GHD Advisory

Benchmark lithium BESS costs

BRCP Procedure update

Economic Regulation Authority

15 March 2024

→ **The Power of Commitment**

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The Power of Commitment

Executive Summary

The Economic Regulation Authority is reviewing the Market Procedure: Benchmark Reserve Capacity Price (Market Procedure) as required by clause 4.16.3 of the Wholesale Electricity Market Rules (WEM Rules).

The current procedure requires the BRCP to be an estimate of the annualised cost to build and connect a hypothetical 160 MW liquid fuelled open cycle gas turbine generator to provide reserve capacity to the SWIS. In December 2023, the Coordinator of Energy (the Coordinator) determined the Benchmark Reference Technology would change.[1]

The Benchmark Peak Capacity Provider will be a lithium battery energy storage system (BESS) with:

– 200 MW injection
– 800 MWh energy storage
– a 330 kV connection near Kwinana or Pinjar.

The Benchmark Flexible Capacity Provider will be a lithium battery energy storage system:

– 200 MW injection
– 800 MWh energy storage
– a 330 kV connection near Kwinana or Pinjar.

The aim of the BRCP is to include all reasonable costs expected to be incurred in the development of the Benchmark Capacity Providers, including annual fixed operating and maintenance costs to operate the facility in the South West Interconnected System (SWIS).

GHD has been engaged to assist the Secretariat of the Economic Regulation Authority (the Secretariat) to recommend updates to the BRCP procedure to reflect the Coordinator's determination on the Peak and Flexible BRCP Reference Technology.

This report is subject to, and must be read in conjunction with, the limitations set out in section 1.3 and the assumptions and qualifications contained throughout the Report.

Method

Our approach to developing recommendations for the Procedure comprised of a bottom-up cost estimation process for a 200 MW/ 800 MWh lithium BESS that aligns with the updated WEM Rules and the Coordinator's determination.

We did this by initially developing a concept design for the BESS and the associated transmission network connection. We then identified key costs across the following categories:

– Development and capital costs
– Transmission connection costs
– Land area and costs
– Fixed operation and maintenance costs

Cost estimates have been developed with an accuracy target of +/- 50%. Estimates are based on GHD's internal database and publicly available information as referenced in this report. GHD have not verified cost inputs through a market engagement process with vendors.

[1] Coordinator of Energy, Benchmark Capacity Providers: Peak Capacity Provider and Flexible Capacity Provider, 18 December 2023. Refer to: **https://www.wa.gov.au/government/document-collections/coordinator-determinations**

Variable costs are excluded. Consistent with the ERA's Offer Construction Guideline, the variable costs including variable operating and maintenance costs, market fees and runway costs of Contingency Reserve Raise are expected to be recovered through bidding in the Real-Time Market in the WEM.[2]

Our method for recommending the parameters to be included in the Procedure drew on the principles set out in WEM Rule 4.16.4, which states that the ERA must not specify a fixed value for parameters in the WEM Procedure that it reasonably expected to change from year to year and instead should specify the principles and processes for determining that parameter in the WEM Procedure.

Design specifications and assumptions

The design specifications and operating assumptions recommended to inform the BRCP and the procedure updates are summarised in Table 5. The specifications and assumptions have been developed to align with the WEM Rules' requirements.

The specifications and assumptions are the same for the Peak and Flexible Reserve Capacity Providers. We discuss the potential for operational differences in meeting these services that affect the assumptions used in the BRCP assessment in section 2.3 below. Later sections discuss the rationale for the recommended specifications and assumptions.

Table 1 BRCP service provider requirements

Parameter	BRCP service requirement
WEM Rule requirements	
Capacity	200 MW injection
Operational duration	4 hours (0.25C)[3]
Operating temperature	41ºC
Additional specifications	
Lithium sub chemistry	Lithium iron phosphate (LFP)
BESS life (years)	Up to 20 years (warranty may be shorter)
Land requirements	6.5 ha
Operational assumptions	
Peak	1 cycle per day, full charge and discharge
Flex	1 cycle per day, full charge and discharge

The WEM Rules provide for additional requirements for Flexible Service Providers (beyond the Peak Service Provider requirements). All BESS technologies considered can achieve both the Peak and Flexible Service requirements. Hence, we have not recommended any specific design differences for the Flexible Service Providers.

Based on the information outlined in this report and with consideration of the current provisions in the BRCP Procedure, we recommend the updated Procedure specify the items as per below.

- Lithium iron phosphate (LFP) as the battery cell sub-chemistry, subject to review in three years[4].
- Land area required should account for the BESS, the BESS substation, and connecting assets to the Western Power network, including the Western Power substation inclusive of buffer zones. Assuming the transmission connection arrangements outlined in Chapter 3.2 of this report, the Procedure should specify a land area of 6.5 ha as this will not change from year to year.

[2] ERA, Offer Construction Guideline, 1 October 2023, p. 10. Available at: **Monitoring the new WEM - Economic Regulation Authority Western Australia (erawa.com.au)**
[3] C-rate is defined as the inverse duration of the battery. C-rate = current (amps) / capacity (amp-hours).
[4] This three year time period suggestion is to align with the Coordinator of Energy's three-yearly review of Benchmark Capacity Providers.

We recommend sizing the BESS to achieve:

- Installed capacity to enable injection of 200 MW on day 1 of operation.
- Battery module provisions to enable 800 MWh of charge and discharge on day 1 of operation.

For the purpose of the Procedure, we recommend BESS sizing to achieve the installed power and energy requirements be revisited on an annual basis. The power capability is linked to WEM Rule requirements that may change and the energy capacity can vary based on the design of the BESS.

Based on our analysis, the factors that could be considered in the Procedure are:

- For power capacity:
  - Temperature derating for operation at 41 degrees Celsius.
  - Reactive power compensation for required levels according to generator performance standards in the WEM rules and expected equipment losses.
  - Voltage stability requirements in accordance with WEM Rules
- For battery energy capacity:
  - Capacity loss from calendar fade during the time between battery enclosure delivery and energisation[5].
  - Temperature effects of idle batteries alongside calendar fade.

However, should the Procedure specify that the ERA engage a suitably qualified consultant to develop BESS cost estimates, these factors may necessarily be considered as part of that engagement and so do not need to be individually specified in the Procedure.

The connection arrangement need not specify Western Power as the sole source of the estimates. However, it will be useful for the ERA to retain the ability to request and receive this input from Western Power given Western Power will oversee and approve the design and will necessarily operate some of the assets in the connecting substation. As a minimum, we recommend retaining an obligation on Western Power to specify the proposed concept design for the connection work to ensure it provides a feasible connection option that is consistent with relevant network standards.

Development and capital costs

The key capital cost components of the BESS include the battery modules/enclosures, power conversion system (PCS), electricity and control balance of plant (BoP) and civil BoP.

In addition, there are various capital overheads incurred in the development and construction of the BESS. The following costs are typically included as part of the expected capital costs of the BESS.

- Transmission connection capital costs
- Land costs
- Connection agreement, market registration and licensing costs
- Environmental and development approval costs
- Design and project management costs
- Legal, financing and insurance costs

Table 27 indicates the proportion of total costs each up front development and capital cost for the BESS represents.

[5] Calendar fade is a particular consideration where the battery suffers time-based degradation irrespective of how or whether it is used.

Table 2 Summary of development and capital cost elements

Item	Proportion of total costs
BESS supply and installation costs	**81.1%**
– Lithium-ion battery modules	54.7%
– Power Conversion System	5.3%
– Electrical and control BoP including BESS substation	9.4%
– Civil BoP	2.3%
– Installation labour & temporary equipment hire	9.4%
Transmission connection capital costs	**11.2%**
Land cost	**2.8%**
Other costs	**5.0%**
– Connection agreement, market registration and licencing costs	0.2%
– Environmental and development approvals	0.1%
– Owner's design and project management	2.9%
– Legal, financing and insurance costs	1.8%
Total cost	**100.0%**

We recommend the Procedure require estimation of the following categories of development and capital costs that will vary from year to year:

- BESS supply and installation costs
- Transmission connection capital costs
- Land costs
- Other reasonable costs including but not limited to:
  - Connection agreement, market registration and licencing costs
  - Environmental and development approvals
  - Owner's design and project management
  - Legal, financing and insurance costs

BESS supply and installation costs should include the costs normally applicable to a BESS including the Lithium-ion battery modules/enclosures, power conversion system, electrical BoP including BESS substation, civil BoP and associated installation labour & temporary equipment hire costs during construction.

The cost categories identified could be estimated using different methods that may require adjustment (i.e. escalation or de-escalation) where the costs have been determined at a different date from the dates required for Year 3 of the relevant Reserve Capacity Cycle. We recommend the Procedure reflect the above categories to enable an appropriate level of transparency on the cost estimation process and adjustments required to reflect future prices.

Fixed operating and maintenance costs

The ongoing fixed operating and maintenance costs for the BESS broadly fall into the following categories:

– BESS, BESS substation and BoP maintenance services
– Transmission network service charges (for use of the Western Power network)
– Transmission connection asset maintenance (related to Western Power's connection assets)
– Corporate overheads and various consulting services (e.g. legal, regulatory and engineering support) and other fixed costs (e.g. site security and local government rates)

Variable costs for the BESS plant such as battery module replacement have not been included in the fixed operating and maintenance costs. Consistent with the ERA's Offer Construction Guideline, variable costs including variable operating and maintenance costs, market fees and runway costs of Contingency Reserve Raise are expected to be recovered through bidding in the WEM Real-Time Market.[6]

Table 3 indicates the proportion of total fixed operating and maintenance costs each type of cost represents.

Table 3 Summary of fixed operating and maintenance cost elements

Item	Proportion of total annual cost
BESS, BESS substation and BoP maintenance	**31%**
Transmission network service charges	**30%**
Transmission connection asset maintenance	**3%**
Corporate overheads, consulting services and other fixed costs	**36%**
– Corporate overheads and various consulting services	28%
– Site security	4%
– Local government rates	4%
Total	**100%**

We recommend that the Procedure require estimation of the following fixed operating and maintenance costs that will vary from year to year:

– BESS, BESS substation and BoP maintenance
– Corporate overheads, consulting services and other reasonable fixed costs
– Transmission connection asset maintenance
– Transmission network service charges for use of the Western Power network

The corporate overheads and consulting costs (e.g. legal, regulatory and engineering support) should represent costs that are fixed regardless of energy throughput beyond the Peak and Flexible Service requirements. As such, these may represent a proportion of the costs associated with a BESS that provides services beyond those required to provide Reserve Capacity. The site security and local government rates identified in our cost identification method represent relatively small amounts and may be accounted for in cost estimates of the BRCP but need not be explicitly referenced in the Procedure as they could be accounted for within the allowance for other reasonable costs.

Consistent with our recommendations for development and capital cost items, the cost categories identified for fixed operating and maintenance could be estimated using different methods that may require adjustments where the costs have been determined at a different date from the dates required for Year 3 of the relevant Reserve Capacity Cycle. We would recommend the Procedure reflect the above categories to enable an appropriate level of transparency on the cost estimation process and adjustments required to reflect future prices.

[6] ERA, Offer Construction Guideline, 1 October 2023, p. 10. Available at: **Monitoring the new WEM - Economic Regulation Authority Western Australia (erawa.com.au)**

Adjustments to estimate future costs

The BRCP is based on the annualised cost estimate of a benchmark reference technology that can be constructed to provide capacity to the SWIS for a capacity year commencing approximately two years into the future.

The need for adjustments to the estimated cost to reflect Year 3 of the relevant Reserve Capacity Cycle will depend on the nature of the cost estimation approach and whether the costs are reasonably expected to change over time. However, for most costs estimated through the BRCP approach, some form of adjustment may be needed for instance, construction labour costs would be expected to change year to year [7].

We have identified a series of potential adjustments that would be suitable for our estimates given these are typically based on current prices and the BRCP Procedure requires prices as of 1 October on Year 3 of the relevant Reserve Capacity Cycle. However, we do not recommend prescribing these in the Procedure as the appropriate approach will vary from year to year.

We recommend the Procedure provide for adjustments where costs have been determined at a different date from the date required for Year 3 of the relevant Reserve Capacity Cycle. The adjustment factors should be clearly identified where these have been used and and how they have been applied.

Indicative BRCP based on estimates

To develop the Procedure recommendations and as a means of testing the suitability of these recommendations, we have estimated costs that enable the calculation of the BRCP.

The calculation of the BRCP requires the division of annualised costs by the capacity credits that the benchmark capacity provider is expected to receive in the relevant capacity year, as illustrated in the following equation.

$$BRCP = \frac{ANNUAL_{Fixed\ O\&M} + ANNUALISED_{CAPEX}}{Capacity\ Credits}$$

The BESS has been designed to achieve 200 MW injection capacity. We therefore assume capacity credits of 200 MW for the purposes of the BRCP.

Assuming a weighted average cost of capital of 10.5% and a finance term of 15 years[8], the estimated BRCP based on the illustrative cost estimate developed for the purpose of updating the Procedure is $383,276 (Table 4).

Table 4 Estimated BRCP

Item	Estimate
Annualised capital cost	$72,733,543
Annual fixed O&M cost	$3,921,740
Capacity Credits	200
Benchmark Reserve Capacity Price	**$383,276**

[7] We have identified a series of potential adjustments that would be suitable for our estimates given these are typically based on current prices and the BRCP Procedure requires prices for Year 3 of the relevant Reserve Capacity Cycle. However, we do not recommend adopting these for the Procedure as the appropriate approach will vary from year to year.
[8] These are example amounts based of previous BRCPs, research on BESS projects and average financial investment terms.

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1. Introduction

The Economic Regulation Authority is reviewing the Market Procedure: Benchmark Reserve Capacity Price (Procedure) as required by clause 4.16.3 of the Wholesale Electricity Market Rules (WEM Rules).

The current Procedure requires the BRCP to be an estimate of the annualised cost to build and connect a hypothetical 160 MW liquid fuelled open cycle gas turbine generator to provide reserve capacity to the SWIS. In December 2023, the Coordinator of Energy (the Coordinator) determined that the Benchmark Reference Technology would change. [9]

The Benchmark Peak Capacity Provider will be a Lithium battery energy storage system (BESS) with:

- 200 MW injection
- 800 MWh energy storage
- a 330 kV connection near Kwinana or Pinjar

The Benchmark Flexible Capacity Provider will be a Lithium battery energy storage system:

- 200 MW injection
- 800 MWh energy storage
- a 330 kV connection near Kwinana or Pinjar

The aim of the BRCP is to include all reasonable non-variable costs expected to be incurred in the development of the Benchmark Capacity Providers, including annual fixed operating and maintenance costs to operate the facility in the South West Interconnected System (SWIS).

The BRCP Procedure documents the method and processes that the ERA follows annually to determine the Flexible BRCP and Peak BRCP for each Reserve Capacity Cycle. In accordance with 4.16.2 and 4.16.2A of the WEM Rules, the two BRCPs going forward are:

- **Peak BRCP** expressed in $/MW of Peak Capacity Credits per year, that reflects the expected annualised capital cost and fixed operating and maintenance costs of the Benchmark Peak Capacity Provider. Where the Benchmark Peak Capacity Provider is a notional new facility expected to provide Peak Capacity at the lowest annual capital cost and fixed operating and maintenance cost.
- **Flexible BRCP** expressed in $/MW of Flexible Capacity Credits per year, that reflects the expected annualised capital cost and fixed operating and maintenance costs of the Benchmark Flexible Capacity Provider. Where the Benchmark Flexible Capacity Provider is a notional new facility expected to provide Flexible Capacity at the lowest annual capital cost and fixed operating and maintenance cost. Facilities receiving Flexible Capacity Credits must meet all the same requirements as Peak Capacity Credits and the ramping requirements as determined by the Coordinator of Energy.

The BRCP is used as an input in the determination of the administered Reserve Capacity Price..

1.1 Purpose of this report

GHD has been engaged to assist the Secretariat of the Economic Regulation Authority (the Secretariat) to recommend updates to the BRCP Procedure to reflect the Coordinator's determination on the Peak and Flexible BRCP Reference Technology.

The cost estimates presented in this report are illustrative and are intended to inform updates to the BRCP Procedure only. The cost estimates are subject to the limitations set out in section 1.3 of this report.

[9] Coordinator of Energy, Benchmark Capacity Providers: Peak Capacity Provider and Flexible Capacity Provider, 18 December 2023. Refer to: **https://www.wa.gov.au/government/document-collections/coordinator-determinations**

1.2 Method

To guide the review of the Procedure, GHD took the view of a prospective investor. Our approach comprised of a bottom-up cost estimation process for the construction of a newly built a 200 MW/800 MWh Lithium BESS that aligns with the updated WEM Rules and the Coordinator's determination.

We did this by initially developing a concept design for the BESS and the associated transmission network connection. We then identified key costs across the following categories:

– Development and capital costs
– Transmission connection costs
– Land area and costs
– Fixed operation and maintenance costs

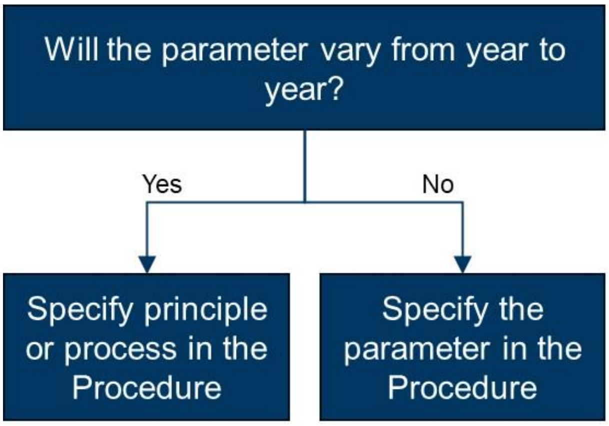
Cost estimates have been developed with an accuracy target of +/- 50%. Estimates are based on GHD's internal database and publicly available information as referenced in this report. GHD have not verified cost inputs through a market engagement process with vendors.

For clarity, our scope excluded variable costs. Consistent with the ERA's Offer Construction Guideline, the variable costs including variable operating and maintenance costs, market fees and runway costs of Contingency Reserve Raise are expected to be recovered through bidding in the Real-Time Market in the WEM.[10]

Our method for recommending the parameters to be included in the Procedure drew on the principles set out in WEM Rule 4.16.4, which states that the ERA must not specify a fixed value for parameters in the WEM Procedure that it reasonably expected to change from year to year and instead should specify the principles and processes for determining that parameter in the WEM Procedure.

Figure 1 summarises our approach to recommending parameters for inclusion in the Procedure.

Figure 1 Process for developing recommendations to be codified in the BRCP Procedure



1.3 Limitations

This report has been prepared by GHD for 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 section 1.1 of 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.

[10] ERA, Offer Construction Guideline, 1 October 2023, p. 10. Available at: **Monitoring the new WEM - Economic Regulation Authority Western Australia (erawa.com.au)**

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 the illustrative costs 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 set out in this report.

The Cost Estimate has been prepared for the purpose of updating the BRCP Procedure and must not be used for any other purpose.

The Cost Estimate is an illustrative estimate only. Actual prices, costs and other variables may be different to those used to prepare the Cost Estimate and may change. GHD does not represent, warrant or guarantee that the costs will be the same as the Cost Estimate.

Accessibility of documents

If this report is required to be accessible in any other format, this can be provided by GHD upon request and at an additional cost if necessary.

2. Design specifications and assumptions

The design specifications and operating assumptions recommended to inform the BRCP and the Procedure updates are summarised in Table 5. The specifications and assumptions have been developed to align with the WEM Rules' requirements.

The specifications and assumptions are the same for the Peak and Flexible Reserve Capacity Providers. We discuss the potential for operational differences in meeting these services that affect the assumptions used in the BRCP assessment in section 2.3 below. Later sections discuss the rationale for the recommended specifications and assumptions.

Table 5 BRCP service provider requirements

Parameter	BRCP service requirement	Comment
WEM Rule requirements		
Capacity	200 MW injection	Coordinator determination. See discussion in section 2.2 below.
Operational duration	4 hours (0.25C)[11]	Based on AEMO determination for the Energy Storage Resource Obligation Interval[12] in accordance with the Procedure developed under WEM Rule 4.11.3A.
Operating temperature	41ºC	WEM Rule requirement 4.10.1.(fA).ii
Additional specifications		
Lithium sub chemistry	Lithium iron phosphate (LFP)	See discussion in section 2.1 below.
BESS life (years)	Up to 20 years (warranty may be shorter)	See discussion in section 2.4 below.
Land requirements	6.5 ha	See discussion in section 2.5 below.
Operational assumptions		
Peak	1 cycle per day, full charge and discharge	See discussion in section 2.3 below.
Flex	1 cycle per day, full charge and discharge	See discussion in section 2.3 below.

The requirements outlined in Table 6 (below) were identified in the BRCP Reference Technology Consultation Paper and are taken to be the requirements in the WEM Rules for Flexible Service providers going forward. These requirements are set in addition to the service requirements for Peak Service (reflected in Table 5 of this report). All BESS technologies considered can achieve both the Peak and Flexible Service requirements. Hence, we have not recommended any specific design differences for the Flexible Service Providers to account for the Table 6 requirements.

Table 6 Flexible Service requirements

Parameter	Flexible service requirements
Ramp rate	100% capacity in 30 min
Start time	30 min
Minimum online generation	25%
Capacity factor	Daily operation

Source: Energy Policy WA, BRCP Reference Technology Review - Consultation Paper, 2 November 2023, Table 6, p. 13.

[11] C-rate is defined as the inverse duration of the battery. C-rate = current (amps) / capacity (amp-hours). A 0.25C C-rate indicates a 4-hour charge/discharge duration whilst a 1C value would refer to 1 hour duration for charging/discharging.

[12] The most recent publication from AEMO is from 2021 for the 2023-24 Capacity Year. AEMO determined the Energy Storage Resource Obligation Interval would commence at Trading Interval 16.30 and conclude at Trading Interval 20:00 for each Trading Day , which is a 4 hour period. Source: AEMO, Electric Storage Resource Obligation Intervals for 2023-24 Capacity Year, 2021, p. 2. Refer to: **2021-esroi-analysis.pdf (aemo.com.au)**

2.1 Lithium sub-chemistry

Battery cell chemistry plays an integral role in the cost, efficiency, technical performance, and safety of a BESS. A Lithium Iron based BESS's battery cells can consist of various possible sub-chemistries all of which may impact performance.

The following section outlines the advantages and disadvantages associated with each Lithium sub-chemistry and details our recommendations on why Lithium Iron Phosphate (LFP) is appropriate to be used as the reference sub-chemistry in the Procedure. When considering BESS chemistries, the following attributes are desirable:

- Low component cost – Minimised capital costs to enhance the likelihood of cost recovery
- Low safety risk – Improved safety performance reduces thermal management costs and parasitic load on the BESS (via temperature controls), thus improving system efficiency
- Life Span (High life cycle/reduced degradation) – A longer lifecycle for the system reduces the overall levelized cost of storage making the system more cost-effective over its lifespan
- High power/energy density – All sub-chemistries have the benefit of instantaneous power. A high-power and energy density sub-chemistry maximises output while minimising material footprint
- Technical Performance: Ideal batteries can handle high charge rates and operate at a wide range of state-of-charge values.

The most mature and applicable Lithium-ion sub-chemistries for utility-scale BESS applications are the following:

- Lithium Iron Phosphate (LFP) – LFP is one of the more cost-effective sub-chemistries and tends to be safer and have a higher life cycle than other sub-chemistries.
- Nickel Manganese Cobalt (NMC) – NMC has a very high energy and a high power density. NMC is used extensively in electric vehicle applications. While NMC was previously widely used in stationary storage for high C-rate applications, recent times have seen a preference to LFP for longer duration applications (i.e. > 1 hour). NMC also has an increased risk of thermal runaway[13] at higher temperatures. Lastly, resourcing Cobalt is a key supply chain issue for this sub-chemistry.
- Lithium Nickel Cobalt Aluminium (NCA) – NCA has a high energy and power density, however it tends to have a high cost and high safety risk.
- Lithium Titanate (LTO) – LTO has a very high cycle life and charge rate compared to other Li-ion chemistries, even at higher temperatures. LTO also has a lower risk of thermal runaway. The key constraints for LTO are the cost due to the high cost of titanium and the low energy density performance compared to the other sub chemistries.

Figure 2 shows a series of snowflake charts summarising the qualitative key attributes and strengths of the different Lithium-ion sub-chemistries. The outer ring of the snowflake indicate a superior rating.

[13] Thermal runaway refers to an event where a battery undergoes a heat-releasing chemical process that becomes uncontrollable and starts a self-feeding chain reaction that increases temperature.

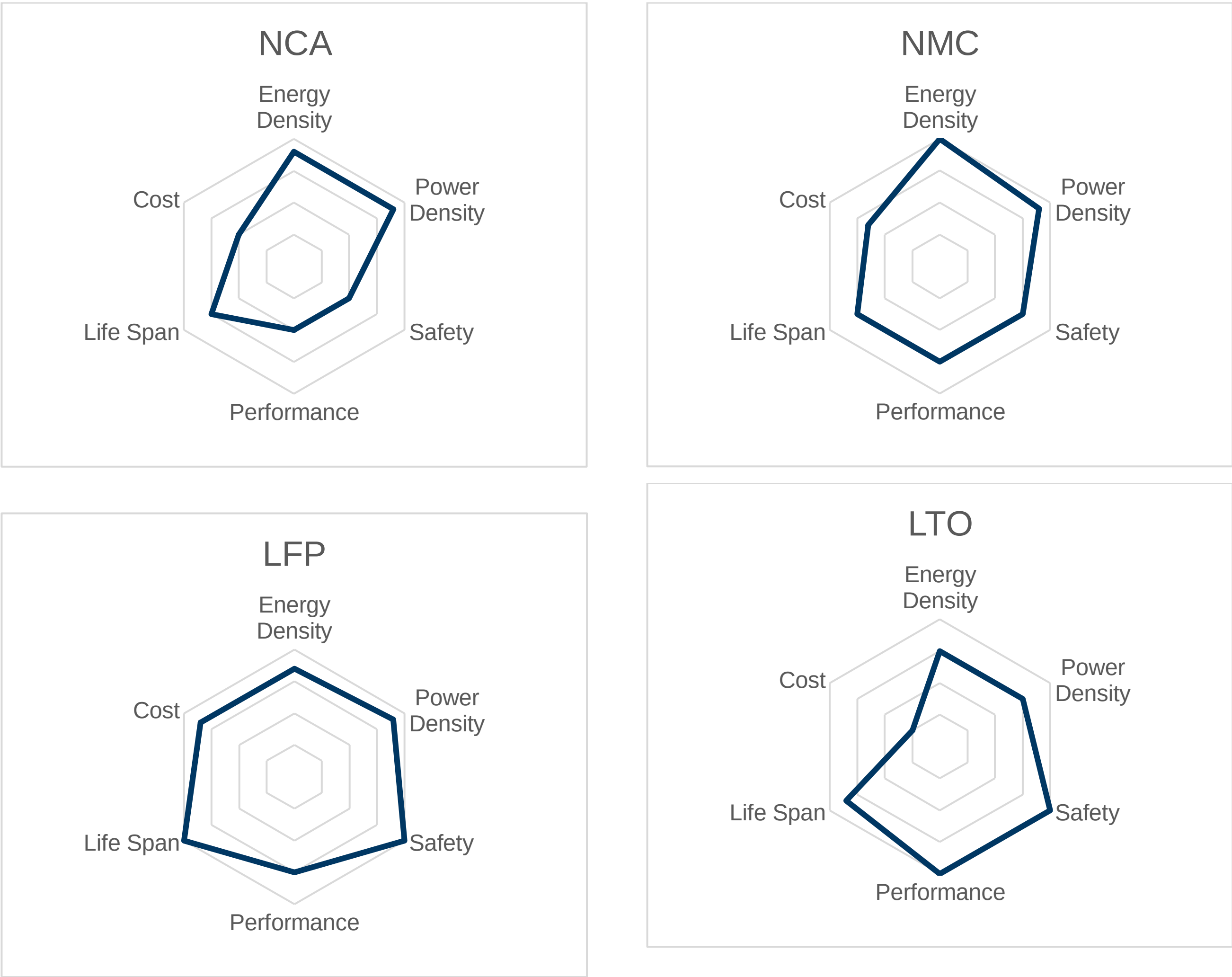


Figure 2 ***Lithium sub chemistry snowflake charts***[14]

Considering the key metrics and the advantages and disadvantages associated with each sub-chemistry above, it can be observed that LFP and NMC are the higher performing sub-chemistries amongst those considered for the BRCP application (i.e. in the context of medium duration, station utility-scale storage).

Of these two higher performing sub-chemistries, LFP is the most widely adopted in medium-duration utility-scale BESS projects both nationally and globally. Many operational and planned BESSs in Australia use LFP sub-chemistries with, some examples including[15] [16] [17]:

– Synergy's KBESS (1&2) developments in Kwinana, Western Australia.
– Synergy's Collie BESS in Collie, Western Australia.
– Genex Power's Bouldercombe BESS in Boulcercombe, Queensland.
– GMR Energy's Mornington BESS in Mornington, Victoria.

[14] Based on findings from a technical review previously conducted by GHD and information published in the following: Battery University. (2023, December 8). BU-205: Types of lithium-ion. **https://batteryuniversity.com/article/bu-205-types-of-lithium-ion**
[15] Colthorpe, A. (2023, July 4). Synergy constructs second large-scale BESS at former coal plant site in Western Australia. Energy-Storage.News. **https://www.energy-storage.news/synergy-constructs-second-large-scale-bess-at-former-coal-plant-site-in-western-australia/**
[16] Howland, N. (2023, December 12). Synergy gets approval for 500MW/2GWh Collie Battery. Energy Source & Distribution. **https://esdnews.com.au/synergy-gets-approval-for-500mw-2gwh-collie-battery/**
[17] RenewEconomy. (2022b, August 30). Big Battery Storage Map of Australia | RenewEconomy. **https://reneweconomy.com.au/big-battery-storage-map-of-australia/**

Given the desirable qualities of LFP as a Lithium sub-chemistry and the fact that there is high adoption of LFP for major grid-scale BESS in Australia, it is reasonable to assume LFP will continue to be the preferred technology in the near term.

The Procedure should consider explicitly stating the sub-chemistry given that there are significant cost and life difference, which inform the warranty, that are not expected to change in the period up to the Coordinator of Energy's next review of the Benchmark Reference Technology. To provide certainty on the BRCP, we recommend the Procedure specify LFP as the BESS sub-chemistry. We note that sub-chemistries are continually evolving and that it would be prudent to revisit this specification when the Coordinator revisits the Reference Technology in 3 years regardless of whether the Reference Technology changes.

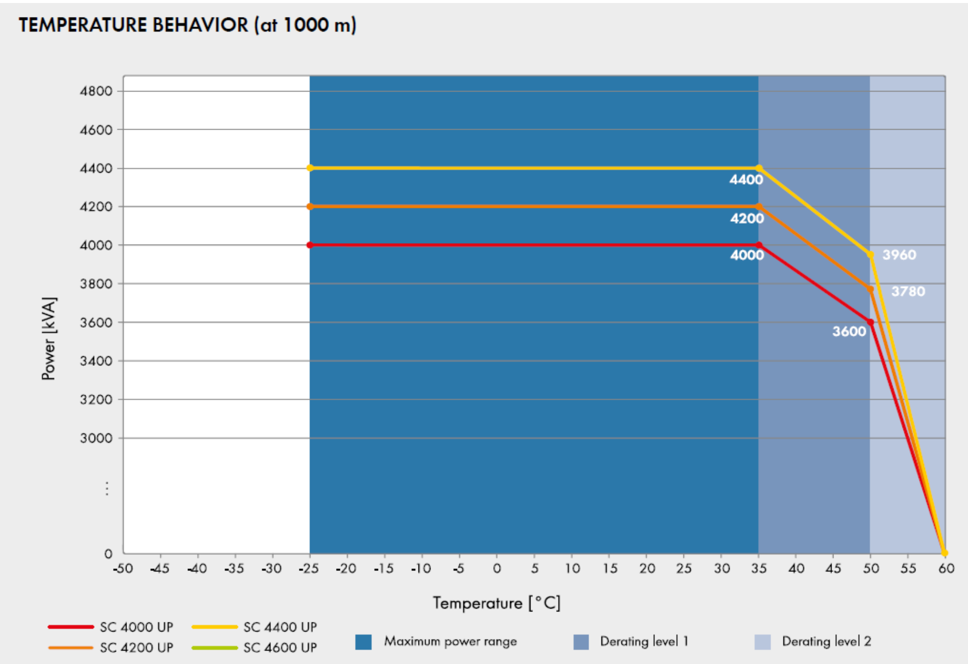
2.2 Installed capacity

2.2.1 Power capacity

The Coordinator's Determination requires the BESS system to provide 200 MW injection capacity and 800 MWh Beginning of Life (BOL) energy storage[18]. To achieve an injection capacity of 200 MW on day 1 of operations, various factors need to be considered which requires oversizing the power capacity of the BESS.

For inverters, higher temperatures will result in the internal controls curtailing the power output to protect internal components, which is called derating. Some inverter OEMs will derate their inverters from various temperature windows between 25°C and 60°C. Figure 3 gives an example of the power output of a leading global inverter OEM being derated from 35°C, which will serve as the basis for the concept design. Due to the requirement for the BESS to operate at 41°C, it is crucial to account for temperature derating when sizing the BESS.

Figure 3 Example of inverter derating curves with increasing temperature



Source: Temperature derating curve for inverter[19].

There is also a requirement for the BESS to ensure sufficient reactive power at the point of connection as well as compensate for the reactive power consumption of the transformers and other electrical equipment. Any generating system in the WEM is required to be able to supply reactive power that is a factor of the active power of the generator (200 MW).

[18] Coordinator of Energy, Benchmark Capacity Providers: Peak Capacity Provider and Flexible Capacity Provider, 18 December 2023, p. 7.
[19] Illustrative curve only. Specific temperature derate curves are vendor specific.

The reactive power compensation required is based on either the ideal or minimum generator performance standard:

– Ideal: the generator is capable of supplying or absorbing reactive power that is a factor of 0.484 of the active power of the generator[20]
– Minimum: the generator is capable of supplying or absorbing reactive power that is a factor of 0.329 of the active power of the generator[21]

Negotiation would be required if the BESS reactive compensation were to be less than the ideal generator performance standard up to the minimum level (factor of 0.329 of active power). It is recommended that the BESS be designed to meet the ideal generator performance standard.

Additionally, there are reactive losses in the system between the inverters of the BESS and the point of connection to Western Power which will need to be compensated for. Losses are incurred through all equipment such as cables and transformers.

The two key options to provide the reactive power compensation for a BESS is:

1. Via a power capacity uplift for the inverters of the BESS
2. Via switched reactive plant (reactors and capacitors) installed in the BESS substation

WEM Rule A12.4.2.7[22] requires continuous control of the reactive power compensation. Switched reactive plant can be discontinuous in that there are scenarios where it is delayed in providing reactive power compensation. It is therefore recommended to meet the reactive power compensation requirements via a power capacity uplift of the inverters of the BESS. The power capacity uplift would also allow the BESS to meet the voltage stability requirements as defined in the WEM[23].

A summary of the approximate power capacity uplifts for the BESS to account for temperature derating and reactive power and voltage stability is tabulated below.

Table 7 BESS power capacity uplift

Item	Estimated uplift requirement	Basis
Temperature derating	+5%	Estimated based on tier 1 battery inverter derating curves at 41°C.
Reactive power compensation and voltage stability	+20%	WEM market requirements ideal scenario = 10% Estimated losses from transformer and other equipment = 10%
Total	**+25%**	

As outlined in Table 7, a power capacity uplift of 25% is required to account for temperature derating and fulfill applicable reactive power and voltage stability requirements.

2.2.2 Energy capacity

A key issue for Lithium-based batteries is that they degrade continuously over time (see section 2.4.3 of this report for further discussion on battery degradation). Many factors cause these batteries to gradually lose their energy-carrying capacity. Factors impacting this includes but is not limited to the items set out in Table 8.

[20] WEM Rule A12.3.2.1 (version 13 December 2023)
[21] WEM Rules, A12.3.3.1 (version 13 December 2023)
[22] ‘A’ refers to Appendix.
[23] WEM Rules, A12.3.3.2 (version 13 December 2023)

Table 8 Energy Capacity Degradation Factors

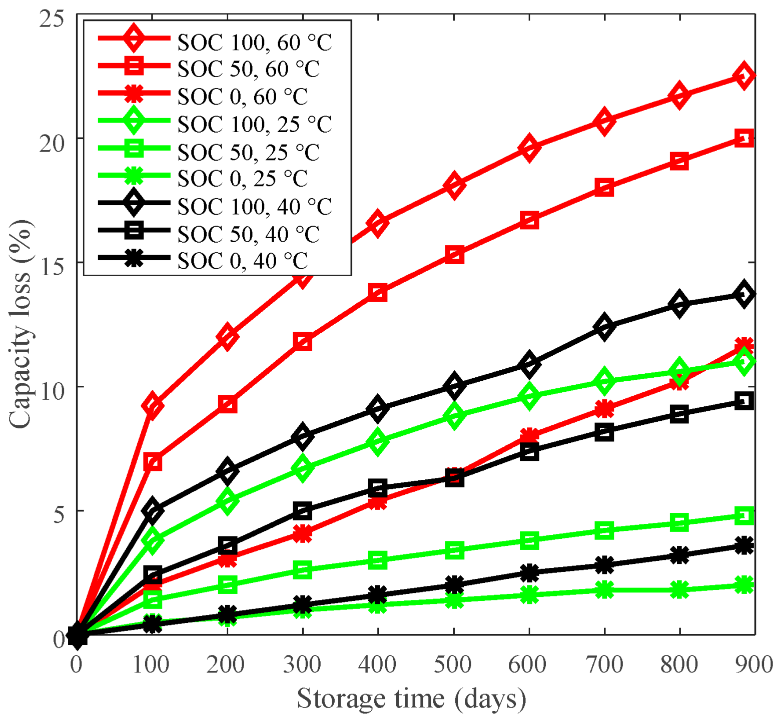
Item	Relevant to initial installed capacity?
Calendar fade	Y
Battery temperature	Y
Rate of charging (C-rate)	N
Duty cycle	N
Installed vs useable capacity	Y

Calendar Fade

Calendar fade is a particular consideration where the battery suffers time-based degradation irrespective of how or whether it is used. This is relevant for initial installed capacity as the battery containers are typically delivered onsite and are sitting idle in the ambient air for at least 3 months without their built-in temperature management system running. Figure 4 shows results from a study that tested individual battery cells being stored at various ambient temperatures. As such, the battery containers are reasonably expected to experience some level of calendar fade and have reduced energy capacity at the beginning of life.

It is therefore recommended to oversize the energy capacity with sufficient contingency to ensure that there is adequate energy capacity at the beginning of life of the BESS.

Figure 4 LFP battery capacity loss when stored at various temperatures



Source: Sun Y, Saxena S, Pecht M. Derating Guidelines for Lithium-Ion Batteries. Energies. 2018; 11(12):3295. Refer to: **https://doi.org/10.3390/en11123295**. Note: SOC refers to State of Charge.

Temperature

As shown in Figure 4, a higher ambient temperature can accelerate battery degradation, particularly when the batteries are just being stored. While this is usually managed effectively, the initial delivery of the batteries will have them sitting idle at the project site for at least 3 months (calendar fade described above). It is therefore recommended that the energy uplift is in place to offset this temperature-based degradation to ensure sufficient energy capacity (800 MWh) at the beginning of the BESS's life.

Installed vs useable energy capacity

Usable energy capacity refers to the amount of energy that the user of a BESS is allowed to access by the energy management system. To preserve the life of the battery, the user may be constrained in how much energy capacity of the battery modules they can access to preserve the life of the battery. This is often achieved by putting a limit on minimum or maximum State Of Charge (SOC). While this was historically common for some NMC OEMs, it is not as common for LFP and for the purposes of this assessment, it is assumed that installed energy capacity is equal to useable energy capacity. We do not recommend making specific allowances for this issue.

2.2.3 Installed power and energy

Based on the WEM requirements for reactive power compensation, temperature derates for power and estimated energy capacity loss over time discussed above, the following is recommended for a BESS to be able to inject 200 MW and have 800 MWh storage at the BOL:

- Oversizing the power capability (i.e. the total inverter capacity) by 25%, and
- Oversizing the energy capacity (i.e. the battery modules/enclosures) by 10%.

A specification that sizing of the BESS components consistent with these values is expected to enable the BESS to be assigned 200 MW of capacity credits (for both Peak and Flexible Capacity) in the first year of operation (subsequent degradation of the BESS, driven by the battery modules, is discussed in section 2.4.3 of this report).

2.3 Operational assumptions

The requirements of the Peak and Flexible Services are necessary to understand the operational use of the plant and whether the intended use alters the BRCP.

Peak Capacity is the Reserve Capacity that contributes to meeting peak demand. Under the WEM Rules, the availability obligations for electric storage can be different for different resources, depending on when they enter the WEM and the facility's unique duration requirement.

AEMO's WEM Procedure published in accordance with clause 4.11.3A provides that it consult with Market Participants on the proposed Electricity Storage Resource Obligation Intervals.[24] The most recent publication of this consultation is from 2021 for the 2023-24 Capacity Year. AEMO determined the Energy Storage Resource Obligation Interval would commence at Trading Interval 16.30 and conclude at Trading Interval 20:00 for each Trading Day[25], which is a 4-hour period.

A Peak Provider that is storage is allocated Capacity Credits based on this period and must be available to meet this obligation each day. Hence, if the service is required and results in the BESS fully discharging over the 4-hour period on any one Trading Day, the BESS will have to fully recharge to ensure it can meet the obligations the following day.

Flexible Capacity is Reserve Capacity that can respond at very short notice to manage changes in load during high ramp periods. The quantity of Flexible Certified Reserve Capacity allocated to a facility is capped at:

- The Certified Reserve Capacity for peak capacity; and
- The maximum MW that the Facility (or Separately Certified Component) could reach 4 hours after being dispatched.

When dispatched, a fully charged 200 MW/ 800 MWh BESS can operate for 4 hours at maximum power and longer at reduced power. During and after this period when the BESS is not dispatched, the BESS would need to be charged to meet the next Flexible Service obligation.

The BRCP must be designed to enable the Peak and Flexible Capacity services to be provided at the lowest annual capital cost and fixed operating and maintenance cost. While the actual use of services may vary, the

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[24] AEMO, WEM Procedure: Electronic Storage Resource Obligation Intervals, 11 July 2023, p. 7. Refer to: **electric-storage-resource-obligation-intervals.pdf (aemo.com.au)**

[25] AEMO, Electric Storage Resource Obligation Intervals for 2023-24 Capacity Year, 2021, p. 2. Refer to: **2021-esroi-analysis.pdf (aemo.com.au)**

minimum specifications must enable these services to be called on in a manner consistent with the WEM Rule requirements (and the allocated Certified Reserve Capacity Credits for that year).

The WEM Rule requirement amounts to being called on daily and, for the initial year when maximum capacity credits are allocated, being able to supply power for the full 4-hour period. Hence, for the purposes of calculating the potential warranty for the Reference Technology BESS (and therefore the life of the plant), we have assumed a maximum operating requirement of 1 full charge/discharge cycle per day.

2.4 Life of the plant

The life of the BESS is ultimately limited by the technical life of the key components of the BESS and dependent on the how the BESS is operated. However, the technical life may be different from the equipment warranty and also different to the financing term (or the life over which investors require a return on their capital expenditure).

The following sections discuss the technical life of a BESS in the context of the life of the key components that make up a BESS. We also discuss typical battery warranties that vary with the use of the BESS and may be shorter than the technical life. It is valuable to consider the life of plant to gain a clearer outlook on various crucial aspects of the BESS relating towards performance, warranty, maintenance and battery health, which in turn influence investor return periods.

2.4.1 Technical life

The key components of a BESS have differing technical lives. The technical life of the battery modules is of particular interest due to their energy capacity degradation compared to the other components. A common mechanism to manage risks with the technical life of the battery is through the battery energy capacity performance warranty which allows the user to map out the expected life of the battery containers based on the OEM warranty. Batteries continuously degrade as they operate over time. At the end of the life of the battery, there are minimal gains in the continuing operation of the battery unless the cell is chemically recycled[26], otherwise the battery modules are retired.

Key components for a BESS system can fall broadly into one of four primary categories:

- Battery modules/enclosures
- Power Conversion System (PCS)
- Electrical and control balance of plant (BoP)
- Civil BoP

Battery modules/enclosures

There are various metrics that can be used to determine when battery modules have reached their end of life. Most generally, the life of the batteries is tied to their state of health (SOH). Batteries are generally considered to be at their end of life when the SOH is below a certain threshold (typically 70%-80%) or when the SOH is observed to be rapidly degrading. However, ultimately the investors' appetite for replacement or decommissioning will determine at which SOH the battery is considered to be at the end of life.

Risks around the battery module life are generally managed through the battery OEM warranty. As discussed in section 2.4.2 of this report, the OEM warranty is manufacturer specific and may take several forms. However, warranties will generally ensure battery operation for between 15-20 years depending on the duty cycle (i.e. how the batteries are operated). Further, assuming the batteries are operating at the maximum levels required under the WEM Rules (i.e. 1 full charge/discharge cycle per day), the warranty would be exhausted in around 8 to 11 years if the manufacturer is using an energy throughput[27] approach (less common) and around 20 years if the approach is based on the intended duty cycle.

[26] There are niche enterprises that are currently aiming to repurpose batteries that have reached this stage but it is not considered to be the norm and so we have not provided for any residual value for the BESS in the BRCP.
[27] Energy throughput refers to the amount of energy that is stored and delivered by a battery at any point in time.

Power Conversion System (PCS)

The PCS is made up of inverters that convert DC power to AC. The typical life of an inverter varies, however, financial models generally assume a lifespan of up to 20 years for an inverter.

The limiting factor for the life of the PCS is typically the inverter software, which will typically become redundant before the equipment itself reaches its' end of life. As such, replacement, upgrade, or overhaul of the PCS may happen more frequently than the actual lifespan of the equipment. Recent trends in software have meant upgrades to the PCS are needed to maintain systems in line with industry standards before the 20 years assumed in financial models. Regardless, the BESS life is not typically limited by the life of the PSC[28].

Electrical and control Balance of Plant (BoP) including the BESS substation

Electrical and control BoP refers to electrical infrastructure that enables the transfer of power from the BESS inclusive of the BESS substation. It refers to equipment such as transformers, switchboards, protection equipment and control equipment. For the most part, the design life of electrical BoP equipment is 25 years.

The most constrained electrical and control BoP would be the control equipment and associated software. As with the PCS, the control system software can quickly become outdated and will require regular updates over the life cycle of the BESS. Moreover, the equipment or the architecture may become outdated within 20 years and require an upgrade or overhaul of the system before the BESS end of life.

The BESS substation has a technical life of 20 to 30 years and is not a limiting factor on the overall life of the BESS. Similar to other types of substations, the maintenance to preserve the life of the substation requires replacement of any aging or malfunctioning assets on an ongoing basis.

Civil Balance of Plant (BoP)

Civil BoP refers to key civil structures that make up the BESS such as the foundations and transformer bunds for the BESS battery containers and BESS substation. Typically made from concrete, civil BoP is generally not a limiting factor in the technical life of the BESS as the elements generally have a design life of 50 years.

2.4.2 Battery warranty

Given the variability in the actual technical life of BESS elements, investors generally look at the manufacturer's warranties for the critical limiting elements such as the battery cells.

Warranties for BESS can depend on the service levels and whether the servicing is being provided by the OEM, but are loosely broken up into two different types. There are two main types of warranties offered by manufacturers as described below (based on energy throughput and based on duty cycle). The most common warranty seen in the market is a warranty based on the duty cycle and is the most likely form of warranty to apply to a BESS being developed to provide Peak and Flexible Reserve Capacity.

The two warranty types below discuss Lithium-ion BESS warranties assuming an LFP sub-chemistry.

Type 1 - Based on the energy throughput

Energy throughput refers to the amount of energy that is stored and delivered by a battery at any point in time. Energy throughput based warranties will give a guaranteed MWh throughput for the batteries, regardless of duty cycle or charge rate.

A more conservative version of this warranty would be based on the number of cycles and may provide for between 3,000 to 4,000 cycles over the life of the battery. Assuming one cycle per day to align with the maximum operational requirement under the WEM Rules, this corresponds to a battery life cycle of 8.2 to 11 years, meaning the BESS warranty would be exhausted before 15 years. The assumption of one cycle per day provides for a conservative estimate of throughput. Investors would expect a lower annual throughput on a BESS if it were only providing Peak and Flexible Services as these services are not necessarily called upon on a daily basis. It is more

[28] We note OEM do not typically contemplate warranties for inverters longer than 5 to 10 years. This is because it is a mature technology and the equipment will typically fail very quickly or last until the end of the approximate 20 years life. Hence there is no need to provide warranties beyond the initial period.

realistic to assume a lower rate of cycling for these purposes, in which case the product would outperform a warranty duration of 11 years.

Type 2 - Based on intended duty cycle

Duty cycle can be described as the operating regime or profile of the battery which includes all the factors of:

– Charge and discharge rates
– Depth of discharge
– Cycle duration
– Length of time resting between cycles

More recently and increasingly common for grid-scale BESS, OEM's will warrant year-on-year state of health or available energy for the BESS based on a specific duty cycle and operating conditions[29]. We refer to this type of warranty as being based on intended duty cycle.

An intended duty cycle is defined by the OEM and forms the basis of their guarantee on performance. The approach allows the OEM guarantee to be adjusted overtime based on the actual usage and duty cycle using predefined methods.

Under intended duty cycle style approaches, OEMs are warranting batteries for a lifetime of between 15 and 20 years rather than the 8 to 11 years estimated for warranties based on energy throughput (Type 1). The intended duty cycle warranty type has a more empirical basis as it maps the energy capacity year-on-year. The year-on-year mapping allows a more effective assessment of how "bankable" a BESS will be over its life. Figure 5 shows illustrative energy capacity degradation curves from various OEMs for two types of lithium sub-chemistries (LFP and NMC). The figure shows the percentage of nameplate capacity guaranteed to be available at the end of each year of operation based on an intended duty cycle.

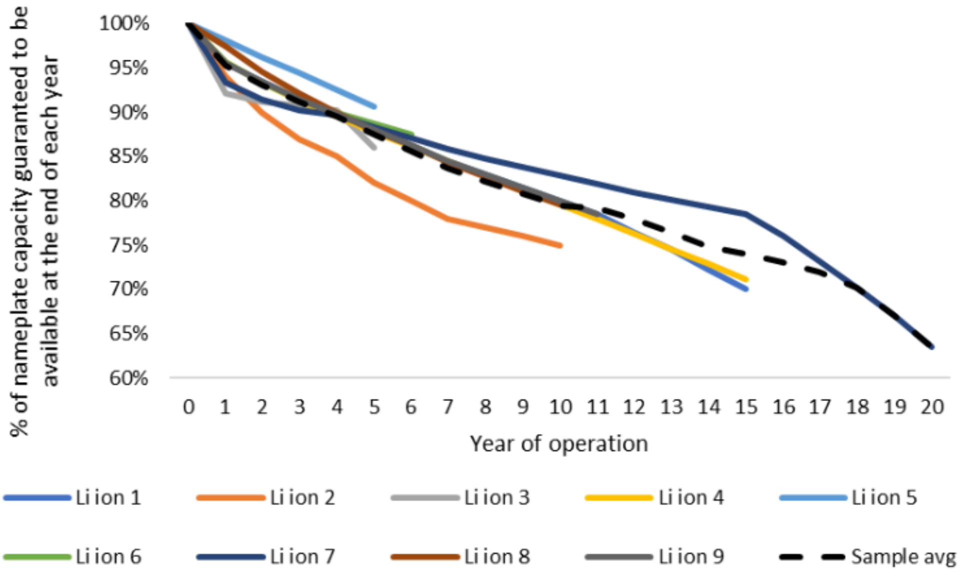


Figure 5 ***Illustrative energy capacity degradation curves from various OEMs for Li ion batteries[29]***

To gain an understanding of the possible warranty outcomes for the Reference Technology BESS, we projected a hypothetical OEM battery degradation warranty for a 4-hour BESS undergoing 1 cycle per day (365 cycles per annum) with no limitations on its duty cycle. These results are presented in Table 9. These results are presented in Table 9 which shows that the BESS, operating under the projected 1 cycle per day with no other limits on duty cycle, will operate for 20 years and have an energy capacity equal to 71.5% of its beginning of life capacity.

[29] Warshay, B. Energy storage Capacity Warranties: Beyond the fine print

Table 9 Illustrative example of OEM warranty for a 4-hour BESS (LFP) assuming 365 cycles per annum

Year	Energy capacity compared to beginning of life (SOH)
0	100.0%
1	94.0%
2	91.5%
3	89.5%
4	87.8%
5	86.4%
6	85.0%
7	83.7%
8	82.5%
9	81.3%
10	80.2%
11	79.2%
12	78.2%
13	77.3%
14	76.4%
15	75.5%
16	74.6%
17	73.8%
18	73.0%
19	72.3%
20	71.5%

Our analysis focuses on the OEM warranty. However, where the BESS has been developed under an engineering, procurement and construction (EPC) contract arrangement, the batteries may be covered initially through the EPC arrangement[30]. In Australia, many warranties for BESS built under an EPC contract are nearing the end of their 24-month defect liability period and the warranties themselves are mostly untested.

Negotiation and extensions

In Australia, grid-scale BESS are typically procured from Tier 1 vendors, who have the greatest market share and the necessary proven track records required by Australian investors. Tier 1 vendors do not commonly negotiate warranties as they have developed robust and well-defined methods for the intended operation of their batteries and adjustments to their warranties based on actual usage.

Extended warranties based on performance may be possible. However, these warranties are typically aligned with a specific use-case. That is, the warranty is offered based on an understanding of how the BESS is going to be operated. While appetite to offer extended warranties may change with increased competition, selection of the BESS generally preferences other key considerations (such as proven track record, ability to supply and capital cost) over the specifics of the performance warranty or the ability for the warranty to be extended.

For these reasons, and in recognition of the marginal improvement in de-risking the BESS that a negotiated extended warranty provides, we have not considered the option of an extended warranty in developing the hypothetical life of the Reference Technology BESS.

[30] Coverage of warranty risks through EPC arrangements will vary but is not uncommon. We note for long-lead procurement items and to enable connection processes to proceed (which require OEM to be specified), an EPC may be prescribed a particular BESS and inverter technology in the interest of scheduling. If this is the case the ability to enforce commercial damages is reduced and the certainty of the lifetime being based on the warranty is diminished and the OEM warranty will provide the owner with coverage during the EPC contract period.

2.4.3 Degradation

Overall, BESS system degradation is affected by the power capacity (meaning the maximum power output in MW) of the balance of the plant, particularly the inverters, and the energy capacity (meaning the capacity to absorb or store electricity in MWh) of the batteries. A battery's energy capacity after degradation is referred to as the state of health (SOH) of the battery. This section describes key considerations that impact BESS power and energy degradation.

Power capacity

The power capacity refers to the capacity BESS to deliver maximum power output (measured in MW). The power capacity is dependent on the balance of plant and predominately driven by the total capacity of the inverters that make up the power conversion system. However, it is also dependent on the maximum discharge capacity of the batteries.

The power capacity of the BESS is expected to remain at its' derated value (based on assumed operating conditions) for the life of the system with minimal degradation. Aside from damage to inverters under fault conditions, inverter hardware will typically undergo wear over time (electromechanical components, fans, capacitors, and integrated circuitry) and this is managed through a maintenance regime.

There is minimal risk of ongoing power capacity degradation, as such, power capacity is generally validated during commissioning and tested as pass/fail in meeting the power capacity requirements over the lifetime of the BESS.

State of health

The key characteristic of a BESS that is susceptible to degradation is the energy capacity of the battery modules. The energy carrying capacity of the battery modules as a percentage of its' beginning of life capacity is known as the state of health (SOH) of the batteries.

The effect of degradation on batteries is a reduction of the energy capacity that they can achieve, reducing the SOH. For example, if a 100 kWh battery system is at 100% SOH, that means that it can charge and discharge 100 kWh of energy. After some time, if the same battery system has degraded to, for example, 80% SOH, it can only charge and discharge 80 kWh of energy.

Battery management systems attempt to optimise the charge balancing of their various cells to prolong the life of the cells. Generally, a BESS is considered to be at its end of life when the SOH of the batteries is 70% or 80%[31]. Key factors that impact the degradation rate include, but are not limited to:

- Duty cycle – High charge and discharge rates (i.e., greater than a C-rate of 1) accelerate battery degradation.
- Energy throughput – The total energy cycled through the batteries. The higher the throughput, the higher the battery degradation.
- Cell temperature – Lithium-based energy storage is particularly susceptible to degradation at higher temperatures. As such, containerised battery offerings typically include built-in systems for temperature control.
- Depth of discharge – Depth of discharge refers to the battery capacity that is discharged during cycles Discharging close to 100% is considered "deep discharge" and doing so regularly can accelerate degradation. Battery management systems will generally attempt to maintain a nominal depth of discharge level below 100% (e.g. 80% or 70%) to preserve the life of the batteries.
- Rest time – Time between cycles when the BESS is at rest. Batteries continually degrade over time when they are not operating.

[31] We note that at SOH of 70% to 80% there will still be some residual economic value as the batteries are still functioning, albeit at a reduced energy capacity. However, our experience has been that at these types of levels, investors would consider the batteries to be at end of life.

LFP capacity test for <2-hour batteries **LFP capacity test for 4-hour batteries**

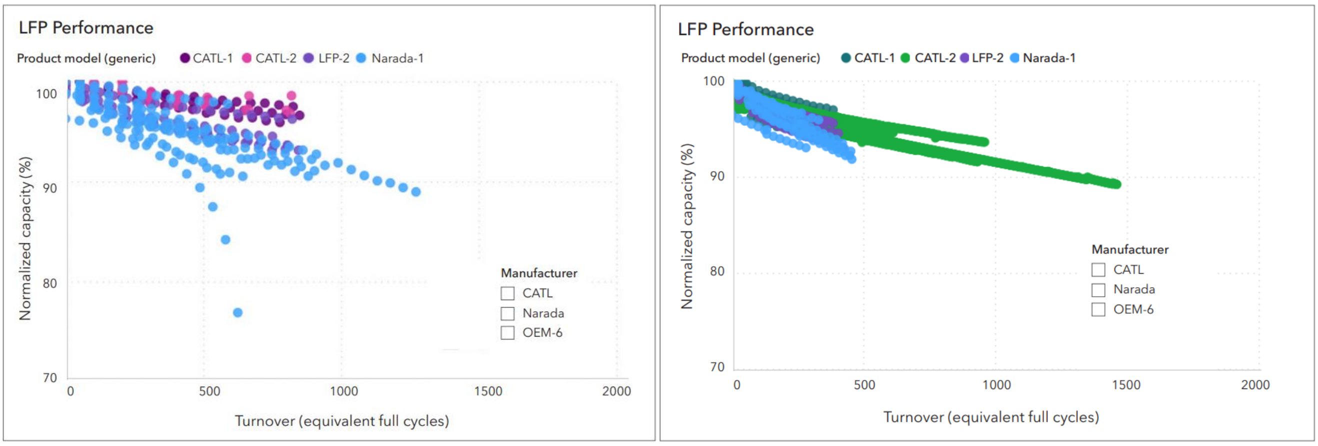


Figure 6 *LFP performance curves*[32]

The graphs in Figure 6 show the performance of various LFP batteries measured as SOH for increasing numbers of cycles. The LFP batteries in this scenario were tested under similar conditions to the BRCP BESS (i.e. 1 cycle per day, 365 cycles per year) and the analysis ran for approximately 4 years.

In the graph showing results for the <2 hour batteries, capacity degradation occurs more quickly in the first year with capacity falling from 3% to 5%, before levelling out to an annual degradation rate between 1% and 3% per year. The trend shifts depending on the use case, cell type, SOC, and temperature.

For the <2 hour batteries, eventually, each cell will fall over a knee point[33] whereby the cells degrade rapidly. This point can be seen in the graph showing results for the 2-hour batteries where the lowest set of blue dots indicate a rapid reduction in capacity after 500 cycles.

In the 4-hour graph on the left, none of the scenarios tested has the cells reaching this knee point of the degradation curve in which the capacity degrades asymptotically towards its end of life. While the lifespan of a 4-hour BESS will be longer than a <2 hour BESS, their degradation still happens quickly within the first year. It is therefore a critical consideration to sufficiently compensate and oversize the energy capacity (MWh) of the BESS to operate as a rated 800 MWh at beginning of life as noted in section 2.2.3.

The risks of lost energy storage capacity are managed through the battery cooling system and the energy management system. The financial losses are mitigated by the battery OEM warranties (see section 2.4.2 of this report).

2.5 Land requirements

The land requirements are primarily determined by the size of the BESS but also cover the BESS substation and connecting assets to the Western Power network.

2.5.1 BESS

We have considered two standard BESS layouts and allowing for an uplift for balance of plant (RMUs, auxiliary skids, etc.) and a buffer zone (2-3 meters around the site) the battery containers would require at least 1.6 ha. Figure 7 shows 1.52 ha and 1.59 ha layouts and includes space that can be used for the balance of plant.

The land required for the BESS is dependent on the size of the containers. Both the standard BESS layouts considered use battery containers with an energy rating of 4 MWh and inverters with a power rating of 4 MW in line with current tier one (1) OEM capacity and dimensions. While there may be some variation in the battery container sizes, this will have minimal impact on the land requirements due to the energy density of the LFP batteries being consistent across the market. Therefore, we consider this approach reasonable for the next 3-year

[32] 2022 Battery Scorecard
[33] This is only obvious for the 2-hour Narada test. However, this may be due to the CATL-1 and CATL-2 cells not being tested under enough cycles

period (before which time the Coordinator must review the Benchmark Capacity Providers in accordance with WEM Rule 4.16.11[34] and the Economic Regulation Authority must subsequently update the BRCP Procedure).

A BESS substation is required for stepping up the system voltage of the BESS (33 kV at the terminals of the outgoing transformer) to 330 kV (Western Power network voltage). A suitably sized 330/33 kV substation for the interconnection between the BESS and the network would require at least 0.4 ha. This includes a sufficient buffer zone to account for noise (of the substation), clearances and fencing.

Finally, depending on the distance between the BESS and the substation as well as the plot shape, we would expect to allow for an additional 0.5 ha to 1 ha uplift to account for the land between the BESS substation and the Western Power substation.

Based on the above requirements, the estimated land that the BESS development (and associated assets) would require is between 2.5 ha to 3 ha.

2.5.2 Western Power substation

As discussed in section 3.2 of this report, we assume a dedicated 330 kV Western Power substation would be built for the BESS. It is assumed a cut-in cut-out arrangement is suitable. This arrangement involves cutting into an existing transmission line and building a substation to serve as the dedicated 330 kV connection point for the BESS.

Based on similar capacity projects with a dedicated Western Power substation, the land expected for the Western Power substation is 3.5 ha including allowances for access roads and additional buffer around the perimeter of the fence.

[34] WEM Rule 4.16.11(c) requires the Coordination of Energy to determine the Benchmark Capacity Providers within three years of the previous determination of the Benchmark capacity Providers. (WEM Rule version 13 December 2023)

Figure 7 BESS layouts used for land sizing

2.5.3 Total land area required

The total land requirements including the BESS facility (3 ha) and Western Power substation (3.5 ha) is approximately 6.5 ha.

2.6 Recommendations for the BRCP Procedure

Based on the information outlined in this report and with consideration of the current provisions in the BRCP Procedure, we recommend the update Procedure specify the items as per below.

- Definition of the Reference Technology can specify:
  - Lithium Iron Phosphate (LFP) as the sub-chemistry, subject to review in three years.
  - Installed capacity to enable injection of 200 MW on day 1 of operation.
  - Battery module provisions to enable 800 MWh charge and discharge on day 1 of operation.
- Land area required should provide for the BESS, the BESS substation, and connecting assets to the Western Power network, including the Western Power substation inclusive of buffer zones. Assuming the transmission connection arrangements outlined in Chapter 3.2 of this report, the Procedure should specify a land area of 6.5 ha as this will not change from year to year

For the purpose of the Procedure, we would recommend oversizing of the BESS to achieve the installed capacity and energy requirements be revisited on an annual basis as the power capability is linked to WEM Rule requirements that may change and the energy capacity can vary based on the design of the BESS.

Based on our analysis, the factors that could be considered in the Procedure are:

- For power capacity:
  - Temperature derating for operation at 41 degrees Celsius.
  - Reactive power compensation for required levels according to generator performance standards in the WEM rules and expected equipment losses.
  - Voltage stability requirements in accordance with WEM Rules
- For battery energy capacity:
  - Capacity loss from calendar fade during the time between battery enclosure delivery and energisation.
  - Temperature effects of idle batteries alongside calendar fade.

However, should the Procedure specify the ERA engage a suitably qualified consultant to develop BESS cost estimates, these factors may necessarily be considered as part of that engagement and so do not need to be specified in the Procedure

We do not consider the life of the plant and operational assumptions need to be explicitly detailed in the Procedure. As described in section 2.4 of this report, the life of a BESS is ultimately limited by the technical life of the battery modules, which is dependent on the usage of the BESS. However, the battery warranty, which investors typically use as an indication of the maximum life is typically shorter than the technical life of the plant. Further, investor preferences on the level of performance that represents an end of life are variable. We expect the WACC calculation will consider these factors in determining the term of financing over which the capital cost components of the BRCP are annualised and that this value will be shorter than the technical and warranty lives presented in our report. Further, we expect investor requirements on the period of return to vary from year to year, and so the Procedure would reasonably be expected to capture the principles rather than specify a period.

The operational assumptions presented in this report have been used to calculate the potential performance of the BESS over its life should the Peak and Flexible Service be called on to the maximum extent possible under the WEM Rules (i.e. one full cycle each Trading Day) and have given an indicative understanding of the warranty curve to show expected energy capacity loss. However, the operational assumptions were not used in the design of the BESS or to inform cost estimates in subsequent sections and hence we do not recommend the Procedure specify operational assumptions.

3. Development and capital cost

The key capital cost components of the BESS include the battery modules/enclosures, power conversion system (PCS), electricity and control balance of plant (BoP) and civil BoP.

In addition, there are various capital overheads incurred in the development and construction of the BESS. The following cost are typically included as part of the expected capital cost of the BESS.

- Transmission connection capital costs
- Land costs
- Connection agreement, market registration and licensing costs
- Environmental and development approval costs
- Design and project management costs
- Legal, financing and insurance costs

The BESS supply and installation costs, which cover the key capital costs are the most significant of the costs and are discussed first. The other costs associated with the development and construction of the BESS are then outlined.

3.1 BESS supply and installation costs

Key components of the capital cost for a BESS system fall broadly into one of four categories:

- Battery modules/enclosures
- Power Conversion System (PCS)
- Electrical and control balance of plant (BoP)
- Civil BoP
- Installation labour & associated temporary equipment hire

The basis of capital cost estimates in this section assumes an engineering, procurement and construction (EPC) contracting strategy, as it has been a common contracting strategy for large-scale BESS in Australia and serves as an effective benchmark for cost estimation purposes. Under an EPC contracting strategy, a contractor is solely responsible for the successful design and construction (including procurement of equipment) of the BESS. This is reflected and included in individual unit costs for BESS components, as well as overhead costs. It should be noted that for new large-scale BESS opportunities, there is a reduced appetite for developers/contractors to enter an EPC arrangement. The actual contract strategy adopted by the BESS will depend on the owner's risk appetite and contractor market conditions at the time of engagement.

3.1.1 Battery modules/enclosures

Battery modules are typically offered by OEMs as containers. The battery containers include racks of battery modules, thermal management systems such as air conditioning or liquid cooling, control equipment and a fire suppression system.

Based on the GHD database, the estimated unit cost per kWh for LFP battery modules/enclosures is approximately $350 per kWh of rated battery capacity (800 MWh). This includes the estimated uplift discussed in Section 2.2 to enable power and energy capacity that aligns with the Coordinator’s determination on day 1 of operation.

3.1.2 Power conversion system (PCS)

The PCS is comprised of multiple inverters that convert DC power to AC, one inverter will be connected to multiple battery containers in uniform groups. The proposed concept design has each inverter placed in close proximity to 4 battery containers.

Based on the GHD database, the estimated unit cost per kW for the PCS is $130 per kW of rated capacity for the system (200 MW). The unit cost factors in sufficient power capacity uplift required to compensate for temperature deratings, reactive power requirements and transformer losses.

For the functionality required across the flex and peak applications for the BESS, inverters are a very mature technology with stable pricing.

3.1.3 Electrical and control BoP including BESS substation

Electrical and control BoP includes all enabling electrical infrastructure, cables and conduits, transformers, switchgear, protection, and control equipment for the batteries and the BESS substation. For the BESS, this includes the 33/330kV substation electrical BoP as well as all equipment in the battery yard between the battery containers and the PCS.

Based on the GHD database, the estimated unit cost for electrical and control BoP is estimated to be $55 per kWh rated capacity of the BESS (800 MWh total). The standard method of estimating electrical and control BoP is to estimate these based on the energy storage (MWh) required. This reflects that the requirement for electrical and control BoP increases with the size of the plant and therefore capital costs increase. Basing BoP on the energy storage requirement rather than a percentage of total plant costs should avoid changes in the BESS modules unduly affecting the estimated cost of BoP.

3.1.4 Civil BoP

The civil BoP consists of the foundations, transformer bunds and equipment pads for the batteries and substation.

Based on the GHD database, the estimated unit cost for civil BoP is estimated to be $15 per kWh rated capacity of the BESS (800 MWh total). Similar to the approach taken for estimating the electrical and control BoP, civil BoP is estimated based on the energy storage requirements (MWh) seeing as the energy storage is a key factor.

3.1.5 Installation labour & temporary equipment hire

The installation labour & temporary equipment hire costs consist of:

- Local construction labour needs to develop the site and install the BESS.
- Temporary equipment hire costs during the construction phase.

Based on the GHD database, the estimated unit cost of installation labour & temporary equipment hire is $60 per kWh. Similar to the approach taken for estimating the BoP items, this estimate is based on the energy storage requirements (MWh) as the energy storage is a key factor driving the overall costs.

3.1.6 Summary of BESS supply and installation costs

Table 10 summarises the BESS supply and installation costs.

Table 10 BESS supply and installation costs

Item	Unit Cost	Unit	Estimated cost	Comment
Lithium-ion battery modules/enclosures	$350	$/kWh	$280,000,000	Assumes 800 MWh.
Power Conversion System	$135	$/kW	$27,000,000	Assumes 200 MW.
Electrical and control BoP including BESS substation	$60	$/kWh	$48,000,000	Assumes 800 MWh.
Civil BoP	$15	$/kWh	$12,000,000	Assumes 800 MWh.
Installation labour & temporary equipment hire	$60	$/kWh	$48,000,000	Assumes 800 MWh.
Total			**$415,000,000**	

3.2 Transmission connection capital costs

For new connections where there is no previous connection point, principles outlined in Western Power's Policy Statement – Transmission Connection Price[35] are applied. Two options are available:

– Where the connection asset will be dedicated to a single user, the asset can be constructed by either the user or by Western Power and the user has the option to own the asset or to allow Western Power to own the asset. If Western Power owns the asset, the capital contribution for the connection asset is determined by the Contributions Policy. The annual connection price is calculated to recover the expected operation and maintenance costs for the connection asset.

– Where there is a high likelihood that other users will connect in the future, Western Power may require the ability to build connection assets for other users on the same site. Under these circumstances, if the user chooses to own the connection assets, the capital contribution and the associated connection access prices are on the same basis as if the user had a dedicated connection asset. However, where the user would prefer Western Power to own the connection assets, the connection access price would be the published price that applies to all multi-user substations within the Western Power network.

For the purposes of the BRCP, we assume the connection assets will be dedicated to the BESS and owned by Western Power. Such an approach is consistent with recent trends in generation developments. We also assume the BESS is located as close as possible to the existing 330 kV lines to minimise the need for transmission lines between the facility and the connection point. The connection configuration and costs assume the Western Power substation is located adjacent to the existing network and provides for the BESS substation and BESS to be located near but not at this same location.

We have not reviewed the detailed design of the connection arrangement and as the arrangement used by Western Power in previous BRCP determinations would be able to support a 200 MW BESS connection, we have developed our cost estimate for transmission connection assets using a similar connection arrangement to that proposed by Western Power for the 2026/27 Reserve Capacity Year.[36]

The scope of the connection works includes:

– A substation,

– 2 km of overhead 330 kV line between the BESS site and the substation,

– An overhead line easement, and

– Cutting in the existing 330 kV line into the new substation.

The cost of these works has been estimated using the AEMO Transmission Cost Database[37]. The easement costs from Western Power's submission to the 2024 BRCP for the 2026/27 Reserve Capacity Year[38] have been used. The costs are shown in the Table 11 below.

Table 11 Transmission connection capital costs

Item	Estimated cost	Detail
Transmission line	$4,981,000	2 km steel tower single circuit 330 kV, built over 50% flat urban and 50% rural undulating land
Line easement	$8,650,000	As per Western Power's input to the 2026/27 Reserve Capacity BRCP.
Substation	$37,543,000	Three-switch mesh 330 kV substation using air insulated switchgear, includes a substation control room. Substation site area = 25,000 m^2
Indirect costs	$5,910,992	Refers to costs associated with project development, procurement, and various other indirect costs.
Total	**$57,084,992**	

[35] Western Power, Appendix F.2 Tariff Structure Statement (ERA Approved), 31 March 2023, p. 55. Available at: **WP-AA5-Approved-Access-Arrangement-Appendix-F-2-Tariff-Structure-Statement-Clean-PDF-Version.PDF (erawa.com.au)**
[36] Western Power, Total Transmission Cost Estimate for the Benchmark Reserve Capacity for 2026/27, 30 August 2023. Available at: **Total Transmission Cost Estimate for the Benchmark Reserve Capacity Price for 2026/27 (erawa.com.au)**
[37] AEMO, Transmission Cost Database 2.0, 2 May 2023. Available by registering at: **AEMO | Transmission Cost Database**
[38] Western Power, Total Transmission Cost Estimate for the Benchmark Reserve Capacity for 2026/27, 30 August 2023. Available at: **Total Transmission Cost Estimate for the Benchmark Reserve Capacity Price for 2026/27 (erawa.com.au)**

3.3 Land cost

As discussed in section 2.5 of this report, the land area required for the BESS development and associated connection to the Western Power network is 6.5 ha.

The Coordinator's determination identifies the Reference Technology as being connected to the 330 kV network in the Pinjar and Kwinana regions. Consistent with our assumptions on the BESS connection arrangement outlined in section 3.2 of this report, we assume the BESS will be located as close as possible to the existing 330 kV network and so will be located in Pinjar or Kwinana.

We have estimated the land costs by scaling up the indicative land costs for Pinjar and Kwinana provided by Landgate for the 2024 BRCP[39], which were based on 3 ha, to reflect the required land area (6.5 ha) and taken an average of the values.

The estimated land costs are outlined in Table 12.

Table 12 Land cost

Item	Estimated cost	Detail
Land cost	$14,121,250	Average total assessed value for Pinjar and Kwinana based on Landgate cost estimates for the 2024 BRCP[40] (scaled up to reflect 6.5 ha and averaged).
Total	**$14,121,250**	

3.4 Connection agreement, market registration and licencing costs

The substantial direct, upfront costs involved in connecting and registering a BESS to the SWIS and the WEM include:

– Network connection agreement with Western Power.

– Market registration and capacity credit participation and certification with AEMO.

– ERA licensing.

Each cost item is discussed in turn.

3.4.1 Network connection agreement

The network connection agreement is negotiated with Western Power with Western Power and AEMO costs (who are involved in reviewing aspects of the connection) being passed on to connecting parties. Under current market conditions, the process can take up to 2.5 years and generally consists of the following steps:

1. Preliminary application

– Application requires high-level information about the size of the generation/load and the location (substation)

– Connection application does not need to detail the connection option but is required to hold place in the connection queue. For this reason, it is best to get it in as soon as possible to hold position

2. High-level concept design

– For the high-level concept design, the customer must have selected a connection option.

– Western Power conducts steady-state modelling to establish if there are any voltage or thermal constraints likely, and considers any potential issues to be mitigated and the mitigation measures required.

– Western Power also provides costings for the connection (+/- 30% accuracy) and a high-level concept design with a breakdown of shared assets and connection assets.

[39] Landgate, Land values for the 2024 Benchmark Reserve Capacity Price, p. 6. Available at: **Consultant-Report---Landgate0.PDF (erawa.com.au)**

[40] Landgate, Land values for the 2024 Benchmark Reserve Capacity Price, p. 6. Available at: **Consultant-Report---Landgate0.PDF (erawa.com.au)**

3. Detailed connection model assessment and dynamic studies

– GPS studies and GPS model assessment are undertaken, with the study results being reviewed by AEMO as part of this process with AEMO's costs being passed on to the connecting parties.
– The dynamic study report and GPS registration form outcomes that feed into the final connection agreement(s).

The detailed GPS studies for the majority of the network connection costs. The fees can vary depending on the suitability of the OEM models, access to Western Power wide-area model and if any of the performance standards need to be negotiated. For the purposes of the BRCP, we have assumed:

– The owner negotiates for Western Power to undertake assessments using their wide-area model. This limits the owner's role in preparing the model but not conducting assessments to demonstrate GPS compliance (which is done by Western Power instead). If the owner undertakes the modelling to demonstrate GPS compliance, the fees could be higher depending on the extent to which GPS modelling is required (up to $400,000, however Western Power's costs would then be lower).
– GPS reached involves minimal negotiation of performance standards.

The Western Power connection access offer is given at the conclusion of the detailed studies and on the basis of the estimated cost for the connection option. The process typically results in two agreements:

– Access Contract or Electricity Transfer Access Contract (ETAC) – This is the standard access contract that Western Power proposes governing access to their network. It covers the ongoing use of the network. An ETAC will be required regardless of whether the User seeks a non-reference or reference service.
– Interconnection Works Contract (IWC) – This covers the shared network connection works necessary to connect to the Western Power network. Western Power typically procures and constructs these assets themselves. The costs associated with these assets, based on Western Power inputs, are discussed in section 3.2 of this report.

Once the connection agreement is in place, procurement and construction can commence. Western Power are also involved in the commissioning process including future tests required under the connection agreement to verify the GPS results. We have included the costs associated with these steps after the connection agreement is in place as part of the overall development costs given commissioning processes and testing are related.

The cost estimates for each stage include BESS, Western Power and, where applicable, AEMO costs that are passed back to the BESS. Legal costs have been estimated separately and are covered in section 3.7 of this report.

Table 13 Network connection agreement costs

Item	Estimated cost	Comment
Preliminary application	$30,000	Assumes site has been identified. Cost could be higher if several sites are being considered.
Concept design	$50,000	Assumes the BESS size is 200 MW/800 MWh and only being used for capacity. If there are multiple uses of the BESS and size is different, then costs could be higher.
Detailed connection model assessment (including GPS studies)	$750,000	Assumes the owner develops the models and Western Power conducts the GPS compliance assessment. Minimal negotiation of GPS standards.
Total cost	**$830,00**	

3.4.2 Market registration and reserve capacity certification

The market registration and accreditation process depends on the range of services being provided by the BESS. To provide Peak and Flexible Reserve Capacity services, the BESS must register as an Electric Storage Resource in the energy market and be certified for reserve capacity.

The market registration and accreditation process typically occur in parallel with the BESS development, with registration and accreditation concluding at the same time as commissioning tests.

The reserve capacity cycle runs two years ahead of the process for participation in the energy market. AEMO can make an early decision on the certifications of new facilities based on data including the Western Power Access Contract status, environmental approvals, financing etc. Certification happens in July and August annually (2 years ahead). Facility Tests (verification and testing of certified capacity) then occur in the commissioning phase.

We note the market registration and reserve capacity participation costs can vary widely between projects depending on the maturity of the proponent and their existing systems. For example, for projects that will form part of an existing portfolio of generation, the processes may be well understood and associated contract management and settlement systems are already in place.

The contract management and settlement system requirements and processes are driven by participant preferences and contract arrangements (e.g., power purchase agreements). These costs are not dependent on market registration or accreditation. As such, we have not itemised these costs as being part of the BRCP cost.

Table 14 Market registration and reserve capacity certification

Item	Estimated cost	Comment
Market registration with AEMO	$30,000	Registration with AEMO. Excludes any commissioning activities or costs associated with contract management systems.
Reserve capacity certification	$25,000	

For clarity, we note that BESS can provide essential system services in addition to energy and there are different registration and accreditation processes for these services. These have not been contemplated as the purpose of the BRCP is to compensate the BESS for costs associated with only the Peak and Flexible Services.

3.4.3 ERA licensing

Generators <100 MW require a generation licence from the ERA with the licence lasting up to 30 years. The ERA licensing process happens when the BESS is being constructed and the ERA must take all reasonable steps to make a decision within 90 business days of application.

The costs involved in applying for a license from the ERA include:

- Preparation of application material including information on the corporate structure, financing information, and technical details of the plant and intended operations[41].
- Consultant to assist with the document preparation and with technical questions.

There are nominal annual licence fees, and the ERA undertakes periodic audits of the licences. These cost are included in the fixed operating and maintenance costs.

Table 15 Market registration and reserve capacity certification

Item	Estimated cost	Comment
ERA licensing	$50,000	

[41] ERA, Licence application guidelines – Electricity, Gas and Water Licences, 19 January 2023. Refer to: **https://www.erawa.com.au/cproot/22386/2/Licence-Application-Guidelines-Electricity-Gas-and-Water-Licences---January-2022-clean-version-in-new-template-.PDF**

3.4.4 Summary of connection agreement, market registration and licencing cost

Table 10 summarises the connection agreement, market registration and licencing costs. These costs typically involve labour and independent of the size of the plant at the 200 MW/ 800 MWh level.

Table 16 Summary of connection and commissioning costs

Item	Estimated cost	Comment
Preliminary connection application	$30,000	Assumes site has been identified. Cost could be higher if several sites are being considered.
Concept design for connection	$50,000	Assumes the BESS size is 200 MW/800 MWh and only being used for capacity. If there are multiple uses of the BESS and size is different costs could be higher.
Detailed connection model assessment (including GPS studies)	$750,000	Assumes the owner develops the models and Western Power conducts the GPS compliance assessment. Limited negotiated GPS standards.
Market registration with AEMO	$30,000	Registration with AEMO. Excludes any commissioning activities or costs associated contract management systems.
Reserve capacity certification	$25,000	
ERA licensing	$50,000	
Total	**$935,000**	

3.5 Environmental and development approvals

There are several federal, state and local government permits and approvals that are applicable to the development of a BESS.

Initially, environmental approvals under Part IV of the Environmental Protection Act 1986 (EP Act) and the Environmental Protection and Biodiversity Conservation Act (EPBC Act) are conducted, as well as development approval under the Planning and Development Act 2005 (PD Act). Depending on the outcome of these initial approvals, there may be further approvals required such as:

- Part V works approval under the EP Act.
- Native vegetation clearing permit (NVCP) under the EP Act.
- Building permit under the Building Act 2011 (BA Act).

Recent legislative amendments mean that some BESS developments undertaken by the Crown, Governor, public authority[42] or local government may be eligible for an exemption for development approval under the PD Act. However, as not all BESS developers will be eligible for this exemption (and some recent developments have sought approval despite being eligible for exemptions), we have assumed exemption does not apply and therefore included development approval costs under the PD Act.

3.5.1 Environmental Protection Act approvals

Approvals under the EPBC and EP Acts will only be triggered if there are areas on the site identified as containing matters of national environmental significance, for example, a threatened ecological community. We have assumed the land area selected does not trigger these approvals.

If approvals were triggered the costs associated with the native vegetation clearing permitting required would be around $30,000.

[42] A public authority is defined by section 4 of the PD Act to include a State Minister, a department of the public service, State trading concern, State instrumentality or State public utility, or any other person or body authorised to administer or carry on a social service or public utility for the benefit of the State.

3.5.2 Development approval

Operating under the Development Assessment Panel Regulations 2011 (DAP Regulations), the Development Assessment Panel (DAP) is a panel that determines development applications as if it were the responsible planning authority, against the relevant local or regional planning scheme.

DAP will determine development applications within certain class and value thresholds set in the DAP Regulations. There are three types of DAP applications:

- Mandatory DAP applications
- Optional "Opt-in" DAP applications
- Local government delegated applications.

The BESS development used for the purpose of this report has been assumed to trigger a mandatory DAP application. The DAP application submitted to the local government will comprise the following:

- Completed application forms including landowner signatures. Forms may comprise a DAP, local authority and region scheme forms.
- Copy of the Certificate of Title.
- A complete electronic set of development plans comprising a site plan, floor plan/s and elevations.
- Appropriate DAP and local government application fees.
- Supporting technical studies/reports which may include:
  - Transport impact assessment (construction and operational traffic)
  - Modelling and Noise impact assessment
  - Hydrological Study (flood risk, stormwater and fire water management)
  - Aboriginal Heritage impact assessment
  - Ecological assessment
  - Geotechnical assessment
  - Bushfire management plan/bushfire risk management plan

Estimated costs associated with the preparation up to the lodgement of a DAP application are presented in Table 17 below.

Table 17 Development approval costs (required)

Item	Estimated cost
Prepare supporting technical studies for development application	
Transport impact assessment (construction and operational traffic)	$25,000
Modelling and Noise impact assessment	$25,000
Hydrological Study (flood risk, stormwater and fire water management)	$20,000
Aboriginal Heritage impact assessment	$20,000
Ecological assessment	$40,000
Geotechnical assessment (preliminary / desktop)	$15,000
Bushfire management plan / bushfire risk management plan	$30,000
Hydrological Study	$30,000
Development Application Fees	
Development Assessment Panel	$34,196.00
Local Authority	$11,236.00

Item	Estimated cost
Prepare, lodge and manage Development Application to determination	
Cost to the owner to prepare, load and manage application	$35,000
Total cost	**$285,432**

3.5.3 Development approval conditions

Development approval is typically granted subject to a number of conditions, including subsequent approvals. Development approval conditions will typically be associated with the following stages of a BESS development:

- Conditions required to be satisfied prior to construction commencement.
- Conditions required to be satisfied prior to operation.
- Conditions required to be satisfied during operation (i.e. ongoing for the duration of the development).
- Conditions required to be satisfied at decommissioning.

Several conditions will require the preparation of additional documentation to the local authority. Indicative costs associated with the preparation of such documents in presented in Table 19 below. Excluded in the indicative cost breakdown below is the development of detailed design/engineering drawings as these costs are covered in the design and project management costs outlined in section 3.5.4 of this report.

Table 18 Development approval conditional costs

Item	Estimated cost
Landscape plan	$10,000
Construction & Operational Management Plan	$30,000
Notifications on Certificates of Title	$5,000
Noise monitoring / operational noise analysis & reporting	$20,000
Total cost	**$65,000**

3.5.4 Building approval

A building approval may be requested by the local authority where an operations and maintenance building associated with a BESS facility is also functioning as a bushfire refuge to satisfy a condition of development approval typically associated with a bushfire management plan.

A building approval will also be required where the proposed works are not eligible for any exemptions under the PD Act.[43]

The indicative costs associated with the preparation of a building permit in presented in Table 19 below.

[43] Recent legislative amendments mean that some BESS developments undertaken by the Crown, Governor, public authority or local government may be eligible for an exemption for development approval under the PD Act.

Table 19 Building approval costs

Description	Estimated cost	Comment
National Construction Codes design consultancy	$5,000	
Certificate of Design Compliance (BA3)	$5,000	
Certificate of Construction compliance (BA17)	$3,000	
Building Application fee	$54,000	0.09% of estimated building works value but not less than $110.00 or as prescribed by the Department Building and Energy. Based on works value of electrical and civil BoP ($60,000,000).
Building Services levy	$82,200	0.137% where construction value >$45,000 or $61.65 minimum fee or as prescribed by the Department Building and Energy. Based on construction value of electrical and civil BoP ($60,000,000).
Construction Training Fund (CTF)	$120,000	0.2% where construction value >$20,000 (less $8.25 commission) or as prescribed by the Construction Training Fund. Based on construction value of electrical and civil BoP ($60,000,000).
Total cost	**$269,200**	

3.5.5 Dangerous goods licence

Lithium-ion batteries are regulated by the Department of Energy, Mines, Industry Regulation and Safety under the Dangerous Goods Safety Act 2004. Based on our experience working with the Department on recent BESS projects, we understand going forward BESS projects will no longer require a dangerous goods storage licence once installed.[44]

Temporary storage of batteries during construction or any other storage other than the placement on their final support foundations is still considered storage and continues to require a dangerous goods storage licence under the Dangerous Goods Safety (Storage and Handling of Non-explosives) Regulations 2007.

The costs associated with the dangerous goods licence required to store batteries prior to final installation are provided in Table 20.

Table 20 Dangerous goods storage licence costs

Description	Estimated cost	Comment
Dangerous goods storage licence	$50,000	Licence required for storage prior to final installation.

3.5.6 Other approvals

Several other approvals and registration processes have been identified as potentially applying to the BESS development. These could include:

- National Greenhouse and Energy Reporting (NGER) Facility Registration with the Clean Energy Regulator (required prior to operation)
- Approvals under the Aboriginal Heritage Act 1972 (required prior to construction if applicable)

We have not provided for these costs in our current estimate given they may not apply.

[44] We understand this is current policy and that amendments to regulations are being progressed.

3.5.7 Summary of approval costs

Table 21 summarises the environmental and development approval costs. These costs typically involve labour and are independent of the size of the plant at the 200 MW/ 800 MWh level.

Table 21 Summary of environmental and development approval costs

Item	Estimated cost	Comment
Clearing permit (EP Act)	$30,000	May not be required depending on site.
Development approval (required)	$285,432	
Development approval conditions	$65,000	
Building approval	$269,200	
Dangerous goods licence	$50,000	Required for temporary battery storage.
Total	**$699,632**	

3.6 Owner's design and project management

The owner's design and project management costs comprise of project management costs and owners' costs.

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

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

The owner's engineer services consider the following costs:

- Feasibility studies, business case development and 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 operating and maintenance manuals and as-built drawings are correct

The costs for a BESS have been prepared assuming a similar process to other types of generation rather than considering costs associated with recent BESS developments in Western Australia that have been developed under streamlined processes to meet specific government objectives.

Table 22 Owner's design and project management costs

Item	Estimated cost	Comment
Project management		
Concept/feasibility study	$202,500	Average cost to produce a concept/feasibility study for a BESS project. The process normally takes 1 to 2 months to complete.
Full Feasibility Study	$810,000	Average cost to produce a full feasibility study for a BESS project. This normally takes 3 to 4 months to complete.
Engagement of an Owner's Engineer	$288,000	Average cost to carry out a tender process to engage an owner's engineer to represent the owner for the construction of the BESS Plant. This normally takes 2 to 3 months to complete.

Item	Estimated cost	Comment
Engagement of legal & financial services	$525,000	Average cost to evaluate legal and financial groups to provide these support services for the BESS. This normally takes 2 to 3 months to complete.
Cost to the owner to provide a project team	$3,300,000	Cost to 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.
Owner's Engineer		
Pre EPC Award: Feasibility studies, business case development & Concept design, Development of bidding documents (Tech Spec/SOW), Contractor selection (tender process and evaluation) up to financial close/FiD and EPC award.	$3,456,000	Average cost to perform feasibility studies and business case development for a BESS project, and a tender process to establish an EPC contractor and the necessary contract for the construction of the BESS plant.
Post EPC Award: Construction management services, detailed design review, FAT and site testing	$6,000,000	Average cost to carry out construction management services by an owners engineer throughout the construction period up to and including testing & commissioning.
Total cost	**$14,581,500**	

3.7 Legal, financing and insurance costs

The legal, financing and insurance costs are grouped in this section as our estimation approach is based on a percentage of capital cost approach, meaning the cost estimates vary with the other input variables.

3.7.1 Legal costs

Legal costs associated with development and construction of the BESS include:

- Contract conditions for specifications, tender analysis, and negotiations
- Negotiation of the PPA/Capacity/offtake contract
- Negotiation of the grid connection agreement
- Financing/ loan procurement
- Contracts for the construction phase

The legal costs for a new BESS development are highly variable. The costs can range from between $200,000 to $10 million, depending on the complexity of the arrangements and the level of support needed. We have seen higher legal costs for BESS in recent times as the way this technology is integrated into the grid and the rules around this technology are new.

For the purposes of updating the Procedure, we have not revised the approach to estimating legal costs, although this should be a consideration when it comes to making estimations following the new Procedure. In calculating the legal costs for the BESS, we have instead assumed the legal cost will be at least the same as those estimated for the OCGT. Using the approach used for the OCGT where various legal support was based on a percentage of the capital costs, the legal support required for the BESS may be around $5,000,000.

Table 23 Legal costs

Item	% of capital costs	Estimated cost	Comment
Support for contract conditions for specifications, tender analysis, and negotiations	0.40%	$1,660,000	
Legal support for PPA/Capacity/offtake contract	0.25%	$1,037,500	
Legal support for financing/loan procurement	0.10%	$415,000	
Legal support for grid connection agreement	0.12%	$498,000	
Legal support for contracts during the construction phase	0.35%	$1,452,500	
Total cost	**1.2%**	**$5,063,000**	**Approximately 1.2% of total capital costs.**

3.7.2 Financing costs

The financing costs are comprised of financial advisory and transaction costs associated with capital raising and setting up the project vehicle for financing during the construction phase. These costs are typically levied on the debt proportion of the capital raised. The debt sizing will depend on the level of gearing unique to each BESS investment. This may range from 40% debt, 60% equity and up to 80% debt, 20% equity depending on the level of contracted revenue.

For the purposes of updating the Procedure, we have estimated financial advisory and transaction costs as 0.5% of the debt and have assumed a debt-equity ratio of 40%/60%, which is consistent with the rate of return parameters in the existing Procedure.[45]

Costs associated with refinancing (and the return on debt and equity) have been considered separately in the WACC calculation.

Table 24 Financing cost

Item	% of capital cost	Estimated cost	Comment
Financing advisory and transaction costs	0.50%	$992,953	Assumes costs are 0.5% of the debt portion of the transaction value.

3.7.3 Construction insurance costs

The cost of insurance assumes several risks that may occur during the construction phase of the BESS. 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.

Insurance costs vary from project to project and are slightly higher for BESS projects than traditional forms of generation (such as OCGTs). We have estimated the insurance covering a loss of the key BESS components rendering the plant to be written off as being between 0.5% and 1.0% of total project costs.

As with past BRCPs, 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 since total loss may occur toward the end of construction when the owner has paid over at least 90% of the commitment.

[45] ERA, Market Procedure: Benchmark Reserve Capacity Price, version 7, effective 9 November 2020, p. 13. Available at: **Market Procedure: Benchmark Reserve Capacity Price (erawa.com.au)**

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. GHD has used a figure mid-way between 0.5% and 1.0%.

Loss of income due to delayed construction is not always a risk that generation 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. Therefore, the estimate for insurance premium for delayed construction risk is not included as part of the insurance cost for this assessment.

Table 25 Construction insurance costs

Item	Estimated cost	Comment
Construction insurance	$3,112,500	Mid-way between 0.5% and 1.0% of total capital costs.

3.7.4 Summary of legal, financing and construction insurance costs

Table 10 summarises the connection agreement, market registration and licencing costs. These costs typically involve labour and are independent of the size of the plant at the 200 MW/ 800 MWh level.

Table 26 Summary of legal, financing and insurance costs

Item	Estimated cost	Comment
Legal costs	$5,063,000	Assumes costs are 1.2% of the total capital costs.
Financing	$992,953	Assumes costs are 0.5% of the debt proportion of the transaction value.
Construction insurance	$3,112,500	Assumes costs are mid-way between 0.5% and 1.0% of the total capital costs.
Total cost	**$9,168,453**	

3.8 Summary of development and capital costs

Table 27 summarises the upfront development and capital cost for the BESS and indicates the proportion of total cost each item represents.

Table 27 Summary of development and capital costs

Item	Estimated total cost	Proportion of total costs
BESS supply and installation costs	**$415,000,000**	**81.1%**
– Lithium-ion battery modules	$280,000,000	54.7%
– Power Conversion System	$27,000,000	5.3%
– Electrical and control BoP including BESS substation	$48,000,000	9.4%
– Civil BoP	$12,000,000	2.3%
– Installation labour & temporary equipment hire	$48,000,000	9.4%
Transmission connection capital costs	**$57,084,992**	**11.2%**
Land cost	**$14,121,250**	**2.8%**
Other costs	**$25,384,585**	**5.0%**
– Connection agreement, market registration and licencing costs	$935,000	0.2%
– Environmental and development approvals	$699,632	0.1%
– Owner’s design and project management	$14,581,500	2.9%
– Legal, financing and insurance costs	$9,168,453	1.8%
Total cost	**$511,590,827**	**100.0%**

3.9 Recommendations for the BRCP Procedure

We recommend the Procedure require estimation of the following categories of development and capital costs that will vary from year to year:

- BESS supply and installation costs
- Transmission connection capital costs
- Land costs
- Other reasonable costs including but not limited to:
    - Connection agreement, market registration and licencing costs
    - Environmental and development approvals
    - Owner's design and project management
    - Legal, financing and insurance costs

BESS supply and installation costs should include the costs normally applicable to a BESS including the Lithium-ion battery modules/enclosures, power conversion system, electrical and civil BoP and associated installation labour & temporary equipment hire costs during construction.

Transmission connection capital costs should cover the assets that enable connection to the 330 kV Western Power network. We have not reviewed the connection arrangements in detail as part of this exercise – beyond considering potential costs. Recent trends in transmission connections indicate improved scope for connecting parties to design, own and operate more of the connection assets. The connection arrangement and the estimation of connection costs need not specify Western Power as the sole source of the estimates. However, it will be useful for the ERA to retain the ability to request and receive this input from Western Power given Western Power will oversee and approve the design and will necessarily operate some of the assets in the connecting substation. As a minimum, we recommend retaining an obligation on Western Power to specify the proposed concept design for the connection work to ensure it provides a feasible connection option that is consistent with relevant network standards.

The land costs have historically been provided as an input by Landgate. While the estimation process need not specify the costs are developed exclusively by Landgate, it may be useful to retain the ability for the ERA to request these cost estimates from Landgate given their access to land value data.

The cost categories identified could be estimated using different methods that may require adjustment where the costs have been determined at a different date from the dates required for Year 3 of the relevant Reserve Capacity Cycle. We recommend the Procedure reflect the above categories to enable an appropriate level of transparency on the cost estimation process and adjustments required to reflect future prices.

4. Fixed operating & maintenance costs

The ongoing fixed operating and maintenance costs for the BESS broadly fall into the following categories:

- BESS, BESS substation and BoP maintenance services
- Corporate overheads and various consulting services
- Local government rates
- Site security services
- Connection asset fixed maintenance services
- Transmission storage service charges (for use of the Western Power network)

Variable costs for the BESS plant such as battery module replacement have not been included in the fixed operating and maintenance costs (refer to section 1.2 of this report).

4.1 BESS, BESS substation and BoP

The fixed operating and maintenance costs are derived from GHD's operating and maintenance database for BESS projects.

Table 28 Fixed operating and maintenance costs (BESS)

Item	Estimated cost per annum	Detail
BESS substation BESS substation costs include: – electrical testing, inspections and preventative maintenance on the primary and secondary electrical equipment, structures, footings, buildings and civil items in accordance with the manufacturer's specifications. – transformer oil and insulation liquid inspection and maintenance as required.	$320,000	
BESS and BoP Service, inspection and preventative maintenance of: – Inverter stations – Battery modules, racks, energy management system, battery temperature monitoring and control, and container auxiliaries – Earthing – Protection, breakers, fuses, isolation – Equipment dust ingress and moisture – Cables – SCADA and controls	$910,000	Using the GHD database, an average expenditure of $2,500 per week is expected to conduct operating and maintenance activities per line item listed above (8 hours per week, one service provider per item).
Total	**$1,230,000**	

4.2 Corporate overheads and various consulting services

There are various ongoing corporate overheads and costs for consulting services that are necessarily covered in the fixed operating and maintenance costs. These include:

– Corporate overhead - This cost 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.
– Legal and regulatory costs - The corporate overheads will allow for some coverage of ongoing legal and regulatory costs. However, from time to time these costs increase (for example, if there are legal disputes or significant regulatory changes). We have assumed an average for legal and regulatory costs that are outside of the normal allowance provided for in corporate overheads.
– Subcontractors - Typically, a service agreement would be in place to oversee of perform the maintenance provider activities for the OEM equipment, particularly the battery inverters. In addition, specialist BESS fire suppression subcontractors may be included as part of the operating and maintenance regime. Performance testing and maintenance activities outside of inspections and checks are expected to be performed 6 monthly or annually depending on the BESS component. Subcontractors may also be engaged for operating and maintenance of the BESS substation.
– Engineering Support - As part of general operation, technical engineering support falls within the scope of the operation of the BESS.

Table 29 Fixed operating and maintenance costs – Corporate overhead and consulting costs

Item	Estimated cost per annum	Detail
Corporate overhead	$250,000	
Legal and regulatory costs	$100,000	
Subcontractors	$240,000	Assuming one subcontractor engagements every other month (at $2500 for 8 hours per week).
Engineering Support	$500,000	The basis for the fixed operating and maintenance estimate for engineering support is two engineers ($200,000 annually per engineer) with at least one other engineer on call (50% availability) per year.
Total	**$1,090,000**	

4.3 Site security

Security primarily pertains to monitoring and oversight of the BESS remotely with regular local inspections and checks of security performed in the interest of the safety of the BESS. Response requirements for emergency measures fall within 2-5 hours.

Table 30 Fixed operating and maintenance costs – Site security

Item	Estimated cost per annum	Detail
Security	$156,000	Assuming a single service provider overseeing security checks and reporting ($2500 for 8 hours per week) with a 20% uplift to account for ad hoc local response and support. The annual expectation for security is $156,000.

4.4 Local Government rates

Local Government rates are to be based on a site that is 65,000 m^2 (6.5 hectares). The Landgate gross rental value (GRV) for a 3-hectare site in the 2024 BRCP determination was $859,078. Following an escalation of 4.1% (consumer price index), the current GRV is assumed to be $894,300 ($29.81/m^2 per annum). The GRV for a 6.5-hectare site was considered to be $1,937,650 (assuming same GRV/m^2 per annum).

We assume the plant will be located in the Kwinana or Pinjar region. The City of Kwinana Council[46] has a fee multiplier of $0.10212 and The City of Wanneroo Council[47] has a fee multiplier of $0.0778. This amounts to an average fee multiplier of $0.08996.

The Local Government rates are GRV x $0.08996 which results in Council rates of $174,311.

Table 31 Fixed operating and maintenance costs – local government rates

Item	Estimated cost per annum	Detail
Local government rates	$174,311	Average rates for The City of Kwinana and The City of Wanneroo based on escalated GRV from Landgate's submission to the 2024 BRCP.

4.5 Connection asset fixed operating and maintenance

Given the connection arrangement assumed for the purpose of updating the Procedure is the same as the arrangement used for the 2024 BRCP (refer to section 3.2 of this report), we have assumed the same approach to estimating the ongoing fixed operating and maintenance for these assets as applied in the 2024 BRCP.[48]

The fixed operating and maintenance costs for the connection assets were calculated from the isolator on the high-voltage side of the generator transformer. The assets being maintained are a substation and a 2 km high voltage connecting line to the tie-in point.

Two types of ongoing maintenance were identified as needing to be separately accounted for:

- Connection switchyard maintenance - For the switchyard, routine maintenance is assumed to take an equivalent annual period of one week and would require the hire of a scissor lift and forklift, as well as project management, planning and organising by management and operations staff.
- Transmission line maintenance - For the overhead transmission line, we assume work would be organised by management and operations staff and that the inspection would be carried out by 2-3 people over a 2-day period and require the hire of a scissor lift, as well as requiring planning and project management. We assume this occurs approximately once every 5 years.

For both types of fixed operating and maintenance, the cost will change from year to year depending on what is required. The estimated costs are representative of a normalised spend over the period of the asset's lifetime of the OCGT in the 2024 BRCP. For the purpose of estimating equivalent maintenance for the BESS connection, which has a shorter life, we have adopted the equivalent annual fixed operating and maintenance estimate for the two items.

Consistent with the 2024 BRCP, the fixed operating and maintenance cost estimates are inclusive of:

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

[46] https://www.kwinana.wa.gov.au/council/documents,-publications-and-forms/publications-and-forms-(all)/budget-and-financials/2022/budget-and-rates-brochure-2022-2023
[47] https://www.wanneroo.wa.gov.au/download/downloads/id/4951/city_of_wanneroo_2023-24_statutory_budget.pdf
[48] GHD, Power station and associated costs: Benchmark Reserve Capacity Price 2024, 4 December 2023, p. 17. Available at: **12617867_BRCP_2024 S4.docx (erawa.com.au)**

Table 32 *Fixed operating and maintenance costs – Connection substation and OHL*

Item	Estimated cost per annum	Detail
Switchyard fixed operating and maintenance	$100,000	
Transmission line fixed operating and maintenance	$8,000	
Total	**$108,000**	

4.6 Transmission network service charges

Western Power charges the following transmission storage services (TRT3) for ongoing use of the transmission network:

- A user-specific charge that is an amount per day that reflects the costs to Western Power of providing the Connection Assets under an Access Contract, which may consist of capital and non-capital costs. This cost was discussed above in Section 3.2 of this report.
- A variable use of system charge.
- A variable control system service charge.
- A fixed metering charge per revenue meter.

The TRT3 tariff that applies to transmission storage services also provides for excess network usage charges where the peak half-hourly demand exceeds the nominated declared sent-out capacity (DSOC). We have assumed the BESS operates within its DSOC at all times.

Table 33 summarises the estimated ongoing transmission storage services charges for the use of the Western Power network. Prices are based on the 2023/24 price list[49].

Table 33 *Transmission network service charges*

Item	Units	Rate	Cost per annum	Detail
Use of system	c/kW/day	1.351	$986,230	Based on Table 8.21 of the Western Power 2023/24 Price list. Assumes and average of the Kwinana (1.475 c/kW/day) and Pinjar (1.227 c/kW/day) prices and assuming 200 MW.
Control system service price (Generators)	c/kW/day	0.238	$173,740	Based on Table 8.23 in the Western Power 2023/24 Price List and assuming 200 MW.
Metering charge	c/revenue meter/day	947.708	$3,459	Based on Table 8.14 in the Western Power 2023/24 Price List and assuming one revenue meter.
Total			**$1,163,429**	

[49] Western Power, 2023/24 price list of the Western Power network. Available at: **https://www.westernpower.com.au/siteassets/documents/network-access-prices/network-access-prices-approved-price-list-20231024.pdf**

4.7 Summary of fixed operating and maintenance costs

Table 10 summarises the fixed operating and maintenance costs and the relative proportions of the total fixed operating and maintenance costs.

Table 34 Summary of fixed operating and maintenance costs

Item	Estimated annual cost	Proportion of total annual cost
BESS, BESS substation and BoP maintenance	**$1,230,000**	**31%**
Transmission network service charges	**$1,163,429**	**30%**
Transmission connection asset maintenance	**$108,000**	**3%**
Corporate overheads, consulting services and other fixed costs	**$1,420,311**	**36%**
– Corporate overheads and various consulting services	$1,090,000	28%
– Site security	$156,000	4%
– Local government rates	$174,311	4%
Total	**$3,919,740**	**100%**

4.8 Recommendations for the BRCP Procedure

We recommend the Procedure require estimation of the following fixed operating and maintenance costs that will vary from year to year:

- BESS, BESS substation and BoP maintenance
- Corporate overheads, consulting services and other reasonable fixed costs
- Transmission connection asset maintenance
- Transmission network service charges for use of the Western Power network

The corporate overheads and consulting costs (e.g. legal, regulatory and engineering support) should represent costs that a fixed regardless of energy throughput beyond the Peak and Flexible Service requirements. As such, these may represent a proportion of the costs associated with a BESS that provides services beyond those required for Reserve Capacity. The site security and local government rates identified in our cost identification method represent relatively small amounts and may be accounted for in cost estimates of the BRCP but need not be explicitly referenced in the Procedure. These could be accounted for within the allowance for other reasonable costs.

Consistent with our recommendations for development and capital cost items, the cost categories identified for fixed operating and maintenance could be estimated using different methods that may require adjustments where the costs have been determined at a different date from the dates required for Year 3 of the relevant Reserve Capacity Cycle. We would recommend the Procedure reflect the above categories to enable an appropriate level of transparency on the cost estimation process and adjustments required to reflect future prices.

5. Estimation approach for future costs

The BRCP is based on the annualised cost estimate of a benchmark reference technology that can be constructed to provide capacity to the SWIS for a capacity year commencing approximately two years into the future. In principle, the BRCP provides price signals for potential investors to develop capacity providers and assumes that the compensation is sufficient for a marginal new entrant to make the net present value of their investment equal zero.

The WEM Rules require that a review be conducted of the BRCP each year. The current Procedure requires estimations to be made as of April or 1 October in Year 3 of the Reserve Capacity Cycle depending on the cost category and provided for escalation of some cost elements or a requirement that these be specified where applied. The BRCP being estimated will apply from 1 October in Year 3 of the Reserve Capacity Cycle.

In recommending groupings of costs identified in this report, we have considered the form of estimation that may be used and the need for adjustments where the date of estimation differs from the required date in Year 3 of the relevant Reserve Capacity Cycle.

The need for adjustments to enable cost estimates to reflect Year 3 of the relevant Reserve Capacity Cycle will depend on the nature of the cost estimation approach and whether the costs are reasonably expected to change over time. As such, we recommend the Procedure retain flexibility on any cost adjustments where the date of estimation differs from the required date in Year 3 of the Reserve Capacity Cycle.

However, for most costs estimated through the BRCP approach, some form of adjustment may be needed. Where costs have been estimated at a different date than the required date, any adjustments should be clearly stated.

In this section, we outline adjustment factors we may consider applying if the estimation methods we adopted for developing the Procedure change recommendations were adopted in the development of a BRCP.

5.1 Indicative adjustments

As highlighted above, the requirement for adjustments to cost estimates will depend on the estimation process. The cost estimates developed by GHD for the purposes of updating the BRCP Procedure have been based on current pricing. As such, some adjustment is appropriate for most costs to reflect the price difference between now and Year 3 of the Reserve Capacity Cycle.

Note that we have not forecast adjustment factors as part of this project. Hence, we have not applied these adjustment factors to the BRCP calculations testing the Procedure recommendations set out in section 6 of this report. The information below is provided to help inform the development of the BRCP Procedure only.

5.1.1 Development and capital cost adjustments

For the development and capital costs, our estimation approach was based on draws on historic EPC prices (for the BESS supply and installation costs) or current prices (for other costs). As such, an adjustment to reflect the cost for Year 3 of the Reserve Capacity Cycle is appropriate if these estimation processes were to apply to the BRCP.

Table 35 summarises our suggested adjustments to fixed operating and maintenance estimates to account for cost differences between now and the Year 3 Reserve Capacity Cycle required for the BRCP should the estimates outlined in this report apply.

Table 35 Adjustments to reflect future prices - BESS development and capital costs

Item	Suggested adjustment	Comment
Lithium-ion battery modules/enclosures	None	
Power Conversion System	None	
Electrical and control BoP	CPI	
Civil BoP	CPI	
Installation labour & temporary equipment hire	60% WA WPI - Labour, 50% CPI	
Transmission connection capital costs	CPI	As per Western Power's Policy Statement – Transmission Connection Price. [50]
Land cost	CPI or land price changes for generic areas near the existing 330 kV network	
Connection agreement, market registration and licencing costs	WA WPI – Labour	
Environmental and development approvals	WA WPI – Labour	
Owner's design and project management	WA WPI – Labour	
Legal, financing and insurance costs	WA WPI – Labour	

Discussion on the reasons for our suggested adjustments is outlined below.

Battery modules/enclosures

While Lithium makes up a small proportion of the batteries themselves, the price of Lithium is heavily tied to the price of batteries. Figure 8 illustrates the prices between 2015 and 2023 for Lithium batteries (yellow points) falling over time and fluctuations in the Lithium price (blue line). The figure shows the falling price of batteries over this period and the effect of the recent spike in Lithium prices – the battery price rises between 2022 and 2023, corresponding to the large increase in lithium prices between mid-2021 and 2023. The increase in Lithium creates a noticeable effect in stabilising the falling price trend.

Going forward, Lithium battery prices are expected to continue falling (Figure 9), with reductions being driven by falling raw material and component prices and increases in production capacity. Without market analysis, it is difficult to understand if future Lithium price increases or other factors might alter the overall price of battery modules/ enclosures.

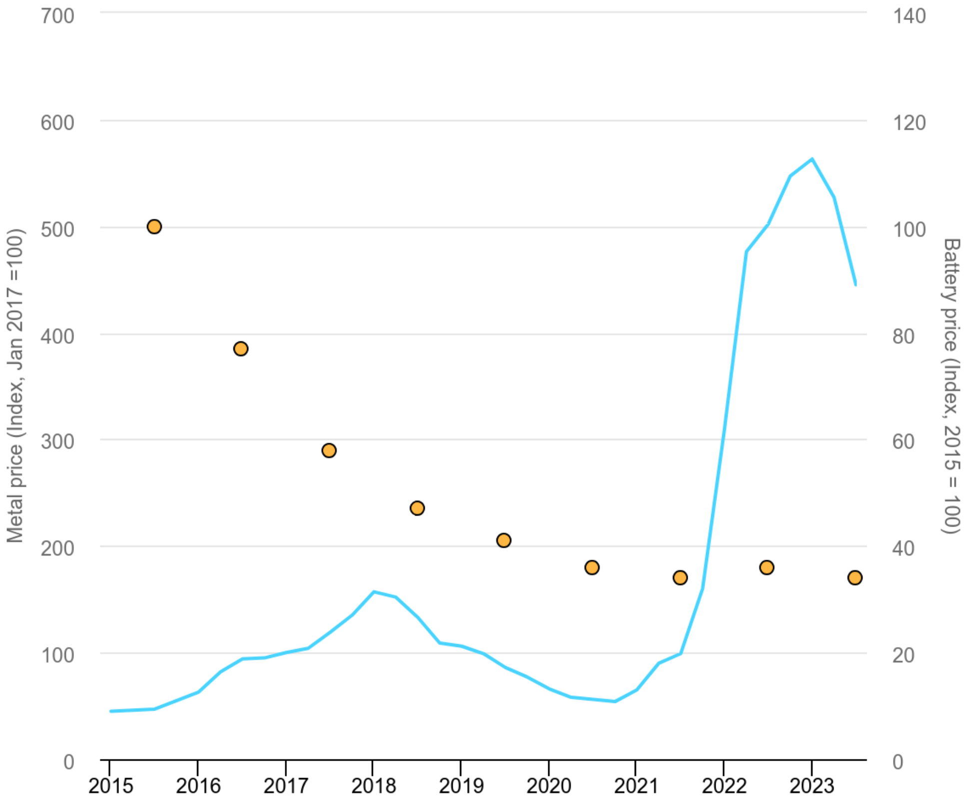
Given the counteracting effects, we would avoid adjusting the estimated current pricing either up or down from the existing estimate to reflect at future Year 3 Reserve Capacity Cycle price.

Battery modules/enclosures are typically sourced from overseas. Hence, the other factor typically affecting battery module/enclosure prices is changes in foreign exchange.

The foreign exchange adjustment that might be needed for a particular project will depend on where the battery modules/enclosures are sourced from and if any financial hedging has been provided for. GHD's cost database gives the cost of the BESS in Australian dollars based on the exchange rate that was applied at the time of the project cost (or entry of the data into the database where data is based on benchmark literature). The approach means foreign exchange risk has been incorporated into the estimates to some extent. On this basis, we would not separately look to estimate exchange rate fluctuations.

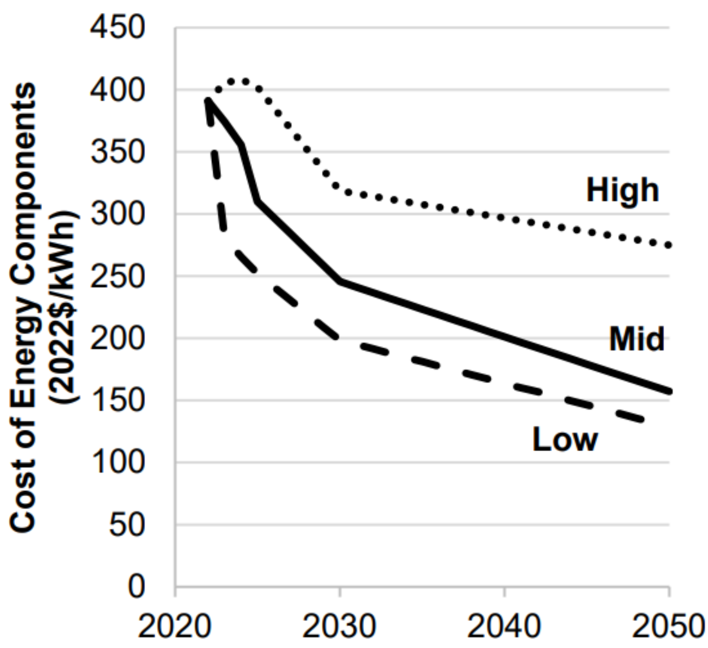
[50] Western Power, Appendix F.2 Tariff Structure Statement (ERA Approved), 31 March 2023, p. 55. Available at: **WP-AA5-Approved-Access-Arrangement-Appendix-F-2-Tariff-Structure-Statement-Clean-PDF-Version.PDF (erawa.com.au)**

Figure 8 Lithium battery price (yellow points) and lithium price (blue line) 2015-2023



Source: IEA, Price of selected battery materials and lithium-ion batteries 2015-2023, last updated 11 April 2023, refer to: **https://www.iea.org/data-and-statistics/charts/price-of-selected-battery-materials-and-lithium-ion-batteries-2015-2023**

Figure 9 Battery cost projection for 4-hour Lithium-ion systems



Source: Cole, Wesley and Akash Karmakar. 2023. Cost Projections for Utility-Scale Battery. Storage: 2023 Update. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-85332.[51]

[51] Refer to: **https://www.nrel.gov/docs/fy23osti/85332.pdf**

Power conversion system

Similar to the approach for procurement of battery modules/enclosure, the power conversion system (i.e. inverters) are typically sourced from overseas.

The foreign exchange adjustment that might be needed for a particular project will depend on where the power conversion system is sourced from and if any financial hedging has been provided for.

GHD's cost database gives the cost of the BESS in Australian dollars based on the exchange rate that was applied at the time of the project cost (or entry of the data into the database where data is based on benchmark literature). The approach means foreign exchange risk has been incorporated into the estimates to some extent. On this basis, we would not separately look to estimate exchange rate fluctuations.

Electrical and control BoP including BESS substation and civil BoP

The components that comprise the electrical and control BoP including the BESS substation and the civil BoP have a long design life and are built up from mature technologies that have stable pricing.

Our cost estimates are based on GHD's database and are reflective of the current pricing for these items. For the purposes of the BRCP, it would be reasonable to adjust these costs by consumer price index to reflect potential changes in the prices to Year 3 of the Reserve Capacity Cycle.

The inputs can be sourced from overseas but are also available in Australia so we have not considered foreign exchange changes for these items.

Installation labour & temporary equipment hire

The estimation for installation labour & temporary equipment hire developed for this report is based on GHD's database which contains a range of projects.

The appropriate way to adjust the two types of costs that make up this component of the BESS supply and installation cost would be to adjust the labour proportion by wage price index and the equipment hire by consumer price index. However, the breakdown between installation labour costs and the associated temporary equipment hire during construction is not a feature of our database.

In the absence of better information, we estimate the breakdown may approximate 60% labour and 40% temporary equipment hire (and related) costs. As such, if we were to estimate the BRCP using our current estimation we would adjust by these factors to provide an estimate for Year 3 of the Reserve Capacity Cycle.

Transmission connection capital costs

Assuming the transmission connection capital costs continue to be developed with input from Western Power, we would consider adjustments in accordance with Western Power's Policy Statement – Transmission Connection Price. The approach outlined in this document is to adjust annually by the "capital consumer price index".[52]

The transmission connection capital costs estimate presented in section 3.2 of this report combines easement and land costs from the current BRCP with other cost components estimated using the AEMO Transmission Cost Database[53]. The AEMO Transmission Cost Database uses historical project costs and escalation factors to produce cost estimates in real dollars for the year in which the estimate is produced. Hence, those components of costs are in real 2023/24 dollars. To account for the movement in costs by Year 3 of the Reserve Capacity Cycle the different components of costs should be adjusted as follows:

- Land and easement costs at consumer price index or land price changes for generic areas near existing 330 kV networks.
- All other costs are at consumer price index. These costs are associated with the provision of equipment that have a long life and are from mature technologies that have stable pricing.

[52] Western Power, Appendix F.2 Tariff Structure Statement (ERA Approved), 31 March 2023, p. 55. Available at: **WP-AA5-Approved-Access-Arrangement-Appendix-F-2-Tariff-Structure-Statement-Clean-PDF-Version.PDF (erawa.com.au)**
[53] AEMO, Transmission Cost Database 2.0, 2 May 2023. Available by registering at: **AEMO | Transmission Cost Database**

Land costs

Assuming the land costs continue to be developed with input from Landgate, we would consider adjustments to also be informed by Landgate or a suitably qualified consultant.

The Procedure currently provides for adjustment of land costs using consumer price index escalation. The narrowing of land locations from six areas in the current Procedure to only two areas (Pinjar and Kwinana) creates a challenge as to escalation where the cost of land parcels in these two areas are changing differently from the rest of SWIS.

Given the BRCP is intended to apply to all areas in the SWIS, we would recommend the Procedure not overly focus on these two areas for adjustments to land costs. As such, we would recommend adjustments that reflect land price trends for a wider range of areas that align with the existing and planned 330 kV network. In the absence of a better estimate, this could be achieved through adjustments reflected in consumer price index estimates.

Other reasonable costs

The following costs have been identified as reasonably being included as 'other' reasonable upfront development and capital costs:

- Connection agreement, market registration and licencing costs
- Environmental and development approvals
- Owner's design and project management
- Legal, financing and insurance costs

These costs are driven by the labour inputs with the exception:

- Some building approval costs, based on the works or construction value, and
- Insurance costs, based on the BESS supply and installation costs.

The Building Approval and insurance costs are relatively small compared with other cost categories and could reasonably be adjusted to reflect Year 3 Reserve Capacity Cycle costs in the same way as other costs in this category are escalated (i.e. based on the wage price index).

Legal and financing costs have been estimated in this report using a percentage of capital cost method. We have adopted this approach as it is consistent with previous BRCP approaches and provides a reasonable indication of the magnitude of the cost items. However, we would recommend visiting these costs in greater detail for any future reviews. These costs are typically driven by labour hours and so using a percentage of capital cost method may expose these estimates to changes in price that are not appropriate given the fixed labour inputs. A future estimation process might consider developing these costs independently of capital costs. Regardless, a cost adjustment based on the wage price index is likely appropriate given the actual driver of these costs.

5.1.2 Fixed operating and maintenance adjustments

Our approach to estimating fixed operating and maintenance costs was based on current prices. As such, an adjustment to reflect the cost for Year 3 of the Reserve Capacity Cycle is appropriate.

The BESS operating and maintenance and the connection switchyard and transmission line both include a combination of labour and equipment or materials costs. We would suggest adjusting costs based on assumed contributions of these components to the overall cost.

For transmission network service charges, we would consider adjustments in accordance with Western Power's Policy Statement – Transmission Connection Price. The approach outlined in this document is to adjust annually by the "capitals consumer price index".[54]

[54] Western Power, Appendix F.2 Tariff Structure Statement (ERA Approved), 31 March 2023, p. 55. Available at: **WP-AA5-Approved-Access-Arrangement-Appendix-F-2-Tariff-Structure-Statement-Clean-PDF-Version.PDF (erawa.com.au)**

Table 36 summarises our suggested adjustments to fixed operating and maintenance estimates to account for cost differences between now the Year 3 Reserve Capacity Cycle required for the BRCP should the estimates outlined in this report apply.

Table 36 Adjustments to reflect future prices - Fixed operating and maintenance items

Item	Suggested adjustment	
BESS operating and maintenance	60% WA WPI – Labour, 40% CPI	
Connection switchyard and transmission line operating and maintenance	80% WA WPI – Labour, and 20% CPI	
Transmission network service charges	CPI	As per Western Power's Policy Statement – Transmission Connection Price. [55]

5.2 Recommendations for the BRCP Procedure

The need for adjustments to the estimated cost to reflect Year 3 of the relevant Reserve Capacity Cycle will depend on the nature of the cost estimation approach and whether the costs are reasonably expected to change over time. However, for most costs estimated through the BRCP approach, some form of adjustment may be needed for instance, construction labour costs would be expected to change year to year.

We recommend the Procedure provide for adjustments where costs have been determined at a different date from the date required for Year 3 of the relevant Reserve Capacity Cycle. The adjustment factors should be clearly identified where these have been used and and how they have been applied.

[55] Western Power, Appendix F.2 Tariff Structure Statement (ERA Approved), 31 March 2023, p. 55. Available at: **WP-AA5-Approved-Access-Arrangement-Appendix-F-2-Tariff-Structure-Statement-Clean-PDF-Version.PDF (erawa.com.au)**

6. BRCP based on recommended Procedure changes

To develop the Procedure recommendations and as a means of testing the suitability of the recommendations, we have estimated costs that enable the calculation of the BRCP.

This section outlines the BRCP calculation and the estimated BRCP based on the costings identified in this report.

6.1 BRCP calculation

The calculation of the BRCP requires the division of annualised costs by the capacity credits allocated to the benchmark capacity provider as illustrated in the following equation.

$$BRCP = \frac{ANNUAL_{Fixed\ O\&M} + ANNUALISED_{CAPEX}}{Capacity\ Credits}$$

As discussed in section 2.2 of the report, the BESS has been designed to achieve 200 MW injection capacity. We therefore assume capacity credits of 200 MW for the purposes of the BRCP.

6.2 Summary of estimated costs

The following tables summarise the annualised capital costs and the annual fixed operating and maintenance costs.

To estimate the annualised capital costs, we have assumed a weighted average cost of capital (WACC) of 10.5% and a term of finance of 15 years.[56] These assumptions have been used for indicative purposes only and are not intended to replace or otherwise inform the ERA's decision on the WACC and financial term aspects of the Procedure.

Table 37 Annualised capital costs

Item	Estimated cost
Total development and capital costs	$511,590,827
Adjust for timing of cash flow	**$537,779,060**
WACC	10.50%
Term of finance (years)	15
Annualised capital cost	**$72,733,543**

Table 38 Annual fixed operating and maintenance costs

Item	Estimated cost per annum
Fixed operating and maintenance for BESS	$2,650,311
Connection switchyard and OHL operating and maintenance	$108,000
Transmission storage service charges	$1,163,429
Annual fixed operating and maintenance costs	**$3,921,740**

[56] These are example amounts based of previous BRCPs, research on BESS projects and average financial investment terms.

The total calculated capital cost corresponds to an approximate value of $639 per kWh for the 800 MWh BESS. For benchmarking purposes, the calculated development and capital cost was compared with the capital cost outlined for a 4-hour BESS in the CSIRO Gencost database[57]. The corresponding capital cost in the CSIRO Gencost database is $530 per kWh (2024 projected value), which is well within the tolerance range of the estimate needed to inform BRCP Procedure updates.The CSIRO GenCost database does not identify connection costs and this is likely contributing to the variation between the generated estimate and the CSIRO GenCost database value. Excluding transmission connection costs, our capital cost estimate is $568 per kWh.

The calculated annual fixed BESS operating and maintenance cost of approximately $5 per kWh is comparable to the $2-$15 per kWh range outlined in the Aurecon 2023 Costs and Technical Parameter report for a lithium-ion BESS[58] . The report notes annual O&M costs for a BESS fall under a large range as they can vary considerably depending on location, BESS technical needs and contract structures.

6.3 Estimated BRCP

Based on the annualised capital costs, the annual fixed operating and maintenance costs and providing for 200 capacity credits, the estimated BRCP is $383,276[59].

The developed values are high-level illustrative estimates that represent 2024 values. The purpose of the estimate exercise was to identify the cost categories that need to be identified in the updated BRCP Procedure.

Table 39 Estimated BRCP

Item	Estimate
Annualised capital cost	$72,733,543
Annual fixed operating and maintenance cost	$3,921,740
Capacity Credits	200
Benchmark Reserve Capacity Price	**$383,276**

[57] CSIRO, GenCost 2023-24- Consultation draft, 19 December 2023. Refer to: **https://www.csiro.au/en/research/technology-space/energy/energy-data-modelling/gencost**
[58] Aurecon, 2023 Costs and Technical Parameter Review, 15 December 2023. Refer to: **https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/2024-forecasting-assumptions-update-consultation-page/aurecon---2023-cost-and-technical-parameters-review.pdf?la=en**
[59] Assuming 10.5% WACC, 15 year term. Based on 2024 cost estimates.

Appendix A

Acronyms and abbreviations

The following acronym and abbreviations are used in this report.

Table 40 Acronyms and abbreviations

AEMO	Australian Energy Market Operator
BESS	Battery Energy Storage System
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*
ERA	Economic Regulation Authority
FEED	Front-end engineering design
GHD	GHD Pty Ltd
GRV	Gross rental value
HV	High voltage
kV	Kilovolt
kW	Kilowatt
MW	Megawatt
O&M	Operating and maintenance
OEM	Original Equipment Manufacturers
PCS	Power conversion system
SWIS	South West interconnected system
WEM Rules	Wholesale Electricity Market Rules
WPI	Wage price index

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