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GOVERNMENT OF
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Energy
Policy WA

2026 Benchmark Technology Review

Draft Determination for consultation

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Abbreviations

Term	Definition
AEMO	Australian Energy Market Operator
BESS	Battery Energy Storage System
BRCP	Benchmark Reserve Capacity Price
CCGT	Combined Cycle Gas Turbine
COD	Commercial Operation Date
CONE	Cost of New Entry
CRC	Certified Reserve Capacity
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DCS	Distributed Control System
DEED	Department of Energy and Economic Diversification
DSP	Demand Side Programme
ERA	Economic Regulation Authority
ESM Rules	Electricity System and Market Rules
ESS	Essential System Services
ESR	Electric Storage Resource
ESOO	Electricity Statement of Opportunities
FCESS	Frequency Co-optimised Essential System Services
FID	Final Investment Decision
FOAK	First Of A Kind
FOM	Fixed Operations and Maintenance
GHD	GHD Pty Ltd
GT	Gas Turbine
HEGT	High Efficiency Gas Turbine
HRSG	Heat Recovery Steam Generator
IASR	Inputs, Assumptions and Scenarios Report
IDC	Interest During Construction
ISP	Integrated System Plan
kV	kilovolt
LP	Linear Programming
MAOP	Maximum Allowable Operating Pressure

MDQ	Maximum Daily Quantity
MIP	Mixed Integer Programming
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NOx	Oxides of Nitrogen
NUOS	Network Use of System
OCGT	Open Cycle Gas Turbine
OTSG	Once Through Steam Generator
PEACE	Plant Engineering and Cost Estimator
POE	Probability of Exceedance
PV	Photovoltaic
RBP	RBP
RCM	Reserve Capacity Mechanism
RH	Relative Humidity
RoCoF	Rate of Change of Frequency
SCGT	Simple Cycle Gas Turbine
SEO	State Electricity Objective
SRMC	Short Run Marginal Cost
SWIS	South West Interconnected System
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital
WEM	Wholesale Electricity Market
WEMSIM	Wholesale Electricity Market Simulation
WICRWG	Wholesale Investment Certainty Review Working Group
WST	Western Standard Time

Executive Summary

The Benchmark Technologies

The Benchmark Technologies are the reference technologies used to set the Benchmark Reserve Capacity Price (BRCP) for both Peak Capacity and Flexible Capacity. As defined in the Electricity System and Market Rules (ESM Rules), the Benchmark Technologies are *notional* new facilities of the Facility Technology Type which is expected to be able to provide capacity at the lowest annual capital cost and annual fixed operating and maintenance costs.

Under clause 4.16.11(c) of the ESM Rules, the Benchmark Technologies must be reviewed every three years, or more frequently if certain conditions have been met.

Under clause 4.16.11(b) of the ESM Rules, the Coordinator of Energy (the Coordinator) must review the Benchmark Technologies within six months of a changed Electric Storage Resource (ESR) Duration Requirement being published in the Wholesale Electricy Market (WEM) Electricity Statement of Opportunities (ESOO).

In the 2026 ESOO, the ESR Duration Requirement changed from 6 hours to 7 hours. The Coordinator is therefore now required to review the Benchmark Technologies (the Review).

The objective of the Review is to determine the Benchmark Technologies, used to set the Peak and Flexible BRCPs, which ensure system reliability is maintained at the most efficient cost to consumers.

In accordance with the definitions in the ESM Rules, the Coordinator must select the Benchmark Technologies on the basis that they are expected to deliver the relevant capacity service at the lowest annual fixed cost, including annualised capital costs and annual fixed operating and maintenance (FOM) costs.

The Benchmark Technologies are determined for a notional new facility that meets the criteria, and do not represent an expectation of the actual technologies that will or should enter the market in the future. Therefore, other project parameters, such as lead times are not taken into account in the selection process.

The BRCP will be determined to reflect a price that will allow the Benchmark Technologies to recover all of their capital and FOM costs without any other market revenue. All other technologies, with higher capital and/or FOM costs, will still be able to recover their costs by receiving energy and Essential System Services (ESS) market revenue.

Consultation

The WEM Investment Certainty Review Working Group (the Working Group) was engaged to assit with the Review and discussed the draft analysis and indicative proposal at its meetings on 16 July 2026 and 6 August 2026.

The Working Group were not consistent in their views regarding the following proposals:

- to not assume an emission intensity threshold for the Reserve Capacity Mechanism (RCM)
  - The Department of Energy and Economic Diversistfiation (DEED) has not changed this proposal because it reflects current conditions.
- to not include a distillate-only gas turbine in the long-list
  - DEED has not changed this proposal because it does not consider that a distillate-only facility would be built in the South West Interconnected System (SWIS).

Some Working Gourp members opposed the proposal to include the cost of a gas lateral but no Dampier to Bunbury Natural Gas Pipeline (DBNGP) gas reservation cost for the dual fuel technology. DEED has not changed the proposal because these costs do not relate to the RCM and should be included in the variable costs.

The Working Group discussed whether gross or net cost of new entry (CONE) should be applied when determining the BRCP and supported the outcome of the assessment.

Detailed meeting papers and minutes of these meetings are published on the Working Group’s website. A high level summary of the key points discussed and DEED’s responses is provided in section 2.6 of this paper.

Draft Determination

This Consultation Paper outlines the Coordinator’s draft determination for the Benchmark Technologies for Peak and Flexible BRCPs, and the approach to CONE. The proposals are summarised in Table 1.

The results of the analysis are outlined in the main body of this report and indicated that:

- the Benchmark Technology for both Peak Capacity and Flexible Capacity should be an E-Class[1] Single Cycle Gas Turbine (SCGT) [2], which is certified for Reserve Capacity on distillate, withpreference to run on gas when practical;
- the BRCP for both Peak and Fexlible Capacity should continue to be calculated based on gross CONE.

Table 1: Proposals - Benchmark Technologies and Gross/Net CONE

[1] E Class is a designation of a class of industrial gas turbine.

[2] Sometimes alternatively known as an Open Cycle Gas Turbine (OCGT).

Proposals	Rationale
Proposal A: The proposed Benchmark Technologies for Peak and Flexible Benchmark Reserve Capacity Prices are: • E-Class Simple Cycle Gas Turbines (SCGT) • Reserve Capacity certified on distillate, with preference to run on gas when practical • Located at a 330KV node on Clean Link North	The E-Class SCGT has the lowest capital cost and fixed operations and maintenance cost per MW per annum for both Peak Capacity and Flexible Capacity. This technology is capable of meeting the requirements of both the Peak and Flexible services as defined.
Proposal B: Retain a gross Cost of New Entry(CONE) approach.	The analysis indicates that the proposed Benchmark Technology will not earn material net revenues from the WEM, other than the RCM revenue. Implementing net CONE would add significant complexity and uncertainty to the BRCP determination procedure. This uncertainty may deter investment, undermining cost efficiency and reliability. Based on the analysis, the net revenues (other than RCM revenue) are not sufficent to justify this additional complexity and uncertainty.

Call for Submissions

Stakeholder feedback is invited on the proposed determination and analysis presented in this Consultation Paper, as outlined in Parts 2-3 of this paper.

Submissions can be emailed to energymarkets@deed.wa.gov.au. Any submissions received will be made publicly available on www.energy.wa.gov.au, unless requested otherwise.

The consultation period closes at 5:00pm WST on 7 October 2026. Late submissions may not be considered.

1. Introduction

1.1. Reason for the review

The Benchmark Technologies are the reference technologies used to set the Benchmark Reserve Capacity Price (BRCP) for both Peak Capacity and Flexible Capacity. As defined in the Electricity System and Market (ESM) Rules, the Benchmark Technologies are *notional* new facilities of the Facility Technology Type which is expected to be able to provide capacity at the lowest annual capital cost and annual fixed operating and maintenance costs.

Under clause 4.16.11(c) of the ESM Rules, the Benchmark Technologies must be reviewed every three years, or more frequently if certain conditions have been met.

Under clause 4.16.11(b) of the ESM Rules, the Coordinator of Energy (Coordinator) must review the Benchmark Technologies within six months of a changed Electric Storage Resource (ESR) Duration Requirement being published in the Wholesale Electricy Market (WEM) Electricity Statement of Opportunities (ESOO).

In the 2026 ESOO, the ESR Duration Requirement changed from 6 hours to 7 hours. The Coordinator is therefore now required to review the Benchmark Technologies (the Review).

The objective of the Review is to determine the Benchmark Technologies, used to set the BRCP for both Peak Capacity and Flexible Capacity (the BRCPs), which ensure system reliability is maintained at the most efficient cost to consumers.

In accordance with the definitions in the ESM Rules, the Coordinator must select the Benchmark Technologies on the basis that they are expected to deliver the relevant capacity service at the lowest annual fixed cost, including annualised capital costs and fixed operating and maintenance (FOM) costs.

The Benchmark Technologies are determined for a notional new facility that meets the criteria, and do not represent an expectation of the actual technologies that will or should enter the market in the future. Therefore, other project parameters, such as lead times are not taken into account in the selection process.

The BRCPs will be determined to reflect a price that will allow the Benchmark Technologies to recover all of their capital and FOM costs without any other market revenue. All other technologies, with higher capital and/or FOM costs, will still be able to recover their costs by receiving energy and Essential System Services (ESS) market revenue.

1.2. Scope of the Review

The objective of the Review is to determine the Benchmark Technologies used to set the BRCPs, which ensure system reliability is maintained at the most efficient cost to consumers. The following aspects related to the BRCPs are out of scope for this Review:

- the methods for setting BRCPs based on the Benchmark Technologies;
- the Reserve Capacity Price regime; and
- the Reserve Capacity Cycle timeline.

The Review consists of two key items:

1. Review of the Benchmark Peak Technology:
   a. to determine whether the current Benchmark Peak Technology is still appropriate or if a different Benchmark Peak Technology should be selected to represent the lowest fixed cost available technology; and
   b. to determine whether gross costs of new entry (CONE) or net CONE should apply to the Peak BRCP.
2. Review of the Flexible Benchmark Technology
   a. to determine whether the current Benchmark Flexible Technology is still appropriate or if a different
   b. to determine whether gross CONE or net CONE should apply to the Flexible BRCP.

1.3. Approach to the analysis

The following approach to the analysis has been undertaken for the Review:

1. Establishment of a long list of technologies
2. Pre-filtering the long list based on technology readiness for service by 2029[3]
3. Creating potential configurations of remaining technologies for assessment
4. Identifying the requirements that must be met to provide the Peak Capacity and the Flexible Capacity Service
5. Filtering of configurations based on service requirements
6. Identifying cost data (includin, based on the previous BRCP determination approach) for each configuration to deliver each Service
7. Identifying additional data for determination of CONE assessment
8. Conducting market modelling to inform the Benchmark Technology and Gross/Net CONE proposals
9. Development of Benchmark Technology and Gross/Net CONE proposals

[3] Technology readiness refers to the maturity of the technology itself and not the lead time for developing a project.

2. Benchmark Technology analysis

2.1. Introduction

The candidate configurations proposed for the 2026 evaluation long list and (preliminarily) evaluation of these against the Peak and Flexible Capacity service requirements has been undertaken to propose a preliminary shortlist.

Within the ESM Rules[4] the Benchmark Technologies are defined as follows:

- Benchmark Peak Technology: *In respect of a Reserve Capacity Cycle, a notional new Facility of the Facility Technology Type which is expected to be able to provide Peak Capacity at the lowest annual capital cost and annual fixed operating and maintenance costs as determined by the Coordinator under* clause 4.16.11.
- Benchmark Flexible Technology: In respect of a Reserve Capacity Cycle, a notional new Facility of the Facility Technology Type which is expected to be able to provide Flexible Capacity at the lowest annual capital cost and annual fixed operating and maintenance costs as determined by the Coordinator under *clause 4.16.11.*

The candidate technologies include simple cycle gas turbine (SCGT), closed cycle gas turbine (CCGT), high efficiency gas turbine (HEGT) and reciprocating engine-based technologies (using distillate or natural gas fuel) plus battery energy storage system (BESS) technologies, and consideration of any other technologies long-listed in 2025.

The GT and reciprocating engine- based configurations are generally as per the 2025 review[5]. Although it was determined in the 2025review that the 2 x F class[6] SCGT was "too big" to be credible as the Benchmark Technology, it was included in this Review (as a single unit) as some stakeholders had expressed an interest. However, it was not assessed as meeting the requirements due to its size.

The analysis, in a later step, includes a calculation of the estimated BRCP for each candidate configuration to identify the least-cost configuration. The BRCPs were determined, applying the method and parameters used by the Economic Regulation Authority (ERA) in its WEM Procedure for the BRCP[7].

Where appropriate, parameters from the 2026 BRCP Final Determination have been applied in the calculations[8] .

AEMO's "2026 Inputs Assumptions and Scenarios" (IASR) Final Report was published 25 June 2026[9]. Updated cost figures from the IASR have been considered.

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4 Electricity System and Market Rules - 1 July 2026

5 2025 Benchmark Technology Review

6 2025 Benchmark Capacity Providers Review

7 ERA, "WEM Procedure : Benchmark Reserve Capacity Prices" Version 9, 14 January 2026

8 ERA, "2026 Benchmark Reserve Capacity Prices for the 2028/29 capacity year – Final Determination", 13 March 2026

9 2026 Integrated System Plan - Inputs and assumptions workbook

2.2. Configuration development

Considerations for determining the long list of technologies

The long list of technology configurations was developed with consideration of the following factors which are unchanged from the 2025 review:

- The technology must be able to be certified by AEMO for the provision of Reserve Capacity under the existing ESM Rules.
- For Peak Capacity, the technology must be able to be configured in a way that limits its largest network contingency to 330 MW. This is because the requirements for Contingency Reserve Raise services are based on the size of the largest contingency which is often set by the largest Facility. Currently, the largest generator in the SWIS has 331 MW of Capacity Credits.
- For Peak Capacity, an Operating Temperature of 41 degrees Celsius is assumed.
- For Flexible Capacity, Peak Capacity compliance must be satisfied, as well as a minimum stable load of 46%, ramp rate of a minimum of 3% of nameplate per minute and dispatch time < 30 minutes.
- The technology must work with existing infrastructure in the SWIS to reflect the fact that an efficient new entrant is most likely to be an incremental development of an existing technology. It is unlikely that an efficient new entrant would be establishing supporting infrastructure from scratch.
- Candidate facilities are located close to existing gas pipeline (if required) and electricity transmission infrastructure, and that the infrastructure has sufficient capacity for the facility.

The long list of technology configurations was developed with consideration of the following factors which are adjusted from the 2025 review:

- Candidate technologies no longer need to meet the indicative 0.55T CO_2 / MWh emission intensisty threshold proposed during the WEM Investment Certainty Review.
  - During the 2025 review, it was DEED’s expectation that the indicative emission intensity threshold developed under the WEM Investment Certainty Review would be implemented.
  - The threshold was applied as a constraint in the shortlisting process.
  - Since 2025 there has been no progress towards introducing the threshold and DEED’s best expectation is that it won’t be imposed in a timeframe relevant to this determination. Therefore, no threshold is applied for this determination.
  - The impact of this change is that several SCGT technologies, including E-Class turbines, are now eligible to be included in the shortlist.
- The amortisation period for thermal plants has been adjusted down to 15 years from 25 years in the 2025 review, better reflecting the financing period of these plants. All annualised costs have been calculated over a consistent 15 year financing period.
- Natural gas only and dual fuel configurations have been assessed for all thermal plants, reflecting that the indicative 0.55T CO_2 / MWh threshold is not taken into consideration in this Review. Natural gas configrautions are assessed with a 36 inch 15 MPa lateral, compressor and DBNGP capacity charges to satisfy 14 hour fuel requirements for every day instead of assuming 14 hours over 3 days. Dual fuel options are assessed with a “skinny” lateral and onsite distillate fuel storage to satisfy the 14 hour fuel requirement.

- An increased ESR Duration Requirement of 7 hours, rules the previous Benchmark Technology of a 200 MW / 12 MWh BESS ineligible on the basis of its duration.

Increased transparency

DEED has aimed to increase transparency around the process used to determine the Benchmark Technologies. This includes increased visibility of the parameters, figures and calculations used alongside the long list of technology configurations to determine the Benchmark Technologies. A calculation workbook, which utilises publically available and reproducible data is provided alongside this paper on the Coordinator's Website, and it can be found on the [Review webpage].

Basic power plant configurations

The long list of configurations for this current Review were initially evaluated against those considered for the 2025 review, with adjustmenst made as noted above (see Table 2 below).

For the SCGT, CCGT, HEGT and reciprocating engine options, DEED used the Thermoflow suite (GTPro and the Plant Engineering and Cost Estimator - PEACE) to configure the plant and to base a cost estimate upon.

The configurations assessed in the modelling were set up with the following assumptions:

- Rating point at 41°C dry bulb. DEED has assumed a coincident relative humidity (RH) of 20% to go with this temperature[10] and a site elevation of 100m.
- 330kV connection at unconstrained network node.
- Site and ancillary plant per DEED's expectations e.g. soft ground, buildings as appropriate (GT and heat recovery steam generator (HRSG) outdoors, steam turbines and water treatment plants indoors), no gas compression on-site[11], dual fuel provisions etc), inclusive of emergency diesel genset, distributed control system (DCS), site firefighting and fire water reserve, fuel tanks etc

Configuration-specific adjustments include:

- The gas turbine and engine-based configurations could be certified using gas fuel (using a compressed gas lateral to provide the necessary firm fuel capacity (this is called a "fat lateral" in this review), or be certified on distillate fuel and have a simpler lateral gas connection. Each option has been considered with the lower cost option anticipated to be the appropriate candidate option.
- The E-Class CCGT (2xGT13E2) has been modelled as multi-shaft and with bypass stacks. This would allow ²/₃rds of capacity to be dispatched in circa 30 mins with full capacity in circa 60 mins if the plant has been offline less than 8 hours.
- The F-Class CCGT (1x9FA) has been modelled as single shaft without bypass stack.
- Configurations based on more numerous units (aero-derivatives and recips) are based on shared generator transformer groups to reduce costs.

[10] This has an impact as the gas turbines are assumed to have inlet air "fogging" cooling

[11] Would be included in the gas connection at the top of the lateral where needed

Costs and parameters of BESS are also shown based on the IASR values with seven-hour BESS being an interpolation of four-hour and eight-hour BESS as provided in the IASR.

Based on information provided by Western Power, DEED has identified that a node on the Clean Energy Link North is the appropriate unconstrained Network location.

Additional parameters

The costs of the following over-and-above the basic power plant costs have been developed as follows:

Pre-FID development	A nominal allowance as per the 2025 review is added to the capital cost of each project. This is a nominal sum for completeness which does not materially impact the costs.
Land (power station)	Power station areas are estimated by comparison against actual power stations of similar configuration in Western Australia or the National Electricity market (NEM). The land cost per hectare is derived from the values for the latest BRCP escalated as appropriate. This is for the power station facility only. The electricity switchyard and gas facilities' land is separately included (below).
Electrical connection	The configurations suit a 330 kV connection fed into one circuit using a breaker-and-a-half, two diameters arrangement assuming a dedicated switchyard. It is assumed there is 2km of 330kV circuit length between the powerplant and the switchyard consistent with the ERA determination[7] Clause 3.4.6(a)(ii).
Gas connection – compressed lateral (fat lateral) case	It is assumed the power station is supplied with a dedicated lateral also serving as the (gas) fuel store. A 36-inch (900dia) pipeline of 15 MPa MAOP is assumed and the length required is determined to contain 14 hours[12] of fuel at a minimum pressure appropriate for each gas turbine/engine (ie assuming no second gas compressor station at the power station site) and a lateral operating pressure of 13 MPa. Compression capacity (in MW) is based on compressing from 3 MPa to 13 MPa x the flow required for each configuration over 14 hours, being provided in (3x24-14) hours of compression time. Pipeline and compressor station costs will be allowed per GHD's report for AEMO[13], escalated (to $2026 for this review). Land area is allowed based on the size of a typical station[14] of 5 Ha A nominal allowance for facilities will be added.
Diesel fuel storage	For the candidate configurations with distillate as the relevant fuel, tankage and demineralised water[15]. A demin. water plant is assumed included.
Water (external infrastructure)	No specific costs for other external infrastructure are added.

[12] The 14 hours of fuel availability has been applied due to the definition of Capability Class 1 Availability Assessment Duration which is defined as 28 Trading Intervals, itself defined as 30 minutes, under the ESM Rules, op cit

[13] GHD for AEMO "Gas Infrastructure Cost Building Block costs for gas infrastructure" 15 May 2025

[14] DBNGP CS3

[15] Incremental tankage is inexpensive and allows for re-ordering before tankage is empty and logistics delays/risks. This assumes a distillate primary-fuelled gas turbine would be water injected for NOx control

2.3. Configurations – longlist

The long-list of technology configurations is shown in Table 2[16]:

Table 2 Previous generation technology longlist (2025 review)

Technology	Evaluation 2025	Evaluation 2026
OCGT Heavy duty (same as Industrial SCGT) • Gas fuelled • Distillate fuelled	Re-evaluated based on higher efficiency units available than were evaluated in 2023	Re-evaluated based on higher efficiency units available than were evaluated in 2023
OCGT Aeroderivative (same as Aero SCGT) • Gas fuelled • Distillate fuelled	Evaluated	Evaluated
High Efficiency Gas Turbine (HEGT) (same as LMS100PB) • Gas fuelled • Distillate fuelled	Evaluated	Evaluated
Reciprocating engine • Gas fuelled • Distillate fuelled	Evaluated	Evaluated
CCGT with once through steam generator (OTSG)	Replaced by alternative drum-type boiler configuration using bypass stacks below which is a proven and common technology[17].	Superseded by configuration below (per 2025 evaluation)
CCGT Drum SG – Gas fuelled	Evaluated	Evaluated
Fuel cell	Not likely to be competitive for this purpose in this timeframe	Not likely to be competitive for this purpose in this timeframe
Lithium based BESS	Evaluated	Evaluated
Vanadium based BESS	Not likely to be competitive for this purpose in this timeframe	Not likely to be competitive for this purpose in this timeframe
Sodium based BESS	Not assessed / Not applicable	Still First-Of-A-Kind in current timeframe. Not included
Pumped storage	Excluded	Excluded
Solar thermal	Not likely to be competitive for this duty in timeframe	Deleted
Solar PV	Not competitive due to low allocation of Capacity Credits per MW of plant capacity	Not competitive due to low allocation of Capacity Credits per MW of plant capacity
Wind	Not competitive due to low allocation of Capacity Credits per MW of plant capacity	Not competitive due to low allocation of Capacity Credits per MW of plant capacity

[16] Includes the long-list of technologies applied in the 2025 review (itself considered against the 2023 review), and considerations for the present review:

[17] OTSG configurations are rare in practice and suffer operational difficulties with maintaining water quality in the steam cycle

In choosing the configuration sizes, DEED has considered the scale and configuration of gas turbine-based projects that are generally applied in developments. Most gas turbine-based plants are designed on a multiple unit basis rather than a single unit.

Multiple units provide efficient use and cost of facilities and infrastructure, sharing of spare parts and operating procedures and operator knowledge, and assists operators to manage the contingency risks (“N-1” risk). Of the 72 significant gas turbine power stations in Australia only 12 stations are based on a single unit (17%) and the remainder are multi-unit stations. In the SWIS two of the current 35 gas turbine-based facilities are single unit configurations.

This consideration does make the industrial SCGT arrangements larger than was historically evaluated for the Benchmark Technology due to the size of individual units (generally > 160MW/unit). While the total fixed cost of the larger facility would be higher than for the smaller facility historically assessed, cost on a $/MW/year basis are lower for the larger facility due to economies of scale.

The Aeroderivative SCGT and reciprocating engine options could readily be developed in smaller facilities, however the costs ($/MW) would be slightly higher due to loss of economies of scale.

The BESS could be developed as a larger or smaller unit. The economy of scale effects are negligable for BESS, with only the site size and the electrical connection costs ($/MW) effected for a smaller or larger seven-hour BESS MW capacity. For these technologies, 200MW nominal facility sizes have been evaluated capturing the economies of scale for the site-works and connection costs.[18]

In making configuration selections, DEED has applied a maximum single contingency of 330 MW, and electrical connection costs are considered in line with this assumption.

The candidate configurations and their parameters are shown in Table 3:

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[18] A smaller sized BESS has not been considered because because the economics of scale would make it more expensive per MW despite lower connection costs.

Table 3 Candidate configurations (performance at 41°C, 20% RH, clean-as-new)

	Industrial SCGT			Aero SCGT			CCGT		Recip.		BESS
	2xGT13E2	2xSGT5-2000E	1xGE 9FA.04	4xLMS100PB	6xLM6000PF-SPRINT	12xLM2500 G4 DLE	2xGT13E2 2+1 w/. Bypass stacks	1xGE 9FA.04 1+1 ss	12xWartsila med spd	24xJenbach. Med Speed	BESS
Gross MW	346.2	353.0	262.0	367.4	268.4	386.3	500.6	399.2	220.5	249.3	
Net MW	341.2	347.8	258.2	356.2	264.1	380.2	489.3	389.5	217.4	244.3	200
# network connections	2	2	2	2	1	2	2	1	1	1	1
Single contingency loss, MW[19]	170	174	258	178	264	190	326	390	217	244	200
HR, net, LHV kJ/kWh	9,771	10,057	9,609	8,720	8,979	9,392	6,818	6,319	7,868	7,882	
Land Ha (excl switchyard) [20]	3.4	3.4	2.5	2.0	3.0	12	4.0	4.0	2.0	2.5	12.1 (7h)
Technical life	35	35	35	35	35	35	35	35	35[21]	35[21]	20[22]
Economic life (assumed)	25	25	25	25	25	25	25	25	25	25	15
Financing period	15	15	15	15	15	15	15	15	15	15	15

The financing periods assumed are the amortisation periods to be applied in the Benchmark Technology calculations.

The economic life assumed for the BESS considers the annualisation prescribed in the current BRCP WEM Procedure, which assumes that investors would consider a 15 year ammortisation period[23].

Economic lives for gas turbine and engine-based plants are consistent with those applied in the 2023 and 2025 reviews[24].

The amortisation period for thermal plants has been adjusted down to 15 years from 25 years in the 2025 review, better reflecting the financing period of these plants.

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19 Assume grouped onto step up transformers, max. 4 transformers per config

20 Land areas have been provided based on actual plants in Australia. Since scope differences exist (such as with/without liquid fuel storage) some inconsistencies are evident however the impact on the calculations is not material

21 In peaking duty

22 Substantial mid-life capex required if operation beyond 20 years envisaged

23 The 15 year annualisation was already applied in previous versions of the Benchmark Reserve Capacity Prices Procedure including versions where the Benchmark Facility was an open cycle gas turbine.

24 2025 Benchmark Capacity Providers Review – 2023 Benchmark Capacity Providers Review

The storage capacity of BESS declines over time relative to the number of cycles experienced. Only the as-new nominal storage duration is considered in this Review. BESS OEM suppliers can now offer warranties for life and performance to 20 years (generally based on one cycle/day) with the supplier factoring in the costs and degradation under the expected duty in their service agreement costs and/or in providing increased initial capacity to meet the warranted duty at the end of the term.

Emissions threshold

The expectation in the 2025 Benchmark Technology Review was based on the indicative proposal for an emissions threshold developed as part of the WEM Investment Certainty Review in 2023. In mid-2025, when the analysis was previously undertaken, it was DEED's expectation that the 0.55t/MWh policy may be implemented and be part of the relevant requirements. Consequently, in 2025 the 0.55t/MWh constraint was imposed on the candidate technologies' shortlisting process, and the long list of candidate technologies only had gas-only configurations.

Subsequent to the 2025 analysis, there has not been any progress towards introducing the 0.55t/MWh limit. It is presently DEED's best expectation that such a limit will not be imposed within a timeframe relevant to this determination, therefore it has not been applied as a constraint on the candidate configurations in this Review.

The impact of this change is that several SCGT technologies, including E-Class turbines, are now eligible to be included in the shortlist, when they previously were not.

If, subsequent to this Review, actions are taken to proceed with the consideration of this threshold for the RCM, then it may be included in future Benchmark Technology determinations.

The environmental limb of the State Electricity Objective (SEO) is still considered by the Coordinator, in balance with the other limbs, as part of this Review.

2.4. Candidate configurations shortlist

Evaluation against requirements

The candidate configurations are assessed against basic performance (for the Peak Capacity service) requirements in Table 4, and for the additional requirements of the Flexible Capacity service in Table 5.

Table 4 Candidate configurations

	Industrial SCGT			Aero SCGT			CCGT		Recip.		BESS		
	2xGT13E2	2xSGT5-2000E	1xGE 9FA.04	4xLMS100PB	6xLM6000PF-SPRINT	12xLM2500 G4 DLE	2xGT13E2 2+1 w/. Bypass stacks	1xGE 9FA.04 1+1 ss	12xWartsila med spd	24xJenbacher med Speed	6h BESS	7h BESS	8h BESS
Single contingency < 340 MW[25]	✓	✓	✓	✓	✓	✓	✓	✗	✓	✓	✓	✓	✓
7-hour rating (storage)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$^6/_7$ cap only	✓	$^7/_8$ cap only

Table 5 Candidate configurations – Flexible Capacity service

	Industrial SCGT			Aero SCGT			CCGT		Recip.		BESS		
	2xGT13E2	2xSGT5-2000E	1xGE 9FA.04	4xLMS100PB	6xLM6000PF-SPRINT	12xLM2500 G4 DLE	2xGT13E2 2+1 w/. Bypass stacks	1xGE 9FA.04 1+1 ss	12xWartsila med spd	24xJenbacher med Speed	6h BESS	7h BESS	8h BESS
Peak service compliance (Table 4)	✓	✓	✓	✓	✓	✓	✓	✗	✓	✓	$^6/_7$ cap only	✓	$^7/_8$ cap only
Min stable load 46% for Non-intermittent[26]	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	N/A	N/A	N/A
Ramp rate 3%/min up & down	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Dispatch time, 30 mins[27]	✓	✓	✓	✓	✓	✓	$^2/_3$ cap only	✗	✓	✓	N/A	N/A	N/A

25 This is not a regulated limit however exceeding this size would impose larger Contingency Raise Reserve causer-pays costs that are not considered in this review

26 Note while the gas turbine-based plant can generally operate down to 20% (typ.) load, the Dry Low Emissions burners will generally switch to a high emitting mode (diffusion configuration – results in higher NOx emissions) below about 50% load. It is not considered good-environmental-practice to operate on a sustained basis in such a mode

27 **Fast Start Facility:** A Scheduled Facility or Semi-Scheduled Facility that is capable of:

(a) synchronizing and changing its rate of Injection or Withdrawal within 30 minutes of receiving a Dispatch Instruction from AEMO; and

(b) shutting down within 60 minutes from the time the Dispatch Instruction to synchronise was issued.

The resulting eligible shortlisted candidate configurations proposed are the configurations that meet the evaluation criteria above, as shown in Table 6:

Table 6 Resulting[28] short-listed candidate configurations

	Industrial SCGT			Aero SCGT			CCGT	Recip.		BESS	
	2xGT13E2	2xSGT5-2000E	1xGE 9FA.04	4xLMS100PB	6xLM6000PF-SPRINT	12xLM2500 G4 DLE	2xGT13E2 2+1 w/. Bypass stacks	12xWartsila med spd	24xJenbacher Med Speed	7h BESS	8h BESS
Peak Service	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	$^7/_8$ cap only
Flexible Service	✓	✓	✓	✓	✓	✓	$^2/_3$ cap only	✓	✓	✓	$^7/_8$ cap only

2.5. Technology cost results

Estimated BRCPs for each shortlisted technology have been calculated. These are the expected values of a generic build cost. They are for a hypothetical project for commissioning by 1 October 2029.

The data sources used in the calculations are publicly available information where possible, with minimal adjustment:

- CSIRO GenCost
- Thermoflow where GenCost does not cover a technology configuration
- BESS: IASR values, with interpolation for 6 and 7-hour storage

The detailed methodology and assumptions used in the calculations are documented in Appendix B.

Thermal plant has been evaluated separately with two fuel supply alternatives:

- Certified on gas, gas fueled with a fat lateral to provide the required 14-hour fuel availability
- Certified on distillate, but assuming gas is the prefered fuel, with a skinny lateral included

The resulting BRCPs are shown below in Figure 1

[28] The six hour BESS is eligible for $^6/_7$ of its capacity however the annual cost after applying this factor makes it higher cost than the seven-hour BESS

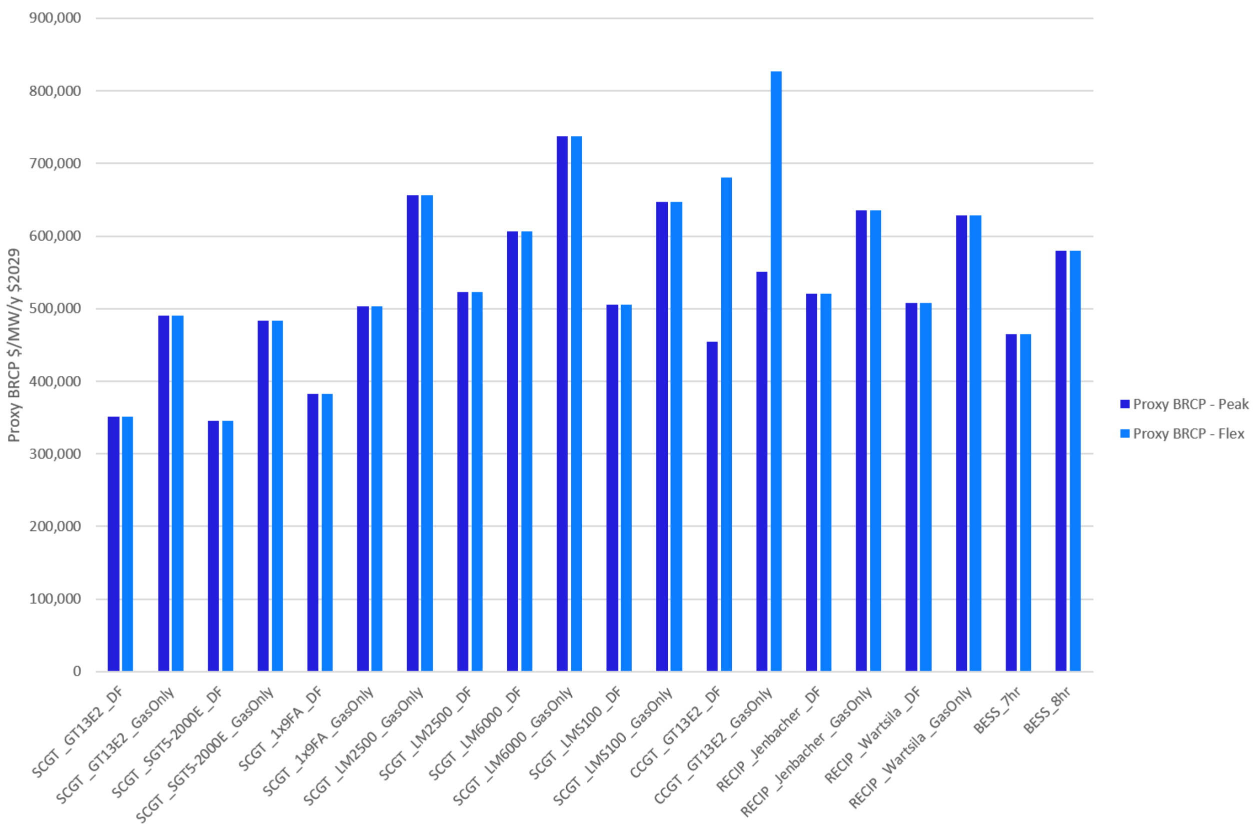


Figure 1. Estimated BRCP by technology

The proposed conclusions from this analysis are as follows:

- An E-Class SCGT certified on distillate, with preference to run on gas when practical, is the lowest cost Benchmark Peak Technology and Benchmark Flexible Technology.
- This is based on an estimated annualised fixed capital and FOM cost of $344,893 / MW
  - The estimated BRCPs of the GE (GT13E2) and Siemens (SGT5-2000E) machines are not significantly different.
- This technology has a 26% lower estimated BRCP than a 7-hr BESS.
- In general, the gas-only GT and reciprocating engine options, using a fat lateral for gas availability, are more expensive than the corresponding options certified on distillate, and hence have a lower cost gas lateral and lower DBNGP gas transport cost allowance to meet RCM availability requirements.

2.6. Proposed Benchmark Technologies

Proposal A:

The proposed Benchmark Technologies for the Peak and Flexible BRCPs are:

- An E-Class SCGT certified on distillate, with preference to run on gas when practical, connected to an unconstrained network node on the Clean Energy Link North.

Consultation questions:

1. Based on the analysis, do stakeholders agree with the proposed Benchmark Peak Technology?
2. Based on the analysis, do stakeholders agree with the proposed Benchmark Flexible Technology?

Working Group Feedback

Working Group meetings were held on 16 July 2026 and 6 August 2026 to discuss the draft analysis and indictative proposals. Detailed meeting papers and minutes of these meetings are published on the Working Group's webpage. In addition to these meetings, Working Group members provided feedback via email.

Below is a high level summary of the key points discussed and DEED's responses.

- Not applying an emission intensity threshold of 0.55 tCO_2e/MWh for the Benchmark Technology
  - Some Working Group member considered that not applying the emission intensity threshold, which results in the dual fuel SCGTs to become the reference technology, is inconsistent with the environmental limb of the SEO.
  - Some Working Group member supported not applying a threshold, as it would better achieve the limb of the SEO relating to cost to consumers and reflects the current regulatory framework.
  - DEED notes that:
    - » The environmental limb of the SEO is still considered in the analysis. However, it is not considered through a specific emission intensity threshold for the RCM for the reasons outlined under section 2.3.
    - » The 2025 analysis showed that the selected SCGT running on gas may meet the emission intensity threshold initially but not over the considered timeframe, due to degradation.
    - » While the dual fuel SCGT would be certified on distillate (with a higher emission intensity), it would be expected to ~~mainly~~ run on gas as the marginal unit when practical. Therefore, overall its emissions would be relatively low.
- distillate-only fueled plant configurations:
  - For thermal technologies, the analysis considered configurations that are either dual fuel (certified on distillate but ~~primarily operating~~ with gas being the primary fuel when practical) or gas only. Distillate-only configurations are not considered.
  - Some Working Group members considered that distillate-only facilities that don't require a connection to the gas network should be considered for the Benchmark Technology as this would likely result in a lower BRCP and therefore better address the limb of the SEO related to the cost to consumers.
  - DEED considers that a distillate-only facility is not a credible option for the Benchmark Technology because:
    - » This would not be consistent with the environmental limb of the SEO;
    - » The Real-Time Market for Energy price will increase significantly every time a distillate only plant is dispatched in the WEM and this will impact on the SEO limb referring to the cost to consumers .
- Including the cost of a gas lateral and no DBNGP gas reservation cost for the dual fuel facility:

- The costs for the dual fuel facilities include the cost of a gas lateral, and assumes the plant runs primarily on gas. However, no fixed costs are included for gas reservation.
- Some Working Group members considered that without a gas reservation, the plant may not be able to access gas during the periods when Peak or Flexible Capacity service may be called on.
- DEED considers that it would not be appropriate to include the costs for gas reservation for a dual fuel facility certified on distillate when determining the BRCP. For the dual fuel facilities, any cost related to the plant operation on gas would be part of its variable costs and the cost for that would be recovered through the Real-Time Market (opportunistic or from the broader Market Participant portfolio) rather than be charged to the RCM.
- The alternative to pipeline reservation charges for a dual fuel facility is trucked LNG, which would also represent a variable cost related to operation of the facility in the Real-Time Market, as opposed to being necessary for certification in the RCM.

-

3. Gross vs Net CONE analysis

3.1. Introduction

This section details the analysis performed to address the question of whether gross or net CONE should be adopted for the BRCP.

3.2. Criteria

The criteria applied to decide whether gross or net CONE should be applied are as follows:

- For Peak BRCP:
  - If the reference technology would be the marginal energy supplier: Gross CONE should be applied.
  - If not, further assess whether applying net CONE would be more appropriate.
- For Flexible BRCP:
  - If the reference technology would be the marginal energy supplier in the intervals Flexible Capacity would be required: Gross CONE should be applied.
  - If not, further assess whether applying net CONE would be more appropriate.

In both cases, the further assessment consists of weighing up the potential advantages and disadvantages of Net and Gross CONE, informed by a forecast of the estimated BRCP values.

3.3. Methodology

This assessment involves financial modelling performed in Robinson Bowmaker Paul's (RBP) WEMSIM model of the WEM (an update of the same model used for the RCM Review) to analyse whether the proposed Benchmark Technology would be the marginal energy supplier in the Real-Time Market and to estimate the BRCP values that would result from the gross or net CONE approaches.

WEMSIM is a tool which simulates and optimises the dispatch of resources in a multi-regional transmission framework to meet the required demand. WEMSIM uses Linear Programming (LP) and/or Mixed Integer Programming (MIP) for solving the optimal dispatch problem while taking into account transmission and other technical constraints.

The modelling methodology used is as follows:

- Perform the above market modelling of the WEM under the ESM Rules. The modelling is performed using RBP's WEMSIM model.
- Include a facility representing a unit of the proposed Benchmark Technology – i.e., an E-Class SCGT (specifically a SGT5-2000E), running entirely on natural gas.
- The assumption that the SCGT runs entirely on natural gas is made to represent the best possible case for justifying net CONE, as this is a lower cost fuel than distillate. This is because the proposed technology is expected to receive significantly higher net revenue due to its dispatch. To confirm this, a scenario in which the SCGT runs solely on distillate was also assessed. The result confirmed the assumption.[29]

For the purposes of this Review, the WEM from 2026 to 2036 has been modelled and the following market results have been forecast:

- Energy market prices – average and captured by the facility;
- Marginal cost of generation for the SCGT;
- Net market revenue for the SCGT, including captured prices while generating, and ESS revenues; and
- Gross CONE and net CONE.

3.4. Assumptions

Modelling assumptions are documented in Appendix C.

3.5. Modelling results

The following sections show the key results of the modelling.

Marginal Energy Supplier

Figure 2 shows the following results from the market modelling for the scenario in which the SCGT is running on natural gas:

- The Short-Run Marginal Cost (SRMC) of the SCGT

[29] The resulting dispatch was so low that the resulting captured prices are considered spurious as they are based on too few Trading Intervals. Therefore the results are not presented in this paper.

- Annual average Real-Time Market price for energy
- The price captured by the SCGT – i.e. the generation-weighted average price received while generating

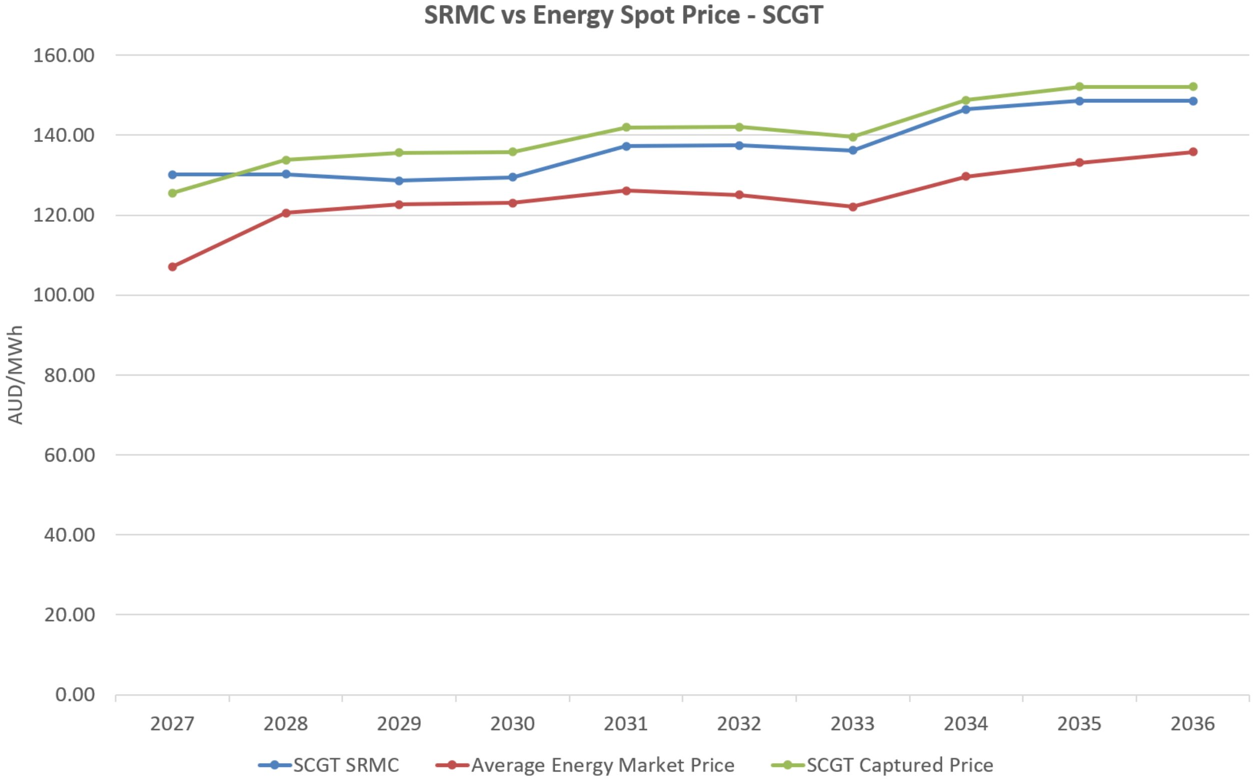


Figure 2. Market price results from modelling

These results show that:

- The SRMC of the SCGT is close to the price captured by the SCGT and is above the average Real-Time Market energy price.
- This indicates that the SCGT is frequently the marginal energy supplier when it is being dispatched.
- Under the first limb of the criteria specified above, this indicates that Gross CONE should be applied.

In the scenario in which the SCGT is running on distillate, the facility received no significant dispatch or revenues, as its SRMC is much higher.

Forecast Gross and Net CONE

Figure 3 shows the forecast Gross and Net CONE values for the SCGT for the scenario in which it is running on natural gas:

- The Gross CONE is the BRCP value estimated in section 2.5
- The Net CONE is the Gross CONE minus the forecast net market revenue

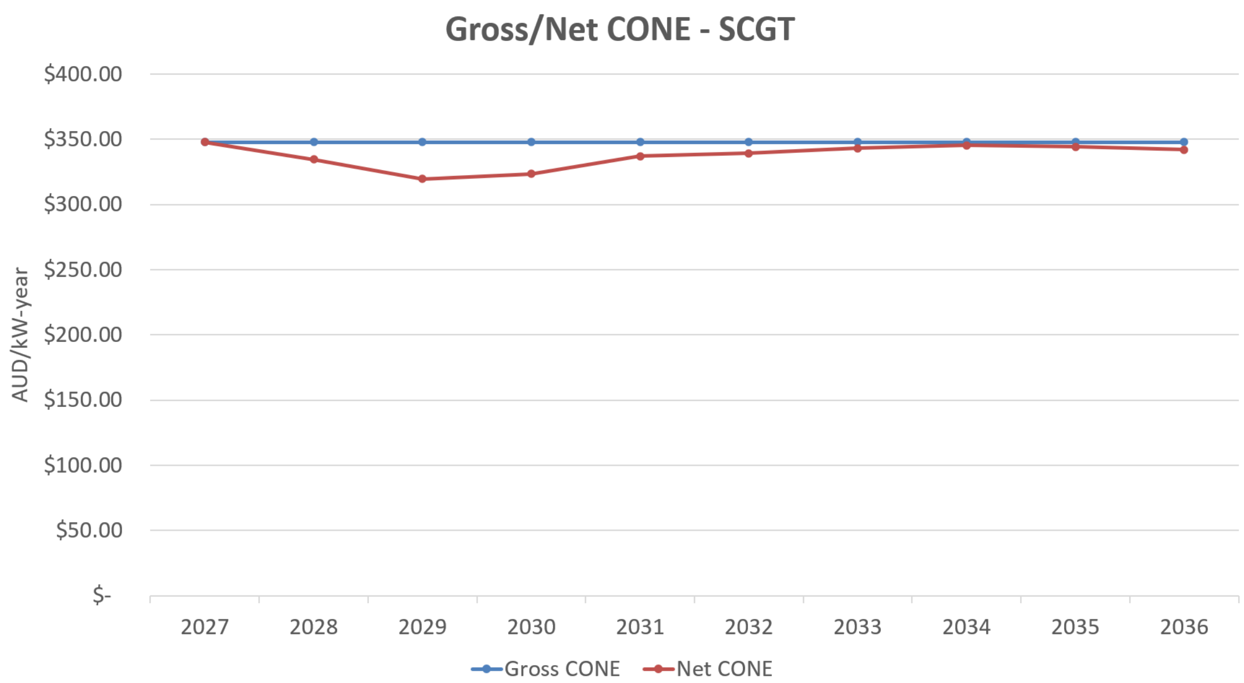


Figure 3. Forecast Gross and Net CONE

These results show that the Net CONE of the SCGT is lower that the Gross CONE, but not by a large margin.

Note that Frequency Co-optimised Essential System Services (FCESS) revenues are not included in this Net CONE calculation. This is because:

- Currently the FCESS markets in the WEM are dominated by ESRs, and GTs are not observed to make significant revenue from the provision of FCESS.
- With the increase of installed ESR capacity in the SWIS this trend is expected to continue.
- It is assumed that the facility does not receive FCESS revenue.

In the scenario in which the SCGT is running on distillate, the facility received no significant revenue, as it was rarely dispatched. Consequently, its net revenue is very low and there is no material difference between Gross and Net CONE.

3.6. Further Assessment

The following is an assessment of the relative advantages and disadvantages of the gross CONE and net CONE approaches:

Net CONE Advantages

- Potentially lower cost to consumers

Net CONE Disadvantages

- Requires forward-looking modelling to forecast net revenues
- This is highly sensitive to input assumptions, such as cost changes, other new build, retirements, renewables output, fuel prices, etc.

- Consensus will be difficult to achieve
- Resulting uncertainty may deter investment, undermining cost savings and reliability

Gross CONE Advantages

- Relatively predictable BRCPs provide investment certainty
- More straightforward BRCP determination process
- Consistent with current BRCP methodology

Gross CONE Disadvantages

- Potentially higher cost to consumers

3.7. Conclusion and recommendation

From the above analysis, DEED has drawn the following conclusions:

- Modelling indicates that it is likely that the Benchmark Technology will be a marginal energy supplier when dispatched.
- While in theory, net CONE may result in lower costs to consumers, the amount of reduction is likely to be insignificant, even in the scenario in which it is entirely fuelled with natural gas.
- Implementing net CONE adds significant complexity and uncertainty to the BRCP determination procedure.
- The resulting uncertainty may deter investment, undermining cost savings and reliability.

Consequently, DEED proposes to retain a gross CONE approach. This approach was supported by the Working Group.

Proposal B:

Retain a gross CONE approach

Consultation question:

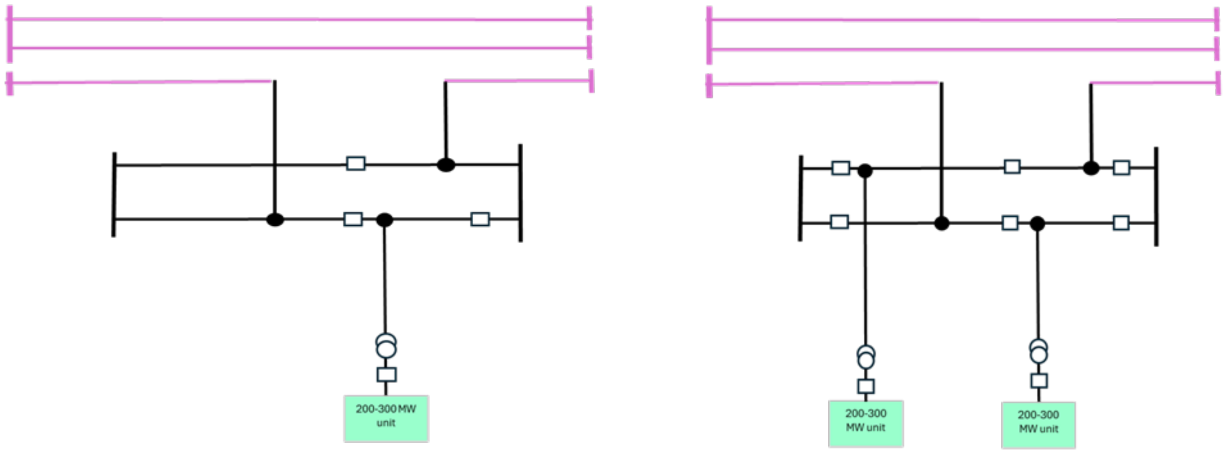
Based on the analysis, do stakeholders agree with retaining a gross CONE approach?

Appendix A. Connection Details

A.1 Electrical connection detail

An electrical connection concept that would suit each of the candidate configurations at the sizes discussed is shown in Figure 4:

Figure 4 Electrical connection concept, cut into a 330kV line (smaller and larger configurations)



In the WEM Procedure for the BRCPs, a 2 km distance (50% rural, 50% urban) link between the generation facility and the cut-in point on the 330kV circuit is specified.

For configurations less than 340 MW total facility capacity, including the BESS option, only a single generator block-to-substation interconnect is required. For configurations larger than this size two connections are considered appropriate (as shown above).

Western Power provided the ERA with a transmission cost estimate for the 2028/29 BRCP calculation in January 2026[30]. This was for the 200MW BESS option and included one link to the power station consistent with the above.

The Western Power cost estimate, which include the escalation factor to 2027/28 but excludes the substation land, is shown in Table 7.

Table 7 Western Power connection cost estimate

Component	Cost, $M
Substation	13.1
Line (1 cct x 2km)	9.5
Easement for overhead line	4.0
Total (before escalation to 2028/29 year)	26.6

For candidate options larger than 340 MW, the cost of an additional line and easement, and three additional circuit breaker/isolator sets is added. The corresponding total is $41.5M.

[30] Western Power "Total Transmission Cost Estimate for the Benchmark Reserve Capacity Price for 2027/28" 10 September 2024 at https://www.erawa.com.au/cproot/24397/2/BRCP-2025-Total-transmission-cost-estimate-for-the-BRCP-for-2027-28-Western-Power.PDF

Additional land of 2.6 Ha for the substation is assumed based on Collie substation size.

A.2 Gas connection detail

The gas connection costs differ for each gas-fuelled option. Considering the different pressures required for each turbine/engine type and the different plant capacities and heat rates, a different compressor sizing is required. A different length of storage lateral is also required. The fat lateral candidate configurations need a lateral sufficiently long to hold the 14 hour fuel requirement at a pressure sufficiently above the gas turbine/engine pressure requirement.

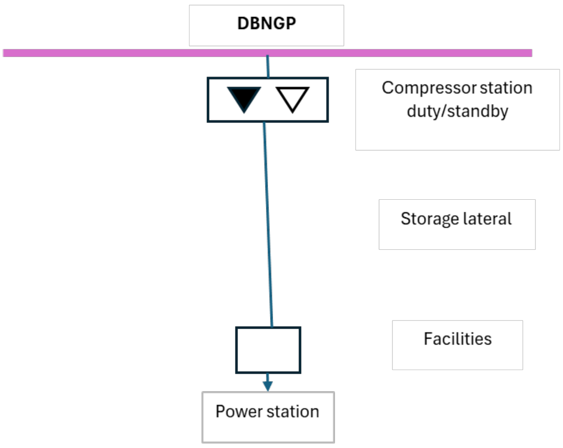
For the 'skinny' lateral candidate configurations the lateral length is the approximate distance of the sites included in the Landgate evaluation from the DBNGP (the average is applied) from Table 7:

Table 8 Distance of potential sites from DBNGP

Location	km
Three Springs	50
Eneabba	3
Badgingarra	15
Cataby	10
Gingin	10
Muchea	13
Pinjar	13
Neerabup	13
Average	**16**

The natural gas connection concept is shown in Figure 5:

Figure 5 Gas connection concept (shown for a compressed lateral[31])



[31] For the 'skinny' lateral case needed for a dual fuel station the compressor station is not required and the lateral pipe is a smaller diameter

For the (fat lateral) candidate configurations with certification on gas fuel, a compressed lateral (36 inch, 15 MPa MAOP) is assumed and is of at least sufficient length to store 14 hours of operational gas (at 41°C, full load) of the power station between the power station minimum operating pressure (varies by gas turbine/engine) and a 13 MPa operating pressure.

For the ‘skinny’ lateral candidate configurations the pipe diameters range from 10” to 16” depending on the configuration[32].

The lateral cost is based on GHD’s report for AEMO[13]. The compressor stations for the gas-only candidate configurations is duty/standby and compressors are sized to provide 14hours of operation fuel in 24 hours and is also costed using the GHD report. A land cost is added.

A nominal allowance for facilities (such as meter/regulation station, heaters) at the power station end is added.

Values/parameters are shown in Table 8.

Table 9 Gas connection parameters (certification on gas fuel candidate configurations)

	14 hours GJ[33]	Press. at PS min, MPa	Lateral km	Compr. Power MW
SCGT				
2xGT13E2	51,653	3.2	20.9	3.7
2xSGT5-2000E	54,205	2.6	18.8	3.9
1xGE 9FA.04	38.463	3.4	15.9	2.8
4xLMS100PB	48,140	6.6	30.3	3.5
6xLM6000PF-SPRINT	36,753	5.7	18.3	2.7
12xLM2500 G4 DLE	55,345	4.3	24.7	4.0
CCGT				
2xGT13E2 2+1 w/. Bypass stack	51,699	3.2	20.9	3.7
1xGE 9FA.04 1+1 ss	38,146	3.4	15.9	2.8
Recips.				
12xWartsila med spd	26,510	1.2	15.9	1.9
24xJenbacher Med Speed	29,845	1.7	15.9	2.2

32 Sized based on a nominal gas flow velocity of 7 m/s at 5 MPa. The MAOP of DBNGP is 8.48 MPa

33 For refill in 24 hours. This is also the MDQ.

Appendix B. Cost Estimation Methodology

B.1 Information sources

In the interest of transparency, it is preferable to minimise the use of parameters obtained in-confidence from industry or which are based on internal databases that are not open to external review.

The preferred sources of information for this Review are:

- CSIRO GenCost (directly or via AEMO's Inputs, Assumptions and Scenarios Report, IASR) – the latest final or draft version at the time of the analysis. CSIRO GenCost is published and widely used in industry for early-stage development and market modelling purposes and is exposed (via the AEMO ISP process for the NEM) to extensive consultation and engagement.
- Where the CSIRO GenCost does not cover a technology configuration (as generally applies for gas turbine configurations since the 'new entrant' candidates in the NEM are generally for larger unit sizes), an alternative method that maximises reproducibility and transparency is sought. For gas turbine and medium speed reciprocating engine options, the Thermoflow suite of software is used as this is widely used and it is being used in the input studies to CSIRO GenCost.
- Parameters in the Thermoflow suite are selected to suit the WEM typical build. These are disclosable if a stakeholder requests. It should be recognised that the Thermoflow cost database is not tailored to latest Australian conditions and may itself be lagging current market prices or may incorporate short-term market event effects.
- Configuration localisations (such as secondary fuel capability and storage, water treatment arrangements, inlet air cooling etc) are done within Thermoflow to maximum extent. Localisation of construction cost adjustments (if appropriate) are limited to only the construction related elements (such as labour) and not to large, imported components (such as gas turbines, BESS modules etc) and use public-domain parameters to the extent practical.
- The cost estimation is the expected value of a generic build cost. This includes appropriate allowances for scope completeness (growth) so that the cost is the best-estimate for the complete plant, but it does not include a risk contingency to reduce the risk of the cost being exceeded to below some low-risk probability[34].
- The Benchmark Technology is a hypothetical project for commissioning only a few years into the future. The best estimate is made for the costs of a plant committed (Final Investment Decision) on the day of the assessment and escalated (using expected Consumer Price Index) to the nominal dollars of the 2029 Capacity Year.

B.2 Basic power plants

For the SCGT, CCGT and reciprocating engine options the Thermoflow suite (GTPro and PEACE) has been used to configure the plant and to base a cost estimate upon.

[34] Informally, the cost should be the P50 estimate rather than (say) a P90 estimate though (more formally) for capex estimates it is generally the case that the expected value (mean) is not the same as the P50 value and it is the mean (expected) value that should be sought

The configurations in the models are:

- Rating point at 41°C dry bulb. A coincident RH of 20% is assumed to go with this temperature[35] and a site elevation of 100m. Net plant outputs are used.
- 330kV connection.
- Site and ancillary plant per expectations (soft ground, buildings as appropriate (GT and HRSG outdoors, steam turbines and water treatment plants indoors), no gas compression on-site[36], dual fuel provisions etc), inclusive of emergency diesel genset, DCS, site firefighting and fire water reserve, fuel tanks etc.

Configuration-specific adjustments include:

- The gas turbine and engine based configurations could be built using gas fuel (using a compressed gas lateral to provide the necessary firm capacity) or using distillate fuel[37]. Each option is be considered with the lower cost option anticipated to be the appropriate candidate option.
- The E class CCGT (2xGT13E2) was modelled as multi-shaft and with bypass stacks. This would allow $^{2}/_{3}$rds of capacity to be dispatched in circa 30 mins (full capacity in circa 60 mins if the plant has ben offline less than 8 hours).
- The F class CCGT (1x9FA) was modelled as single shaft without bypass stack.
- Configurations based on more numerous units (aero-derivatives and recips) were based on shared generator transformer groups to reduce costs.

The 0.55 t Co2/MWh net emissions intensity threshold that was applied in the 2025 review is now not expected to be implemented in the relevant timeframe and is not included in the current assessment.

The modelling was set up with Thermoflow's Regional Factors for Australia and converted to AUD at 0.655 USD/AUD.

The Thermoflow suite latest version is v33 (released March 2025). The previous version (v32 from 2024) would have been the version applied in the GenCost analysis underpinning AEMOs then draft IASR[38]. It is noted that from v32 to v33 Thermoflow has significantly increased some expected costs, most noticeably for the aeroderivative units. This does reflect the current world market where such units are in urgent demand due to (for example) data centre load growth overseas. It is presently difficult to obtain an aeroderivative unit for delivery before 2030.

Many gas turbine manufacturers shuttered facilities while demand was low (following covid etc) and manufacturing capacity has not yet responded to increased demand. These supply shortfalls may pass, and this could impact on prices, however there is no visibility of when/if this will occur.

Additionally, since Thermoflow is only an indicative cost estimation program, it includes some parameters as a percentage or function of the prime equipment costs. Most notably,

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35 This has an impact as the gas turbines are assumed to have inlet air "fogging" cooling

36 Would be included in the gas connection at the top of the lateral where needed

37 That a new entrant might in practice add functionality to choose differently or use both fuels to additionally trade in the energy markets is not included in the Benchmark Technology configuration

38 The Final version of the 2025 IASR has subsequently been published

it includes the contractor's soft costs with significant percentages based on prime equipment costs. This creates the outcome that where the unit is an aeroderivative the contractor's soft costs (in $/kW) are significantly higher than those for an industrial gas turbine build of similar capacity. This difference is considered doubtful, especially if applied over a sustained projection into the future (as opposed to considering plants that might be ordered immediately (2026)).

To avoid presenting relative costs with this factor applying (which would prejudice aeroderivative configurations), contractor's soft costs are replaced by a fixed $/kW value across the options (with a separate and higher allowance for CCGT).

The owner's cost allowances have been applied as a 10% allowance in all cases.

In this Review the proposed capex is presented. The capex based on Thermoflow 32 and Thermoflow 33 is available for comparison.

B.3 Additional costs

The costs of the following over-and-above the basic power plant costs have been developed as follows:

Pre-FID development	A nominal allowance of $20M is added to the capital cost of each project. This is a nominal sum for completeness which does not materially impact the costs.
Land (PS)	Power station areas are estimated by comparison against actual power stations of similar configuration in WA or the NEM. The land cost per hectare is derived from the latest values published in the most recent ERA review. Resulting value is $536,250/Ha. This is for the power station facility only. The electricity switchyard and gas facilities' land is separately included (below). This would be adjusted if a later value is published.
Electrical connection	All the configurations suit a 330 kV connection teed into one circuit using a breaker-and-a-half, two diameters arrangement assuming a dedicated switchyard. It is assumed there is 2km of 330kV circuit length between the powerplant and the switchyard consistent with the (then latest) ERA determination Clause 3.4.6(a)(ii).
Gas connection – compressed (fat) lateral case	It is assumed the power station is supplied with a dedicated lateral also serving as the (gas) fuel store. A 36-inch (900dia) pipeline of 15 MPa MAOP is assumed and the length required is determined to contain 14 hours of fuel at a minimum pressure appropriate for each gas turbine/engine (ie assuming no second gas compressor station at the power station site) and a lateral operating pressure of 13 MPa. Compression capacity (in MW) is based on compressing from 3 MPa to 15 MPa timesthe flow required for each configuration over 14 hours, being provided in (3x24-14) hours of compression time. Pipeline and compressor station costs were allowed per GHD's report for AEMO[39], escalated to $2026. Land area is allowed based on the size of a typical station[40] of 5 Ha A nominal allowance for facilities of $2M was added.

[39] GHD for AEMO "Gas Infrastructure Cost Building Block costs for gas infrastructure" 15 May 2025

[40] DBNGP CS3

Diesel fuel storage	For the candidate options with distillate as the relevant fuel, tankage and demineralised water[41]. A demin. water plant is assumed included.
Water (external infrastructure)	No other specific costs for other external infrastructure are added.

B.4 Fixed Operations and Maintenance costs (FOM)

The following items were included in the estimates of FOM:

Plant FOM	Technology specific from IASR
Transmission connection asset maintenance	0.5%/y of connection capex
Transmission NUOS	$6,000/MW/y used in 2025 review
DBNGP capacity	Est. MDQ x 365 x DBNGP tariff ($1.818828/GJ/day) – applied for gas-fuelled configurations
Gas connection FOM	0.25%/y of connection capex where relevant
Corporate overheads etc	$1.31M/y
Insurance adjustment	0.3% x plant capex[42]
Site security	$168.5k/year
Rates	$222k/year
Working capital	Assumed 30 day payment cycle under contracts (and hence working capital for FOM x 30days) plus fuel inventory, each calculated using the Weighted Average Cost of Capital (WACC).

B.5 Interpretation of the impacts of constraints

ESM Rule 4.16.12(c) requires that when determining the Benchmark Technologies, the Coordinator must also determine the uncongested network location to be used for each Benchmark Technology, or if there is no uncongested network location, a network location with relatively low congestion.

The likely site for evaluation is a connection to Clean Energy Link North. Such a site would be near the DBNGP and is located north of Perth, away from the majority of existing Capacity Credit generation in the WEM, which is south of Perth.

The link is assumed to be unconstrained at the likely time of Reserve Capacity dispatch because a large amount of renewable generators is usually not injecting energy at this time.

A review of any any additional information from Western Power where available, will be undertaken before deciding on the treatment of this parameter.

B.6 Fixed Capital Contribution charge

A fixed charge[43] of AUD100,000/MW has been included in the analysis.

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[41] Incremental tankage is inexpensive and allows for re-ordering before tankage is empty and logistics delays/risks. This assumes a distillate primary-fuelled gas turbine would be water injected for NOx control

[42] In reviewing earlier studies and in reviewing the derivation of the costs in the IASR no sight insurance allowances were observed and it needs an adjustment in this review

[43] [Energy Policy WA - Fixed Capital Contributions - Consultation]

B.7 Other parameters

The following parameters in the calculation were applied:

WACC	10.85% used in 2026 calculations per ERA's then draft determination Section 4.6.
Escalation	2.5%/y from date of calculation to date in 2028 that the calculation is to apply to.
Tilt	1
Amortisation period	15 years applied to all technologies in discussion with DEED
Cashflow timing adjustment	$(1+\text{WACC})^{0.5} - 1$. An allowance for IDC

B.8 Technology-specific parameters

The following technology-specific parameters were applied as shown in the following 2 tables:

Configuration		SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT	SCGT
		GT13E2	GT13E2	SGT5-2000E	SGT5-2000E	1x9FA	1x9FA	LM2500	LM2500	LM6000	LM6000
	Unit	DF	GasOnly	DF	GasOnly	DF	GasOnly	GasOnly	DF	DF	GasOnly
Configuration Net MW (clean-as-new)	MW	341.2	341.2	347.8	347.8	258.2	258.3	380.2	380.2	264.1	264.1
HR, net, LHV (clean-as-new)	GJ/MWh	9.771	9.771	10.057	10.057	9.61	9.608	9.392	9.392	8.98	8.98
Gas supply pressure at skid edge	Bara	26.6	26.6	20.75	20.75	28.37	28.37	37.61	37.61	50.91	50.91
Fuel (on gas, approx)	GJ/h	3,690	3,690	3,872	3,872	2,747	2,747	3,953	3,953	2,625	2,625
Proportion of powerplant capex that is installation		30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Localisation factor for capex		104%	104%	104%	104%	104%	104%	104%	104%	104%	104%
# Electrical connections		2	2	2	2	1	1	2	2	1	1
Area (powerplant excl switchyard)	Ha	2.7	2.3	2.6	2.2	2.4	1.8	3.8	4.6	3.2	2.8
Electrical Connection Cost	$M	41.50	41.50	41.50	41.50	26.55	26.55	41.50	41.50	26.55	26.55
Gas connection cost	$M	28.79	102.63	28.79	95.58	22.10	78.72	118.16	28.79	22.10	87.21
Water connection cost	$M	0	0	0	0	0	0	0	0	0	0
MDQ	GJ/day	0	51,667	0	54,205	0	38,463	55,345	0	0	36,753
MDQ cost	$M/year	0.0	34.3	0.0	36.0	0.0	25.6	36.8	0.0	0.0	24.4
Capacity credits multiplier - Peak		1	1	1	1	1	1	1	1	1	1
Capacity credits multiplier – Flexible		1	1	1	1	1	1	1	1	1	1
TUOS											
- Use of system	$M	2.68	2.68	2.73	2.73	2.03	2.03	2.98	2.98	2.07	2.07
- Control system service price	$M	0.38	0.38	0.39	0.39	0.29	0.29	0.42	0.42	0.29	0.29
- Metering charge	$M	0.0089	0.0089	0.0089	0.0089	0.0089	0.0089	0.0089	0.0089	0.0089	0.0089
-Total	$M	3.06	3.06	3.12	3.12	2.32	2.32	3.41	3.41	2.37	2.37
Working capital											
- Fuel inventory	hours	36	14	36	14	36	14	14	36	36	14
- Fuel inventory	$	4,089,368	719,198	4,290,293	754,535	3,044,184	535,398	770,397	4,380,486	2,908,952	511,608
- FOM/year (excl WC)	$	11,429,537	45,888,488	11,576,017	47,704,088	9,142,112	34,710,337	51,969,390	15,073,096	11,299,662	35,817,112
- Cash cycle WC	$	1,408,157	5,653,612	1,426,203	5,877,300	1,126,338	4,276,428	6,402,800	1,857,055	1,392,155	4,412,786
- Total WC	$	5,497,525	6,372,810	5,716,497	6,631,835	4,170,522	4,811,826	7,173,197	6,237,541	4,301,108	4,924,394
WC annual cost	$M	0.60	0.69	0.62	0.72	0.45	0.52	0.78	0.68	0.47	0.53

Configuration		SCGT	SCGT	CCGT	CCGT	RECIP	RECIP	RECIP	RECIP	BESS	BESS
		LMS100	LMS100	GT13E2	GT13E2	Jenbacher	Jenbacher	Wartsila	Wartsila	7hr	8hr
	Unit	DF	GasOnly	DF	GasOnly	DF	GasOnly	DF	GasOnly		
Configuration Net MW (clean-as-new)	MW	356.2	356.2	489.3	489.3	245.8	245.8	217.4	217.4	200.0	200.0
HR, net, LHV (clean-as-new)	GJ/MWh	8.72	8.72	6.818	6.818	7.836	7.836	7.868	7.868		
Gas supply pressure at skid edge	Bara	60.21	60.21	26.6	26.6	11.35	11.35	6.993	6.993		
Fuel (on gas, approx)	GJ/h	3,439	3,439	3,693	3,693	2,132	2,132	1,894	1,894	0	0
Proportion of powerplant capex that is installation		30%	30%	30%	30%	30%	30%	30%	30%	17%	17%
Localisation factor for capex		104%	104%	104%	104%	104%	104%	104%	104%	103%	103%
# Electrical connections		2	2	2	2	1	1	1	1	1	1
Area (powerplant excl switchyard)	Ha	5.7	4.8	4.1	3.6	3.1	2.5	2.5	2.1	12.1	13.8
Electrical Connection Cost	$M	41.50	41.50	41.50	41.50	26.55	26.55	26.55	26.55	26.55	26.55
Gas connection cost	$M	25.44	136.96	28.79	102.69	18.75	75.64	18.75	74.44	0.00	0.00
Water connection cost	$M	0	0	0	0	0	0	0	0	0	0
MDQ	GJ/day	0	48,141	0	51,699	0	29,846	0	26,510	0	0
MDQ cost	$M/year	0.0	32.0	0.0	34.3	0.0	19.8	0.0	17.6	0.0	0.0
Capacity credits multiplier - Peak		1	1	1	1	1	1	1	1	1	0.875
Capacity credits multiplier - Flexible		1	1	0.66	0.66	1	1	1	1	1	0.875
TUOS											
- Use of system	$M	2.79	2.79	3.84	3.84	1.93	1.93	1.70	1.70	1.57	1.57
- Control system service price	$M	0.40	0.40	0.55	0.55	0.27	0.27	0.24	0.24	0.22	0.22
- Metering charge	$M	0.0089	0.0089	0.0089	0.0089	0.0089	0.0089	0.0089	0.0089	0.0089	0.0089
-Total	$M	3.20	3.20	4.39	4.39	2.21	2.21	1.96	1.96	1.80	1.80
Working capital											
- Fuel inventory	hours	36	14	36	14	36	14	36	14	0	0
- Fuel inventory	$	3,810,256	670,120	4,091,906	719,652	2,362,294	415,457	2,098,275	369,024	0	0
- FOM/year (excl WC)	$	14,143,346	46,323,785	17,161,356	51,637,354	13,049,960	32,953,330	11,655,735	29,351,465	11,843,653	12,853,129
- Cash cycle WC	$	1,742,507	5,707,242	2,114,335	6,361,892	1,607,798	4,059,958	1,436,025	3,616,197	1,459,177	1,583,548
- Total WC	$	5,552,762	6,377,362	6,206,241	7,081,543	3,970,092	4,475,416	3,534,300	3,985,221	1,459,177	1,583,548
WC annual cost	$M	0.60	0.69	0.67	0.77	0.43	0.49	0.38	0.43	0.16	0.17

Appendix C. Modelling assumptions to assess gross and net cost of new entry

C.1 Load assumptions

The demand profile is obtained from the 2026 WEM ESOO published by AEMO. Demand traces for the Expected 50% Probability of Exceedance scenario are used[44], with some processing to obtain a single complete demand trace for 10 calendar years[45].

The resulting annual, peak and minimum demand values by calendar year are as follows:

Table 10: Demand Assumptions

Calendar Year	Annual Demand (GWh)	Peak Demand (MW)	Minimum Demand (MW)
2026	4,105	4,276	346
2027	17,940	4,426	353
2028	18,436	4,600	254
2029	19,006	4,689	187
2030	19,852	4,774	181
2031	20,559	5,025	165
2032	21,063	5,153	237
2033	21,606	5,296	220
2034	22,481	5,487	159
2035	23,657	5,584	258
2036	25,111	5,924	273

C.2 Fuel Prices

The fuel prices for diesel, natural gas and coal used in the modelling were provided by DEED. The diesel prices are an adopted forecast from the Gas Powered Generation, 2024 Integrated System Plan and 2020 Whole of System Plan. Fuel price for renewables and biomass was assumed to be $0. Table 10 below shows the prices for each fuel type in AUD.

44 10% POE traces are used to set the Reserve Capacity Target, but for the purposes of forecasting future outcomes, 50% POE is more appropriate as the forecast that is considered more likely to occur.

45 Specific processing is as follows: (1) The demand traces finish at 1 Oct 2036. To obtain a complete set of values for the 2036 calendar year, the missing values have been estimated by scaling the corresponding values from the previous year by the annual growth rate. (2) 10 demand traces are provided in the ESOO based on 10 historical demand years; the trace based on the 2023-24 base year was selected, as this year presents an average degree of demand volatility.

Table 11: Fuel Prices

Capacity Year	Coal Price	Diesel Price	Natural Gas Price
2026	5.82	41.46	9.95
2027	5.82	41.03	12.57
2028	5.82	40.60	12.57
2029	5.82	40.18	12.41
2030	5.82	39.79	12.49
2031	5.82	39.44	13.26
2032	5.82	39.12	13.28
2033	5.82	38.82	13.16
2034	5.82	38.54	14.17
2035	5.82	38.27	14.38

C.3 Retirements

The retirements used in the modelling are based on known retirement dates according to state government announcements.

C.4 Planned outages

Table 13 summarises the planned outage assumptions for existing facilities. These assumptions were sourced from the BRCP 2025 model, with the following exceptions:

- Facility PERTHENERGY_KWINANA_GT1: Planned outage assumptions were based on those of PINJAR_GT1, as both facilities are OCGT units.
- Facility ALCOA_WGP: Planned outage assumptions were based on those of ALINTA_PNJ_U1, as both facilities are cogeneration units.

The values presented in Table 13 are defined as follows:

- Average Planned Outages per Year = Number of planned outages ÷ number of years when planned outages occured.
- Average Outage Duration = Average length in days of each planned outage.
- Average Planned Outage Days per Year = Outages per year × Average duration.

Table 12: Planned Outages of Existing Facilities

Generator	Average Planned Outages per year	Average Outage Duration (days)	Average Planned Outage Days per year[46]
ALCOA_WGP	1.5	29.3	44.0
ALINTA_PNJ_U1	1.5	23.0	34.5
ALINTA_PNJ_U2	1.3	23.5	31.3
ALINTA_WGP_GT	1.0	6.0	6.0
ALINTA_WGP_U2	1.0	6.0	6.0
BW1_BLUEWATERS_G2	1.0	30.0	30.0
BW2_BLUEWATERS_G1	1.0	29.8	29.8
COCKBURN_CCG1	1.0	19.4	19.4
COLLIE_G1	1.1	25.5	28.1
KEMERTON_GT11	1.0	81.0	81.0
KEMERTON_GT12	1.0	81.0	81.0
KWINANA_GT2	2.0	16.1	32.1
KWINANA_GT3	2.0	16.2	32.4
MUJA_G7	1.1	53.3	58.1
MUJA_G8	1.1	52.9	57.8
NEWGEN_KWINANA_CCG1	1.0	15.9	15.9
NEWGEN_NEERABUP_GT1	1.0	61.0	61.0
PERTHENERGY_KWINANA_GT1	1.1	32.9	36.2
PINJAR_GT1	1.0	11.8	12.4
PINJAR_GT10	1.1	24.4	25.7
PINJAR_GT11	1.0	20.5	21.4
PINJAR_GT2	1.0	12.9	12.9
PINJAR_GT3	1.0	11.6	11.6
PINJAR_GT4	1.0	12.4	12.4
PINJAR_GT5	1.0	10.9	10.9
PINJAR_GT7	1.0	12.3	12.3
PINJAR_GT9	1.0	20.2	20.2
TIWEST_COG1	1.1	8.8	9.6

C.5 Existing facilities

[46] Describes how many days each generator is expected to be unavailable due to planned maintenance in a typical year

Table 14 describes the existing facilities that are WEM registered facilities[47], with their technology, facility size and Capacity Credits[48]. The following facility classes were excluded from the list of WEM registered facilities:

- Interruptible Load
- Network
- Non-Dispatchable load

Table 13: Existing Facilities

Facility	Technology	Facility Size (MW)	Capacity Credits (MW)
ALBANY_WF1	Wind	21.6	7.986
ALCOA_WGP	Cogeneration	16	26
ALINTA_PNJ_U1	Cogeneration	143	142.447
ALINTA_PNJ_U2	Cogeneration	143	142.447
ALINTA_WGP_ESR1	Utility Storage - 2h	200	49.693
ALINTA_WGP_GT	OCGT	196	208
ALINTA_WGP_U2	OCGT	196	208
ALINTA_WWF	Wind	89.1	21.011
AMBRISOLAR_PV1	Hybrid (Solar)	0.96	0.71
BADGINGARRA_WF1	Wind	130	26.117
BIOGAS01	Landfill gas	2	0.425
BLAIRFOX_KARAKIN_WF1	Wind	5	0.045
BREMER_BAY_WF1	Wind	0.6	0.227
BW1_BLUEWATERS_G2	Coal	217	217
BW2_BLUEWATERS_G1	Coal	217	217
COCKBURN_CCG1	CCGT	240	240
COLLIE_BESS2	Battery	600	293.56
COLLIE_ESR1	Utility Storage - 4h	400	185.975
COLLIE_ESR4	Battery	500	250
COLLIE_ESR5	Battery	500	250
COLLIE_G1	Coal	318.3	317.2
DCWL_DENMARK_WF1	Wind	1.44	0.566
EDWFMAN_WF1	Wind	80	10.409
FLATROCKS_WF1	Wind	75.6	27.432
GRASMERE_WF1	Wind	13.8	5.552
GREENOUGH_RIVER_PV1	Solar	40	3.403
GRIFFINP_DSP_01	DSP	45	45
HENDERSON_RENEWABLE_IG1	Landfill gas	3.192	1.474
INVESTEC_COLLGAR_WF1	Wind	218.5	29.982

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48 AEMO | Assignment of Capacity Credits

KALBARRI_WF1	Wind	1.6	0.096
KEMERTON_GT11	OCGT	155	151.919
KEMERTON_GT12	OCGT	155	151.919
KWINANA_ESR1	Utility Storage - 2h	200	42.75
KWINANA_ESR2	Utility Storage - 4h	450	224.045
KWINANA_GT2	OCGT	103.94	106.763
KWINANA_GT3	OCGT	103.94	106.804
MERSOLAR_PV1	Solar	100	5.561
MUJA_G7	Coal	212.6	211
MUJA_G8	Coal	212.6	211
MWF_MUMBIDA_WF1	Wind	55	7.996
NAMKKN_MERR_SG1	Liquid Fuel	82	82
NEWGEN_KWINANA_CCG1	CCGT	334.8	327.8
NEWGEN_NEERABUP_GT1	OCGT	342	330.6
NORTHAM_SF_PV1	Solar	9.8	0.56
PERTHENERGY_KWINANA_GT1	OCGT	109	109
PHOENIX_KWINANA_WTE_G1	Biomass	43	35.684
PINJAR_GT1	OCGT	40.35	32
PINJAR_GT10	OCGT	118.2	110.5
PINJAR_GT11	OCGT	128.2	123.35
PINJAR_GT2	OCGT	40.35	29.72
PINJAR_GT3	OCGT	42	37
PINJAR_GT4	OCGT	42	35.95
PINJAR_GT5	OCGT	42	37
PINJAR_GT7	OCGT	42	35.166
PINJAR_GT9	OCGT	118.2	114.314
PRDSO_WALPOLE_HG1	Pumped hydro	1.5	1.5
PRK_AG	Natural Gas	68	0[49]
RED_HILL	Landfill gas	3.75	2.274
ROCKINGHAM	Landfill gas	4.192	0.999
SBSOLAR1_CUNDERDIN_PV1	Hybrid (Solar)	100	40.794
SBSOLAR1_CUNDERDIN_PV1_ESR	Hybrid (Utility Storage - 4h)	102.509	37.297
SKYFRM_MTBARKER_WF1	Wind	2.43	0.924
SOUTH_CARDUP	Landfill gas	1.912	1.6
STHRNCRS_EG	OCGT	23	23
SYNERGY_DSP_04	DSP	42	42
TAMALA_PARK	Landfill gas	5.55	3.242
TESLA_KEMERTON_G1	Liquid Fuel	9.999	9.999
TESLA_PICTON_G1	Liquid Fuel	9.999	9.999
TIWEST_COG1	Cogeneration	42.1	36
WARRADARGE_WF1	Wind	180	56.388

[49] No capacity credits were assigned for the 2027/2028 capacity year

YANDIN_WF1	Wind	211.7	37.5

C.6 New build

First, the model assumes the candidate facility is being built in 2026, which in this case is an E-Class SCGT, specifically a 347.8 MW SGT5-2000E facility.

The committed new build facilities included are listed in Table 15.

Table 14: Committed new build facilities

Facility	Entry Capacity Year	Technology	Facility Size (MW)	Capacity Credits (MW)
AMBRISOLAR_PV2_ESR	2027	Utility Storage (<8h)	28.39	3.155
ARROWSMITH_EAST_G1	2027	OCGT	85	85
BALDIVIS_ESR1	2027	Utility Storage (<8h)	0.576	0.576
BOONANARRING_ESR	2027	Utility Storage (<8h)	1.481	1.481
BOONANARRING_PV	2027	Solar	3	0.27[50]
CAREYPARK_ESR1	2027	Utility Storage (<8h)	0.209	0.209
CAREYPARK_ESR2	2027	Utility Storage (<8h)	0.209	0.209
COMMITTED_DSP	2026	DSP	100	85.7[51]
ENELX_DSP_01	2027	DSP	112	112
ENELX_DSP_02	2027	DSP	18	18
EPWA_DSP	2026	DSP	108.004	92.5
ERRRF_WTE_G1	2028	Biomass	29	21.8
GER_ESR1	2027	Utility Storage (<8h)	10	9.999
KING_ROCKS_WF1	2027	Wind	103	17.13
MERREDIN_ESR1	2027	Utility Storage (<8h)	100	94.168
MUCHEA_ESR1	2027	Utility Storage (<8h)	150	150
NOR_ESR1	2027	Utility Storage (<8h)	10	9.9
PERTHENERGY_KWINANA_GT 2	2027	OCGT	176	176
PINJAR_GT_NEW_1	2029	OCGT	150	148.2

50 Capacity credits for BONNANARRING_PV were not provided by Endgame, nor present in the WEM facilities with capacity assigned, thus these capacity credits were calculated by multiplying the facility size by the solar factor from Table 7.

51 Capacity credits for COMMITTED_DSP were not provided by Endgame, nor present in the WEM facilities with capacity assigned, thus these capacity credits were calculated by multiplying the facility size by the DSP factor from Table 7.

Facility	Entry Capacity Year	Technology	Facility Size (MW)	Capacity Credits (MW)
PINJAR_GT_NEW_2	2029	OCGT	150	148.2
SIMCOA_DSP_01	2027	DSP	23	23
SOUTHERNRIVER_ESR1	2027	Utility Storage (<8h)	0.284	0.284
TESLA_COLLSMALL_ESR1	2027	Utility Storage (<8h)	5	5
TESLA_KEMERTON_G2	2027	Liquid Fuel	9.999	9.999
TESLA_KEMERTON_G3	2027	Liquid Fuel	9.999	9.999
USHER_ESR1	2027	Utility Storage (<8h)	0.209	0.209
WADDI_WF1	2027	Wind	108	18.169
WAROONA_PV1_ESR1	2027	Utility Storage (<8h)	80	88.06
WAROONA_PV2	2027	Solar	99	6.336
WARRADARGE_WF_UPG	2027	Wind	102	21.486
WITHERS_ESR1	2027	Utility Storage (<8h)	0.209	0.209
WITHERS_ESR2	2027	Utility Storage (<8h)	0.209	0.209

C.7 Service provision

The modelling assumes that:

- Gas, coal, and distillate facilities provide Rate of Change of Frequency, Regulation Raise, Regulation Lower, Contingency Raise, and Contingency Lower
- Storage facilities provide Regulation Raise, Regulation Lower, Contingency Raise, and Contingency Lower
- Wind, solar, biomass and hydro facilities as well as Demand Side Programmes do not provide FCESS or Flexible Capacity.

C.8 Commercial parameters

C.8.1 Weighted average cost of capital

When calculating the CONE for each facility type, a nominal pre-tax WACC of 10.85% was assumed, as specified by the ERA for the 2026 BRCP Determination for the 2028/29 Capacity Year.