AEMO SERVICES

Consumer Trustee

Market Briefing

MC1 evaluation for generation Projects in Tender Round 4

1. Purpose of this Document

This Market Briefing sets out information on the Merit Criteria 1 (MC1) evaluation for Tender Round 4 and recaps characteristics of competitive bids from previous Tender Rounds.

The MC1 evaluation is a component of the Financial Value assessment for Generation LTESAs. MC1 assesses the value of a Project by evaluating the benefits of the Project to the NSW electricity market and the costs of the LTESA to the Scheme Financial Vehicle (SFV).

This Market Briefing aims to help Proponents understand how their generation Projects are assessed in MC1 and provides examples of what has constituted a competitive Financial Value Bid in previous Tender Rounds. Please note, competition evolves with each Tender Round. As such, examples of competitive Bid characteristics provided in this Market Briefing are provided for information purposes only, and are not indicative of the characteristics that may constitute a winning Bid in future Tender Rounds.

This Market Briefing builds on those released in previous Tender Rounds and should be read in its entirety. This Market Briefing focuses on Tender Round 4.

Please refer to Appendix C for further information on terms used throughout this Market Briefing.

What you need to know when preparing your Financial Value Bid

MC1 evaluates both the costs and benefits of the Project associated with your Financial Value Bid. Section 4 of this Market Briefing provides more information on the characteristics of a competitive Bid in MC1. In summary:

Benefits are primarily driven by the physical characteristics of the Project. The MC1 evaluation recognises the value of:

- A generation shape that produces energy at times of high prices, including by utilising storage technology as a Hybrid.
- A Project with low curtailment and a grid location that supports the Project's generation meeting demand at load centers in NSW.
- An earlier COD, such that Projects are able to contribute towards reducing high market price forecast in early modelled years.

Costs are driven by the Bid Variables submitted by Proponents, which can be reduced by having:

- A low LTESA Fixed Price, noting this has a larger impact on MC1 outcomes than the Repayment Threshold.
- A Contracted Percentage significantly below 100%, which has a large impact on reducing Forecast LTESA Cost.
- An early COD to capture high Project revenues in early modelled years, reducing the forecast likelihood of LTESA exercise.
- Any commitments to forfeit swaps in certain periods or a reduced contract term. Forfeiting swaps in later periods has a larger impact on reducing Forecast LTESA Cost than forfeiting swaps in earlier years.
- A structured LTESA Fixed Price that bids a low price when electricity prices are also forecast to be low.

2. Tender Guidelines

The Tender Guidelines are the single source of information for Proponents seeking to understand how AEMO Services (acting as Consumer Trustee under the *Electricity Infrastructure Investment Act 2020* (NSW) (EII Act)) will evaluate Bids. AEMO Services evaluates Bids against seven Merit Criteria under a two-step process, as detailed in the Tender Guidelines. In summary:

- Project Bids are sought from Proponents and are evaluated against five non-financial Merit Criteria (MC), such as their impact on the electricity system, and regional economic development.
- Project Bids are shortlisted, and are evaluated against two financial Merit Criteria:
  - MC1 – Financial value.
  - MC2 – Commercial departures.

AEMO Services will make recommendations on Projects to receive an LTESA based on a combined evaluation against all Merit Criteria as detailed in the relevant Tender Guidelines, with financial value being the primary consideration.

Please note, the description of the financial value assessment in this Market Briefing is not an exhaustive or comprehensive summary of the evaluation process. It is provided for information purposes only and is not intended as advice. Scoring against Merit Criteria is a key input considered by AEMO Services. Under the EII Act, AEMO Services may only recommend a Bid where it considers that the recommendation would be in the long-term financial interests of NSW electricity customers (having regard to the assessment as a whole), and the recommendation satisfies or is consistent with all relevant statutory requirements and duties. AEMO Services retains discretion to score and assess Bids and make recommendations. It will not be held to a rigid assessment formula or policy. Nothing in this Market Briefing should be construed as binding on AEMO Services or limiting its statutory discretion. To the extent of any inconsistency between this Market Briefing and the Tender Guidelines, the Tender Guidelines will prevail.

3. MC1 evaluation of a generation Project - an overview

Financial Value Components are calculated using the Financial Value Bid Returnable Schedule submitted by Proponents. The Financial Value Components represent the benefits and cost of each Project to NSW electricity customers and are calculated against a set of electricity market scenarios that represent a range of future electricity market outcomes, weather reference years, large-scale generation certificates (LGC) prices and exercise behaviours.

The outcomes from scenario analysis are used to calculate Evaluation Metrics, for ranking and scoring Projects. As measured via the Evaluation Metrics, an attractive generation Project will provide financial value under many future electricity market outcomes. A less attractive generation Project may only provide financial value under fewer future electricity market outcomes.

3.1. Financial Value Components

Project Benefits

Wholesale Electricity Cost and Market Benefit[1]

Projects incentivised to enter the market through a Generation LTESA are expected to put downward pressure on wholesale electricity prices, reducing costs to NSW electricity customers. Modelling is conducted to compare the wholesale price impact of the Project against baseline scenarios of the future without the Project.

Additional generation is expected to result in a net benefit to NSW electricity customers, as additional supply of renewable energy generation in NSW (with low short run marginal cost) is expected to result in lower wholesale prices in NSW.

Project Costs

Forecast LTESA Cost[2]

Estimated cost of the LTESA to the SFV, with consideration given to the Fixed Price, exercise behaviour, Repayment Threshold, generation shape, and wholesale price scenarios.

The Forecast LTESA Cost reflects expected costs incurred by the SFV, passed onto NSW customers via Distribution Use of System (DUOS) charges.

Portfolio Impact[3]

The addition of new generation into the market will have an impact on wholesale prices and therefore the expected cashflows from the SFV's existing portfolio of LTESAs.

This estimates the extent to which each additional Project reduces the Project revenues of the existing portfolio of LTESAs, thus increasing the payments under the existing portfolio of LTESAs.

This component has a significantly smaller impact on MC1 outcomes than Wholesale Market Benefits and Forecast LTESA Cost.

Adjustment factor

Uncertainty[4]

An adjustment factor applied to Forecast LTESA Cost and Wholesale Electricity Cost and Market Benefit, determined through each Project's output profile variability and correlation with high wholesale price variability.

Some Projects' generation output is highly variable when prices are highest (or most volatile), reducing the perceived certainty around benefit and cost estimates from the perspective of NSW electricity customers. This cost and benefit estimation uncertainty is amplified when a Project's high expected generation coincides with periods of high price variability.

This component has a significantly smaller impact on MC1 outcomes than Wholesale Market Benefits and Forecast LTESA Cost.

Calculated across multiple scenarios as described in Section 3.2.

For more information on the calculation of the Financial Value Components, see Appendix A.

1. Relevant to EII Regulation s26(4)(a)(e)
2. Relevant to EII Regulation s26(4)(b)(c)(d)
3. Relevant to EII Regulation s26(4)(d)
4. Relevant to EII Regulation s26(4)(a)(d)(e)

3.2. Scenario based analysis

The Financial Value Components are tested under a range of scenarios. Due to the long-term nature of the LTESAs and uncertainty in future market outcomes, these scenarios aim to test the relative performance of Projects under different future market conditions. Scenarios used in previous Tender Rounds consider variations in:

- **Market price:** Future electricity market prices are uncertain due to rapid changes in the NEM. In previous tenders, three scenarios have been modelled to consider a range of possible future price outcomes. More detail is provided on the market price scenarios below in Section 3.2.1.
- **Weather reference years:** Weather variations impact both renewable generation output and consumer demand. In previous tenders, three historical reference years have been used to reduce the risk of basing the evaluation on an outlier year. A range of years are selected. This could include historical reference years with high, medium, and low VRE output. Each reference year has been weighted equally in previous tenders.
- **LGC price:** Renewable Projects are currently eligible for LGCs. In previous tenders, a central and low LGC price scenario has been used in the evaluation. The central scenario assumed forward LGC prices up to 2030 and a flat price assumption beyond 2030. The low price assumes half of the LGC price of the central scenario. The central scenario has had a higher weighting in previous tenders.
  - The LGC price impacts revenues for a Project and exercise behaviour in the evaluation. For more information on how LGCs are considered in the evaluation, see Appendix A.
- **Exercise behaviour:** Projects will base their LTESA exercise decisions in line with financing structure and risk tolerance. In previous tenders, scenarios included a 'perfect foresight' and 'always exercise' variation on LTESA exercise behaviour. The weighting of these variations were heavily skewed to perfect foresight (~95% weighting), with a lower (~5% weighting) allocation to a Project always exercising their option.

3.2.1. Market price assumptions

As summarised above, previous Generation LTESA Tender Rounds have used three market price scenarios for evaluation. These scenarios reflect a likely future state (central scenario), and two extreme cases with assumptions designed to lead to high and low prices. These scenarios have included:

- Central scenario: The most likely future state, mostly following assumptions from the latest Input Assumptions and Scenarios Report by AEMO, the Infrastructure Investment Objectives Report by AEMO Services.
- Low price scenario: An extreme case where market prices are low. Driven by delayed coal closure, low gas prices, low capex prices and high renewable uptake.
- High price scenario: An extreme case where market prices are high. Driven by high gas prices, supply chain constraints and slow renewable uptake.

Scenarios are ascribed a weighting according to a view of the importance of each scenario for evaluation. In previous Generation LTESA Tender Rounds, the central scenario has been the highest weighted of the three scenarios, followed by the low case.

3.3. Evaluation Metrics

The Evaluation Metrics are used to translate modelled Financial Value Components into information for making recommendations. The primary metric for the evaluation of MC1 is the Benefit-to-Cost Ratio (BCR). This is calculated by dividing the discounted Project Benefits by Project Costs, weighted by scenario as described above. Other Evaluation Metrics presented to inform recommendations include:

- Project Benefits: Wholesale Electricity Cost and Market Benefits after the Uncertainty factor has been applied.
- Project Costs: The sum of Forecast LTESA Cost, Portfolio Impact and Uncertainty factor.
- Net Value: Project Benefits less Project Costs.
- Worst Case: The highest modelled cost of a Project to the SFV. Uses low price scenario, one weather reference year, perfect foresight and low LGC price scenario to determine the worst case outcomes to the SFV.

An example calculation has been displayed in Appendix B to show how Financial Value Components can be translated into Evaluation Metrics.

3.4. Spotlight: Hybrid Projects

Hybrid Projects are eligible to participate in Tender Round 4 and have done so in previous Tender Rounds. This section provides a short summary on the evaluation approach of Hybrid Projects.

What is a Hybrid Project?

Hybrid Projects are defined in the Tender Guidelines as co-located generation Project with an associated Project (such as a storage asset) which either:

- share a common AEMO registration;
- share a common connection point; or
- have a direct connection that allows for the storage asset to be charged directly from the generation asset.

A combined generation asset (e.g., wind and solar) that shares a connection point is not considered a Hybrid for the purposes of the MC1 evaluation. Cost and benefits will be assessed as one combined generation Project.

Election of Hybrid Project category

There are two categories of Generation LTESA Bids that a Hybrid Project can make in Tender Round 4, which must be elected by the Proponent as part of its Financial Value Bid:

- **Assessed Hybrid Project** – Proponent bids for the Hybrid Project to be assessed in the Financial Value Bid. This means both the generation Project and the associated Project will be:
  - Assessed in MC1 for the combined Financial Value of the Hybrid Project; and
  - Contractually obligated to be delivered. That is, all components of the generation Project and the associated Project (e.g. BESS) must be built, which would be reflected accordingly in the LTESA PDA and assessed in MC2.
- **Non-assessed Hybrid Project** – Proponent bids for only the generation Project to be assessed in the Financial Value Bid. If the Proponent intends to build an associated Project but does not wish to contractually commit to its delivery, then the benefits of this associated Project will not be included in the assessment of MC1. This means non-assessed Hybrid Projects will be assessed in MC1 as if the generation Project is standalone.

MC1 assessment of the Assessed Hybrid Project category

Both the generation Project and associated Project of an assessed Hybrid Project will be evaluated in MC1. This means the following will be assessed:

- Wholesale Electricity Cost and Market Benefit: The Wholesale Market Benefit component will be assessed by considering the combined hybrid shape.
- Forecast LTESA Cost: MC1 evaluation does not consider the storage component in determining the exercise probability because the Generation LTESA payments are settled solely on the generation Project's energy volume.

4. Characteristics of high performing Bids in previous Tender Rounds

AEMO Services has run two Generation LTESA Tender Rounds to date, awarding over 2GW of capacity. Submitted Bids have represented a diverse range of technologies, including wind, solar and hybrids. This section provides a short recap of the Tender Round 3 Outcomes Market Briefing Note. Please refer to this document for further information.

The flexibility of the Generation LTESA

The Generation LTESA provides Proponents with significant flexibility to tailor the relevant product to their Project's needs. A Financial Value Bid can be developed in a targeted way that suits the Proponent's use-case and minimises Forecast LTESA Costs to NSW electricity customers, making it more competitive in MC1.

Characteristics of high performing Bids

In previous Tender Rounds, for example, Proponents have provided bids that exclude swap periods in the first 10-15 years of their Generation LTESA. This could be reflective of Proponents forecasting sufficiently high merchant revenues in those years or expecting to have an offtake agreement in place that means they will not rely on the availability of LTESA swaps. The Proponent is foregoing the right to enter swap periods and the SFV will not make any LTESA payments in these years. This is a lower forecast LTESA cost outcome for NSW electricity customers compared with these periods not being excluded.

Table 1 shows the characteristics of high performing Bids in the MC1 evaluation, based on previous Tender Rounds.

Table 1: Characteristics of high performing Bids in Generation LTESA assessment

Key	Outcomes
Forecast LTESA Cost	The competitive Projects were assessed as having low Forecast LTESA Costs relative to less competitive Projects. Forecast LTESA Costs were assessed as lower where Bids had the following features: • Low Fixed Prices. • Low Contracted Percentage. • Excluded Swap Periods. Using these Bid Variables improved a bid where they reduced the assessed cost and risk to the SFV under the LTESA.
Bid Prices	While competitive bids had a low Fixed Price and low Repayment Threshold, the Fixed Price has been seen to have a much greater impact on MC1 assessment outcomes. It is a key driver for minimising Forecast LTESA Cost. A reduction in Fixed Price can impact the exercise behaviour in MC1 modelling. The relationship between Fixed Price and option exercise is non-linear. As a result, a reduction in Fixed Price could reduce the LTESA option exercise across a number of periods in the model.
Earlier Commercial Operations Date (COD)	An earlier COD was assessed favourably where the Project being available in the market earlier allowed it to capture more of the value arising from the high modelled wholesale market prices observed in earlier years. In periods of high spot prices, LTESA options were modelled to be less likely to be exercised. Furthermore, high wholesale prices were generally correlated with greater opportunity for wholesale price suppression, increasing the marginal benefit of a Project's generation.
Generation profile	Competitive Projects have been seen to consistently reduce NSW wholesale market prices across forecast scenarios. MC1 considers each Project's benefits in terms of lowering wholesale cost to NSW customers through wholesale prices suppression. These benefits were assessed as being higher if a Project's generation was correlated with times of tight supply demand balance. This was generally around the afternoon and evening peak pricing periods where it was more common for wind Projects to be generating, and hence their modelled Project benefits were higher than solar-only Projects. Refer to Section 3.4 for information on Hybrid Projects and how a hybrid profile is considered in MC1.
Network Location	Projects located further from regional interconnectors (e.g. Vic-NSW and NSW-Qld interconnectors) were in general assessed to be more additive to NSW supply. Projects electrically closer to interconnectors are more likely to displace interconnector flow due to transmission constraints along flow-paths. This lessened their impact on suppressing wholesale prices in NSW and reduced their Project Benefits for NSW electricity customers.
Contracted Percentage	Some bids put forward a contracted percentage of less than 100% which led to them being assessed as more competitive, compared with if they had bid 100% of their output with the same terms. Contracted Percentage was assessed to have a significant impact on Forecast LTESA Cost in MC1. All else being equal, a lower Contracted Percentage was modelled to lower a bid's Forecast LTESA Cost. Reducing the Contracted Percentage did not always lead to a low Forecast LTESA Cost being assessed if the Fixed Price was comparatively high.
Excluded Swap Periods	Some Financial Value Bids forfeited at least one swap start date, including one of the successful bids. This meant they were assessed as being more competitive for the same Fixed Price, compared with if they had not forfeited any swap start dates. Forfeiting swap periods in later contract years was assessed more favourably than in earlier contract years. The extent to which forfeiting a particular swap period lowers Forecast LTESA Cost is dependent on the forecast wholesale energy price for that period. Forfeiting an LTESA swap period indicates that the Project will not be reliant on LTESA payments in that period.
Structured LTESA Fixed Price	The Alternative Financial Value Bid gives Proponents more flexibility in how the LTESA Fixed Price changes between swap periods. LTESA costs are forecast against a range of future energy market scenarios in MC1. In the near-term, wholesale energy prices are forecast to be relatively high. In scenarios where they reduce in later years, AEMO Services assessed that there is less risk for NSW electricity customers where a Proponent: • forfeits a swap start date in later years of the contract term; • sculpts the LTESA Fixed Price such that LTESA Fixed Prices are low in periods where electricity prices are also forecast to be low.

Appendix A – Financial Value Component Deep Dive

Wholesale Electricity Cost and Market Benefit

The impact on the wholesale electricity cost of each Project bidding for a Generation LTESA can be considered through the following steps:

1. Wholesale electricity costs in NSW estimated using a counterfactual case without the Project. This requires a market forecast of NSW demand and wholesale spot prices. This step is completed prior to receiving Financial Value Bids.
2. The downwards impact on the wholesale spot price from a Project's expected generation output can then be estimated.

- This is done by modelling the adjusted wholesale price outcomes in NSW with the existence of the Project, at each 30-minute interval (modelled price intervals) across each forecast year;[5]
- A Project is assumed to contribute marginal MWs of generation to the modelled price interval according to the Project's generation profile.[6] This additional generation is expected to put downward pressure on the wholesale electricity market in modelled price intervals where the Project generates;
- An estimate of wholesale electricity costs in NSW is produced which includes generation from the Project bidding for an LTESA.

The wholesale electricity cost with the Project included can be subtracted from the wholesale electricity cost without the Project for each model interval to determine the Project's Benefits, per the following:

$$\sum_{i=1} (PriceBase_i - PriceAdjusted_i) \times NSWLoad_i$$

Where

- $\boldsymbol{PriceBase_i}$ is the wholesale price forecast which is derived in step 1 above without the Project;
- $\boldsymbol{PriceAdjusted_i}$ is the wholesale price forecast which is derived in step 2 above with the inclusion of the Project; and
- $\boldsymbol{NSWLoad_i}$ is NSW load assumed in the modelled scenario.

This calculation will be repeated for all forecast years (with discounting to present value terms) and across multiple electricity market scenarios.

5. We note this does not take into consideration that there is a risk that the generation may not actually be available when it is assumed to be available, resulting in inaccurately estimating its impact on the wholesale spot market price. See page 5 for further detail on how the uncertainty of generation is considered.
6. This stems from the policy intent of a LTESA incentivising new Project entry by providing greater revenue certainty.

Forecast LTESA Cost

Awarding an LTESA is likely to impose a cost on NSW electricity customers. The Forecast LTESA Cost considers the Bid terms, the Project's generation profile, and modelled LTESA option exercise behaviour – all based on a range of wholesale price forecasts. The Forecast LTESA Cost can be calculated as follows:

1. Estimate Project revenue

The Dispatch Weighted Average Price (DWAP) for each Project can be forecast using generation output profiles provided by Proponents (Bid generation profiles). The price forecast used can be the same wholesale spot price forecast used for the wholesale price benefit.

LGC revenues are a source of revenue for a Project and when exercised, the LTESA would require the LGCs to be transferred to the SFV. Based on the DWAP, annual Project revenues are estimated as:

$$Project\ annual\ revenue\ \ before\ repayment = \begin{cases} F \times V\ when\ exercised \\ D \times V\ when\ not\ exercised \end{cases}$$

Where

- ***F*** = LTESA Fixed Price
- ***D*** = Bundled DWAP (including LGCs)
- ***V*** = Volume

2. Estimate cost to SFV based on LTESA exercise behaviour

Two scenarios are used for exercise behaviour assumptions:

- Exercise behaviour based on perfect foresight of market revenues; and
- LTES Operator exercises every available LTESA option.

These are simulated as two discrete scenarios, as detailed as detailed in Section 3.2. For each assumption, costs to the SFV can be estimated as follows:

$$SFV\ annual\ cashflow\ before\ repayment = \begin{cases} (F - D) \times V\ when\ exercised \\ 0\ when\ not\ exercised \end{cases}$$

3. Estimate Repayment Threshold payments

Revenues to the SFV (offsetting costs to customers) from the repayment mechanism are estimated for the non-exercise periods based on the difference between the DWAP and the repayment threshold, per the below formula:

$$Project\ annual\ repayment = \begin{cases} 0\ when\ D \leq R \\ Min(75\%(D-R) \times V, P)\ when\ D > R \end{cases}$$

Where

- ***D*** = DWAP
- ***R*** = Repayment threshold
- ***P*** = Cumulative net payments to date (from SFV to Project)

Portfolio Impact

The subsequent entry of new generation will have an impact on the costs incurred to the SFV from its existing portfolio of LTESAs. The entry of new renewable energy generation can reasonably be expected to lower wholesale spot prices.

This makes it more likely that:

- An existing LTESA Project will exercise its option and cause the SFV to incur a liability.
- The value of the payments from the SFV to the existing portfolio of Projects contracted to LTESAs will increase as the difference between the wholesale spot price and LTESA fixed price widens.

Uncertainty

Some Projects have a more variable generation output profile than others, adding uncertainty to benefit and cost calculations. In particular, the uncertainty of benefit and cost calculations which rely on predetermined Bid generation profiles is amplified when a Project's generation uncertainty coincides with periods of high price variability. As an example, wind Projects have highly uncertain generation output which may coincide with overnight prices which experience high variability as well.

An adjustment on cost and benefit estimations could be applied to Projects with more variable Bid generation profiles or Bid generation profiles with high output during times of expected price variability. This would account for the uncertainty in absolute cost and benefit estimates compared with Projects of more certain Bid generation profiles.

Appendix B – Example Calculation

As an illustrative example, a calculation of each Financial Value Component and Evaluation Metric for a sample forecast year is shown against three generic Projects. Please note that the numbers used in the example are illustrative and fictitious.

		Project type		
		Wind	**Solar PV with storage**	**Solar**
Project characteristics	**Project size (generation only) (MW)**	150	100	100
	Additional components	N/A	25MW of storage	N/A
Bid assumptions	**LTESA Bid?**	Yes	Yes	Yes
Evaluation framework calculations (illustrative example for a sample year)				
Wholesale Market Benefits	**NSW load cost (pre-Project, $m)**	5,000.5		
	NSW load cost (post-Project, $m)	4,995.6	4,995.6	4,999.1
	Wholesale Market Benefit ($m)	5,000.5 – 4,995.6 = 4.9	5,000.5 – 4,995.6 = 4.9	5,000.5 – 4,999.1 = 1.4
Forecast LTESA Cost	**Forecast LTESA Cost estimate ($m)**	-1.8	-1.2	-0.7
	Project repayment ($m)	0.0 (no repayment in year)	0.0 (no repayment in year)	0.0 (no repayment in year)
	Cost estimate ($m)	-1.8 + 0.0 = -1.8	-1.2 + 0.0 = -1.2	-0.7 + 0.0 = -0.7
Portfolio	**Portfolio Impact ($m)**	**-0.08**	**-0.04**	**-0.1**
Uncertainty	**Uncertainty ($m)**	-0.2	-0.05	-0.13

Evaluation framework calculations (illustrative example for a sample year)				
Project Benefits	**Project Benefits ($m/MW)** = sum of Wholesale Market Benefits and Uncertainty[7]	[4.9 + (-0.1)] ÷ 150 = 0.032	[4.9 + (-0.025)] ÷ 100 = 0.049	[1.4 + (-0.065)] ÷ 100 = 0.013
Project Costs	**Project Costs ($m/MW)** = sum of Forecast LTESA Cost, Portfolio Impact and Uncertainty[8]	[(-1.8) + (-0.08) + (-0.1)] ÷ 150 = -0.013	[(-1.2) + (-0.04) +(-0.025)] ÷ 100 = -0.013	[(-0.7) + (-0.1) + (-0.065)] ÷ 100 = -0.009
Net Value	**Net value[9] ($m/MW))** = Project Benefits - Project Costs	0.032 + (-0.013) = 0.019	0.049 + (– 0.013) = 0.036	0.013 + (-0.009) = 0.004
Benefit Cost	**Benefits Cost Ratio[10]** = Project Benefits / Project Costs	0.032 / 0.013 = 2.5	0.049 / 0.013 = 3.8	0.013 / 0.009 = 1.4

7. Note for this example, allocated as 50% of total uncertainty
8. Note for this example, allocated as 50% of total uncertainty
9. For this example, Project Benefits and Project Costs have been rounded to three decimal places to calculate the Net value
10. For this example, Project Benefits and Project Costs have been rounded to three decimal places to calculate the BCR

Appendix C – Definitions

Term	Definition
Benefit Cost Ratio (BCR)	One of the Evaluation Metrics used in the MC1 evaluation. Calculated by dividing Project Benefits by Project Costs.
Bid Variables	Input assumptions supplied by a Project in the MC1 Returnable Schedule. Include Fixed Price, contracted percentage, forfeited periods, contract term, Repayment Threshold.
Bundled DWAP	Dispatch-Weighted Average Price (as defined below) including LGC price.
Contracted Percentage	Contracted Percentage is a Bid Variable. It is the percentage of a Project's total registered capacity that a LTESA relates to. For example, a Project with a registered capacity of 500MW may request an LTESA for 250MW by nominating a Contracted Percentage of 50%.
Dispatch-Weighted Average Price (DWAP)	The average of the electricity spot price that a Project is exposed to, weighted by the volume of energy it dispatches in a period.
Evaluation Metrics	Metrics including Benefit Cost Ratio (BCR), Net Value, Worst Case, Project Benefits and Project Costs that are used to evaluate Projects. BCR is the default metric for evaluation.
Fixed Price	The Fixed Price is a Bid Variable. It is the strike price of each swaption period in a Generation LTESA.
Forecast LTESA Cost	As defined in Section 3.1 of this Market Briefing. Note the Forecast LTESA Cost has been termed the Net LTESA Cost in the Tender Guidelines.
Hybrid Project	As defined in Section 3.4 of this Market Briefing.
Net Value	One of the Evaluation Metrics used in the MC1 evaluation. Calculated by subtracting Project Costs from Project Benefits.
Portfolio Impact	As defined in Section 3.1 of this Market Briefing.
Project Benefits	The sum of Wholesale Market Benefits and the impact of Uncertainty (factor).
Project Costs	The sum of Forecast LTESA Costs, Portfolio Impact and the impact of Uncertainty (factor).
Repayment Threshold	The Repayment Threshold is a Bid Variable. A fixed price per megawatt hour higher than the Fixed Price, that is used to calculate potential repayments. The repayment mechanism applies in non-exercise periods if the LTES Operator's dispatch-weighted average price is above the Repayment Threshold. Seventy-five (75) percent of the revenue above the threshold is paid to the SFV, which is capped at the historical cumulative net payments from the SFV to the LTES Operator and is reduced where the LTES Operator has entered an eligible contract.
Uncertainty	As defined in Section 3.1 of this Market Briefing.
Wholesale Electricity Cost and Market Benefit (Wholesale Market Benefit)	As defined in Section 3.1 of this Market Briefing.
Worst Case	As defined in Section 3.3 of this Market Briefing.

This publication has been prepared by AEMO Services using information available in January 2024.