Intervention Pricing Methodology

Prepared by:	AEMO Electricity Market Monitoring
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Current version release details

Version	Effective date	Summary of changes
2.3	3 June 2024	Minor and administrative changes to reflect the National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021 No.13 and National Electricity Amendment (Implementing integrated energy storage systems) Rule 2023 No.2. Updated template.

Note: There is a full version history at the end of this document.

1. Introduction

1.1. Purpose and scope

This is the Intervention Pricing Methodology made under clause 3.9.3(e) of the National Electricity Rules (**Methodology**).

This Methodology has effect only for the purposes set out in the National Electricity Rules (**NER**). The NER and the National Electricity Law prevail over this Methodology to the extent of any inconsistency.

This Methodology is designed to assist AEMO in setting energy and FCAS prices at the values which AEMO considers would have prevailed had AEMO not intervened in the market.

1.2. Definitions and interpretation

1.2.1. Glossary

Terms defined in the National Electricity Law and the NER have the same meanings in these Procedures unless otherwise specified in this clause.

Terms defined in the NER are intended to be identified in these Procedures by italicising them, but failure to italicise a defined term does not affect its meaning.

In addition, the words, phrases and abbreviations in the table below have the meanings set out opposite them when used in this Methodology.

Term	Definition
AEMO	Australian Energy Market Operator
FCAS	Frequency Control Ancillary Service
MNSP	Market Network Service Provider
NC	Non-conformance
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NRM	Negative Residue Management
NSA	Network Support Agreement
Outturn run	The *central dispatch* run used to set dispatch targets during an *AEMO intervention event*. Also known as the ‘intervention run’ or ‘base case target run’.
Pricing run	The *central dispatch* run used to set prices during an *AEMO intervention event*. Also know as the ‘“what-if” run’.
RHS	Right-Hand Side
ROC	Rate-of-Change
SCADA	Supervisory Control and Data Acquisition

1.2.2. Interpretation

This Methodology is subject to the principles of interpretation set out in Schedule 2 of the National Electricity Law.

2. National Electricity Rules requirements for intervention pricing

The requirements for intervention pricing in the National Electricity Market (NEM) are specified in Clause 3.9.3 of the NER.

2.1. Intervention pricing calculation

NER 3.9.3(b) requires that intervention prices are set:

> "…at the value which AEMO, in its reasonable opinion, considers would have applied as the *spot price* and *ancillary services prices* for that *trading interval* in the relevant *region* had the *AEMO intervention event* not occurred."

The intervention prices are designed to preserve the market signals that would have existed had AEMO not intervened, and are used as the *energy* and *market ancillary service* prices for price setting and settlement.

2.2. Intervention pricing consistent with price determination principles

NER 3.9.3(f) requires that the Methodology must, wherever reasonably practicable, be consistent with the principles for determining *energy* and *market ancillary service* prices specified in NER 3.9.1, 3.9.2 and 3.9.2A.

2.3. Intervention pricing calculated and published every five minutes

The NER require intervention prices to be calculated and published every five minutes as part of *central dispatch*.

There is no NER requirement to calculate and publish intervention prices for *pre-dispatch*. However, AEMO started publishing intervention prices as part of *pre-dispatch* in November 2003.

3. Intervention pricing process

3.1. Initiation

Every run of *dispatch* and *pre-dispatch* checks for the presence of any AEMO-invoked intervention-type generic constraints applying for any interval over the relevant scheduling period.

If any intervention-type generic constraints are detected an additional intervention pricing run of the NEMDE dispatch algorithm is automatically performed in parallel with the base case target run to calculate intervention prices.

3.2. Calculation

On initiation of the intervention pricing run, all invoked generic constraints with an "intervention" status are automatically ignored in the intervention pricing run calculations.

The same inputs that are used in the base case target run are loaded into the intervention pricing calculation, with the exceptions listed below (and discussed further in Sections 3.2.1 – 3.2.5):

- The initial *loading level* for each *generating unit* or *bidirectional unit* is set equal to the "What-if" value of that unit's dispatch target calculated in the intervention pricing run of the previous interval (if one was performed) rather than using the metered SCADA value.
- The initial *loading level* for each *scheduled load* and *wholesale demand response unit* is set equal to the "What-if" value of that unit's dispatch target calculated in the intervention pricing run of the previous interval (if one was performed) rather than using the metered SCADA value[1].
- The initial operating mode for each fast start unit is set equal to the "What-if" value of that unit's fast start mode calculated in the intervention pricing run of the previous interval (if one was performed).
- The initial loading for each *interconnector* is set equal to the "What-if" value of that interconnector's flow target calculated in the intervention pricing run of the previous interval (if one was performed) rather than using the metered SCADA value.

For the first interval of the first intervention pricing run, where there are no "What-if" run values available from the previous interval, the same inputs that are used in the base case target run are loaded.

The NEMDE dispatch algorithm is then run and all the "What-if" *energy* and *market ancillary service* prices, "What-if" unit dispatch targets, and "What-if" *interconnector* targets are written back to the MMS database for reporting to the market.

The "What-if" run may be performed twice if the Basslink interconnector is capable of transferring *market ancillary services*. One run is performed with the Frequency

[1] For a wholesale demand response unit, the metered SCADA value may be an estimated load reduction value derived from a measured load.

Controller "on" and the other run is performed with the Frequency Controller assumed to be "off". The *energy* and *market ancillary service* prices from the "What-if" run with the lower objective function value are published.

3.2.1. RHS computation of feedback constraints in intervention pricing runs

The Right-Hand Side (RHS) of feedback constraint equations in the intervention pricing run are computed the same as the base case target run. In other words, *generating unit, bidirectional unit, scheduled load, wholesale demand response unit* and *interconnector* terms on the RHS of feedback constraint equations in the intervention pricing run use metered SCADA values rather than the "What-if" dispatch targets or "What-if" flow targets calculated in the previous interval of the intervention pricing run (if one was performed). This is because the technical envelopes for all network elements in the base case target run and intervention pricing run are the same, and hence the RHS of the constraint equations reflecting network limits should be computed the same.[2]

Table 1 below summarizes the inputs for feedback constraint equations in the Intervention Pricing runs.

Table 1 Inputs for feedback constraint equation RHSs during intervention

Generic constraint RHS term	Input for outturn run	Input for pricing run
Rating	Defined Value	Defined Value
Scheduled Generators, Loads and Bidirectional Units	Measured value	Measured value
Semi-scheduled Generators	Measured value	Measured value
Interconnector flows	Measured value	Measured value
Intra-regional flows	Measured value	Measured value
Wholesale Demand Response Units	Measured value[3] (if provided and used in the central dispatch system)	Measured value (if used in the outturn run)

3.2.2. RHS computation of non-feedback constraints in intervention pricing runs

Other generic constraints that are market-related (e.g. negative residue management, non-conformance, MNSP ROC, or FCAS constraints) are determined dynamically, i.e. the RHS for these constraint equations is determined based on the "What-if" dispatch targets or "What-if" flow targets calculated in the previous interval of the intervention pricing run (if one was performed). This is because these constraint equations are not reflective of a network limit but are used to manage market outcomes or FCAS requirements, both of which are dependent on

[2] The only exception to this process would occur if the line flows or limits in a constraint equation were a non-linear function of generator outputs or interconnector flows.

[3] It may be an estimated load reduction value derived from a measured load.

scheduled resource and *interconnector* operating points. Table 2 below outlines the approach for each generic constraint type in the pricing run.

Table 2 Generic constraint RHS computation approach in pricing runs

Constraint type	Constraint description	RHS calculation
FCAS	FCAS requirement constraints	Dynamic (RHS calculated as per outcomes in pricing run)
Ramping	Network ramping constraints	Dynamic (RHS calculated as per outcomes in pricing run)
NC	Non-conformance constraints	Dynamic (RHS calculated as per outcomes in pricing run)
NRM	Negative Residue Management constraints	Dynamic (RHS calculated as per outcomes in pricing run)
NSA	Network Support Agreement constraints	Dynamic (RHS calculated as per outcomes in pricing run)
Fixed loading	Unit fixed loading constraints	Dynamic (RHS calculated as per outcomes in pricing run)
ROC	Rate-of-change constraints	Dynamic (RHS calculated as per outcomes in pricing run)
System normal	Feedback constraints	Static (RHS calculated same as outturn run)
	Non-feedback constraints	Dynamic (RHS calculated as per outcomes in pricing run)
Network outage	Feedback constraints	Static (RHS calculated same as outturn run)
	Non-feedback constraints	Dynamic (RHS calculated as per outcomes in pricing run)

3.2.3. Identifying tripped generators in intervention pricing runs

Generators that trip in the base case target run will be treated similarly in the pricing run.[4] A generator trip may involve a partial trip (actual output reduces well below bid availability but above 0 MW) or a full trip (actual output reduces to 0 MW). A generator that has bid availability **and** Initial MW (actual output in the base case target run) less than the What-If Initial MW (the “What-if” dispatch target calculated in the previous interval of an intervention pricing run) by more than twice the rate of change down (ROC down) will be treated as a tripped generator, i.e. the unit’s What-If Initial MW will be set to Initial MW in the intervention pricing run.

The following check will be used to identify tripped generators in the pricing run:

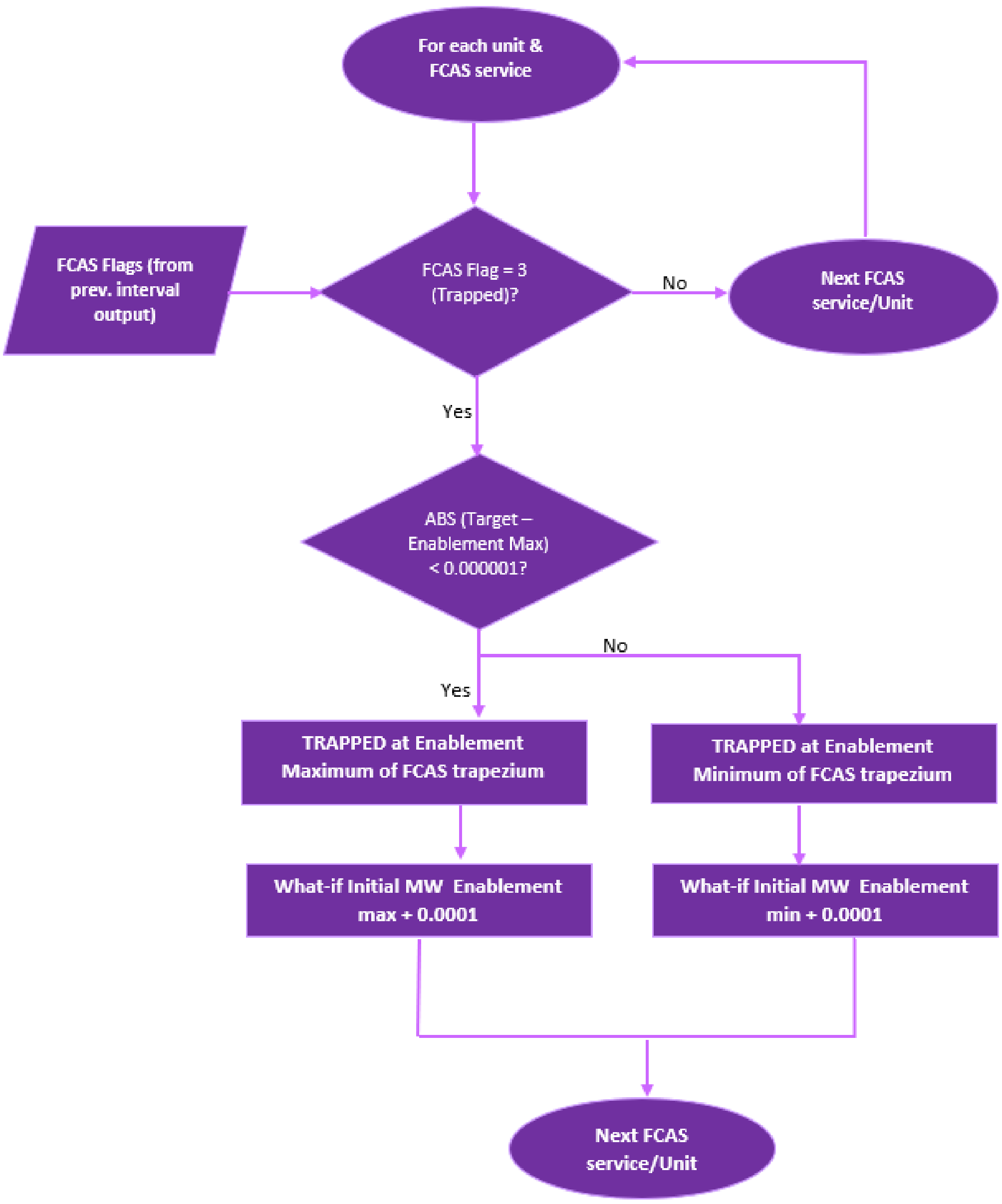
> ***For all generators in each interval:***
>
> ***IF*** *[Bid Availability < (What-If Initial MW - 2 x ROC down)* ***AND***
>
> *InitialMW < (What-If Initial MW - 2 x ROC down)]*
>
> ***THEN*** *What-If Initial MW = Initial MW.*

[4] This modification is awaiting implementation.

3.2.4. FCAS un-trapping logic in intervention pricing runs

To avoid generators being trapped in their FCAS trapeziums for extended periods in the intervention pricing run, an FCAS un-trapping logic will be implemented.[5] The logic involves checking whether a unit is trapped at the Enablement Maximum or Enablement Minimum of each FCAS trapezium and if so, amending the What-If Initial MW (the “What-if” dispatch target calculated in the previous interval of an intervention pricing run) by a very small amount (0.0001 MW) to move the unit’s operating point outside the FCAS trapezium, thereby un-trapping the unit. Figure 1 below shows the proposed un-trapping logic to be applied in intervention pricing runs.

Figure 1 FCAS trapezium un-trapping logic



5 This modification is awaiting implementation.

3.2.5. Generators, bidirectional units, scheduled loads, or wholesale demand response units with zero ramp rates in intervention pricing runs

Generating units, bidirectional units, scheduled loads, or wholesale demand response units that offer zero ramp rates will have their What-If Initial MW set to their Initial MW for all intervals in the intervention pricing run. [6] This is to reflect the fact that unit output can vary even if zero ramp rates are offered.

3.3. Reporting

After completing the intervention pricing run, both the original base case target run and the pricing run solutions will be fully reported to the market.

The base case target run solution is flagged as "Intervention=1" and the intervention pricing run solution is flagged as "Intervention=0".

Spot prices from the intervention pricing run are used in the averaging calculation of *30-minute prices*.

4. "What-if" inputs to the intervention pricing calculation

Apart from the "What-if" inputs, the remaining market-based inputs that are passed to both the target and intervention pricing runs of the NEMDE dispatch algorithm (i.e. bids, network constraints, demand) are identical.

Note that as an intervention progresses over time, the values of the "What-if" inputs derived in the intervention pricing run may differ significantly from the values of the corresponding inputs used in the base case target run, with this difference potentially increasing the longer the intervention continues.

[6] This modification is awaiting implementation.

Version release history

Version	Effective date	Summary of changes
2.3	3 June 2024	Minor and administrative changes to reflect the National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021 No.13 and National Electricity Amendment (Implementing integrated energy storage systems) Rule 2023 No.2. Updated template.
2.2	24 October 2021	Updated to include *Wholesale Demand Response Unit*. Corrected an omission of scheduled load in section 3.2.
2.1	February 2019	Minor and administrative changes to the use of measured values in constraint RHSs in the pricing run
2	September 2018	Use measured values in feedback constraint RHSs in the pricing run. Identify tripped generators in the pricing run. Untrap generators in the pricing run. Use measured outputs in the pricing run for generators offering zero ramp rates. Terminology changes in preparation for 5-minute settlement.
1	October 2014	2014 template formatting