2019 Costs and Technical Parameter Review

Consultation Report

Australian Energy Market Operator (AEMO)

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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 PV
- Solar thermal (with and without storage)
- Reciprocating engines
- Combined-cycle gas turbine (CCGT)
- Open-cycle gas turbine (OCGT)
- Electrolysers / fuel cells
- Battery Energy Storage Systems (BESSs) 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 2019 GenCost publication to be prepared by CSIRO in conjunction with AEMO as well as other various AEMO forecasting publications.

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
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.

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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. Throughout the report, the source and basis of this information is identified.

Our 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 2019 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
Grid connection voltage	220 – 275 kV
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 ▪ 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
2	Grid connection	HV side of generator step-up transformer
3	Raw / potable water	Site boundary
4	Waste water	Site boundary
5	Road access	Site boundary

3.2.3 Fuel connection

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 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)

3.2.4 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.

3.2.5 Financial assumptions

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

- Prices in AUD, 2019 basis
- New plant (no second hand or refurbished equipment assumed)
- Competitive tender process for the plant and equipment
- Taxes and import / custom duties excluded
- 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

Term	Definition
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 it has been assumed that the total EPC programme = lead time + construction time. In reality there will be an overlap which would result in a longer 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 outages 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.
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.

Term	Definition
Heat rate	The ratio 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 state and the minimum allowance charge state.
Total EPC cost	The EPC contract sum.
Equipment cost	The component of the EPC contract sum that is primarily attributed to the supply of the major equipment. *Note that the 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 generally distributed.*
Installation cost	The component of the EPC contract sum that is primarily attributed to the site construction, installation, and commissioning works. *Note that the 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 generally distributed.*
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 2019 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 160 m rotors.

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 battery and or adjoined solar PV generation 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. Figure 4-1 below illustrates the historical and projected trend for wind turbine sizes.

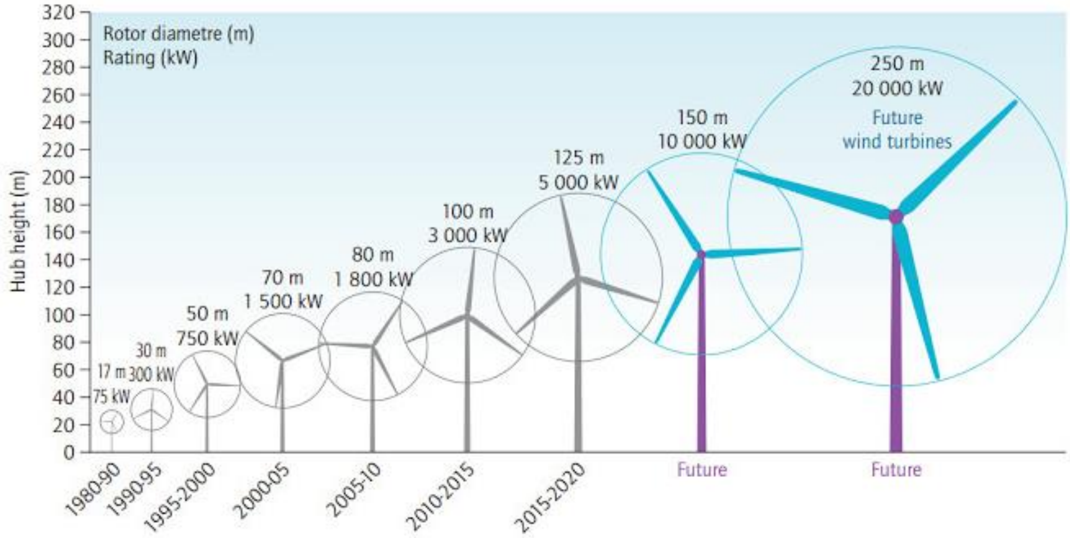

Figure 4-1 Increase in wind turbine size over time[1]

For projects that are currently planned and under construction, wind turbine sizes in the 4 – 6 MW range are being used.

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 800 MW.

Typical capacity factors range from 27% to over 40%. Capacity factors are linked to the wind resource and turbine used. With recent developments in blade design, tip to tail ratio, bearing efficiency, etc., 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, 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		V136-4.2	Based on current new installations
Unit size (nominal)	MW	4.2	ISO / nameplate rating

[1] *Picture from IEA (2013)*

Item	Unit	Value	Comment
Number of units		50	
Performance			
Total plant size (Gross)	MW	210.0	
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	203.7	25°C, 110 metres, 60%RH
Seasonal rating – Summer (Net)	MW	194	Derating above 30°C based on OEM datasheet.
Seasonal rating – Not Summer (Net)	MW	210	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.
Effective annual capacity factor (year 0)	%	40%	Dependent on wake losses, wind resource, and electrical losses. Based on gross capacity.
Annual generation	MWh / yr	735,840	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. 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	2019	

Item	Unit	Value	Comment
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	25	
Technical life (operational life)	Years	30	Does not include life extension or 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	1,800	
Total EPC cost	$	378,000,000	
▪ Equipment cost	$	226,800,000	60% of EPC cost – typical.
▪ Installation cost	$	151,200,000	40% of EPC cost – typical.
CAPEX – Other costs			
Cost of land and development	$	22,680,000	Assuming 6% of CAPEX.
Fuel connection costs	$	N/A	
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	21,930	Average annual cost over the design life.
Variable O&M Cost	$ / MWh (Net)	-	Included in the fixed component.
Total annual O&M Cost	$	4,500,000	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 7 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[2] and so this is still considered to be in the early commercialisation stage.

[2] https://www.windpowerengineering.com/business-news-projects/worlds-first-floating-wind-farm-delivers-promising-results/

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.[3] 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 GE's 12 MW Halidae X platform).

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 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 in the early stages of planning (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 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	

[3] 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

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	2019	
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	6,200	Based on the 2018 global weighted-average installed costs for offshore wind[4].

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

Item	Unit	Value	Comment
Total EPC cost	$	6,218,600,000	
▪ Equipment cost	$	4,353,020,000	70% of EPC cost – typical.
▪ Installation cost	$	1,865,580,000	30% of EPC cost – typical.
CAPEX – Other costs			
Cost of land and development	$	124,372,000	Assuming 2% of CAPEX due to large project scale.
Fuel connection costs	$	N/A	
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	157,680	Based on an indicative average of 25 Euro/MWh[5].
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. Typically, 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, are becoming a viable option.

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

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.

Due to the relatively low cost of the solar PV modules, solar developers are increasingly installing more solar panel capacity than inverter 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 generation in the early morning and late afternoon.

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 increasingly being considered for utility projects, allowing greater power generation for the same overall footprint.

Many solar farms under construction are experiencing delays in the grid connection process. In order to meet power quality restrictions enforced under the Generator Performance Standards, several projects have been required to implement harmonic filters or other power quality remediation measures (i.e. synchronous condensers), adding cost and time to the project.

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, 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	120.0	
Plant AC Capacity	MW	100.0	
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)	97.1	
Seasonal Rating – Summer (Net)	MW (AC)	97.1	Degradation expected above 35°C. Expect approximately 10% de-rate at 50°C.
Seasonal Rating – Not Summer (Net)	MW (AC)	97.1	
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.

Item	Unit	Value	Comment
Annual generation	MWh / yr.	252,000	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	2019	
EPC Programme	Years	1.16	14 months for NTP to COD.
▪ Total lead time	Years	0.75	Time from NTP to first inverter on site.
▪ Construction time	Weeks	21	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)	1.15	
Total EPC cost	$	138,200,000	
▪ Equipment cost	$	82,800,000	60% of EPC cost – typical.
▪ Installation cost	$	55,200,000	40% of EPC cost – typical.
CAPEX – Other costs			
Cost of land and development	$	8,292,000	Assuming 6% of CAPEX.
Fuel connection costs	$	N/A	

Item	Unit	Value	Comment
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	$	1,650,000	Annual average cost over the design life

4.5 Concentrated solar thermal

4.5.1 Overview

Concentrating solar thermal technology in power generation applications generally refers to the use of mirrors to collect solar energy over a wide area and concentrate 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 direct for power generation.

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

- Parabolic Trough Collectors (PTC) – PTC 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 (LFC) – LFCs use 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.
- Solar Tower (ST) – 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 Dish (PD) – a PD 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 state.

The key advantage of concentrated solar thermal, in comparison to solar PV and wind technologies, is that solar thermal plants can incorporate thermal energy storage. This increases the capacity factor and could provide dispatchable renewable power.

Solar thermal plants are however capital intensive, with cost drivers including whether or not storage is included, the solar multiple, and the DNI of the location.

O&M of solar thermal is lower in comparison to fossil fuel plants. However, these costs are still significant. Much of the O&M costs are related to the fixed labour cost. Key O&M cost include replacement of receivers and mirrors due to breakage, cost of field mirror cleaning including water cost, and plant insurance.

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[6].

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[6].

4.5.3 Recent trends

Solar thermal capacity grew tenfold globally between 2006 and 2016 on the back of incentive schemes in key markets like Spain and the USA. Currently an estimated 3.2 GW of concentrated solar thermal projects are either under development or under construction[6]. The actual status of these projects is unclear, as some may have been abandoned. As mentioned above, the trend is to have thermal storage integrated with the solar thermal plant. Molten salt is the 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.

Plant capacity factors have increased over time, leading to larger thermal storage capacities of over 50% recorded with plants with 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 proposed:

- Aurora Solar Energy Project – 150 MW solar tower with 8 hours molten salt energy storage. This has been 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 delays in achieving financial close. It is believed SolarReserve is seeking a potential purchaser for the project development.
- Vast Solar – Vast Solar is currently developing a 30 MW solar tower demonstration plant with 10 hours 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, 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.

[6] https://solarpaces.nrel.gov/by-status
[7] https://www.afr.com/business/energy/solar-energy/vast-solar-in-75m-raising-as-it-advances-240m-solar-thermal-plant-20190221-h1bkix

Item	Unit	Value	Comment
Power block		1 x Steam Turbine, dry cooling system	
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.

[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
Start-up time	Minutes	Hot: 60 - 120 Warm: 120 - 270 Cold: 200 - 480	Standard operation.
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	2019	
Total EPC programme	Years	3	36 months from NTP to COD.
▪ Total Lead Time	Years	1.5	Time from NTP to main equipment on site.
▪ Construction time	Weeks	78	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."[10]
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.
CAPEX – 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 power house 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 network 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 factors, 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.

There are currently three large-scale medium-speed reciprocating engine power stations either under construction or in development for installation in the NEM. These include;

- AGL's Barker Inlet Power Station (Stage 1 – 210 MW, 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.

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 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 also offer a comparable engine option.
Make model		18V50DF	Including SCR for NOx 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
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.

Item	Unit	Value	Comment
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	2019	
EPC programme	Years	1.66	For NTP to COD.
▪ Total Lead Time	Years	0.83	10 months typical to engines on site.
▪ Construction time	Weeks	43.33	10 months assumed from engines to site to COD.
Economic Life (Design Life)	Years	25	
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.
CAPEX – Other costs			
Cost of land and development	$	25,400,000	Assuming 9% of CAPEX.
Fuel connection costs	$M	$20M +$1.5M/km	
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. However, as mentioned in Section 4.7.3, there are instances where F class machines have been installed on OCGT configuration in Australia. 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. Recent gas turbine power projects proposed or under development in Australia 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 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.
- 250 MW Emergency power generation plant in South Australia. Various OCGT and Reciprocating engine solutions were considered for this project, including LM6000, TM2500, and GE Frame 6 gas turbines.

Overall, demand for gas turbines has declined over the last year, with a corresponding drop in prices. Gas turbine prices for utility-scale power generation units are expected to decline by 10% in 2019-2020 relative to those seen in 2017-2018[11].

4.7.4 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 4-16 Configuration and performance

Item	Unit	Value	Comment
Configuration			
Technology		Aero-derivative	
Make model		LM 6000 PD SPRINT	
Unit size (nominal)	MW	47	ISO / nameplate rating, GT Pro.
Number of units		6	
Performance			
Total plant size (Gross)	MW	258.0	25°C, 110 metres, 60%RH
Auxiliary power consumption	%	2%	
Total plant size (Net)	MW	253.5	25°C, 110 metres, 60%RH
Seasonal Rating – Summer (Net)	MW	227.0	35°C, 110 metres, 60%RH
Seasonal Rating – Not Summer (Net)	MW	272.0	15°C, 110 metres, 60%RH
Heat rate at minimum operation	(GJ/MWh) LHV Net	10.397	25°C, 110 metres, 60%RH. Assuming a Minimum Stable Generation of 50% on gaseous fuel.
Heat rate at maximum operation	(GJ/MWh) LHV Net	9.079	25°C, 110 metres, 60%RH
Thermal Efficiency at MCR	%, LHV Net	39.65%	25°C, 110 metres, 60%RH
Heat rate at minimum operation	(GJ/MWh) HHV Net	11.510	Assuming LHV to HHV conversion ratio of 1.107.
Heat rate at maximum operation	(GJ/MWh) HHV Net	10.051	Assuming LHV to HHV conversion ratio of 1.107.
Thermal Efficiency at MCR	%, HHV Net	35.82%	Assuming LHV to HHV conversion ratio of 1.107.
Annual Performance			
Average Planned Maintenance	Days / yr.	3	
Equivalent forced outage rate	%	2%	

[11] Gas Turbine World 2019 GTW Handbook

Item	Unit	Value	Comment
Effective annual capacity factor (year 0)	%	10%	Average capacity factor for existing aero-derivative GTs on the NEM.
Annual generation	MWh / yr.	226,008	
Annual degradation over design life - output	%	0.24%	Assuming straight line degradation.
Annual degradation over design life – heat rate	%	0.16%	Assuming straight line degradation.

Table 4-17 Technical parameters and project timeline

Item	Unit	Value	Comment
Technical parameters			
Ramp Up Rate	MW/min	300	Station ramp rate (all units) under standard operation. Based on OEM data.
Ramp Down Rate	MW/min	300	Station ramp rate (all units) under standard operation. Based on OEM data.
Start-up time	Min	5	Standard operation.
Min Stable Generation	% of installed capacity	50%	Assuming Dry Low NOx burner technology.
Project timeline			
Time for development	Years	2	includes pre/feasibility, design, approvals etc.
First Year Assumed Commercially Viable for construction	Year	2019	
EPC programme	Years	2	For NTP to COD.
▪ Total Lead Time	Years	0.66	Time from NTP to gas turbine on site.
▪ Construction time	Weeks	70	Time from gas turbine on site to COD.
Economic Life (Design Life)	Years	25	
Technical Life (Operational Life)	Years	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	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW	1,250	Net basis
Total EPC cost	$	316,875,000	
▪ Equipment cost	$	221,812,500	70% of EPC cost – typical.
▪ Construction cost	$	95,062,500	30% of EPC cost – typical.

Item	Unit	Value	Comment
CAPEX – Other costs			
Cost of land and development	$	28,500,000	Assuming 9% of CAPEX.
Fuel connection costs	$M	$20M +$1.5M/km	
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	12,600	Based on Aurecon internal database.
Variable O&M Cost	$ / MWh (Net)	4.1	Based on Aurecon internal database.
Total annual O&M Cost	$	4,120,000	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 were preferred. Popular CCGT configuration options are:

- 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 by manufacturers.

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 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 start-up time and ability to ramp-up/down CCGT plant.

Globally, the gas turbine market has declined in the last couple of years and is expected to continue that downward trend[12]. In addition, there are indications that operators are seeing less value in centralised CCGT plants[13].

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 PD 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 we believe an 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, given the above discussion on typical options and current trends.

Table 4-19 Configuration and performance

Item	Unit	Value	Comment
Configuration			
Technology		CCGT	With mechanical draft cooling tower.
Make model		GE 9F.03	Smallest model available selected.
Unit size (nominal)	MW	409	ISO / nameplate rating.
Number of units		1 GT + 1 ST	HP pressure – 165 bar HP temperature – 582°C Reheat temperature – 567°C
Performance			
Total plant size (Gross)	MW	380	25°C, 110 metres, 60%RH
Auxiliary power consumption	%	2.5%	
Total plant size (Net)	MW	371	25°C, 110 metres, 60%RH
Seasonal Rating – Summer (Net)	MW	348	35°C, 110 metres, 60%RH
Seasonal Rating – Not Summer (Net)	MW	389	15°C, 110 metres, 60%RH
Heat rate at minimum operation	(GJ/MWh) LHV Net	7.103	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	

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

Item	Unit	Value	Comment
Thermal Efficiency at MCR	%, LHV Net	56.4%	
Heat rate at minimum operation	(GJ/MWh) HHV Net	7.863	Assuming LHV to HHV conversion of 1.107.
Heat rate at maximum operation	(GJ/MWh) HHV Net	7.068	Assuming LHV to HHV conversion of 1.107.
Thermal Efficiency at MCR	%, HHV Net	50.9%	Assuming LHV to HHV conversion of 1.107.
Annual Performance			
Average Planned Maintenance	Days / yr.	12.8	Based on 3.5% average planned outage rate over a full maintenance cycle.
Equivalent forced outage rate	%	3.5%	
Effective annual capacity factor	%	60%	
Annual generation	MWh / yr.	1,949,135	Provided for reference.
Annual degradation over design life - output	%	0.20%	Assuming straight line degradation.
Annual degradation over design life – heat rate	%	0.12%	Assuming straight line degradation.

Table 4-20 Technical parameters and project timeline

Item	Unit	Value	Comment
Technical parameters			
Ramp Up Rate	MW/min	22	Standard operation.
Ramp Down Rate	MW/min	22	Standard operation.
Start-up time	Min	Cold: 145 Warm: 115 Hot: 30	Standard operation.
Min Stable Generation	% of installed capacity	46%	Differs between GT models.
Project timeline			
Time for development	Years	2	includes pre/feasibility, design, approvals etc.
First Year Assumed Commercially Viable for construction	Year	2019	
EPC programme	Years	2.5	For NTP to COD.
▪ Total Lead Time	Years	0.66	Time from NTP to gas turbine on site.
▪ Construction time	Weeks	95	Time from gas turbine on site to COD.
Economic Life (Design Life)	Years	25	
Technical Life (Operational Life)	Years	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	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW	1,500	
Total EPC cost	$	573,000,000	
▪ Equipment cost	$	401,100,000	70% of EPC cost – typical.
▪ Construction cost	$	171,900,000	30% of EPC cost – typical.
CAPEX – Other costs			
Cost of land and development		51,570,000	Assuming 9% of CAPEX.
Fuel connection costs	$M	$20M +$1.5M/km	
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	10,900	Based on Aurecon internal database.
Variable O&M Cost	$ / MWh (Net)	3.7	Based on Aurecon internal database.
Total annual O&M Cost	$	11,255,700	Annual average cost over the design life

4.9 Electrolysers / fuel cells

4.9.1 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 or for potential blending with natural gas in existing gas pipelines. Only a small percentage of hydrogen-based projects involve fuel cells for stationary power generation applications. Power to gas and mobility applications of hydrogen are not discussed in this report with the scope focused on power generation fuel cells.

4.9.2 Typical options

Hydrogen is typically produced either by electrolysis of water, or by a thermochemical process which uses fossil fuel. 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 traditional electrolyser technology based on submersed electrodes in liquid alkaline electrolyte solution.

- Proton Exchange Membrane (PEM) – a new electrolyser technology categorised by its solid polymer electrolyte which separate the electrodes.

Electrolyser unit sizes of the individual modules vary in sizes up to 20 MW comprising of individual cell stacks of 2 to 5 MW depending on the suppliers.

For fuel cells in stationery power generation applications, these are currently limited to small off-grid installations supporting back-up power for homes, businesses, and hospitals. Below are some of the most commonly used fuel cells[14].

- 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 installation could either be standalone plants, or may be installed in addition to other power (e.g. Rooftop PV) or energy storage (e.g. Lithium battery) solutions.

4.9.3 Recent trends

For hydrogen production, PEM electrolysers have been growing in popularity relative to more traditional alkaline technology. 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 – 50 MW Electrolyser (21 tonnes/day) in Crystal Brook, South Australia
- Hydrogen Supply Chain Demonstration Project: 20 MW (4 x 5 MW units) Electrolyser, 10 tonnes/day, H2 production and 5 MWe PEM-FC generator in Port Lincoln, South Australia.

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 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).

[14] http://www.fchea.org/fuelcells

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 of the approximately 70 MW is fuelled by hydrogen[15]. 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[16]. 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[17].

4.9.4 Selected hypothetical project – Electrolyser

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 4-22 Electrolyser configuration and performance[18]

Item	Unit	Value	Comment
Configuration			
Technology		Proton Exchange Membrane	PEM selected as this the technology is being increasingly considered for new projects in Australia
Plant Size	MW	50	
Make, OEM		SILYZER 300, Siemens	Example
Electrical rating	MW	10	
Efficiency	%	~75%	HHV basis
No of Electrolysers		5	
Output pressure	bar	35	
Life cycle design	hrs	80,000	
Hydrogen Production	kg/MWh	19.5	OEM datasheet at 100% load factor
Raw water consumption	L/kgH_2	20 - 30	Typical un-treated water consumption volumes, for hydrogen production only (excludes any cooling water make-up)
Annual degradation	%	1	Typical PEM published value.
Annual Performance			
Average Planned Maintenance	Days / yr.	15	
Equivalent forced outage rate	%	3%	

[15] The Future of Hydrogen, Report prepared by the IEA for the G20, Japan, Seizing today's opportunities
[16] https://www.powermag.com/worlds-largest-fuel-cell-plant-opens-in-south-korea/
[17] https://new.gbca.org.au/showcase/projects/sir-samuel-griffith-centre/
[18] Siemens Data Sheet

Table 4-23 Technical parameters and project timeline

Item	Unit	Value	Comment
Technical parameters			
Ramp Up Rate	MW/min	N/A	10% to 100% achievable in 30 sec
Ramp Down Rate	MW/min	N/A	100% to 10% achievable in 30 sec
Start-up time	Min	Cold: 5 min Warm: 30 secs	Typical PEM value, depends on manufacturer. (note that Alkaline electrolysers can be in the order of 1 minute for a warm start)
Min Stable Generation	% of installed capacity	10%	Typical PEM value.
Project timeline			
Time for development	Years	2	includes pre/feasibility, design, approvals etc.
First Year Assumed Commercially Viable for construction	Year	2019	
EPC programme	Years	2	For NTP to COD.
▪ Total Lead Time	Years	1.5	Time from NTP to main equipment on site.
▪ Construction time	Weeks	26	Time from main equipment on site to COD.
Economic Life (Design Life)	Years	8	Typical PEM value (time to membrane replacement).
Technical Life (Operational Life)	Years	20	Typical PEM value.

4.9.5 Cost estimate – Electrolyser

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

Table 4-24 Cost estimates

Item	Unit	Value	Comment
CAPEX – EPC cost			
Relative cost	$ / kW	1,800	For PEM. Note that Alkaline electrolysers may be 30 – 40% lower in cost compared to PEM.
Total EPC cost	$	90,000,000	
▪ Equipment cost	$	72,000,000	80% of EPC cost – typical.
▪ Construction cost	$	18,000,000	20% of EPC cost – typical.
CAPEX – Other costs			
Cost of land and development	$	7,2000,000	Based on 8% of CAPEX per annum.
Fuel connection costs	$	N/A	
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	54,000	Based on 3% of CAPEX per annum. Note that this includes allowance for the 8 year overhaul. Excludes power consumption costs

Item	Unit	Value	Comment
Variable O&M Cost	$ / MWh (Net)	-	Included in fixed O&M component.
Total annual O&M Cost	$	2,700,000	Annual average cost over the design life Excludes power consumption cost

4.9.6 Selected hypothetical project – Fuel Cell Generator

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 4-25 Fuel cell configuration and performance[19]

Item	Unit	Value	Comment
Configuration			
Technology		PEM-FC	Technology offer for the demonstration plant in SA.
Make model		Hydrogenics HyPM-XR12	Example.
Electrical Output	MWe	0.0125	
Total Capacity	MWe	0.25	20 x XR12 modules.
Electrical Efficiency	%	53	OEM datasheet.
Hydrogen purity	%	99.99	
Fuel Consumption	Nm^3/MWh	750	OEM datasheet.
Auxiliary Electrical Input	kW	5	
Annual Performance			
Average Planned Maintenance	Days / yr.	-	Included in EFOR below.
Equivalent forced outage rate	%	2%	

Table 4-26 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.[20]
Ramp Down Rate	MW/min	2.1	Based on 100% to 0% in 7 secs as per OEM datasheet.[20]
Start-up time	Min	0.5	Typical
Min Stable Generation	% of installed capacity	2%	Operation down to “idle” levels.[20]

[19] Hydrogenics Data Sheet
[20] https://www.h2fc-fair.com/hm10/images/pdf/hydrogenics02.pdf

Item	Unit	Value	Comment
Project timeline			
Time for development	Years	< 1	includes pre/feasibility, design, approvals etc.
First Year Assumed Commercially Viable for construction	Year	2019	
EPC programme	Years	< 1	For NTP to COD.
▪ Total Lead Time	Years	0.5	Time from NTP to main equipment on site.
▪ Construction time	Weeks	26	Time from main equipment on site to COD.
Economic Life (Design Life)	Years	8	
Technical Life (Operational Life)	Years	20	

4.9.7 Cost estimate – Fuel Cell Generator

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	2,320	Based on CSIRO's National Hydrogen Roadmap estimate for stationary fuel cells.[21]
Total EPC cost	$	580,000	
▪ Equipment cost	$	464,000	80% of EPC cost – typical.
▪ Construction cost	$	116,000	20% of EPC cost – typical.
CAPEX – Other costs			
Cost of land and development		116,000	Assuming 20% of CAPEX due to small scale.
Fuel connection costs	$	Excluded	
OPEX – Annual			
Fixed O&M Cost	$ / MW (Net)	116,000	Based on 5% of CAPEX per year.[22]
Variable O&M Cost	$ / MWh (Net)	-	Included in the fixed O&M component.
Total annual O&M Cost	$	29,000	Annual average cost over the design life

[21] Bruce S, Temminghoff M, Hayward J, Schmidt E, Munnings C, Palfreyman D, Hartley P (2018) National Hydrogen Roadmap. CSIRO, Australia.
[22] 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

4.10 Battery Energy Storage System (BESS)

4.10.1 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.

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.

4.10.2 Typical options

The key driver for BESS design is the intended operating regime and purpose of the installation. 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 (e.g. Tesla Powerpack).

4.10.3 Recent trends

Grid-connected batteries installed within the last couple of years range from residential systems, to the 100 MW/129 MWh 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.

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 (primary frequency response) 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 installation on the NEM include:

- Hornsdale Power Reserve – 100 MW / 129 MWh
- Dalrymple North BESS – 30 MW / 12.2 MWh
- Kennedy Energy Park – 2 MW / 4 MWh
- Gannawarra Solar ESS – 25 MW / 50 MWh
- Ballarat Station ESS – 30 MW / 30 MWh

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, given the above discussion on typical options and current trends.

Table 4-28 Fuel cell configuration and performance

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
Configuration						
Technology		Li-ion				
Performance						
Power Capacity (gross)	MW	25				
Energy Capacity	MWh	25	50	100	200	
Auxiliary power consumption (operating)	kW	540	1,030	2,000	3,940	Indicative figures (highly variable, dependent on BESS arrangement, cooling systems etc.).
Auxiliary power consumption (standby)	kW	230	440	860	1,690	Based on Aurecon internal database of similarly sized projects, Indicative figures (highly dependent on BESS arrangement, cooling systems etc.).
Power Capacity (Net)	MW	24.5	24.0	23.0	21.1	
Seasonal Rating – Summer (Net)	MW	24.5	24.0	23.0	21.1	Dependent on inverter supplier. Potentially no de-rate, or up to approx. 4% at 35°C.
Seasonal Rating – Not Summer (Net)	MW	24.5	24.0	23.0	21.1	
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.

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
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 4-29 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.
Round trip efficiency	%	83%	85%	87%	90%	Energy retention, at the point of connection, for a full cycle of charge and discharge
▪ Charge efficiency	%	91.5%	92.5%	93.5%	95.0%	Assumed to be half of the round-trip efficiency.
▪ Discharge efficiency	%	91.5%	92.5%	93.5%	95.0%	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.'

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
Project timeline						
Time for development	Years	1				
First Year Assumed Commercially Viable for construction	Year	2019				
Total EPC Programme	Years	*0.66*	*0.75*	1	1	For NTP to COD.
▪ Total lead time	Years	0.5	0.6	0.75	0.75	
▪ Construction time	Weeks	8	8	12	12	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.

4.10.5 Cost estimate

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

Table 4-30 Cost estimates

Item	Unit	1 hour	2 hours	4 hours	8 hours	Comment
CAPEX – EPC cost						
Total EPC cost	$M	19.9	26.3	44.3	84.3	Based on Aurecon internal database of similarly sized projects and scaled for additional energy storage capacity.
▪ Equipment cost	$M	15.9	21.0	35.4	67.4	As above.
▪ Installation cost	$M	4.0	5.3	8.9	16.9	As above.
CAPEX – Other costs						
Cost of land and development	$	4,800,000				
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	$	120,000	240,000	470,000	940,000	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.

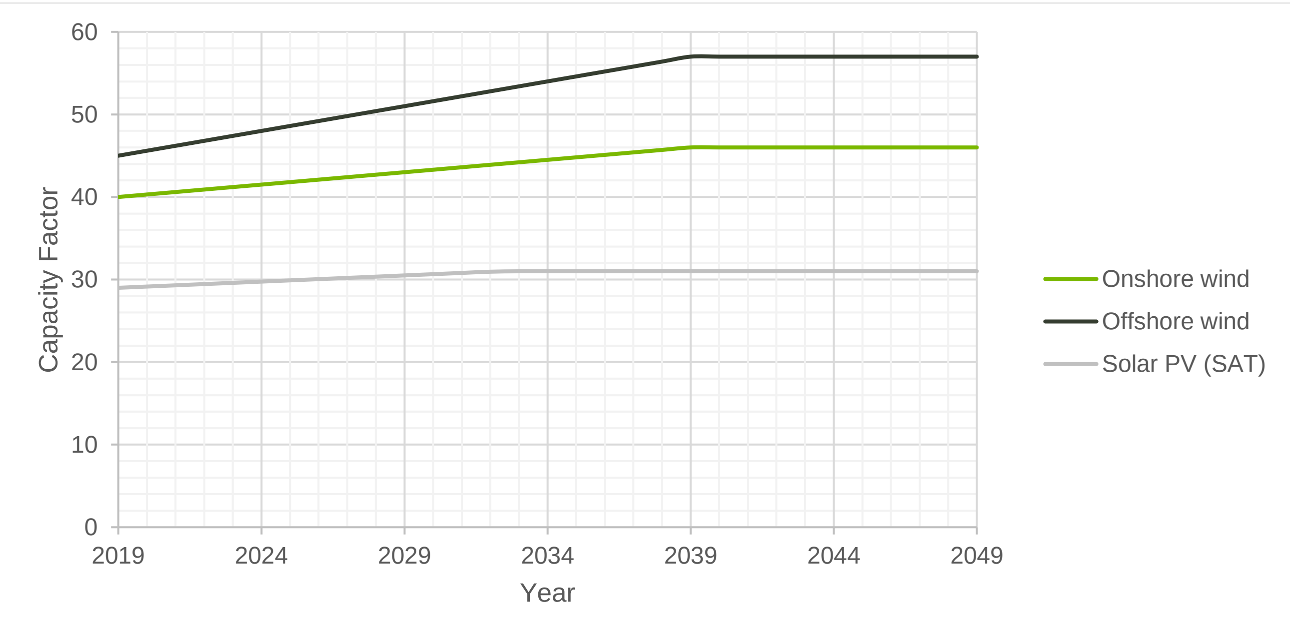

Figure 5-1 Capacity Factors for new solar and wind generators over time – NEM wide trend

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[1]. 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

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

Year	Solar PV - Single axis tracking	Wind - Onshore	Wind - Offshore
2042-43	31.0	46.0	57.0
2043-44	31.0	46.0	57.0
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 2019 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: Summer (MW) (Net)	Seasonal Ratings: Not summer (MW) (Net)	Generation Type	Fuel Type	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs	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
CCGT - With CCS				Thermal	Natural Gas								
CCGT - Without CCS	380.0	348.0	389.0	Thermal	Natural Gas	401,100,000	$20M +$1.5M/km	51,570,000	171,900,000				
OCGT - Without CCS	258.0	227.0	272.0	Thermal	Natural Gas	221,812,500	$20M +$1.5M/km	28,500,000	95,062,500				
Reciprocating Engine	211.2	209.1	209.1	Thermal	Natural Gas/Diesel	169,371,000	$20M +$1.5M/km	25,400,000	112,914,000				
Fuel cells	0.250	0.250	0.250	Storage	N/A	464,000	Excluded	116,000	116,000				
Large Scale Battery Storage (1hr)	25.0	24.5	24.5	Storage	N/A	15,900,000	N/A	4,800,000	4,000,000				
Large Scale Battery Storage (2hr)	25.0	24.0	24.0	Storage	N/A	21,000,000	N/A	4,800,000	5,300,000				
Large Scale Battery Storage (4hr)	25.0	23.0	23.0	Storage	N/A	35,400,000	N/A	4,800,000	8,900,000				
Large Scale Battery Storage (8hr)	25.0	21.1	21.1	Storage	N/A	67,400,000	N/A	4,800,000	16,900,000				
Flow Battery Storage (8hr)													
Electrolysers	50.0	N/A	N/A	Storage	N/A	72,000,000	Excluded	7,200,000	18,000,000				
Solar PV - Single axis tracking	100.0	97.1	97.1	Renewable	N/A	82,800,000	N/A	8,292,000	55,200,000				
Solar Thermal Central Receiver with storage	150.0	135.0	135.0	Renewable	N/A	721,500,000	N/A	38,480,000	240,500,000				
Solar Thermal Central Receiver without storage													
Wind - onshore	210.0	194.0	210.0	Renewable	N/A	226,800,000	N/A	22,680,000	151,200,000				
Wind - offshore	1,045.0	1,003.0	1,003.0	Renewable	N/A	4,353,020,000	N/A	124,372,000	1,865,580,000				

Technology	Cost of energy storage ($/MWh)	Cost of storage capacity ($/MW)
Fuel cells	Excluded	
Large Scale Battery Storage (1hr)	$0.57 / MWh storage	$0.23 / MW installed
Large Scale Battery Storage (2hr)	$0.42 / MWh storage	$0.21 / MW installed
Large Scale Battery Storage (4hr)	$0.39 / MWh storage	$0.21 / MW installed
Large Scale Battery Storage (8hr)	$0.39 / MWh storage	$0.21 / MW installed
Flow Battery Storage (8hr)		
Electrolysers	Excluded	
Solar Thermal Central Receiver with storage	N/A	

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)	Economic Life (Design Life) (yrs)	Technical Life (Operational Life)(yrs)	Time for development (includes pre/feasibilty, design, approvals and so on) (yrs)	Construction time (weeks)	Total Lead Time (years)	Min Stable Generation (% of installed capacity)	Auxiliary load (% of installed capacity)
CCGT - With CCS	Thermal	Natural Gas											
CCGT - Without CCS	Thermal	Natural Gas	2019	380.0	348.0	389.0	25	40	2	95.0	0.66	46.0%	2.5%
OCGT - Without CCS	Thermal	Natural Gas	2019	258.0	227.0	272.0	25	40	2	70.0	0.66	50.0%	2.0%
Reciprocating Engine	Thermal	Natural Gas/Diesel	2019	211.2	209.1	209.1	25	40	2	43.3	0.83	40.0%	1.0%
Fuel cells	Storage	N/A	2019	0.250	0.250	0.250	8	20	< 1	26.0	0.50	2.0%	2.0%
Large Scale Battery Storage (1hr)	Storage	N/A	2019	25.0	24.5	24.5	10	20	1	8.0	0.50	Near 0	2.2%
Large Scale Battery Storage (2hr)	Storage	N/A	2019	25.0	24.0	24.0	10	20	1	8.0	0.60	Near 0	4.1%
Large Scale Battery Storage (4hr)	Storage	N/A	2019	25.0	23.0	23.0	10	20	1	12.0	0.75	Near 0	8.0%
Large Scale Battery Storage (8hr)	Storage	N/A	2019	25.0	21.1	21.1	10	20	1	12.0	0.75	Near 0	15.8%
Flow Battery Storage (8hr)	Storage	N/A											
Electrolysers	Storage	N/A	2019	50.0	N/A	N/A	8	20	2	26.0	1.50	10.0%	N/A
Solar PV - Single axis tracking	Renewable	N/A	2019	100.0	97.1	97.1	25	30	2 – 3	21.0	0.75	Near 0	2.9%
Solar Thermal Central Receiver with storage	Renewable	N/A	2019	150.0	135.0	135.0	25	40	2 – 3	78.0	1.50	20.0%	10.0%
Solar Thermal Central Receiver without storage	Renewable	N/A											
Wind - onshore	Renewable	N/A	2019	210.0	194.0	210.0	25	30	3 – 5	52.0	1.00	Near 0	3.0%
Wind - offshore	Renewable	N/A	2019	1,045.0	1,003.0	1,003.0	25	35	4 – 5	156.0	2.00	Near 0	4.0%

Technical parameters and operating costs for new technologies

General Details

Technology	Auxiliary load for Generators operating in Synchronous Condenser mode (% of installed capacity)	Forced outage rate (full forced outages) %	Frequency of full forced outage per annum	Full outage Mean time to repair (h)	Partial Forced outage rate (partial forced outages)	Frequency of partial forced outages	Partial Outage derating factor (% lost during partial outage)	Partial outage Mean time to repair (h)	Equivalent forced outage rate (%)	Minimum Load required for Synchronous Condensers (MW)	Ramp Up Rate (MW/h) - standard operation	Ramp Down Rate (MW/h) - standard operation
CCGT - With CCS												
CCGT - Without CCS		included in EFOR			included in EFOR				3.5%		1,320	1,320
OCGT - Without CCS		included in EFOR			included in EFOR				2.0%		18,000	18,000
Reciprocating Engine		included in EFOR			included in EFOR				2.0%		2,160	2,160
Fuel cells		included in EFOR			included in EFOR				2.0%		2.1	2.1
Large Scale Battery Storage (1hr)		included in EFOR			included in EFOR				1.5 - 3%		10,000+	10,000+
Large Scale Battery Storage (2hr)		included in EFOR			included in EFOR				1.5 - 3%		10,000+	10,000+
Large Scale Battery Storage (4hr)		included in EFOR			included in EFOR				1.5 - 3%		10,000+	10,000+
Large Scale Battery Storage (8hr)		included in EFOR			included in EFOR				1.5 - 3%		10,000+	10,000+
Flow Battery Storage (8hr)												
Electrolysers		included in EFOR			included in EFOR				3.0%		N/A	N/A
Solar PV - Single axis tracking		included in EFOR			included in EFOR				1.5%		Resource dependant	Resource dependant
Solar Thermal Central Receiver with storage		included in EFOR			included in EFOR				3.0%		6.0	6.0
Solar Thermal Central Receiver without storage												
Wind - onshore		included in EFOR			included in EFOR				3.0%		Resource dependent	Resource dependent
Wind - offshore		included in EFOR			included in EFOR				5.0%		Resource dependant	Resource dependant

Technical parameters and operating costs for new technologies

General Details

Technology	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)	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
CCGT - With CCS												
CCGT - Without CCS	7.863	7.068	50.90%		12.8							
OCGT - Without CCS	11.510	10.051	35.82%		3.0							
Reciprocating Engine	11,356.000	8,790.000	40.90%		2.7							
Fuel cells	N/A	N/A	N/A		-							
Large Scale Battery Storage (1hr)	N/A	N/A	N/A		-			92%	92%	0%	100%	3,650
Large Scale Battery Storage (2hr)	N/A	N/A	N/A		-			93%	93%	0%	100%	3,650
Large Scale Battery Storage (4hr)	N/A	N/A	N/A		-			94%	94%	0%	100%	3,650
Large Scale Battery Storage (8hr)	N/A	N/A	N/A		-			95%	95%	0%	100%	3,650
Flow Battery Storage (8hr)												
Electrolysers	N/A	N/A	N/A		15.0							
Solar PV - Single axis tracking	N/A	N/A	N/A		-							
Solar Thermal Central Receiver with storage	N/A	N/A	N/A		7.0							
Solar Thermal Central Receiver without storage												
Wind - onshore	N/A	N/A	N/A		-							
Wind - offshore	N/A	N/A	N/A		-							

Technical parameters and operating costs for new technologies

General Details

Technology	Battery storage: Depth of Discharge (DoD)	Fixed Operating Cost ($/MW Net/year)	Variable Op Cost ($/MWh Net)	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)
CCGT - With CCS													
CCGT - Without CCS		10,900	3.7										
OCGT - Without CCS		12,600	4.1										
Reciprocating Engine		24,100	7.6										
Fuel cells		116,000	-										
Large Scale Battery Storage (1hr)	100%	4,833	-										
Large Scale Battery Storage (2hr)	100%	9,717	-										
Large Scale Battery Storage (4hr)	100%	19,239	-										
Large Scale Battery Storage (8hr)	100%	39,314	-										
Flow Battery Storage (8hr)													
Electrolysers		54,000	-										
Solar PV - Single axis tracking		16,990	-										
Solar Thermal Central Receiver with storage		142,500	-										
Solar Thermal Central Receiver without storage													
Wind - onshore		21,930	-										
Wind - offshore		157,680	-										

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	2034-35
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	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	44.5
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	54.0

	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
Wind - onshore	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	54.6	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

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