Economic Regulation Authority

Offer Construction Guideline

Draft for consultation

21 June 2023

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 intends to update this guideline to take into account any relevant court or tribunal decisions or other relevant change in circumstances.

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 their 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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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

Invitation to make submissions

Submissions are due by 4:00 pm WST, 18 July 2023

The ERA invites comment on this paper and encourages all interested parties to provide comment on the matters discussed in this paper and any other issues or concerns not already raised in this paper.

We would prefer to receive your comments via our online submission form https://www.erawa.com.au/consultation

You can also send comments through:

Email: publicsubmissions@erawa.com.au
Post: Level 4, Albert Facey House, 469 Wellington Street, Perth WA 6000

Please note that submissions provided electronically do not need to be provided separately in hard copy.

All submissions will be made available on our website unless arrangements are made in advance between the author and the ERA. This is because it is preferable that all submissions be publicly available to facilitate an informed and transparent consultative process. Parties wishing to submit confidential information are requested to contact us at info@erawa.com.au.

For further information please contact

General Enquiries

Bruce Layman
Ph: 08 6557 7965
Mob: +61 416 133 078
info@erawa.com.au

Media Enquiries

Danielle Asarpota
Ph: +61 428 859 826
media@erawa.com.au

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1. Purpose of guideline

The Wholesale Electricity Market (WEM) in the Western Australian South-West Interconnected System operates under the *Electricity Industry Act 2004*, *Electricity Industry (*Wholesale *Electricity Market) Regulations 2004* and Wholesale Electricity Market Rules (WEM Rules).[1,2,3]

The Economic Regulation Authority is responsible for monitoring and enforcing compliance with the WEM Rules. From the commencement of the new WEM in October 2023, all Market Participants will be required to comply with the general trading obligations.[4] The obligation to comply is 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 has published the Offer Construction Guideline and the Trading Conduct Guideline to provide regulatory guidance on the general trading obligations. The Offer Construction Guideline concerns the price offer obligations in clause 2.16A.1 of the WEM Rules:[5]

> A Market Participant must offer prices in each of its STEM Submissions and Real-Time Market Submissions that reflect only the costs that a Market Participant without market power would include in forming profit-maximising price offers in a STEM Submission or Real-Time Market Submission.

The Offer Construction Guideline has been prepared to support Market Participants to include efficient costs in their Market Submissions. Efficient market outcomes in the WEM will minimise the long-term cost of electricity supply to consumers.

References in the Offer Construction Guideline to the Rules are to the Consolidated Companion version of the WEM Rules, which are the WEM Rules intended to be in force from commencement of the new market. Terms that are capitalised in this guideline are defined terms in Chapter 11 (Glossary) of the WEM Rules.

The Offer Construction Guideline [clause 2.16D.1(a)]:

i. Provides guidance to Market Participants in relation to the price offer obligations under clause 2.16A.1.

ii. Details how the ERA will assess prices offered under clause 2.16C.6.

iii. Permits the recovery of all efficient variable costs of producing the relevant electricity, including all costs incurred under long-term take-or-pay fuel contracts.

iv. Outlines how the ERA will consider price offers for different facility types, including Electric Storage Resources.

v. Provides examples illustrating the types of conduct that the ERA considers would be likely to contravene the price offer obligations under clause 2.16A.1.

[1] *Electricity Industry Act 2004 (WA)*, (online).

[2] *Electricity Industry (Wholesale Electricity Market) Regulations 2004 (WA)*, (online)

[3] Wholesale Electricity Market Rules (WA), 29 April 2023, (online)

[4] Clause 2.16A in the Consolidated Companion version of the WEM Rules. 29 April 2023 (online).

[5] Changes to the WEM Rules that have been Gazetted, but commence in the future are captured in the Consolidated 'Companion' Version of the Wholesale Electricity Market Rules (as at 29 April 2023), (online).

vi. Provides guidance to Market Participants on how the ERA will assess inefficient market outcomes under clause 2.16C.7.

The Offer Construction Guideline applies to all Market Participants.

All Market Participants are advised to keep records underlying their respective costs, price offers and governance arrangements consistent with section 10 of this guideline.

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.

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 intends to update this guideline to take into account any relevant court or tribunal decisions or other relevant change in circumstances.

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 or other technical advice tailored to their 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.

1.1 Updating the guideline

The ERA may amend this guideline at any time following a public consultation process, as specified in the WEM Rules [clauses 2.16D.2 to 2.16D.4].

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:

- Regulation Raise and Regulation Lower
- Contingency Reserve Raise and Contingency Reserve Lower
- Rate of Change of Frequency (RoCoF) Control Service.

2.1 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.[6] STEM Submissions are made for each Trading Interval of a Trading Day.

A Portfolio Supply Curve may include up to 30 Price-Quantity Pairs. Clause 6.6.5 of the WEM Rules 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 8 of this guideline provides guidance for price offers related to Portfolio Supply Curve for STEM submissions.[7]

2.2 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.[8]

Participation in the Real-Time Market for energy is mandatory for Market Participants that hold Capacity Credits in respect to any of their Registered Facilities. Participation in the FCESS markets is mandatory for the first six months after the New WEM Commencement Day for those Market Participants that have facilities providing any of load following, spinning reserve

6 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 clause 6.4.6B

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

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

and load rejection reserve ancillary services in the existing market (section 1.49 of the WEM Rules).

3. Test of market power

The price offer obligations require a Market Participant to offer as though it does not have market power [clause 2.16A.1]. A Market Participant without market power would offer its Price-Quantity Pairs based on the additional costs it expects to incur by making and honouring the offer, relative to the costs it expects to incur if it were not selected to produce electricity or provide a service. In assessing its costs, a profit maximising Market Participant considers the value it forgoes – for example, by using its factors of production such as fuel, stored energy or use of material and equipment – by choosing to produce the service. That is, the Market Participant considers the 'opportunity cost' of producing services when determining its cost of supply.[9]

A Market Participant can only be found in breach of the price offer obligations if the ERA determines that the Market Participant had market power at the time of offering the price in question [clause 2.16A.2].

Market power is the ability of a firm to raise prices above competitive levels. Indicators of market power include exclusive dealing, tying arrangements, predatory pricing or refusal to deal, and other behaviour that excludes competition.[10]

A range of factors are relevant in determining whether a Market Participant has market power. Factors include the market share of a Market Participant, the ability of other Market Participants to competitively respond to the Market Participant's pricing behaviour and the impact of the Market Participant's behaviour on market dispatch and prices. The ability to raise prices does not need to be profitable to be considered an exercise of market power.

Given the design of the WEM includes the Reserve Capacity Mechanism, for the purpose of clause 2.16A.2 the ability of a Market Participant to raise prices for any period of time will be sufficient to establish that the Market Participant has market power.

9 For example, the cost a Market Participant would incur in producing electricity does not include artificial costs introduced through bilateral supply contracts with customers, because the opportunity cost of such supply/transactions is zero. Related party transactions will be considered based on the opportunity cost of trading with related parties.

10 Electricity Review Board in Economic Regulation Authority vs Synergy, at [291], p75, (online), citing Melway Publishing Pty Ltd v Robert Hicks Pty Ltd, at [67], (online).

4. Constructing energy price offers

This chapter outlines how the ERA will consider cost components when assessing compliance with the price offer obligations for Real-Time Market Submissions. In general, each submission may include all efficient variable costs (EVC) and costs incurred under long-term take-or-pay (LTTOP) fuel contracts, to the extent they relate to the production of electricity.

Costs that may not be included in submissions are fixed costs that the facility incurs regardless of 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 Efficient variable costs

A Market Participant may only include costs in its offers that a Market Participant without market power would include in profit-maximising offers [clause 2.16A.1]. In general, a Market Participant without market power would only include EVC in its profit-maximising offers.

When a Market Participant includes only EVC related to producing the relevant electricity, it would incur no loss or costs if its facility is not dispatched or discharged when the market-clearing price does not reach its offer price. If the market-clearing price matches or exceeds its offer price, then the Market Participant will cover its costs and could make a profit in the relevant market.

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'.[11] 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. A Market Participant without market power includes these costs in its submission. To maximise profit, Market Participants amortise the cost they incur to start-up their plant over the expected dispatch period.

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 that a profit-maximising Market Participant without market power would use, and costs explicitly allowed for in clause 2.16D.1(a)(iii).
- Forecasts or estimates reflect reasonable expectations of variables where technical parameters, prices or costs are uncertain at the time of making the offer and forecasts or approximate estimates of such variable must be produced.
- The costs are allocated across time and production in a manner consistent with the allocations of a profit-maximising Market Participant without market power, which are

[11] Varian, H., 2010. Intermediate Microeconomics: A Modern Approach, 8th edition p. 373 (online).

supported by expert advice – for example, regarding engineering or financial aspects or methods used for the estimation of costs and allocation of those costs to price offers.

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

Table 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 periodic 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
Avoidable fixed costs (AFC)		
Start-up costs (SUC)	The AFC of starting a generator for operation. This can include fuel costs, additional maintenance costs and wear and tear on plant directly related to starting the generator.[12]	$/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.[13]	$/hour
Ramping Costs	Costs incurred when generators are required to be available at the start of the first 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

[12] The PJM Energy Market formally define start-up costs as: The unit costs required to bring the boiler, turbine, and generator from shut-down conditions to the point after breaker closure which is typically indicated by telemetered or aggregated state estimator MWs greater than zero and is determined based on the cost of start fuel, total fuel-related cost, Performance Factor, electrical costs (station service), start maintenance adder, and additional labour cost if required above normal station manning levels (PJM, PJM Manual 15, Cost Development Guidelines, 2022, p. 27, (online)).

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

Cost	Description	Unit
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 reasonably 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 a Renewable Energy Certificate (REC)	A renewable generator gains a large-scale REC for every MWh of electricity that it produces. That means if the generator does not dispatch it forgoes the REC and its value.	$/MWh

4.2 Efficient variable cost and 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 EVCs 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.[14,15] The $IEVC$ is the basis for the price offers and when included in the Price-Quantity Pairs allows for the recovery of EVCs.

[14] 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.

[15] 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 (Equation 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.

Incremental efficient variable cost components (Equation 2)

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

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.

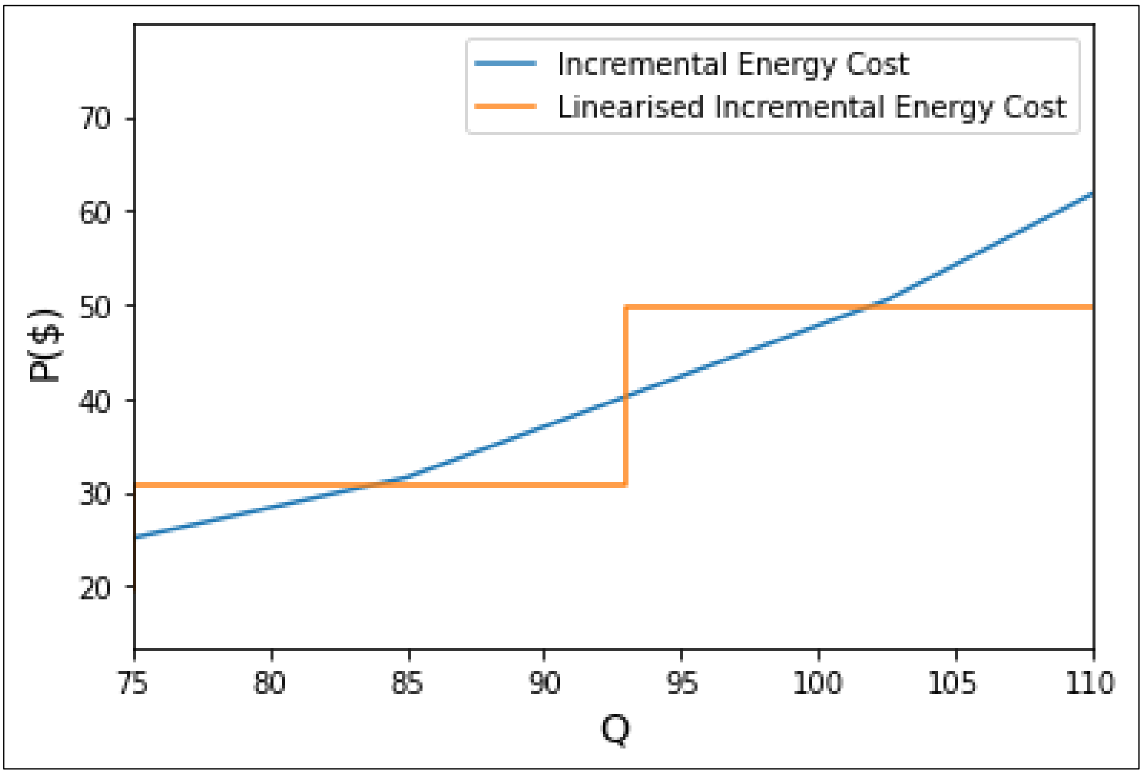
This equation does not include AFC, which will be explained in section 4.6.

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 a Market Participant's IEVCs to Price-Quantity Pairs, however a Market Participant may not over-recover EVCs over time due to its conversion method.

One example of a transformation is demonstrated in 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 1. Conversion of Incremental Variable Cost curve to two-step Price-Quantity Pair



Source: ERA calculations

This Market Participant would 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 1. This is because:

- Thermal generators have large one-off costs such as start-up costs, which are significantly high for the first part of a Market Participant's production schedule but decline thereafter. Start-up costs are discussed in section 4.6.1.
- 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 4.3.

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 profitable Price-Quantity Pairs. A potential strategy to profitably dispatch or discharge into the WEM is to make its offers based on the average operating cost (AOC) of producing electricity in each Dispatch Interval.

4.2.1 Average operating cost

A Market Participant's AOC is its IEVC 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 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:

$AOC(\Delta Q,t)$ 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. Find 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.[16]

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 4.3 to 4.8 and as shown in Equation 4.

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

Average operating cost components (Equation 4)

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

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.

$OPC(t)$ is the opportunity cost in \$/MWh incurred by 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.

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.

Section 5 explains the consideration for uncertainty when forming price offers.

4.3 Fuel Costs

The main component of EVCs for many facilities is the cost they incur to produce services. 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.

4.3.1 *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 fuel cost (MFC) is defined in Average fuel cost (Equation 5).

Average fuel cost (Equation 5)

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

Where:

$MFC(Q,t)$ is the average (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 (12* $q1$ MW) to $Q2$ MWh (12* $q2$ MW).

Incremental fuel cost (Equation 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.

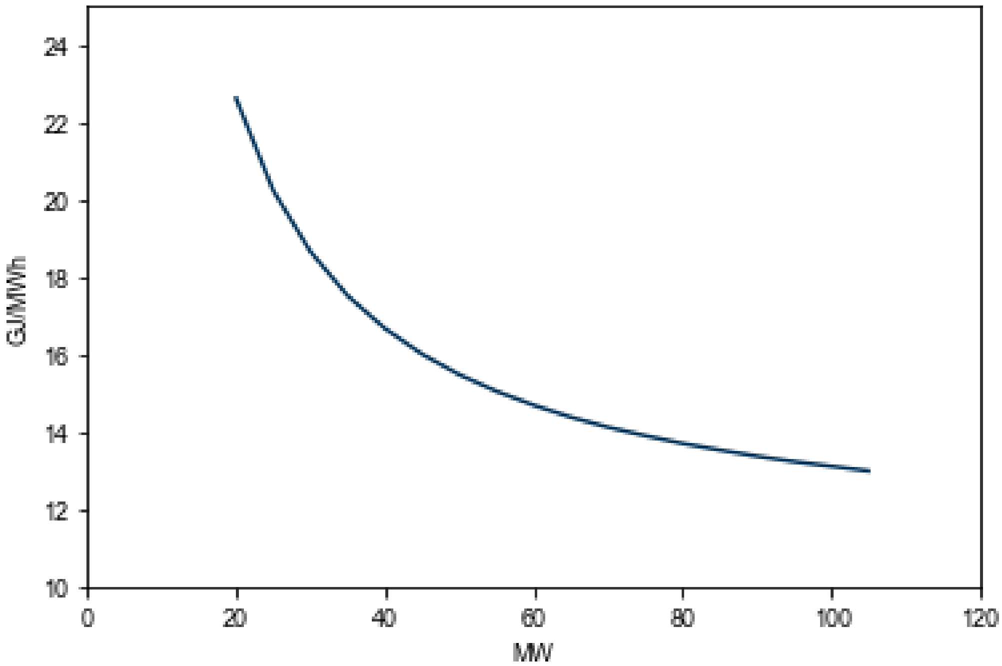
$Q1_t$ is the lower level of electricity generation in MWh from Market Participant p in Dispatch Interval t.

$Q2_t$ 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 1.

However, constructing Price-Quantity Pair offers with monotonically increasing prices is less straightforward for thermal generators as many become more fuel efficient as production increases. 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 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 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.

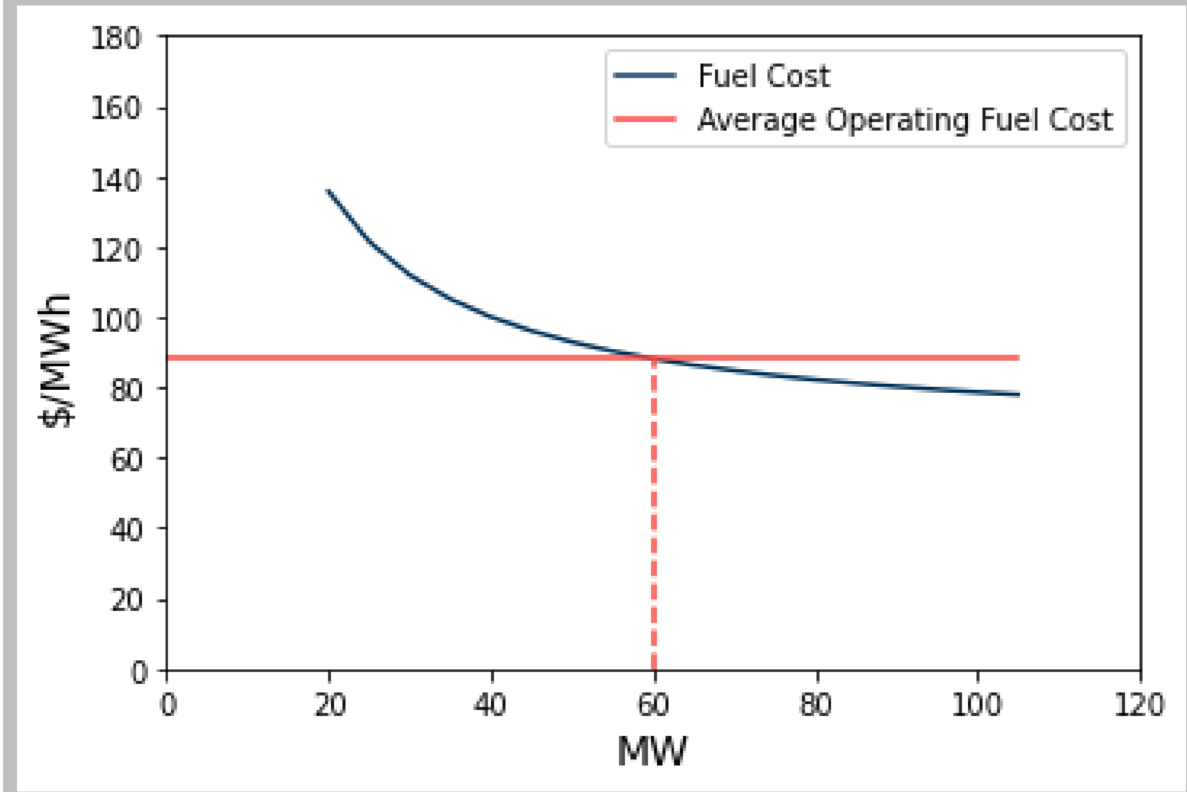
Example 1. Gas-fired generator fuel cost estimation

A gas-fired generator has an average heat rate curve as shown in Figure 1, 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 3.

Figure 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 a Market Participant without market power and is consistent with clause 2.16A.1

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

This Price-Quantity Pair offer is consistent with clause 2.16A.1 of the Rules and is not an Irregular Price Offer.

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 5.1.

4.3.2 *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 (clause 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.[17]

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 clause 2.16A.1 of the WEM Rules and would not result in an Irregular Price Offer.

A profit maximising Market Participant without market power that has a variable quantity gas contract would 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 contract out-of-the-money.

Example 3. Opportunity cost of fuel – variable 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 clause 2.16A.1 of the WEM Rules and is an Irregular Price Offer.

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

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.

However, clause 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 clause 2.16A.1, if it has a LTTOP contract that is out-of-the-money and uses its LTTOP contract price as its fuel-input-cost.

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 of 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, as it has market power and can pass this cost through into the electricity market without the risk of not being cleared in the electricity market.

An offer based on a gas-input price of $10/GJ is consistent with clause 2.16A.1 and the provision of clause 2.16D.1(a)(iii) of the WEM Rules, even though it exceeds the cost of fuel incurred by the generator in purchasing fuel under its LTTOP fuel contract. It is not an Irregular Price Offer.

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 has market power and 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 clause 2.16D.1(a)(iii) as it recovers the exact cost of its LLTOP fuel contract in its offers. It is not an Irregular Price Offer

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 clauses 2.16A.1 and 2.16D.1(a)(iii).

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. 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 each Price-Quantity Pair), to form its price offers. However, this cost must be backed by prudent forecast of its expected fuel use.

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. Averaging 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.

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.

An offer based on the fuel-input cost of $8/GJ undelivered is not consistent with clause 2.16A.1 and is an Irregular Price Offer.

4.3.3 *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 gas pipeline and then a commodity charge for each unit of gas transported.[19]

When fuel transport costs are included in price offers, the ERA will consider if the costs are consistent with that of a prudent, profit-maximising Market Participant. Typically, this would include managing contracts to minimise costs and maximise profits.

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

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

[19] For example, a T1 Service described on p.26. ERA (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, (online).

charge.[20] 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. Peaking generators might also have 'dual fuel capability' and consider short term spot trades or bilateral transactions for sourcing gas to ensure availability of plant through access to liquid fuel. In these circumstances, the reservation charge payable is deemed as an AFC and may be included in price offers.

Conversely, a generator that frequently produces a large amount of electricity and whose Price-Quantity Pair offers are mostly below the market price, may find it profitable to enter a long-term fuel transport contract with a reservation and a commodity charge. To maximise profit, offers from such generators will not include the fixed reservation charges as transport charges payable under the contract do not vary with the increase in plant output.

In this case, the opportunity cost of using the pipeline capacity would also depend on the prevailing market price for pipeline capacity that, for example, may be determined based on prices cleared in the spot market for the pipeline capacity.

As contracts for fuel take various forms (including how transport costs are incorporated), it is not possible to include exhaustive guidance on cost recovery for all possible contract terms and circumstances. Market Participants are encouraged to provide information to the ERA and seek guidance about the inclusion of transport charges in price offers.

4.4 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 periodic 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.

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.

20 Called a Peaking Service, ERA (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).

Incremental variable operating and maintenance (Equation 8)

$$IVOM(t) = \frac{(OE + AM)}{\sum_{t=1}^{210,240} Q(t)}$$

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 $.

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 increase as electricity production increases. Market Participants must allocate maintenance costs to only one area (e.g. 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 Market Participant containing $22.83/MWh is inconsistent with clause 2.16A.1 of the WEM Rules and is an Irregular Price Offer.

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.

4.5 Other Variable Costs

4.5.1 *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 [section 2.24]. This is $1.16/MWh in 2022/23 and is a valid inclusion in incremental energy costs. [21]

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.

4.5.2 *Runway Cost Allocation for Contingency Reserve Raise*

The costs of Contingency Reserve Raise in any interval are recovered from generators operating in that interval using a runway method. These costs are a valid EVC to be included in price offers.

The Contingency Reserve Raise costs allocated to a generator are discernible through market settlement. Market Participants must not attempt to over-recover these costs in price offers.

4.6 Avoidable Fixed Costs

Sections 4.6.1 to 4.6.4 explain different types of AFC that can be included in price offers.

4.6.1 *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 need for parts replacement and servicing must be caused by the registered facility starting and stopping to produce electricity.

Start-up costs (Equation 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 4.3 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

[21] Western Australia Wholesale Electricity Market 2022-23 AEMO Budget and Fees, June 2022, (online).

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 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 (60 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 clause 2.16A.1 and would not lead to an Irregular Price Offer.

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.

SUC may not include costs that have been allocated elsewhere, such as in ramping 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.[22]

Incorporation of this amount into a Market Participant's Price-Quantity Pair offers is compliant with clause 2.16A.1 and would not lead to an Irregular Price Offer.

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.

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

The same generator in Example 9 calculates start-up-related 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.

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 clause 2.16A.1 and would lead to an Irregular Price Offer.

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

4.6.2 *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.

[22] The present value of an annual cash flow equal to $\$735 \times 250$ over a 20-year period using a discount rate 0.05 yields $2.29 million.

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

Amortised shut-down costs (Equation 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 ramping costs.

4.6.3 *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 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

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

However, 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.

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

Table 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 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 clause 2.16A.1 and would not lead to an Irregular Price Offer

There may be cases where slow-ramping baseload generators may not be able to ramp quickly enough to produce at the level that would maximise their operating returns immediately after re-start. This missed opportunity in avoided start-up cost can be included in the calculation of amortised avoided start-up and shut-down cost but should not be double counted with ramping costs.

4.6.4 *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 ramping 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)

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

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.

4.7 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 and without market power 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 clause 2.16A.1.

The costs of Electric Storage Resources (ESRs), including batteries, costs are largely opportunity costs of such type explained in Example 12. 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 gas-fired generator and without market power 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 clause 2.16A.1. 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 6.6 shows that batteries have additional restrictions on when they can discharge, but this example 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 which does not have market power, 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 clause 2.16A.1.

Market Participants with renewable energy facilities, such as wind and solar generators, receive large-scale Renewable Energy Certificates for every MWh of electricity they produce.[23] They can sell these RECs to electricity retailers who are required to procure them. That means if the generator does not dispatch it forgoes the REC and the value that it has. Therefore, the generator will incorporate the negative value of a REC in its offers.

[23] Australian Government, The renewable energy certificate market, Clean Energy Regulator (online).

Example 15. Opportunity cost of lost Renewable Energy Certificate Sales

If a REC is worth $40 per MWh generated, a wind-powered generator without market power 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 price falls to -$30/MWh, the generator is still better off by $10/MWh by generating and receiving a REC.

A Price-Quantity Pair of 60 MW at -$40/MWh is consistent with clause 2.16A.1 and it is not an Irregular Price Offer.

4.8 Other costs

Generators may claim other costs that have not been covered elsewhere in this guideline as part of their EVCs, if Market Participants can justify that the cost is reasonably expected to occur and that the cost is related to the facility in question producing electricity.

The ERA 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.

5. Uncertainty and offers below cost

This section provides an explanation about the effect of uncertainty in forming price offers, and the degree to which price offers below cost may be compliant with section 2.16A of the WEM Rules.

5.1 Forecasting and uncertainty

As Market Participants must submit offers prior to dispatch, Price-Quantity Pairs must be based on the Market Participant's reasonable expectations at Gate Closure of costs that will be incurred during dispatch.

AEMO is required to publish 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 [clauses 7.1.3, 7.4.2 and 7.4.2A]. If sufficient information is available in market schedules, Market Participants can adopt an iterative approach to offer construction as market activity is expected to converge as Gate Closure approaches.

Market Participants are expected to forecast their run-time, production and costs using a simple, repeatable, and mechanistic method that accounts for, to the extent reasonable, AEMO's published Pre-Dispatch Schedules.

Alternatively, a Market Participant may use its historical data to make judgements about its future production of electricity and update its assumptions as operations change over time.

Forecasts produced by Market Participants for a set of Dispatch Intervals will inevitably include forecast errors, resulting in under or over recovery of production costs. However, a commercially prudent Market Participant would continuously monitor its forecasting accuracy and over time would produce unbiased forecasts. Unbiased forecasts lead to neither persistent gain nor loss in each market.

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

Prudent profit-maximising Market Participants review their forecasts periodically to ensure they are not making systematic gains in the Real-Time Market over long periods. A participant, regardless of whether it had market power, would review its forecasting method so that it did not make systematic losses over long periods. A Market Participant without market power would not include a risk margin in its price offers as an additional cost.

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 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 profit maximising generator cannot forecast perfectly, so a short period of Price-Quantity Pair offers of 105 MW at $92.89 is not inconsistent with clause 2.16A.1. However, a prudent Market Participant without market power 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 the first month of operation, may be inconsistent with clause 2.16A.1 and may constitute an Irregular Price Offer if it experiences a persistent over-recovery of costs due to its offers.

5.2 Below-Cost Offers

Typically, Market Participants without market power will submit Price-Quantity Pair offers based on recovering the EVC of making those offers. However, Market Participants may make Price-Quantity Pair offers below the EVC of those offers, which are consistent with clause 2.16A.1.

Offers below cost are unusual, because a Market Participant that seeks to maximise its profits would pursue recovering its costs. Offers below cost may be consistent with clause 2.16A.1 if:

- The Market Participant can demonstrate the reason for offers below cost of supply.
- The strategy is consistent with clause 2.16A.3, which includes the obligation not to manipulate market prices.
  - For example, offers below cost for the purpose of predatory pricing would constitute a breach of clause 2.16A.3.

Examples of circumstances where offering below cost could manipulate prices include:

- Offering below cost offers in one market, for example the Real-Time Market for energy, does in certain circumstances influence prices in another market, such as FCESS markets; and
- Large market customers contracting certain generators to offer prices below EVC to artificially depress the market price, which saves the customer money on the remainder

of its purchases. This strategy is viable in situations where a small increase in production can lead to a large fall in the market price.

Additional guidance on complying with clause 2.16A is in the Trading Conduct Guideline.[24]

Contract conditions that might lead to a Market Participant offering prices below EVC is only consistent with clause 2.16A.1 if the offer is also consistent with clause 2.16A.3.

24 ERA, 2023, Trading Conduct Guideline: Draft for Consultation (online)

6. Costs for Generator Types

This section outlines how the ERA will consider price offers for different facility types, including ESR. It also presents examples illustrating the types of conduct that the ERA considers would be likely to contravene the price offer obligations under clause 2.16A.1.

6.1 Gas-fired generator

The efficient costs incurred by a gas-fired generator without market power, which can be incorporated into its Price-Quantity Pair offers, are shown in 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 but are not common.

Table 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 Contingency Reserve Raise Costs in $/MWh, if applicable.
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.
Ramping 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 17 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 offer cost 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 4. 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 at its AOC of $85.20.

This offer is consistent with clause 2.16A.1 of the WEM Rules and is not an Irregular Price Offer.

6.2 Coal-fired generator

The efficient costs incurred by a coal-fired generator without market power, which can be incorporated into its Price-Quantity Pair offers, are shown in 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, but such generators tend to run for very long periods so these costs are insignificant when allocated across each dispatch cycle.

Table 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.
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.

6.3 Diesel-fired generator

The efficient costs incurred by a diesel-fired generator without market power, which can be incorporated into its Price-Quantity Pair offers, are shown in Table 6. These costs include fuel costs, VOM, market fees, AFCs, start-up costs and shut-down costs.

Table 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

6.4 Wind and solar Generators

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

Table 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 REC.
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 large-scale generation certificates (LGCs) from the Australian Government Clean Energy Regulator when they generate, which, for example, currently have a value of $52/MWh for renewable energy generated.[25]

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 $52/MWh LGC for their potential electricity production.

[25] See the Clean Energy Regulator: Large scale generation certificates $52 in Q1 2023 (online)

Example 18. Wind-powered generator offer formation

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

Table 8. Example estimated wind-powered generator offer tranches

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

LGCs are currently 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 clause 2.16A.1 of the WEM Rules.

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

6.5 Electric Storage Resources

ESRs including batteries may become more common in the WEM and so the potential exists for these resources to gain market power and act in a way that a competitive ESR would not.

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 (clause 4.25.2E (a)).

Table 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.

Cost	Description
Opportunity Costs	
Opportunity cost related to production-based subsidy	Not applicable for an ESR.
Opportunity costs of dispatch in different trading/Dispatch Intervals	Allowable subject to Electric Storage Resource Obligation Intervals restrictions.
Other Costs	
Other Costs	Other costs as appropriate

6.6 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 their own forecast of the Real-Time Market prices, but like the efficient cost of thermal generators, ESRs must be able to demonstrate that their method complies with clause 2.16A.1.

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.

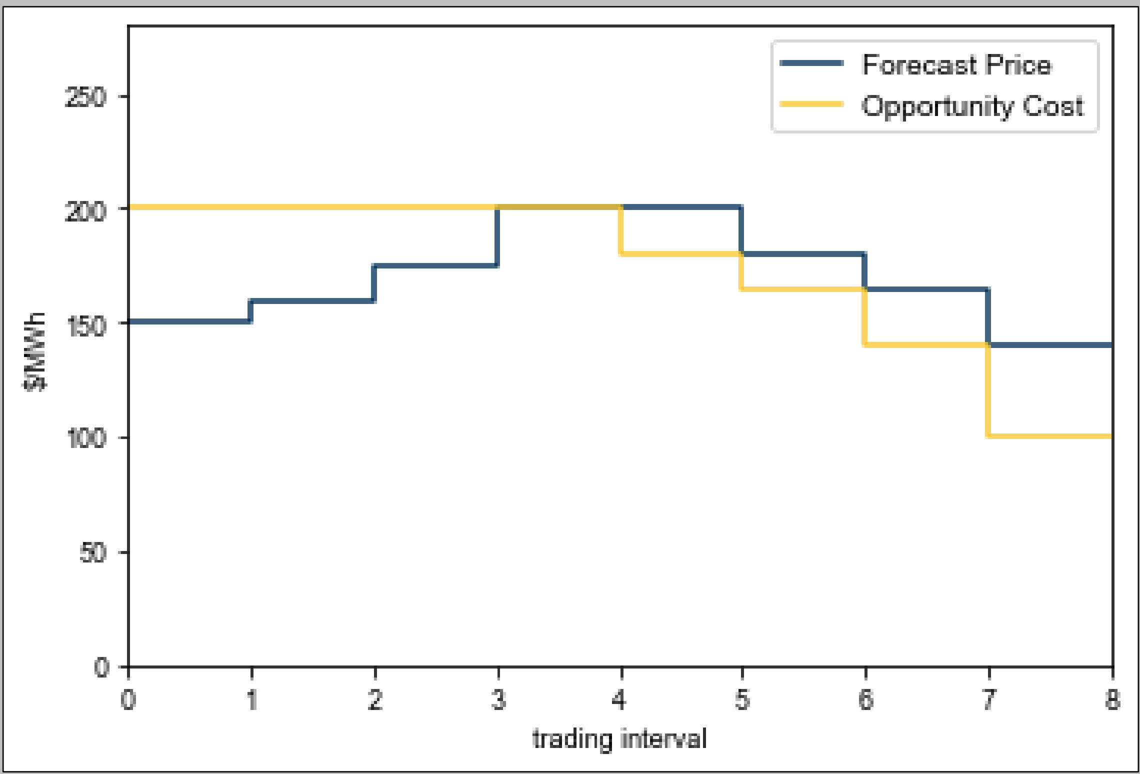
It has market power and can affect the price with its offers, for the Trading Intervals considered in this example.

The ESR must have at least 5MW (2.5MWh) available in every 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 4, regardless of whether it discharges. 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 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 4. 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 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 clause 2.16A.1 of the WEM Rules

Another simple method might be for ESRs to base their efficient cost and hence offer price on their cleared offers from previous trading intervals. For example, one method could be that the ESR 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.

6.7 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. Consistent with other markets, the ERA will initially not apply any specific market power mitigation restrictions on co-located and hybrid resources as they enter the market. The ERA will monitor these resources for behaviour that is inconsistent with behaviour from a Market Participant without market power.

The ERA expects to develop specific market power mitigation measures if required as co-located and hybrid ESRs resources become more common.

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

7. FCESS markets submissions

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 price will automatically compensate the participant for the foregone production in the energy market.[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 (clause 9.10.3A of the WEM Rules).

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

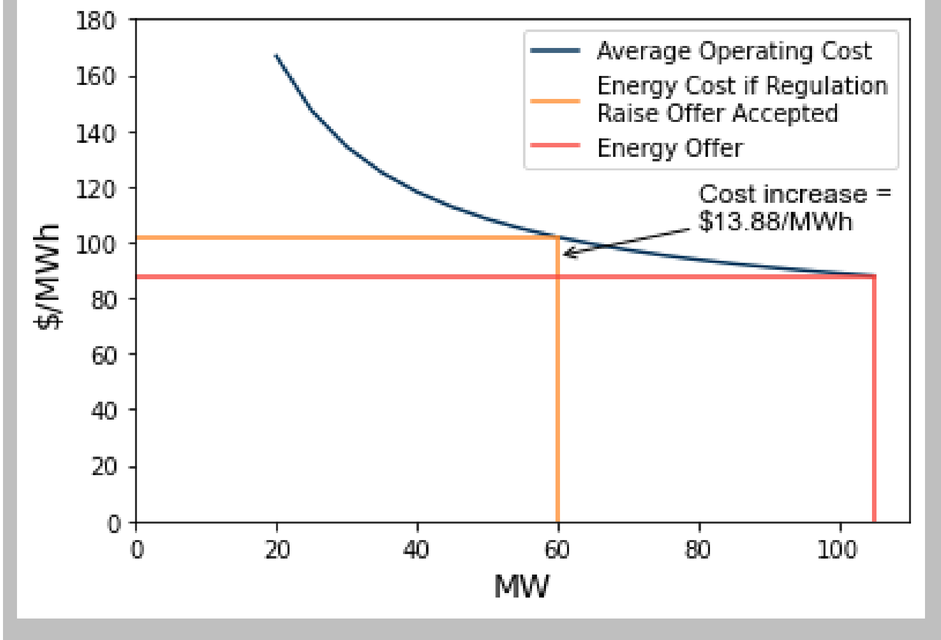
Example 20. Market Participant ESS market offer calculation

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. It is not the price-setting generator. Its efficient single Price-Quantity Pair AOC-based offer is 105 MW production at $87.91/MWh is shown in red inFigure 5.

Figure 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.

This Market Participant's offer is consistent with clause 2.16A.1 of the WEM Rules and would not constitute an Irregular Price Offer.[28]

Consequently, a Market Participant without market power wishing to be selected for FCESS markets only need 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 could include, but are not limited to:

- 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.

[28] For emphasis, the inclusion of 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.

8. 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 without market power 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 21. 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 complaint with clause 2.16A.1 and is not an Irregular Price Offer.

To make compliant offers Market Participant must use forecasts that are:

- Unbiased, when considered over a long period of time.
- 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 22. Non-compliant STEM Offer

The same Market Participant in Example 21 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 Maximum 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 cleared in that Trading Interval over and above what is 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 potentially not complaint with clause 2.16A.1 and may be an Irregular Price Offer.

9. 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 [clause 2.16C.7]. The ERA will only take enforcement action for a breach of clause 2.16A.1 if the Irregular Price Offers resulted in an inefficient market outcome [clause 2.16E.1].[29]

In examining the market impact of Irregular Price Offers, the ERA may consider efficiency impacts such as:

- An increase in real-time price above competitive level, leading to a transfer of wealth from consumers to producers.
- Inefficient dispatch, as defined by the lowest cost dispatch for the available combination of generators.

When making its assessment, 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 23.

[29] The ERA's Monitoring Protocol WEM Procedure sets out how the ERA will monitor, investigate and enforce compliance. This WEM Procedure will be updated for New WEM Commencement day (online).

Example 23. 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. Assume that this generation Portfolio has market power.

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

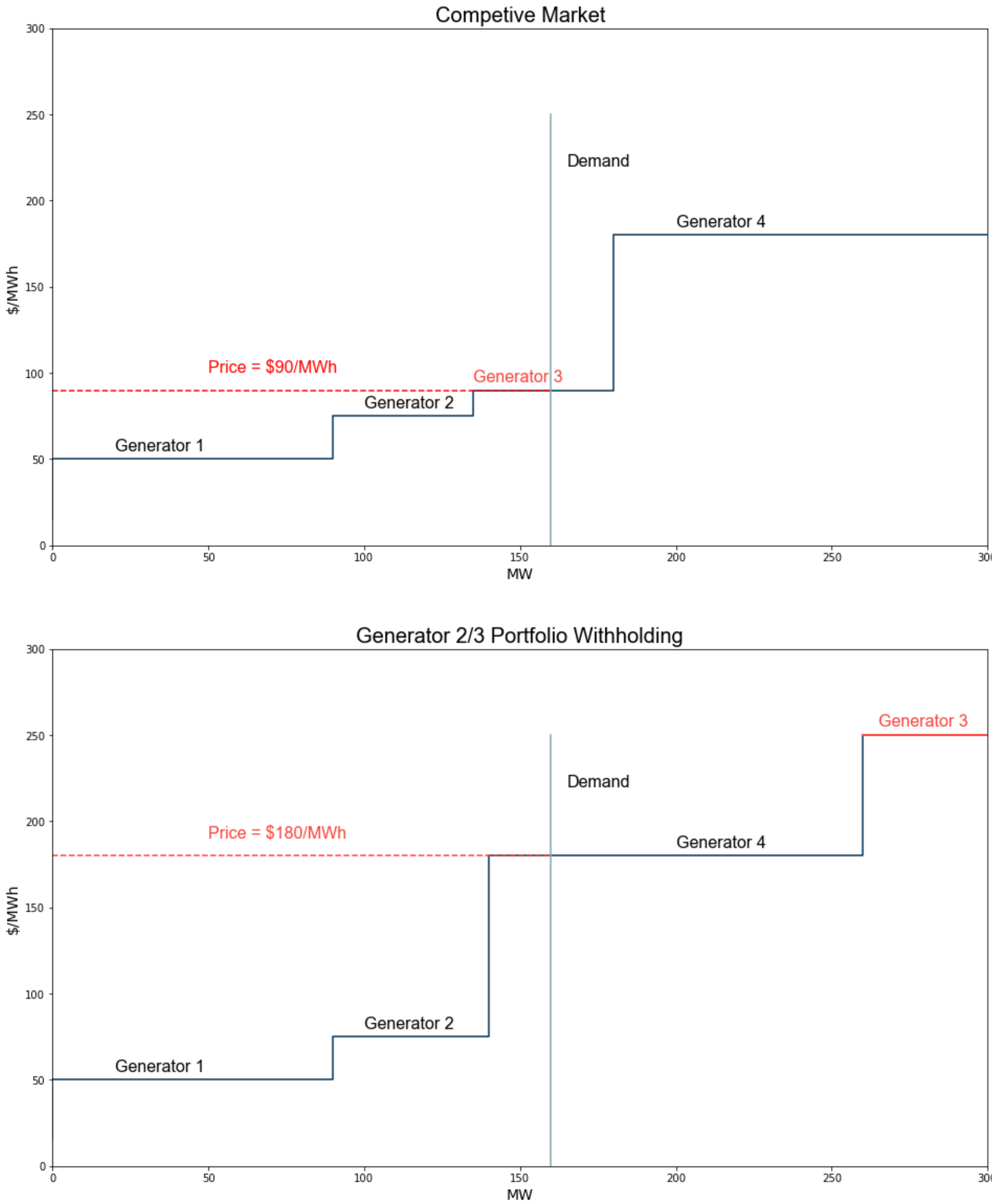
The market call upon the expensive Generator 4 to produce, which set the real-time price of $180/MWh,

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 profit-maximising generator without market power would not make such an offer.

Generator 2 has made an offer above its efficient cost of $90/MWh, which is not consistent with clause 2.16A.1 of the WEM Rules. It is an irregular price outcome and, if sustained, and if it results in inefficient market outcomes, would be a breach of clause 2.16A.1.

The market outcome from the actual Price-Quantity Pair offers is shown in the top panel of Figure 6, while the outcomes from the efficient dispatch order are shown in the lower panel.

Figure 6. Generator 3 Market-Power Based Economic Withholding



Source: ERA calculations

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.

10. 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, under clause 2.16C.11.

Market Participants are responsible for demonstrating reasonable grounds for the prices, quantities, or Ramp Rate Limits in Real-Time Market Submissions [clause 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 [clause 2.16C.3].

Market Participants not designated as a Material Portfolio or a Material Constrained Portfolio are advised to also maintain records as outlined in clause 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 market power monitoring and investigations.

10.1 Recording internal governance

The records kept under clause 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 clause 2.16A.1. 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 clause 2.16A.1, 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 clause 2.16A.1.
- 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 clause 2.16A.1.

10.2 Recording methods, assumptions and cost inputs

Clauses 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. 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 the guidelines provided in section 4.1 of this document. 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