Offer Construction Guideline

Effective 1 February 2025

This document provides general guidance to explain how the ERA currently proposes to interpret the WEM Rules. Courts or tribunals may make decisions that are different from the ERA's interpretation. The ERA may amend the guideline at any time following a public consultation process, as specified in WEM Rules 2.16D.2 to 2.16D.4. Circumstances for updating the guideline may include relevant changes in the regulatory framework, and related court or tribunal decisions.

Examples provided are for illustration only and are not exhaustive. This guideline is not a substitute for legal, economic or other technical advice. Market Participants are encouraged to obtain legal advice tailored to its specific circumstances. This guideline does not reproduce all requirements in the WEM Rules. Market Participants are advised to refer to the WEM Rules for a full list of obligations.

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Name:	Steve Edwell
Title:	ERA Governing Body Chair

VERSION HISTORY

Version	Effective Date	Notes
1.2	1 October 2023	New WEM Commencement Day
2.0	1 February 2025	Update following FCESS Cost Review Amending Rules.

Economic Regulation Authority

Level 4, Albert Facey House

469 Wellington Street, Perth WA 6000

Telephone 08 6557 7900

Email info@erawa.com.au

Website www.erawa.com.au

This document can also be made available in alternative formats on request.

National Relay Service TTY: 13 36 77

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1. Purpose of this guideline

The Economic Regulation Authority (**ERA**) is responsible for monitoring and enforcing compliance with the Wholesale Electricity Market (**WEM**) Rules. Market Participants are required to comply with the price offer requirements of the WEM Rules in section 2.16C and general trading obligations.[1] These obligations are binding on all participants in the Short-Term Energy Market (**STEM**) and Real-Time Market, which includes the energy and the Frequency Co-optimised Essential System Services (**FCESS**) markets.

The ERA maintains this Offer Construction Guideline **(Guideline)** under WEM Rule 2.16D.1(a) to:

1. Provide guidance to Market Participants in relation to the application of WEM Rule 2.16C.6A (formulating an Economic Price Offer).
2. Assist Market Participants in identifying what may be included as efficient variable costs when offering prices in a Portfolio Supply Curve or Real-Time Market Submissions (including all costs incurred under long-term take-or-pay fuel contracts).
3. Detail how the ERA will assess prices offered under WEM Rule 2.16C.6.
4. Outline how the ERA will consider price offers for different facility types, including Electric Storage Resources.
5. Provide examples illustrating the types of conduct that the ERA considers would be likely to contravene the obligation of Market Participants to submit Economic Price Offers.
6. Provide guidance to Market Participants on how the ERA will assess inefficient market outcomes under WEM Rule 2.16C.7.

Many of the examples provided relate to price offers for scheduled (thermal) generators. This is because price offers for thermal generators are subject to more factors, such as having more cost components, when compared to non-scheduled generators such as wind and solar. Guidelines and examples are also provided for non-scheduled generators and battery storage facilities.

1.1 Interpretation

In this Guideline, unless the contrary intention is expressed:

1. terms used have the same meaning as those given in the WEM Rules (made pursuant to the *Electricity Industry (Wholesale Electricity Market) Regulations 2004*) **"WEM Regulations"**;
2. to the extent that this procedure is contrary or inconsistent with the WEM Rules, the WEM Rules shall prevail to the extent of the inconsistency;
3. a reference to the WEM Rules, WEM Procedures or Trading Conduct Guideline includes any associated forms required or contemplated by the WEM Rules or WEM Procedures;
4. words expressed in the singular include the plural and vice versa;

[1] Wholesale Electricity Market Rules (WA), 20 November 2024, Rule 2.16C.6A.

5. the term ‘breach’ used in this document also refers to the terms non-compliance and contravention which are also used in the WEM Rules and WEM Regulations; and

6. the terms 'alleged breach' or 'suspected breach' are both used in the WEM Rules to refer to matters where the ERA or a Rule Participant forms the view that it has sufficient information to reasonably suspect a breach of the WEM Rules and/or WEM Procedures has occurred, but where the ERA has not yet made a determination that a breach has occurred. For the avoidance of doubt, where the ERA has used the term 'suspected breach' in this document it also refers to 'alleged breaches' in the WEM Rules.

References in this Guideline to the WEM Rules are to the WEM Rules ~~as~~ in force as at 20 November 2024.

References to the WEM Rules in this ~~Procedure~~ Guideline in square brackets [WEM Rule #] are included for convenience only and do not form part of this Guideline.

Terms defined in the *Electricity Industry Act 2004*, the WEM Regulations and the WEM Rules have the same meanings in this Guideline unless the context requires otherwise.

1.2 Monitoring, record keeping and compliance

1.2.1 Monitoring

The ERA’s Monitoring Protocol WEM Procedure sets out how the ERA will monitor, investigate and enforce compliance.[2] The ERA will conduct any investigation of a suspected breach of the general trading obligations in accordance with the Monitoring Protocol.

1.2.2 Record-keeping

All Market Participants are advised to keep records underlying their respective costs, price offers and governance arrangements consistent with section 8 of this Guideline.

There are additional record-keeping obligations for Market Participants with Facilities identified in a Material or Material Constrained Portfolio. The ERA’s Portfolio Determination WEM Procedure outlines the ERA’s determination of Material Portfolios.[3]

Market Participants with Facilities (except Non-Scheduled Facilities) identified in a Material Portfolio or Material Constrained Portfolio must:

a. maintain adequate records of the internal governance arrangements that it has in place to comply with its obligations under WEM Rule 2.16C.5;

b. maintain adequate records of the methods, assumptions and cost inputs used to develop the prices in the Portfolio Supply Curve offered in its STEM Submissions or Standing STEM Submissions, including, for each relevant Facility; and

c. maintain adequate records of the methods and cost inputs used to develop the prices offered, quantities and Ramp Rate Limits in its Real-time Market Submissions or Standing Real-Time Market Submissions, including, for each relevant Facility.[4]

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[2] Economic Regulation Authority, 2024, Monitoring Protocol WEM Procedure, (online).

[3] Economic Regulation Authority, 2024, Portfolio Determination WEM Procedure, Section 2.3, (online).

[4] Wholesale Electricity Market Rules (WA), 20 November 2024, Rule 2.16C.3.

1.2.3 Compliance

To determine if a Market Participant has not met its price offer obligations under Section 2.16C of the WEM Rules, the ERA will consider:

a. if the price offered was an Irregular Price Offer [WEM Rule 2.16C.6]

- If the ERA considers that a price offered by a Market Participant in its Portfolio Supply Curve, or by a Market Participant in its Real-Time Market Submissions, is inconsistent with an Economic Price Offer, the ERA must determine that the price was an Irregular Price Offer;

and

b. If the Irregular Price Offer resulted in an inefficient market outcome [WEM Rules 2.16C.5 and 2.16C.7].

Under WEM Rule 2.16C.6, the ERA must investigate potential breaches of clause 2.16C.5. An investigation is done in accordance with the Portfolio Determination WEM Procedure and WEM Rule 2.13.27 (requirements for compliance investigations) and with regard to this Offer Construction Guideline. Section 7 of this Guideline outlines how inefficient market outcomes will be assessed.

2. Price offers

This section presents a high-level summary of the matters Market Participants must consider when constructing submissions for the STEM and Real-Time Market. The Real-Time Market comprises the energy and the five FCESS markets:

1. Regulation Raise
2. Regulation Lower
3. Contingency Reserve Raise
4. Contingency Reserve Lower
5. Rate of Change of Frequency (**RoCoF**) Control Service.

2.1 Price offer obligations

Market Participants have price offer obligations which require the construction of an Economic Price Offer [WEM Rule 2.16C.6A]. Market Participants must ensure their price offer is not an Irregular Price Offer that results in an inefficient market outcome. [WEM Rule 2.16C.5]. An Irregular Price Offer is a price offer which is inconsistent with an Economic Price Offer.

An Economic Price Offer is a price offered by a Market Participant, in its Portfolio Supply Curve or in a Real-Time Market Submission, which is not greater than the Market Participant's reasonable expectation (based on the information available at the time the offer was made) of the sum of all efficient variable costs for the provision of the relevant Market Service, including all costs incurred under long-term take-or-pay fuel contracts.[5]

2.1.1 Reasonable Expectation

A Market Participant is expected to have a working knowledge of the WEM Rules and to be able to produce scrutable evidence in the form of factors, information and analyses relevant to the circumstances of that Market Participant and its facilities, that the Market Participant has used to form its *reasonable expectation* of the sum of its efficient variable costs for a Market Service at the time the relevant Market Submission was made.

This means that a Market Participant must be able to produce records, assumptions, methods and any other relevant material that the Market Participant has used to form its reasonable expectation of the efficient variable costs it will incur when constructing its price offer in its Market Submission.

Where new or revised information becomes ~~reasonably~~ available to the Market Participant and that information results in changes to the Market Participant's reasonable expectation, the Market Participant must use reasonable endeavours to update the relevant price offer in the relevant Market Submission for the relevant Dispatch Intervals ~~must be updated~~ before Gate Closure [WEM Rule 7.4.2(c)].

For instance, AEMO publishes Pre-Dispatch Schedules in a Real-Time Market timetable and Market Participants are required to account for the information provided in Pre-Dispatch Schedules when constructing their offers [WEM Rules 7.1.3, 7.4.2 and 7.4.2A]. If sufficient

[5] Wholesale Electricity Market Rules (WA), 20 November 2024, Rule 2.16C.6A.

information is available in market schedules, Market Participants might adopt an iterative approach to forming their reasonable expectation of costs to be incurred, as market activity is expected to converge as Gate Closure approaches. The critical consideration here is the formation of reasonable expectation at the time of Gate Closure.

2.1.1.1 Treating uncertainty in the formation of reasonable expectation

In forming a reasonable expectation of efficient variable costs to be incurred, a Market Participant will forecast the costs it will incur, the quantum to which these costs will be incurred, the time frame over which these costs will be incurred, and whether there are alternative courses of action to incurring those costs. Forecasts produced by Market Participants will inevitably include forecast errors, resulting in under or over recovery of incurred costs in the short term. However, a Market Participant should continuously monitor its forecasting accuracy and over time produce forecasts that lead to neither persistent gain nor loss in each market when the offer price is paid in a Dispatch Interval.

Over time it is expected that Market Participants' offers will approximate the efficient cost they incur over that same period. The period over which this may occur will be dependent on the circumstances of the individual Market Participant and facility.

Market Participants are expected to review their forecasts periodically to ensure they are not making systematic gains in the STEM or Real-Time Market for energy or FCESS over long periods. A Market Participant would review its forecasting method so that it did not make systematic losses over long periods.

2.1.2 Efficient variable costs (EVC)

In forming price offers consistent with Economic Price Offers in WEM Rule 2.16C.6A, a Market Participant can offer a price up to the sum of all EVC for the provision of the relevant Market Service, including all costs incurred under long-term take-or-pay fuel contracts.

When a Market Participant includes only the EVC related to producing the relevant Market Service in its offers, it would incur no operating losses or operating costs if its facility is not dispatched or discharged when the market-clearing price does not reach its offer price.

A variable cost for a Market Service is one that varies with the production of that Market Service. This can be from zero production to some level of production, or between different non-zero levels of production.

Other costs are independent of the level of production but are only incurred if a facility produces a positive output – commonly referred to as 'avoidable fixed costs' (AFC) or 'quasi-fixed costs'.[6] For example, a change in the production of Market Services, such as production of energy, often includes the choice of whether to start a generator, to incur a large start-up cost, and to run over a series of Dispatch Intervals.

Such costs become variable when viewed from the perspective of producing electricity or not (i.e. zero to some level of production). A Market Participant c~~w~~ould include these costs in its submission. To maximise profit, Market Participants might amortise the cost they incur to start-up their plant over the expected dispatch period.

6 Varian, H., 2010, *Intermediate Microeconomics: A Modern Approach*, 8th edition, p. 373 (online).

The ERA will consider a variable cost incurred by a Market Participant is efficient if:

- The technical parameters relied upon to estimate costs are correct and supported by expert advice.
- Costs are calculated using input prices and costs explicitly allowed for in WEM Rule 2.16D.1(a)(iii).
- Forecasts or estimates are based on an independently verifiable method using all information available.
- The costs are allocated across time and production, as well as number of starts using a methodology that reflects a reasonable relationship between these costs and variables such as time, production and number of starts. The methodology should be able to be independently verified by applying good electricity industry practice.[7]
- A Market Participant's EVC of generating electricity in the Real-Time Market is not affected by its contract position for electricity sales (for example, by prices agreed under power purchase agreements), long-term contract prices for Large-scale Generation Certificates (LGC) (as opposed to the LGC spot price which are part of a Market Participant's Facility's EVC), its STEM sales or its Net Contract Position.[8]

A risk margin is not included in calculation of efficient variable cost.

Table 1 shows the EVCs that are allowable in a Market Participant's offers and are covered in this guideline.

Table 11~~1~~. Efficient variable cost components of producing electricity

Cost	Description	Unit
Incremental / Average operating costs		
Fuel costs	The cost of burning fuel by thermal generators for electricity generation. Equal to heat rate (GJ/MWh) times transport cost inclusive fuel cost ($/GJ).	$/MWh
Variable operating and maintenance (VOM)	The VOM cost component are costs that vary with the generation of electricity and include costs incurred in operating a generator (other than fuel cost) and conducting maintenance work required to maintain the generating unit in an efficient and reliable condition. These costs mainly comprise maintenance service, parts and labour expenses.	$/MWh
Market Fees	Costs charged by AEMO for the operation and regulation of the market that vary with the generation of electricity.	$/MWh
Runway costs of Contingency Reserve Raise	Contingency Reserve Raise costs allocated to generators using the runway method as determined in market settlement.	$/MWh

7 In practice, Market Participants need to forecast the number of starts over a maintenance period and the output produced over a typical dispatch cycle based on verifiable information. Costs are then amortised over starts or the expected output produced during a typical cycle.

8 Australian Government, The renewable energy certificate market, Clean Energy Regulator (online).

Cost	Description	Unit
Avoidable fixed costs (AFC)		
Start-up costs (SUC)	The AFC of starting a generator and bringing the generator to its minimum stable generation. This can include fuel costs, additional maintenance costs and wear and tear on plant directly related to starting the generator.	$/start
Shut-down costs (SDC)	The AFC of shutting down a generator. This can include fuel costs and additional maintenance costs associated with shutting down the generator.	$/shut-down
Other AFC (non-start-up and shut- down costs)	An AFC is an expenditure that must be borne by the firm if it chooses to produce any amount of output in a given time period.[9]	$/hour
Enablement costs	Costs incurred when generators are required to be available at the start of a Dispatch Interval so must start and generate at a loss the Dispatch Interval prior to enable them to ramp up to required production. This is similar when ramping down from producing electricity to shut-down.	$/shift
Other opportunity costs		
Opportunity costs of dispatch in different Trading/Dispatch Intervals	The expected revenue forgone from supplying a service (such as producing or discharging energy) in the current Dispatch Interval. This occurs when the decision to supply the service in the current Dispatch Interval is expected to restrict the production of services in future Dispatch Intervals. For clarity, this opportunity cost reflects the maximum value a Market Participant expects to receive from using its limited production resources – such as fuel or stored energy – in future Dispatch Intervals as opposed to using the resources for production of services in the current Dispatch Interval.	$/MWh
Opportunity cost of not receiving Large-scale Generation Certificates	A renewable generator gains a LGC for every MWh of electricity that it produces. That means if the generator does not dispatch, it forgoes the LGC spot price and its value.	$/MWh
Other costs		
Other costs	Other costs as appropriate (for example, other ESS charges allocated to Facilities that vary with the production of energy).	

2.2 STEM submissions

A STEM Submission includes a Portfolio Supply Curve and a Portfolio Demand Curve for each Trading Interval. A Market Participant may submit a STEM Submission for a Trading Day up to seven days prior to the start of the Scheduling Day and the STEM Submission Cutoff for the Trading Day.[10] STEM Submissions are made for each Trading Interval of a Trading Day.

9 McHugh, A., 2008, *Portfolio Short Run Marginal Cost of Electricity Supply in Half Hour Trading Intervals*, Discussion Paper, p. 10. (online)

10 STEM Submission Cutoff is 10:50 AM on the Scheduling Day for the Trading Day, or such other time as may be notified by AEMO under WEM Rule 6.4.6B.

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A Portfolio Supply Curve may include up to 30 Price-Quantity Pairs. WEM Rule 6.6.5 sets out the requirements for each Price-Quantity Pair.

Market Participants are required to construct STEM Submissions in accordance with the WEM Rules. This includes accounting for all known market factors at the time of constructing the submission. Factors may include planned outages and network constraints.

Section 6 of this guideline provides guidance for price offers related to Portfolio Supply Curve for STEM submissions.[11]

2.3 Real-Time Market submissions

Real-Time Market Submissions are made in respect to a Registered Facility, a Market Service and a Dispatch Interval.

A Market Participant makes Market Submissions to the Real-Time Market for each Dispatch Interval in the Week-Ahead Schedule Horizon for the following Market Services:

- Energy, for each of its Scheduled Facilities, Semi-Scheduled Facilities and Non-Scheduled Facilities
- For each FCESS market, for each of its Registered Facilities that is accredited to provide FCESS.[12]

A Market Participant must make reasonable endeavours to ensure that its Real-Time Market Submission accurately reflects the price at which the Market Participant intends its Registered Facility to participate in the -Real-Time Market, and may revise its price based on any changes to its reasonable expectation, until Gate Closure.

[11] The scope of the ERA's determination of Irregular Price Offer for STEM Submissions is limited to prices offered in Portfolio Supply Curves [WEM Rule 2.16C.6(c)].

[12] Week-Ahead Schedule Horizon is the seven-day (336 Pre-Dispatch Intervals) period prior to a Dispatch Interval.

3. Offer construction

This section outlines the principles for constructing offers as the sum of all EVC's, including average operating costs.

3.1 Mapping cost to Price-Quantity Pairs

A Market Participant must submit its offers into the Real-Time Market for energy in the form of Price-Quantity Pairs. The offer prices in Price-Quantity Pairs allow the recovery of EVC's the Market Participant incurs when its facility is cleared to dispatch for the Market Service.

To illustrate how such a Market Participant p would form its Price-Quantity Pairs, firstly consider its EVCs as it moves from one level of output q_1 – expressed in MW – to a higher level of output, q_2, in a Dispatch Interval.

A Market Participant's incremental EVC (IEVC) is its change in EVC – expressed in $ – to produce $Q2$ MWh of electricity in a Dispatch Interval, rather than a lower amount of $Q1$ MWh. This $IEVC$ for a discrete change ΔQ for a single Dispatch Interval t is shown in Equation 1.[13,14] The $IEVC$ is the basis for the price offers and when included in the Price-Quantity Pairs allows for the recovery of EVCs.

Incremental efficient variable cost (Equation 11~~1~~)

$$IEVC(\Delta Q, t) = (EVC(Q2, t) - EVC(Q1, t))/(Q2(t) - Q1(t))$$

Where:

$IEVC(\Delta Q, t)$ is the incremental efficient variable cost – expressed in $/MWh – of Market Participant p to produce $Q2$ MWh in Dispatch Interval t, rather than a lower production of $Q1$ MWh.

$EVC(Q2, t)$ is the total efficient variable cost in $ of Market Participant p to produce $Q2$ MWh of electricity during Dispatch Interval t.

$EVC(Q1, t)$ is the total efficient variable cost in $ of Market Participant p to produce $Q1$ MWh of electricity during Dispatch Interval t.

$Q2(t)$ is production of electricity in MWh of Market Participant p during Dispatch Interval t.

$Q1(t)$ is production of a lower amount of electricity in MWh of Market Participant p during Dispatch Interval t.

A Market Participant's electricity production of Q MWh in a 5-minute Dispatch Interval is its output of q MW scaled for production during $\frac{5}{60}$ of an hour. For example, one MWh increase in production during a Dispatch Interval, requires 12 MW increase in plant output.

The incremental EVC of a Market Participant p for a Dispatch Interval t for an increment in production output of ΔQ MWh can be obtained by summing the incremental cost components of producing electricity.

[13] This is also the change in total costs but is equivalent to the change in variable costs because fixed costs do not change in the short run.

[14] A Market Participant may use the instantaneous change in costs if it is able to express its total cost function in a single mathematical equation.

Incremental efficient variable cost components (Equation 22~~2~~)

$$IEVC(\Delta Q, t) = IFC(\Delta Q, t) + IVOM(t) + IOVC(t) + IOPC(t) + IOC(t)$$

where:

$IEVC(\Delta Q, t)$ is the incremental efficient variable cost in $/MWh incurred by Market Participant p to produce ΔQ more MWh of electricity in Dispatch Interval t. This is equivalent to increasing output by $\Delta Q \times 12$ MW over the Dispatch Interval.

$IFC(\Delta Q, t)$ is the incremental fuel cost in $/MWh incurred by Market Participant p to produce ΔQ more MWh of electricity in Dispatch Interval t.

$IVOM(t)$ is the incremental variable operating and maintenance cost in $/MWh incurred by Market Participant p to produce electricity in Dispatch Interval t.

$IOVC(t)$ is other incremental variable costs in $/MWh incurred by Market Participant p to produce electricity in Dispatch Interval t.

$IOPC(t)$ is the incremental opportunity cost in $/MWh incurred by Market Participant p to produce electricity in Dispatch Interval t.

$IOC(t)$ are other incremental costs in $/MWh to produce electricity in Dispatch Interval t.

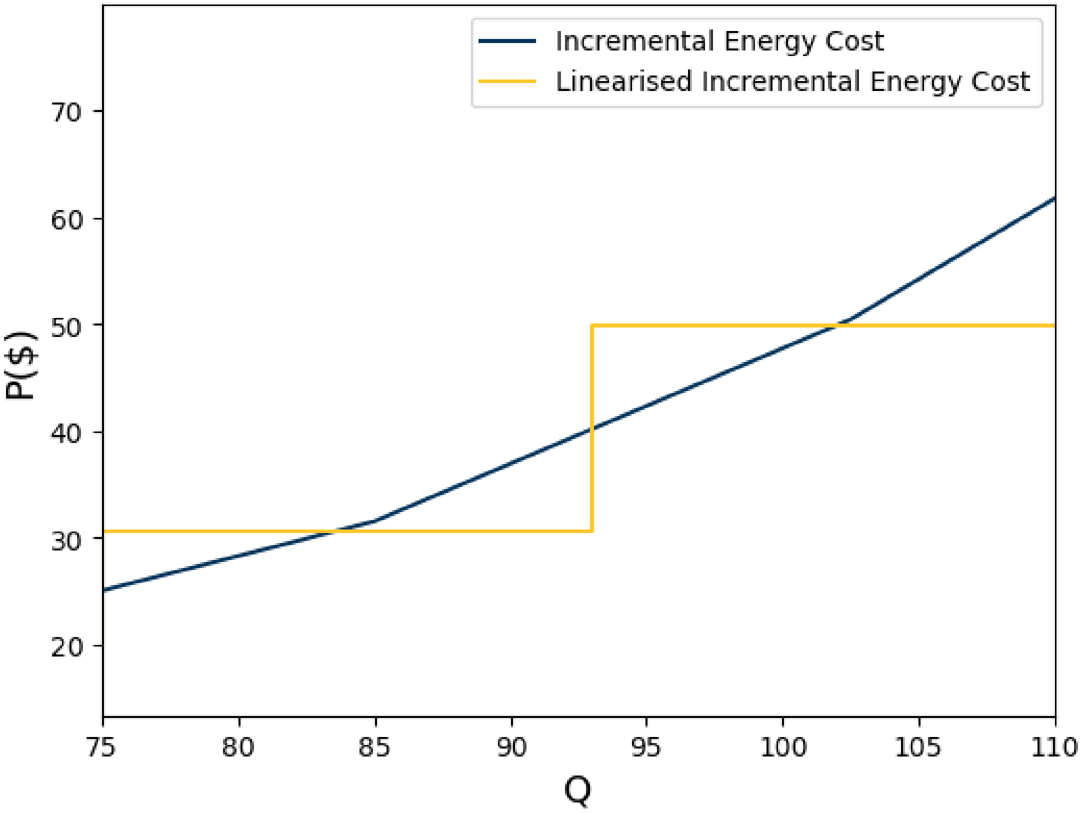
This equation does not include AFC, which will be explained in sections 3.1.1 and 3.2.4.

To offer electricity in the Real-Time Market for energy a Market Participant must transform its IEVCs into a series of steps, representing Price-Quantity Pairs.

There is no standard approach to converting IEVCs to Price-Quantity Pairs, however a Market Participant may not use a conversion method that would be expected to lead to the over-recovery of EVCs in their offers over time.

One example of a transformation is demonstrated in Figure 11~~Figure 1~~, where the Market Participant offers two Price-Quantity Pairs for the range of output in MW shown, where the price for each step is its IEVC at the mid-point of each quantity step.

Figure 11~~1~~. Conversion of Incremental Efficient Variable Cost curve to two-step Price-Quantity Pair



Source: ERA calculations

This Market Participant could make two Price-Quantity Pair offers for the range of output shown:

- 20 MW (1.66 MWh per Dispatch Interval) at $31.55/MWh and
- 20 MW (1.66 MWh per Dispatch Interval) at $50.42/MWh.

For some Market Participants with thermal generators, constructing a series of Price-Quantity Pairs with monotonically increasing prices is not as straightforward as shown in Figure 11~~Figure 1~~. This is because:

- Thermal generators have large one-off costs such as start-up costs, which are high for the first part of a Market Participant's production schedule but decline thereafter. Start-up costs are discussed in section 3.2.4.1.
- Many thermal generators become more fuel efficient as their output increases – that is, their IEVC decreases as their output increases. Fuel costs are discussed in section 3.2.1.
- Therefore, if such a Market Participant offers into the Real-Time Market for energy at a series of Price-Quantity Pairs based on its IEVC, the Market Participant:
  - Will make a loss in the Real-Time Market if it is the marginal generator and is paid its offer price – which does not include one-off costs such as start-up costs.
  - Cannot offer electricity Price-Quantity Pairs consistent with its physical increase in electricity production in a monotonically increasing manner, as its Price-Quantity Pairs corresponding to lower electricity production are more expensive than its higher levels of production.

There is no single standard method for Market Participants with this cost structure to construct Price-Quantity Pairs. Market Participants may use their own method as long as it does not systematically over-recover costs, if it were paid its offer price, and they do not use the method to manipulate market prices, which may be a breach of WEM Rule 2.16A.3.

A potential strategy to profitably dispatch or discharge into the WEM is to make its offers based on the reasonable expectation of a facility's average operating cost (AOC) of producing electricity in each Dispatch Interval.

3.1.1 Average operating cost

A Market Participant's AOC is its ~~I~~EVC over a dispatch cycle – that is to move from zero production to starting and producing electricity over a series of Dispatch Intervals – with amortisation of certain costs as detailed below. A Market Participant's AOC includes costs that change when a Market Participant runs over a series of Dispatch Intervals, relative to not running for those Dispatch Intervals.

Average operating cost (Equation 33~~3~~)

$$AOC(\Delta Q,t)=\frac{\sum_{t=1}^{n}EVC(Q2,t)-\sum_{t=1}^{n}EVC(Q1,t)}{\sum_{t=1}^{n}Q2(t)-\sum_{t=1}^{n}Q1(t)}=\frac{\sum_{t=1}^{n}EVC(Q2,t)-0}{\sum_{t=1}^{n}Q2(t)-0}=\frac{\sum_{t=1}^{n}EVC(Q2,t)}{\sum_{t=1}^{n}Q2(t)}$$

Where:

Where $Q1 = 0$,

$AOC(\Delta Q,t)$ is the average operating cost in \$/MWh of producing $Q2$ MWh of electricity by Market Participant p in Dispatch Interval t, where t ranges from 1 to n, and n denotes the Dispatch Interval at the end of a dispatch cycle.

Other variables are as previously defined in Equation 1.

Costs must be considered across a dispatch cycle because thermal generators incur costs – for example start-up costs – too large to recoup in a single Dispatch Interval. Market Participants must amortise start-up costs over the time and production of electricity to which the start-up is relevant – that is, over the respective dispatch cycle.

A Market Participant using the AOC method could:

1. Estimate the number of Dispatch Intervals over which the facility will run (run-time) and production (MWh and MW) in these Dispatch Intervals.

2. Calculate the facility's AOC in each Dispatch Interval.

3. Offer a single Price-Quantity Pair in each of the Dispatch Intervals with its maximum stable energy output in MW priced at its AOC at the point of its production of electricity.

A Market Participant's AOC consists of fuel costs, load-dependent variable operating and maintenance costs, avoidable costs per hour that are incurred only when the generator is running but which are not load-dependent (and are therefore incurred when the generator is operating to meet the demand), and start-up costs.[15]

A Market Participant's AOC for production of electricity of Q MWh for Dispatch Interval t can be calculated by summing the components examined in sections 3.2.1 to 3.2.6 and as shown in Equation 4.

[15] Western Australian Electricity Review Board, Application No 1 of 2019, Decision, p. 57, (online).

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Average operating cost components (Equation 444)

$$AOC(Q,t) = AOFC(Q,t) + IVOM(t) + IOVC(t) + AAFC(t) + ASUC(t) + ASDC(t) + AASUSDC(t) + OPC(t) + OC(t)$$

where:

$AOC(Q,t)$ is the expected AOC in \$/MWh incurred by Market Participant p to produce Q MWh in Dispatch Interval t, equivalent to output of $12 \times Q$ MW.

$AOFC(Q,t)$ is the average operating fuel cost in \$/MWh incurred by Market Participant p to generate Q MWh in Dispatch Interval t.

$IVOM(t)$ is the incremental variable operating and maintenance costs in \$/MWh incurred by Market Participant p to generate electricity in Dispatch Interval t.

$IOVC(t)$ are other incremental variable costs in \$/MWh incurred by Market Participant p to generate electricity in Dispatch Interval t.

$AAFC(t)$ are avoidable fixed costs in \$/hour incurred by Market Participant p in Dispatch Interval t, amortised to \$/MWh by electricity production in Dispatch Interval t.

$ASUC(t)$ are start-up costs in \$/start incurred by Market Participant p in Dispatch Interval t, as amortised to \$/MWh using electricity production by Market Participant p in Dispatch Intervals from 1 to n after the start-up.

$ASDC(t)$ are shut-down costs in \$/shut-down incurred by Market Participant p in Dispatch Interval t, as amortised to \$/MWh by electricity production over Dispatch Intervals t in which Market Participant p produces electricity before the shut-down, from 1 to n.

$AASUSDC(t)$ are avoided start-up and shut-down costs incurred by Market Participant p in Dispatch Interval t, as amortised using electricity production by Market Participant p in Dispatch Intervals from 1 to n before the shut-down, from 1 to n. See section 3.2.4.3 for more explanation.

$OPC(t)$ is the other opportunity costs in \$/MWh for Market Participant p to produce electricity in Dispatch Interval t.

$OC(t)$are other costs incurred by Market Participant p in Dispatch Interval t as amortised to \$/MWh using electricity production by Market Participant p in Dispatch Intervals from 1 to n before the shut-down.

Market Participants must form offers prior to the Dispatch Interval in question and, if using the AOC offer formation method, are unlikely to know exactly what their respective AOC is when doing so. However, Market Participants will have access to Pre-Dispatch Schedules published by AEMO to assist with estimating their run-times and dispatch levels (WEM Rules section 7.8). Market Participants must base offers on their reasonable expectation of incremental EVCs (for example, their AOC), and offers will be assessed on this basis (as discussed in section 2.1.1).

For example, Market Participants might use averages of historical operation dispatch-cycles and output for determining their expected AOC, and update this value as their operation changes over time.

3.2 Components of EVC

3.2.1 Fuel costs

This section explains the main factors in determining fuel costs: heat rate, the opportunity cost of using fuel for producing services (fuel-input-cost), and fuel transport charges.

3.2.1.1 Heat rate and fuel cost calculation

A Market Participant's incremental fuel cost is its change in the cost of burning fuel to move from one level of discharge or production to another.

Heat rates are commonly measured in average terms. Hence a Market Participant's ~~average~~ mean fuel cost (MFC) is defined in Average fuel cost (Equation 55~~Average fuel cost (Equation 5~~).

Average fuel cost (Equation 55~~5~~)

$$MFC(Q,t) = AHR(q,t) \times P(t)$$

Where:

$MFC(Q,t)$ is the mean fuel cost in \$/MWh of Market Participant p at output of q MW, to produce $q \times \frac{5}{60}$ MWh, in Dispatch Interval t.

$AHR(q,t)$ is the average sent out heat rate, net of internal load, in GJ/MWh for Market Participant p at output q MW, to produce electricity of $q \times \frac{5}{60}$ MWh, in Dispatch Interval t, adjusted for ambient temperature sensitivity if necessary.

$P(t)$ is the transport inclusive fuel-input-cost for Market Participant p in Dispatch Interval t, in \$/GJ.

A Market Participant can calculate its incremental fuel cost (IFC) as a discrete change in costs for increases in production as appropriate. For a shift in electricity production in a Dispatch Interval from $Q1$ MWh ($\frac{q_1}{12}$ MW) to $Q2$ MWh ($\frac{q_2}{12}$MW).

Incremental fuel cost (Equation 66~~6~~)

$$IFC_{\Delta Q,t} = \frac{MFC_{Q2,t} \times Q2_t - MFC_{Q1,t} \times Q1_t}{Q2_t \ - Q1_t}$$

Where:

$IFC_{\Delta Q,t}$ is the incremental fuel cost in \$/MWh of Market Participant p to move from $Q1$ to $Q2$ MWh output in Dispatch Interval t.

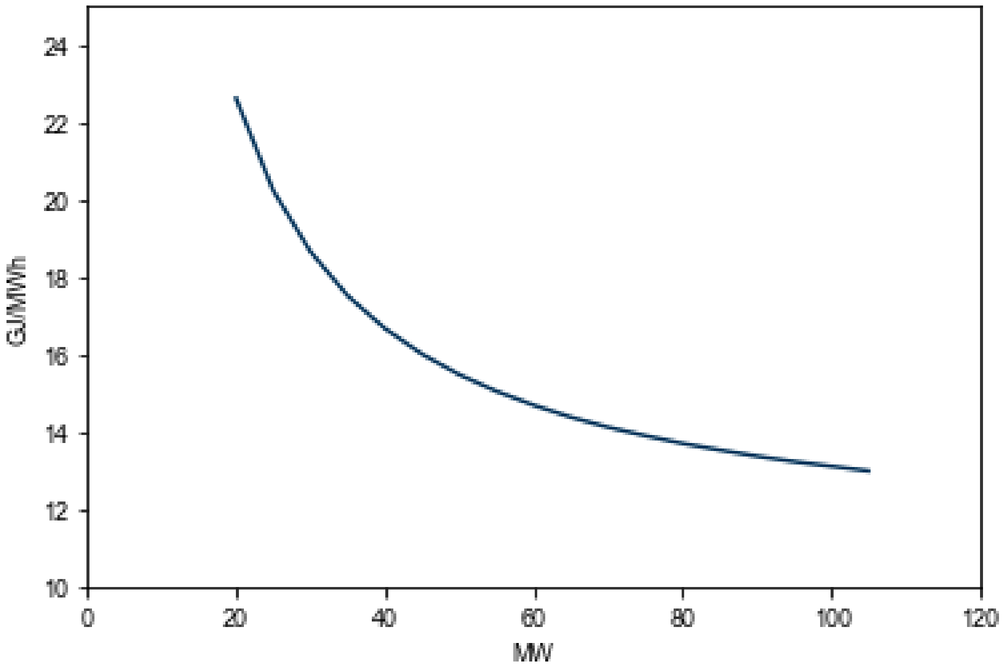
$Q1_t \, (q1_t \, MW \times \frac{5}{60})$ is the lower level of electricity generation in MWh from Market Participant p in Dispatch Interval t.

$Q2_t \, (q2_t \, MW \times \frac{5}{60})$ is the higher level of electricity generation in MWh from Market Participant p in Dispatch Interval t.

If a Market Participant's IFC increases as it increases production then its fuel costs can be converted to form part of a series of Price-Quantity Pairs that increase in price as it is required to produce more electricity, as shown in Figure 11~~Figure 1~~.

However, constructing Price-Quantity Pair offers with monotonically increasing prices is not straightforward for thermal generators as many become more fuel efficient as production increases. Figure 22~~Figure 2~~ shows that more energy is required (GJ/MWh) to produce lower levels of electricity generation (MW) than at higher levels of electricity generation.

Figure 22~~2~~. Stylised average heat rate chart for a thermal generator with increasing efficiency



An IFC curve based on such a heat rate curve cannot directly be transformed into a series of Price-Quantity Pairs that increase in price as production of electricity increases. A potential solution to this problem for a Market Participant is to use the AOC method for its Price-Quantity Pair offers by computing its average operating fuel cost (AOFC) to ensure the recovery of its EVCs.

A Market Participant's AOFC is its fuel cost of moving from zero production to some level of production.

Average operating fuel cost (Equation 77~~7~~)

$$IFC(\Delta Q, t) = \frac{(MFC(Q2, t) \times Q2(t) - 0)}{(Q2(t) - 0)} = MFC(Q2, t) = AOFC(Q2, t)$$

Where:

$AOFC(Q2, t)$is the average operating fuel cost in $/MWh of Market Participant p to produce $Q2 \times 12$ MW output in Dispatch Interval t.

Other variables are as previously defined in Equations 5 and 6.

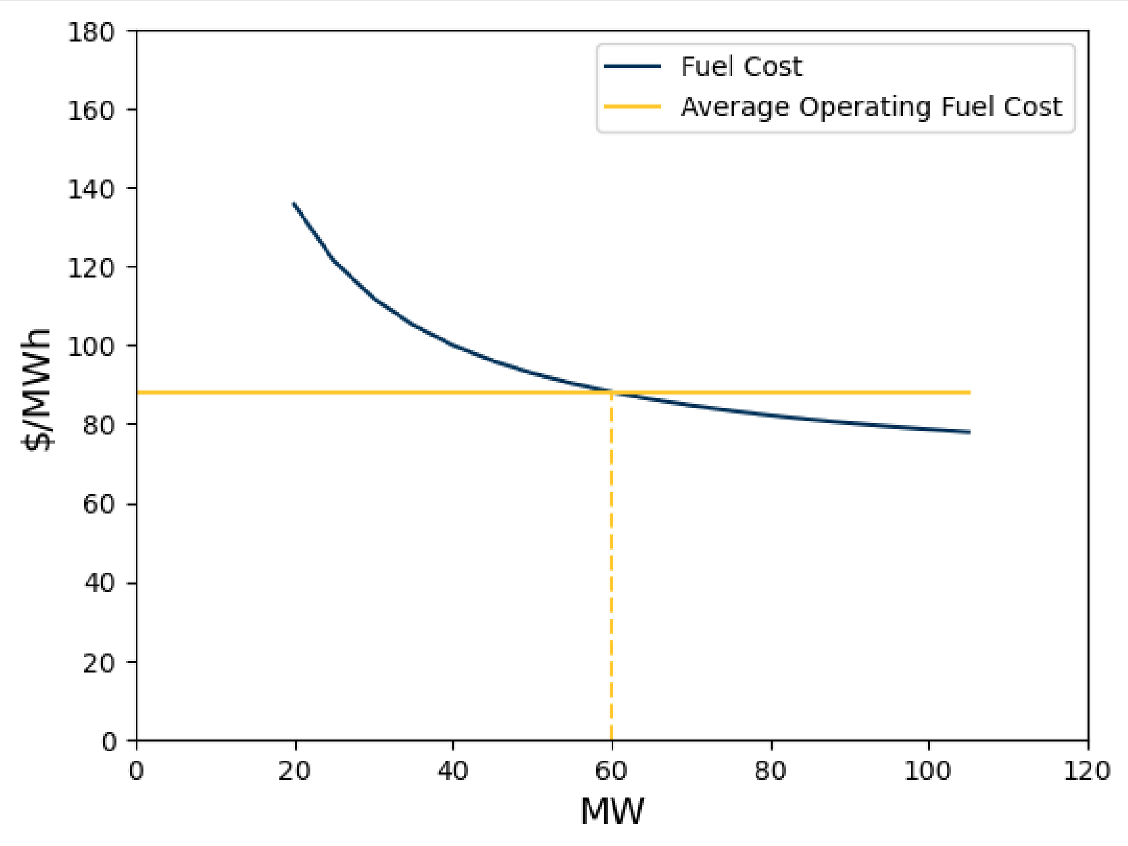
Example 1. Gas-fired generator fuel cost estimation

A gas-fired generator has an average heat rate curve as shown in Figure 11~~Figure 1~~2, with minimum stable generation of 20 MW and maximum output of 105 MW. It has a fuel-input cost of $6/GJ delivered from a gas supply contract, in which the payment for the use of gas varies in proportion to the actual consumption of gas.

The generator will run for 60 MW for a period of four hours and chooses to offer all its estimated production in a single price tranche.

The generator's fuel cost estimation is shown in Figure 33~~Figure 3~~.

Figure 33~~3~~. Estimation of Average Operating Cost of Fuel for a stylised fuel cost curve for a generator with increasing thermal efficiency.



This equals a fuel-cost of $88.14/MWh (at the output level of 60 MW), which is a fuel cost calculation consistent with that of an Economic Price Offer.

This requires the Market Participant to make a single price quantity pair offer of 105 MW priced at its EVC, that incorporates its AOFC of $88.14/MWh.

This Price-Quantity Pair offer is consistent with WEM Rule 2.16C.6A and would be an Economic Price Offer. It would not result in an Irregular Price Offer under WEM Rule 2.16C.6(c), or (d).

In reality, a thermal generator seeking to make such an offer will need to forecast its production and runtime, so its offer will be based on this forecast at the time of making the offer to the market. The implications from forecasting and uncertainty are covered in section 3.2.7.

3.2.1.2 Pre-transport fuel-input-cost

A thermal generator's fuel-input-cost is its per unit cost of fuel for electricity generation measured in $/GJ.

A generator's fuel-input-cost is made up of its pre-transport fuel-input-cost and a transport charge. This section provides guidance for thermal generators on how to calculate their pre-transport fuel-input-cost.

A Market Participant's fuel price is valued on an opportunity cost basis, which means that it is valued at the next best alternative that is sacrificed when a decision is made to use the fuel for electricity generation. This may be avoiding having to buy the fuel or the forgone opportunity to sell the fuel to other Market Participants or parties at the prevailing market price for gas.

An exception is a Market Participant's fuel procured under a LTTOP contract (WEM Rule 2.16D.1(a)(iii)).

If a generator has a variable quantity fuel contract – where it pays only when it uses the fuel and is not subject to any minimum purchase restriction or take-or-pay arrangement – its opportunity cost of fuel is the unit price paid for delivery of fuel under the contract, likely in $/GJ, unless the generator has an alternative use for the fuel of higher value than the contract price, in which case the fuel is valued at its alternate use.

Example 2. Opportunity cost of fuel – variable quantity contract in-the-money

A generator has a long-term variable quantity gas contract from which it can purchase gas for $5/GJ pre-transport, but the Western Australian gas market has tightened since it signed the contract, and it can on-sell its gas to another user for $7/GJ.[16]

In this case the contract is said to be in-the-money.

The generator includes a gas-input cost of $7/GJ in its offers for electricity generation because, within limits, it could on-sell its contracted gas for $7/GJ rather than burning it for electricity.

A price offer based on a gas-input price of $7/GJ is consistent with WEM Rule 2.16C.6A and would be an Economic Price Offer. It would not result in an Irregular Price Offer under WEM Rules 2.16C.6(c) and (d).

A Market Participant that has a variable quantity gas contract will include in its price offers a fuel-input-cost equal to the market price of gas, if the prevailing market price of gas was below the unit fuel price payable in its contract. This is demonstrated in Example 3 (Opportunity cost of fuel – variable quantity contract out-of-the-money~~Opportunity cost of fuel – variable quantity contract out-of-the-money~~).

[16] The term gas market refers to all trades in spot markets and bespoke contracts in Western Australia.

Example 3. Opportunity cost of fuel – variable quantity contract out-of-the-money

A generator has a long-term variable quantity gas contract for $5/GJ pre-transport, but the Western Australian gas market price has fallen to $3/GJ. The generator can source lower-cost gas from the market in the quantities it needs in time for dispatch.

In this case the contract is said to be out-of-the-money.

The generator includes a fuel price of $5/GJ on the basis that this is its contracted price. However, it could choose not to call on its contracted gas and buy from the market.

An offer based on a gas-input price of $5/GJ is not consistent with an Economic Price Offer (WEM Rule 2.16C.6A) and would result in an Irregular Price Offer under WEM Rule 2.16C.6(c), or (d).

Under a take-or-pay contract for fuel, either long-term or short-term, a Market Participant must pay for a contracted fuel at the take-or-pay contract price, regardless of whether it uses the fuel or not. Therefore, it incurs no additional cost if it uses one more unit of fuel for the generation of electricity. [17]

For example, a Market Participant that enters a 20 TJ/day take-or-pay contract for a 365-day year at a take-or-pay contract price of $5/GJ must pay $36.5 million regardless of whether it uses zero TJ/day or 20 TJ/day. Its incremental cost of sourcing an additional GJ of gas up to the 20 TJ/day limit is $0/GJ.

If the Market Participant has the chance to sell the fuel to another user or a market on a commercial basis, then its opportunity cost of fuel is the price it can receive for that alternative use. This is the case whether the alternative price be less or more than the generator's take-or-pay contract price.

WEM Rule 2.16D.1(a)(iii) states that a Market Participant may recover the cost of a LTTOP fuel contract in its offers, which means a Market Participant's price-quantity offers are consistent with WEM Rule 2.16C.6A, if it has a LTTOP contract that is out-of-the-money and uses its LTTOP contract price as its fuel-input-cost.

[17] For example, in a take-or-pay contract for natural gas, the buyer agrees to either 'take' a certain quantity of gas from the seller or 'pay' a specified amount (typically expressed per unit of gas) even if they do not take the contracted quantity. This means that the buyer is obligated to pay for a minimum volume of gas, whether they actually consume that amount or not. The seller, in return, commits to providing the agreed-upon quantity of gas, regardless of whether the buyer takes it all.

Example 4. Long-term take-or-pay contract – In-the-money

A gas-fired generator has a LTTOP gas contract price of $5/GJ pre-transport, which has a contract take-or-pay quantity that exceeds its range of expected electricity production. The Western Australian market gas price has risen to $10/GJ and is liquid enough for the generator to sell all its contracted gas at the market price of $10/GJ.

The generator could sell its take-or-pay gas into the gas market for $10/GJ, so would be indifferent to whether it received this return in the gas market or use the gas for electricity generation and include a $10/GJ in its price offer for electricity generation.

The generator uses a fuel-input price of $10/GJ.

An offer based on a gas-input price of $10/GJ is consistent with WEM Rule 2.16C.6A and would be an Economic Price Offer. It is also consistent with WEM Rule 2.16D.1(a)(iii), even though it exceeds the cost of fuel incurred by the generator in purchasing fuel under its LTTOP fuel contract. It would not result in an Irregular Price Offer under WEM Rule 2.16C.6(c), or (d).

Given a choice, a profit-maximising Market Participant would use its opportunity cost of fuel as the fuel-input-cost of its LTTOP contract was in the money and the Market Participant could sell its fuel to other users for a higher price than its take-or-pay contract price. This is consistent with WEM Rules 2.16C.6A and 2.16D.1(a)(iii).

An example of where the market price has fallen below the contract price is in Example 5.

Example 5. Long-term take-or-pay contract – Out-of-the-money

A gas-fired generator has a LTTOP gas-input contract price of $5/GJ pre-transport, and with a quantity which exceeds its range of expected electricity production. The Western Australian market gas price has fallen to $3/GJ.

The generator could sell its take-or-pay gas into the gas market for $3/GJ, so would be indifferent to whether it received this return in the gas market or the electricity market.

The generator uses a fuel-input price of $5/GJ because it can pass this cost through into the electricity without the risk of a competitive response by other Market Participants.

An offer based on a gas-input price of $5/GJ is compliant with the WEM Rules given the allowance provided by WEM Rule 2.16D.1(a)(iii) as it recovers the exact cost of its LLTOP fuel contract in its offers. It would not result in an Irregular Price Offer under WEM Rules 2.16C.6(c) or (d).

The WEM Rules do not provide guidance on how long the term of a take-or-pay fuel contract must be to be considered long-term. In practice, long-term contracts for natural gas refer to contracts with multiple years. Several sources indicate that in recent years the term 'long-term' contract for natural gas is used to refer to contracts that have terms starting from one to two years.[18] For the purpose of this guideline, long-term contracts for fuel are deemed as contracts with a minimum term of one year.

Thermal generators' fuel arrangements are often complex, including the use of multiple contracts or arrangements. When forming a Price-Quantity Pair, a Market Participant can use its marginal (incremental) fuel-input price, or the highest fuel-input-cost that it expects to incur under its fuel purchase arrangements for the respective quantities (of fuel consumption) in that Price-Quantity Pair. However, this cost must be backed by prudent forecast of its expected fuel use.

[18] For example, refer to AER, 2023, *Gas markets in eastern Australia, State of the Energy Market 2022*, p. 121, (online).

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Contracts for the supply of fuel take various forms and use different terms and conditions. If Market Participants consider they require further guidance, the ERA can provide bespoke guidance to assist them to comply with the WEM Rules requirements.

Example 6. Fuel cost under multiple variable fuel contracts

A gas-generation Portfolio has a variable quantity gas contract, where it pays a fixed price for every unit of fuel used, of 5 PJ/day at $5/GJ undelivered and a further 5 PJ/day at a second such contract at $8/GJ undelivered. The market price for gas is also approximately $5/GJ.

A variable quantity fuel contract is one where a Market Participant pays only for the gas it uses and is not subject to any minimum purchase restriction or take-or-pay arrangement.

The Portfolio expects to use 4 PJ/day during a month, after which it will review its gas consumption forecasts. It bases its Price-Quantity Pair offers on the AOFC method.

The generator submits offers based on a fuel-input cost of $8/GJ undelivered, and claims that this is the marginal value of its expected daily gas use over the month in question.

However, this is higher than the marginal price for its expected daily gas use, which is $5/GJ undelivered, and the market gas price.

An offer based on the fuel-input cost of $8/GJ undelivered is not consistent with WEM Rule 2.16C.6A and would not be an Economic Price Offer. It would result in an Irregular Price Offer under WEM Rules 2.16C.6(c) or (d).

~~Market Participants may acquire fuel from several sources, with different price and quantities applicable to each source. Prices payable under a fuel supply arrangement may also vary with the consumption amount and timing of the use of the fuel.~~

Consistent with the approach explained in section 3.1 for estimating IEVC, the fuel cost included in the IEVC, is the incremental fuel cost incurred for the respective quantities in the Price-Quantity Pair. That is, the fuel cost included in a set of Price-Quantity Pairs varies with the fuel prices payable and quantities available from each fuel source.

For example, a Market Participant with LTTOP fuel contracts and non-LTTOP fuel contracts may use both sources over a particular period. However, the Market Participant must not average the prices payable under those fuel contracts for use as a single fuel cost for that period in a set of Price-Quantity Pairs.

If a Market Participant has a LTTOP fuel contract that is out-of-the-money, it may use the LTTOP contract price to form its offers (as if the unit fuel price applicable to the take-or-pay volumes is the incremental fuel cost) if the volume of fuel used over the relevant period remains below the LTTOP contract quantity (for example TJ/day, TJ/month or TJ/year).[19] Where, for a LTTOP contract quantity, constraints apply for different time periods (for example, when both daily and monthly off-take quantity constraints apply), the Market Participant may use the out-of-the-money contract price as long the volume of gas used remains below the quantity constraints applicable to that period.

A Market Participant may allocate fuel between generators and Dispatch Intervals flexibly within the constraints of its contracts. Once the Market Participant exceeds it LTTOP contract volume it must revert to its new cost of fuel (for example, the prevailing market price).

19 In principle, for take-or-pay volumes the incremental cost of using fuel for electricity generation is zero. However, given the exception in WEM Rule 2.16D.1(a)(iii) for LTTOP fuel contracts, this zero value can be substituted with the unit fuel price applicable to the take or pay volumes.

The allocation of costs across time and resources must also be compliant with the Trading Conduct Guidelines. For example, Market Participants must not use the method to manipulate market prices, which may be a breach of WEM Rule 2.16A.3.

When forming a view on the prevailing price of gas a Market Participant must consider the most appropriate way to estimate this price. When calculating its fuel input cost, the Market Participant may use the spot price as the market price and may use other information such as offer and purchase prices in bespoke contract negotiations.

3.2.1.3 Fuel transport

In Western Australia, fuel transport is often priced in terms of an access or capacity charge for the right to use infrastructure and then a volume-based commodity transport fee. For example, gas transport includes a capacity reservation charge for the right to use capacity of a gas pipeline and then a commodity charge for each unit of gas transported.[20]

Some Market Participants purchase gas transport (as well as the gas commodity) on short-term contracts that may have a low-capacity reservation charge but a higher commodity charge.[21] Market Participants may also procure transport capacity through spot arrangements for pipeline transport capacity. This is profit-maximising behaviour for a peaking generator that runs occasionally and cannot justify the commitment to enter long-term gas contracts that include a large capacity reservation charge.

Conversely, a generator that frequently produces a large amount of electricity from a fuel type, may find it profitable to enter a long-term fuel transport contract with a reservation and a commodity charge, or with a bundled price.

A Market Participant should use the opportunity cost of fuel transport service. A Market Participant can infer the opportunity cost of fuel transport service for each of its Facilities and their expected consumption levels based on the prevailing price of fuel transport in the spot market for fuel transport. This prevailing market price for the transport service may be above or below its contract price for fuel transport and can enable a Market Participant to recover all or some of its contracted capacity reservation charge.

Market Participants should base the cost of using stored fuel on the opportunity cost of using the stored fuel. In addition to the costs of physically storing fuel, a Market Participant must decide on its opportunity cost of stored fuel, or the price that the fuel is worth in the future. At this cost a Market Participant will be indifferent between using the fuel for electricity generation now or storing it for the future. This value must be derived using an industry accepted forecasting method that considers all factors relevant to the Western Australian market for that fuel.

3.2.2 Variable operating and maintenance

Variable operating and maintenance (VOM) includes any costs incurred in operating the facility of a Market Participant (other than fuel cost) and conducting maintenance work required to maintain the generating unit in an efficient and reliable condition. These costs must be incurred as the result of electricity production for the Real-Time Market for energy and increase as that production increases.

[20] For example, a T1 Service described in Economic Regulation Authority (2021), *Final decision on proposed revisions to the Dampier to Bunbury Natural Gas Pipeline access arrangement 2021 to 2025,* Submitted by DBNGP (WA) Transmission Pty Ltd, p.26 (online).

[21] Called a Peaking Service, Economic Regulation Authority (2021), Final decision on proposed revisions to the *Dampier to Bunbury Natural Gas Pipeline access arrangement 2021 to 2025,* Submitted by DBNGP (WA) Transmission Pty Ltd, paragraph 170, p.45 (online).

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Incremental VOM costs mainly comprise maintenance service, parts and labour expenses. Unless a Market Participant can pinpoint exact VOM costs for each level of output, its incremental VOM cost can be calculated on an average.

Incremental variable operating and maintenance (Equation 88~~8~~)

$$IVOM(t) = \frac{(OE + AM)}{\sum_{t=1}^{105,120} Q(t)}$$

Where:

$IVOM(t)$ is the incremental operating variable operating and maintenance costs in \$/MWh of Market Participant p in Dispatch Interval t;

OE is the annual operating expense of Market Participant p in \$ as a result of production.

AM is the annual maintenance expense of Market Participant p in \$.

$Q(t)$ is the electricity production in MWh of Market Participant p in Dispatch Interval t.

VOM may be bundled into annual contracts. However, to be included in offers, these costs must be variable with respect to electricity production. Market Participants must allocate maintenance costs to only one area (for example to either VOM or start-up) with no double counting.

Costs which must be borne by the facility regardless of whether the facility produces electricity or not, are fixed costs and may not be recovered in the Real-Time Market or the STEM.

Example 7. Variable operating and maintenance

A gas-fired generator has a \$3 million per annum labour cost, which must be incurred whether the generator operates or not, given the facility must be always staffed. It also incurs costs that vary with the generation of electricity comprising \$500,000 in annual water and lubricant costs and annual maintenance of \$1.5 million due to frequent generation, which it contracts to an external provider through an annual contract.

The generator expects to operate at an average of 25 MW for every Dispatch Interval of the next 365-day year, for a total of 219,000 MWh.

The generator submits Real-Time Market offers with its VOM equal to:

$$VOM(t) = \frac{(\$3\ million + \$500{,}000 + \$1.5\ million)}{219{,}000\ MWh} = \$22.83/MWh$$

However, this offer includes its fixed labour cost and is above its IVOM cost of \$9.13/MWh.

An offer from this generator containing \$22.83/MWh is inconsistent with an Economic Price Offer (WEM Rule 2.16C.6A) and would result in an Irregular Price Offer under WEM Rules 2.16C.6(c), or (d).

The generator may include any labour costs that vary with the production of electricity. Such costs include labour costs for conducting maintenance for the unit, where the maintenance service is driven by the frequency of plant start-ups or hours of operation. In this example, such costs might already be included in the \$1.5 million annual maintenance costs.

For example, the allocation of costs to variable and fixed components should reasonably reflect the underlying operating and maintenance costs due to operation of a generator before the bundling of those costs through maintenance contracts.

3.2.3 Other variable costs

3.2.3.1 Market fees

AEMO charges Market Participants a fee in $/MWh generation/discharge into the WEM to cover its own costs, as well as to cover the cost of services the ERA and the Coordinator deliver in relation to the WEM Rules (section 2.24). This is $1.8105/MWh in 2023/24 and is a valid inclusion in incremental energy costs. [22]

Fees may only be included in a Market Participant's Price-Quantity Pair offers where the fees are charged on a $/MWh basis. Fees that do not depend on the production of energy may not be included in offers.

3.2.3.2 Runway cost allocation for Contingency Reserve Raise

The costs of Contingency Reserve Raise in any interval are recovered in part from generators operating in that interval using a runway method described in Appendix 2A of the WEM Rules. These costs are a valid EVC to be included in price offers.

3.2.4 Avoidable fixed costs

Sections 3.2.4.1 to 3.2.4.4 explain different types of AFC that can be included in price offers.

3.2.4.1 Start-up costs

Start-up costs (SUC) for thermal generators are the costs of starting a generator from the point of non-operating (shut-down) to the point of being synchronized with the network to produce electricity. SUC are measured in $/start.

SUC include fuel costs required to bring the generator to an operating state to produce electricity. Additionally, frequent starting, stopping or operation of a registered facility can lead to physical depreciation of some parts necessitating their replacement within the useful life of the plant. These costs can be included in a facility's SUC if facility starts cause additional tear and wear. Example 8 and Example 9 present how these costs can be appropriately accounted for to prevent under or over recovery.

Start-up related depreciation and maintenance costs mainly comprise maintenance service, parts and labour expenses. They may be contracted maintenance services allocated across annual production, but the need for labour, parts replacement and servicing must be caused by the registered facility starting and stopping to produce electricity, for such costs to be included in a facility's SUC.

[22] Australian Energy Market Operator, June 2023, *Western Australia Wholesale Electricity Market 2023-24 AEMO Budget and Fees*, (online).

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Start-up costs (Equation 99~~9~~)

$$SUC = SUCF \times P + STARTMAINT$$

Where:

SUC is the start-up cost in $/Start of Market Participant p.

$SUCF$ is the fuel required to start the generator in GJ/start incurred by Market Participant p.

P is the fuel price as determined in 3.2.1 in $/GJ incurred by Market Participant p.

$STARTMAINT$ is additional maintenance in $/start required on the generator due to its number of start-up over and above the maintenance required if it did not operate.

A Market Participant may not be able to offer its entire start-up cost in its Price-Quantity Pair energy offers in the Dispatch Interval in which the Market Participant produces electricity after the start-up, as this cost may be above the Energy Offer Price Ceiling and, may be so high that the Market Participant would never be dispatched for that Dispatch Interval.

Amortised start-up costs (Equation 1010~~10~~)

$$\mathrm{ASUC(t)} = \frac{\mathrm{SUC}}{\sum_{\mathrm{t=1}}^{\mathrm{n}} \mathrm{Q(t)}}$$

Where:

$ASUC(\mathrm{t})$ is start-up costs in $/start incurred by Market Participant p in Dispatch Interval t, as amortised to $/MWh using expected electricity production in MWh by Market Participant p in Dispatch Intervals from 1 to n related to the start-up, where Dispatch Interval 1 is the first Dispatch Interval of electricity production cleared to dispatch after the start-up and n is the last Dispatch Interval of electricity production; and

$Q(t)$ is the electricity production in MWh of Market Participant p in Dispatch Interval t, where t ranges for the participant's period of operation from 1 to n.

To enable recovery of start-up costs, Market Participants may amortise start-up costs over the production of a generator after the start-up until it shuts down.

Example 8. Start-up cost amortisation – compliant offer

A Market Participant with a fast-start generator that can start within a Dispatch Interval, has a start-up cost of $5,000 and expects to run for 20 Trading Intervals (120 Dispatch Intervals) at 25 MW, producing 250 MWh of electricity.

The generator could allocate its start-up cost of $5,000/start across the 250 MWh it expects to produce once it is started. The generator would include $20/MWh for its start-up cost in its offers.

Incorporation of this amount into a Market Participant's Price-Quantity Pair offers is compliant with WEM Rule 2.16C.6A and would be an Economic Price Offer. It would not result in an Irregular Price Offer under WEM Rule 2.16C.6(c) or (d).

In practice, at the time of making an offer to the market the duration of a dispatch cycle is uncertain. Market Participants may use their forecast and historical dispatch data to form a reasonable expectation of the duration of a dispatch cycle.

Example 8 allocates a Market Participant's SUC evenly across the set of Dispatch Intervals over which it expects to run. A Market Participant may allocate its SUC in a different manner, for example to mitigate against the risk of under-recovery, by allocating a greater proportion of its SUC in the early Dispatch Intervals of a run-cycle and less in later Dispatch Intervals~~,~~ but only if it does not over-recover the SUC in its offers over a run cycle.

In addition, the allocation of costs across time and resources must comply with WEM Rule 2.16A.3, as described in the Trading Conduct Guideline.[23] For example, Market Participants must not prioritise recovering most of their SUC during the periods they can raise prices, if they have the opportunity to partly or fully recover those costs during periods they cannot influence market prices.

SUC may not include costs that have been allocated elsewhere, such as in enablement costs or VOM.

Example 9. Depreciation-related start-up costs – compliant offer

Consider a Market Participant with a gas-fired generator constructed in 2022/23 that has a useful life of 20 years, after which it is fully depreciated. The initial cost of this capital investment can be, but is not guaranteed to be, recovered through the WEM's capacity payment and inframarginal profits in the Real-Time Market.

It costs the facility $2,000/start in fuel to start the facility.

The generator's turbine rotor blades will last the full 20-year life of the remainder of the plant if the generator is started 4,000 times or less, or an average of 200 times per year.

However, the Market Participant estimates that the facility will be started 250 times per year, or 5,000 times over 20 years. This means the turbine rotor blades must be replaced after 16 years, leading to an additional capital cost of $5 million, or a present value of $2.29 million in 2022/23 dollars at a real (after inflation) discount rate of 5 per cent per annum.

The Market Participant decides to allocate the cost of the additional capital expenditure to the 5,000 starts over the life of the generator.

The Market Participant adds $735/start leading to a total of $2,735/start, plus an allowance for inflation to every start of the 20-year life of the plant.[24]

Incorporation of this amount into a Market Participant's Price-Quantity Pair offers is compliant with WEM Rule 2.16C.6A and would be an Economic Price Offer. It would not result in an Irregular Price Offer under WEM Rules 2.16C.6(c)~~,~~ ~~and~~or (d).

In allocating maintenance and depreciation costs, the additional parts-replacement and/or maintenance must be forecast to occur and lead to real expenditures in the future. Market Participants are advised to have a documented forecasting process to support its method and are advised to update the method as appropriate.

23 Economic Regulation Authority, 2024, Trading Conduct Guideline (online).

24 The present value of an annual cash flow equal to $735 × 250 over a 20-year period using a discount rate 0.05 yields $2.29 million.

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Example 10. Depreciation-related start-up costs – Non-compliant offer

The same generator in Example 9Error! Reference source not found. calculates start-up-related costs based on rotor replacement after 4,000 starts, which equates to $845.19/start for a planned recovery over the 16-year period. It adds this amount plus inflation indexation to its start-up cost for all 5,000 starts in its 20-year life.

This would constitute a compliant offer if the Market Participant added $845/start to its offers from starts 1 to 4,000, but then $0/start thereafter. Adding this amount to each start from start number 4,001 onwards represents an attempt at recovery of costs that are not incurred and so incorporation of this amount into a Market Participant's Price-Quantity Pair offers is not compliant with WEM Rule 2.16C.6A and would not be an Economic Price Offer. It would result in an Irregular Price Offer under WEM Rules 2.16C.6(c) ~~and~~or (d).

Expenditures that are not expected to occur before the end of the facility's life or expenditure for maintenance that would occur regardless of the facility's activity, are not valid components of start-up costs.

3.2.4.2 Shut-down costs

Shut-down costs (SDCs) are the costs incurred when a generator moves from producing electricity to a state of zero production.

These can include some labour, materials and fuel costs, as well as the cost of generating electricity during a generator's ramp down that is not fully compensated for by the real-time price.

Shut-down costs can be allocated across the Dispatch Intervals over which the generator has just operated.

Amortised shut-down costs (Equation 111~~11~~)

$$ASDC(t) = \frac{SDC}{\sum_{t=1}^{n} Q(t)}$$

Where:

$ASDC(t)$ is the SDC in $/MWh of Market Participant p, amortised over electricity produced during a series of Dispatch Intervals t, which ranges from 1 to n, where Dispatch Interval 1 is the first Dispatch Interval of electricity production cleared to dispatch and n is the last Dispatch Interval of electricity production, related to the shut-down.

$\mathrm{Q(t)}$ is electricity production in MWh of Market Participant p in half-hour Dispatch Interval t.

Shut-down costs may not include costs that have been allocated elsewhere, such as in enablement costs.

3.2.4.3 Avoided start-up-and shut-down costs

In its EVC, a Market Participant that is currently generating electricity may include costs it would avoid by continuing to produce electricity for the market. The most common example of avoided costs is avoided start-up costs where, to avoid switching off, baseload generators frequently offer minimum stable generation capacity at negative prices, with their subsequent capacity at their efficient cost, up to maximum stable generation.

Consider a baseload generator, which expects that its AOC based Price-Quantity Pair offers will not be cleared to dispatch during a series of Dispatch Intervals ranging from 1 to n.

Amortised avoided start-up cost (Equation 1212~~12~~)

$$AASUSDC(t) = \frac{SUC + SDC + \left(\sum_{t=1}^{n} R(t) - \sum_{t=1}^{n} AOC(t)\right)}{\sum_{t=1}^{n} \mathrm{Q(t)}}$$

Where:

$AASUSDC(t)$ is the avoided start-up cost $/MWh of Market Participant p amortised over electricity production in a series of Dispatch Intervals t, where t ranges from 1 to n, where Dispatch Interval 1 is the first Dispatch Interval where the Market Participant would not be cleared to dispatch and n is the last.

$R(t)$ is the Real-Time Market for energy revenue in $ earned by Market Participant p producing electricity in Dispatch Interval t.

$AOC(t)$ is the average operating cost incurred by Market Participant p to produce electricity in Dispatch Interval t.

SUC is the start-up-cost of Market Participant p.

SDC is the shut-down cost of Market Participant p and

$Q(t)$ is electricity produced in MWh of Market Participant p in Dispatch Interval t.

Example 11. Avoided costs for a coal-fired generator

A coal fired generator operates in the Real-Time Market for energy and has an ex-start-up AOC of $48/MWh across all of its capacity of 200 MW. Its start-up cost is $70,000/start to its minimum generation of 100 MW and it has no shut-down cost.

The generator has a minimum shut-down time of four-hours, meaning once it shuts down it must stay offline for four hours before being able to re-synchronise with the network.

It is producing electricity at a level above its minimum stable generation.

The generator forecast that over a four-hour period the market price will be $24/MWh, so the generator's operating loss (OL) would be

$$OL = (\$24 - \$48) * 400 = -\$9{,}600$$

The Generator has a choice to keep running and not incur any start-up costs. In this case, the Generator would make a loss of $24/MWh ($24/MWh in revenue minus $48/MWh in ex-start-up costs) or $9,600.

Alternatively, the Generator could shut down and start up again after 4 hours incurring a cost of $70,000.

Staying in operation at a loss would avoid the generator incurring its $70,000 re-start-up-cost. It would save $60,400 by staying in operation.

Amortising this amount ($60,400) across the 400MWh produced over the period yields an amortised avoided start-up and shut-down cost of $151/MWh.

$$AASUSDC(t) = \frac{-\$70{,}000 - (\$24/MWh - \$48/MWh) \times 400MWh}{400\ MWh} = -\$151/MWh$$

Table 22~~2~~. Example estimated coal-fired generator offer tranches

	0 to 100MW	100 to 200MW
Offer	*-$151/MWh*	*$48*

The generator's prudent offer strategy is then that shown in Table 22~~Table 2~~, where it offers the remainder of its production above 100 MW in a single offer at its ex-start-up AOC of $48/MWh. This series of Price-Quantity Pair offers is compliant with WEM Rule 2.16C.6A and would be an Economic Price Offer. It would not result in an Irregular Price Offer under WEM Rules 2.16C.6(c) ~~and~~or (d).

Market Participants may consider factors other than those presented in Example 11 where relevant to the calculation of avoided costs. ~~Section 5.20 covers the circumstances under which offers below cost are compliant.~~

3.2.4.4 Other avoidable fixed costs

Market Participants may incur additional AFC that occur when producing but do not vary with production. These are usually measured in $/hour. These can include some labour, materials and fuel costs. They may also include enablement costs which, where not included in shut-down or start-up costs, can occur while part of a generator's production is not cleared to dispatch and not compensated by the real-time-price, but necessary if it is ramping down from, or up to, a higher level of production.

AFCs costs should be allocated across a Market Participant's production in MWh of electricity in each hour of running.

Average Avoidable fixed costs (Equation 13~~13~~)

$$AAFC(t) = \frac{AFC(h)}{Q(h)}$$

Where:

$AAFC(t)$ is the Market Participant's average AFC in $/hour (amortised to $/MWh by electricity production in an hour h).

$Q(h)$ is the electricity production in MWh of Market Participant p at $Q \times 12$ MW in hour h.

Market Participants are advised to not include costs that have been allocated to other categories.

3.2.5 Other opportunity costs

A cost allowance for opportunity cost of electricity sales may be an EVC of producing electricity. This might be valid in cases where a Market Participant is limited in the amount of electricity it may produce due to an unexpected disruption to its fuel supply, so if it sells electricity into the current Dispatch Interval, it forgoes the opportunity to sell that electricity in other periods.

Example 12. Opportunity Cost for a fuel-limited thermal generator – Compliant offer

Under its fuel contract, a Market Participant with gas-fired generator usually makes an offer with a single Price-Quantity Pair based on its AOC of $75/MWh for its full capacity of 100 MW. However, its gas supplier experiences an outage, and the generator can only purchase enough gas in the spot market to produce for 2 hours per day at 100 MW and its AOC of $75/MWh.

If the generator forecasts that in a day the highest real-time-price will be $200/MWh for two hours between 5:00PM to 7:00PM, it is justified to use a $125/MWh opportunity cost (which is the difference between the forecast real-time price of $200/MWh and AOC of $75/MWh) in its Real-Time Market offers prior to 5:00 PM, for a total offer price of $200/MWh.

This is because, for the Market Participant to produce electricity at say 2:00 PM, it must receive at least $200/MWh or it is better off waiting until 5:00 PM.

The Market Participant's opportunity cost offer component and total Price-Quantity Pair offer are consistent with WEM Rule 2.16C.6A and would be an Economic Price Offer. It would not result in an Irregular Price Offer under WEM Rules 2.16C.6(c) ~~and,~~or (d).

Market Participants that operate Electric Storage Resources (ESRs), including batteries, may face such opportunity costs of the type explained in Example 12**Error! Reference source not found.**. Once charged, an ESR's charging costs are sunk and its costs to discharge energy at a Dispatch Interval would be the expected revenue foregone of not discharging during the highest priced period for Real-Time Market Services over the next charge/discharge cycle.

Example 13. Opportunity Cost for a fuel-limited thermal generator – Non-compliant offer

A Market Participant with a gas-fired generator usually makes an offer with a single Price-Quantity Pair based on its AOC of $75/MWh for its full capacity of 100 MW. It sources gas through spot market for gas or bilateral short-term contracts with other parties.

The generator forecasts that in the coming month the highest Real-Time Market price will be on average $200/MWh for two hours between 5:00PM to 7:00PM on weekdays.

The Market Participant chooses to source enough gas for operating two hours per day and claims that it has not been able to source gas given a gas supply shortage.

The Market Participant includes a $125/MWh opportunity cost (which is the difference between the forecast real-time price of $200/MWh and AOC of $75/MWh) in its Real-Time Market offers prior to 5:00 PM, for a total offer price of $200/MWh.

The Market Participant's opportunity cost offer component and total Price-Quantity Pair offer are inconsistent with an Economic Price Offer (WEM Rule 2.16C.6A) and would result in an Irregular Price Offer (WEM Rules 2.16C.6(c) or (d)). This is because there is no evidence for the shortage of gas in the market and the opportunity cost of using gas for electricity generation is already reflected in the prevailing market price of gas.

Section 4.6 shows that batteries have additional restrictions on when they can discharge, but Example 14 is only to demonstrate the inclusion of opportunity cost at a conceptual level. Other factors, such as round-trip efficiency, can influence the opportunity cost of discharging stored energy over a Dispatch Interval.

Example 14. Opportunity cost for a battery

A 100 MWh battery that can dispatch at 50MW for two hours, and, is able to charge fully at a cost of $10/MWh. It forecasts that the peak two-hour price during the next day is $200/MWh.

The battery's charging cost is now sunk and does not vary with the dispatch of energy in future Trading Intervals. However, if it discharges before the peak-price period for energy then it would miss out on revenue during the peak price Trading Intervals.

The battery is justified to use close to a $200/MWh opportunity cost in its Real-Time Market for energy offers.

The Market Participant's opportunity cost-based Price-Quantity Pair offer is consistent with WEM Rule 2.16C.6A and is an Economic Price Offer.

Market Participants with renewable energy facilities, such as wind and solar generators, receive LGCs for every MWh of electricity they produce. They can sell these LGCs to electricity retailers who are required to procure them. That means if the generator does not dispatch it forgoes the LGC and the spot value that it has. Therefore, the generator ~~will~~ could incorporate the negative value of a LGC in its offers.

Example 15. ~~Example 15.~~ Opportunity cost of lost Renewable Energy Certificate Sales

If an LGC is worth $40 per MWh generated, a wind-powered generator will include -$40/MWh in its Price-Quantity Pair offer, based on its full output of 60 MW, in addition to other costs.

If the Real-Time Market price for energy falls to -$30/MWh, the generator is still better off by $10/MWh by generating and receiving an LGC.

A Price-Quantity Pair of 60 MW at -$40/MWh is consistent with WEM Rule 2.16C.6A and would be an Economic Price Offer. It would not result in an Irregular Price Offer under WEM Rules 2.16C.6(c) or~~, and~~ (d).

The LGC market is a market against which Market Participants may price the opportunity cost of not generating renewable electricity. A generator may place a greater value on this opportunity cost than the current LGC price is, for example, if it considers that the LGC price will rise in the future, and it is able to hold the LGC until the price rises.

This would imply an offer price lower than an LGC-based offer.

~~Alternatively, a renewable generator may have minimum contract commitments to deliver a certain amount of renewable electricity over a certain period. While electricity contract terms should not form part of a Market Participant's Real-Time Market Offers, such commitments may imply a higher value for renewable generation than implied by the LGC market and a lower Price-Quantity Pair offer than one based on the LGC market. Section 05.2 provide guidance on below-cost offers.~~

Possible contractual arrangements for generation of renewable electricity may influence supply or demand in the market for LGCs. As a result, the effect of such contractual arrangements on the value of LGCs is captured in the prevailing market price for an LGC.

3.2.6 Other costs

Costs that have not been covered elsewhere in this guideline may be included as EVCs, if Market Participants can justify that the cost is reasonably expected to occur and that the cost is related to the production of electricity by the facility in question.

This guideline does not provide an exhaustive list of costs, and it is the responsibility of the Market Participant to justify the inclusion of costs other than those identified in this guideline.

3.2.7 Accounting for uncertainty

Market Participants have to invariably account for uncertainty in forecasting the costs incurred over a dispatch cycle. Section 2.1.1 and example 16 below explains how a Market Participant will account for uncertainty.

Example 16. Gas-fired generator offer construction under uncertainty

A Market Participant gas-fired generator has an average heat-rate curve as shown in Figure 11~~Figure 1~~ with minimum stable generation of 20MW and maximum stable generation of 105 MW. It has a fuel-input cost of $6/GJ delivered from a variable quantity contract. For simplicity, this example assumes the generator has no other costs.

This generator expects to be dispatched between 7:00AM and 11:00AM on weekdays but does not know, if it is dispatched, what its production level will be.

The generator forecasts that, over the next month, it will be dispatched for 50 MW for the four-hour period at a cost of $92.89/MWh. It submits a single Price-Quantity Pair offer of 105 MW at $92.89/MWh.

No Market Participant can forecast perfectly, but if its forecast is unbiased it may produce at 60 MW with a lower AOC in some Dispatch Intervals and 40 MW with a higher AOC in others, for no net gain or loss.

However, during its first month of operation after its forecast, it produces electricity at an average of 60 MW on weekdays between 7:00 AM and 11:00 AM at a cost of $88.14/MWh. This means that, if it were the marginal facility, the Market Participant over-recovered $22,848 from the market (four hours over 20 days at 60 MW multiplied by the offer price difference).

A generator cannot forecast perfectly, so a short period of Price-Quantity Pair offers of 105 MW at $92.89 is not inconsistent with WEM Rule 2.16C.6A. However, a Market Participant will review its offers regularly and would quickly correct a persistent over or under-recovery of its costs.

The Market Participant's Price-Quantity Pair offer of 105 MW at $92.89/MWh, after a period of operation, may be inconsistent with WEM Rule 2.16C.6A and may not constitute an Economic Price Offer and could result in an Irregular Price Offer under WEM Rules 2.16C.6(c)~~,~~ or~~and~~ (d) if there is a persistent over-recovery of costs due to its offers.

4. Real-Time Market Submissions for energy

This chapter outlines how the ERA will consider cost components when assessing compliance with the price offer obligations for Real-Time Market Submissions for energy.

Costs that may not be included in submissions are fixed costs that the facility incurs regardless of the electricity produced. Market Participants may not include costs which have been accounted for (or will be accounted for) elsewhere, for example, through the Reserve Capacity Mechanism.

4.1 Gas-fired generator

The efficient costs incurred by a gas-fired generator, which can be incorporated into its Price-Quantity Pair offers, are shown in Table 33~~Table 3~~.

These costs include those related to fuel, variable operating and maintenance, market fees, AFC, start-up costs and shut-down costs. Avoided start-up and shut-down costs may be incurred by gas-fired generators have not been common but may become more frequent as the market evolves.

Table 33~~3~~. Gas-fired generator costs

Cost	Description
Incremental / Average operating energy costs	
Fuel costs	Equal to Heat Rate (AHR, GJ/MWh) * Transport Inclusive Fuel Price ($/GJ). This may be IFC or AOFC depending on the heat rate curve of the individual generator.
Variable operating and maintenance (VOM)	VOM in $/MWh.
Other Variable Costs	Market Fees in $/MWh
Avoidable fixed costs	
Avoidable fixed costs (non-start-up and shut- down costs)	AFC in $/hr, amortised to $/MWh based on estimated production.
Start-up costs (SUC)	SUC in $/start, amortised to $/MWh based on estimated production and runtime.
Shut-down costs (SDC)	SDC in $/start, amortised to $/MWh based on estimated production and runtime.
Enablement costs	Costs in $/enablement or disablement, amortised to $/MWh by electricity generation cleared to dispatch associated with the loss.
Other opportunity costs	
Opportunity cost related to production-based subsidy	Not applicable for a gas-fired generator.
Opportunity costs of dispatch in different trading/Dispatch Intervals	Not applicable for a gas-fired generator unless a gas production shortage leads to not enough gas flowing from the generator's suppliers to generate as it would like.

Cost	Description
Other costs	
Other Costs	Other costs as appropriate.

Example 17Error! Reference source not found. provides an ex-post calculation of the efficient cost for a four-hour run cycle of a gas-fired peaking generator.

Example 17. Gas-fired generator AOC calculation

A hypothetical 120 MW gas-fired peaking generator with:

- a $2,000 start-up cost, no shut-down cost
- an average heat rate of 15 GJ/MWh at 100MW, a fuel price of $5/GJ
- VOM of $5/MWh
- AFCs of $20/hour.

Initially the generator is not running and so must be started to generate. If this generator is dispatched for four hours at 100MW, for a total of 400MWh, then its ex- post efficient cost is shown below.

Table 444. Average variable cost for hypothetical gas-fired peaking generator

Cost category	Calculation	Value
Start-up cost	$2,000/start / 400MWh	$5/MWh
Fuel cost	15 GJ/MWh * $5/GJ	$75/MWh
VOM (incl water)	-	$5/MWh
AFCs	$20/hour / 100MW/h	$0.20/MWh
AOC	-	$85.20/MWh

By choosing to make the series of offers over four hours, the generator incurs an additional $85.20 for each of the 400MWh which it produces. This is its efficient cost, and it equates to a total cost of $34,080 relative to the scenario in which it did not make the offers.

This requires the Market Participant to make a single Price-Quantity Pair offer of 120 MW lat its AOC of $85.20.

This offer is consistent with WEM Rule 2.16C.6A and would be an Economic Price Offer. It would not result in an Irregular Price Offer under WEM Rules 2.16C.6(c) or ~~and,~~(d).

4.2 Coal-fired generator

The efficient costs incurred by a coal-fired generator, which can be incorporated into its Price-Quantity Pair offers, are shown in Table 55~~Table 5~~.

These costs include fuel costs, VOM, market fees, AFCs and avoided start-up and shut-down costs. Start-up and shut-down costs are incurred by coal-fired generators. However, when such generators run for very long periods, these costs become insignificant when allocated across each dispatch cycle.

Table 55~~5~~. Coal-fired generator costs

Cost	Description
Incremental / Average operating energy costs	
Fuel costs	Equal to Heat Rate (AHR, GJ/MWh) * Transport Inclusive Fuel Price ($/GJ). This may be IFC or AOFC depending on the heat rate curve of the individual generator.
Variable operating and maintenance (VOM)	VOM in $/MWh.
Other Variable Costs	Market Fees in $/MWh.
Avoidable fixed costs	
Avoidable fixed costs (non-start-up and shut-down costs)	AFC in $/hr, amortised to $/MWh based on estimated production.
Start-up costs (SUC)	SUC in $/start, amortised to $/MWh based on estimated production and runtime.
Shut-down costs (SDC)	SDC in $/start, amortised to $/MWh based on estimated production and runtime.
Enablement costs	Costs in $/enablement or disablement, amortised to $/MWh by cleared to dispatch electricity generation associated with the loss.
Other opportunity costs	
Opportunity cost related to production-based subsidy	Not applicable for a coal-fired generator.
Opportunity costs of dispatch in different trading/Dispatch Intervals	Not applicable for a coal-fired generator unless a fuel production shortage leads to not enough coal flowing from the generator's suppliers to generate as it would like.
Other costs	
Other Costs	Other costs as appropriate

In its efficient cost, a coal-fired generator may consider including any cost it would avoid by offering to the market. The most common example of avoided costs is avoided start-up costs where, to avoid switching off, baseload generators frequently offer minimum stable generation capacity at negative prices, with their subsequent capacity at their efficient cost, up to maximum stable generation.

An example of a complaint Price-Quantity Pair offer for a coal-fired generator is given in Example 11**Error! Reference source not found.**.

4.3 Diesel-fired generator

The efficient costs incurred by a diesel-fired generator, which can be incorporated into its Price-Quantity Pair offers, are shown in Table 66~~Table 6~~. These costs include fuel costs, VOM, market fees, AFCs, start-up costs and shut-down costs.

Table 66~~6~~. Diesel-fired generator costs

Cost	Description
Incremental / Average operating energy costs	
Fuel costs	Equal to Average Heat Rate (AHR, GJ/MWh) * Transport Inclusive Fuel Price ($/GJ). This may be IFC or AOFC depending on the heat rate curve of the individual generator.
Variable operating and maintenance (VOM)	VOM in $/MWh.
Other Variable Costs	Market Fees in $/MWh.
Avoidable fixed costs	
Avoidable fixed costs (non-start-up and shut- down costs)	AFC in $/hr, amortised to $/MWh based on estimated production.
Start-up costs (SUC)	SUC in $/start, amortised to $/MWh based on estimated production and runtime.
Shut-down costs (SDC)	SDC in $/start, amortised to $/MWh based on estimated production and runtime.
Enablement costs	Costs in $/enablement or disablement, amortised to $/MWh by cleared to dispatch electricity generation associated with the loss.
Other opportunity costs	
Opportunity cost related to production-based subsidy	Not applicable for a diesel-fired generator.
Opportunity costs of dispatch in different trading/Dispatch Intervals	Not applicable for a diesel-fired generator unless a gas production shortage leads to not enough diesel flowing from the generator's suppliers to generate as it would like.
Other costs	
Other costs	Other costs as appropriate

4.4 Wind and solar generators

Renewable wind and solar generators usually have close to zero generation costs but may incur some VOM costs. However, their EVCs include the opportunity cost of not receiving a LGC should it not generate electricity. This is shown in Table 77~~Table 7~~.

Table 77~~7~~. Renewable generator costs

Cost	Description
Incremental/Average operating energy costs	
Fuel costs	Not applicable for a wind or solar generator.
Variable operating and maintenance (VOM)	VOM in $/MWh to the extent that running the facility causes wear and tear requiring maintenance.
Other Variable Costs	Market Fees in $/MWh.
Avoidable fixed costs	
Avoidable fixed costs (non-start-up and shut-down costs)	Not applicable for a wind or solar generator.
Start-up costs (SUC)	Not applicable for a wind or solar generator.
Shut-down costs (SDC)	Not applicable for a wind or solar generator.
Enablement costs	Not applicable for a wind or solar generator.
Other opportunity costs	
Opportunity cost related to production-based subsidy	Applicable for a wind or solar generator. For example, the opportunity cost of LGC.
Opportunity costs of dispatch in different trading/Dispatch Intervals	Not applicable for a wind or solar generator.
Other costs	
Other Costs	Other costs as appropriate

Wind and solar generators have an opportunity cost related to a production-based subsidy because they are eligible for renewable LGCs from the Australian Government Clean Energy Regulator when they generate, which, for example, had a value of $46.75/MWh for renewable energy generated in Q1 2024.[25]

VOM costs allocated for wind and solar generators should be related to the generation of electricity. These costs must be verified by expert reports or by manufacturer specifications.

While these generators can only produce electricity when their resource is available, if they do not produce when they could, either because their offers were not price competitive in the Real-Time Market or they choose to be on outage, they would forego the $46.75/MWh LGC for their potential electricity production.

25 See the Clean Energy Regulator, *Large scale generation certificates $46.75 in Q1 2024* (online)

Field Code

Example 18. Wind-powered generator offer formation

A 200MW windfarm incurs VOM costs of $4/MWh.

Table 88~~8~~. Example estimated wind-powered generator offer tranches

Component	Calculation
VOM cost	$4/MWh
LGC opportunity cost	-$52/MWh
Total offer	**-$48/MWh**

If LGCs are trading at $52/MWh. The generator is eligible for one LGC for every MWh of electricity that it generates, so it will forgo $52/MWh for each LGC not received if the wind is blowing and it could produce electricity but is not dispatched by the market.

Therefore, the generators efficient cost offer is -$48/MWh.

This offer is compliant with WEM Rule 2.16C.6A and would be an Economic Price Offer. It would not result in an Irregular Price Offer under WEM Rules 2.16C.6(c) ~~and~~ or (d).

Consequently, an efficient cost-based offer for a renewable generator is the sum of its VOM costs and the opportunity cost of LGCs.

4.5 Electric storage resources

ESRs in the WEM will be restricted by the need for its certified capacity to be available for eight Electric Storage Resource Obligation Intervals, which are eight contiguous Trading Intervals (each Trading Interval consisting of six Dispatch Intervals) that will be specified by AEMO annually for each Trading Day of a reserve capacity year (WEM Rule 4.25.2E (a)).

Table 99~~9~~. Electric Storage Resource costs

Cost	Description
Incremental / Average Operating Energy Costs	
Fuel costs	Not applicable for an ESR.
Variable operating and maintenance (VOM)	VOM in $/MWh to the extent that running the facility causes wear and tear requiring maintenance.
Other Variable Costs	Market Fees in $/MWh.
Avoidable fixed costs	
Avoidable fixed costs (non-start-up and shut-down costs)[15]	Not applicable for an ESR.
Start-up costs (SUC)	Not applicable for an ESR.
Shut-down costs (SDC)	Not applicable for an ESR.
Enablement costs	Not applicable for an ESR.
Round-trip LGC losses.	Allowable and amortised to a $/MWh basis.
Other opportunity Costs	
Opportunity cost related to production-based subsidy	Not applicable for an ESR.

Cost	Description
Opportunity costs of charging (including cycling costs) and dispatch in different Dispatch Intervals	Allowable subject to Electric Storage Resource Obligation Intervals restrictions.
Other Costs	
Other Costs	Other costs as appropriate

ESRs – for example, lithium-ion batteries – incur cycling costs as they charge and discharge, causing the storage cells to degrade and making them less effective in total charging capability, eventually requiring cell replacement. This degradation cost is an incremental cost related to the production of electricity, and therefore, can be included in the formation of price offers.

4.6 Stand-alone battery – Real-Time Market

ESRs have incentives to charge and conserve electricity prior to the Electric Storage Resource Obligation Intervals period otherwise they will be liable for capacity refunds if they cannot meet the reserve capacity obligations. This could include offering very high prices up to the energy offer price ceiling, prior to Electric Storage Resource Obligation Intervals period.

Inside of the Electric Storage Resource Obligation Intervals period, an ESR's optimal pricing strategy will be a combination of:

- An offer, perhaps at close to the energy offer price ceiling preserving some charged capacity to meet its capacity obligations later in the Electric Storage Resource Obligation Intervals.
- An opportunity cost offer, where the opportunity cost is the next best alternative return from discharging that energy in other Dispatch Intervals or for providing other Market Services.

An ESR could, if it were a price taker, forecast prices during a day's Electric Storage Resource Obligation Intervals period and construct its opportunity cost accordingly.

ESRs are free to make forecasts of the Real-Time Market prices, but like the efficient cost of thermal generators, an ESR must be able to demonstrate that its method complies with WEM Rule 2.16C.6A.

Example 19. Electric storage resource offers – Electric Storage Resource Obligation Intervals

Consider a 20MWh ESR, which could discharge its full 20MWh in one 30-minute Trading Interval. The generator has certified capacity credits of 5MW.

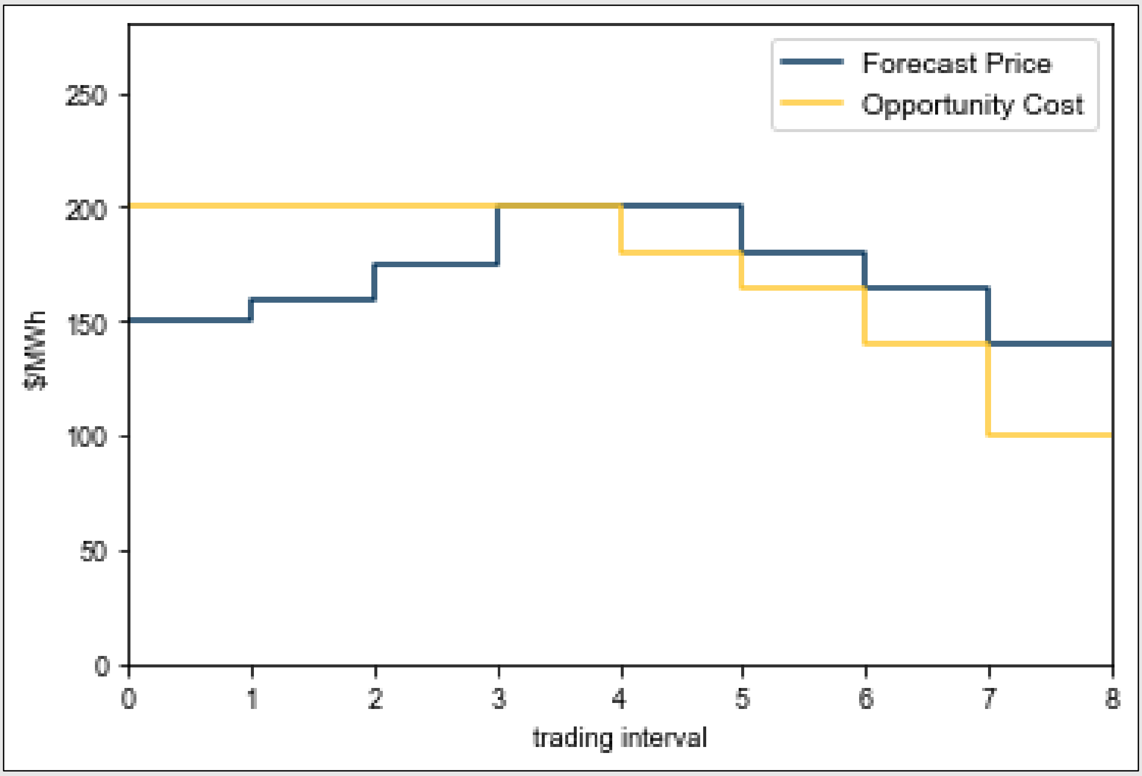
The ESR must have at least 5MW (2.5MWh) available in every Electric Storage Resource Obligation Interval~~Trading Interval~~, although it does not have to be dispatched for that amount in each of those and can defer discharge if higher-priced Trading Intervals are forecast to occur in later intervals.

It forecasts real-time prices, as shown in Figure 44~~Figure 4~~. The ESR faces a $200/MWh opportunity cost if it could discharge in the Dispatch Intervals of a future Trading Interval for $200/MWh. This occurs in the first three Trading Intervals in the day's Electric Storage Resource Obligation Intervals.

It estimates that it can recharge for $0/MWh after the Electric Storage Resource Obligation Intervals finish.

It fulfills its Electric Storage Resource Obligation Intervals obligations by being available for 5MW in the first three Trading Intervals, but prices itself so that it is not dispatched until the highest price trading intervals. This ensures the ESR's capacity is available for the entire Electric Storage Resource Obligation Intervals period but can discharge when electricity is most valuable if it is not discharged in the early Trading Intervals.

Figure 444. Example ESR Real-Time Market offer prices during Electric Storage Resource Obligation Intervals



Source: ERA calculations

Once the price peak for the day's Electric Storage Resource Obligation Intervals has been reached and prices begin to decline, the ESR's opportunity cost becomes the next highest price in the future.

The ESR submits a series of 5 MW Price-Quantity Pair offers, plus any amount of undischarged electricity not needed to meet its Electric Storage Resource Obligation Intervals obligations, at the opportunity cost shown in Figure 44~~Figure 4~~.

This is a simplified example and does not include, for example, the opportunity cost to offer into the FCESS markets, which may be a large part of the revenue for batteries. This series of Price-Quantity Pair offers is compliant with WEM Rule 2.16C.6A and would be an Economic Price Offer. It would not result in an Irregular Price Offer under WEM Rules 2.16C.6(c) ~~and~~ or (d).

Another simple method may be for ESRs to base their efficient cost and hence offer price on their cleared offers from previous trading intervals. For example, the ESR could base its opportunity cost offers during each upcoming Electric Storage Resource Obligation Intervals no higher than the lower of the median or mean of accepted competitive offers for the previous 90 days in similar periods and load levels.

4.7 Co-located and hybrid ESRs

Recently multiple technology systems have entered electricity markets around the world. These include:

- Co-located resources – a battery co-located with another technology, operating separately behind one limited connection point.
- Hybrid resources – a battery co-located with another technology, operating as one unit behind the one connection point.

The development of electric storage participation models in some jurisdictions provides a starting point for understanding the physical and operational characteristics of ESR, however little history is available to tell how ESRs co-located with generation resources will operate in electricity markets.[26]

Identifying the difference between anti-competitive physical withholding and co-optimising the joint operation of the two facilities will be difficult for the ERA. The ERA will monitor these resources for behaviour by a Market Participant that is inconsistent with efficient market outcomes (as required by WEM Rule 2.16C.5).

The ERA anticipates developing specific measures if required as co-located and hybrid ESRs resources become more common.

4.8 Other facilities

This guideline does not cover every possible type of electricity generation or facility. Market Participants that believe their situation is not captured in this guideline are advised to offer into the market based on their EVC of producing electricity or the respective Market Service. The ERA can update this guideline in response to requests from Market Participants and new information about constructing offers.

[26] Economic Regulation Authority, July 2022, *Triennial review of the effectiveness of the Wholesale Electricity Market 2022 – Discussion Paper,* Appendix 6: Cross jurisdictional review – Battery storage participation. (online).

5. Real-Time-Market Submissions for FCESS

This section provides guidance on offer construction for Market Participants intending to provide FCESS.

Dispatch in the Real-Time Market, including dispatched energy and essential systems services, are now co-optimised, meaning that prices and quantities are chosen simultaneously to minimise the total cost of providing energy and FCESS.

Where the Market Participant needs to dispatch or discharge at a lower level than their Real-Time Market Submission for energy would indicate, the method of calculating the FCESS market price is expected to compensate the participant for the foregone production in the energy market, allowing the Market Participant to remain commercially indifferent between energy or FCESS dispatch.[27]

FCESS Uplift Payments are made to Market Participants when a generator is required to provide FCESS and not energy, and market-price based compensation does not cover costs (WEM Rule 9.10.3A).

[27] See Energy Policy WA, 1 December 2019, *Essential System Services - Scheduling and Dispatch* (online).

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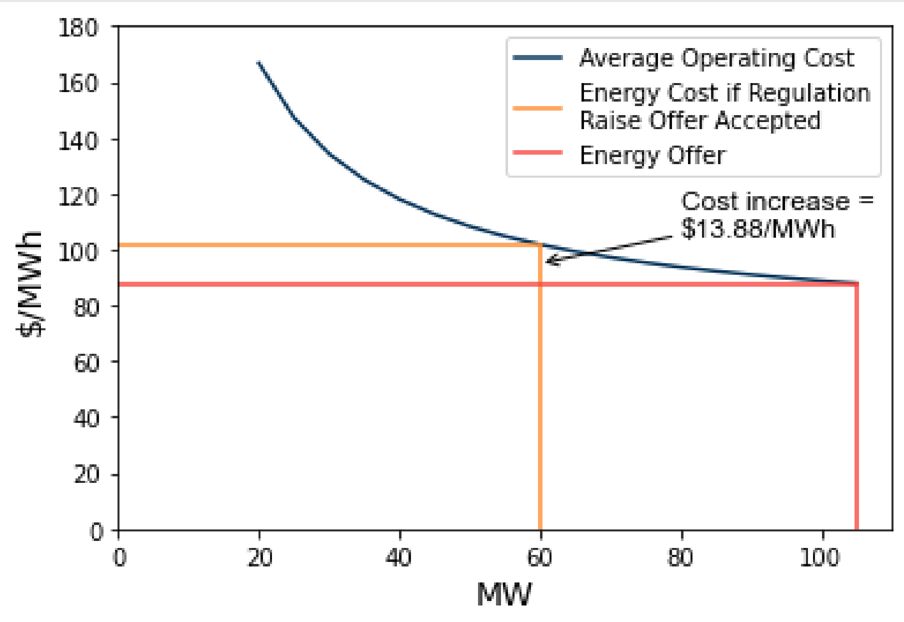
Example 20. Contingency Reserve Raise FCESS market offer calculation

A hypothetical Market Participant with a gas-fired peaking generator has the following costs and characteristics:

- a $2,000 start-up cost, no shut-down cost
- an average heat rate of 12.99 GJ/MWh at 105 MW
- a fuel price of $6/GJ
- VOM of $5/MWh
- AFCs of $20/hour.

Initially the Market Participant is not running and so must be started to generate. This generator is expected to be dispatched for four hours at its maximum generation of 105 MW, for a total of 420MWh. Its efficient single Price-Quantity Pair AOC-based offer is 105 MW production at $87.91/MWh is shown in red in Figure 55~~Figure 5~~.

Figure 55~~5~~. Increase in Fuel Costs for Real-Time Market for energy dispatch for a generator selected for Contingency Reserve Raise essential services



The Market Participant wants to offer 45 MW into the Contingency Reserve Raise market for these series of Dispatch Intervals. If cleared for 45 MW Contingency Reserve Raise, the generator's remaining 60 MW of production now costs $101.80/MWh to produce because of a higher average heat rate. This is an additional total cost per hour of $833.02 (for providing 60MW, which would clear in the Real-Time Market for energy), or $18.51/MW for each MW of Contingency Reserve Raise provided.

This increase in cost includes the effect of allocating its start-up cost to smaller generation in the Real-Time Market for energy dispatch.

The Market Participant calculates it will incur no additional maintenance cost for providing the Contingency Reserve Raise service.

The Market Participant submits a single Price-Quantity Pair offer in the Contingency Reserve Raise market of 45 MW at $18.51/MW. It justifies this on the basis that it incurs an additional $13.88/MWh to produce at 60 MW, if the offer is accepted, rather than 105 MW.

Alternatively, if the Market Participant is confident of being selected to provide Contingency Raise, it could recover all of its energy market costs in its Price-Quantity Pair offer

($101.80/MWh for 60 MW) and submit an offer of $0/MW for 45 MW of Contingency Raise service.

This Market Participant's offer is consistent with WEM Rule 2.16C.6A and would be an Economic Price Offer. It would not result in an Irregular Price Offer under WEM Rules 2.16C.6(c) ~~and~~or (d).[28]

[28] For emphasis, the inclusion of a cost component related to the degradation of efficiency in this example is plausible given the use of AOC approach for making offers to the Real-Time Market for energy. In practice, a Market Participant must consider whether its conversion method for producing monotonically increasing Price-Quantity Pairs in the Real-Time Market for energy provides for the recovery of its costs given its expected dispatch for the Contingency Reserve Raise market.

Example 21. Contingency Reserve Raise FCESS market offer calculation (enablement maximum less than maximum capacity)

A hypothetical Market Participant has the following characteristics:

- Maximum capacity of 105 MW.
- An enablement maximum for FCESS of 95 MW, due to technical limitations preventing it from providing FCESS at or near its maximum generation.
- Cost of production is independent of the level of production and constant at $100/MWh,

And the Market Participant expects the price in the Real-Time-Market for energy to be $150/MWh and the Contingency Reserve Raise price $50/MWh.

In this case if the Market Participant offers 105MW at $100/MWh into the energy market with no FCESS offer, the Market Participant expects to earn a profit of $50/MWh (or $5,250 per hour) in the energy market.

However, if the Market Participant makes an FCESS offer, it is constrained to be within its FCESS trapezium limited by its enablement maximum of 95 MW.

If the Market Participant offers 45 MW in the Contingency Reserve Raise market and the remaining 50 MW (95MW minus 45MW) is expected to be dispatched in the energy market, expected profit in the energy market would be $2,500 per hour (50MW times $50/MWh) and in the Contingency Raise market would be $2,250 per hour (45 MW times $50/MWh).

The Market Participant would lose out on expected profit of $500 ($5,250 minus $2,500 and $2,250) ~~when offering~~if dispatched in the Contingency Reserve Raise market, as compared to offering its entire capacity in the energy market. This is because of enablement maximum being lower than maximum capacity.

This foregone profit of $500 can be claimed from offering 45 MW at $11.11/MWh ($500 over 45 MW). In this case the price in the Contingency Reserve Raise market would need to rise to $61.11/MWh before the Market Participant was selected for this service and recoup its foregone expected profit. The Market Participant is expected to earn $2,750 per hour (approximately) in the Contingency Reserve Raise market and $2,500 per hour in the energy market making them indifferent between offering entire capacity in the energy market and offering 45 MW in the Contingency Reserve Raise market and being dispatched for remaining capacity in the energy market.

This offer is consistent with WEM Rule 2.16C.6A and would be an Economic Price Offer. It would not result in an Irregular Price Offer under WEM Rules 2.16C.6(c) ~~and~~or (d).

Example 22. Regulation Lower FCESS market offer calculation

The Market Participant in Example 20 wishes to participate in the Regulation Lower market for 20 MW during its four-hour estimated run-time.

It submits a Price-Quantity Pair into the Real-Time Market for energy of $87.91 for 105 MW, which is a competitive offer.

It estimates that it will incur additional maintenance costs from regularly ramping up and down in the Regulation Lower market, which it estimates at $2/MW per Dispatch Interval when amortised across its expected participation in this market.

It also expects that, based on experience when providing Regulation Lower (but not offsetting Regulation Raise) it is dispatched on average for 95 MW, at which its AOC of electricity generation is $89.86/MWh. The forgone revenue for the Market Participant from lowering its output when it is called to provide Regulation Lower is $184.80, or $9.24/MW per hour which can be spread over 20 MW Regulation Lower service.

Its offer for the Regulation Lower Market is $11.24/MW for 20 MW.

This Market Participant's offer is consistent with WEM Rule 2.16C.6A and would be an Economic Price Offer. It would not result in an Irregular Price Offer under WEM Rules 2.16C.6(c) ~~and~~or (d).

Consequently, a Market Participant wishing to be selected for FCESS markets only needs to enter its additional cost of providing the relevant FCESS service relative to dispatching or discharging at their preferred level in the Real-Time Market for energy. This additional cost could include:

- Higher fuel costs for generating at a lower efficiency than its Real-Time Market for energy offer.
- Additional maintenance from wear and tear from ramping and frequently starting and stopping if necessary.

However, the claimed degradation must be a genuine cost from the costs the generator would have produced if it were not selected for FCESS duties. If a generator forecasts that it has spare capacity in certain Dispatch Intervals, then it faces no additional cost to provide that capacity for certain FCESS services.

Where a plant is started to provide FCESS only, then the Market Participant may allocate that start-up cost to FCESS offers.

6. STEM submissions

The STEM is a financial market for Market Participants to trade around their bilateral positions rather than for energy dispatch in the Real-Time Market.

A Market Participant constructing an Economic Price Offer would offer their supply into the STEM in the Trading Interval based on the forecast opportunity cost of selling energy forward at the STEM and receiving STEM clearing price in place of receiving the clearing price at the Real-Time Market.

Example 23. Compliant STEM offer

A Market Participant has a Portfolio of a single 105 MW capacity gas-fired generator that expects one day ahead to make a single Price-Quantity Pair offer into the Real-Time Market for energy dispatch for 105 MW incorporating its AOC of $82.91/MWh.

It expects to make the same offer for six Dispatch Intervals (comprising one Trading Interval).

For the STEM Trading Interval corresponding to this Real-Time Market Trading Interval, the Market Participant expects the Real-Time Market for energy dispatch price to be $100/MWh.

The Market Participant has a long-term bilateral contract of 80 MW in the Trading Interval, so 25 MW of its expected generation capacity is not covered through any forward financial contract.

In the STEM, the Market Participant submits a single Price-Quantity Pair offer of 25 MW at $100/MWh, based on its expectation of the Real-Time Market for energy dispatch price.

This offer is compliant with WEM Rule 2.16C.6A and would be an Economic Price Offer. It would not result in an Irregular Price Offer under WEM Rules 2.16C.6(c) ~~and~~or (d).

To make compliant offers Market Participants must use forecasts of the next-day Real-Time-Market for energy price that are:

- Unbiased, when considered over a long period of time, leading to neither persistent gain nor loss.
- Based on a documented method or procedure which incorporates all available information including the Market Participant's reasonable expectation of costs included in its Price-Quantity Pair offers into the Real-Time Market for energy.

Example 24. Non-compliant STEM offer

The same Market Participant in Example 23 has a Portfolio of a single 105 MW capacity with a gas-fired generator that expects one day ahead to make a single Price-Quantity Pair offer into the Real-Time-Market for energy dispatch for 105 MW incorporating its AOC of $82.91/MWh.

It expects to make the same offer for six Dispatch Intervals within a Trading Interval.

For the STEM Trading Interval corresponding to this Real-Time Market for energy Trading Interval, the Market Participant expects the Real-Time Market for energy dispatch price to be $100/MWh.

The Market Participant has a long-term bilateral contract of 80 MW in the Trading Interval, so has 25 MW uncontracted capacity.

The Market Participant submits a Price-Quantity Pair offer of 10 MW at $100/MWh, based on its expectation of the Real-Time Market for energy dispatch price, and another of 15 MW at the Energy Offer Price Ceiling.

The Market Participant's offer strategy increases the STEM clearing price to $120/MWh. The Real-Time Market for energy is $100/MWh as expected and so in total the Market Participant receives an additional $20/MWh for 5 MWh (10 MW for 30 minutes) cleared in that Trading Interval over and above what it would have received if it had offered all 25 MW at its forecasted Real-Time Market for energy price.

The Price-Quantity Pair of 15 MW at the Maximum Energy Offer Price Ceiling is not compliant with WEM Rule 2.16C.6A and is inconsistent with an Economic Price Offer. It would result in an Irregular Price Offer under WEM Rule 2.16C.6(c) or (d).

7. Market outcomes

This section provides guidance on how inefficient market outcomes will be assessed. The ERA investigates and determines whether an Irregular Price Offer has resulted in an inefficient market outcome [WEM Rule 2.16C.7]. Likewise, the ERA will only take enforcement action for a breach of WEM Rule 2.16C.5 if the Irregular Price Offer resulted in an inefficient market outcome. If the Irregular Price Offer has not resulted in an inefficient market outcome, the ERA will notify the Market Participant about the result of the investigation and the reasons for its decision [WEM Rule 2.16E.2].[29]

WEM Rule 2.16C.9 states that:

In conducting an investigation under clause 2.16C.7, the ERA:

(a) Must consider any changes to:

i. A STEM Clearing Price or Reference Trading Price;

ii. Energy Uplift Payments; or

iii. The quantities of energy scheduled in respect of Market Participants in STEM Auction, or the dispatch of Facilities in the Real-Time Market,

That are likely to have occurred as a result of Irregular Price Offer; and

(b) may consider any other matters it considers relevant.

For these purposes, the ERA may use a model or other analytical tools. As an example, the ERA may apply the following steps for each Dispatch Interval when assessing if an Irregular Price Offer has resulted in inefficient market outcomes:

1. Take the inputs (including but not limited to energy dispatch and Price-Quantity Pair offers from each Market Participant) required to generate the actual market outcomes (dispatch and market prices).

2. Calculate Real-Time Market co-optimised energy and FCESS market prices and dispatch quantities for each Registered Facility, or STEM prices and quantities.

3. Remove the Irregular Price Offer(s).

4. In place of Irregular Price Offers, insert ERA-calculated EVC-based Price-Quantity Pair offers into the inputs required to generate an efficient market outcome.

5. Calculate efficient Real-Time Market co-optimised energy and FCESS market prices and dispatch quantities for each Registered Facility in the efficient dispatch order, or efficient STEM prices and quantities.

6. Compare the market prices and dispatch quantities found under the efficient market outcomes with those found under the actual market outcomes.

An example of the ERA's process is demonstrated graphically for a simple four-generator market for energy in Example 25.

[29] The ERA's Monitoring Protocol WEM Procedure sets out how the ERA will monitor, investigate and enforce compliance. (online).

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Example 25. Market impact of economic withholding

Consider a Portfolio of two generators, called Generator 2 and Generator 3, in a simple four generator Real-Time Market for energy.

If the Portfolio offered at efficient cost, Generator 2 would make an offer of $80/MWh and Generator 3 of $90/MWh.

This Portfolio's EVC-based offer curve follows the offers of the two generators as if they were individual Market Participants. This is shown in the top chart below for a single Dispatch Interval where demand is 160 MW and the resulting ~~r~~Real-~~t~~Time Market price is $90/MWh as set by Generator 3's offer.

However, the Portfolio prices part of Generator 2's capacity out of the market by making an offer of $250/MWh, well above its efficient cost of $80/MWh.

The market calls upon the expensive Generator 4 to produce, which set the real-time price of $180/MWh,

Generator 3's $250/MWh offer is found to be an Irregular Price Offer. If Generator 3 were a stand-alone generator, then it would lose a profitable dispatch opportunity of $450 ($10/MWh times 90 MW times 30 minutes). A generator offering at efficient variable cost would not make such an offer.

Generator 2 has made an offer above its efficient cost of $90/MWh, which is not consistent with an Economic Price Offer [WEM Rule 2.16C.6A]. It would result in an Irregular Price Offer under WEM Rules 2.16C.6(c) ~~and~~or (d). Moreover, if it results in inefficient market outcomes, it would also be a breach of WEM Rule 2.16C.5.

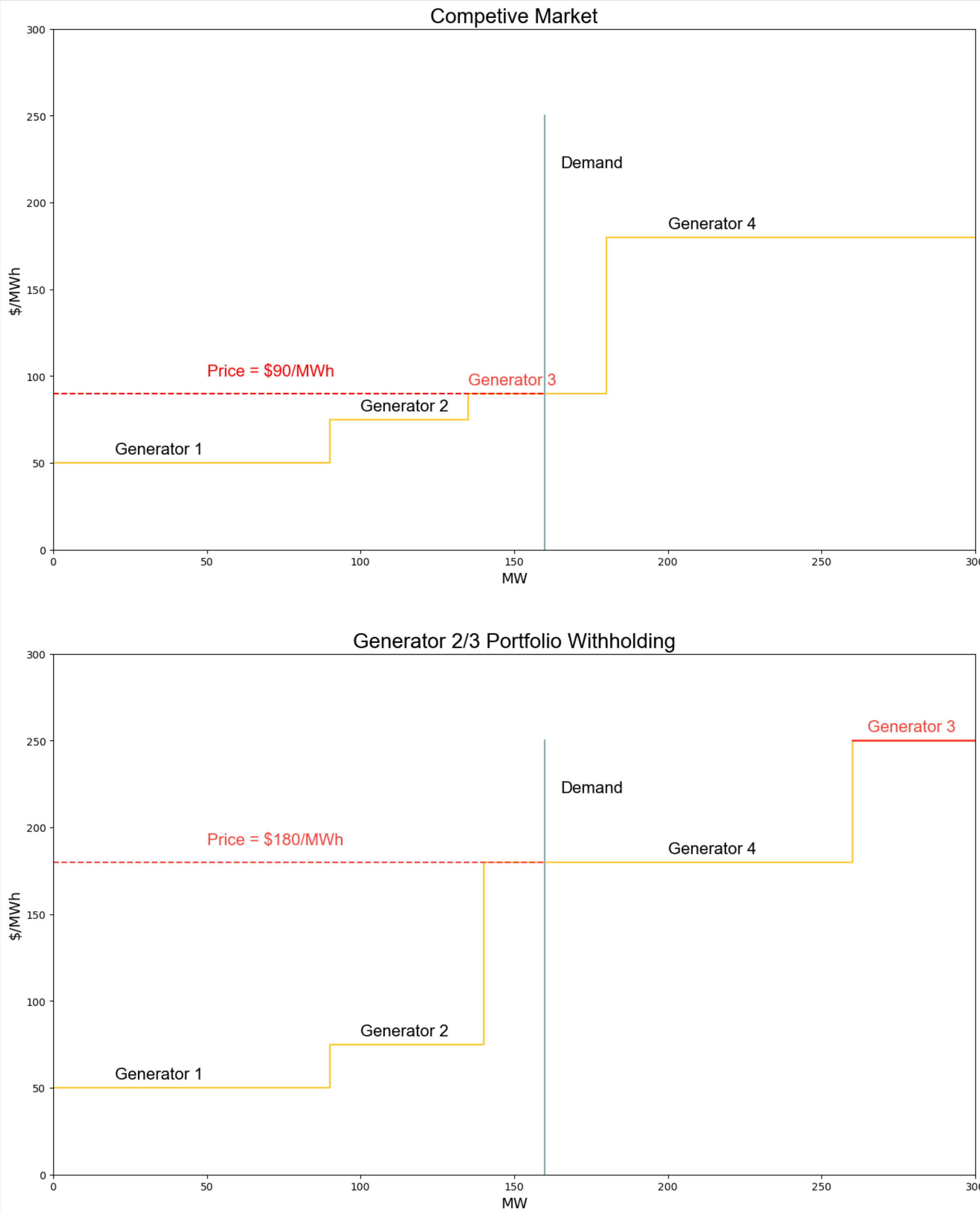
Comparing the market impacts of the Portfolio's pricing strategy, by examining the efficient dispatch order versus the order of actual dispatch, shows:

- The Real-Time Market price rises from $90/MWh to $180/MWh;
- The Real-Time Market no longer achieves lowest cost dispatch, with the last 20 MW produced by the high-cost Generator 4 rather than the lower cost Generator 2;
- There is a transfer of wealth from consumers to producers due to Generator 2/3's offer strategy, as consumers now pay a higher real-time price, meaning the price paid by consumers is not minimised.

The Irregular Price Offer of $250/MWh by Generator 3 has resulted in inefficient market outcomes.

In this example, regardless of whether Generator 3 is in a portfolio or not, Generator 3's offer (of a tranche, for example) at $250/MWh would not be an Economic Price Offer resulting in an Irregular Price Offer [WEM Rules 2.16C.6(c) or ~~and~~ (d)].

Figure 66~~6~~. Generator 3 economic withholding



Source: ERA calculations

8. Record keeping

All Market Participants making STEM and/or Real-Time Market Submissions are advised to maintain adequate records for their pricing behaviour and strategies to enable the ERA to conduct investigations, if necessary.

Market Participants are responsible for demonstrating reasonable grounds for the prices, quantities, or Ramp Rate Limits in Real-Time Market Submissions (WEM Rule 2.16A.8).

A Market Participant with a Registered Facility in a Material Portfolio or a Material Constrained Portfolio is required to maintain adequate records relating to their STEM and/or Real-Time Market Submissions to assist the ERA in any investigation (WEM Rule 2.16C.3).[30]

Market Participants not designated as a Material Portfolio or a Material Constrained Portfolio are advised to also maintain records as outlined in WEM Rule 2.16C.3. Maintaining adequate records will assist with an investigation into a breach of the general trading obligations, which apply to all Market Participants, should such an investigation be required.

This section provides guidance on the types of records that a Market Participant can retain to support ERA's monitoring and investigations.

8.1 Recording internal governance

The records kept under WEM Rule 2.16C.3(a) must be adequate to demonstrate the internal governance arrangements that the Market Participant has in place to comply with the price offer obligation in WEM Rule 2.16C.5. These records include but are not limited to:

- Board minutes, where the discussion relates to how the organisation calculates its Price-Quantity Pair offer prices in the STEM and/or Real-Time Market or the actual prices offered.
- Minutes of any relevant sub-committee of the board that has oversight of the organisation's compliance with WEM Rule 2.16C.5, where the discussion relates to how the organisation calculates its Price-Quantity Pair offer prices in the STEM and/or Real-Time Market or the actual prices offered.
- Records of decisions on risk and strategy regarding recovering efficient costs balanced with compliance with WEM Rule 2.16C.5.
- Records of changes in strategy or major price revisions, including changes in input-costs such at the beginning of a new fuel contract or an engineering review of the technical parameters of Registered Facilities in the Portfolio.
- Records of training for staff responsible for setting offer methods or submitting offers into the market (for example, traders).
- Policies regarding the amount of flexibility traders have in setting offers in terms of deviating from Portfolio policies.
- Any other information relevant to the governance procedures implemented by a Portfolio to comply with WEM Rule 2.16C.

[30] This obligation is also described in the ERA's WEM Procedure: Portfolio Determination (online).

8.2 Recording methods, assumptions and cost inputs

WEM Rules 2.16C.3(b) and 2.16C.3(c) require Market Participants to maintain adequate detailed records of the methods, assumptions and cost inputs used in forming their offers. Market Participants are expected to maintain records that allow for offers to be replicated. These records include but are not limited to:

- The records of the technical specifications of the Registered Facilities in the Portfolio, including: thermal generator heat rates; minimum stable generation; maximum stable generation; ramp rates; start-up time; shut-down down time; minimum down time; and minimum-up time.
- Technical consultants' reports establishing or reviewing the technical parameters of facilities.
- Calculations of and, where applicable, consultants' reports calculating variable operating and maintenance costs, start-up costs and shut-down costs for each registered facility.
- Records that explain the reasoning and calculation of offers below costs.
- Details of fuel contracts, records of past spot fuel purchases and/or assumptions regarding spot-fuel purchases in the future, such as estimated spot prices.
- Consultants' reports underlying any on-contract assumptions such as forecast prices.
- Documents, spreadsheets and consultants' reports on how fuel-inputs prices from various sources are allocated across different generators and levels of production.
- Electric Storage Resource factory specifications including but not limited to maximum capacity, maximum storage rates, maximum discharge rates and charge-based depreciation of capacity.
- Documents, spreadsheets, software code, models and consultants' reports on methods for evaluating the opportunity cost of discharge for ESRs, including those on general methods and specific offers.
- Documents, spreadsheets, software code and consultants' reports regarding the general method(s) behind the calculation of offers from each registered facility in a Portfolio, including those on general methods and specific offers.
- Any other information relevant to the calculation of offers by Registered Facilities.

Market Participants must maintain adequate records to demonstrate how they ensure efficiency of costs included in their price offers, consistent with section 8 of this guideline. For example, Market Participants must maintain adequate records that establish if and how their forecasts and estimates reflect the Market Participant's reasonable expectations of factors that influence its production costs at the time of making offers to the market.

Market Participants are advised to also keep any major company or Portfolio review, such as a strategic review, that are not directly relevant to the construction of offers into the Real-Time Market and/or STEM, but lead to reviews of pricing strategies.

Appendix 1 List of tables

Appendix 2 List of equations

Appendix 3 List of examples