GHD Advisory

Power station and associated costs

Benchmark reserve capacity price 2023

Economic Regulation Authority

8 December 2022

→ **The Power of Commitment**

GHD Pty Ltd | ABN 39 008 488 373
999 Hay Street, Level 10
Perth, Western Australia 6000, Australia
T +61 8 6222 8222 | **F** +61 8 6222 8555 | **E** permail@ghd.com | **ghd.com**

Client name	Economic Regulation Authority
Project name	ERA OCGT cost estimate for the 2023 BRCP
Project number	12588501

Document status

Status Code	Revision	Author	Reviewer		Approved for issue		
			Name	Signature	Name	Signature	Date
S3	Draft	Nello Nigro	Matt Nichol	M.Nichol	E. O'Brien		19/08/2022
S4	Final	Nello Nigro	E. O'Brien	E. O'Brien*	E O'Brien	E. O'Brien*	08/12/2022

** Denotes original signature on report*

Contents

Table index

Appendices

1. Introduction

1.1 Overview

The Economic Regulation Authority (ERA) must calculate the 2023 Benchmark Reserve Capacity Price (BRCP) following the Market Procedure: Benchmark Reserve Capacity Price (Market Procedure)[1] as required by clause 4.16 of the Wholesale Electricity Market Rules (WEM Rules). The BRCP is used to set the maximum price that may be offered in a Reserve Capacity Auction, or as an input in the determination of the administered Reserve Capacity Price if an auction is not required.

The ERA has commissioned GHD to provide development cost estimates for a 160 MW open cycle gas turbine (OCGT) power station located in the South West interconnected system (SWIS) as this is the reference generator in the Market Procedure. This includes fixed Operating and Maintenance (O&M) costs and fixed fuel costs as required by the Market Procedure.

The Market Procedure outlines the method used to determine the BRCP, which is calculated by undertaking a technical, bottom-up, cost evaluation of the entry of a new 160 MW Open Cycle Gas Turbine (OCGT) generation facility in the SWIS. The power station must:

1. Be representative of an industry-standard liquid-fuelled OCGT power station.
2. Have a nominal nameplate capacity of 160 MW before the addition of any inlet cooling system.
3. Operate on distillate as its fuel source with distillate storage for 14 hours of continuous operation.
4. Have a capacity factor of 2%.
5. Include low nitrous oxide (NOx) burners or associated technologies (for example water injection) as considered suitable and required to demonstrate good practice in power station development.
6. Include an inlet air cooling system where this would be cost-effective.
7. Include water receivable and storage capability to support 14 hours of continuous operation that is cost-effective.
8. Include the minimum level of equipment or systems required to satisfy the Balancing Facility Requirements (as stated in the Market Procedure: Balancing Facility Requirements).

Section 2 of this Report outlines the cost escalation assumptions and Section 3 provides the cost for the OCGT power plant. Section 4 of this Report outlines the fixed operating and maintenance costs, and Section 5 provides the fixed fuel costs. Section 6 of this Report provides the Margin M costs.

1.2 Scope

The WEM Rules require that a review be conducted of the Benchmark Reserve Capacity Price (BRCP) each year. GHD was commissioned by the ERA to carry out a bottom-up cost evaluation for an OCGT Power Station as of April 2025 (Year 3 of the 2023 Reserve Capacity Cycle), which includes:

– The power station costs for a single liquid-fuelled 160 MW OCGT unit inclusive of components for the gas turbine plant and all other costs that would normally apply to such a power station
– The fixed operating and maintenance costs (O&M) for the power station operating with a capacity factor of 2%
– The fixed fuel costs (FFC) for the power station, inclusive of a 1,000-tonne capacity fuel storage tank, fuel handling facility, and initial supply of fuel sufficient for operating the power station for 14 hours at its maximum capacity

[1] Economic Regulation Authority, *Market Procedure: Benchmark Reserve Capacity Price*, Version 7, effective 9 November 2020.

– The value of Margin M, which constitutes the following costs associated with the development of the power station project:
  - Legal costs associated with the design and construction of the power station.
  - Financing costs associated with equity raising.
  - Insurance costs associated with the project development phase.
  - Approval costs including environmental consultancies and approvals, and local, state and federal licensing, planning and approval costs.
  - Other costs reasonably incurred in the design and management of the power station construction.
  - Contingency costs.

1.3 Limitations

This Report has been prepared by GHD for the Economic Regulation Authority and may only be used and relied on by the Economic Regulation Authority for the purpose agreed between GHD and the Economic Regulation Authority as set out in this Report.

GHD otherwise disclaims responsibility to any person other than the Economic Regulation Authority arising in connection with this Report. GHD also excludes implied warranties and conditions, to the extent legally permissible.

The services undertaken by GHD in connection with preparing this Report were limited to those specifically detailed in the Report and are subject to the scope limitations set out in the Report.

The opinions, conclusions and any recommendations in this Report are based on conditions encountered and information reviewed at the date of preparation of the Report. GHD has no responsibility or obligation to update this Report to account for events or changes occurring subsequent to the date that the Report was prepared.

The opinions, conclusions and any recommendations in this Report are based on assumptions made by GHD described in this Report. GHD disclaims liability arising from any of the assumptions being incorrect.

GHD has prepared this Report on the basis of information provided by the Economic Regulation Authority and others who provided information to GHD (including Government authorities), which GHD has not independently verified or checked beyond the agreed scope of work. GHD does not accept liability in connection with such unverified information, including errors and omissions in the Report which were caused by errors or omissions in that information.

GHD has prepared the cost estimates set out in this Report (“Cost Estimate”) using information reasonably available to the GHD employee(s) who prepared this Report; and based on assumptions and judgments made by GHD, including inputs provided by others including the Economic Regulation Authority and it’s consultants.

The Cost Estimate has been prepared for the purpose of estimating the 2022 benchmark reserve capacity price for the 2024-25 capacity year and must not be used for any other purpose.

The Cost Estimate is a preliminary estimate only. Actual prices, costs and other variables may be different to those used to prepare the Cost Estimate and may change. Unless as otherwise specified in this Report, no detailed quotation has been obtained for actions identified in this Report. GHD does not represent, warrant or guarantee that the project can or will be undertaken at a cost which is the same or less than the Cost Estimate.

Where estimates of potential costs are provided with an indicated level of confidence, notwithstanding the conservatism of the level of confidence selected as the planning level, there remains a chance that the cost will be greater than the planning estimate, and any funding would not be adequate. The confidence level considered to be most appropriate for planning purposes will vary depending on the conservatism of the user and the nature of the project. The user should therefore select appropriate confidence levels to suit their particular risk profile.

2. Cost Escalation

2.1 Escalation factors provided by ERA

The ERA provided the following annual forecast escalation factors:

Table 1 Escalation factors provided by ERA

	FY ending June 2023	FY ending June 2024	FY ending June 2025	FY ending June 2026	FY ending June 2027
WPI – EWGGS	2.81%	3.06%	3.06%	3.06%	2.85%
WPI – Construction	2.65%	2.90%	2.90%	2.90%	2.79%
AUD/USD ($)	0.703	0.7517	0.7692	0.7692	0.7692
Steel Price	-43.82%	-10.63%	-4.17%	-2.26%	-3.12%
Copper Price	-23.14%	-3.13%	2.44%	2.20%	0.18%

The escalation factors shown in the table above were used for the determination of the power plant cost, fixed operating & maintenance cost, fixed fuel cost, and Margin M costs.

2.2 Australian Consumer Price Index

The ERA also provided the Australian Consumer Price Index (CPI) figures summarised in Table 2 below.

Table 2 Australian CPI % change forecast[2]

Year to June	2021-22 Actual	2022-23 Forecast	2023-24 Forecast	2024-25 Forecast	2025-26 Forecast	2026-27 Forecast
CPI % Change	6.10%	6. 30%	4.20%	3.35%	2.50%	2.50%

The ERA uses the Reserve Bank of Australia's (RBA) Statement on Monetary Policy to forecast CPI. For the forecasts beyond the RBA's estimates (after the 2023-24 forecast), the ERA:

The 2024-25 forecast uses the midpoint between the previous year's forecast and 2.5% (the mid-point of the RBA's inflation target band).

The 2025-26 forecast and beyond uses the mid-point of the RBA's inflation target band.

2.3 Capital cost escalation factors

Based on the analysis outlined in Section 3 of this Report, the Siemens SGT5-2000E is deemed the best option for this year's OCGT.

The complete OCGT Siemens SGT5-2000E weighs approximately 236 tonnes. Based on previous work carried out by GHD, an OCGT of 160 MW capacity contains an estimated 1.3 tonnes/MW of steel and an estimated 0.175 tonne/MW of copper. Using these figures and the forecasts for WPI Construction, exchange rate, copper and steel prices in Table 1 above, GHD has evaluated the power station capital cost escalation factors to the end of June for the next 5 years, as shown in Table 3 below.

Table 3 Annual capital cost escalation factors

Year to June	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
Power station	-4.26%	-4.83%	0.426%	2.35%	2.04%

[2] RBA November Statement of Monetary Policy – provided by ERA on 28 November 2022.

This year the cost for the 160 MW OCGT was evaluated to be A$135,508,167 (refer to section 3.5 of this Report).

Using the escalation factors in the above table, the total capital cost estimate of the power plant on 1 April 2025 is forecasted to be $123,862,427[3], which equates to $819/kW[4].

This year's escalated cost estimate is $2,210,729[5] lower than last year's estimate. The decrease was influenced mainly by a rise in last year's cost which was then eroded by a weakened exchange rate of the Australian dollar against the US dollar that was applied to the capital cost of the power plant for this year's estimate. The forward exchange rates, provided by ERA, for the future years are also lower than the rates forecasted in the 2022 BRCP.

This year's estimate is as per the Market Procedure, which requires the estimate to be as of April in Year 3 of the reserve capacity cycle.

2.4 Fixed operational & maintenance cost escalation factors

The annual operating and maintenance cost escalation factors determined by GHD for the forecast year to the end of June for the next 5 years are shown in Table 4 below.

Table 4 Annual O&M cost escalation factors

Year to June	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
Power station[6]	1.99%	4.44%	-1.00%	2.95%	2.84%
Connection Switchyard[7]	-2.41%	1.79%	2.90%	2.86%	2.36%
Overhead transmission line[5]	-2.41%	1.79%	2.90%	2.86%	2.36%

The fixed Operating & Maintenance (O&M) escalation factors for the connection switchyard and overhead transmission line follow the Australian EGW WPI figures, and the fixed O&M escalation factors for the power plant were evaluated by applying the relevant cost indices weighted by the relevant plant cost items.

[3] April 2025 cost estimate is: $135,508,167 x (1+(-4.26/100)) = $129,738,505 (year 2023), $129,738,505 x (1+(-4.83/100)) = $123,467,596 (year 2024), $123,467,596 x (1-(((0.426 x (3/12))/100))) = **$123,862,427** (year April 2025) (value may vary due to the number of decimal points used.)
[4] Based on 151.17 MW net output as stated in section 3.4.
[5] Based on last year's value of $126,073,156.
[6] The combined rate is assumed to be comprised of the following components: 70% of WPI construction escalation rates and 30% of the WPI EGW escalation rates. AUD/USD escalation is applied to the 30% WPI EGW that is subjected to exchange rate for materials and spares. GHD has assumed the various escalation rates with the quoted weightings to reflect the expected O&M escalation that includes labour, material and fluctuation in exchange rate for imported spares/materials.
[7] The combined rate is assumed to be comprised of the following components: 40% of WPI construction escalation rates and 40% of the WPI EGW escalation rates and 20% of the copper escalation rates. GHD has assumed the various escalation rates with the quoted weightings to reflect the expected O&M escalation that includes labour, material and fluctuation in components that are made of copper.

3. Cost of Power Plant

3.1 Method used to estimate cost of power plant

GHD used the current Version 30.0 of GT PRO® /PEACE®, which is part of Thermoflow's suite of software packages. This software allows the user to evaluate the performance output for most commercially available gas turbines under any assumed site conditions. The outputs include an estimate of the current capital cost for the gas turbine and the balance of plant, which in this case, applies to a gas turbine configured as an open cycle gas turbine (OCGT). Thermoflow updates the software periodically by interviewing relevant Original Equipment Manufacturers (OEM) such as GE, Siemens, Mitsubishi, etc., to obtain current performance and cost detail from each OEM.

The list of available gas turbines in GTPro includes key models that are provided by OEMs and their variants. For this reason, GTPro is considered a more accurate source for gas turbine performance (output, efficiency, etc.) than other sources such as internet websites, which tend to provide performance output for a specifically configured model under specific site conditions.

Our approach to modelling the 160 MW OCGT for both performance and project cost was to:

- Choose a suitable gas turbine and configure the turbine with the relevant balance of plant equipment for OCGT operation and configure it to run on diesel fuel; (using assumptions outlined in section 3.3 of this Report).
- Adjust the labour cost and commodity factors in the software's input assumption list to reflect that the plant is to be built in WA.
- Run the model for ISO[8] conditions and record the performance output.
- Re-run the model at the required site conditions and record the performance output.
- Obtain a cost estimate output from PEACE[9] (this is an add-on feature of Thermoflow software) for the model configured to operate at site conditions (all costs are provided in US$ and GHD used the US$/A$ currency exchange as of September 2021 to convert these costs to A$).
- For evaluation of the cost of the power station, GHD has applied a cost escalator that is based on the mid-point of the BRCP forecast period (April 2025).

3.2 Overview of diesel-fuelled power plant

As a requirement of the BRCP, an assessment was carried out for a single unit, industrial type, liquid-fuelled 160 MW open cycle gas turbine power plant located in the SWIS region of Western Australia.

GHD has reviewed the following gas turbines for suitability for the 160 MW OCGT power plant:

Table 5 OCGT Units considered for this cost estimate

Gas turbine	Comments
Siemens SGT5-2000E (33MAC)	The 33MAC variant of this unit was used in the last several years to develop the Benchmark Reserve Capacity Price. There are three variants of the SGT5-2000E: the 25MAC, 33MAC and 41MAC. All variants feature evaporative cooling and dry low Nox combustion. The 33MAC is also able to be water injected for power augmentation. At the prevailing site conditions (41°C, 30% relative humidity), the 33MAC is designed to have a net capacity of 162.22 MW (net at site conditions). It is, therefore, the closest of the three variants to the 160 MW target. GTPro reports all variants to have almost identical CAPEX and efficiency. This unit is closest to the required output and therefore has been used for the assessment outlined in this Report.

[8] International Organisation for Standardisation
[9] PEACE is a Cost Estimate component for Thermoflow GTPro software

Gas turbine	Comments
GE GT13E2 (MXL2), previously owned by Alstom	The nameplate rating for this unit when running on diesel fuel is 180.6 MW (gross) at ISO conditions. The unit comes in 2 versions; the GT13E2 and GT13E2 (MXL2). The MXL2 features dry low NOx combustion and is also compatible with water injection for power augmentation. For prevailing site conditions (41°C, 30% relative humidity), this unit will have a net rating of 162.02 MW (net at site conditions with evaporative cooling and water injection for power augmentation). This unit has a higher output at site conditions than the SGT5-2000E 33MAC and, therefore, has been discounted from further assessment.
GE 9E.04	The nameplate rating for the 9E.04 unit is 143.25 MW (gross) at ISO conditions. The 9E.04 features dry low NOx combustion and is also compatible with water injection for power augmentation. The GE 9E unit comes in two versions; the GE 9E.03 and 9E.04, with the 9E.03 variant having a lower capacity than the 9E.04. There is no larger variant of the 9E, with the next step up being the 9F.03 model with a gross capacity above 260+ MW. At the prevailing site conditions (41°C, 30% relative humidity), the 9E.04 is designed to have a net rating of 140.64 MW (with water injection for power augmentation). This unit has a significantly lower output at site conditions than the SGT5-2000E 33MAC and, therefore, has been discounted from further assessment.
Ansaldo AE94.2	The nameplate rating for the AE94.2 unit is 183.32 MW (gross) at ISO conditions. The AE94.2 features dry low NOx combustion and is also compatible with water injection for power augmentation. The AE94.2 unit is manufactured by Ansaldo and is based on Siemens technology. At the prevailing site conditions (41°C, 30% relative humidity) the AE94.2 is designed to have a net rating of 162.52MW (with water injection for power augmentation). This option has been added to the units investigated this year. However, the Ansaldo AE94.2 has a higher output at site conditions than the SGT5-2000E 33MAC and, therefore, has been discounted from further assessment.

From the results obtained for the single unit OCGT configurations, GHD has chosen to base this year's assessment and this Report on the Siemens SGT-2000E OCGT 33MAC. This is because the SGT5-2000E closely matches the requirement for a 160 MW OCGT at the required site conditions and provides good value in terms of capital and O&M costs.

As outlined in section 3.1 of this Report, in developing the capital cost estimate, GHD used the latest version of GTPro (Version 30.0) to model the SGT5-2000E 33MAC machine under ISO conditions at a typical power plant site in the SWIS (near Muja Power Station). We then applied the necessary inlet cooling system and water injection rate for the gas turbine operating at 41°C ambient conditions and providing the lowest NOx emissions. The capital cost estimates for the reference power plant were obtained from GTPro's PEACE output, which has current estimates for 2022. A cross-check with last year's estimate (2021) for the same machine was carried out to identify any significant variations. Where possible, cost references were made to Australian power projects involving the SGT5-2000E machines[10]. GHD applied the relevant escalation to establish the 2021 project cost for these projects and compared them with the project cost obtained from GTPro. The cost obtained from GTPro was found to be within the limit of accuracy[11].

In Australia, the SGT5-2000E has been installed for the following power plants:

- One unit in Queensland at the Townsville Power Station (firing gas) (Yabulu PS)
- Three units in Queensland at the Braemar 2 Power Station (firing gas)
- Two units in Queensland at Oakey Power Station (firing gas)
- Two units in Victoria at Laverton Power Station (firing gas & diesel)

[10] All these projects were constructed pre 2010 and the appropriate escalation was used to compare prices.
[11] For cost estimates produced by GTPro without Front End Engineering Design (FEED) the level of accuracy is usually about +/-30%.

– Four units in NSW at Uranquinty Power Station (firing gas)
– Two units in Western Australia at Neerabup Power Station (firing gas)

3.3 Assumptions

The capital cost for the liquid-fuelled OCGT power plant has been estimated by GHD assuming an EPC[12] contracting strategy where the capital cost is comprised of engineering, procurement and construction. The construction cost includes commissioning and testing.

The following assumptions apply to the capital cost for the power plant:

– An SGT5-2000E machine was used as the basis of the OCGT plant.
– Evaporative air cooling is included in the supply package for the power plant.
– Water injection for NOx emission abatement is used for distillate fuel operation.
– Distillate fuel storage and handling are not included in the cost for the power plant (it is treated separately in Section 5 of this Report).
– Site conditions have the following values:
  - A site elevation of 217 metres above sea level (based on a site close to Muja Power Station).
  - A maximum ambient temperature of 41°C.
  - Relative humidity of 30%.
  - The power plant site is assumed to be relatively flat, requiring minimal civil works, and all foundations are of the spread footing type.
  - The natural ground water table is assumed to be below the depth required for excavation.
  - Plant and equipment can be transported from a nearby seaport to the site over existing roads and bridges.
  - Land cost is not included.
  - A demineralised water treatment plant together with a 1,200 tonne demineralised water storage tank is included in the cost estimate.
– A storage tank for potable water of 300-tonne capacity plus a fire water storage tank is included in the cost estimate

3.4 Plant output at ISO and 41°C ambient temperature

The site assumptions applied in the GTPro model are as shown in Section 3.3 of this Report. The performance data for the SGT5-2000E gas turbine is provided in the table below.

Table 6 Performance for the SGT5-2000E at site conditions

Description	Units	Value
Ambient Conditions	Deg C / % RH	41.0 / 30% RH
Gross Power	MW	164.60
Net Power	MW	162.20
Auxiliary/Losses	MW	2.34
Gross Heat Rate / Efficiency (LHV)	kJ/kWh / (%)	10,660 / 33.77%
Net Heat Rate / Efficiency (LHV)	kJ/kWh / (%)	10,820 / 33.27%
Air temperature post evaporative cooler	Deg C	27.0
Diesel Fuel Consumption	Tonnes/hr	41.45

[12] Engineering Procurement Construction.

As discussed in Section 3.1 of this Report, the SGT5-2000E 33MAC unit was modelled first using ISO conditions to obtain the respective gross (at generator terminal) and net (export to the grid) output. Next, the SGT5-2000E was modelled at site conditions. This year's results show similar outputs as last year's results for the SGT5-2000E.

The ISO output for the SGT5-2000E machine is 177.34 MW (gross) and 175.04 MW (net). For the 160 MW generic power plant, GHD set the gross output for the generic power plant to 160 MW., Based on the parameters of the SGT5-2000E power plant, the net output for ISO conditions was established by using the scaled-down quantity of ancillary power usage. The net output for the generic 160 MW power plant was determined to be 157.92 MW. For the SGT5-2000E machine at site conditions, with evaporative cooling, the gross and net outputs reduce to 164.60 MW and 162.20 MW, respectively. For the generic 160 MW machine at site conditions, with evaporative cooling and water injection, the gross and net outputs reduce to 153.51 MW and 151.17 MW, respectively. The values obtained in this year's modelling for the SGT5-2000E provided a slight difference compared with last year's results primarily due to the variations in data within the GTPro software. Output from the generic machine was attained by considering additional water injection for power augmentation, which is achievable in units of this class of technology.

The performance of the SGT5-2000E 33MAC and the generic 160 MW power plant is provided in the table below.

Table 7 Siemens SGT5-2000E Performance

Case	ISO Conditions		Site Conditions	
	MW (gross)	MW (net)	MW (gross)	MW (net)
Siemens SGT5-2000E	177.34	175.04	164.60	162.20
160 MW (generic)	160.00	157.92	153.51	151.17

3.5 Capital cost estimate

The cost breakdown for the OCGT power plant is provided in Table 8 below

Table 8 Capital cost breakdown for the power plant

Cost Item	Based on Siemens SGT5-2000E *	Equivalent 160 MW power station
Specialised Equipment**	71,624,541	64,619,661
Other Equipment**	3,126,162	2,820,424
Civil works**	13,061,360	11,783,959
Mechanical Works**	10,075,165	9,089,814
Electrical Works**	3,364,727	3,035,656
Building & Structures	2,863,236	2,863,236
Engineering & Plant Start-up	7,264,559	7,264,559
Contractor soft cost & Misc. Costs	34,030,859	34,030,859
Total	145,410,608	135,508,167
A$/kW (net)	896***	896****

* All costs are as of FY end 2022 in AUD
** Scalable costs
*** ($145,410,608/162,20) (162,200 is 162.20MW (net) in kW)
**** ($135,508,167/151,170) (151,170 is 151.17MW (net) in kW)

The costs were established from GTPro (Peace) and were converted from US$ using an exchange rate of AU$1.00 = US$0.7137[13] (financial year ending for 2022 exchange rate). From the table above, the capital cost for a 160 MW liquid fuelled OCGT is $896/kW.

The reference capital costs used to check the output of GTPro Peace estimates are based on recent power plant projects - Braemar Power Station and Mortlake Power Station. We note that there have been more recent projects completed or in the process of being completed but these more recent projects are based on aero-derivative gas turbines, not industrial turbines such as the unit assumed for this Report.

Based on last year's capital cost estimate for the generic 160 MW plant, there is a variation of $2,210,729[14] from this year's cost estimate. The decrease was influenced mainly by a rise in last year's cost which was subsequently eroded by a weakened exchange rate of the Australian dollar against the US dollar that was applied to the capital cost of the power plant for this year's estimate.

[13] Obtained August 2022 from an online foreign exchange service.

[14] Based on last year's cost estimate which was $126,073,156 and, therefore, the difference between this year and last year is 123,862,427-126,073,156=-$2,210,729.

4. Fixed Operating & Maintenance Costs

4.1 Overview of fixed operating & maintenance costs

Once the power plant configuration was defined, GHD used our internal O&M database to establish the fixed operating cost estimate using a bottom-up approach. The fixed O&M cost is comprised of:

– Plant operator labour costs
– Corporate overhead for operating costs
– Regular and routine maintenance costs associated with an OCGT substation, and the balance of plant
– Regular reporting on generator licence and environmental issues pertaining to emissions and compliance with the EPA[15] permit
– Annual legal costs
– Travel
– Subcontractors
– Annual engineering reports/studies
– Security
– Servicing and support for the fire detection and protection system
– Fixed O&M for associated overhead transmission line and connection at switchyard inclusive of:
  - Labour costs for routine maintenance
  - Cost for machinery, plant and tool hire for routine maintenance
  - Overhead corporate costs (management, administration, and operations)

For the evaluation of all fixed O&M costs for the power station, GHD has applied the cost escalators provided by the ERA.

4.2 Assumptions

The fixed O&M cost for the liquid-fuelled OCGT power plant has been estimated by GHD on the following basis:

– The assumed power plant capacity factor is 2% per annum
– An annualised fixed O&M cost associated with each major component has been estimated for each 5-year period for up to 60 years
– Fixed O&M costs were determined as of 1 October 2025 which is year 3 of the 2023 reserve Capacity Cycle
– Variable costs for the OCGT plant such as scheduled maintenance have not been included in the fixed O&M costs
– One shift for operators and maintenance crew has been assumed

4.3 Fixed O&M costs

The fixed O&M costs have been derived using GHD's O&M database for OCGT plants. Where applicable, cost escalators outlined in Section 2 of this Report, were used to establish the fixed cost estimate for 2023 BRCP. The cost escalator to October of the third year of the 2023 reserve capacity cycle was evaluated for both the power station (O&M) and switchyard/electrical & overhead transmission and is shown in the table below.

[15] Environmental Protection Authority

The table shows the total cost escalation factors used to escalate a cost to October 2025 (year 3 of the 2023 capacity cycle).

Description of cost escalator	Cost escalator to October of Year 3 of the 2023 reserve capacity cycle
Power station O&M	5.72%
Switchyard / Electrical	1.50%
Overhead Transmission	1.50%

The above cost escalators were used, for the relevant cost components, in determining the fixed O&M costs shown in the table below.

Table 9 O&M costs

O&M cost component	Cost escalator applied (if applicable)	Fixed cost estimate ($ pa)
Plant Operator Labour Last year Plant Operator Labour was based on (1 x Plant Mgr, 2 x Operators, 2 x Technical Assistants and 1 x receptionist). The cost last year was $676,144. This year GHD has applied WPI escalation on last year's value ($676,144 x 1.0572[16]) = $714,819).	Power station O&M	714,819
OCGT Substation (connection to tie line) OCGT Substation (connection to tie line), has been escalated by 1.5%[17] from last year's figure of $271,072.	Switchyard / Electrical Overhead Transmission	275,134
Rates This year's rates are based on a site that is 30,000 m^2 (3 hectares). The Landgate gross rental value (GRV) for a site of this size for last year was $761,700. For this year, we assumed that the GRV increases by CPI. Therefore, based on last year's GRV, and applying this year's CPI, the GRV is $808,164. This is equivalent to a weekly rental of $15,541/wk or $26.94/$m^2$ per annum). We assume the plant will be located somewhere near the Collie region of South Western Australia. As there is insufficient information available from the Shire of Collie, publicly available rates for the City of Bunbury are used as a proxy. The City of Bunbury Council[18] for this year has a fee multiplier of **$0.09994** and therefore this year's fees are: **GRV x $0.09994** which results in Council rates of $80,767 for this year.		80,767
Market Fees This year, AEMO's fees have increased significantly over last year's fees. This year's AEMO fee is $1.112/MWh (last year was $0.894/MWh). The ERA WEM fee is $0.1727, and the Energy Policy WA Energy Co-ordinator fee is $0.0718/MWh, therefore the total annual fees will be based on a total charge rate of $1.4004. Therefore, fees are based on a generation of 26,484 MWh (151.17 MW x 8760 hrs x 2% = 26,484 MWh) which results in an annual fee of $37,088 (26,484 x 1.4004).		37,088
Balance of Plant Balance of Plant (service of pumps, water plant, fire system, etc., using a contract of 0.12% of capital for Mechanical and Electrical services ($135,508,167 x 0.0012)		162,609

[16] April 2025 cost estimate is: $676,144 x (1+(1.992/100)) = $689,616 (year 2023), $689,616 x (1+(4.437/100)) = $720,211(year 2024), $720,211 x (1+(((-0.752 x (9/12))/100))) = **$714,797** (year April 2025) (value may vary due to the number of decimal points used.). This escalation is used for all power related items. (Overall factor is 1.0419)
[17] April 2025 cost estimate is: $271,072 x (1 + (-2.412)/100)) = $264,534 (year 2023), $264,534 x (1+ 1.79/100)) = $269,269 (year 2024), $269,269 x (1+ (((2.178 x (9/12))/100))) = **$275,134** (year April 2025) (value may vary due to the number of decimal points used.). This escalation is used for all power related items. (Overall factor is 1.015)
[18] http://www.bunbury.wa.gov.au/Pages/Ra(tes.aspx

O&M cost component	Cost escalator applied (if applicable)	Fixed cost estimate ($ pa)
Consent (EPA annual charges emission testing) This year's figure is based on previous relevant data. A range of $30,000 to $45,000 is considered a reasonable fee for this service. GHD has assumed a last year's charges ($40,487) and added escalation resulting in a fee of $42,802, i.e. ($40,487 x 1.0572).	Power station O&M	42,802
Legal There are years when legal costs are negligible and some years, depending on the number of legal disputes, when this cost could be as high as $40,000 or more. GHD assumed last year's legal cost ($33,033) and added escalation resulting in a legal fee for this year of $34,922 i.e. ($33,033 x 1.0572).	Power station O&M	34,922
Corporate Overhead This cost is 30% of the Plant Operator Labour cost. It covers items such as superannuation contributions, work cover contributions, contribution to corporate office lease, the cost for office staff in the corporate office, ongoing training of staff, and employee insurance. GHD assumed last year's overhead ($202,506) and added escalation ($202,506 x 1.0572 = $214,089).	Power station O&M	214,084
Travel An allowance of 10 domestic flights/accommodation @ $1,326* each plus 2 International flights/accommodation @ $8,833* each. Because there are occasions when Siemens may conduct workshops or training courses overseas, GHD has allowed for 2 x international flights. This allowance could also be extended to overseas conferences that would be relevant to OCGT plants. The costs for air travel are based on pre-Covid prices as the costs for post-Covid are not clearly known.		30,926
Subcontractors Based on a similar working environment among subcontractors as last year. Last year's cost ($316,432) has been increased by WPI escalation for services by Subcontractors. Therefore, a cost of $321,178 ($316,432 x 1.0150) is used for this year's value for subcontractor fees.	Switchyard / Electrical	321,178
Engineering Support Similar to the approach for subcontractor costs, GHD has applied an increase in Engineering services on last year's cost estimate of $61,617 increasing this cost to $62,541 ($61,617 x 1.015).	Switchyard / Electrical	62,541
Security Last year's cost of $129,183 was considered reasonable. This year GHD has increased last year's cost by escalation ($129,183 x 1.015 = $131,120).	Switchyard / Electrical	131,120
Electrical (including control & instrumentation) This is similar to services for security. Last year's cost is considered reasonable and was based on 8 hours/week for a service provider to check and report on the operation of electrical, instrumentation and controls equipment at a rate of $2,155/wk. This year GHD has adjusted last year's value with this year's escalation which took the weekly rate up to $2,187/wk. The total cost will therefore be $113,724 pa	Switchyard / Electrical	113,724
Fire detection and protection systems Similarly, as per last year for fire detection and protection systems, GHD made an allowance of 2 hours/wk to check and report on the status of the fire detection and protection system. Based on a weekly rate of $864/wk last year and applying an escalation for this year, the weekly rate is $876/wk and the annual cost will be $45,552	Switchyard / Electrical	45,552
Total		**2,267,271**

*Escalated by CPI.

The total fixed O&M cost estimate has increased by $86,229 from last year's report. The reasons for this increase are provided in the following table:

Table 10 Table outlining O&M cost variation

O&M cost component	Variation from last year's results ($ pa)	Comments
Plant Operator Labour.	+$38,675	This year GHD has continued with the allocated number of staff, staff type and salaries for a typical OCGT plant and has applied the relevant escalation to establish this year's cost which is an increase of $38,675 over last year's estimate.
OCGT Substation (connection to tie line)	+$4,062	An escalation (for the sub-station) has been applied this year on last year's value which resulted in an increase of $4,062 over last year's estimate.
Rates	+$5,572	This year's cost is based on the year's GRV with this year's escalation rate applied to last year's GRV. The Council multiplier increased slightly over last year's figure resulting in a slightly increased value for rates of $5,572 this year.
Market Fee	+$6,270	This year the AEMO fees have increased significantly this year and coupled with a slight decrease in ERA WEM fees and the Energy Policy WA co-ordinator fee resulted in an increase in market fees of $6,270 over last year's value.
Balance of Plant (BOP)	$4,932	This year, the BOP estimate has increased slightly over last year's value compared with the capital cost for the previous year.
Consent (EPA annual Charges emission testing)	+$2,315	This is an increase of $2,315 over last year's figure and is based upon last year's charge for this service plus this year's escalation.
Legal	+$1,889	This year there is an increase over last year's legal fee as this year's fee is based on last year's fee plus an escalation rate.
Corporate Overhead	+$11,583	GHD retained corporate overhead based on 30% of the value of salaries. This year's value is an increase over last year's value due to this year's escalation factor which was applied to last year's value for corporate overhead.
Travel	+$1,036	This value is an increase of $1,036 over last year's travel allowance due to this year's escalation factor.
Subcontractors	+$4,746	value has increased by $4,746 over last year's value due to this year's escalation factor.
Engineering Support	+$924	Similarly, as for the subcontractor services, the value for engineering support increased slightly by this year's escalation over last year's value resulting in an increase this year of $924.
Security	+$1,937	This value has increased by $1,937 over last year's security cost due to this year's escalation factor.
Electrical (including control & instrumentation)	+$1,664	This year's cost estimate is based on 8 hrs/wk @ $2,187/wk.to carry out these services. This is an increase over last year's value due to this year's positive escalation factor.
Fire detection and Protection Systems	+$624	This year's cost estimate is based on 2 hrs/wk @ $876wk.to carry out these services (an increase of $12/week from the rate used last year).
Total Variation	**+$86,229**	

Five yearly aggregate fixed O&M costs for the power plant are provided in Table 11 below.

Table 11 Fixed O&M cost for OCGT power plant ($2021)

Five yearly intervals	Fixed O&M costs ($)
1 to 5 Years	11,336,355
6 to 10 Years	11,336,355
11 to 15 Years	11,336,355
16 to 20 Years	11,336,355
21 to 25 Years	11,336,355
26 to 30 Years	11,336,355
31 to 35 Years	11,336,355
36 to 40 Years	11,336,355
41 to 45 Years	11,336,355
46 to 50 Years	11,336,355
51 to 55 Years	11,336,355
56 to 60 Years	11,336,355
1 to 60 Years	**136,036,260**

4.4 Connection switchyard and overhead transmission line

The fixed O&M costs have been calculated from the isolator on the high voltage side of the generator transformer.

The transmission line is assumed to be a single circuit 330 Kilo-Volts (kV) construction with 2 conductors per phase. The assumed power factor is 0.8 and for the 160 MW plant, the line can facilitate the transport of up to 200 mega-volt amperes (MVA).

A bottom-up approach has been used to estimate the fixed O&M cost of switchyard and transmission line assets based on evaluating an annual charge for the connection infrastructure that assumes the substation and a 2 km High Voltage (HV) connecting line to the tie-in point. This is then compared with last year's estimate.

Maintenance costs for these types of assets occur irregularly and therefore GHD has assessed the costs before producing an annualised fixed cost.

The fixed O&M cost estimate is inclusive of:

- Labour cost for routine maintenance
- Overheads (management, administration, operations, etc.)
- Hire cost of machinery and equipment to support routine maintenance

4.4.1 Assumptions

The following key assumptions apply to the switchyard and transmission line O&M fixed cost estimates:

- The annualised fixed O&M cost does not allow for the replacement of defective asset items over the life of the assets.
- Insurance and tax costs are not included in the annualised fixed O&M costs.
- Depreciation of assets has not been included in the normalised O&M fixed costs.

4.4.2 Switchyard fixed O&M costs

The fixed O&M cost over the asset life for the switchyard is $84,045[19] pa in current dollars (applying a 1.5% escalation factor), This is an increase of $1,242 p.a. over the value used in last year's O&M cost for the Switchyard ($82,803).

Table 12 shows the fixed O&M costs presented in five year periods over the lifetime of the switchyard assets.

Table 12 Five yearly aggregate fixed O&M costs for switchyard assets

Five yearly intervals	Fixed O&M costs ($)
1 to 5 Years	420,225
6 to 10 Years	420,225
11 to 15 Years	420,225
16 to 20 Years	420,225
21 to 25 Years	420,225
26 to 30 Years	420,225
31 to 35 Years	420,225
36 to 40 Years	420,225
41 to 45 Years	420,225
46 to 50 Years	420,225
51 to 55 Years	420,225
56 to 60 Years	420,225
1 to 60 Years	**5,042,700**

GHD assumed that routine maintenance would take an equivalent annual period of one week and would require the hire of a scissor lift and forklift, as well as requiring project management, planning and organising by management and operations staff. This will change from year to year depending on what is required but essentially this cost is representative of a normalised spend over the period of the asset's lifetime.

4.4.3 Transmission line fixed O&M costs

Based on last year's fixed O&M cost GHD has added an escalation (of 1.5%) and therefore this year's fixed O&M cost for the transmission line is $5,245[20] pa in current dollars. This cost represents an increase of $77 pa over the value used in last year's report.

GHD assumed that the work would be organised by management and operations staff and that the inspection would be carried out over a 2-day period and require the hire of a scissor lift, as well as requiring planning and project management. The fixed O&M cost will change from year to year depending on the O&M required but essentially this cost is representative of a normalised spend over the period of the asset's lifetime.

Table 13 shows the fixed O&M costs presented in five year periods over the lifetime of the transmission line asset.

Table 13 Five yearly aggregate fixed O&M costs for transmission line asset

Five yearly intervals	Fixed O&M costs ($)
1 to 5 Years	26,225
6 to 10 Years	26,225
11 to 15 Years	26,225
16 to 20 Years	26,225

[19] Applying an escalation for labour component only (assumed to be 60% of total cost)
[20] Applying an escalation for labour component only (assumed to be 60% of total cost)

Five yearly intervals	Fixed O&M costs ($)
21 to 25 Years	26,225
26 to 30 Years	26,225
31 to 35 Years	26,225
36 to 40 Years	26,225
41 to 45 Years	26,225
46 to 50 Years	26,225
51 to 55 Years	26,225
56 to 60 Years	26,225
1 to 60 Years	**314,700**

5. Fixed fuel costs

5.1 Overview of fixed fuel cost estimate

The fixed fuel cost component is an estimate of an on-site liquid fuel (diesel) storage and supply facility for the 160 MW OCGT power plant. The storage facility has sufficient capacity for 24 hours of operation on diesel fuel. However, these costs are based on having the storage facility filled with enough fuel for the power plant to operate for 14 hours.

5.2 Assumptions

– Key assumptions for the fixed fuel cost, which are consistent with a previous GHD report[21] and section 2.6 of the Market Procedure, for the 160 MW power plant include:
  - A fuel tank of 1,000 tonnes (nominal) capacity including foundations and spillage bund suitable for 14 hours of operation
  - Facilities to receive fuel from road tankers
  - All associated pipework, pumping and control equipment

– Land is available for use, and all appropriate permits and approvals for both the power station and the use of liquid fuel have been received.

– The basis of the estimate for fuel storage and handling assets is based on GHD's Report mentioned in the first dot point.

– The fuel facility concept design would be reasonably typical for the storage and handling of diesel fuel for service to an open-cycle gas turbine power station.

– The facility battery limits[22] start from the loading bay and manifold for receipt of fuel from road tankers through to the storage tank, diesel transfer pumps, and diesel filtration and ends at a tie-in point on the fuel transfer pipe to the gas turbine, not further than 100m upstream from the turbine fuel train limits.

– The facility design complies with AS 1940-2004[23] and includes spillage bund containment and fire protection accordingly.

5.3 Estimated fixed fuel cost

Fuel facility cost

The estimated total fuel facility cost is $7,602,706. This is an increase over last year's estimate of $6,918,374. The increase is mainly due to the CPI escalation and a significant rise in fuel price that is thought to be triggered by the ongoing conflict in Ukraine.

Table 14 below provides a breakdown of our estimate for the liquid fuel storage and handling facility for the 160 MW OCGT.

Table 14 Cost breakdown for the diesel storage & handling facility

No.	Item description	A$
1	Fuel Storage Tank* – • Fabrication and construction of the roofed vertical tank, externally coated, process nozzles, access manholes and concrete ring foundation • Spillage bund of concrete wall and floor • Stairways and access platforms • Instrumentation for level and temperature measurement • Geotechnical investigation, hydrostatic testing and cathodic protection	1,754,394

[21] GHD, *Review of fixed fuel cost for maximum reserve capacity price in the wholesale electricity market*, November 2009. https://www.aemo.com.au/-/media/archive/docs/default-source/reserve-capacity/153877-rev-a5eee.pdf
[22] The battery limit is an area within the plant boundary limits
[23] Australian Standard for the storage and handling of combustible liquids

No.	Item description	A$
2	Fuel Supply Loading Manifolds (two sets)* – • Loading manifolds including valves and coupling • Loading pumps and motors • Piping and electrical works	58,734
3	Road Tanker Loading Bay of sealed road surface*	139,643
4	Fuel transfer mainline piping (from pumps to the gas turbine including valves)*	110,823
5	Fuel transfer system consisting of: • Fuel Transfer Pumping (duty run & standby run)* • Two fuel pump runs each with motor, filters & oil separators • Flow meters • Piping and basic instrumentation, including floating suction header in tank • Concrete foundation and bunded plant area	485,413
6	Oily Water Treatment System* consisting of: • Sump pump • Oil separator unit • Piping and electrical • Concrete foundation and bunded plant area	80,897
7	Site preparation, civil and early works*	2,427,111
8	Perimeter fencing (cyclone wire mesh)*	43,218
9	Fire protection (including hose reels and fire extinguishers)*	39,896
10	Lighting*	27,703
11	Mobilisation and De-mobilisation*	96,424
12	Engineering, procurement and construction management (12%)**	631,710
13	Contractor risk, insurance and profit (15%)***	789,638
14	Spares and consumables*	84,229
A	Sub-total for facility installation	6,769,833
B	Base fuel storage of 638,168 litres (539.89 tonne) @ A$1.305/L[24]	832,873
	TOTAL	**$7,602,706**

*Estimate values have had 2021/22 CPI[25] applied to last year's estimates (and rounded) unless otherwise stated.
**Based on specified % (in brackets) profit margin for the total of items 1 through to 11.
***15% is a typical average figure.

[24] Provided by ERA and was the price of diesel as at 31 October 2022 (via email).
[25] 6.1% as per CPI forecast in section 2.2 of this Report.

Cost of fuel

The reference cost for diesel was obtained from the ERA. The wholesale price provided by the ERA for distillate was $34.00/GJ[26] .

Based on the above, the delivered cost for distillate is 130.51 cents/litre[27]. This is a 45.51 cents/litre increase from last year's GHD report. The price rise is believed to be due to the prolonged conflict in Ukraine which saw the distillate price increase to 130.51 cents/litre compared with last year's figure of 85.00 cents/litre.

The estimated gross High Heat Value (HHV) heat rate for the 160 MW OCGT operating at the specified site conditions is 11,353 kJ/kWh (10,660 kJ/kWh *1.0651 (HHV/LHV ratio)). The hourly fuel consumption would therefore be 1,758,560 MJ (for 153.51 MW gross output), which, based on an HHV for distillate of 45.6 MJ/kg (45,600 MJ/tonne), represents a fuel consumption of 38.564 tonnes of distillate/hour.

For 14 hours of operation at maximum capacity, the fuel required is estimated to be 539.89 tonnes or 638,168[28] litres of distillate.

The estimated cost for the first fill capacity (lasting 14 hours of operation at full load) is $832,873[29]. This figure is approximately $295,124 higher than last year's figure. This difference in fuel cost between last year and this year is due to the conflict in Ukraine which is impacting fuel costs throughout the world.

[26] Primary source for this value was information provided by the ERA, on 1 August 2022 (via email).
[27] Based on a calorific value of 38.6 MJ/L.
[28] Based on density of Diesel of 846 kg/m3.
[29] Last year's fuel cost was $537,749.

6. Margin M costs

6.1 Overview of Margin M costs

The allowance for the Margin M factor includes:

– Legal costs associated with the design and construction of the power station.
– Financing costs associated with equity raising.
– Insurance costs associated with the project development phase.
– Approval costs including environmental consultancies and approvals, and local, state and federal licensing, planning and approval costs.
– Other costs reasonably incurred in the design and management of the power station construction.
– Contingency costs.

The following sub-sections provide an overview of the cost estimate that make up the M factor.

6.2 Derivation of M factor in 2022

6.2.1 Legal costs

The legal cost estimated in 2021 was $2,220,620. This figure is approximately 1.69% of the 2021 reported capital cost applicable for a 160 MW OCGT power plant.

GHD has maintained the bottom-up approach used last year to determine the legal costs and has updated the table below based on this year's reported capital cost. The evaluation for legal costs is shown in the following table.

Table 15 Legal costs

Description	GHD's % estimate on project costs (based on previous projects)	GHD's estimate (A$)
Support for contract conditions for specifications, tender analysis, and negotiations	0.60	813,049
Legal content for diesel fuel supply contract	0.12	162,619
Legal support for PPA/Capacity/offtake contract	0.40	542,032
Legal support for financing/loan procurement	0.10	135,508
Legal support for grid connection agreement	0.12	162,619
Legal support for contracts during the construction phase	0.35	474,278
Total		**2,290,105**

Based on our assessment, in the table above for a 160 MW OCGT plant, our estimate for legal cost is $2,290,105. This is higher than last year's legal costs with the cost difference being due to this year's higher capital cost for the 160 MW unit.

6.2.2 Financing cost

The financing cost is comprised of capital raising costs and the cost of setting up the project vehicle for financing during the construction phase. Last year's assessment involved a bottom-up approach to evaluate the financing costs, which comprised of senior and subordinate debt loans. Last year's financing cost was estimated at $1,521,072.

Using the BRCP market procedure CAPM parameters, the equity to debt ratio this year is 60%/40% with a senior debt of 60% (of the total project loan[30] – (0.4 * ((135,508,167 + 6,769,833)*0.6))) = 34,146,720) and a subordinate debt of 40% (of the total project loan - (0.4 * ((135,508,167 + 6,769,833)*0.4))) = 22,764,480). GHD's estimate for loan fees based on the loan amount ($ for borrowing 40% of the full project cost) is as follows.

Table 16 Finance cost

Loan fee	% fee for the loan	Amount A$
Senior loan	2.50%	853,668
Subordinate loan	3.15%	717,081
Total		**1,570,749**

*Note the % split and magnitude for Senior and Sub-ordinate loans were derived from a previous project and is indicative of a project of this capacity.

Based on our assessment, the financing cost is estimated to be $1,570,749 this year and is $49,677 higher than last year's cost for financing. This difference is due to this year's slight increase in OCGT capital cost and diesel plant capital cost increase for the 160 MW generic unit.

6.2.3 Insurance cost

The cost of insurance assumes considering several risks that may occur during the construction phase of the power plant. An OCGT of this technology is a relatively simple technology compared with other power plant technologies and, therefore, would attract a premium commensurate with its comparatively low risks.

Insurance for a plant of this nature generally covers the following key risks:

– Loss due to fire and irreparable damage to the major plant components.
– Loss of income of the power plant due to lengthy delays during the construction phase.

The cost of insurance covering a loss of the key power plant component rendering it to be written off is generally about 0.5 to 0.7% of the capital cost for the project. It is assumed that the capital outlay during construction will ramp up during construction to the full project value until after the plant is commissioned, tested and handed over to the owner. However, insurance is based on the value of the commitment[31] since total loss may occur toward the end of construction when the owner has paid over at least 90% of the commitment. Insurance premiums take into consideration the payment schedule during construction and therefore will initially be based on the commitment or asset value insured by the owner. Similarly, as was done last year, GHD has used a figure mid-way between 0.5% and 0.7% and therefore the insurance cost is estimated to be $813,049.

Loss of income due to delayed construction is not always a risk that power plant owners insure against, and since the loss of income is very subjective between insurance companies it can usually be recovered by the owner through liquidated damages[32]. Therefore, as was the case in last year's assessment, the estimate for insurance premium for delayed construction risk is not included as part of the insurance cost for this assessment.

[30] Note that this capital is the capital cost for the power plant plus the cost for fuel storage excluding the cost for fuel.
[31] The value of the 160 MW power station.
[32] Albeit there is typically a cap on liquidated damages.

6.2.4 Permit and approvals cost

In developing the permit & approvals cost, GHD considered the following potential cost items:

– Greenhouse gas management plan development.
– Approvals and licences under Part V of the *Environmental Protection Act 1986*.
– Local government development approval.

Greenhouse Gas Management Plan

The Western Australian Environmental Protection Authority (EPA) *Environmental Factor Guideline Greenhouse Gas Emissions* (GHG Guidelines; EPA 2020) require greenhouse gas (GHG) emissions for all proposals that exceed 100,000 tonnes of scope 1 emissions each year measured in CO2-e. This is currently the same as the threshold criteria for the designation of a large facility under the Australian Government's Safeguard Mechanism.

The estimated CO2 emissions for a Siemens SGT5-2000E operating for 2% of the year at maximum capacity is 22,800 tonnes/annum, well below the 100,000 tonnes of scope 1 emissions threshold mentioned above. However, there is no guarantee that the plant will only operate for this limited period of time. As such, environmental approvals are likely to be based on the design capacity, not the expected operation capacity.

In addition to the estimated cost associated with the development of a greenhouse gas management plan and a strategy to avoid, reduce or offset emissions (as per below) costs associated with GHG emission abatements will also need to be considered. In addition to the GHG Guidelines, the EPA has released a *July 2022 Draft Revised Greenhouse Gas Guidance* for consultation (EPA 2022). The 2022 draft also includes the following statement:

"*The EPA considers that global warming should be limited to no more than 1.5 degrees Celsius (1.5C) above pre-industrial levels to minimise the risk of environmental harm to WA's environment. In order to contribute to this goal, the EPA's view is that there should be a deep and substantial reduction in WA's emissions this decade, and achievement of net zero emissions no later than 2050 through a straight-line trajectory (at a minimum) from 2030. This is the EPA's minimum expectation in terms of emission reductions. The EPA emphasises that proponents should seek to exceed these expectations and reach net zero well before 2050*."

Assuming that Draft guidance is adopted, then the measures required to abate the GHG emission would need to be significant and credible. GHD notes the assessment for this year is based on a 160MW gas turbine running on diesel. As technology progresses, it may be possible for future industrial gas turbines to run on less GHG-intensive fuel. Alternatively, long-duration storage technologies are developing at a fast rate and may come under consideration in the future.

Approvals and licences under the Environmental Protection Act

The basis of this costing assumes that the proposed power station will be constructed on land which is appropriately zoned under the relevant local government planning scheme. Following on from the release of the GHG Guidelines (EPA 2020) the EPA has applied an increased focus on GHG emissions. On this basis, it is anticipated that the EPA would require assessment under Part IV of the *Environmental Protection Act 1986* (EP Act).

The power station would also require a Works Approval and Licence under Part V of the EP Act and development approval under the relevant local government planning scheme.

Part IV approval

The project is expected to require referral and assessment under Part IV of the EP Act. Assuming the power station is located to avoid significant impacts on ecological values, the main emissions would be associated with emissions affecting air quality. The impact assessment would need to provide a full emissions inventory and assessment of the local and regional air quality values. Again, it is expected that the project is located in an area with sufficient setbacks to avoid air quality impacts in the local airshed, such that the project can be implemented without significant environmental impacts.

To support the project, as outlined above, a GHG Management Plan would be required. The *Environmental Factor Guideline Greenhouse Gas Emissions* (EPA 2020) specifies a requirement to demonstrate how a project contributes towards the Western Australia Government's aspiration of net zero emissions by 2050. Specifically, the guidance states:

> *"At a minimum, a Greenhouse Gas Management Plan should outline:*
>
> – *intended reductions in scope 1 emissions over the life of the proposal*
> – *regular interim and long-term targets that reflect an incremental reduction in scope 1 emissions over the life of the proposal*
> – *strategies which demonstrate that all reasonable and practicable measures have been applied to avoid, reduce and offset a proposal's scope 1 emissions over the life of the proposal."*

It is anticipated that a review of opportunities to avoid, reduce and offset GHG emissions would be required to identify strategies to address the requirements of the GHG Management Plan. Given the expectation for all projects to contribute to meeting the Western Australia Government target of net-zero by 2050, it is expected that staged emission reduction targets would be applied (i.e., 20% reduction in emissions by 2030, 40% reduction by 2035, 60% reduction by 2040, 80% reduction by 2045 and a 100% reduction by 2050). The method of achieving reductions may involve the replacement of the fuel source with green hydrogen or green ammonia. In the absence of a suitable replacement fuel, GHG offsets may need to be purchased.

Based on the above, for this year's assessment, costs associated with the development of a strategy to avoid, reduce or offset emissions have been included. However, given current policy uncertainty, the cost of conversion of the project to reduce GHG emissions or to offset the project has not been considered at this time.

Table 17 Part IV approval costs

Description	Estimate ($A)
Prepare and Part IV documentation	$85,000
Air and noise modelling	$30,000
Biological survey	$30,000
Preparation of GHG Management Plan	$45,000
Development of avoidance, reduction and offset strategies	$90,000
Total	**$280,000**

Works approval

A Works Approval issued by the Department of Water and Environmental Regulation under the Environmental Protection Regulations 1987 will be required to allow the construction of the power station.

An environmental assessment by the Department will focus on air, liquid and noise emissions. We have assumed that the site will contain remnant vegetation and consequently a biological survey will be required to support a Clearing Permit but will not require heritage clearance (given the nature of its zoning).

The Works Approval will need to provide the following information:

– General specifications of the main pieces of plant
– Proposed facility layout
– Standard emissions
– Typical operating conditions
– Storage of hazardous goods
– Details of any liquid runoff
– Fuel source and estimated consumption
– Proposed mitigation measures for any emissions, as well as any surface water runoff

Indicative costs are based on last year's assessment with an increase in cost due to current hourly rates. GHD notes air and noise modelling and the biological survey costs that were itemised under the Works Approval last year have now been included in the Part IV approval above. Similarly, while clearing permit costs are not separately itemised, these are included in the Part IV documentation and are also included in the total costs for Part IV costs. The Part IV approval was selected this year as the primary mechanism for approvals under the EP Act as it covers GHG aspects that are considered a likely cost going forward.

Table 18 Works approval costs

Description	Estimate ($A)
Prepare and submit Works Approval	$45,000
Application fee (est.)	$80,000
Total	**$125,000**

Licence

Once the power station is constructed, a licence to operate will need to be sought from the Department of Water and Environmental Regulation in relation to ongoing emissions obligations. The licence will document the type of emissions from the facility and specify the regular (annual) testing and reporting requirements.

Indicative costs are based on last year's estimates with an increase in cost due to current hourly rates:

Table 19 Department of Water and Environmental Regulation licence costs

Description	Estimate ($A)
Prepare and submit the licence application	$20,000
Annual license fee	$8,000
Annual stack monitoring	$15,000
Annual compliance report	$28,000
Total	**$71,000**

Local government development approval

The proposed facility will require development approval under the local government planning scheme. The development approval application will likely need to include:

– Appropriate application fee
– Details of the use proposed for the land or buildings
– Submission of three sets of plans consisting of:
  - Site plan
  - Elevations and sections of any building proposed to be erected or altered and of any building intended to be retained
  - Floor plan
  - Landscape plan
  - Drainage plan

Plans will need to include:

– Street names, lot number(s), north point and the dimensions/contours of the site.
– The location and proposed use of any existing buildings to be retained and the location and use of buildings proposed to be erected.
– The existing and proposed means of access for pedestrians and vehicles.
– The location, number, dimensions and layout of all car parking spaces are to be provided.
– The location and dimensions of any area proposed to be provided for the loading and unloading of vehicles carrying goods or commodities and the means of access to and from those areas.
– The location, dimensions and design of any landscaped or open storage areas.

– Building materials, including the specification of roof colours.
– The location of on-site remnant vegetation, in particular, mature trees.
– Boundary fencing treatments.
– The location of any underground service lines.

Indicative costs are based on last year's estimates with an increase in cost to reflect current hourly rates:

Table 20 Development approval costs

Description	Estimate (A$)
Prepare landscape & drainage plans	$40,000
Prepare and submit the Development Application	$30,000 (assumes engineering and building details are provided)
Application Fee	$50,000
Total	**$170,000**

Summary of permit and approval costs

A summary of the permit and approval costs included in this year's estimate is provided below. The total estimated cost is $500,028. This is $175,850 higher than last year's cost ($299,912). Primarily, this is due to the change requiring a Part IV approval under the EP Act, which includes the development of a GHG management plan and a strategy for reducing or offsetting emissions.

Table 21 Permit & approval costs

Description	Estimate ($A)
Part IV approval under the EP Act (including the development of GHG Management Plan)	$280,000
Works approval under the EP Act	$125,000
Licence under the EP Act	$71,000
Local government development approval	$170,000
Total	**$646,000**

6.2.5 Design and project management (project development)

The project development cost is comprised of project management costs, owners' costs, initial spares, site services, and start-up costs. Our analysis of these costs is outlined in detail in the sub-sections below.

6.2.6 Project management

The project management services considered in this section pertain to project development by the developer which will include all costs associated with:

– Concept/pre-feasibility study
– Full feasibility
– Costs for the engagement of an Owner's Engineer
– Costs for the engagement of legal and financial services
– Cost associated for the owner to provide a project team

6.2.7 Owner's engineer

The owner's engineer services consider the following costs:

– Front End Engineering Design (FEED) which includes all site-related studies, specification, tendering, EPC contractor selection and contract negotiations up to financial close
– Construction management services to include, design drawing and document reviews, overseeing construction activities, witness testing and commissioning activities and ensuring that the O&M manuals and as-built drawings are correct

Last year's methodology used to establish project management and owner's engineering services was re-examined this year and was found to be sound and consistent with current practice.

The cost associated with project management and owner's cost is therefore based on last year's assessment with consideration to the current applicable hourly rate and is provided in the following table.

Table 22 Cost associated with project management and owner's engineer services.

Item	Cost (A$)	Description
Project Management		
Concept/feasibility study	$178,086	This is an average cost to produce a concept/feasibility study for an OCGT project. This normally takes 1 to 2 months to complete. This cost has increased by 5% being a conservative rate increase over last year's rate which was impacted by COVID.
Full Feasibility Study	$664,864	This is an average cost to produce a full feasibility study) for an OCGT project. This normally takes 3 to 4 months to complete. This cost has increased by 5.0% being a conservative rate increase over last year's rate which was impacted by COVID.
Engagement of an Owner's Engineer	$261,787	This is an average cost to carry out a tender process to engage an owner's engineer to represent the owner for the construction of the OCGT Plant. This normally takes 2 to 3 months to complete. This cost has increased by 5.0% being a conservative rate increase over last year's rate which was impacted by COVID.
Engagement of legal & financial services	$361,511	This is the average cost to evaluate legal and financial groups to provide these support services for the OCGT plant. This normally takes 2 to 3 months to complete. This cost has increased by 5.0% being a conservative rate increase over last year's rate which was impacted by COVID.
Cost associated for the owner to provide a project team	$1,059,600	This is the cost associated for the owner to provide a team of staff to oversee the progress of the project from concept to commercial operation. This normally takes 2 to 3 years to complete. This cost has increased by 5.0% being a conservative rate increase over last year's rate which was impacted by COVID.
Owner's Engineer		
FEED & Contractor selection (tender process) up to Financial close	$2,065,800	This is an average cost to produce a front-end engineering design (FEED) and for an OCGT project and a tender process to establish an EPC contractor and the necessary contract for the construction of the OCGT plant. This cost has increased by 5.0% being a conservative rate increase over last year's rate which was impacted by COVID.
Construction management services	$2,754,400	This is the average cost to carry out construction management services by an Owners engineer throughout the construction period up to and including testing & commissioning. This cost has increased by 5.0% being a conservative rate increase over last year's rate which was impacted by COVID.
Total	**$7,346,048**	

Based on the table above, the cost associated with project management and owner's engineering services is $7,346,048 and is $349,808 higher than last year's estimate of $6,996,248. This cost has increased compared to last year as this year it was assumed that a consultancy rate increase of 5.0% is applied post the commencement of COVID in the year 2020, where consultancy rates were assumed to remain stagnant in 2020 and subjected to a modest increase in 2021.

6.2.8 Other costs

Initial spares

As was the case in last year's assessment, it was assumed that a minimum quantity of spares will be held by the power plant operators. GHD considers that spares will be held for scheduled maintenance such as hot gas path inspections and minor overhauls, and thereafter replacement parts will be ordered on an as-need basis.

The following table outlines areas of concern for the Siemens gas turbine, and only those items marked "Wear" under the category "Findings" are likely to be held in stock at the power station.

Table 23 Areas of concern for Siemens V94.2 GT

Item	Component	Findings	Measures
1	Compressor Blades	Corrosion & cracks	Replacement
2	Compressor Vanes	Cracks on Hooks	Replacement
3	Flame Tube Tile Holders	Wear	Replacement
4	Burner	Corrosion & cracks	Replacement
5	Seal Ring	Wear	Replacement
6	Casing	Cracks	Repair
7	Turbine Blades	Cracks/Degradation	Rotatable spare or Life extension for one further interval
8	Inner Casing	Oxidation	Rotatable spare or repair and life extension for one further interval
9	Rotor Disk	Oxidation	Requalification and life extension for 100,000 EOH
10	BOP plant spares for wear (filters, gaskets, hoses, bolts, nuts, spare transfer pump, fuses, control cards, etc.	Wear	Replacement

Source Life Extension for Siemens Gas Turbine[33]

The cost estimate for the parts marked "Wear" was estimated to be approximately $560,818 in last year's assessment. This will differ from plant to plant depending on the adopted operator's maintenance strategy. For this year's assessment, GHD has added applicable escalation (5.72%) since last year. Therefore, our estimate for initial spares is $592,896.

Site services

Last year's allowance for site services was $171,962. GHD considers last year's estimate for site services to be reasonable (based on the site services required for this technology power plant). GHD's assessment for site services for this year is based on last year's estimate with an allowance for O&M escalation of 5.72%. Therefore, our estimate of $181,798 is assumed to cater for the cost of site services for this year.

Start-up costs

The start-up cost for the 160 MW OCGT power plant considers the cost of recruiting and training and employing staff during commercial operations as well as the cost of fuel and consumables used for testing and commissioning the plant.

[33] Life Extension for Siemens Gas Turbine, Guido Lipiak, Susanne Bussmann, Power-Gen Europe 2006 30 May-1 June 2006, Cologne, Germany.

The value used in last year's Report was 1.5% of the capital value for the 160 MW OCGT plant. GHD considers this value to be reasonable as it was based on the output from GTPro. Therefore, based on using 1.5% of the capital value for the 160 MW OCGT plant, our estimate is $2,032,622. This is an increase of $61,658 over last year's value of $1,970,964 due mainly to a slight increase in the capital cost for this year's assessment.

6.2.9 Contingency

The contingency is an allowance for items that were not identified at the time of producing a cost estimate resulting from the level of design available. The major cost for an OCGT power plant is the gas turbine package, which in this case is well defined by GTPro. Costs for gas turbines are updated regularly and therefore GHD considers that the level of accuracy for the gas turbine is high.

In last year's Report, a contingency of 5% of the capital cost for the 160 MW OCGT plant was used which is consistent with the previous year's and, therefore, for this year's report GHD maintains that a contingency of 5% is reasonable. Therefore, our estimate is $6,775,408. This is higher than last year's estimate ($6,569,880) due to slightly higher power station capital costs.

6.3 Overall M factor

The M factor for this year is provided in Table 24 below.

Table 24 Calculation of M factor for 2021

Component of "M"	2021 Cost (A$)	2022 Cost (A$)	Difference (A$)
Legal Cost	2,220,620	2,290,105	69,485
Financing Cost	1,521,072	1,570,749	49,677
Insurance Cost	788,385	813,049	24,664
Permitting & Approvals Cost	500,028	646,000	145,972
Design & Project Management	6,996,248	7,346,048	349,800
Other Costs:			
Initial Spares	560,818	592,896	32,078
Site services	171,962	181,798	9,836
Start-up cost	1,970,964	2,032,622	61,658
Contingency	6,569,880	6,775,408	205,528
Total	**21,299,977**	**22,248,675**	**948,698**

Following our assessment of the 2022 cost, the overall M factor has increased by approximately $948,698 primarily due to this year's higher capital cost for the 160 MW OCGT.

The overall M factor value is sensitive to several assumptions and styles of management from the specification of the plant to the operating and maintenance strategy adopted. However, the figure of $22,248,675 is considered to be within the range expected for this factor.

Appendix A

Acronyms and abbreviations

The following acronym and abbreviations are used in this report.

Acronym or abbreviation	Definition
AEMO	Australian Energy Market Operator
BOP	Balance of plant
BRCP	Benchmark reserve capacity price
CPI	Consumer price index
EGW	Australia electricity, gas, water (used in the context of the labour wage price index)
EP Act	*Environmental Protection Act 1986*
EPA	Environmental Protection Authority, Western Australia
EPWA	Energy Policy WA
ERA	Economic Regulation Authority
FEED	Front-end engineering design
FFC	Fixed fuel costs
GHD	GHD Pty Ltd
GHG	Greenhouse gas
GJ	Gigajoule
GRV	Gross rental value
HHV	High heat value
HV	High voltage
ISO	International Organisation for Standardisation
kV	Kila-volt
kW	Kila-watt
LHV	Low heat value
MJ	Megajoule
MVA	Mega-volt amperes
MW	Megawatt
NO	Nitrous oxide
O&M	Operating and maintenance
OCGT	Open cycle gas turbine
OEM	Original Equipment Manufacturers
SWIS	South West interconnected system
WEM Rules	Wholesale Electricity Market Rules
WPI	Wage price index

ghd.com

→ The Power of Commitment