery systems with their generation to meet Fast Frequency Response (FFR) requirements.

The BESS flexibility in controlling the power supply, with their four quadrant inverters, provides a range of capabilities that have not been yet deployed in large numbers in the NEM, but that have been proven as reliable in other systems. These features include synthetic inertia and Static Synchronous Compensator (STATCOM) type services.

As household batteries are becoming more common, aggregators are emerging, with the role of operating distributed residential battery systems under a virtual power plant regime. Virtual power plants may challenge grid-scale batteries in some markets. However, these have differing economics and technical capability when compared to larger systems.

Recent BESS installations on the NEM include:

- Hornsdale Power Reserve – 150 MW / 194 MWh
- Dalrymple North BESS – 30 MW / 12.2 MWh
- Gannawarra Solar ESS – 25 MW / 50 MWh
- Ballarat Station ESS – 30 MW / 30 MWh
- Lake Bonney BESS – 25 MW / 52 MWh

There are several other BESS installations being planned for the NEM in the over 100 MW class which are expected to be operational within the next 2 years (i.e. Wandoan BESS, AEMO SIPS BESS, etc). Most new BESS development currently require the support of funding or similar support mechanisms to achieve a financially viable project. This is expected to fall away in the near future with large scale BESS project supporting the transition to higher penetration of renewables.

Proponents of large-scale renewable plants (i.e solar and wind farms) are also increasingly interested in large BESS integration / collocation at the same grid connection point (i.e. Lake Bonney wind farm). For these collocated installations the BESS is typically connected at the MV bus (i.e. 33kV) and shares the same step-up transformer to grid voltage. There are also some development synergies associated with GPS studies and development approvals.

4.13.4 Selected hypothetical project

The following tables outline the technical parameters for the hypothetical project. The hypothetical project has been selected based on what is envisaged as a plausible project for installation in the NEM, given the above discussion on typical options and current trends.

Table 4-34 BESS configuration and performance

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
Configuration						
Technology		Li-ion				
Performance						
Power Capacity (gross)	MW	100				
Energy Capacity	MWh	100	200	400	800	
Auxiliary power consumption (operating)	kW	1,190	1,620	2,510	4,290	Indicative figures (highly variable, dependent on BESS arrangement, cooling systems etc.).
Auxiliary power consumption (standby)	kW	500	940	1,830	3,610	Based on Aurecon internal database of similarly sized projects, Indicative figures (highly dependent on BESS arrangement, cooling systems etc.).
Power Capacity (Net)	MW	98.8	98.3	97.5	95.7	
Seasonal Rating – Summer (Net)	MW	98.8	98.3	97.5	95.7	Dependent on inverter supplier. Potentially no de-rate, or up to approx. 4% at 35°C.
Seasonal Rating – Not Summer (Net)	MW	98.8	98.3	97.5	95.7	
Annual Performance						
Average Planned Maintenance	Days / yr.	-				Included in EFOR.
Equivalent forced outage rate	%	1.5 - 3%				Dependent on level of long-term service agreement, retention of strategic spares etc.
Annual number of cycles		365				Typical default assumption is one cycle per day, however this is highly dependent on functional requirements and operating strategy.
Annual degradation over design life	%	2.8%				70-80% capacity after 10 years (based on one cycle per day). Degradation dependent on factors such as energy throughput, charge / discharge rates, depth of discharge, and resting state of charge.

Table 4-35 Technical parameters and project timeline

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
Technical parameters						
Ramp Up Rate	MW/min	10,000+				0 to 100% rated MW capacity within less than a second (150ms typical however for specific applications higher performance is available).
Ramp Down Rate	MW/min	10,000+				As above.

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
Round trip efficiency	%	84%	84%	85%	83%	Energy retention, at the point of connection (including auxiliaries), for a full cycle of charge and discharge
▪ Charge efficiency	%	92%	92%	92.5%	91.5%	Assumed to be half of the round-trip efficiency.
▪ Discharge efficiency	%	92%	92%	92.5%	91.5%	Assumed to be half of the round-trip efficiency.
Allowable maximum state of charge (SOC)	%	100%				Typically defined in terms of 'useable state of charge (SOC).' Operation permissible throughout full range of useable SOC. Note that there is an increased degradation impact to hold at high or low SOC. Important to note that some suppliers quote battery capacity inclusive of unusable capacity/ for these suppliers a max and min SOC of 90% and 10% respectively could be expected.
Allowable minimum state of charge (SOC)	%	0%				As above.
Maximum number of cycles		3,650				Typical warranty conditions based on one cycle per day for 10 years. Extended warranties or additional (unwarranted) life may also be possible. Design life number of cycle varies from 500 to 5,000 depending of the application and technology
Depth of Discharge	%	100%				100% in terms of typically defined 'useable state of charge.'
Project timeline						
Time for development	Years	1-2				
First Year Assumed Commercially Viable for construction	Year	2020				
Total EPC Programme	Years	0.75	1	1.2	1.4	For NTP to COD.
▪ Total lead time	Years	0.6	0.8	0.9	1.1	
▪ Construction time	Weeks	8	8	12	20	Significantly dependent on BESS arrangement.
Economic Life (Design Life)	Years	10				Nominally based on initial 10-year battery life however highly dependent on the technology and function supplied
Technical Life (Operational Life)	Years	20				Extended project life with battery upgrades.

4.13.5 Cost estimate

The following table provides the cost parameters for the hypothetical project as outlined above.

Table 4-36 Cost estimates

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
CAPEX – EPC cost for 100 MW BESS (with dedicated grid connection)						
Relative cost - Power component	$ / kW	370	370	370	370	Indicative cost for power related components
Relative cost - Energy component	$ / kWh	370	300	300	300	Indicative cost for energy related components
Total EPC cost	$M	74	97	157	277	Based on Aurecon internal database of similarly sized projects and scaled for additional energy storage capacity.
▪ Equipment cost	$M	61.4	80.5	130.3	229.9	As above.
▪ Installation cost	$M	12.6	16.5	26.7	47.1	As above.
CAPEX – EPC cost for 100 MW BESS (co-located with large renewable installation)						
Relative cost - Power component	$ / kW	300	300	300	300	Indicative cost for power related components
Relative cost - Energy component	$ / kWh	370	300	300	300	Indicative cost for energy related components
Total EPC cost	$M	67	90	150	270	Based on an assumed $7,000,000 savings in transformer and associated grid voltage equipment (i.e. cost worn by co-located project)
▪ Equipment cost	$M	55.6	74.7	124.5	224.1	As above.
▪ Installation cost	$M	11.4	15.3	25.5	45.9	As above.
Other costs						
Cost of land and development	$	7,000,000				
OPEX – Annual						
Fixed O&M Cost	$/MW (Net)	4,833	9,717	19,239	39,314	Provided on $/MW basis for input into GenCost template only.
Variable O&M Cost	$/MWh (Net)	-	-	-	-	BESS long term service agreements not typically based on fixed / variable.
Total annual O&M Cost	$	483,000	971,000	1,923,000	3,931,000	Highly variable between OEMs. Annual average cost over the design life Does not include battery replacement cost at end of Economic Life (Design Life)

5 Capacity Factors for New Solar and Wind Generators

As part of this exercise, AEMO has requested a forecast of benchmark new entrant capacity factors for the following technologies:

- Solar PV - single axis tracking
- Wind - onshore
- Wind - offshore

The intention is to provide an indication of the likely future capacity factor improvements in a NEM context for long term forecast purposes.

It is important to note that capacity factors for wind and solar PV are highly variable and dependent on the resource availability at the project location. Generally speaking the achieved capacity factor for a specific project location has been a result of optimising the cost of energy and not technological advancement. Achieving notably higher capacity factors with wind turbines, and to a lesser extent Solar PV, is possible today however with inefficient increases in capital cost. As the capital cost of wind farms (on a $/MW basis) and solar PV modules continues to come down project capacity factors are likely to continue to increase in the near term. In the medium to long term continued improvements in capacity factors for NEM based projects are increasingly unlikely.

For this analysis NEM based projects has been assumed in line with the hypothetical projects represented throughout this report. The projected capacity factor trends are shown in the figure below with the raw data in the subsequent table which are intended to indicate NEM fleet wide trends over time taking into account the range of factors as discussed above.

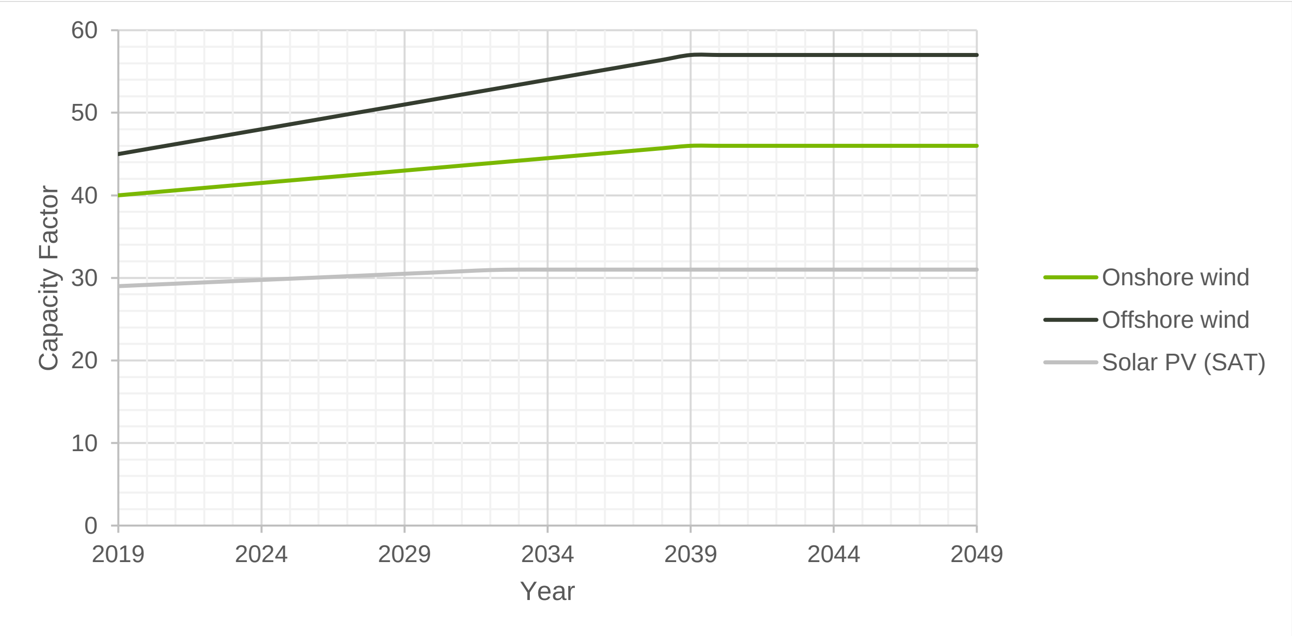

Figure 5-1 Capacity Factors for new solar and wind generators over time – NEM wide trend

For SAT solar PV, capacity factors currently achievable with single axis tracking are approaching the theoretical maximum for current site with the technology currently available. Fleet wide averages are expected to increase only marginally. It has been assumed that over time further minor improvements in the tracking algorithms, module spacings, and reduction in system losses will result in a marginal increase in capacity factors. Further increases in the typical DC:AC ratio is also likely with falling module prices pushing up capacity factors. Further improvements in capacity factors beyond the next 10 to 15 years may be unlikely to be commercially attractive if the rate of cost reduction of modules and other components decreases.

For wind (both onshore and offshore) project capacity factors are continually seeing improvement with developments in blade design, tip to tail ratio, and bearing efficiency as well as increases in hub heights. For the purpose of this exercise continued improvements along the current long term global weighted average trend has been assumed as reported by IRENA, 2019[29]. Wind turbine sizes, which have a large impact on capacity factor, are likely to reach physical size limits due to construction and transport constraints as well as potential approval restrictions. This will potentially put downward pressure on capacity factors for wind. On a NEM fleet wide basis however it is anticipated that the existing low capacity factor sites will reach the end of their design life and undergo repowering. This will effectively increase the fleet average capacity factor.

For offshore wind, continued theoretical improvement along the same global weighted average trend has been assumed in the absence of any data for an Australian context. Theoretical Australian offshore resource potential has not been reviewed or examined as part of this exercise.

Table 5-1 Capacity Factors for new solar and wind generators

Year	Solar PV - Single axis tracking	Wind - Onshore	Wind - Offshore
2019-20	29.0	40.0	45.0
2020-21	29.2	40.3	45.6
2021-22	29.3	40.6	46.2
2022-23	29.5	40.9	46.8
2023-24	29.6	41.2	47.4
2024-25	29.8	41.5	48.0
2025-26	29.9	41.8	48.6
2026-27	30.1	42.1	49.2
2027-28	30.2	42.4	49.8
2028-29	30.4	42.7	50.4
2029-30	30.5	43.0	51.0
2030-31	30.7	43.3	51.6
2031-32	30.8	43.6	52.2
2032-33	31.0	43.9	52.8
2033-34	31.0	44.2	53.4
2034-35	31.0	44.5	54.0
2035-36	31.0	44.8	54.6
2036-37	31.0	45.1	55.2
2037-38	31.0	45.4	55.8
2038-39	31.0	45.7	56.4
2039-40	31.0	46.0	57.0
2040-41	31.0	46.0	57.0
2041-42	31.0	46.0	57.0
2042-43	31.0	46.0	57.0
2043-44	31.0	46.0	57.0

[29] IRENA (2019), Renewable Power Generation Costs in 2018, International Renewable Energy Agency, Abu Dhabi

Year	Solar PV - Single axis tracking	Wind - Onshore	Wind - Offshore
2044-45	31.0	46.0	57.0
2045-46	31.0	46.0	57.0
2046-47	31.0	46.0	57.0
2047-48	31.0	46.0	57.0
2048-49	31.0	46.0	57.0
2049-50	31.0	46.0	57.0

Appendices

Appendix A
AEMO GenCost 2020 Excel Spreadsheets

Technical parameters and operating costs for new technologies

General Details

Technology	Assumed unit size (MW) (Gross) @ 25°C, 110 metres, 60%RH	Seasonal Ratings: Not summer (MW) (Net)	Generation Type	Fuel Type	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs
Advanced Ultra Supercritical PC - Black coal with CCS	1,000.0	811.9	Thermal	Black Coal	1,440,000,000	$2,000,000/km	1,260,000,000	2,160,000,000
Advanced Ultra Supercritical PC - Black coal without CCS	1,000.0	939.5	Thermal	Black Coal	1,440,000,000	$2,000,000/km	720,000,000	2,160,000,000
CCGT - With CCS	353.4	303.6	Thermal	Natural Gas	389,550,000	$20M +$1.5M/km	110,187,000	166,950,000
CCGT - Without CCS	380.0	348.0	Thermal	Natural Gas	389,550,000	$20M +$1.5M/km	50,085,000	166,950,000
OCGT - Without CCS, Small unit size	257.2	235.3	Thermal	Natural Gas	221,306,000	$20M +$1.5M/km	28,454,000	94,845,000
OCGT - Without CCS, Large unit size	244.3	226.4	Thermal	Natural Gas	126,906,000	$20M +$1.5M/km	16,316,000	54,388,000
Reciprocating Internal Combustion Engines	211.2	209.1	Thermal	Natural Gas/Diesel	169,371,000	$20M +$1.5M/km	25,400,000	112,914,000
Large Scale Battery Storage (1hr)	100.0	98.8	Storage	N/A	61,400,000	N/A	7,000,000	12,600,000
Large Scale Battery Storage (2hr)	100.0	98.3	Storage	N/A	80,500,000	N/A	7,000,000	16,500,000
Large Scale Battery Storage (4hr)	100.0	97.5	Storage	N/A	130,300,000	N/A	7,000,000	26,700,000
Large Scale Battery Storage (8hr)	100.0	95.7	Storage	N/A	229,900,000	N/A	7,000,000	47,100,000
Large Scale Battery Storage (1hr) for hybrid generation	100.0	98.8	Storage	N/A	55,600,000	N/A	7,000,000	11,400,000
Large Scale Battery Storage (2hr) for hybrid generation	100.0	98.3	Storage	N/A	74,700,000	N/A	7,000,000	15,300,000
Large Scale Battery Storage (4hr) for hybrid generation	100.0	97.5	Storage	N/A	124,500,000	N/A	7,000,000	25,500,000
Large Scale Battery Storage (8hr) for hybrid generation	100.0	95.7	Storage	N/A	224,100,000	N/A	7,000,000	45,900,000
Electrolysers - Proton Exchange Membrane	10.0	10.0	Storage	N/A	22,750,000	N/A	2,600,000	9,750,000
Electrolysers - Alkaline	10.0	10.0	Storage	N/A	16,310,000	N/A	1,864,000	6,990,000
Fuel cells	0.1	0.1	Storage	N/A	672,000	Excluded	168,000	168,000
Solar PV - Single axis tracking	200.0	194.2	Renewable	N/A	180,600,000	N/A	15,480,000	77,400,000
Solar Thermal Central Receiver with storage (8hr)	150.0	135.0	Renewable	N/A	721,500,000	N/A	38,480,000	240,500,000
Wind - onshore	315.0	291.0	Renewable	N/A	374,850,000	N/A	32,130,000	160,650,000
Wind - offshore	1,045.0	1,003.0	Renewable	N/A	3,972,045,000	N/A	113,487,000	1,702,305,000
Biomass - Electricity only	30.0	26.8	Thermal	Woodchip	77,000,000	N/A	38,500,000	115,500,000

Technology	Carbon Capture equipment and installation costs (separate from the generation plant)	Carbon storage costs (separate from capture costs) ($/t CO2)	Carbon transportation costs ($/t CO2)	Disposal costs	Gas Compressors	Gas Storages[1]	Hydrogen Gas Turbines	Hydrogen Compressors	Hydrogen Transport (pipes/lines)	Hydrogen Storages
Advanced Ultra Supercritical PC - Black coal with CCS	2,700,000,000.0	$12 - $25	$0.1/tCO2/km							
Advanced Ultra Supercritical PC - Black coal without CCS	N/A									
CCGT - With CCS	667,800,000.0	$12 - $25	$0.1/tCO2/km							
CCGT - Without CCS	N/A									
OCGT - Without CCS, Small unit size	N/A				2,500,000	Fixed: $0.015 - $0.025 /GJ/Day Variable (injection): $0.014 - $0.093 /GJ Variable (withdraw): $0.041 - $0.093 /GJ	Same as for natural gas			
OCGT - Without CCS, Large unit size	N/A						Same as for natural gas			
Reciprocating Internal Combustion Engines	N/A									
Large Scale Battery Storage (1hr)	N/A									
Large Scale Battery Storage (2hr)	N/A									
Large Scale Battery Storage (4hr)	N/A									
Large Scale Battery Storage (8hr)	N/A									
Large Scale Battery Storage (1hr) for hybrid generation	N/A									
Large Scale Battery Storage (2hr) for hybrid generation	N/A									
Large Scale Battery Storage (4hr) for hybrid generation	N/A									
Large Scale Battery Storage (8hr) for hybrid generation	N/A									
Electrolysers - Proton Exchange Membrane	N/A							2,200,000	$150,000/km	$2,350 /kgH2
Electrolysers - Alkaline	N/A							5,200,000	$150,000/km	$2,350 /kgH2
Fuel cells	N/A									
Solar PV - Single axis tracking	N/A									
Solar Thermal Central Receiver with storage (8hr)	N/A									
Wind - onshore	N/A									
Wind - offshore	N/A									
Biomass - Electricity only	N/A									

Note:

1. Gas storage refers to underground storage facility in a depleted natural gas field.

Technology	Cost of energy storage ($/MWh) - Gross Basis	Cost of storage capacity ($/MW) - Gross Basis
Large Scale Battery Storage (1hr)	370,000	370,000
Large Scale Battery Storage (2hr)	300,000	370,000
Large Scale Battery Storage (4hr)	300,000	370,000
Large Scale Battery Storage (8hr)	300,000	370,000
Large Scale Battery Storage (1hr) for hybrid generation	370,000	300,000
Large Scale Battery Storage (2hr) for hybrid generation	300,000	300,000
Large Scale Battery Storage (4hr) for hybrid generation	300,000	300,000
Large Scale Battery Storage (8hr) for hybrid generation	300,000	300,000
Electrolysers - Proton Exchange Membrane		
Electrolysers - Alkaline		
Fuel cells		

Technical parameters and operating costs for new technologies

General Details

Technology	Generation Type	Fuel Type	First Year Assumed Commercially Viable for construction	Assumed unit size (MW) (Gross) @ 25°C, 110 metres, 60%RH	Seasonal Ratings: Summer (MW) (Net)	Seasonal Ratings: Not summer (MW) (Net)	Design Life (yrs)	Operational Life (yrs)	Lead time for development (yrs)	Construction time (weeks)
Advanced Ultra Supercritical PC - Black coal with CCS	Thermal	Black Coal	2020	1,000.0	811.9	832.3	30	50	3	104
Advanced Ultra Supercritical PC - Black coal without CCS	Thermal	Black Coal	2020	1,000.0	939.5	966.0	30	50	3	104
CCGT - With CCS	Thermal	Natural Gas	2020	353.4	303.6	336.9	25	40	3	78
CCGT - Without CCS	Thermal	Natural Gas	2020	380.0	348.0	389.0	25	40	2	78
OCGT - Without CCS, Small unit size	Thermal	Natural Gas	2020	257.2	235.3	267.2	25	40	2	65
OCGT - Without CCS, Large unit size	Thermal	Natural Gas	2020	244.3	226.4	258.2	25	40	2	58
Reciprocating Internal Combustion Engines	Thermal	Natural Gas/Diesel	2020	211.2	209.1	209.1	25	40	2	52
Large Scale Battery Storage (1hr)	Storage	N/A	2020	100.0	98.8	98.8	10	20	1 - 2	8
Large Scale Battery Storage (2hr)	Storage	N/A	2020	100.0	98.3	98.3	10	20	1 - 2	8
Large Scale Battery Storage (4hr)	Storage	N/A	2020	100.0	97.5	97.5	10	20	1 - 2	12
Large Scale Battery Storage (8hr)	Storage	N/A	2020	100.0	95.7	95.7	10	20	1 - 2	20
Large Scale Battery Storage (1hr) for hybrid generation	Storage	N/A	2020	100.0	98.8	98.8	10	20	1 - 2	8
Large Scale Battery Storage (2hr) for hybrid generation	Storage	N/A	2020	100.0	98.3	98.3	10	20	1 - 2	8
Large Scale Battery Storage (4hr) for hybrid generation	Storage	N/A	2020	100.0	97.5	97.5	10	20	1 - 2	12
Large Scale Battery Storage (8hr) for hybrid generation	Storage	N/A	2020	100.0	95.7	95.7	10	20	1 - 2	20
Electrolysers - Proton Exchange Membrane	Storage	N/A	2020	10.0	10.0	10.0	10	25	2	26.0
Electrolysers - Alkaline	Storage	N/A	2020	10.0	10.0	10.0	10	25	2	26
Fuel cells	Storage	N/A	2020	0.1	0.1	0.1	8	20	< 1	13
Solar PV - Single axis tracking	Renewable	N/A	2020	200.0	194.2	194.2	25	30	2 – 3	26
Solar Thermal Central Receiver with storage (8hr)	Renewable	N/A	2020	150.0	135.0	135.0	25	40	2 – 3	91
Wind - onshore	Renewable	N/A	2020	315.0	291.0	305.6	20 - 25	20 - 30	3 – 5	52
Wind - offshore	Renewable	N/A	2020	1,045.0	1,003.0	1,003.0	25	35	4 – 5	156
Biomass - Electricity only	Renewable	Woodchip	2020	30.0	26.8	28.0	30	50	3	65

Technical parameters and operating costs for new technologies

General Details

Technology	Total Lead Time (years)	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)
Advanced Ultra Supercritical PC - Black coal with CCS	2.00	30.0%	17.0%		included in EFOR			included in EFOR		
Advanced Ultra Supercritical PC - Black coal without CCS	2.00	30.0%	4.0%		included in EFOR			included in EFOR		
CCGT - With CCS	1.00	46.0%	8.9%		included in EFOR			included in EFOR		
CCGT - Without CCS	1.00	46.0%	2.5%		included in EFOR			included in EFOR		
OCGT - Without CCS, Small unit size	0.75	50.0%	1.7%		included in EFOR			included in EFOR		
OCGT - Without CCS, Large unit size	1.00	35.0%	1.1%		included in EFOR			included in EFOR		
Reciprocating Internal Combustion Engines	1.00	40.0%	1.0%		included in EFOR			included in EFOR		
Large Scale Battery Storage (1hr)	0.60	Near 0	1.2%		included in EFOR			included in EFOR		
Large Scale Battery Storage (2hr)	0.80	Near 0	1.6%		included in EFOR			included in EFOR		
Large Scale Battery Storage (4hr)	0.90	Near 0	2.5%		included in EFOR			included in EFOR		
Large Scale Battery Storage (8hr)	1.10	Near 0	4.3%		included in EFOR			included in EFOR		
Large Scale Battery Storage (1hr) for hybrid generation	0.60	Near 0	1.2%	-	included in EFOR	-	-	included in EFOR	-	-
Large Scale Battery Storage (2hr) for hybrid generation	0.80	Near 0	1.6%	-	included in EFOR	-	-	included in EFOR	-	-
Large Scale Battery Storage (4hr) for hybrid generation	0.90	Near 0	2.5%	-	included in EFOR	-	-	included in EFOR	-	-
Large Scale Battery Storage (8hr) for hybrid generation	1.10	Near 0	4.3%	-	included in EFOR	-	-	included in EFOR	-	-
Electrolysers - Proton Exchange Membrane	1.50	10.0%	100.0%		included in EFOR			included in EFOR		
Electrolysers - Alkaline	1.50	10.0%	100.0%		included in EFOR			included in EFOR		
Fuel cells	0.75	10.0%	10.0%		included in EFOR			included in EFOR		
Solar PV - Single axis tracking	1.00	Near 0	2.9%		included in EFOR			included in EFOR		
Solar Thermal Central Receiver with storage (8hr)	1.75	20.0%	10.0%		included in EFOR			included in EFOR		
Wind - onshore	1.00	Near 0	3.0%		included in EFOR			included in EFOR		
Wind - offshore	2.00	Near 0	4.0%		included in EFOR			included in EFOR		
Biomass - Electricity only	1.75	40.0%	8.3%		#REF!			#REF!		

Technical parameters and operating costs for new technologies

General Details

Technology	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) HHV Net	Heat rate at maximum operation (GJ/MWh) HHV Net	Thermal Efficiency (%, HHV, Net) MCR	Maintenance Frequency (no of maintenance events per year)	Average Planned Maintenance (no of days/year)
Advanced Ultra Supercritical PC - Black coal with CCS		4.0%		1,800	1,800	14.591	11.887	30.28%		10.5
Advanced Ultra Supercritical PC - Black coal without CCS		4.0%		1,800	1,800	10.323	8.470	42.50%		10.5
CCGT - With CCS		3.5%		1,320	1,320	9.608	8.142	44.20%		12.8
CCGT - Without CCS		3.5%		1,320	1,320	8.271	7.068	50.90%		12.8
OCGT - Without CCS, Small unit size		2.0%		15,000	15,000	12.684	10.017	35.94%		3.0
OCGT - Without CCS, Large unit size		2.0%		1,320	1,320	16.312	10.811	33.30%		5.0
Reciprocating Internal Combustion Engines		2.0%		2,160	2,160	11,356.000	8,790.000	40.90%		2.7
Large Scale Battery Storage (1hr)		1.5 - 3%		10,000+	10,000+	N/A	N/A	N/A		-
Large Scale Battery Storage (2hr)		1.5 - 3%		10,000+	10,000+	N/A	N/A	N/A		-
Large Scale Battery Storage (4hr)		1.5 - 3%		10,000+	10,000+	N/A	N/A	N/A		-
Large Scale Battery Storage (8hr)		1.5 - 3%		10,000+	10,000+	N/A	N/A	N/A		-
Large Scale Battery Storage (1hr) for hybrid generation	-	1.5 - 3%	-	10,000+	10,000+	N/A	N/A	N/A	-	-
Large Scale Battery Storage (2hr) for hybrid generation	-	1.5 - 3%	-	10,000+	10,000+	N/A	N/A	N/A	-	-
Large Scale Battery Storage (4hr) for hybrid generation	-	1.5 - 3%	-	10,000+	10,000+	N/A	N/A	N/A	-	-
Large Scale Battery Storage (8hr) for hybrid generation	-	1.5 - 3%	-	10,000+	10,000+	N/A	N/A	N/A	-	-
Electrolysers - Proton Exchange Membrane		3.0%		105	105	N/A	N/A	65.70%		15.0
Electrolysers - Alkaline		3.0%		60	60	N/A	N/A	71.70%		15.0
Fuel cells		2.0%		2	2	14.180	11.344	32.00%		-
Solar PV - Single axis tracking		1.5%		Resource dependant	esource dependant	N/A	N/A	N/A		-
Solar Thermal Central Receiver with storage (8hr)		3.0%		6	6	N/A	N/A	N/A		7.0
Wind - onshore		3.0%		Resource dependent	esource dependent	N/A	N/A	N/A		-
Wind - offshore		5.0%		Resource dependant	esource dependant	N/A	N/A	N/A		-
Biomass - Electricity only		4.0%		72	72	15.933	12.596	28.58%		22.8

Technical parameters and operating costs for new technologies

General Details

Technology	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)	Fixed Operating Cost ($/MW Net/year)	Variable Op Cost ($/MWh Net)
Advanced Ultra Supercritical PC - Black coal with CCS									77,800	8.0
Advanced Ultra Supercritical PC - Black coal without CCS									53,200	4.2
CCGT - With CCS									16,350	7.2
CCGT - Without CCS									10,900	3.7
OCGT - Without CCS, Small unit size									12,600	4.1
OCGT - Without CCS, Large unit size									10,200	2.4
Reciprocating Internal Combustion Engines									24,100	7.6
Large Scale Battery Storage (1hr)			0.9	0.9	0%	100%	3,650.0	1.0	4,833	-
Large Scale Battery Storage (2hr)			0.9	0.9	0%	100%	3,650.0	1.0	9,717	-
Large Scale Battery Storage (4hr)			0.9	0.9	0%	100%	3,650.0	1.0	19,239	-
Large Scale Battery Storage (8hr)			0.9	0.9	0%	100%	3,650.0	1.0	39,314	-
Large Scale Battery Storage (1hr) for hybrid generation	-	-	0.9	0.9	0%	100%	3,650.0	1.0	4,833	-
Large Scale Battery Storage (2hr) for hybrid generation	-	-	0.9	0.9	0%	100%	3,650.0	1.0	9,717	-
Large Scale Battery Storage (4hr) for hybrid generation	-	-	0.9	0.9	0%	100%	3,650.0	1.0	19,239	-
Large Scale Battery Storage (8hr) for hybrid generation	-	-	0.9	0.9	0%	100%	3,650.0	1.0	39,314	-
Electrolysers - Proton Exchange Membrane									97,500	-
Electrolysers - Alkaline									69,900	-
Fuel cells									350,000	-
Solar PV - Single axis tracking									16,990	-
Solar Thermal Central Receiver with storage (8hr)									142,500	-
Wind - onshore									25,000	-
Wind - offshore									157,680	-
Biomass - Electricity only									131,600	8.4

Technical parameters and operating costs for new technologies

General Details

Technology	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 (Hr)	Warm Start-up Notification Time (Hr)	Hot Start-up Notification Time (Hr)	Cold Start-up Costs ($/MW as gen)	Warm Start-up Costs ($/MW as gen)	Hot Start-up Costs ($/MW as gen)	Combustion Emissions (kg CO2-e/GJ of fuel)	Fugitive Emissions (kg CO2-e/GJ of fuel)
Advanced Ultra Supercritical PC - Black coal with CCS										
Advanced Ultra Supercritical PC - Black coal without CCS										
CCGT - With CCS										
CCGT - Without CCS										
OCGT - Without CCS, Small unit size										
OCGT - Without CCS, Large unit size										
Reciprocating Internal Combustion Engines										
Large Scale Battery Storage (1hr)										
Large Scale Battery Storage (2hr)										
Large Scale Battery Storage (4hr)										
Large Scale Battery Storage (8hr)										
Large Scale Battery Storage (1hr) for hybrid generation	-	-	-	-	-	-	-	-	-	-
Large Scale Battery Storage (2hr) for hybrid generation	-	-	-	-	-	-	-	-	-	-
Large Scale Battery Storage (4hr) for hybrid generation	-	-	-	-	-	-	-	-	-	-
Large Scale Battery Storage (8hr) for hybrid generation	-	-	-	-	-	-	-	-	-	-
Electrolysers - Proton Exchange Membrane										
Electrolysers - Alkaline										
Fuel cells										
Solar PV - Single axis tracking										
Solar Thermal Central Receiver with storage (8hr)										
Wind - onshore										
Wind - offshore										
Biomass - Electricity only										

Capacity Factors for new solar and wind generators

Approximate future capacity factors of renewable resources.

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
Solar PV - Single axis tracking	29.0	29.2	29.3	29.5	29.6	29.8	29.9	30.1	30.2	30.4	30.5	30.7	30.8	31.0	31.0
Wind - onshore	40.0	40.3	40.6	40.9	41.2	41.5	41.8	42.1	42.4	42.7	43.0	43.3	43.6	43.9	44.2
Wind - offshore	45.0	45.6	46.2	46.8	47.4	48.0	48.6	49.2	49.8	50.4	51.0	51.6	52.2	52.8	53.4

	2034-35	2035-36	2036-37	2037-38	2038-39	2039-40	2040-41	2041-42	2042-43	2043-44	2044-45	2045-46	2046-47	2047-48	2048-49	2049-50
Solar PV - Single axis tracking	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0
Wind - onshore	44.5	44.8	45.1	45.4	45.7	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0
Wind - offshore	54.0	54.6	55.2	55.8	56.4	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0

Document prepared by

Aurecon Australasia Pty Ltd
ABN 54 005 139 873
Ground Floor, 25 King Street
Bowen Hills QLD 4006
Locked Bag 331
Brisbane QLD 4001
Australia

T +61 7 3173 8000
F +61 7 3173 8001
E brisbane@aurecongroup.com
W aurecongroup.com

aurecon

Bringing ideas to life

Aurecon offices are located in:
Angola, Australia, Botswana, China,
GDC, Ghana, Hong Kong, Indonesia, Kenya,
Lesotho, Mozambique,
Namibia, New Zealand, Nigeria,
Philippines, Qatar, Rwanda, Singapore, South Africa,
Swaziland, Tanzania, Thailand, Uganda,
United Arab Emirates, Vietnam, Zambia,