EXPOSURE DRAFT: TRANCHE 4B

PROPOSED WEM AMENDING RULES

Explanatory Note for Tranche 4B Proposed WEM Amending Rules

This Exposure Draft contains proposed Amending Rules for the following areas of the Wholesale Electricity Market Rules:

1. Section 3.6: Under Frequency Load Shedding
2. Change management for specified WEM Technical Standards
3. Transitional rules for AGC dispatch
4. Amendments to Appendix 12: Generation Performance Standards
5. Aligning the availability declarations process with the Reserve Capacity Mechanism (RCM) obligations
6. Aligning the storage constraints opt-in process for storage facilities with the RCM
7. Amendments to Chapter -4
8. Treatment of voluntary reduction of Capacity Credits by Demand Side Programmes

The draft rules presented in this Exposure Draft are pending legal review. Following industry consultation and legal review, the proposed Amending Rules will be submitted to the Minister for Energy for making and gazettal.

Tentative commencement dates, where available, have been provided in the explanatory notes preceding the relevant draft rules.

Energy Policy WA is seeking stakeholder feedback on this Exposure Draft by 5:00 PM 30 June 2021. Feedback can be sent to **energymarkets@energy.wa.gov.au**

Explanatory Note: Under Frequency Load Shedding

Replacement section 3.6 outlines the obligations of AEMO and Network Operators in relation to managing under frequency load shedding on the SWIS. AEMO is required to prepare and publish an UFLS Requirements document to set out the aggregate UFLS requirements for the SWIS taking into account the SWIS Frequency Operating Standards. Network Operators are required to design and develop UFLS specifications to adhere to the requirements set out by AEMO. This section also sets out obligations for AEMO and Network Operators to consult with each other when amendments to UFLS Requirements are necessary and to monitor ongoing performance against these documents.

In practice, when a frequency event occurs on the power system resulting in frequency dropping below the levels identified in the Frequency Operating Standard, the under frequency load shedding schemes will operate in accordance with the parameters in the UFLS Requirements and UFLS Specification documents. Other WEM rules (e.g. section 3.2A) are already in place to ensure appropriate coordination between AEMO as the System Operator and Western Power.

Replacement section 3.6 is tentatively proposed to commence on 1 December 2021.

3.6 Under Frequency Load Shedding

3.6.1. AEMO must prepare and publish an UFLS Requirements document containing the aggregate requirements for automatic under frequency load shedding, taking into account the SWIS Frequency Operating Standards.

3.6.2. The UFLS Requirements document must include guidance for a Network Operator to design and implement automatic under frequency load shedding schemes that support Power System Security. These items include but are not limited to:

(a) the quantity of load required for shedding, or guidance on how to determine the required quantities;
(b) prioritisation of load types;
(c) details of any staging requirements;
(d) initiation criteria;
(e) speed of operation;
(f) any required variation in settings or functional requirements based on system conditions; and
(g) any other relevant matters required to support Power System Security.

3.6.3. AEMO must consult in good faith with each impacted Network Operator when it develops, and each time it reviews, the UFLS Requirements document.

3.6.4. If for any reason, either AEMO or a Network Operator proposes an amendment to the UFLS Requirements document, the relevant entity must consult in good faith with the other entity and AEMO must only progress the amendment if both entities agree such amendment is reasonably necessary.

3.6.5. AEMO must publish the UFLS Requirements document, and any amendments to it, on the WEM Website.

3.6.6. A Network Operator that has obligations under the UFLS Requirements document, must develop and maintain an UFLS Specification document setting out how the Network Operator will design and implement its schemes to meet the requirements outlined in the UFLS Requirements Document.

3.6.7. Each Network Operator's UFLS Specification document must be submitted to AEMO for review, including when changes are initiated by the Network Operator, or as a result of a change to the UFLS Requirements document.

3.6.8 Within a reasonable timeframe agreed with a Network Operator, AEMO must review and approve the Network Operator's UFLS Specification document once any reasonable amendments suggested by AEMO have been agreed and incorporated.

3.6.9. Each Network Operator must implement and maintain schemes in accordance with its UFLS Specification document, and must agree a timeframe with AEMO for changes to its schemes triggered by any changes to its UFLS Specification document.

3.6.10. Each Network Operator must report to AEMO on the compliance of its schemes with the UFLS Specification, and performance in meeting the UFLS Requirements:

(a) annually, on the projected ability to meet the requirements over a future ten-year horizon; and

(b) within an agreed timeframe with AEMO, following each under frequency load shedding event.

Chapter 11 Glossary

UFLS Requirements: The document referred to in clause 3.6.1 containing the functional requirements for the SWIS under frequency load shedding system, and any future planned amendments or modifications to those functional requirements.

UFLS Specification: The document referred to in clause 3.6.6 containing the design specification of a Network Operator's under frequency load shedding system demonstrating compliance with the functional requirements specified in the UFLS Requirements document.

~~3.6. Demand Control~~

~~3.6.1. AEMO must determine the aggregate requirements for automatic under frequency load shedding in accordance with the SWIS Operating Standards.~~

~~3.6.2. AEMO must produce operational plans to implement the aggregate under frequency load shedding requirements. These operational plans must account for sensitive loads and for the rotation of loads between load shedding bands.~~

~~3.6.3. [Blank]~~

~~3.6.4. AEMO must inform all Network Operators of its operational plans for under frequency load shedding.~~

~~3.6.5. Network Operators must implement AEMO's operational plans for automatic under frequency load shedding by:~~

~~(a) setting their automatic under frequency load shedding equipment in accordance with AEMO's operational plans, including the rotation of loads between load shedding bands;~~

~~(b) maintaining the equipment which will implement the automatic under frequency load shedding in good order; and~~

~~(c) reporting to AEMO at the times required by AEMO on their compliance with AEMO's operational plans.~~

~~3.6.6. AEMO must make plans for manual load shedding, and must inform Network Operators of these plans.~~

~~3.6.6A. AEMO may issue manual disconnection directions to Network Operators, where such directions must be in accordance with AEMO's load shedding plans.~~

~~3.6.6B. Network Operators must comply with any manual disconnection directions received from AEMO.~~

Explanatory Note: Change Management Framework for WEM Technical Standards
The proposed Amending Rules enable the Coordinator to seek technical or engineering advice or information from Western Power and AEMO when a Rule Change Proposal relates to amending a WEM Technical Standard. This additional step ensures that when standards related to Power System Security and Reliability are proposed to be modified, proper engineering advice has been provided by the two primary entities responsible for system security and reliability. The Coordinator retains the discretion to request technical advice at any time throughout the Standard Rule Change Process. These changes are proposed to commence on 1 August 2021.

2.4.3. In deciding whether to make Amending Rules, the Coordinator must have regard to the following:

(a) any applicable statement of policy principles given to the Coordinator under clause 2.5.2;

(aA) any advice provided by the Market Advisory Committee regarding the evolution or the development of the Wholesale Electricity Market or these WEM Rules;

(b) the practicality and cost of implementing the Rule Change Proposal;

(c) the views expressed in any submissions on the Rule Change Proposal;

(d) any advice by the Market Advisory Committee where the Market Advisory Committee met to consider the Rule Change Proposal;

(dA) whether the advice from the Market Advisory Committee provided under clause 2.4.3(d) reflects a consensus view or a majority view, and, if the latter, any dissenting views included in or accompanying the advice and how these views have been taken into account by the Coordinator; ~~and~~

(e) any technical studies that the Coordinator considers are necessary to assist in assessing the Rule Change Proposal; and

(f) any advice and/or information provided by AEMO and/or Western Power under clause 2.4.3C.

2.4.3B. Where the Coordinator considers that making Amending Rules will affect a WEM Technical Standard, the Coordinator must request advice and/or information from AEMO and/or Western Power to assist in assessing the relevant Rule Change Proposal. The following applies to the request:

(a The Coordinator must consult AEMO and/or Western Power, as applicable, on the requirements and the timeframes applicable to the request; and

(b) The Coordinator may, at her or his discretion, require AEMO and Western Power to provide advice jointly or independently.

2.4.3C. Subject to 2.4.3D, AEMO and/or Western Power must provide the advice and/or information requested by the Coordinator under clause 2.4.3B in accordance with the timeframes or any other requirement specified in the request.

2.4.3D. Where AEMO and/or Western Power require a longer timeframe to provide the advice requested by the Coordinator under clause 2.4.3B, AEMO and/or Western Power:

(a) may seek an extension to the timeframe; and

(b) must outline the reasons for seeking the extension.

…

2.5.1D. AEMO or Western Power, as applicable, must, before submitting a Rule Change Proposal that may affect a WEM Technical Standard, consult with the other party on the Rule Change Proposal, and must take into account the outcome of that consultation in the Rule Change Proposal.

…

2.7.7. The Draft Rule Change Report must contain:

(a) the information in the notice of the Rule Change Proposal under clause 2.5.7;

(b) all submissions received before the due date for submissions, a summary of those submissions, and the Coordinator's response to issues raised in those submissions (and the report may in the Coordinator's discretion contain any or all of this material in respect of a submission received after the due date);

(c) a summary of any public forums or workshops held;

(cA) a summary of the advice provided by AEMO and/or Western Power in response to a request under clause 2.4.3B, and reasons if the Coordinator does not propose to follow partially or fully the advice;

(d) a summary of the views expressed by the members of the Market Advisory Committee where the Market Advisory Committee met to consider the Rule Change Proposal and, if the Market Advisory Committee has delegated its role to consider the Rule Change Proposal to a Working Group under clause 2.3.17(a), a summary of the views expressed by that Working Group;

(dA) reasons if the Coordinator does not propose to follow partially or fully the advice received from the Market Advisory Committee;

(e) the Coordinator's assessment of the Rule Change Proposal in light of clauses 2.4.2 and 2.4.3;

(f) a proposal as to whether the Rule Change Proposal should be accepted in the form proposed. The proposal may be that:

i. the Rule Change Proposal be accepted in the proposed form; or

ii. the Rule Change Proposal be accepted in a modified form; or

iii. the Rule Change Proposal be rejected; and

(g) if the Coordinator proposes to make Amending Rules arising from the Rule Change Proposal:

i. the wording of the proposed Amending Rules; and

ii. a proposed date and time the proposed Amending Rules will commence.

2.7.8. The Final Rule Change Report must contain:

(a) the information in the Draft Rule Change Report;

(b) all submissions received before the deadline for submissions specified in relation to the relevant Draft Rule Change Report under clause 2.7.6(b), a summary of those submissions, and the Coordinator's response to the issues raised in those submissions (and the report may in the Coordinator's discretion contain any or all of this material in respect of a submission received after the deadline));

(bA) reasons if the Coordinator has decided not to follow partially or fully the advice received from the Market Advisory Committee;

(bB) reasons if the Coordinator has decided not to follow partially or fully any advice provided by AEMO and/or Western Power under clause 2.4.3C;

(c) any further analysis or modification to the Rule Change Proposal;

(d) the Coordinator's assessment of the Rule Change Proposal in light of clauses 2.4.2 and 2.4.3;

(e) the decision made by the Coordinator under clause 2.7.7A(a) on the Rule Change Proposal;

(f) the Coordinator's reasons for the decision; and

(g) if the Coordinator decides to make Amending Rules arising from the Rule Change Proposal:

i. the wording of the Amending Rules; and

ii. the proposed date and time that the Amending Rules will commence.

Explanatory Note Clause 2.8.14 sets out the WEM Technical Standards that require protecting under the rule change process to ensure that technical and engineering advice is sought from AEMO and/or Western Power when any of these clauses are the subject of a Rule Change Proposal. Some of these clauses do not commence until New WEM Commencement, and so the commencement of some sub-clause items will be deferred.

2.8.14. The following clauses are WEM Technical Standards:

(a) section 3.1;

(b) clause 3.2.5;

(c) clauses 3.3.3 and 3.4.3.

(d) section 3.6;

(e) section 3.7;

(f) chapter 3A and appendix 12; and

(g) chapter 3B;

Chapter 11 Glossary

WEM Technical Standard: A chapter, section, or clause of the WEM Rules, identified in clause 2.8.14.

Explanatory Note: Transitional Rules for AGC Dispatch Market Participants can voluntarily participate in trialling central ramping dispatch of their facilities to facilitate new market readiness. The transitional rules enable AEMO to take operational control of a Market Participant's facility for this purpose, while ensuring compliance with dispatch instructions as issued under the current Balancing and LFAS Markets. To the extent AEMO ensures its operational control of the facility remains consistent with the applicable dispatch instruction, the participant is required to maintain its dispatch compliance. It should be highlighted these transitional rules do not affect any existing aspects of market operation or compensation. They are purely intended for the purposes of testing a facility's physical ability to ramp linearly in response to a dispatch instruction in the new WEM and to help participants prepare for cutover. These transitional clauses will commence on 1 August 2021.

1.49.1. Where necessary to test or implement operational controls required for AEMO and Market Participants to operate under the Tranches 2 and 3 Amending Rules and associated WEM Procedures, AEMO may request to control specified operations of a Registered Facility. If accepted by the relevant Market Participant, AEMO's operational control of the Facility may include:

(a) the starting, loading and stopping of the Facility; and

(b) limiting the injection of the Facility.

1.49.2. The operational control of a Registered Facility by AEMO pursuant to an acceptance by a Market Participant referred to in clause 1.49.1:

(a) does not remove AEMO's obligation to record Dispatch Instructions for those Registered Facilities; and

(b) does not affect or modify a Market Participant's rights and obligations in respect of a Registered Facility under these WEM Rules.

1.49.3. Where AEMO has operational control of a Facility under clause 1.49.1:

(a) AEMO is not required to issue a Dispatch Instruction to the Facility where the adjustments relate to implementation of a previously recorded Dispatch Instruction.

(b) AEMO must operate the Registered Facility in compliance with Dispatch Instructions recorded for the Registered Facility.

1.49.4. To the extent AEMO's operational control of a Facility under clause 1.49.1 is compliant with the recorded Dispatch Instruction, the Market Participant in respect to that Facility must continue to comply with the obligations in section 7.10.

Explanatory Note

Amendments are proposed to Appendix 12: Transmission Connected Generating Systems Generator Performance Standards. The proposed amendments seek to correct errors and provide additional clarity.

A summary of the changes:

Modifications to definitions

- Credible Contingency Event – definition changed to match current Technical Rule definition and usage, and accompanying clause changes
- Settling Time – definition change to address typographical errors

Voltage and Reactive Power Control

- Inclusion of clarifying wording in the footnotes and tables to provide consistency of interpretation

Active Power Control

- Inclusion of clarifying clause to ensure consistency of understanding and application of A12.5 and A12.6 requirements in relation to active power ramping under different conditions

Inertia and Frequency Control

- Movement of repeated requirements in both Ideal and Minimum Standards to the Common Requirements section for ease of application
- Clarity that tripping schemes will not be normally accepted to meet this standard going forward
- Improved definition of droop response
- Improved clarity on require frequency response under the Ideal Standard
- Introduction of a clear Minimum Standard, allowing for different technology types

Disturbance Ride Through

- Clarifying that where an agreed tripping scheme does exist, it will not breach this standard

The clauses in this Appendix commenced on 1 February 2021. The amendments presented here will commence on 1 August 2021.

A12.1 Definitions

Credible Contingency ~~Event~~~~: As described~~ An unplanned disconnection of equipment, or other event, that a Generating System may reasonably be exposed to as described in the Technical Rules.

Settling Time: In relation to a control system, means the time measured from initiation of a step change in an input quantity to the time when the magnitude of error between the output quantity and its final settling value remains less than 10% of:

(a) if the sustained change in the quantity is less than half of the maximum change in that output quantity, half of the maximum change~~d~~ induced in that output quantity; or otherwise

(b) the sustained change~~d~~ induced in that output quantity.

A12.4.2. Voltage and Reactive Power Control - Common Requirements

A12.4.2.10. Each Synchronous Generating Unit must have an Excitation Control System that:

(a) is capable of operating the stator continuously at 105% of nominal voltage with Rated Maximum Active Power output;

(b) has an excitation ceiling voltage of at least:

(i) for a Static Excitation System, 2.3 times; or

(ii) for other Excitation Control Systems, 1.5 times,

the excitation required to achieve generation at the Nameplate Rating for rated Power Factor, rated speed and nominal voltage;

(c) has a power system stabiliser with sufficient flexibility to enable damping performance to be maximised, with the stabilising circuit responsive and adjustable over a frequency range from 0.1 Hz to 2.5 Hz; and

(d) achieves a minimum equivalent gain of 200[8]

Footnote 8: For both proportional and integral control actions. Note that one per unit excitation voltage is that field voltage required to produce nominal voltage on the air gap line of the Generating Unit open circuit characteristic (~~R~~refer IEEE Standard 115-1983 - Test Procedures for Synchronous Machines)

A12.4.2.11. The performance characteristics required for AC exciter, rotating rectifier and Static Excitation Systems are specified in Table A12.4.2.11.

Table A12.4.2.11: Synchronous Generating Unit Excitation Control System performance requirements

Performance Item	Units	Static Excitation	AC exciter or rotating rectifier
Generating Unit Field voltage *Rise Time:* Time for field voltage to rise from rated	Second	0.05 maximum	0.5 maximum

field voltage[1] to excitation ceiling voltage following the application of a short duration impulse to the voltage reference.			
Settling Time with the Generating Unit unsynchronised following a disturbance equivalent to a 5% step change in the sensed Generating Unit terminal voltage.	Second	1.5 maximum	2.5 maximum
Settling Time with the Generating Unit synchronised following a disturbance equivalent to a 5% step change in the sensed Generating Unit terminal voltage. It must be met at all operating points within the Generating Unit capability.	Second	2.5 maximum	5 maximum
Settling Time following any disturbance which causes an excitation limiter to operate.	Second	5 maximum	5 maximum

Notes:

1. rated field voltage is that voltage required to give nominal Generating Unit terminal voltage when the Generating Unit is operating at its Rated Maximum Apparent Power

A12.5.1. Active Power Control - Common Requirements

A12.5.1.6. The requirements in this section A12.5 do not override any specific Active Power ramping requirements specified in section A12.6 in response to frequency deviations.

A12.6.1. Inertia and Frequency Control - Common Requirements

A12.6.1.6 Unless otherwise agreed by the Network Operator and AEMO, protection or other schemes, that disconnect the Generating System or elements of the Generating System, must not be used in order to meet the requirements of this section A12.6.

A12.6.1.7 A Generating System must have an automatic variable Active Power control characteristic, where Generating Units with Turbine Control Systems must include equipment for both speed and Active Power control.

A12.6.1.8 All Generating Units, or the Generating System as applicable, capable of operating in a mode in which it will automatically alter its Active Power output to arrest and correct to changes in power system frequency, with all Generating Units operating in this mode unless instructed otherwise by AEMO.

A12.6.1.9 A dead band on each Generating Unit, or the Generating System as applicable, (the sum of increase and decrease in power system frequency before a measurable change in the Generating Unit's Active Power output occurs) which is less than +/-0.025 Hz symmetrical around 50.0 Hz.

A12.6.1.10 Unless otherwise stated in this section A12.6, the overall required frequency response of each Generating Unit, or Generating System as applicable, must be settable and be capable of:

(a) automatically achieving an increase in Active Power output proportional to a change in power system frequency of not less than 5% of the Rated Maximum Active Power for each 0.1 Hz reduction in power system frequency from the lower frequency dead band for any initial output up to Rated Maximum Active Power output; and

(b) automatically achieving a reduction in Active Power output proportional to a change in power system frequency of not less than 5% of the Rated Maximum Active Power for each 0.1 Hz increase in power system frequency from the upper frequency dead band, provided this does not require operation below its Rated Minimum Active Power;

A12.6.1.11 The frequency response capability described in section A12.6.6.10:

(a) must not exhibit any step changes in Active Power as the power system frequency changes, unless otherwise agreed by the Network Operator and AEMO under section A12.6.1.6;
(b) must commence responding with a delay no greater than that required to ensure stable operation or to allow for control system latency, as agreed by the Network Operator and AEMO;
(c) must not increase Active Power output in response to an increase in power system frequency; and
(d) must not decrease Active Power output in response to a decrease in power system frequency;

A12.6.2. Inertia and Frequency Control - Ideal Standard

A12.6.2.1 The Ideal Generator Performance Standard requires that:

(a) ~~a Generating System must have an automatic variable Active Power control characteristic, where Generating Units with Turbine Control Systems must include equipment for both speed and Active Power control~~ [Blank];
(b) ~~all Generating Units, or the Generating System as applicable, capable of operating in a mode in which it will automatically alter its Active Power output to arrest and correct to changes in power system frequency, with all Generating Units operating in this mode unless instructed otherwise by AEMO~~ [Blank];
(c) ~~a dead band on each Generating Unit, or the Generating System as applicable, (the sum of increase and decrease in power system frequency before a measurable change in the Generating Unit's Active Power output occurs) which is less than +/-0.025 Hz symmetrical around 50.0 Hz~~ [Blank]; and

(d) control ranges, ~~and~~ response times and sustain times, are achieved ~~subject to energy source availability,~~ for Generating Units, or the Generating System as applicable, such that, subject to energy source availability:

(i) ~~the overall response of each Generating Unit, or the Generating System as applicable, for power system frequency excursions must be settable and be capable of achieving an increase in the Generating Unit's Active Power output of not less than 5% for 0.1 Hz reduction in power system frequency (4% droop), for any initial output up to Rated Maximum Active Power~~ [Blank];

(ii) ~~the overall response of each Generating Unit, or the Generating System as applicable, must also be capable of automatically achieving a reduction in the Generating Unit's Active Power output of not less than 5% for 0.1 Hz increase in power system frequency, Rated Minimum Active Power~~ [Blank];

(iii) ~~the Generating System must be able to sustain Active Power output changes of at least 10% for a frequency decrease and 30% for a frequency increase, and for not less than 10 seconds, if changes occur within the above limits of output~~ [Blank];

(iv) for Synchronous Generating Systems, for any frequency disturbance where the change in power system frequency is sufficient to change the Active Power of the Generating System by at least 5% of its Maximum Rated Active Power, the Generating Unit or Generating System achieves ~~of~~ at least 90% of the ~~maximum~~ required frequency response ~~expected~~ specified in clause A12.6.1.10 ~~according to the droop characteristic~~ within 6 seconds; ~~and~~

(v) for Asynchronous Generating Systems, for any frequency disturbance where the change in power system frequency is sufficient to change the Active Power of the Generating System by at least 5% of its Maximum Rated Active Power, the Generating Unit or Generating System achieves ~~of~~ at least 90% of the ~~maximum~~ required frequency response ~~expected~~ specified in clause A12.6.1.10 within 2 seconds;

(vi) the new output is sustained ~~indefinitely, and in any case~~ for not less than a further 10 seconds, subject to a restoration of power system frequency in which case the Active Power output must be changed in proportion to the power system frequency in accordance with the required frequency response specified in clause A12.6.1.10; and

(vii) each Generating Unit's or Generating System's, as applicable, capability to sustain response beyond 10 seconds must be included as part of the relevant Generator Performance Standard;

A12.6.3. Inertia and Frequency Control - Minimum Standard

A12.6.3.1. [Blank] ~~Subject to energy source availability, a Generating System must have:~~

~~(a) an automatic variable Active Power control characteristic, where Generating Units, or Generating Systems as applicable, with Turbine Control Systems must also include equipment for both speed and Active Power control;~~
~~(b) all Generating Units, or Generating Systems as applicable, capable of operation in a mode in which they will automatically alter their Active Power output to arrest and correct to changes in power system frequency, with all Generating Units operating in this mode unless instructed otherwise by AEMO; and~~
~~(c) a dead band on each Generating System (the sum of increase and decrease in power system frequency before a measurable change in the Generating Unit's Active Power output occurs) which is less than +/-0.025 Hz symmetrical around 50.0 Hz.~~

A12.6.3.2 Subject to energy source availability, a Generating System is required to have control ranges and response times for each Generating Unit, or Generating Systems as applicable, such that:

(a) ~~the overall response of each Generating Unit, or Generating Systems as applicable, for power system frequency excursions must be settable and be capable of achieving an increase in the Generating Unit's, or Generating System's as applicable, Active Power output of not less than 5% for 0.1 Hz reduction in power system frequency (4% droop) for any initial output~~ it is able to comply with the required frequency response specified in clause A12.6.1.10(a), up to 85% of Rated Maximum Active Power output;

~~(b) each Generating Unit, or Generating Systems as applicable, must be capable of achieving a reduction in the Generating Unit's, or Generating System's as applicable, Active Power output of not less than 5% for 0.1 Hz increase in power system frequency provided this does not require operation below its Rated Minimum Active Power~~ [Blank];

(c) for initial outputs above 85% of Rated Maximum Active Power output, each Generating Unit's or Generating System's, as applicable, response capability must be agreed with the Network Operator and AEMO, and included as part of the relevant Generator Performance Standard;

~~(d) the Generating System must be able to sustain Active Power output changes of at least 10% for a frequency decrease and 30% for a frequency increase, and for not less than 10 seconds, if changes occur within the above limits of output~~ [Blank];

(e) ~~[Blank]~~ for Synchronous Generating Systems, for any frequency disturbance where the change in frequency is sufficient to change the Active Power of the Generating System by at least 5% of its Maximum Rated Active Power output, the Generating Unit or Generating System achieves at least 60% of the required frequency response specified in clause A12.6.1.10 within 6 seconds, and 90% of the required frequency response specified in clause A12.6.1.10 within 15 seconds;

(f) ~~[Blank]~~ for Asynchronous Generating Systems, for any frequency disturbance where the change in frequency is sufficient to change the Active Power of the Generating System by at least 5% of its Maximum Rated Active Power output, the Generating Unit or Generating System achieves at least 60% of the required frequency response specified in clause A12.6.1.10 within 6 seconds, and at least

90% of the required frequency response specified in clause A12.6.1.10 within 15 seconds;

(g) the new output is sustained for not less than a further 10 seconds, subject to a restoration of power system frequency in which case the Active Power output must be changed in proportion to the power system frequency in accordance with the required frequency response specified in clause A12.6.1.10; and

(h) each Generating Unit's or Generating System's, as applicable, capability to sustain response beyond 10 seconds must be included as part of the relevant Generator Performance Standard;

A12.6.4. Inertia and Frequency Control - Negotiation Criteria

A12.6.4.3 ~~For Scheduled Generators, the Generating System must seek to achieve a rate of response for any frequency disturbance of at least 90% of the maximum response expected according to the droop characteristic within 6 seconds, and the new output must be sustained for not less than a further 10 seconds. However, an alternative rate of response may be agreed by the Network Operator and AEMO as part of a Negotiated Generator Performance Standard taking into account the specified maximum ramp rate~~ [Blank]

A12.6.4.4 ~~For Non-Scheduled Generators, the Generating System must seek to achieve a rate of response for any frequency disturbance of at least 90% of the maximum response expected within 2 seconds, and the new output must be sustained for not less than a further 10 seconds. However, an alternative rate of response may be agreed by the Network Operator and AEMO as part of a Negotiated Generator Performance Standard taking into account the specified maximum ramp rate~~ [Blank]

A12.7.1. Disturbance Ride Through (frequency) - Common Requirements

A12.7.1.3. Where the Network Operator and AEMO have agreed to a protection, or other scheme, that will disconnect the Generating System or elements of the Generating System, in order to satisfy the requirements of section A12.6, the operation of those schemes based on their agreed parameters will not be taken to be a breach of the requirements of section A12.7.

A12.9.2. Disturbance Ride Through - Ideal Requirements

A12.9.2.2. A Generating System and each of its operating Generating Units must remain in Continuous Uninterrupted Operation for any disturbances caused by:

(a) a Credible Contingency ~~Event~~;

A12.9.3. Disturbance Ride Through - Minimum Requirements

A12.9.3.2. A Generating System and each of its operating Generating Units must remain in Continuous Uninterrupted Operation for any disturbance caused by:

(a) a Credible Contingency ~~Event~~; or

Explanatory Note: Determining Not-In-Service Capacity to enable the calculation of Forced Outage Refunds

The following proposed amendments enable the determination of the Not-In-Service Capacity for every Registered Facility that has Capacity Credits. Facilities holding Capacity Credits are required to present their capacity at least up to their Reserve Capacity Obligation Quantity in their market submissions as 'available' or 'in-service'. If a price/quantity offer is "in merit" for a trading interval, or directed to be in service by AEMO, the relevant Market Participant must, subject to applicable start up timeframes, amend the availability declaration to 'in service'. When this is not the case, the not-in-service capacity will be subject to capacity refunds.

These clauses will commence with the majority of dispatch clauses at New WEM Commencement Day.

7.13.1I. AEMO must determine the Not In-Service Capacity for each Registered Facility f for which a Market Participant holds Capacity Credits, excluding Demand Side Programmes, in the Dispatch Interval as either:

NISCap(f,DI) = Max(0, EstDispEnergy(f,DI) – Max(ISSDCEnergy(f,DI), ISDispEnergy(f,DI))

or where AEMO has directed a Registered Facility to offer its capacity as In Service:

NISCap(f,DI) = Max(0, ReqDispEnergy(f,DI) – Max(ISSDCEnergy(f,DI), ISDispEnergy(f,DI))

where:

(a) NISCap(f,DI) is the Not In-Service Capacity quantity for the Registered Facility f in Dispatch Interval DI;

(b) EstDispEnergy(f,DI) is the quantity of estimated energy dispatch just prior to the Start Decision Cutoff time for Registered Facility f, calculated in accordance with clause 7.13.1J;

(c) ISSDCEnergy(f,DI) is the quantity of in service capacity offered just after the Start Decision Cutoff time for Registered Facility f, calculated in accordance with clause 7.13.1K;

(d) ISDispEnergy(f,DI) is the total MW quantity of In-Service Capacity included in the Real-Time Market Offers for energy that were used to calculate Dispatch Instructions and Market Clearing Prices for that Dispatch Interval DI;

(e) ReqDispEnergy(f,DI) is the quantity of in service capacity required In Service by AEMO;

7.13.1J. EstDispEnergy(f, DI) for Registered Facility f in Dispatch Interval DI is:

(a) where at least one Dispatch Schedule has been published before Registered Facility f's Start Decision Cutoff that contains Dispatch Interval DI, the total MW quantity of energy scheduled for dispatch in the Dispatch Interval DI for Registered Facility f determined in the Reference Scenario of the Dispatch Schedule published most recently before Registered Facility f's Start Decision Cutoff; or

(b) where at least one Pre-Dispatch Schedule has been published before Registered Facility f's Start Decision Cutoff that contains Dispatch Interval DI within a Trading Interval, the total MW quantity of energy scheduled for dispatch in the Trading Interval for Registered Facility f determined in the Reference Scenario of the Pre-Dispatch Schedule published most recently before Registered Facility f's Start Decision Cutoff; or

(c) where at least one Week-Ahead Schedule has been published before Registered Facility f's Start Decision Cutoff that contains Dispatch Interval DI within a Trading Interval, the total MW quantity of energy scheduled for dispatch in the Trading Interval for Registered Facility f determined in the Reference Scenario of the Week-Ahead Schedule published most recently before Registered Facility f's Start Decision Cutoff; or

(d) otherwise, zero.

7.13.1K. ISSDCEnergy(f,DI) for Registered Facility f in Dispatch Interval DI is:

(a) where at least one Dispatch Schedule has been published before Registered Facility f's Start Decision Cutoff that contains Dispatch Interval DI, the total MW quantity of In-Service Capacity included in the Real-Time Market Submission for energy from Registered Facility f in the Dispatch Interval DI as used in the Dispatch Schedule published most recently after Registered Facility f's Start Decision Cutoff; or

(b) where at least one Pre-Dispatch Schedule has been published before Registered Facility f's Start Decision Cutoff that contains Dispatch

Interval DI within a Trading Interval, the total MW quantity of In-Service Capacity included in the Real-Time Market Submission for energy from Registered Facility f in the Trading Interval as used in the Pre-Dispatch Schedule published most recently after Registered Facility f's Start Decision Cutoff; or

(c) where at least one Week-Ahead Schedule has been published before Registered Facility f's Start Decision Cutoff that contains Dispatch Interval DI within a Trading Interval, the total MW quantity of In-Service Capacity included in the Real-Time Market Submission for energy from Registered Facility f in the Trading Interval as used in the Week-Ahead Schedule published most recently after Registered Facility f's Start Decision Cutoff

(d) otherwise, zero.

7.13.1B. Within 5 minutes of each time AEMO uses the Dispatch Algorithm for the purposes of the Central Dispatch Process, and no later than the end of the relevant Dispatch Interval, AEMO must publish:

(a) Dispatch Targets, Dispatch Caps, Dispatch Forecasts as applicable for each Facility;

(b) Essential System Service Enablement Quantities for each Registered Facility and each Frequency Co-optimised Essential System Service;

(c) the Market Clearing Price for each Market Service for the relevant Dispatch Interval;

(d) binding Constraint Equations;

(e) Constraint Equations within 10% of binding;

(f) the Minimum RoCoF Control Requirement;

(g) the Additional RoCoF Control Requirement;

(h) the RoCoF Control Requirement;

(i) the Contingency Raise Factor;

(j) the Contingency Lower Factor; and

(k) Facility Performance Factors.

(l) The quantity of Not In-Service Capacity for each Registered Facility for which a Market Participant holds Capacity Credits, excluding Demand Side Programmes, in each Dispatch Interval.

Not In-Service Capacity: Means, for a Registered Facility in a Dispatch Interval, the sent-out capacity in MW that was expected to be required for dispatch but was not offered as In-Service Capacity, as calculated in clause 7.13.1I.

Start Decision Cutoff: for a Registered Facility and a Dispatch Interval and a Price-Quantity Pair, the latest amount of time before the start of the Dispatch Interval at which a Market Participant could change Available Capacity to In-Service Capacity so as to achieve synchronisation for the energy in that Price-Quantity Pair in the Dispatch Interval, as reflected in its Real Time Market Submission.

Explanatory Note: Determining Not-In-Service Capacity to enable the calculation of Forced Outage Refunds

In the following proposed amendments, AEMO is obligated to calculate the Not-In-Service Capacity refund for Facilities that hold Capacity Credits.

4.26.1D. AEMO must calculate the Not In-Service Capacity Refund for each Registered Facility f for which a Market Participant holds Capacity Credits in each Trading Interval t as:

$$NISRefund(f,t) = \frac{\sum_{DI \in t}\left(MIN\left(\left(RCOQ_{(f,DI)} - CAFO(f,DI)\right),\ NISCap_{(f,DI)}\right)\right)}{6} \times TIRR(f,t)$$

where:

(a) NISRefund(f,t) is the Not In-Service Capacity Refund for the Registered Facility in the Trading Interval t;

(b) RCOQ(f,DI) is the RCOQ for the Registered Facility in the Dispatch Interval DI;

(c) CAFO(f,DI) is the Capacity Adjusted Forced Outage Quantity for the Registered Facility in the Dispatch Interval as determined under clause 3.21.7C;

(d) NISCap(f,DI) is the Not In-Service Capacity quantity AEMO has determined under clause 7.13.1I;

(e) DI∈t is the set of all Dispatch Intervals in Trading Interval t; and

(f) TIRR(f,t) is the Trading Interval Refund Rate for the Facility f in Trading Interval t.

Not In-Service Capacity Refund: The capacity refund for a Registered Facility in a Trading Interval calculated in clause 4.26.1D.

Explanatory Note: Determining a Refund quantity for a storage facility that has an insufficient charge level and is not able to meet its Reserve Capacity Obligation Quantity.

A storage facility must pay a refund if it is unable to present is capacity at least up to its RCOQ in its relevant RCOQ obligation intervals, as indicated by its real-time charge status after taking into account any equipment limits.

Charge Level: An Equipment Limit indicating t~~T~~he current level of stored energy in MWh in an Electric Storage Resource, as provided to AEMO in a real-time data feed in accordance with Chapter 2.

4.26.1E. Where a Separately Certified Component of a Scheduled Facility or a Semi-Scheduled Facility which is an Electric Storage Resource has inadequate Charge Level to satisfy its Reserve Capacity Obligation Quantity determined for the Electric Storage Resource, AEMO must determine the shortfall in Reserve Capacity as:

$$\text{ESRChargeShortfall(f,t)} = \frac{\sum_{\mathrm{DI}\in \mathrm{t}}\left(ESRRCOQShortfall_{(c,DI)}\right)}{6} \times TIRR(f,t)$$

where:

(a) ESRChargeShortfall (f,t) is the total MW shortfall determined for the Registered Facility in the Trading Interval;

(b) ESRRCOQShortfall(c,DI) is the capacity shortfall in MW determined as:

$$\text{ESRRCOQShortfall(c,DI)} = \mathrm{MAX}\left(0, RCOQ_{(c,DI)} - CAFO_{(c,DI)} - 12 \times \left(ChargeLevel_{(c,DI)} - minChargeLvl_{(c,DI)}\right)\right)$$

Where

i. RCOQ(c,DI) is the Reserve Capacity Obligation Quantity for the Separately Certified Component which is an Electric Storage Resource in the Dispatch Interval;

ii. CAFO(c,DI) is the Capacity Adjusted Forced Outage Quantity for the Separately Certified Component which is an Electric Storage Resource in the Dispatch Interval as determined under clause 3.21.7;

iii. ChargeLevel(c,DI) is the Charge Level in MWh, or alternative estimate from AEMO where not available, of the Separately Certified Component which is an Electric Storage Resource in the Dispatch Interval;

iv. minChargeLvl(c,DI) is the minimum charge level capability in MWh as specified in Standing Data for the Electric Storage Resource in the Dispatch Interval; and

(c) DI∈t is the set of all Dispatch Intervals in Trading Interval t; and

(d) TIRR(f,t) is the Trading Interval Refund Rate for the Facility f in Trading Interval t.

4.9.10. AEMO must document the following in a WEM Procedure:

(a) the procedures that Market Participants must follow when applying for Certified Reserve Capacity;

(b) the methodology AEMO uses for determining Planned Outage rates and Forced Outage rates, which must treat Electric Storage Resource Charge Level shortfalls as calculated under clause 4.26.1E as Forced Outages;

(c) the procedures AEMO must follow when processing applications for Certified Reserve Capacity, including:

i. how Certified Reserve Capacity is assigned;

ii. how Reserve Capacity Obligation Quantities are set under clause 4.12.4; and

iii. how AEMO will account for any degradation of an Electric Storage Resource, based on:

1. the performance standards and specifications for the Electric Storage Resource provided by the relevant manufacturer; and

2. the performance of the Electric Storage Resource in the Capacity Year at the time the application for certification of Reserve Capacity is required to be processed, where available.

Explanatory Note: Amending Generation Reserve Capacity Deficit Refund The Generation Reserve Capacity Deficit Refund for a Market Participant needs to be amended to include the Not-In-Service Capacity Refund and ESR Charge Shortfall.

4.26.1B. AEMO must calculate the Generation Reserve Capacity Deficit Refund for each Market Participant for each Trading Interval as ~~the sum of the Facility Reserve Capacity Deficit Refunds for the Trading Interval for each Facility registered to the relevant Market Participant, excluding any registered Demand Side Programmes.~~:

$\text{GRCDR(p,t)} = \sum_{f \in p} FRCDR(f,t) + NISRefund(f,t) + \text{ESRChargeShortfall(f,t)}$

where:

(a) GRCDR(p,t) is the Generation Reserve Capacity Deficit Refund for Market Participant p in the Trading Interval t;

(b) FRCDR(f,t) is the Facility Reserve Capacity Deficit Refund for the Facility f in the Trading Interval t, as determined in clause 4.26.1A;

(c) NISRefund(f,t) is the Not In-Service Capacity Refund for the Facility f in the Trading Interval t, as determined in clause 4.26.1D;

(d) ESRChargeShortfall(f,t) is the capacity shortfall of an Electric Storage Resource which has inadequate Charge Level to satisfy its Reserve Capacity Obligation Quantity as determined in clause 4.26.1E; and

(e) f∈p is the set of all Facilities associated with Market Participant p holding Capacity Credits in the Trading Interval t, excluding any registered Demand Side Programmes.

Explanatory Note:

The rules described above require some additional consequential amendments:

- Include the creation of CAFO at the facility level for the Dispatch Interval in order to support Not In-Service Refund calculation (currently only at a component level under 3.21.7).
- As Not In-Service refunds and ESR charge shortfall refunds will now be calculated separately (per 4.21.6D and 4.21.6E), modifications to clause 4.26.2 are required:
    - To remove references to Not In-Service capacity
    - To remove references to Demand Side Programs
    - To align formatting and structure to other parts of chapter 4 & 9 for consistency
    - To ensure the correct Remaining Available Capacity figures are used
- Include additions to Real-Time Market Submissions (7.4.40) and the Glossary definition of Available Capacity to include the minimum synchronisation time for the “Available” energy in the submission.
- Associated changes to the inputs used in determining the Dispatch Schedule, Pre-Dispatch Schedule, or Week-ahead Schedule in order to consider “Available” only where it has adequate time to synchronise for the dispatch interval.

3.21.7C AEMO must determine the Capacity Adjusted Forced Outage Quantity for each Dispatch Interval for each Registered Facility with a Reserve Capacity Obligation Quantity greater than zero:

$$\text{CAFO(f, DI)} = \sum_{\text{c in f}} \text{CAFO(c, DI)}$$

Where:

CAFO(f,DI) is the Capacity Adjusted Forced Outage Quantity for Facility *f* in Trading Interval t

c in f denotes all Separately Certified Components of Facility f

CAFO(c,DI) is the Capacity Adjusted Forced Outage Quantity for Separately Certified Component *c* in Trading Interval t as calculated in clause 3.21.7

…

4.26.2AA. AEMO must determine the shortfall ("Net Offer Shortfall") in Reserve Capacity supplied by each Market Participant p holding Capacity Credits associated with its Registered Facilities, in each Trading Interval t in accordance with clauses 4.26.2AB to 4.26.2AM (inclusive).

4.26.2AB. The Net Offer Shortfall for Market Participant p in Trading Interval t is:

$$\mathrm{NetOfferShortfall(p,t) = Max(RTMSF(p,t), STEMSF(p,t))}$$

where:

(a) RTMSF(p,t) is the shortfall in the Real-Time Market for Market Participant p in Trading Interval t, which is equal to the average of RTMSF(p,DI) for all Dispatch Intervals in Trading Interval t as calculated in accordance with clause 4.26.2AC; and

(b) STEMSF(p,t) is the shortfall in STEM for Market Participant p in Trading Interval t as calculated in accordance with clause 4.26.2AG.

4.26.2AC. The shortfall in the Real-Time Market for Market Participant p in Trading Interval t is:

$$\mathrm{RTMSF(p,t)} = \frac{\sum_{\mathrm{DI \in t}} \mathrm{RTMSF(p,DI)}}{6}$$

where:

(a) RTMSF(p,DI) is determined for Market Participant p in Dispatch Interval DI as calculated in accordance with clause 4.26.2AD; and

(b) DI∈t is the set of all Dispatch Intervals in Trading Interval t.

4.26.2AD. RTMSF(p,DI) for Market Participant p in Dispatch Interval DI is:

$$\mathrm{RTMSF(p,DI)} = \sum_{\mathrm{f \in SFFacilities(p,DI)}} \mathrm{RTMFSF(f,DI)}$$

where:

(a) RTMFSF(f,DI) is the shortfall in the Real-Time Market for Registered Facility f in Dispatch Interval DI as calculated in accordance with clause 4.26.2AE; and

(b) SFFacilities(p,DI) is the set of all Registered Facilities registered to Market Participant p in Dispatch Interval DI, for which Market Participant p holds Capacity Credits in Dispatch Interval DI, excluding Demand Side Programmes, and f is a Facility within that set.

4.26.2AE. RTMFSF(f,DI) for Registered Facility f in the set SFFacilities(p,DI) in Dispatch Interval DI is:

RTMFSF(f, DI) = Max (0, RTMREQ(f, DI) − OfferAvail(f, DI))

where:

(a) RTMREQ(f,DI) is calculated in accordance with clause 4.26.2AF; and

(b) OfferAvail(f,DI) is the total MW quantity included in Real-Time Market Offers for energy from Registered Facility f in Dispatch Interval DI (whether offered as Available Capacity or In-Service Capacity) that were used to calculate Dispatch Instructions and Market Clearing Prices for that Dispatch Interval. ~~less Not-In Service Capacity for Registered Facility f in Dispatch Interval DI is:~~

~~i. for a Demand Side Programme, zero; and~~

~~ii. for a Registered Facility other than a Demand Side Programme, the total MW quantity included in Real-Time Market Offers for energy from Registered Facility f in Dispatch Interval DI (whether offered as Available Capacity or In-Service Capacity) that were used in the final Dispatch Schedule for that Dispatch Interval less Not In-Service Capacity. ; and~~

~~(c) BidAvail(f,DI) for Registered Facility f in Dispatch Interval DI is:~~

~~i. for a Demand Side Programme, the total MW quantity included in Real-Time Market Bids for energy from Registered Facility f in Dispatch Interval DI (whether offered as Available Capacity or In-Service Capacity) that were used in the final Dispatch Schedule for that Dispatch Interval; and~~

~~ii. for a Registered Facility other than a Demand Side Programme, zero.~~

4.26.2AF. RTMREQ(f,DI) for Registered Facility f in Dispatch Interval DI under any Outage is:

$$RTMREQ(f, DI) = \min(RCOQ(f, DI), min(PlannedOutageAvail(o), ForcedOutageAvail(o)))$$

where:

(a) RCOQ(f,DI) is the Reserve Capacity Obligation Quantity for Registered Facility f in Dispatch Interval DI;

(b) PlannedOutageAvail(o) is the Remaining Available Capacity for energy under Outage o that is the latest Planned Outage for Registered Facility f which include Dispatch Interval DI that has not been rejected, withdrawn or subject to an Outage Recall Direction; and

(c) ForcedOutageAvail(o) is the Remaining Available Capacity for energy under Outage o that is the latest Forced Outage for Registered Facility f which include Dispatch Interval DI that has not been withdrawn.

4.26.2AG. STEMSF is the shortfall in STEM for Market Participant p in Trading Interval t calculated as:

$$\mathrm{STEMSF(p,t)} = \mathrm{Max}\big(0, \mathrm{STEMREQ(p,t)} - \mathrm{CAPASTEM(p,t)}\big)$$

where:

(a) STEMREQ(p,t) is for Market Participant p in Trading Interval t, the average of STEMREQ(p,DI) for Market Participant p for all Dispatch Intervals in Trading Interval t calculated in accordance with clause 4.26.2AH;

(b) CAPASTEM(p,t) for Market Participant p in Trading Interval t is calculated in accordance with clause 4.26.2AK.

4.26.2AH. STEMREQ(p,t) for Market Participant p in Trading Interval t is:

$$\mathrm{STEMREQ(p,t)} = \frac{\sum_{\mathrm{DI} \in \mathrm{t}} \mathrm{STEMREQ(p,DI)}}{6}$$

where:

(a) STEMREQ(p,DI) is for Market Participant p in Dispatch Interval DI equal to the sum of STEMREQ(f,DI) calculated in accordance with clause 4.26.2AI; and

(b) DI∈t is the set of all Dispatch Intervals in Trading Interval t and DI is a Dispatch Interval within that set.

4.26.2AI. STEMREQ(p,DI) for Market Participant p in Dispatch Interval DI is:

$$\mathrm{STEMREQ(p,DI)} = \sum_{\mathrm{f} \in \mathrm{SFFacilities(p,DI)}} \mathrm{STEMFREQ(f,DI)}$$

where:

(a) STEMFREQ(f,DI) for Registered Facility f in the set SFFacilities in Dispatch Interval DI is calculated in accordance with clause 4.26.2AJ; and

(b) f∈SFFacilities(p,DI) is the set of all Registered Facilities registered to Market Participant p in Dispatch Interval DI, for which Market Participant p holds

Capacity Credits in Dispatch Interval DI, excluding Demand Side Programmes, and f is a Facility within that set.

4.26.2AJ. STEMFREQ(f,DI) for Registered Facility f in Dispatch Interval DI is:

$$STEMFREQ(f,DI) = \min\left(RCOQ(f,DI),\ min(BSPlannedOutageAvail(o), BSForcedOutageAvail(o))\right)$$

where:

(a) RCOQ(f,DI) is the Reserve Capacity Obligation Quantity for Registered Facility f in Dispatch Interval DI;

(b) BSPlannedOutageAvail(f,DI,o) is the Remaining Available Capacity for energy under Outage(o) that is the latest Planned Outage for Registered Facility f in Dispatch Interval DI that has not been rejected, withdrawn or subject to an Outage Recall Direction, as at the Bilateral Submission Cutoff; and

(c) BSForcedOutageAvail(f,DI,o) is the Remaining Available Capacity for energy under Outage(o) that is the latest Forced Outage for Registered Facility f in Dispatch Interval DI that has not been withdrawn, as at the Bilateral Submission Cutoff;

4.26.2AK. CAPASTEM(p,t) for Market Participant p in Trading Interval t is STEMREQ(p,t), as determined under clause 4.26.2AH where the STEM Auction has been suspended by AEMO in accordance with section 6.10 or where STEMREQ(p,t)=0. Otherwise is:

$$\mathrm{CAPASTEM(p,t)} = \left(\frac{\mathrm{NCP(p,t)} + \mathrm{UnclearedSTEMOffers(p,t)} + \mathrm{ClearedSTEMBids(p,t)}}{\mathrm{LF(p,t)} \times \frac{30}{60}\mathrm{h}}\right)$$

where:

(a) NCP(p,t) is Market Participant p's Net Contract Position for Trading Interval t in MWh;

(b) UnclearedSTEMOffers(p,t) is the total MWh quantity covered by the STEM Offers which were not scheduled in the relevant STEM Auction, determined by AEMO for Market Participant p under section 6.9 for Trading Interval t;

(c) ClearedSTEMBids(p,t) is the total MWh quantity covered by the STEM Bids which were scheduled in the relevant STEM Auction, determined by AEMO for Market Participant p under section 6.9 for Trading Interval t; and

(d) LF(p,t) is calculated in accordance with clause 4.26.2AL.

4.26.2AL. LF(p,t) for Market Participant p for Trading Interval t is:

$$\mathrm{LF(p,t)} = \sum_{\mathrm{DI}\in\mathrm{t}} \mathrm{LF(p,di)}$$

where:

(a) LF(p,DI) is the capacity obligation weighted average of the Loss Factors for the Market Participant p's Registered Facilities which are not Demand Side Programmes in Dispatch Interval DI calculated in accordance with clause 4.26.2AM; and

(b) DI∈t is the set of all Dispatch Intervals in Trading Interval t and di is a member within that set.

4.26.2AM. LF(p,DI) for Market Participant p in Dispatch Interval DI is:

$$\mathrm{LF(p,DI)} = \frac{\sum_{\mathrm{f \in SFFacilities(p,DI)}} (\mathrm{LossFactor(f,DI)} \times \mathrm{RCOQ(f,DI)})}{\sum_{\mathrm{f \in SFFacilities(p,DI)}} \mathrm{RCOQ(f,DI)}}$$

where:

(a) LossFactor(f,DI) is the Loss Factor for Registered Facility f in Dispatch Interval DI;

(b) RCOQ(f,DI) is the Reserve Capacity Obligation Quantity for Registered Facility f in Dispatch Interval DI; and

(c) f∈SFFacilities(p,DI) is the set of all Registered Facilities registered to Market Participant p in Dispatch Interval DI, for which Market Participant p holds Capacity Credits in Dispatch Interval DI, excluding Demand Side Programmes, and f is a Facility within that set.

……….

7.4.40. A Real-Time Market Submission for Injection or Withdrawal by a Registered Facility must, in addition to the matters listed in clause 7.4.39, specify, as applicable:

(a) the In-Service Capacity for Injection in MW;

(b) the Available Capacity for Injection in MW;

(c) the In-Service Capacity for Withdrawal in MW;

(d) the Available Capacity for Withdrawal in MW;

(e) the Maximum Upwards Ramp Rate in MW per minute;

(f) the Maximum Downwards Ramp Rate in MW per minute;

(g) up to the number of Price-Quantity Pairs specified in the WEM Procedure referred to in clause 7.4.38, where:

i. the prices are to be stated in dollars and whole cents per MWh;

ii. the sum of all positive MW quantities is to equal the total of Available Capacity and In-Service Capacity for Injection;

iii. the sum of all negative MW quantities is to equal the total of Available Capacity and In-Service Capacity for Withdrawal;

iv. where the Enablement Minimum is an Injection quantity greater than zero for an Essential System Service, the quantity of that Enablement Minimum is to be in a single Price-Quantity Pair; ~~and~~

v. where the Enablement Maximum is a Withdrawal quantity less than zero for an Essential System Service, the quantity of that Enablement Maximum is to be in a single Price-Quantity Pair;

vi. the minimum time to synchronise the Available Capacity for Injection in minutes; and

vii. the minimum time to synchronise the Available Capacity for Withdrawal in minutes; and

(h) if the Registered Facility is Inflexible.

7.8.5. A Reference Scenario for a Dispatch Schedule must:

(a) represent AEMO's best estimate of future dispatch and market outcomes;

(b) take into account:

i. Enablement Minimums;

ii. Low Breakpoints;

iii. High Breakpoints;

iv. Enablement Maximums;

v. whether each Facility is Inflexible; and

vi. approved Planned Outages and Forced Outages; and

(c) exclude any Available Capacity in Real-Time Market Submissions where the Start Decision Cutoff has passed for the Registered Facility. ~~from Registered Facilities that are not currently synchronised and, according to start up times specified in Standing Data, could not be synchronised in time to provide a Market Service in the relevant Pre-Dispatch Interval.~~

7.8.5A. A Reference Scenario for a Pre-Dispatch Schedule or Week-Ahead Schedule must:

(a) represent AEMO's best estimate of future dispatch and market outcomes; and

(b) exclude any Available Capacity in Real-Time Market Submissions where the Start Decision Cutoff has passed for the Registered Facility. ~~from Registered~~

~~Facilities that are not currently synchronised and, according to start up times specified in Standing Data, could not be synchronised in time to provide a Market Service in the relevant Pre-Dispatch Interval.~~

Available Capacity: For a Registered Facility in a Dispatch Interval, the sent out capacity in MW that is not currently synchronised and is not expected to be synchronised in the Dispatch Interval, but would be available for dispatch if the Registered Facility was given notice in accordance with ~~start times~~ minimum times to synchronise in its ~~Standing Data~~ Real Time Market Submission.

Explanatory Note: Amendments to Bilateral Trade Declaration
The purpose of proposed amendment to clause 4.14.1 is to accommodate the participation of "hybrid" facilities, containing more than one technology type in the RCM

4.14.1. Subject to clause 4.14.3, each Market Participant holding Certified Reserve Capacity for the current Reserve Capacity Cycle must, by the date and time specified in clause 4.1.14 provide the following information to AEMO for each Facility and component of a Facility (expressed in MW to a precision of 0.001 MW):

~~4.14.1A. Where AEMO assigns Certified Reserve Capacity to an Electric Storage Resource component of a Facility, the Market Participant for the Facility must, at the same time it makes a submission under clause 4.14.1 for the Facility, notify AEMO of the amount of Reserve Capacity the Market Participant intends to trade bilaterally for:~~

~~(a) the Electric Storage Resource component of the Facility; and~~

~~(b) the remaining part of the Facility.~~

Explanatory Note: Publishing Capacity Credit information
The proposed amendment is to correct an error in the original drafting as, after the commencement of the NAQ regime, at this stage AEMO has no certainty of how many Capacity Credits are assigned to each component of the "hybrid" facility.

4.20.5A. AEMO must:

(a) subject to clause 4.20.5C, assign a quantity of Capacity Credits to each Facility ~~and record the Capacity Credits associated with each component of the Facility, where relevant,~~ where the quantity is determined in accordance with clause 4.20.5B for the relevant Facility;

…

Explanatory Note: Capacity Credits for ESR component

Amendments are proposed to 4.20.17 to allow association of Capacity Credits with all relevant components, including Electric Storage Resources.

4.20.17. Where AEMO has assigned Capacity Credits to a Facility ~~containing an Electric Storage Resource~~ for a Capacity Year, AEMO must set the number of Capacity Credits to be associated with each component of the Facility ~~Electric Storage Resource~~ for the Capacity Year as:

(a) the number of Capacity Credits the Market Participant nominated to trade bilaterally ~~for the Electric Storage Resource~~ under clause 4.14.1; or

(b) where clause 4.20.16 applies, the number of Capacity Credits notified to AEMO under that clause to be associated with ~~the Electric Storage Resource~~ each component of the Facility.

Explanatory Note: Voluntary reduction of Capacity Credits by Demand Side Programme

Clause 4.25.4E is proposed to be deleted to provide a consistent treatment of all facilities, including Demand Side Programmes, in relation to voluntary reduction of Capacity Credits. This amendment will commence at New WEM Commencement.

4.25.4E. [Blank] ~~Where the Capacity Credits associated with a Demand Side Programme are reduced in accordance with clause 4.25.4C the Market Participant must pay a refund of an amount equal to all Reserve Capacity payments associated with the reduced Capacity Credits minus the prorated amount of all Capacity Cost Refunds already paid by the Market Participant for the relevant Capacity Year to AEMO calculated in accordance with the provisions of section 4.26.~~

Explanatory Note

Clause 4.26.6(b) is amended to accommodate the removal of Capacity Refunds for DSM seeking a voluntary reduction of Capacity Credits. (clause 4.25.4E)

4.26.6. The Facility Capacity Rebate in Trading Interval t for Facility f, being a Scheduled Facility, Semi-Scheduled Facility or a Demand Side Programme for which a Market Participant holds Capacity Credits:

$$FCR(f,t) = \frac{Cshare(f,t)x\,E(f,t)}{\sum_{f\in F} CShare(f,t)x\,E(f,t)}\,x\,TAR(t)$$

where:

(a) FCR(f, t) is the Facility Capacity Rebate for Facility f in the Trading Interval t;

(b) TAR(t) is the sum of all Trading Interval Capacity Cost Refunds ~~and any amounts collected in accordance with 4.25.4E,~~ for all Market Participants in Trading Interval t;

(c) F is the set of Facilities, being Scheduled Facilities, Semi-Scheduled Facilities and Demand Side Programmes and f is a Facility within that set;

(d) CShare(f,t) for a Facility f in a Trading Interval t is the Facility's Reserve Capacity Obligation Quantity less any Forced Outages in Trading Interval t determined as follows:

- i. for a Scheduled Facility or Semi-Scheduled Facility, the greater of zero and:
  - 1. the Reserve Capacity Obligation Quantity for Facility f in Trading Interval t; less
  - 2. the Capacity Adjusted Forced Outage Quantity for Facility f in Trading Interval t calculated in 3.21.7B; and
- ii. for a Demand Side Programme, the lesser of—
  - 1. the Demand Side Programme Load multiplied by two so as to be a MW quantity less the sum of the Minimum Consumptions in MW for each of the Facility's Associated Loads; and
  - 2. the Demand Side Programme's Reserve Capacity Obligation Quantity in t; and

(e) E(f, t) is the eligibility of Facility f in Trading Interval t, equal to—

- i. one for any Facility which is a Scheduled Facility or Semi-Scheduled Facility and the following applies—
  - 1. the Facility has a Sent Out Metered Schedule greater than zero in any one of the 1,440 Trading Intervals prior to and including Trading Interval t;
  - 2. the sum of the Facility Reserve Capacity Deficit Refunds for Facility f, in Capacity Year y that the Trading Interval t falls in, for Trading Intervals prior to and including Trading Interval t, is less than the Maximum Facility Refund for Facility f in Capacity Year y; and

3. the sum of the ~~Generation Reserve~~ Trading Interval Capacity ~~Deficit~~ Cost Refund in Capacity Year y that the Trading Interval t falls in, for Trading Intervals prior to and including Trading Interval t, is less than the Maximum Participant ~~Generation~~ Refund for the Market Participant p which the Facility is registered to, in Capacity Year y; and

ii. one for any Facility which is a Demand Side Programme and the following applies—

1. the Facility received a Dispatch Instruction to reduce consumption in any one of the 1,440 Trading Intervals prior to and including Trading Interval t;

2. the Reserve Capacity Obligation Quantity for the Demand Side Programme does not equal zero under clause 4.12.4(c); and

3. the sum of the Demand Side Programme Capacity Cost Refunds for Facility f, in Capacity Year y that the Trading Interval t falls in, for Trading Intervals prior to and including Trading Interval t, is less than the Maximum Facility Refund for Facility f in Capacity Year y; and

4. the sum of the Trading Interval Capacity Cost Refund in Capacity Year y that the Trading Interval t falls in, for Trading Intervals prior to and including Trading Interval t, is less than the Maximum Participant Refund for the Market Participant p which the Facility is registered to, in Capacity Year y; and

iii. zero otherwise.