Department of **Energy, Mines, Industry Regulation and Safety**
Energy Policy WA

GOVERNMENT OF WESTERN AUSTRALIA

TDOWG Meeting 52

20 August 2024

Working together for a **brighter** energy future.

Agenda

9.30am	Welcome and overview
9.35am	FCESS Cost Review Amending Rules - Exposure Draft • Addressing WEM Rules problems / deficiencies • Clarifying Participants’ obligations • Other proposed amendments
10:50am	Implementation Sequencing of WEM Amending Rules
11:20am	Next Steps

Welcome

Please place your microphone on mute, unless you are asking a question or making a comment.

- Please keep questions relevant to the agenda item being discussed.
- If there is no break in discussion and you would like to say something, you can ‘raise your hand’ by typing ‘question’ or ‘comment’ in the meeting chat. Questions and comments can also be emailed to energymarkets@demirs.wa.gov.au after the meeting.
- If you are having connection/bandwidth issues, you may want to disable the incoming and/or outgoing video.

FCESS Cost Review Amending Rules – Exposure Draft Addressing WEM Rules problems / deficiencies

Jenny Laidlaw/Douglas Birse

Tiebreak method changes (1)

The problem:

- **Tied FCESS and energy offer tranches are dispatched on a pro-rata basis (i.e. in proportion to tranche size)**
- **For FCESS**
  - Dispatches the maximum number of Facilities – potential increase in FCESS Uplift Payments
  - Increases likelihood of dispatching Facilities for negligible Enablement Quantities
- **For energy**
  - Increases likelihood of dispatching Facility for infeasible energy quantities

Proposed changes:

- **New tiebreak method for FCESS to**
  - Reduce where possible the number of Facilities dispatched for a given FCESS
  - Prioritise the dispatch of Facilities that are more likely to have lower FCESS Uplift Payments
- **New tiebreak method for energy to reduce likelihood of dispatching infeasible energy quantities**

Tiebreak method changes (2)

New clause 7.5.15 specifies high level order for FCESS and energy

- **For FCESS**
- Quantities from Interruptible Loads, in ascending order of Facility Tiebreak Number; then
- Quantities from Scheduled Facilities and Semi-Scheduled Facilities with Enablement Minimum <= 0, in ascending order of Facility Tiebreak Number; then
- Quantities from Scheduled Facilities and Semi-Scheduled Facilities with Enablement Minimum > 0, in ascending order of
    - Estimated energy dispatch cost for the Enablement Minimum (clause 7.5.16), then
    - Facility Tiebreak Number
- **For energy, in ascending order of Facility Tiebreak Number**

Tiebreak method changes (3)

Five options considered for Tiebreak as below because it is not possible to forecast with certainty the FCESS Uplift Cost as the Energy Market Clearing Price (EMCP) is an outcome of the dispatch engine

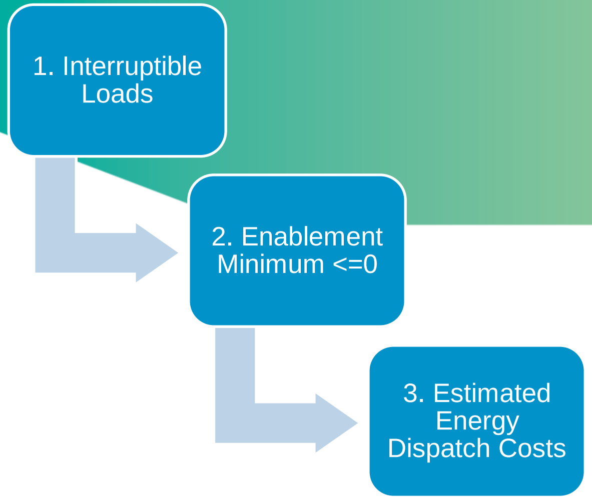
	Theory	Commentary
Product	Utilise the sum of the product of price-quantity energy offers up to the enablement minimum	Does not consider the sensitivity to EMCP in outcome
LFAOP	Utilise the Loss Factor Adjusted Offer Price of the Enablement Minimum	Does not consider the size of the Enablement Minimum
Maximum Availability	Prioritise based on the quantity of offered service	Most direct way to limit number of facilities Disincentivises participation from smaller providers
Forecast EMCP	Utilise the forecast Energy Market Clearing price to estimate the potential FCESS Uplift Cost	Introduces a known inaccuracy into the WEM Dispatch Engine Currently all inputs to the WEM Dispatch Engine are system state values or Market Participant submissions
Directly Solve for FCESS Uplift Cost	Introduce a multiple iteration solution or mixed-integer programming (MIP) solution	Comes at the cost of significant complexity and performance of WEMDE AEMO to review possibility of option at a future date

- **No perfect option but selected product option meets the key criteria**
  - Accounts for Enablement Minimum sizes and energy offer prices
  - Can be implemented in a short time frame

Tiebreak method changes (4)

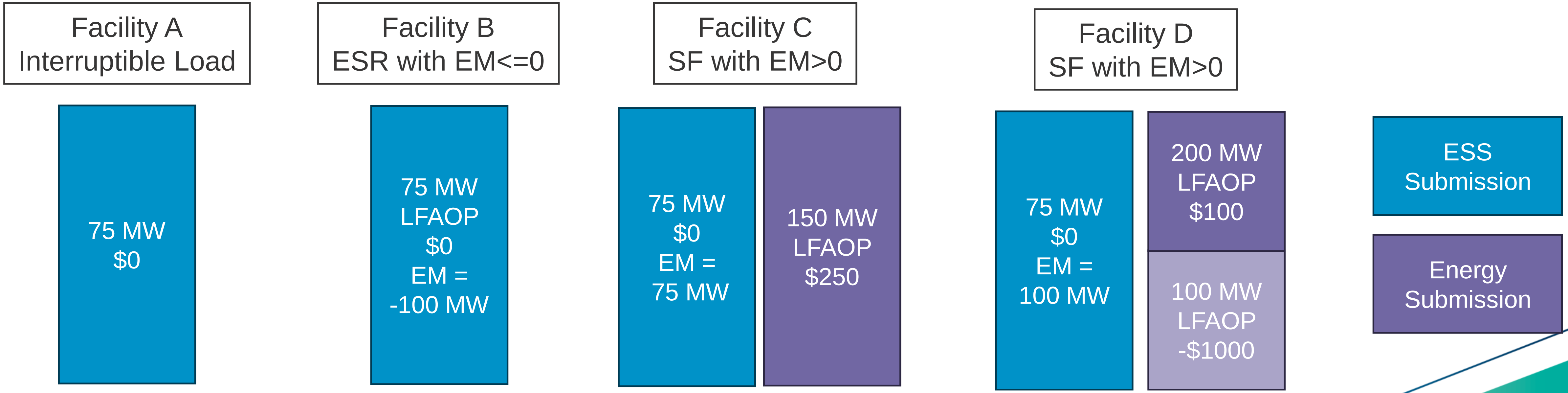
- **New clause 7.5.17 requires AEMO, for each Trading Day, to**
  - Determine a unique random number (Facility Tiebreak Number) for each Scheduled Facility, Semi-Scheduled Facility and Interruptible Load
  - Use the Facility Tiebreak Numbers to resolve tied offers as specified in clause 7.5.15
- **New clause 7.5.18 requires AEMO to document the method used to determine Facility Tiebreak Numbers in a WEM Procedure**
- **New defined term “Facility Tiebreak Number”**
- **Clauses 7.6.23 and 7.6.27(a) removed – allows AEMO to override Dispatch Algorithm outputs to resolve ties – never used**

Tiebreak method changes (5)



Example 1 – Prioritisation of zero uplift potential

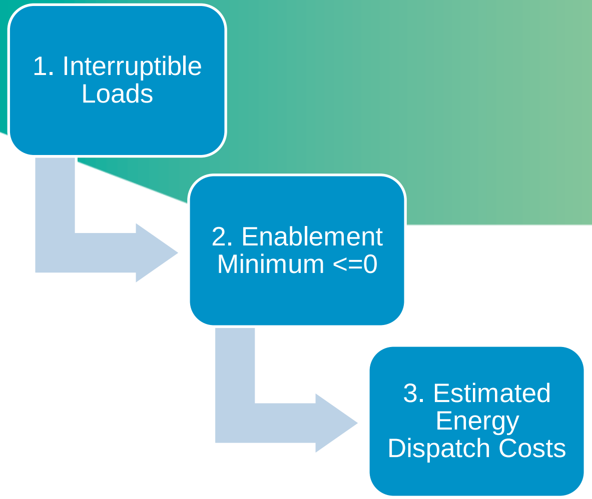
Contingency Raise Requirement = **100 MW***
All Contingency Reserve Raise PF = 1



*assume to be a fixed requirement

IL – Interruptible Load   ESR – Energy Storage Resource
SF – Scheduled Facility

Tiebreak method changes (6)



Example 1 – Prioritisation of zero uplift potential

	Priority Order	Facility Tiebreak Number	Estimated Dispatch Cost	ESS Scheduled Quantity	Previous Tiebreak Method
Facility A	1.01	1	N/A	75 MW	25 MW
Facility B	2.01	2	N/A	25 MW	25 MW
Facility C	3.02	3	$18,750 (2)	0 MW	25 MW
Facility D	3.01	4	-$100,000 (1)	0 MW	25 MW

Tiebreak method changes (7)

1. Interruptible Loads

2. Enablement Minimum <=0

3. Estimated Energy Dispatch Costs

Example 2 – Multiple ESRs

Contingency Raise Requirement = **100 MW***
All Contingency Reserve Raise PF = 1

Facility A Interruptible Load	Facility B ESR with EM<=0	Facility C ESR with EM<=0	Facility D ESR with EM<=0
75 MW $0	75 MW $0 EM = -100 MW	75 MW $0 EM = -100 MW	75 MW $0 EM = -100 MW

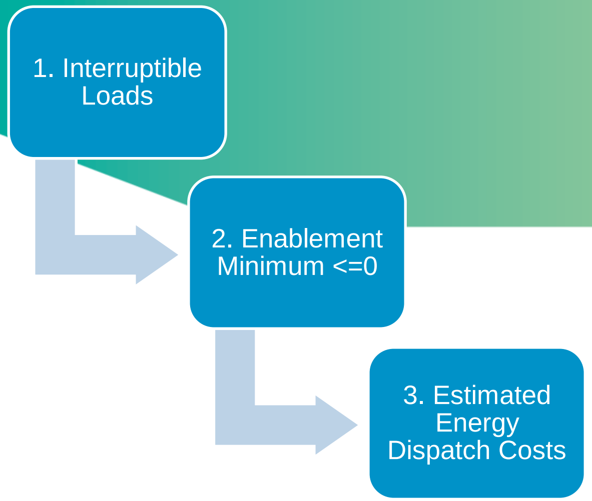
ESS Submission

Energy Submission

IL – Interruptible Load ESR – Energy Storage Resource

*assume to be a fixed requirement

Tiebreak method changes (8)

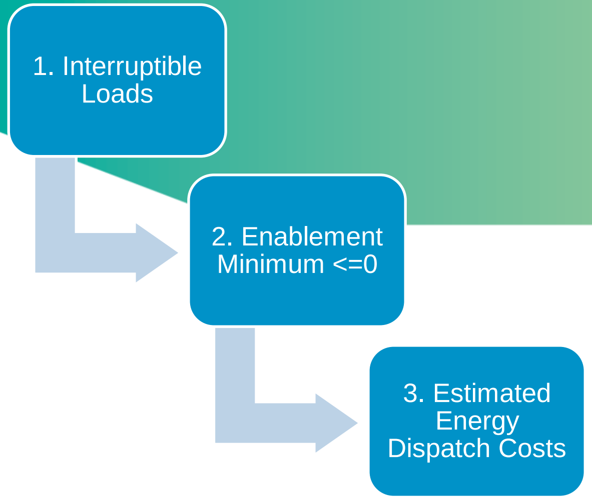


Example 2 – Multiple ESRs

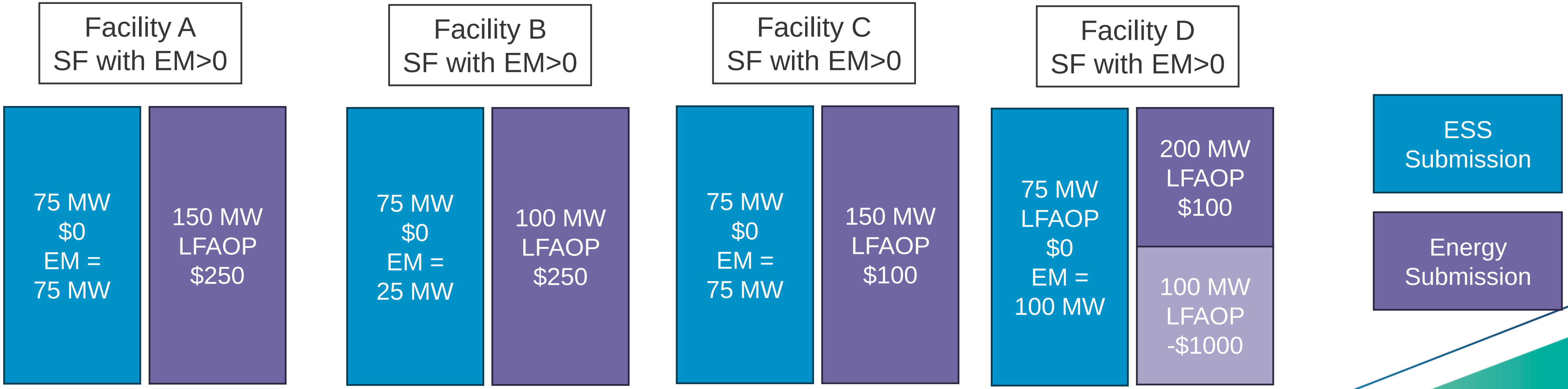
	Priority Order	Facility Tiebreak Number	Estimated Dispatch Cost	ESS Scheduled Quantity	Previous Tiebreak Method
Facility A	1.01	1	N/A	75 MW	25 MW
Facility B	2.01	2	N/A	25 MW	25 MW
Facility C	2.02	3	N/A	0 MW	25 MW
Facility D	2.03	4	N/A	0 MW	25 MW

Tiebreak method changes (9)

Example 3 – Facility Energy Dispatch Cost



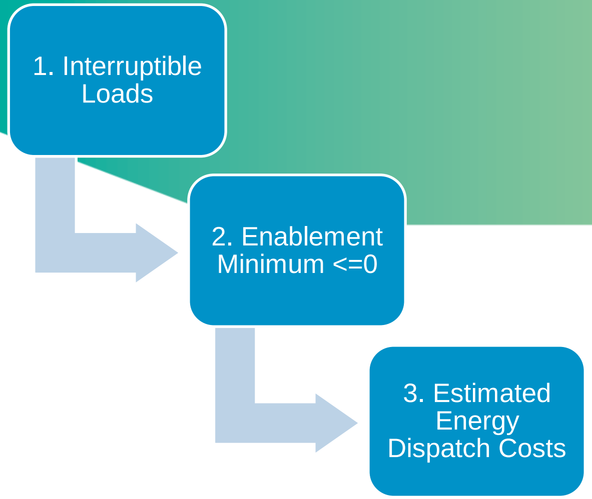
Contingency Raise Requirement = **100 MW***
All Contingency Reserve Raise PF = 1



SF – Scheduled Facility

*assume to be a fixed requirement

Tiebreak method changes (10)



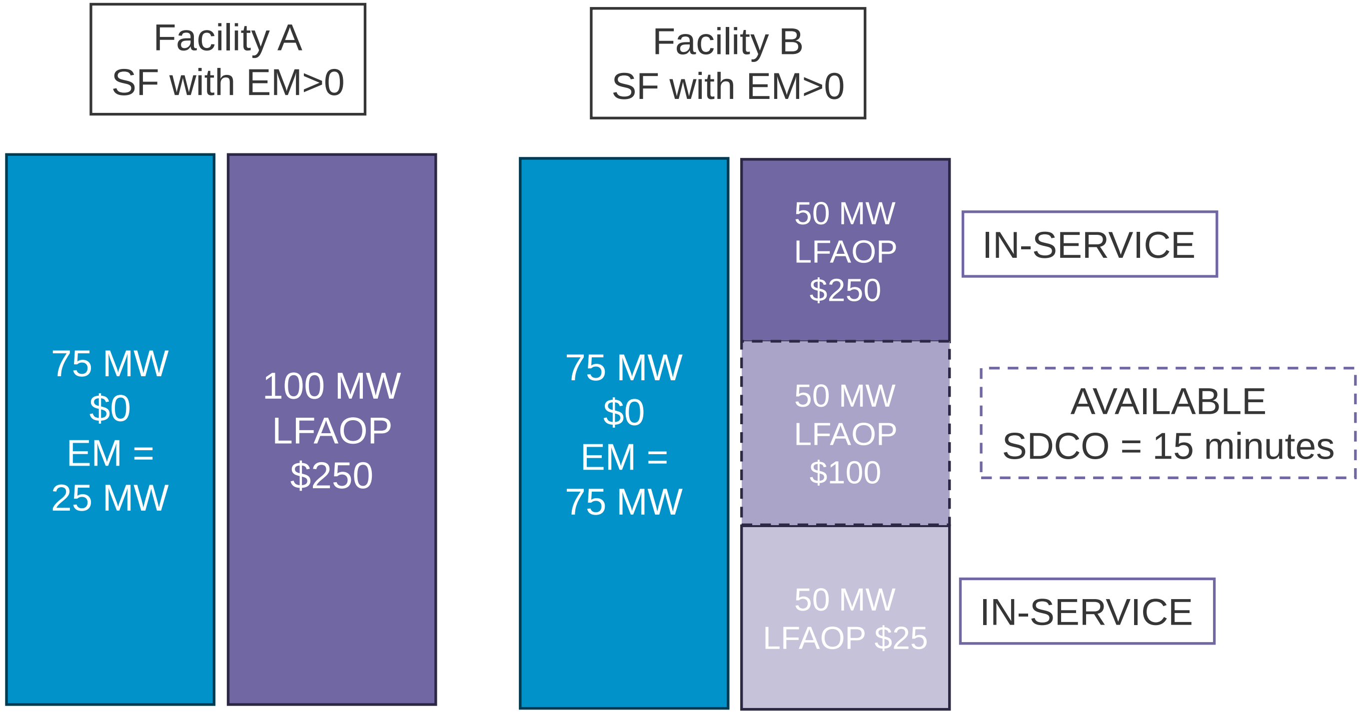
Example 3 – Facility Energy Dispatch Cost

	Priority Order	Facility Tiebreak Number	Estimated Dispatch Cost	ESS Scheduled Quantity	Previous Tiebreak Method
Facility A	3.04	1	$18,750 (4)	0 MW	25 MW
Facility B	3.02	2	$6,250 (2)	25 MW	25 MW
Facility C	3.03	3	$7,500 (3)	0 MW	25 MW
Facility D	3.01	4	-$100,000 (1)	75 MW	25 MW

Tiebreak method changes (11)

Example 4 – Available Capacity

The below example outlines a scenario where the tiebreak order could change in the Available Capacity schedule due to Available offers being past the declared Start Decision Cutoff time



	Before SDCO		After SDCO	
Facility A	$6,250	(1)	$6,250	(2)
Facility B	$7,500	(2)	$3,750	(1)

SDCO – Start Decision Cutoff

RoCoF Control Service changes (1)

The problem:

- WEMDE/DFCM dispatches all available RoCoF Control Service because assumed to be zero cost
- Can lead to unnecessary FCESS Uplift Payments if the inertia provided by additional synchronised Facilities is not needed

Proposed short term solution (pending broader review of RoCoF Control Service procurement and compensation)

- Restore mandatory offer requirements for accredited Facilities
- Remove FCESS Uplift Payments for RoCoF Control Service provision
- AEMO will constrain a Facility on specifically to provide RoCoF Control Service if necessary
- Enable Energy Uplift Payments for Facilities constrained on to provide RoCoF Control Service

RoCoF Control Service changes (2)

Overview of changes:

- **New clause 7.4.5A – reintroduces pre-April 2024 obligation to offer accredited RoCoF Control Service capacity in the Real-Time Market**
- **Removal of FCESS Uplift Payments for RoCoF Control Service**
- Included in changes to clauses 9.10.3B-9.10.3O
- Change to clause 9.10.15 (RCS_Payable(DI) calculation)
- Consequential changes to Estimated FCESS Uplift Payment calculation
- **New clause 7.7.8A(a) – deems Constraint Equations to implement directions to provide RoCoF Control Service to be Network Constraint Equations**
- Eligible for Energy Uplift Payments

Additional Energy Uplift Payment triggers (1)

The problem – need to compensate Market Participants when:

- **AEMO constrains on a Registered Facility to provide RoCoF Control Service (because Facility will no longer receive FCESS Uplift Payments); or**
- **When**
- AEMO has issued a Low Reserve Conditions declaration; and
- A Market Participant has offered the capacity of its Facility as In-Service Capacity; and
- AEMO constrains the Facility on to provide at least a minimum level of Injection (typically its minimum stable load level)

Proposed changes

- **Deem the associated Constraint Equations to reflect Network Constraints**
- **Use existing Energy Uplift Payment mechanism to compensate Market Participants**
- **Clarify that the relevant capacity must be offered as In-Service Capacity**

Additional Energy Uplift Payment triggers (2)

Overview of changes

- **New clause 7.7.8A – specifies the criteria for deeming certain Constraint Equations to reflect Network Constraints**
- Simplest and fastest option for implementing compensation payments
- Approach expected to be refined in future (e.g. to allocate these Constraint Equations to their own, distinct categories)
- **Changes to clause 9.9.9 (IsMisPriced trigger) to ensure that providing a RoCoF Control Service does not make a Facility ineligible for Energy Uplift Payments**
- **Changes to clause 9.9.10 to ensure Energy Uplift Payments are only made for capacity offered as In-Service Capacity**

Additional Energy Uplift Payment triggers (3)

Two Additional Energy Uplift Payment triggers are included via the Congestion Rental calculation:

- AEMO direction for RoCoF Control Service (Inertia)
- AEMO direction to maintain Facility Commitment during a period subject to a Low Reserve Condition Declaration

In both cases AEMO will invoke a Constraint Equation for the Facility at a minimum stable loading level

These constraint equations will be implemented as:

- Greater than or equal constraints marginally above the max of:
    - the Enablement Minimum of the standing submission at the time of constraint creation
    - the Facility Low Limit value provided via SCADA
- constraintType: “Network”

AEMO will take best endeavours to provide at least 1 hour notice

When AEMO direct a Facility, they will provide an indicative minimum run time

FCESS Uplift Payment calculation changes (1)

The problem:

- FCESS Uplift Payments intended to keep Market Participants whole when they provide one or more FCESS in a Dispatch Interval
- Current calculation covers losses on Enablement Minimum when energy offer price > energy Market Clearing Price (enablement losses)
- FCESS Market Clearing Prices can be high enough to cover all or part of a Market Participant’s enablement losses – no need for all the current FCESS Uplift Payment

Proposed solution

- Revised FCESS Uplift Payment calculation to avoid over-compensation

FCESS Uplift Payment calculation changes (2)

Overview of changes:

- **Remove concept of Enablement Losses (old clauses 9.10.3C-9.10.3H and defined term)**
- **Clause 9.10.3C – if Facility is eligible, sets the FCESS Uplift Payment to**
  max(0, RTMDispatchCost(f,DI) – RTMBaseCompensation(f,DI))
- **Clause 9.10.3D calculates the estimated Real-Time Market dispatch cost based on Real-Time Market Offers – comprises energy offers for "FCESS Minimum Dispatch Target" and FCESS offers for each cleared FCESS except RoCoF Control Service**
- **Clause 9.10.3E calculates the Real-Time Market base compensation amount based on the market prices for the FCESS Minimum Dispatch Target and the cleared FCESS Enablement Quantities**
- **Clause 9.10.3F sets the FCESS Uplift Payment eligibility flag – Facility is eligible for an FCESS Uplift Payment if**
- AEMO has not suspended the Real-Time Market
- Facility is a Scheduled Facility or Semi-Scheduled Facility issued a Dispatch Target > 0
- IsMisPriced trigger = 0 (i.e. not eligible for an Energy Uplift Payment)
- Facility has been dispatched for at least one FCESS (apart from RoCoF Control Service)

FCESS Uplift Payment calculation changes (3)

Overview of changes (continued):

- **Clauses 9.10.3G – 9.10.3HA calculate the FCESS Minimum Dispatch Target**
- The minimum theoretical Dispatch Target from which the Facility would have been able to provide the Essential System Service Enablement Quantities that were determined for the Facility for the Dispatch Interval
- Used instead of Dispatch Target to account for exception situations, e.g. if the Facility is ramping down due to an energy price change and is subject to a binding ramp down rate constraint in the Dispatch Interval
- Set to 0 if the Facility is not eligible for an FCESS Uplift Payment
- If eligible for an FCESS Uplift Payment then set to

  max(0, minimum theoretical Dispatch Target for provision of Raise FCESS services,
  minimum theoretical Dispatch Target for provision of Lower FCESS Services)
- Clause 9.10.3H – minimum theoretical Dispatch Target for provision of Raise FCESS services is the maximum Enablement Minimum for a cleared Raise FCESS
- Clause 9.10.3HA – minimum theoretical Dispatch Target for provision of Lower FCESS services is the maximum Enablement Minimum for a cleared Lower FCESS, plus the sum of the cleared Lower FCESS Enablement Quantities

FCESS Uplift Payment calculation changes (4)

Worked Example 1 – Lower Services with Equal Outcome

ESS Offer & Enablement:

(only 1 tranche offered in each Market Service)

FCESS	Reg. Raise	Reg. Lower	RoCoF
Offered Price	$0	$0	$0
EM	25 MW	25 MW	25 MW
Enabled Quantity	50 MW	50 MW	500 MWs
Clearing Price	$0	$140	$0

Tranche	1	2	3
Offered Price	$100	N/A	N/A
Cleared Qty	75 MW	N/A	N/A
FRTP	-$40	N/A	N/A

For convenience we will make simplifying assumptions such as:

Eligibility flags = 1

Loss Factors = 1

Performance Factors = 1

FRTP = FEMCP

Equations from the exposure draft are simplified slightly for readability. Consult the exposure draft for full details.

FCESS Uplift Payment calculation changes (5)

Worked Example 1 – Lower Services with Equal Outcome

ESS Offer & Enablement:

(only 1 tranche offered in each Market Service)

FCESS	Reg. Raise	Reg. Lower	RoCoF
Offered Price	$0	$0	$0
EM	25 MW	25 MW	25 MW
Enabled Quantity	50 MW	50 MW	500 MWs
Clearing Price	$0	$140	$0

Cleared Energy Offers:

Tranche	1	2	3
Offered Price	$100	N/A	N/A
Cleared Qty	75 MW	N/A	N/A
FRTP	-$40	N/A	N/A

$$Raise\_MinDT = \begin{cases} \max(EM\_CR, EM\_RR) \ if\ enabled\ for\ RR\ and\ CR \\ EM\_CR\ if enabled\ for\ CR\ but\ not\ RR \\ EM\_RR\ if enabled\ for\ RR\ but\ not\ CR \\ 0, otherwise \end{cases}$$

Therefore, Raise_MinDT = EM_RR = 25 MW

$$Lower\_MinDT$$

$$= \begin{cases} \mathrm{CL\_EnablementQuantity} + \mathrm{RL\_EnablementQuantity} + \max(EMCL, EMRL) \ if\ enabled\ for\ RL\ and\ CL \\ \mathrm{CL\_EnablementQuantity} + EM\_CL\ if enabled\ for\ CL\ but\ not\ RL \\ \mathrm{RL\_EnablementQuantity} + EM\_RL\ if enabled\ for\ RL\ but\ not\ CL \\ 0, otherwise \end{cases}$$

Therefore, Lower_MinDT = RL_EnablementQuantity + EM_RL = 50 MW + 25 MW = 75 MW

$$FCESSMinDispatchTarget = \begin{cases} \max(0, Raise\_MinDT, Lower\_MinDT)\ if\ eligible \\ 0\ otherwise \end{cases}$$

We have assumed it is eligible, therefore:

FCESSMinDispatchTarget = max(0, 25, 75) = <u>75 MW</u>

Note that in this case the Min Dispatch Target is equal to the Enabled Quantity, but this will not always be the case.

FCESS Uplift Payment calculation changes (6)

Worked Example 1 – Lower Services with Equal Outcome

ESS Offer & Enablement:

(only 1 tranche offered in each Market Service)

FCESS	Reg. Raise	Reg. Lower	RoCoF
Offered Price	$0	$0	$0
EM	25 MW	25 MW	25 MW
Enabled Quantity	50 MW	50 MW	500 MWs
Clearing Price	$0	$140	$0

Cleared Energy Offers:

Tranche	1	2	3
Offered Price	$100	N/A	N/A
Cleared Qty	75 MW	N/A	N/A
FRTP	-$40	N/A	N/A

$$RTMBaseCompensation = \Big($$

$$FCESSMinDispatchTarget \times ReferenceTradingPrice$$

75 * (-40) = -3000.00

$$+\textstyle\sum_{for\ FCESS\ except\ RoCoF} EnablementQty \times MCP \times PF$$

RR: 50 * 0 * 1 = 0.00

RL: 50 * 140 * 1 = 7000.00

RoCoF 1: N/A

$$\Big) \times \frac{5}{60}$$

RTM Base Compensation = (-3000 + 7000) * 5/60 = $333.33

FCESS Uplift Payment calculation changes (7)

Worked Example 1 – Lower Services with Equal Outcome

ESS Offer & Enablement:

(only 1 tranche offered in each Market Service)

FCESS	Reg. Raise	Reg. Lower	RoCoF
Offered Price	$0	$0	$0
EM	25 MW	25 MW	25 MW
Enabled Quantity	50 MW	50 MW	500 MWs
Clearing Price	$0	$140	$0

Cleared Energy Offers:

Tranche	1	2	3
Offered Price	$100	N/A	N/A
Cleared Qty	75 MW	N/A	N/A
FRTP	-$40	N/A	N/A

$$RTMDispatchCost = \Big($$

$$\sum_{for\ each\ tranche} ClearedEnergyQty \times EnergyPrice$$

*tranche 1: 75 * 100 = 7500.00*

tranche 2: N/A

$$+\sum_{for\ FCESS\ except\ RoCoF} \sum_{for\ each\ tranche} ClearedQty \times FCESSprice \times PF$$

*RR tranche 1: 50 * 0 * 1 = 0.00*

*RL tranche 1: 50 * 0 * 1 = 0.00*

RoCoF tranche 1: N/A

No tranche 2

$$\Big) \times \frac{5}{60}$$

RTM Dispatch Cost = (7500 + 0) * 5/60 = <u>$625.00</u>

FCESS Uplift Payment calculation changes (8)

Worked Example 1 – Lower Services with Equal Outcome

ESS Offer & Enablement:

(only 1 tranche offered in each Market Service)

FCESS	Reg. Raise	Reg. Lower	RoCoF
Offered Price	$0	$0	$0
EM	25 MW	25 MW	25 MW
Enabled Quantity	50 MW	50 MW	500 MWs
Clearing Price	$0	$140	$0

Cleared Energy Offers:

Tranche	1	2	3
Offered Price	$100	N/A	N/A
Cleared Qty	75 MW	N/A	N/A
FRTP	-$40	N/A	N/A

$$FCESSUpliftPayment = \begin{cases} max(0, RTMDispatchCost - RTMBaseCompensation) & if\ eligible \\ 0 & Otherwise \end{cases}$$

FCESS Uplift Payment = max(0, $625 - $333.33) = $291.67

This is a negligible change from the current approach, which results in an FCESS Uplift payment of about $292 (there may be small differences either way depending on the difference between Final Reference Trading Price and Final Energy Market Clearing Price).

FCESS Uplift Payment calculation changes (9)

Worked Example 2 – Raise Services Only FCESS Uplift Offset

ESS Offer & Enablement:

(only 1 tranche offered in each Market Service)

FCESS	Con. Raise	Reg. Raise	RoCoF
Offered Price	$0	$0	$0
EM	30 MW	30 MW	30 MW
Enabled Quantity	50 MW	25 MW	500 MWs
Clearing Price	$20	$10	$0

Cleared Energy Offers:

Tranche	1	2	3
Offered Price	$110	N/A	N/A
Cleared Qty	30 MW	N/A	N/A
FRTP	-$10	N/A	N/A

For convenience we will make simplifying assumptions such as:

Eligibility flags = 1

Loss Factors = 1

Performance Factors = 1

FRTP = FEMCP

Equations from the exposure draft are simplified slightly for readability. Consult the exposure draft for full details.

FCESS Uplift Payment calculation changes (10)

Worked Example 2 – Raise Services Only FCESS Uplift Offset

ESS Offer & Enablement:

(only 1 tranche offered in each Market Service)

FCESS	Con. Raise	Reg. Raise	RoCoF
Offered Price	$0	$0	$0
EM	30 MW	30 MW	30 MW
Enabled Quantity	50 MW	25 MW	500 MWs
Clearing Price	$20	$10	$0

Cleared Energy Offers:

Tranche	1	2	3
Offered Price	$110	N/A	N/A
Cleared Qty	30 MW	N/A	N/A
FRTP	-$10	N/A	N/A

$$Raise\_MinDT = \begin{cases} \max(EM\_CR, EM\_RR) \; if\ enabled\ for\ RR\ and\ CR \\ EM\_CR\ if enabled\ for\ CR\ but\ not\ RR \\ EM\_RR\ if enabled\ for\ RR\ but\ not\ CR \\ 0, otherwise \end{cases}$$

Therefore, Raise_MinDT = max(EM_RR, EM_CR) = max(30,30) = 30 MW

$$Lower\_MinDT$$

$$= \begin{cases} \mathrm{CL\_EnablementQuantity} + \mathrm{RL\_EnablementQuantity} + \max(EMCL, EMRL) \; if\ enabled\ for\ RL\ and\ CL \\ \mathrm{CL\_EnablementQuantity} + EM\_CL\ if enabled\ for\ CL\ but\ not\ RL \\ \mathrm{RL\_EnablementQuantity} + EM\_RL\ if enabled\ for\ RL\ but\ not\ CL \\ 0, otherwise \end{cases}$$

Therefore, Lower_MinDT = 0

$$FCESSMinDispatchTarget = \begin{cases} \max(0, Raise\_MinDT, Lower\_MinDT) \; if\ eligible \\ 0\ otherwise \end{cases}$$

We have assumed it is eligible, therefore:

FCESSMinDispatchTarget = max(0, 30, 0) = <u>30 MW</u>

Note that in this case the Min Dispatch Target is equal to the Enabled Quantity, but this will not always be the case.

FCESS Uplift Payment calculation changes (11)

Worked Example 2 – Raise Services Only FCESS Uplift Offset

ESS Offer & Enablement:

(only 1 tranche offered in each Market Service)

FCESS	Con. Raise	Reg. Raise	RoCoF
Offered Price	$0	$0	$0
EM	30 MW	30 MW	30 MW
Enabled Quantity	50 MW	25 MW	500 MWs
Clearing Price	$20	$10	$0

Cleared Energy Offers:

Tranche	1	2	3
Offered Price	$110	N/A	N/A
Cleared Qty	30 MW	N/A	N/A
FRTP	-$10	N/A	N/A

$$RTMBaseCompensation = \Big($$

$$FCESSMinDispatchTarget \times ReferenceTradingPrice$$

30 * (-10) = -300.00

$$+\sum_{for\ FCESS\ except\ RoCoF} EnablementQty \times MCP \times PF$$

RR: 25 * 10 * 1 = 250.00

CR: 50 * 20 * 1 = 1000.00

RoCoF: N/A

$$\Big) \times \frac{5}{60}$$

RTM Base Compensation = (-300 + 1250) * 5/60 = <u>$79.17</u>

FCESS Uplift Payment calculation changes (12)

Worked Example 2 – Raise Services Only FCESS Uplift Offset

ESS Offer & Enablement:

(only 1 tranche offered in each Market Service)

FCESS	Con. Raise	Reg. Raise	RoCoF
Offered Price	$0	$0	$0
EM	30 MW	30 MW	30 MW
Enabled Quantity	50 MW	25 MW	500 MWs
Clearing Price	$20	$10	$0

Cleared Energy Offers:

Tranche	1	2	3
Offered Price	$110	N/A	N/A
Cleared Qty	30 MW	N/A	N/A
FRTP	-$10	N/A	N/A

$$RTMDispatchCost = \ ($$

$$\sum_{for\ each\ tranche} ClearedEnergyQty \times EnergyPrice$$

*tranche 1: 30 * 110 = 3300.00*

tranche 2: N/A

$$+\sum_{for\ FCESS\ except\ RoCoF} \sum_{for\ each\ tranche} ClearedQty \times FCESSprice \times PF$$

*RR tranche 1: 25 * 0 * 1 = 0.00*

*CR tranche 1: 50 * 0 * 1 = 0.00*

RoCoF tranche 1: N/A

No tranche 2

$$) \times \frac{5}{60}$$

RTM Dispatch Cost = (3300 + 0) * 5/60 = $275.00

FCESS Uplift Payment calculation changes (13)

Worked Example 2 – Raise Services Only FCESS Uplift Offset

ESS Offer & Enablement:

(only 1 tranche offered in each Market Service)

FCESS	Con. Raise	Reg. Raise	RoCoF
Offered Price	$0	$0	$0
EM	30 MW	30 MW	30 MW
Enabled Quantity	50 MW	25 MW	500 MWs
Clearing Price	$20	$10	$0

Cleared Energy Offers:

Tranche	1	2	3
Offered Price	$110	N/A	N/A
Cleared Qty	30 MW	N/A	N/A
FRTP	-$10	N/A	N/A

$$FCESSUpliftPayment = \begin{cases} max(0, RTMDispatchCost - RTMBaseCompensation) & if\ eligible \\ 0 & Otherwise \end{cases}$$

FCESS Uplift Payment = max(0, $275 - $79.17) = $195.83

This is a significant decrease from the current approach, which results in an FCESS Uplift payment of about $300

Working together for a **brighter** energy future.

FCESS Uplift Payment calculation changes (14)

Overview of changes (continued):

- **Consequential changes to clause 9.10.3I to 9.10.3O (e.g. to use the FCESS Uplift Payment eligibility flag)**
- **New section 7.17 – revised Estimated FCESS Uplift Payment calculation**
- Based on clauses 9.10.3C – 9.10.3HA but uses available inputs (e.g. energy Market Clearing Price instead of Reference Trading Price)
- **Update to Estimated FCESS Uplift Payment definition**

FCESS Cost Review Amending Rules – Exposure Draft Clarifying Participants' obligations

Dora Guzeleva / Douglas Birse / Nathan Viles

Available/In-Service Capacity changes (1)

The problem:

- Market Participants are failing to convert Available Capacity to In-Service Capacity
- Leads to real-time shortfalls and unnecessarily high Market Clearing Prices

Proposed changes:

- Redefinition of dispatch Scenarios to make the Reference Scenario only consider In-Service Capacity
- Include an obligation on Market Participants to move their capacity to “In-Service” if AEMO projects a shortfall in energy, Contingency Reserve Raise or Regulation Raise
- New Energy Uplift Payment trigger for Low Reserve Conditions (covered earlier)

Available/In-Service Capacity changes (4)

Obligation to move Available Capacity to In-Service Capacity

7.4.2C. Subject to clause 7.4.2D, if:

(a) a Market Participant offers capacity as Available Capacity in its Real-Time Market Submissions for energy for a Dispatch Interval;

(b) the Reference Scenario for the Dispatch Interval in the last Pre-Dispatch Schedule or Dispatch Schedule provided to the Market Participant before the relevant Start Decision Cutoff predicts a real-time shortfall in energy, Contingency Reserve Raise or Regulation Raise; and

(c) the shortfall identified under clause 7.4.2C(b) relates to a lack of energy In-Service Capacity in the Dispatch Interval,

then the Market Participant must, as soon as practicable, update its Real-Time Market Submissions for the Dispatch Interval to convert the Available Capacity to In-Service Capacity to alleviate the predicted shortfall.

Available/In-Service Capacity changes (5)

Obligation to move Available Capacity to In-Service Capacity

7.4.2D. Clause 7.4.2C does not apply to:

- (a) Available Capacity that is not subject to Reserve Capacity Obligations;
- (b) Available Capacity that would not assist in alleviating the predicted shortfall if it was converted to In-Service Capacity; and
- (c) Available Capacity held by a Market Participant in excess of the quantity required to resolve the predicted shortfall.

Note that Market Participants can offer as In-Service Capacity with Fast Start Inflexibility Profiles to both meet the obligation and ensure dispatch profiles adhere to physical limitation of their Facilities

Available/In-Service Capacity changes (3)

Scenario redefinition – consequential changes

- **Changes to clauses 3.11.2, 7.4.5, 7.7.4, 7.7.5, 7.13A.2, definition of Not In-Service Capacity**
- **New defined term Available Capacity Scenario**
- **Includes key Market Schedule inputs/outputs provided to Market Participants under clause 7.13.1A**

Available/In-Service Capacity changes (2)

Scenario redefinition (section 7.8 and Glossary)

Current Name	New Name	Market Schedules	Tranches Included
InServiceCapacityOnly	Reference	All	In-Service Capacity only
Reference	Available Capacity	All	In-Service Capacity and Available Capacity up to Start Decision Cutoff
High forecast/low forecast	High forecast/low forecast	Week-Ahead	In-Service Capacity and Available Capacity up to Start Decision Cutoff
High forecast/low forecast	High forecast/low forecast	Pre-Dispatch	In-Service Capacity only

Start Decision Cutoff Obligations (1)

The problem:

- **Notice periods for Available Capacity in some Real-Time Market Submissions appear to be longer than necessary**
- **This can lead to capacity shortfalls and/or the dispatch of more expensive plant when less expensive plant should have been dispatched instead**

Proposed changes:

- **Require Market Participants to specify reasonable Start Decision Cutoff times in their Real-Time Market Submissions**
- **Account for time needed to respond to a trigger event, update Real-Time Market Submissions and carry out the requisite physical activities to make the capacity ready for dispatch**

Start Decision Cutoff Obligations (2)

New clause 7.4.12

7.4.12. A Market Participant must not specify a Start Decision Cutoff for a quantity of Available Capacity in a Real-Time Market Submission for a Facility in a Dispatch Interval that exceeds the sum of:

(a) 10 minutes; and

(b) the greater of:

i. the sum of:

1. the number of minutes between Gate Closure for the Dispatch Interval and the start of the Dispatch Interval; and

2. 5 minutes; and

ii. the minimum time needed to carry out the requisite physical activities to make the capacity ready for dispatch in the Dispatch Interval, given the Market Participant's reasonable expectation of the state of the Facility at the time those activities would commence.

Seeking feedback on the time periods in clauses 7.4.12(a) and 7.4.12(b)(i)(2)

Market Power Mitigation framework changes (1)

The problem:

- Energy Market Clearing Prices reaching the cap due to the prices in submissions. This behaviour has led to unnecessarily high Market Clearing Prices.
- Market Participants may have market power or transitory market power and can potentially be unaware of their potential to influence market prices with their offer.

Proposed changes:

- It is proposed to revise some of the Market Power Mitigation Strategy changes made in 2023 to ensure offers reflect costs.
- It is proposed to align the rules with ERA's Offer Construction Guideline – i.e. that Market Participants' offers must not exceed the sum of all of their efficient variable costs.
- The proposed changes will remove the need to demonstrate that a Market Participant had market power when formulating its offers.
- This removes an element of uncertainty from preparing market offers and seeks to limit the practice of withdrawing capacity from the market by pricing at the market cap.
- The intention is not to reverse the policy decision to allow market participants to bid their efficient variable costs, including the costs incurred under long-term take-or-pay fuel contracts.

Market Power Mitigation framework changes (2)

Key proposed changes

2.16A.1. ~~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.~~[Blank]

2.16A.2. ~~The Economic Regulation Authority must not determine that a Market Participant has engaged in conduct prohibited by clause 2.16A.1 unless the Economic Regulation Authority has first determined that the Market Participant had market power at the time of offering the relevant prices in its STEM Submission or Real-Time Market Submission.~~[Blank]

…

2.16C.6. The Economic Regulation Authority must investigate potential breaches of clause 2.16C.5 ~~2.16A.1~~:

(a) in accordance with clause 2.13.27 and the WEM Procedure referred to in clause 2.16D.15; and

(b) having regard to the Offer Construction Guideline,

and if it considers that:

(c) a price offered by a Market Participant in its Portfolio Supply Curve was inconsistent with ~~the price that a Market Participant without market power would offer in a profit-maximising Portfolio Supply Curve~~ an Economic Price Offer; or

(d) a price offered by a Market Participant in its Real-Time Market Submissions was inconsistent with ~~the price that a Market Participant without market power would offer in a profit-maximising Real-Time Market~~ an Economic Price Offer,

the Economic Regulation Authority must determine that the price was an Irregular Price Offer.

2.16C.6A. An Economic Price Offer is an offer which is not greater than the sum of all efficient variable costs for the provision of the relevant Market Service, including all costs incurred under long-term take-or-pay fuel contracts.

Market Power Mitigation framework changes (3)

Changes to Portfolio determination process

Frequency reduced from six monthly to an annual determination.

Clarifies that a Registered Facility is part of the same Portfolio:

Where there is whole or partial ownership or control of that Registered Facility by a Market Participant.

Removes complexities of the Corporations Act definitions.

Requires all Market Participants to provide declarations on ownership and control to the ERA:

- **by 1 August each year; or**
- **within 30 Business Days of the registration of a new Facility or a change in a Facility's ownership/registration.**

Market Power Mitigation framework changes (4)

Changes to Material Constrained Portfolio determination process

The ERA's determination deadline has been amended to ensure that all Rolling Test Window period data is available before the ERA is required to publish its determination.

Previously, due to data processing times, the data for the last Trading Day of the Rolling Test Window could potentially be unavailable by the publishing deadline set in the WEM Rules.

Change to the definition of "Rolling Test Window" to clarify that each window is separate, consecutive, and does not overlap. The definition remains a 3-monthly period based on Trading Days.

FCESS Cost Review Amending Rules – Exposure Draft
Other proposed amendments

Jenny Laidlaw

Other proposed amendments

- Clause 2.26.2 – amend definition of Heat Rate in Energy Offer Price Ceiling calculation
- Removal of clause 7.4.6 (not required)
- New clause 9.5.2A – confirm Metered Schedules of Scheduled Facilities, Semi-Scheduled Facilities and Non-Scheduled Facilities are Public Information
- Minor enhancements to settlement equations around the use of RTM Suspension Flag (e.g. clauses 9.9.8 and 9.9.9)
- Minor error corrections (e.g. clause 7.13A.1)

Next Steps

Dora Guzeleva

Next Steps

Step	Completed By
Rules consulted	09/08/2024 - 09/09/2024
Rules Made and Gazetted	18/10/2024 (TBC
Systems implemented	20/11/2024
Commencement of Rules and System Changes, FCESS administered price ends	20/11/2024

NOTE: This will complete Stage 1 of our investigation in the FCESS market, we will continue to investigate some of the above issues and those in our Long List of Issues through Stage 2 and our FCESS Requirements and SESSM Review

Stakeholders’ role

Consultation on the WEM Amending Rules Exposure Draft closes on 9 September 2024

We will not be able to accept late submissions

Please provide your feedback as soon as practicable leading to the 9 September

Happy to have 1:1 discussions if of benefit

Implementation Sequencing of WEM Amending Rules

Mike Hales

Rule Commencement Sequencing

Sequencing is determined by several factors:

- Alignment of Reserve Capacity certification with the commencement of the obligations.
  - **Capacity certified in Year 1 of the Reserve Capacity Cycle will have obligations in Year 3.**
  - **Rules commence in January for certification and October for obligations.**

- Market factors driving the priority for commencement.
  - **To enable connection or efficient dispatch of new generation.**
  - **To enable the operation of AEMO or Market Participant obligations.**

- Risks associated with AEMOs implementation.
  - **Availability of specialist resources to deliver the system and processes changes.**
  - **Uncertainty in implementation requirements and impacts.**

2024 Rule Commencement

Sept 2024

Miscellaneous 3

- Registration of Separate Facilities

Oct 2024

Miscellaneous 3

- Recovery of capacity related NCESS via IRCR

Nov 2024

FCESS Cost Review

- Tie breaking methodology
- RoCoF Control Service changes
- FCESS Uplift calculation changes
- Changes to Real-Time bids and offer obligations

2025 Rule Commencement

RCM Review
- Flexible Capacity Expressions of Interest
- Certification of Flexible Capacity
- DER certified in Demand Side Programmes

WEM Investment Certainty
- New Peak RC Price curve
- Flexible RC Price curve
- Fixed RC Price inflation adjustment
- 10 Year price guarantee

Jan 2025

Oct 2025

Cost Allocation Review
- Co-optimisation of Contingency Lower
- Recovery of Contingency Lower via runway method

2026 Rule Commencement

Jan 2026

RCM Review
- Publication of constrained Transmission Nodes

Apr 2026

RCM Review
- Registration of DSP Facilities and Associated Loads

Oct 2026

RCM Review
- RC Testing changes for DSP Facilities
- Settlement refunds for DSP Facilities
- Capacity Credit Allocations by Facility/component
- Settlement refunds for DSP Facilities
- Dynamic Baseline

Miscellaneous 3
- Contingency Raise recovery via runway

2027 Rule Commencement

Oct 2027

RCM Review

- RC Testing of Flexible Capacity Facilities
- Flexible Capacity Credit Allocations
- Settlement refunds and payments for Flexible Capacity
- Peak IRCR
- Flexible IRCR

WEM 5-minute Settlement

- 5-minute interval data
- Settlement at 5-minute interval granularity

2028 Rule Commencement

Jan 2028

RCM Review

- Certification of Peak Capacity via new Relevant Level Method

Oct 2028

Cost Allocation Review

- Regulation Raise/Lower cost recovery

Feedback

Participants wanting to provide feedback or ask questions about the proposed commencement timeline please email energymarkets@demirs.wa.gov.au.

Feedback requested before 5pm on 9 September 2024.