MISCELLANEOUS AMENDMENTS NO. 3: EXPOSURE DRAFT

PROPOSED WHOLESALE ELECTRICITY MARKET (WEM) AMENDING RULES

Explanatory Note for the Exposure Draft of the Wholesale Electricity Market Amendment (Miscellaneous Amendments No. 3) Rules 2024.

This Exposure Draft contains proposed Amending Rules to:

- require AEMO to inform EPWA and the ERA of any issues that are likely to adversely affect the effectiveness of the market or achievement of the Wholesale Market Objectives;
- require AEMO to investigate and report on significant incidents in the SWIS;
- reduce the deadline for providing AEMO any final details of a Forced Outage from fifteen days to seven days after the relevant Trading Day to allow for certain settlement calculations to be performed earlier;
- allow AEMO to proactively share information with EPWA and the ERA without requiring a formal request;
- clarify the publication requirements associated with NCESS contracts;
- allow AEMO to require more reserve capacity security to be lodged in the event that security has been drawn upon due to Facility not commencing on time;
- provide clarity around the Availability Duration Gap determination for all years in the LT PASA horizon;
- amend the definitions of Enablement Maximum and Enablement Minimum to improve clarity, and ensure that Enablement Limits accurately reflect the capability of a Facility;
- modify the settlement rules to allocate the costs of NCESS Contracts for peak capacity as a Reserve Capacity cost, i.e. on the basis of IRCR;
- remove barriers to entry and encourage participation of aggregated DSPs in the RCM;
- update clause 7.4.35 to allow a Market Participant to make a Real-Time Market Submission after Gate Closure if directed to do so by AEMO;
- refine the cost allocation methodology for Contingency Reserve Raise;
- define a Facility by its Metering Point, rather than its connection point, to allow for registration of multiple Facilities behind a single connection point following approval from AEMO;
- include transitional rules to extend the timeframes related to the submission, consideration and approval of AEMO's Allowable Revenue for the 2025 to 2028 period;
- clarify the settlement provisions related to calculating FCESS Uplift Payments;
- error corrections and enhancements across all the WEM Rules.

This exposure draft is divided into three parts, based on the expected commencement dates of the Amending Rules. The draft rules presented in this Exposure Draft are pending legal review.

Following stakeholder consultation and legal review, the proposed Amending Rules in this Exposure Draft, as amended as the result of this consultation, will be submitted to the Minister for Energy for making and gazettal.

This Exposure Draft notes clauses which are intended to be nominated as a civil penalty provision in Schedule 1 of the Electricity Industry (Wholesale Electricity Market) Regulations 2004. Feedback is welcome on these in submissions.

Energy Policy WA is seeking stakeholder feedback on this Exposure Draft by **5:00 PM (AWST) on 8 July 2024 (AWST)**. Feedback can be sent to energymarkets@energy.wa.gov.au.

Mark-up Colour guide:

Text in black	Rules that are in force

Text in green	Amending Rules that have been made and will commence on a specified date
Text in blue	Amending Rules that have been made but no commencement date has been specified
Text in red - underlined ~~and strikethrough~~	New amendments proposed under these Amending Rules

Part 1: Amending Rules to commence on Gazettal

…

2.10. Procedure Change Process

…

Explanatory Note
Clause 2.10.13(dA) requires a Procedure Change Report to include information about Market Advisory Committee views on a Procedure Change Proposal "and how these views have been taken into account by the Coordinator". Since AEMO, the ERA and Network Operators can also be Procedure Administrators, the clause is amended to extend the requirement to the other parties that could prepare a Procedure Change Report.

2.10.13. The Procedure Change Report must contain:

(a) the wording of the proposed WEM Procedure or amendment to or replacement for the WEM Procedure;

(b) the reason for the proposed WEM Procedure or amendment to or replacement for the WEM Procedure;

(c) all submissions received before the due date for submissions, a summary of those submissions, and the response of the Coordinator, AEMO, the Economic Regulation Authority or the Network Operator, as applicable, to the issues raised in those submissions;

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

(dA) whether any advice from the Market Advisory Committee regarding the Procedure Change Proposal 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<u>, AEMO, the Economic Regulation Authority or the Network Operator, as applicable</u>;

(e) [Blank]

…

…

2.16. Monitoring the Effectiveness of the Market

…

Explanatory Note

Clauses 2.16.3A to 2.16.3E are inserted to ensure AEMO must inform the Coordinator and ERA of any issues it observes that are likely to affect the effectiveness of the WEM and or the achievement of the WEM Objectives, and allows the Coordinator or ERA to request more information or data about the issue identified.

2.16.3A. If, in the performance of its functions under these WEM Rules, AEMO identifies an issue that adversely affects the operation of the Wholesale Electricity Market or affects the achievement of the Wholesale Electricity Market Objectives, as soon as practicable after it becomes aware of the issue AEMO must notify the Coordinator and the Economic Regulation Authority of the issue.

2.16.3B. The Coordinator or the Economic Regulation Authority may request further information, including documents, data or analysis, regarding an issue notified in accordance with clause 2.16.3A.

2.16.3C. Before making a request under 2.16.3B, the Coordinator or the Economic Regulation Authority, as applicable, must consult with AEMO about the scope of the request and the time by which the information must be provided and take into account that consultation.

2.16.3D. AEMO must comply with a request made in accordance with 2.16.3B before the date and time specified in the request.

2.16.3E. The Coordinator or AEMO must treat information provided by AEMO under clauses 2.16.3A and 2.16A.3B as confidential and must not publish any of the information provided unless the information is published in a form that:

(a) does not identify the Market Participant or Market Participants to which the information relates; and

(b) the relevant Market Participant or Market Participants cannot be reasonably identified as a result of publication of the information.

…

2.22A. Determination of AEMO's budget

…

Explanatory Note

Clause 2.22A.2A is amended to extend subclause (d) to capture new clause 2.22A.2C(c). This change is required to allow for the Market Fees to continue at the same rate in the event that the ERA does not publish its final determination before 30 June 2025.

2.22A.2A. A submission by AEMO under clause 2.22A.2 must be made and processed in accordance with the following timelines:

(a) by 31 October of the year prior to the start of the Review Period, AEMO must submit a proposal for its Allowable Revenue and Forecast Capital Expenditure over the Review Period to the Economic Regulation Authority;

(b) by 31 March of the year in which the Review Period commences, the Economic Regulation Authority must publish on its website a draft determination of AEMO's Allowable Revenue and Forecast Capital Expenditure for the Review Period for public consultation;

(c) by 30 April of the year in which the Review Period commences, the Economic Regulation Authority must prepare and publish on its website its final determination of AEMO's Allowable Revenue and Forecast Capital Expenditure for the Review Period together with any submission received in response to the draft determination published in accordance with clause 2.22A.2A(b); and

(d) where the Economic Regulation Authority does not make a determination by the date in clause 2.22A.2A(c), ~~or~~ clause 2.22A.2B(c), or clause 2.22A.2C(c) the Market Participant Market Fee rate determined in accordance with section 2.24 for the current Financial Year will continue to apply until the Economic Regulation Authority makes a determination.

…

Explanatory Note

New clause 2.22A.2C is introduced to extend the date by which AEMO is required to submit its seventh Allowable Revenue (AR7) period proposal to the ERA until 31 January 2025. This change is essential to allow:

- consideration of a pending Rule Change Proposal to amend the framework for oversight of AEMO's Allowable Revenue and Forecast Capital Expenditure, which may apply for the AR7 period; and
- • AEMO adequate time to develop a submission that captures the full scope of its activities in the context of ongoing WEM reform and the energy transition, or undertake other activities required in accordance with any changes to the framework.

2.22A.2C. Notwithstanding clause 2.22A.2A, for the Review Period from 1 July 2025 to 30 June 2028, the following timelines apply:

(a) AEMO must submit a proposal for its Allowable Revenue and Forecast Capital Expenditure for the Review Period to the Economic Regulation Authority by 31 January 2025;

(b) the Economic Regulation Authority must publish on its website a draft determination of AEMO's Allowable Revenue and Forecast Capital Expenditure for the Review Period for public consultation by 30 April 2025; and

(c) the Economic Regulation Authority must prepare and publish on its website its final determination of AEMO's Allowable Revenue and Forecast Capital Expenditure for the Review Period by 30 June 2025.

Explanatory Note

Clause 2.22A.3 is amended to include new clause 2.22A.2C.

2.22A.3. AEMO's proposal under clauses 2.22A.2A(a), ~~or~~ 2.22A.2B(b), 2.22A.2C(a) or AEMO's application for reassessment under clauses 2.22A.12 or 2.22A.13 must, to the extent practicable, identify proposed costs that are associated with a specific project or where that is not practicable, one or more specific functions.

…

Explanatory Note

Clause 2.22A.6 is amended to include new clause 2.22A.2C.

2.22A.6. The Economic Regulation Authority may do any or all of the following in respect to AEMO's proposal under clauses 2.22A.2A(a), ~~or~~ 2.22A.2B(b), or 2.22A.2C(a):

(a) approve the costs of any project;

(b) approve the costs of AEMO performing its functions;

(c) if the Economic Regulation Authority considers that some costs do not meet the requirements of clause 2.22A.5, reject the costs fully or partially, or substitute those costs with costs the Economic Regulation Authority considers meets the requirements of clause 2.22A.5; and

(d) recommend to AEMO that some of the costs be considered in a subsequent Review Period or in accordance with clause 2.22A.14.

Explanatory Note

New clause 2.22A.7A is introduced to allow for AEMO to publish its budget after 30 June in the event that the ERA does not make a final determination before this time. This is essential, as otherwise AEMO's Budget would not reflect the Final Determination as required by clause 2.22A.7A and AEMO would have no mechanism to recover the correct Market Fees.

2.22A.7. Subject to clause 2.22A.7A, by ~~By~~ 30 June each year, AEMO must publish on the WEM Website a budget for the costs AEMO will incur in performing its functions for the coming Financial Year (including, without limitation, the amount to be paid to a Delegate). AEMO must ensure that its budget is:

(a) consistent with the Allowable Revenue and Forecast Capital Expenditure determined by the Economic Regulation Authority for the relevant Review Period and any reassessment; and

(b) reported in accordance with the Regulatory Reporting Guidelines issued by the Economic Regulation Authority from time to time in accordance with clause 2.22A.9.

2.22A.7A. If the Economic Regulation Authority publishes a final determination under clause 2.22A.2A(c) or 2.22A.2C(c) less than five Business Days before 30 June, or after 30 June, then AEMO must publish the budget specified in clause 2.22A.7 within 10 Business Days after the ERA publishes a final determination.

…

Explanatory Note
Clause 2.22A.17 is amended to capture new clause 2.22A.2C(c).

2.22A.17. The Economic Regulation Authority may amend a determination under clauses 2.22A.2A(c), ~~or~~ 2.22A.2B(d), or 2.22A.2C(c) if AEMO makes a reassessment application under clauses 2.22A.12, 2.22A.13 or 2.22A.14 and the Economic Regulation Authority:

(a) must take the matters referred to in clause 2.22A.5 into account in determining any reassessment;

(b) may consider as part of its amended determination any earlier determined costs where the Economic Regulation Authority reasonably considers it necessary to review those earlier determined costs as part of the reassessment;

(c) is not required to reassess earlier determined costs in making its redetermination of the Allowable Revenue or Forecast Capital Expenditure; and

(d) must complete such public consultation as the Economic Regulation Authority considers appropriate in the circumstances.

…

2.24. Determination of Market Fees

…

Explanatory Note
Existing clause 2.24.2A is amended to allow AEMO to publish the Market Fee rates within five days of receiving the ERA's final determination if the final determination is received less than five Business Days before 30 June or after 30 June. This will ensure that AEMO is provided with adequate time to update and publish its budget and fee.

2.24.2. Before 30 June each year, AEMO must determine and publish the level of:

(a) the Market Participant Market Fee rate (unless clause 2.24.2C applies);

…

…

2.24.2C. If the Economic Regulation Authority publishes a final determination under clause 2.22A.2A(c) or 2.22A.2C(c) less than five Business Days before 30 June, or after 30 June, then AEMO must determine and publish a level of Market Participant Market Fee rate within 10 Business Days after the final determination publication date.

Explanatory Note
Clause 2.24.3 is amended to reflect the current market fee structure, whereby Market Participant Market Fees are a single fee item.

2.24.3. At the same time as AEMO publishes a level of revised Market Participant Market Fee rate, Market Participant Coordinator Fee rate or Market Participant Regulator Fee rate (as applicable), AEMO must also publish an estimate of the total amount of revenue to be earned from:

(a) Market Participant Market Fees collected,~~ for AEMO's:~~

~~i. market operation services;~~

~~ii. system planning services;~~

~~iii. market administration services; and~~

~~iv. system management services,~~

where the amount~~s to be earned for each service~~ is equal to the relevant costs in AEMO’s budget published in accordance with clause 2.22A.7 or as adjusted under clause 2.24.2A;

(b) Market Participant Coordinator Fees collected for:

i. the Coordinator's functions under these WEM Rules;

ii. the costs associated with the remuneration and other expenses for the independent Chair of the Market Advisory Committee; and

iii. in the Coordinator’s discretion, costs associated with the remuneration and other expenses of the representatives of small-use consumers on the Market Advisory Committee,

where the amount to be earned for those services is equivalent to the costs identified by the Coordinator as costs incurred in the performance of the Coordinator's functions under these WEM Rules or the WEM Regulations, where the amount must be consistent with the relevant amount notified to AEMO in accordance with clause 2.24.6A; and

(c) Market Participant Regulator Fees collected for the Economic Regulation Authority’s monitoring, compliance, enforcement and regulation services where the amount must be consistent with the relevant amount notified to AEMO in accordance with clause 2.24.6.

…

2.27. Determination of Loss Factors

Explanatory Note

Section 2.27 is amended to allow and require the Network Operator to create a Loss Factor at the relevant Metering Point for each Facility, as opposed to the connection point.

New clause 2.27.1A is added to require the Network Operator to only determine a single Loss Factor, if a Facility is connected behind two or more Metering Points.

It is intended that proposed clause 2.27.1A will be nominated as a civil penalty provision in Schedule 1 of the Electricity Industry (Wholesale Electricity Market) Regulations 2004.

2.27.1. Network Operators must, in accordance with this section 2.27, calculate and provide to AEMO Loss Factors for:

(a) each ~~connection point~~ Metering Point in their Networks at which any of the following is connected:

i. a Scheduled Facility;

iA. a Semi-Scheduled Facility;

ii. a Non-Scheduled Facility; or

iii. [Blank]

iv. [Blank]

v. a Non-Dispatchable Load equipped with an interval meter; and

(b) in the case of Western Power, the Notional Wholesale Meter.

…

2.27.1A. If a Facility is electrically connected behind two or more Metering Points, the Network Operator must determine a single Loss Factor applicable to the Facility under clause 2.27.1.

2.27.2. A Market Participant may request, during the process of obtaining a relevant Arrangement for Access, that the relevant Network Operator determine and provide to AEMO Loss Factors to apply to a Facility where there are no Loss Factors applying to the ~~connection point~~ Metering Point at which the Facility will be connected.

…

2.27.4. Subject to clauses 2.27.5(d) and 2.27.1A, for each Network Operator AEMO must, in consultation with that Network Operator, develop a classification system to assign each of the ~~connection points in the Network Operator's Network~~ Metering Points identified under clause 2.27.1(a) to a Transmission Loss Factor Class and a Distribution Loss Factor Class, where:

(a) the assignment of a ~~connection point~~ Metering Point to a Loss Factor Class is based on characteristics indicative of the expected transmission or distribution system losses (as applicable) for the ~~connection point~~ Metering Point;

(b) each ~~connection point~~ Metering Point in a Loss Factor Class is assigned the same Transmission Loss Factor or Distribution Loss Factor (as applicable); and

(c) ~~connection points~~ Metering Points on the transmission system are assigned to a Distribution Loss Factor Class with a Distribution Loss Factor equal to one.

2.27.5. In calculating Loss Factors, Network Operators must apply the following principles:

(a) Transmission Loss Factors must notionally represent the marginal transmission system losses for a ~~connection point~~ Metering Point relative to the Reference Node, averaged over all Trading Intervals in a year, weighted by the absolute value of the net demand at that ~~connection point~~ Metering Point during the Trading Interval;

(b) Distribution Loss Factors must notionally represent the average distribution system losses for a ~~connection point~~ Metering Point over a year;

…

(f) the Transmission Loss Factors calculated for each Transmission Loss Factor Class and the Distribution Loss Factors calculated for each Distribution Loss Factor Class are static, and apply to each ~~connection point~~ Metering Point in the relevant Loss Factor Class until the time published by AEMO under clause 2.27.8 for the application of an updated Transmission Loss Factor or Distribution Loss Factor to that Loss Factor Class.

…

2.27.6. Each year by 1 June each Network Operator must, in accordance with the WEM Procedure specified in clause 2.27.17, recalculate the Loss Factors for its ~~connection points~~ Metering Points and provide AEMO with updated Transmission Loss Factors and Distribution Loss Factors (as applicable) for each Loss Factor Class in the Network Operator's classification system.

…

2.27.10. A Network Operator must develop new Loss Factor Classes if required to implement the classification system prescribed by AEMO for that Network Operator. If a Network Operator develops a new Loss Factor Class then it must:

(a) calculate the initial Transmission Loss Factor or Distribution Loss Factor (as applicable) for the new Loss Factor Class in accordance with the WEM Procedure specified in clause 2.27.17; and

(b) provide to AEMO details of the new Loss Factor Class and its initial Transmission Loss Factor or Distribution Loss Factor as soon as practicable but before a ~~connection point~~ Metering Point is assigned to the new Loss Factor Class.

…

2.27.12. A Network Operator must determine the Transmission Loss Factor Class and Distribution Loss Factor Class for each new ~~connection point~~ Metering Point in its Network identified under clause 2.27.1(a), in accordance with the classification system prescribed by AEMO for that Network Operator.

2.27.13. A Network Operator must re-determine the Loss Factor Classes for ~~connection point~~ Metering Point in its Network identified under clause 2.27.1(a) if a change occurs to the ~~connection point~~ Metering Point that might alter its applicable Loss Factor Classes under the classification system prescribed by AEMO for that Network Operator.

2.27.14. When a Network Operator determines a Loss Factor Class for a ~~connection point~~ Metering Point under clause 2.27.12 or changes a Loss Factor Class for a ~~connection point~~ Metering Point under clause 2.27.13, the Network Operator must provide to both AEMO and the relevant Market Participant the new Loss Factor Class for the ~~connection point~~ Metering Point and the Trading Day from which it takes effect, as soon as practicable but before the information is required for use in calculations under the WEM Rules.

2.27.15. A Market Participant may apply to AEMO for a reassessment of any Transmission Loss Factor or Distribution Loss Factor applying to a Scheduled Facility, Semi-Scheduled Facility, Non-Scheduled Facility or Non-Dispatchable Load registered to that Market Participant. The following requirements apply to each application for reassessment:

…

(f) Where an audit reveals an error in the assignment of a ~~connection point~~ Metering Point to a Loss Factor Class, AEMO must direct the relevant Network Operator to correct the error and re-determine the Loss Factor Class for the ~~connection point~~ Metering Point in accordance with the classification system prescribed by AEMO for that Network Operator.

(g) Where AEMO directs a Network Operator to re-determine a Loss Factor Class for a ~~connection point~~ Metering Point, then the Network Operator must do so, and must as soon as reasonably practicable provide to AEMO and the relevant Market Participant the revised Loss Factor Class and the Trading Day from which it should apply.

(h) The costs of an audit conducted by AEMO in response to an application for reassessment, including any costs incurred by the Network Operator and any costs, not otherwise included in AEMO's budget, incurred by AEMO, are payable by the Market Participant who made the application for reassessment, unless the audit reveals:

i. an error of more than 0.0025 in the calculation of a Transmission Loss Factor or Distribution Loss Factor; or

ii. an incorrect assignment of a ~~Connection Point~~ Metering Point to a Loss Factor Class,

in which case all costs are payable by the relevant Network Operator.

…

2.29. Facility Registration Classes

…

Explanatory Note Clause 2.29.1B is amended to define all Facilities at the Metering Point.

2.29.1B. The following are Facilities for the purposes of these WEM Rules:

(a) a transmission system;

(b) a distribution system;

(c) all Facility Technology Types that are connected behind a single Metering Point ~~network connection point~~ or electrically connected behind two or more Metering Points ~~shared network connection points~~;

(d) one or more Facilities described in clause 2.29.1B(c), aggregated under section 2.30 at an Electrical Location;

(e) a Small Aggregation;

(f) a Demand Side Programme; or

(g) an Interruptible Load.

…

2.30. Facility Aggregation

…

Explanatory Note Clause 2.30.5B is amended because registration of a Facility is proposed to be at the Metering Point, as opposed to the connection point.

2.30.5B. If two or more Facilities are electrically connected behind multiple ~~connection points, such that one or more of those Facilities could Inject into or Withdraw from the Network at more than one of the network connection points~~ Metering Points, and one or more of the Facilities is registered or AEMO has received an application to register one or more of the Facilities, then AEMO must aggregate the relevant Facilities into an Aggregated Facility.

…

2.30B. Intermittent Load

…

Explanatory Note Clause 2.30.5B is amended because registration of a Facility is proposed to be defined at the Metering Point in clause 2.29.1B, as opposed to the connection point.

2.30B.2. For a Load or part of a Load to be eligible to be an Intermittent Load AEMO must be satisfied that the following conditions are met:

(a) an Energy Producing System must have the following characteristics:

i. it can typically supply the maximum quantity of energy consumed by that Load to be treated as Intermittent Load without requiring energy to be withdrawn from a Network; and

ii. the output of which is netted off consumption of the Load by the meter measuring consumption of the Load, or which is always or at times electrically connected to the Load behind two or more ~~shared network connection points~~ Metering Points;

(b) the Intermittent Load shall reasonably be expected to have net consumption of energy (based on Metered Schedules calculated in accordance with the methodology prescribed in clauses 2.30B.10 or 2.30B.11) for not more than 4320 Trading Intervals in any Capacity Year, excluding Trading Intervals in which the Facility containing the Load is delivering a service under an NCESS Contract;

(c) the Market Participant for the Facility containing the Load must have an agreement in place with a Network Operator to allow energy to be supplied to the Load from a Network;

(d) [Blank]

(e) the Facility containing the Load is not expected (based on applications accepted by AEMO under clause 2.29.5D and any amendments accepted by AEMO under clause 2.29.5K) to be associated with any Demand Side Programme for any period following the registration of the Load or part of the Load as an Intermittent Load; and

(f) the Facility containing the Load is connected to the transmission network registered by the Network Operator referred to in clause 2.30B.2(c).

…

2.31. Registration Process

Explanatory Note New clause 2.31.2A added to allow a person to request approval from AEMO to register a Facility where the connection point and Metering Point are not electrically equivalent. An assessment of whether a connection point and Metering Point are electrically equivalent is to ensure that AEMO is satisfied that registration at the Metering Point will not compromise the performance of a facility compared to as if it was measured at the connection point, having regard to any electrical losses that may occur in the Market Participant's network between these points. New clause 2.31.2B outlines what AEMO must consider when approving an application under clause 2.31.2A. New clauses 2.31.2C and 2.31.2D are added to allow AEMO to request additional information to support their assessment in clause 2.31.2B, of a request made under clause 2.31.2A. New clause 2.31.2E requires the Network Operator to install a meter for each new Facility registered under clause 2.31.2B. New clauses 2.31.2F, 2.31.2G and 2.31.2H are added to: • ensure that all obligations which applied, or would have applied when the components were registered as a single Facility, still apply; • allow AEMO to specify SCADA for unregistered Loads behind a connection point that also has a Facility behind it registered under clause 2.31.2B; and • provide further clarification around registration of a Facility under clause 2.31.2B. It is intended that proposed clause 2.31.2E will be nominated as a civil penalty provision in Schedule 1 of the Electricity Industry (Wholesale Electricity Market) Regulations 2004.

2.31.2A. A person intending to submit an application described in clause 2.31.1 may request approval from AEMO to proceed with an application to register a Facility for which the Metering Point is not electrically equivalent to the connection point.

2.31.2B. Following a request under clause 2.31.2A, AEMO must approve registration of the Separate Facility if it is satisfied that:

(a) the Metering Point is not, or is not intended to be, electrically equivalent to the network connection point or shared network connection points;

(b) each Separate Facility must have a Metering Point, and there must be no Facility without a Metering Point behind the network connection point or shared network connection points;

(c) all Separate Facilities behind the network connection point or shared network connection points will remain registered to the same Market Participant;

(d) there is, or is intended to be, more than one Separate Facility behind a network connection point or shared network connection points;

(e) AEMO considers that registration of the Separate Facility would not adversely impact AEMO's ability to maintain Power System Security and Power System Reliability; and

(f) the Separate Facility is not, or is not going to be, electrically connected to other Separate Facilities behind the network connection point or shared network connection points, such that one or more of these Facilities could Inject or Withdraw at more than one of the Metering Points.

2.31.2C. AEMO may, at its discretion, request further information from a Rule Participant or a Network Operator, to support its assessment of the requirements in clause 2.31.2B.

2.31.2D. A Rule Participant must comply with a request made under clause 2.31.2C.

2.31.2E. If AEMO approves registration of a Separate Facility under clause 2.31.2B, the Network Operator must install a revenue grade interval meter at the point which is intended to become the Metering Point a Separate Facility.

2.31.2F. If AEMO approves registration of a Separate Facility under clause 2.31.2B, any obligation that would have applied to the Market Participant with respect to all components, including any network equipment, located behind the network connection point or shared connection points, if the Separate Facilities were registered as a single Facility continue to apply, including, but not limited to, any obligation to:

(a) respect the thermal limits of the network equipment;

(b) ensure accurate SCADA is made available and provided to AEMO via the Network Operator and meet all relevant SCADA requirements that would have applied if a single Facility was registered instead; and

(c) ensure Outages related to the separate Facilities reflect Outages of the network equipment located behind the network connection point or shared connection points.

2.31.2G. If AEMO approves registration a Separate Facility under clause 2.31.2B, the relevant Market Participant must comply with any additional SCADA requirements that AEMO may specify for an unregistered Load or Loads located between the network connection point and the Metering Point of any of the Separate Facilities.

2.31.2H. Regarding the registration of a Separate Facility, if approved by AEMO under clause 2.31.2B:

(a) the network connection point behind which the Separate Facility is located is not a Metering Point for the purposes of these WEM Rules;

(b) there is no limit to the number of Separate Facilities that are approved to be registered;

(c) the Separate Facilities may be of the same or different Facility Technology Type;

(d) the Separate Facilities may be, but are not required to be, Separately Certified Components; and

(e) registration of the separate Facilities does not redefine the network connection point for the purposes of other requirements, including Appendix 12 of these WEM Rules.

…

2.32. Rule Participant Suspension and Deregistration

…

Explanatory Note
Clause 2.32.2 is amended to extend the obligation on AEMO to publish and issue a Market Advisory if a Suspension Notice is issued under section 9.19.

2.32.2. Where AEMO has issued a Suspension Notice under section 9.19 or pursuant to a notification by the Economic Regulation Authority in accordance with clause 2.32.1~~ that a Rule Participant be suspended~~, AEMO must publish a notice on the WEM Website and issue a Market Advisory specifying that the Rule Participant has been suspended from the Wholesale Electricity Market and provide details of the suspension, including the reason for the suspension and the date the suspension took effect.

…

Explanatory Note
Clause 2.32.7BA is amended to correct typographical and clause reference errors.

2.32.7BA. If AEMO becomes aware that a Rule Participant has become a Chapter 5 body corporate (as defined in the Corporations Act), or is under a similar form of administration under any laws applicable to it in any jurisdiction, then AEMO must, as applicable:

(a) ~~where~~if AEMO intends to issue a Suspension Notice, issue the Suspension Notice to the Chapter 5 body corporate and the External Administrator, which may include directions that would have been given in a notice to the relevant Rule Participant pursuant to~~ clause 2.32.1~~ clause 2.32.3; or

(b) ~~where~~if AEMO ~~intends~~is required to issue a Registration Correction Notice, issue the Registration Correction Notice to the Chapter 5 body corporate and the External Administrator, specifying details that it would have specified in a notice to the relevant Rule Participant pursuant to clause 2.32.7C; or

(c) notify the Economic Regulation Authority that the Rule Participant is a Chapter 5 body corporate or has had an External Administrator appointed, and that AEMO is not required to, as applicable:

i. issue a Suspension Notice to the Rule Participant pursuant to clause 2.32.1; or

ii. issue a Registration Correction Notice to the Rule Participant pursuant to clause 2.32.7B(b).

…

2.34. Standing Data

…

Explanatory Note
Clause 2.34.11 is replaced with a provision that establishes an obligation on AEMO to verify the accuracy of the Standing Data provided by a Rule Participant and amended to require (not just permit) AEMO to request a Rule Participant to provide updated Standing Data for any of its Facilities if AEMO considers the information to be inaccurate or no longer accurate.

2.34.11. ~~AEMO may require that a Rule Participant provide updated Standing Data for any of its Facilities if AEMO considers the information provided by the Rule Participant to be inaccurate or no longer accurate.~~ AEMO must:

(a) use reasonable endeavours to verify that the Standing Data required by the WEM Rules to be provided by a Rule Participant to AEMO is and remains accurate; and

(b) require that a Rule Participant provides updated Standing Data for a Facility, if AEMO considers the information provided by the Rule Participant to be inaccurate or no longer accurate.

…

2.34.A. Essential System Service Accreditation

…

Explanatory Note
Clause 2.34A.11 is amended to require (not just permit) AEMO to reassess the Frequency Co-optimised Essential System Service Accreditation Parameters if it becomes aware that the performance of a Facility has varied, is varying, or is likely to vary significantly from these parameters, or performance requirements.

2.34A.11. If AEMO becomes aware, either pursuant to clause 2.34A.10 or through its own monitoring activities, that the performance of a Facility has varied, is varying, or is likely to vary, significantly from the Frequency Co-optimised Essential System Service Accreditation Parameters for the Facility, or any performance requirements specified in the WEM Procedure referred to in clause 2.34A.13, AEMO ~~may~~ must reassess the Frequency Co-optimised Essential System Service Accreditation Parameters, and notify the Market Participant of its decision to either:

(a) amend the Frequency Co-optimised Essential System Service Accreditation Parameters, the amendments it will make and the date that the amendments will take effect from; or

(b) not amend the Frequency Co-optimised Essential System Service Accreditation Parameters,

and the reasons for its decision.

…

3.8B. Significant Incident Reporting

Explanatory Note

Section 3.8B is inserted to provide an obligation on AEMO to investigate and report on significant incidents in the SWIS.

It is intended that proposed clause 3.8B.3 will be nominated as a civil penalty provision in Schedule 1 of the Electricity Industry (Wholesale Electricity Market) Regulations 2004.

3.8B.1. AEMO must investigate any incidents that:

(a) endanger Power System Security or Power System Reliability to a significant extent; or

(b) causes significant disruption to the operation of the dispatch process; or

(c) which AEMO considers have had, or had the potential to have had, a significant impact on the effectiveness of the market.

3.8B.2. AEMO may require the Rule Participants involved in the incident to provide a report on the incident within a reasonable time period specified by AEMO.

3.8B.3. A Rule Participant must comply with any request by AEMO for a report under clause 3.8B.2.

3.8B.4. AEMO may conduct its own investigation of, or engage independent experts to report on, the incident.

3.8B.5. Following the investigation, AEMO must provide a report detailing its findings to the Coordinator and the Economic Regulation Authority. The report must identify any information that cannot be made public, or which AEMO considers should be removed from any public version of the report.

3.8B.6. Following the investigation, AEMO must publish a report detailing its findings and including:

(a) any reports provided in accordance with clause 3.8B.3 or 3.8B.5 after AEMO has removed any confidential information; and

(b) a description of any changes to the WEM Rules or WEM Procedures that AEMO considers necessary to prevent the future occurrence of similar incidents.

3.8B.7. If AEMO considers that changes in the WEM Rules are necessary, it must draft a suitable Rule Change Proposal and submit it in accordance with the rule change process in section 2.7.

3.8B.8. If AEMO considers that changes to a WEM Procedure are necessary, it must draft a suitable Procedure Change Proposal and progress it using the Procedure Change Process in section 2.10.

3.8B.9. If AEMO has recommended any changes to a WEM Procedure, the development of which is the responsibility of the Coordinator, Economic Regulation Authority or Western Power, then the relevant party must draft a suitable Procedure Change Proposal and progress it using the Procedure Change Process in section 2.10.

…

3.11B. Procuring Non-Co-optimised Essential System Services

…

Explanatory Note
This change is made to ensure consistency with Clause 5.2A.2.

3.11B.7. An NCESS Submission form must, at a minimum, include:

(a) the name and type of facility or equipment, and whether it is registered or intended to be registered under these WEM Rules;

(b) the name of the Market Participant or service provider, as applicable, in respect to the facility or equipment;

(c) the quantity of service the facility or equipment will provide for the NCESS;

(d) the timing and duration of the service availability for the NCESS;

(e) the location of the facility or equipment on the network;

(f) any operational requirements or limitations that must be respected for use of the facility or equipment for the NCESS;

(g) where the NCESS Submission is made in respect to a type of technology that would ordinarily be capable of being assigned Certified Reserve Capacity, the information required to be provided by the Market Participant or service provider to demonstrate that it will be able to meet the relevant requirements in clause 4.10.1 in respect of each Reserve Capacity Cycle that the Facility would be eligible to participate in over ~~for at least the first Reserve Capacity Cycle coinciding with~~ the period of the NCESS Contract;

(gA) where the NCESS Submission is made in respect to a type of technology that would not ordinarily be capable of being assigned Certified Reserve Capacity, the information required to be provided by the Market Participant or service provider to demonstrate that it is not able to meet the relevant requirements of clause 4.10.1;

(h) whether the facility or equipment participates, or will participate, in Central Dispatch or is accredited or will be accredited under these WEM Rules to provide an Essential System Service;

(i) the fixed costs for that facility or equipment applicable for the period of the NCESS Contract, including any Capacity Credit payments expected or received;

(iA) if the facility or equipment would ordinarily be capable of being assigned Certified Reserve Capacity, whether the Market Participant or service provider would require any reimbursement for any reduction in a Reserve Capacity settlement amount determined for it under clause 9.8.2 that is a direct consequence of the enablement or dispatch of the NCESS;

(j) the highest price at which the facility or equipment will provide the NCESS when enabled or dispatched; and

(k) any other payment that the facility or equipment requires to provide the NCESS

…

Explanatory Note
Clause 3.11B.15 is amended to provide further clarification around what is to be published regarding the payment structure and amounts specified in an NCESS Contract.

3.11B.15. AEMO or the Network Operator, as applicable, must publish the following details regarding each NCESS Contract on the WEM Website, in the case of AEMO, or the Network Operator's website, in the case of the Network Operator, as soon as practicable after the NCESS Contract has been signed by all parties:

(a) the name of each Market Participant or service provider and the Facility or equipment that will provide the NCESS;

(b) the location on the network of the facility or equipment;

(c) the type of service the facility or equipment will provide as NCESS;

(d) the timing and duration of the NCESS to be provided under the NCESS Contract; and

(e) the payment structure and the amounts specified in the NCESS Contract~~.~~, including but not limited to:

i. if applicable, the price to make the facility or equipment available for enablement or dispatch, and the nature of the availability obligations;

ii. if applicable, the price at which the facility or equipment will provide the NCESS when enabled or dispatched; and

iii. if applicable, any other payment that the facility or equipment requires to provide the NCESS.

…

3.21. Forced Outages and Outage Quantity Calculations

…

> **Explanatory Note**
>
> Clause 3.21.2(d) is amended to reduce the deadline for providing AEMO any final details of a Forced Outage from fifteen days to seven days after the relevant Trading Day. AEMO has proposed the change to allow certain settlement calculations that are reliant on Outage data (e.g. for Supplementary Capacity and NCESS Contracts) to be performed earlier.
>
> Feedback from Market Participants is requested on whether the earlier deadline would prevent a Market Participant from collecting any specific information that it needs to finalise its Forced Outage details.
>
> It is intended that proposed clauses 3.21.2 and 3.21.3(a) will be nominated as a civil penalty provision in Schedule 1 of the Electricity Industry (Wholesale Electricity Market) Regulations 2004.

3.21.2. If an Outage Facility suffers, or will suffer, a Forced Outage, the relevant Market Participant or Network Operator must:

(a) as soon as practicable after the Market Participant or Network Operator becomes aware of the Forced Outage, notify AEMO in accordance with the WEM Procedure referred to in clause 3.21.10 of:

i. the Outage Facility affected by the Outage and, where relevant, each Facility Technology Type of the Outage Facility affected by the Outage;

ii. the Outage Capabilities affected by the Outage for the Outage Facility and for each Facility Technology Type of the Outage Facility;

iii. the cause of the Outage;

iv. the date and time the Outage commenced or is expected to commence;

v. the date and time the Outage ended or is expected to end;

vi. where relevant, an estimate of the Remaining Available Capacity of each Outage Capability for the Outage Facility;

vii. where relevant, an estimate of the Remaining Available Capacity for each Facility Technology Type of the Outage Facility; and

viii. any other details specified in the WEM Procedure referred to in clause 3.21.10;

(b) provide AEMO with full available details of the Forced Outage referred to in clause 3.21.2(a), as well as the time that the information required in clause 3.21.2(a) was first notified to AEMO, in accordance with the WEM Procedure referred to in clause 3.21.10:

i. as soon as practicable;

ii. subject to clause 3.21.2A, using best endeavours to provide AEMO with the full available details within 24 hours of the Forced Outage occurring; and

iii. subject to clause 3.21.2A, in all cases no later than the end of the next Business Day of the Forced Outage occurring;

(c) must inform AEMO of any material change to the information provided under this clause as soon as practicable after becoming aware of that change, in the manner prescribed in the WEM Procedure referred to in clause 3.21.10; and

(d) notwithstanding the requirements of this clause 3.21.2, in respect of each affected Trading Day, as soon as practicable, and in any case no later than the end of the day that is ~~fifteen~~ seven calendar days after the day on which the Trading Day ends, provide AEMO with any further information or changes to the Forced Outage notification information provided under clause 3.21.2(b).

3.21.2A. A Market Participant or Network Operator is not required to comply with clauses 3.21.2(b)(ii) or 3.21.2(b)(iii) for a Self-Scheduling Outage Facility if AEMO has granted an exemption for the Self-Scheduling Outage Facility in accordance with the process described in the WEM Procedure referred to in clause 3.21.10.

3.21.3. Where additional information relating to a Forced Outage becomes available after the timeframes specified in clause 3.21.2:

(a) if the additional information is held by a Market Participant or Network Operator, the Market Participant or Network Operator must notify AEMO of the additional information as soon as practicable;

(b) AEMO may require a Market Participant or Network Operator to submit a Forced Outage reflecting that additional information; and

(c) a Market Participant or Network Operator may request AEMO to allow it to enter or revise a Forced Outage in order to reflect that additional information, including where that may result in the Forced Outage being withdrawn.

3.21.4. Where AEMO receives a request under 3.21.3(c), AEMO must review the information provided by the Market Participant or Network Operator and determine whether there is sufficient evidence to support the Forced Outage being revised or withdrawn, and must notify the Market Participant or Network Operator of its determination as soon as practicable.

…

4.1. The Reserve Capacity Cycle

…

> **Explanatory Note:**
>
> AEMO is currently required to publish the following information by around 30 September of Year 1 of a Reserve Capacity Cycle:
>
> - the Reserve Capacity Prices and the aggregate MW of Capacity Credits assigned to Facilities and components at each price (clauses 4.1.18A, 4.20.5AA); and
> - whether the Reserve Capacity Requirement has been met or exceeded with Capacity Credits satisfying certain conditions (clauses 4.1.16A(b), 4.20.5A(aA)).
>
> However, AEMO cannot determine this information until it has certainty around how Market Participants with multiple Separately Certified Components for a Facility with a Network Access Quantity too low to cover the total Certified Reserve Capacity will allocate their Capacity Credits to their Separately Certified Components. Market Participants are required to notify AEMO of their allocations by around 30 October of Year 1 under clause 4.1.21A.
>
> To resolve this timing issue:
>
> - clauses 4.1.16A, 4.1.22, 4.1.26, 4.20.5A and 4.20.5AA are amended, clause 4.1.18A is deleted and new clause 4.20.17B is inserted to delay these publications until five Business Days after AEMO receives the required notifications; and
> - clauses 4.1.16A(b) and 4.20.5A(b) are amended to retain the publication of the relevant Reserve Capacity Prices (albeit without associated quantities of Capacity Credits) by around 30 September.

4.1.16A. By 5:00 PM on the last Business Day falling on or before 30 September of Year 1 of a Reserve Capacity Cycle, AEMO must:

(a) assign Capacity Credits in accordance with clause 4.20.5A(a);

~~(b) determine in accordance with clause 4.20.5A(aA) whether the Reserve Capacity Requirement has been met or exceeded with the Capacity Credits assigned for Year 3 of the Reserve Capacity Cycle:~~

~~i. to Facilities to which section 4.13 applies, for which no Reserve Capacity Security was required to be provided under section 4.13; or~~

~~ii. to Demand Side Programmes determined by AEMO to be in Commercial Operation;~~

(b) publish the information required to be published under clause 4.20.5A(b);

(c) notify each Market Participant of the Network Access Quantity determined for each of its Facilities in accordance with clause 4.15.11; and

(d) publish the information required to be published under clause 4.15.16.

4.1.17. [Blank]

4.1.18. [Blank]

Explanatory Note:
Clause 4.1.18A is no longer required because the publication timing for the clause 4.20.5AA information is covered in clause 4.1.22.

~~4.1.18A. AEMO must publish the summary of information described in clause 4.20.5AA by the date and time specified in clause 4.1.16A.~~

4.1.19. The Economic Regulation Authority must commence a review of the Benchmark Reserve Capacity Prices as required by clause 4.16.3 with the objective of completing the review, including consideration of public submissions in relation to that review, so as to allow a reasonable time for the Economic Regulation Authority to determine any proposed change in value and for that value to be implemented prior to the date and time specified in clause 4.1.4 that relates to the following Reserve Capacity Cycle.

4.1.20. [Blank]

4.1.21. A Market Participant may apply to AEMO:

(a) under clause 4.13.2A for a recalculation of the amount of Reserve Capacity Security required to be held by AEMO for a Facility in accordance with clause 4.13.2(b); or

(b) under clause 4.13A.8 for a recalculation of the amount of DSP Reserve Capacity Security required to be held by AEMO for a Demand Side Programme in accordance with clauses 4.13A.1 or 4.13A.4, as applicable,

after 5:00 PM on the last Business Day falling on or before 1 October of Year 1 of a Reserve Capacity Cycle.

4.1.21A. By 5:00 PM on the last Business Day falling on or before 30 October of Year 1 of a Reserve Capacity Cycle, each relevant Market Participant must notify AEMO of the number of Capacity Credits that are to be associated with each component of their Facility for the Capacity Year in accordance with clause 4.20.16.

4.1.21B. If required under clause 4.20.8, AEMO must issue a Notice of Intention to Cancel Capacity Credits by 5:00 PM on the last Business Day falling on or before 15 August of Year 3 of a Reserve Capacity Cycle, where the notice relates to the Capacity Year that commences on 1 October of Year 3 of that Reserve Capacity Cycle.

4.1.22. Within five Business Days after the notification deadline specified in clause 4.1.21A, AEMO must:

(a) set the number of Capacity Credits to be associated with each component of a Facility in accordance with clause 4.20.17;~~ and~~

(b) publish the information determined in clause 4.1.22(a)~~ on the WEM Website.~~;

(c) publish the summary of information described in clause 4.20.5AA; and

(d) publish AEMO's determination under clause 4.20.17B(a).

…

Explanatory Note:

Clause 4.1.26 is amended to:

- remove provisions relating to the 2018-2020 Reserve Capacity Cycles, which are no longer required;
- specify the initial Trading Day for Reserve Capacity Obligations more explicitly for the 2021-2023 Reserve Capacity Cycles, because AEMO has already decided whether the Reserve Capacity Requirement has been met for those Reserve Capacity Cycles;
- reflect the timing change for AEMO's determination from the 2024 Reserve Capacity Cycle onwards (i.e. by updating the relevant clause references from 4.20.5A(aA) to 4.20.17B(a));
- clarify that a Facility upgrade may be eligible for early Reserve Capacity payments if it meets the relevant criteria; and
- clarify that when Reserve Capacity Security (RCS) is required to be provided for only part of a Facility under section 4.13 (i.e. for a Facility upgrade), the capacity of the Facility for which RCS is not required should contribute to meeting the Reserve Capacity Requirement in the test specified in clause 4.1.26(e)(i).

4.1.26. Reserve Capacity Obligations apply:

(a) [Blank]

(b) [Blank]

~~(c) [Blank]~~

~~(d) for the 2018 Reserve Capacity Cycle:~~

~~i. where AEMO has determined in accordance with clause 4.20.5A(aA) that the Reserve Capacity Requirement has been met or exceeded with the Capacity Credits assigned for Year 3 of the Reserve Capacity Cycle for which no Reserve Capacity Security was required to be provided under section 4.13, from the Trading Day commencing on 1 October of Year 3 of the Reserve Capacity Cycle; and~~

~~ii. where AEMO has determined in accordance with clause 4.20.5A(aA) that the Reserve Capacity Requirement has not been met with the Capacity Credits assigned for Year 3 of the Reserve Capacity Cycle for which no Reserve Capacity Security was required to be provided under section 4.13:~~

~~1. from the Trading Day commencing on 1 October of Year 3 of the Reserve Capacity Cycle, for Facilities that were commissioned as at 17 September 2018 or for Facilities which have provided Capacity Credits in one or both of the two previous Reserve Capacity Cycles;~~

~~2. from the Trading Day commencing on 1 June of Year 3 of the Reserve Capacity Cycle, for Facilities commissioned between 17 September 2018 and 1 June of Year 3 of the Reserve Capacity Cycle;~~

~~2A. from the Trading Day commencing on the scheduled date of commissioning, as specified in accordance with clause 4.10.1(c)(iii)(7), or as revised in accordance with clause 4.27.11A, for Facilities commissioned between 1 June of Year 3 of the Reserve Capacity Cycle and 1 October of Year 3 of the Reserve Capacity Cycle; or~~

~~3. from the Trading Day commencing on 1 October of Year 3 of the Reserve Capacity Cycle, for new Energy Producing Systems undertaking Commissioning Tests after 1 October of Year 3 of the Reserve Capacity Cycle; and~~

(c) for the 2021 Reserve Capacity Cycle, from the Trading Day commencing on 1 October of Year 3 of the Reserve Capacity Cycle;

(d) for the 2022 Reserve Capacity Cycle and 2023 Reserve Capacity Cycle, from the Trading Day commencing:

i. on 1 October of Year 3 of the Reserve Capacity Cycle, for Facilities that were commissioned as at 16 September 2019 or for Facilities which have provided Capacity Credits in one or both of the two previous Reserve Capacity Cycles;

ii. on 1 June of Year 3 of the Reserve Capacity Cycle, for Facilities or Facility upgrades commissioned between 16 September 2019 and 1 June of Year 3 of the Reserve Capacity Cycle;

iii. on the scheduled date of commissioning, as specified in accordance with clause 4.10.1(c)(iii)(7), or as revised in accordance with clause 4.27.11A, for Facilities or Facility upgrades commissioned between 1 June of Year 3 of the Reserve Capacity Cycle and 1 October of Year 3 of the Reserve Capacity Cycle; or

iv. on 1 October of Year 3 of the Reserve Capacity Cycle, for new Energy Producing Systems or upgrades to Energy Producing Systems undertaking Commissioning Tests after 1 October of Year 3 of the Reserve Capacity Cycle; and

(e) from the ~~2019~~ 2024 Reserve Capacity Cycle:

i. from the Trading Day commencing 1 October of Year 3 of the Reserve Capacity Cycle, where AEMO has determined in accordance with ~~clause 4.20.5A(aA)~~ clause 4.20.17B(a) that the Reserve Capacity Requirement has been met or exceeded with the Capacity Credits assigned for Year 3 of the Reserve Capacity Cycle:

1. to Facilities or parts of Facilities to which section 4.13 applies, for which no Reserve Capacity Security was required to be provided under section 4.13; or

2. to Demand Side Programmes determined by AEMO to be in Commercial Operation, and

ii. where AEMO has determined in accordance with ~~clause 4.20.5A(aA)~~ clause 4.20.17B(a) that the Reserve Capacity Requirement has not been met with the Capacity Credits assigned for Year 3 of the Reserve Capacity Cycle:

1. to Facilities or parts of Facilities to which section 4.13 applies, for which no Reserve Capacity Security was required to be provided under section 4.13; or

2. to Demand Side Programmes determined by AEMO to be in Commercial Operation,

from the Trading Day commencing:

3. on 1 October of Year 3 of the Reserve Capacity Cycle, for Facilities that were commissioned as at 16 September 2019 or for Facilities which have provided Capacity Credits in one or both of the two previous Reserve Capacity Cycles;

4. on 1 June of Year 3 of the Reserve Capacity Cycle, for Facilities or Facility upgrades commissioned between 16 September 2019 and 1 June of Year 3 of the Reserve Capacity Cycle;

5. on the scheduled date of commissioning, as specified in accordance with clause 4.10.1(c)(iii)(7), or as revised in accordance with clause 4.27.11A, for Facilities or Facility upgrades commissioned between 1 June of Year 3 of the Reserve Capacity Cycle and 1 October of Year 3 of the Reserve Capacity Cycle; or

6. on 1 October of Year 3 of the Reserve Capacity Cycle, for new Energy Producing Systems or upgrades to Energy Producing Systems undertaking Commissioning Tests after 1 October of Year 3 of the Reserve Capacity Cycle.

…

4.5. Long Term Projected Assessment of System Adequacy

Explanatory Note: Clause 4.5.12 is amended to allow calculation of the Availability Duration Gap based on the 90th percentile peak days, rather than all Trading Days in a relevant Capacity Year, and to revise the Indicative Peak ESR Obligation Intervals to delink them from the Mid Peak ESR Obligation Intervals to minimise the daily peak demand for the Trading Day.

4.5.12. For the third Capacity Year of the Long Term PASA Study Horizon, AEMO must determine the following information:

(a) [Blank]~~the Availability Duration Gap Load Scenario, which is the load scenario described in clause 4.5.10(a)(iv), adjusted as if:~~

~~i. each Electric Storage Resource which has Capacity Credits for any future Capacity Year was dispatched to discharge evenly across its Peak Electric Storage Resource Obligation Intervals, adjusted to reflect the Indicative Peak Electric Storage Resource Obligation Intervals for that Capacity Year;~~

~~ii. all Demand Side Programmes with Capacity Credits for a future Capacity Year were activated during the Capacity Year so as to minimise the peak demand during that Capacity Year; and~~

~~iii. any other Facility or Separately Certified Component that is expected to have a Peak Reserve Capacity Obligation Quantity of zero in some Trading Intervals and greater than zero in other Trading Intervals is activated during the Capacity Year so as to minimise the peak demand during that Capacity Year;~~

(b) [Blank]~~the Indicative Peak Electric Storage Resource Obligation Intervals;~~

(c) [Blank]~~Availability Duration Gap, which is the maximum number of Trading Intervals adjacent to the Indicative Peak Electric Storage Resource Obligation Intervals in any Trading Day in the Availability Duration Gap Load Scenario in which demand is greater than the maximum demand in any of the Indicative Peak Electric Storage Resource Obligation Intervals for that Trading Day;~~

(d) [Blank]~~the ESR Duration Requirement, which is the ESR Duration Requirement for the previous Reserve Capacity Cycle plus the Availability Duration Gap;~~

(e) [Blank]~~the maximum over all Trading Days in the Availability Duration Gap Load Scenario of the greater of zero and:~~

~~i. the maximum consumption in MWh in a Trading Interval that is not an Indicative Peak Electric Storage Resource Obligation Interval in that Trading Day; less~~

~~ii. the maximum consumption in MWh in any Indicative Peak Electric Storage Resource Obligation Interval in that Trading Day,~~

~~multiplied by 2 to convert to MW;~~

(f) the MW peak demand in the load scenario described in clause 4.5.10(a)(iii) less the number of Peak Capacity Credits issued to Demand Side Programmes in the Reserve Capacity Cycle immediately prior to this Reserve Capacity Cycle ("**Indicative Demand Side Programme Dispatch Threshold**");

(g) the Peak Demand Side Programme Dispatch Requirement;

(h) the Flexible Demand Side Programme Dispatch Requirement, which is the minimum number of Trading Intervals in the applicable Capacity Year in which a Demand Side Programme with Flexible Capacity Credits can be dispatched in addition to its Peak Demand Side Programme Dispatch Requirement and is the greater of eight and the Peak Demand Side Programme Dispatch Requirement; and

(i) the minimum capacity required to be provided by Capability Class 1 and Capability Class 3 capacity if clause 4.5.9(b) is to be satisfied. This minimum capacity is to be set at a level such that if clauses 4.5.9(a) and 4.5.9(b) and the criteria for evaluating Outage Plans set out in clause 3.18E.8 were to be applied to the Availability Gap Load Scenario, then it would be possible to satisfy the Planning Criterion and the Outage Evaluation Criteria using, to the extent that the capacity is anticipated to provide Certified Reserve Capacity, the anticipated installed Capability Class 1 and Capability Class 3 capacity and to the extent that further Capability Class 1 and Capability Class 3 capacity would be required, an appropriate mix of Capability Class 1 and Capability Class 3 capacity to make up that shortfall.

4.5.13. The Statement of Opportunities Report must include:

…

(eC) for each Capacity Year of the Long Term PASA Horizon:

i. the Availability Duration Gap Load Scenario, which is the load scenario described in clause 4.5.10(a)(iv), adjusted as if:

1. each Electric Storage Resource which has Capacity Credits for any future Capacity Year was dispatched to discharge evenly across its Peak Electric Storage Resource Obligation Intervals, adjusted to reflect the Indicative Peak Electric Storage Resource Obligation Intervals for that Capacity Year;

2. all Demand Side Programmes with Capacity Credits for a future Capacity Year were activated during the Capacity Year so as to minimise the peak demand during that Capacity Year; and

3. any other Facility or Separately Certified Component that is expected to have a Peak Reserve Capacity Obligation Quantity of zero in some Trading Intervals and greater than zero in other Trading Intervals is activated during the Capacity Year so as to minimise the peak demand during that Capacity Year;

ii. the Indicative Peak Electric Storage Resource Obligation Intervals;

iii. Availability Duration Gap, which:

1. is the maximum number of Trading Intervals adjacent to the Indicative Peak Electric Storage Resource Obligation Intervals in any Trading Day identified in clause 4.5.12(c)(ii) that is in the Availability Duration Gap Load Scenario, in which demand is greater than the maximum demand in any of the Indicative Peak Electric Storage Resource Obligation Intervals for that Trading Day; and

2. only considers Trading Days that have a daily peak demand that falls within the 90th percentile of the peak demand for the given Capacity Year in the load scenario described in clause 4.5.10(a)(iv);

…

…

4.10. Information Required for the Certification of Reserve Capacity

Explanatory Note:

Clause 4.10.1(fD)(iii) is amended to replace the term "Parasitic Loads" with "Loads", for consistency with other sub-clauses of clause 4.10.1 that were updated to remove the word "Parasitic" by the Tranche 5 Amendments (paragraph 25A, Schedule I).

4.10.1. Each Market Participant must ensure that information submitted to AEMO with an application for certification of Reserve Capacity pertains to the Reserve Capacity Cycle to which the certification relates, and is supported by documented evidence and includes, if applicable, except to the extent that it is already accurately provided in Standing Data:

(a) the identity of the Facility;

…

(fD) in addition to any other requirements in this clause 4.10.1 for a Non-Scheduled Facility, for a Non-Scheduled Facility comprising only an Electric Storage Resource, including a Small Aggregation comprising aggregated Electric Storage Resources:

i. the location of the single Transmission Node Identifier behind which the aggregated Electric Storage Resources will be connected;

ii. the nameplate capacity and minimum and maximum Charge Level capabilities of each Electric Storage Resource and the temperature dependence of that capacity;

iii. the sent-out capacity, net of ~~Parasitic~~ Loads that can be guaranteed to be available for supply across the Peak Electric Storage Resource Obligation Duration, to the relevant Network from each Electric Storage Resource when it is operated normally at an ambient temperature of 41 degrees Celsius for each year of the expected life of the Electric Storage Resource, supported by manufacturer data; and

iv. evidence that demonstrates the Electric Storage Resources are expected to discharge during their Peak Electric Storage Resource Obligation Intervals;

…

Explanatory Note

New transitional clause 4.10.1B was recently added to exempt a Market Participant who is applying for certification of Reserve Capacity for a DSP comprised of more than one Associated Loads each with an expected Peak Capacity of less than 5 MW, from providing the single TNI for the Facility under 4.10.1(f)(viii).

The clause previously only applied to the 2024 Reserve Capacity Cycle and is now amended to apply to the 2025 Reserve Capacity Cycle as well.

4.10.1B. A Market Participant applying for certification of Reserve Capacity for the 2024 and 2025 Reserve Capacity Cycles, for a Demand Side Programme with more than one Associated Load, is exempt from the requirement in clause 4.10.1(f)(viii) if the expected quantity of Peak Capacity for each Associated Load associated with the Demand Side Programme is less than 5 MW.

…

4.13. Reserve Capacity Security

Explanatory Note:

Clauses 4.13.1A and 4.13.1C are amended to correct a typographical error.

Clause 4.13.1B is amended to simplify and provide clarity around the circumstances in which the obligation to provide Reserve Capacity Security under clause 4.13.1 applies (i.e. if AEMO does not already hold security).

New clause 4.13.1D is introduced to ensure that AEMO continues to hold the benefit of a Reserve Capacity Security for a Facility in scenarios where:

- AEMO has already drawn down upon the Reserve Capacity Security of the Facility;
- the Market Participant has been assigned Capacity Credits for a subsequent Reserve Capacity Cycle; and
- the Facility is yet to enter Commercial Operation.

It is intended that proposed clause 4.13.1D will be nominated as a civil penalty provision in Schedule 1 of the Electricity Industry (Wholesale Electricity Market) Regulations 2004.

4.13.1. If AEMO assigns Certified Reserve Capacity to a Facility (which, for the purposes of this section 4.13, excludes a Demand Side Programme) that is yet to enter service (or re-enter service after significant maintenance or having been upgraded), the relevant Market Participant must ensure that AEMO holds the benefit of a Reserve Capacity Security that is:

(a) in the form specified in clause 4.13.5; and

(b) an amount determined under clause 4.13.2(a) by the date and time specified in clause 4.1.13.

4.13.1A. For the purposes of this section 4.13, if an existing Facility is undergoing significant maintenance or being upgraded the requirement to provide Reserve Capacity Security applies only to the part of the Facility either undergoing significant maintenance or being upgraded.

4.13.1B. ~~The obligation under clause 4.13.1 to provide Reserve Capacity Security does not apply if the Market Participant has provided Reserve Capacity Security in relation to the same Facility for a previous Reserve Capacity Cycle, unless:~~

~~(a) the Facility is an existing Facility undergoing significant maintenance or being upgraded; or~~

~~(b) AEMO cancelled the Peak Capacity Credits assigned to the Facility for that previous Reserve Capacity Cycle in accordance with clause 4.20.14.~~The obligation under clause 4.13.1 to provide Reserve Capacity Security only applies if AEMO does not already hold the benefit of a Reserve Capacity Security for the Facility or Facility upgrade.

4.13.1C. For the purposes of this section 4.13, a Facility includes part of a Facility, any upgrade or significant maintenance to an existing Facility, unless otherwise stated.

4.13.1D. If AEMO has drawn upon the Reserve Capacity Security for a Facility under clause 4.13.11A, and the Market Participant continues to have an obligation under clause 4.13.1, then the Market Participant must ensure that AEMO holds the benefit of a replacement Reserve Capacity Security by a date and time specified by AEMO, which must be:

(a) in the form specified in clause 4.13.5; and

(b) an amount not less than the amount required under clause 4.13.2.

…

Explanatory Note:
Clause 4.13.2B is amended to ensure that AEMO is required to return the Reserve Capacity Security to the Market Participant if the amount recalculated under clause 4.13.2(b) is zero.

4.13.2B. Within 10 Business Days after receipt of a request from a Market Participant under clause 4.13.2A AEMO must recalculate the amount of Reserve Capacity Security required to be held by a Facility using the formula in clause 4.13.2(b). If the amount recalculated by AEMO under clause 4.13.2(b) is less than that originally calculated under clause 4.13.2(a) then AEMO must:

(a) notify the Market Participant of the result of the calculation;

(aA) if the amount recalculated under clause 4.13.2(b) is zero, return the Reserve Capacity Security;

(b) if the amount recalculated under clause 4.13.2(b) is greater than zero, offer the Market Participant the opportunity to replace the Reserve Capacity Security in accordance with clause 4.13.2C, and

(c) if the Market Participant provides a replacement Reserve Capacity Security in accordance with clause 4.13.2C, return any excess Reserve Capacity Security.

…

Explanatory Note:
Clauses 4.13.12 and 4.13A.8 are amended to correct clause reference errors.

4.13.12. If the Reserve Capacity Security drawn upon under ~~clause 4.13~~ clause 4.13.11A is a Security Deposit, then the Market Participant forfeits the amount of the Security Deposit.

…

4.13A.8. In respect of a Reserve Capacity Cycle, after the time and date referred to in ~~clause 4.1.23~~clause 4.1.21, a Market Participant may apply to AEMO for a recalculation of the amount of DSP Reserve Capacity Security required to be held for a Demand Side Programme under clauses 4.13A.1 or 4.13A.4, as applicable.

…

4.20. Capacity Credits

…

Explanatory Note:
Clause 4.20.5A is amended to resolve a timing issue regarding AEMO's publication of matters regarding the Reserve Capacity Cycle, as explained in the Explanatory Note of clause 4.1.16A.

4.20.5A. AEMO must:

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

~~(aA) determine whether the Reserve Capacity Requirement has been met or exceeded with the Capacity Credits assigned for the third Capacity Year of the Long Term PASA Study Horizon for a Reserve Capacity Cycle;~~

~~i. to Facilities to which section 4.13 applies, for which no Reserve Capacity Security was required to be provided under section 4.13; or~~

~~ii. to Demand Side Programmes determined by AEMO to be in Commercial Operation; and~~

(b) publish, by the date and time specified in clause 4.1.16A:

~~i. AEMO's determination under clause 4.20.5A(aA); and,~~

~~ii. for each Facility assigned Capacity Credits under clause 4.20.5A(a):~~

~~1. the quantity of Capacity Credits assigned;~~

~~2. [Blank]~~

~~3. the Facility Class.~~

i. for each Facility assigned Capacity Credits under clause 4.20.5A(a):

1. the quantity of Capacity Credits assigned; and

2. the Facility Class;

ii. the Peak Reserve Capacity Price for the Reserve Capacity Cycle;

iii. if the Reserve Capacity Cycle is a Transitional Reserve Capacity Cycle, the Facility Monthly Reserve Capacity Price determined under clause 4.29.1B for the Reserve Capacity Cycle multiplied by 12; and

iv. each Facility Monthly Reserve Capacity Price that may be determined under clause 4.29.1D for the Reserve Capacity Cycle multiplied by 12.

4.20.5AA. For each Reserve Capacity Cycle, if AEMO has assigned Capacity Credits to Facilities or Separately Certified Components at any of the following prices, AEMO must, by the date and time specified in clause 4.1.22, publish a summary of the aggregate quantity of MW of Capacity Credits assigned to Facilities or Separately Certified Components at each price for the Reserve Capacity Cycle:

(a) the Peak Reserve Capacity Price;

(b) if the Reserve Capacity Cycle is also a Transitional Reserve Capacity Cycle the Facility Monthly Reserve Capacity Price for a Transitional Facility or Transitional Component multiplied by 12; and

(c) if the Reserve Capacity Cycle is also a Fixed Price Reserve Capacity Cycle the Facility Monthly Reserve Capacity Price for each Facility and Separately Certified Component that is a Fixed Price Facility or Fixed Price Component for that Reserve Capacity Cycle multiplied by 12.

...

4.20.16. Where AEMO has assigned Capacity Credits to a Facility for a Capacity Year that is less than the total Certified Reserve Capacity for each component of the Facility for that Capacity Year, the Market Participant must, by the date and time specified in clause 4.1.21A, notify AEMO of the number of Capacity Credits that are to be associated with each component of the Facility for the Capacity Year, where the number must not exceed the Certified Reserve Capacity assigned to each component of the Facility for that Capacity Year.

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

(a) the number of Capacity Credits the Market Participant nominated to trade bilaterally 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 each component of the Facility.

…

Explanatory Note: The determination and publication of whether the Reserve Capacity Requirement has been met or exceeded for a Reserve Capacity Cycle is relocated from clause 4.20.5A to new clause 4.20.17B because these events occur later than the other events described in clause 4.20.5A. The new clause is number 4.20.17B because a new clause 4.20.17A will be inserted by Schedule 2 of the RC Reform Amendments.

4.20.17B. AEMO must, by the date and time specified in clause 4.1.22:

(a) determine whether the Reserve Capacity Requirement has been met or exceeded with the Capacity Credits assigned for the third Capacity Year of the Long Term PASA Study Horizon for a Reserve Capacity Cycle:

i. to Facilities or parts of Facilities to which section 4.13 applies, for which no Reserve Capacity Security was required to be provided under section 4.13; or

ii. to Demand Side Programmes determined by AEMO to be in Commercial Operation; and

(b) publish AEMO's determination under clause 4.20.17A(a).

4.20.18. AEMO must publish on the WEM Website, for each Market Participant holding Capacity Credits, the Capacity Credits provided by each Facility for each Reserve Capacity Cycle.

…

4.25. Reserve Capacity Testing

…

Explanatory Note

Clause 4.25.2(b) is amended to prevent a Demand Side Programme from being subjected to an unnecessary Reserve Capacity Test when it has successfully demonstrated its capability through the normal dispatch process.

4.25.2. AEMO may verify the matters specified in clause 4.25.1 by:

(a) in the case of a Facility that is not required to install Facility Sub-Metering in accordance with clause 2.29.12:

i. observing the Facility operate as part of normal market operations as determined from Meter Data Submissions for not less than:

1. for a Non-Intermittent Generating System, two consecutive Trading Intervals; or

2. for an Electric Storage Resource, the Electric Storage Resource Obligation Duration; or

ii. subject to clause 4.25.2B, testing, in accordance with clause 4.25.9, for not less than:

1. for a Non-Intermittent Generating System, two consecutive Trading Intervals; or

2. for an Electric Storage Resource, the Electric Storage Resource Obligation Duration,

and the Facility successfully passing that test as determined from Meter Data Submissions;

(b) in the case of a Demand Side Programme:

i. ~~[Blank]~~observing the Facility decrease its consumption in response to a Dispatch Instruction issued by AEMO, for at least two consecutive Trading Intervals, as determined from metered consumption; or

ii. testing, in accordance with clause 4.25.9, for not less than two consecutive Trading Intervals and the Facility successfully passing that test as determined from metered consumption;

(c) [Blank]

…

...

Explanatory Note

Clause 4.25.4 is amended to allow AEMO to reduce the number of Capacity Credits held by a Facility which has failed testing, to the greatest value obtained during testing.

4.25.4. Subject to clause 4.25.4G, if a Facility, or a Separately Certified Component of a Facility, fails a Reserve Capacity Test requested by AEMO under clause 4.25.2, AEMO must re-test that Facility, or Separately Certified Component of that Facility, as applicable, in accordance with clause 4.25.2, not earlier than 14 days and not later than 28 days after the first Reserve Capacity Test. If the Facility, or Separately Certified Component of that Facility, as applicable, fails this second Reserve Capacity Test, then AEMO must, from the second Trading Day following the Scheduling Day on which AEMO determines that the second Reserve Capacity Test was failed:

(a) if the Reserve Capacity Test related to a Non-Intermittent Generating System, reduce the number of Capacity Credits held by the relevant Market Participant for that Facility or Separately Certified Component of that Facility to ~~reflect the maximum capabilities achieved~~ the greatest of the values obtained in the failed intervals in either Reserve Capacity Test performed~~, in accordance with 4.25.2E(b)~~ (after adjusting these results to the equivalent values at a temperature of 41 degrees Celsius and allowing for the capability provided by operation on different types of fuels);

…

…

4.29. Settlement Data

…

Explanatory Note

Clause 4.29.3(d)(vii) is deleted to remove the requirement for AEMO to determine Participant Capacity Rebates for each Market Participant and Trading Day. The values are no longer required because the concept of Participant Capacity Rebates was removed on 13 December 2023 by Schedule 1 of the RC Reform Amendments.

4.29.3. AEMO must determine the following information in time for settlement of each Trading Day d:

…

(d) for each Market Participant p and for Trading Day d:

i. the quantity of Capacity Credits (including Capacity Credits from Facilities subject to NCESS Contracts) for each Facility acquired by AEMO;

ii. the quantity of Capacity Credits for each Demand Side Programme for Trading Day d;

iii. [Blank]

iv. the quantity of Capacity Credits for each Facility traded bilaterally in accordance with section 4.30;

v. the Individual Reserve Capacity Requirement for each Market Participant for that Trading Month in which Trading Day d falls; and

vi. the total Capacity Cost Refund to be paid by the Market Participant to AEMO for all Trading Intervals in Trading Day d; ~~and~~

~~vii. the total Participant Capacity Rebate to be paid to the Market Participant by AEMO for all Trading Intervals in Trading Day d;~~

(dA) for each Market Participant, the sum over all of Market Participant p's Intermittent Loads, deemed to be Intermittent Loads under clause 1.48.2, of the Intermittent Load Refund payable to AEMO by Market Participant p in respect of each of its Intermittent Loads for Trading Day d; and

…

…

6.3. Determination of Electric Storage Resource Obligation Intervals

…

Explanatory Note Clause 6.3.1 is amended to require AEMO to publish the Mid Peak Electric Storage Resource Obligation Interval.

6.3.1. AEMO must, in accordance with the WEM Procedure referred to in clause 4.11.3A, determine, ~~and~~ record, and publish the following information by 6:50 AM on each Scheduling Day on the WEM Website:

(a) the Mid Peak Electric Storage Resource Obligation Interval~~s~~ that will apply during the Trading Day for the Scheduling Day; and

(b) the Mid Peak Electric Storage Resource Obligation Intervals that AEMO expects will apply during each of the seven following Trading Days.

…

6.3A. Information to Support the Bilateral and STEM Submission Process

…

Explanatory Note Clause 6.3A3 is amended to give allow AEMO an additional 30 minutes to complete the required calculations.

6.3A.3. Between ~~8:00~~ 7:30 AM and 8:30 AM each Scheduling Day, AEMO must:

(a) identify and record the details of each approved Commissioning Test Plan that includes one or more Dispatch Intervals in the STEM Submission Information Window;

…

…

7.4. Real-Time Market Submissions

…

> **Explanatory Note**
>
> Clause 7.4.35 is amended to allow Market Participants to make a Real-Time Market Submission after Gate Closure, if the submission is being made to comply with a direction issued by AEMO.
>
> This amendment is required to address historical scenarios, wherein Market Participants have been required to breach the WEM Rules by making a submission after Gate Closure, after being directed to do so by the AEMO Control Room to maintain Power System Security.
>
> It is intended that proposed clause 7.4.35 will be nominated as a civil penalty provision in Schedule 1 of the Electricity Industry (Wholesale Electricity Market) Regulations 2004.

7.4.35. A Market Participant must not make a Real-Time Market Submission for a Dispatch Interval after Gate Closure for the Dispatch Interval, except where the Real-Time Market Submission is made for the sole purpose of:

(a) adjusting the Unconstrained Injection Forecast or Unconstrained Withdrawal Forecast for a Semi-Scheduled Facility or Non-Scheduled Facility;

(b) adjusting Available Capacity, In-Service Capacity and quantities in Price-Quantity Pairs for a Registered Facility that has suffered a Forced Outage, to reflect the Registered Facility's Remaining Available Capacity under that Forced Outage;

(c) adjusting the Dispatch Inflexibility Profile of a Scheduled Facility or Semi-Scheduled Facility to reflect a delay in starting the Facility; ~~or~~

(d) complying with clause 7.6.31(a) in respect of a Registered Facility that has become Inflexible~~.~~; or

(e) complying with a direction issued by AEMO.

…

> **Explanatory Note**
>
> Clause 7.4.47 is amended because registration of a Facility is proposed to be defined at the Metering Point in clause 2.29.1B, as opposed to the connection point.

7.4.47. The prices in Price-Quantity Pairs in a Real-Time Market Submission:

(a) apply at the ~~network connection point~~ Metering Point or Electrical Location, as applicable, for the Registered Facility;

(b) must increase monotonically with an increase in the available quantity for each Market Service; and

(c) for Withdrawal must be lower than the prices in Price-Quantity Pairs for Injection.

…

> **Explanatory Note**
>
> Clause 8.3.1 is amended and new clause 8.3.1A is added because registration of a Facility is proposed to be defined at the Metering Point in clause 2.29.1B, as opposed to the connection point.

8.3.1. Each Metering Data Agent must maintain a separate Meter Registry for each Network it serves. At a minimum, the Meter Registry for a Network must:

(a) record each meter connected to the Network or otherwise at a Metering Point;

(b) record the Market Participant(s) whose generation or consumption is measured by the meter;

(c) facilitate changes to the identity of the Market Participant(s) whose generation or consumption is measured by a meter as of a specified time;

(d) record how metered quantities are to be allocated between Market Participants if more than one Market Participant's generation or consumption is measured by that meter.

8.3.1A. The Meter Registry described in clause 8.3.1 must not record a meter placed at a network connection point behind which multiple Metering Points not electrically equivalent to the connection point exist.

…

9.10. Settlement Calculations - Essential System Services

…

> **Explanatory Note**
>
> Section 9.10 is amended because registration of a Facility is proposed to be defined at the Metering Point in clause 2.29.1B, as opposed to the connection point.
>
> Clauses 9.10.3C(a)(v), 9.10.3D(a)(v), 9.10.3E(a)(v), 9.10.3F(a)(v), and 9.10.3G(a)(v) are updated to clarify that LFAOP(f,DI) is derived from the Enablement Minimum for the relevant Frequency Co-optimised Essential System Service as specified in the relevant Real-Time Market Submission, and not as updated by AEMO, if applicable, under clause 7.4.52.

9.10.3C. The Enablement Losses in respect of Contingency Reserve Raise for Registered Facility f in Dispatch Interval DI are:

(a) if Registered Facility f is a Scheduled Facility or Semi-Scheduled Facility:

$$\text{EnablementLosses\_CR(f,DI)} = \text{Max(0, EL\_CR\_Factor(f,DI))} \times \frac{5}{60} \times \text{LF(f,DI)}$$
$$\times \text{Max(0, EM\_CR(f,DI))} \times \text{(LFAOP(f,DI)} - \text{Energy\_MCP(DI)))}$$

where:

i. EL_CR_Factor(f,DI) is:

1. 1 if:

i. CR_EnablementQuantity(f,DI), determined in accordance with clause 9.10.6(c) for Registered Facility f in Dispatch Interval DI, is greater than zero; and

ii. IsMisPriced(f,DI), determined in accordance with clause 9.9.9 for Registered Facility f in Dispatch Interval DI, is equal to zero; and

2. zero otherwise;

ii. 5/60 represents the period of a Dispatch Interval in hours;

iii. LF(f,DI) is the Loss Factor applicable to the ~~network connection point~~ Metering Point associated with Registered Facility f in Dispatch Interval DI;

iv. EM_CR(f,DI) is the Enablement Minimum for Contingency Reserve Raise for Registered Facility f in Dispatch Interval DI as specified in the relevant Real-Time Market Submission in accordance with clause 7.4.41(d) and updated by AEMO, if applicable, under clause 7.4.52;

v. LFAOP(f,DI) is the Loss Factor Adjusted Price in the Price-Quantity Pair for energy which corresponds to the Enablement Minimum for Contingency Reserve Raise for Registered Facility f in Dispatch Interval DI, as specified in the relevant Real-Time Market Submission ~~EM_CR(f,DI) in the Real-Time Market Submission for energy for Registered Facility f and Dispatch Interval DI~~; and

vi. Energy_MCP(DI) is the Final Energy Market Clearing Price for Dispatch Interval DI; and

(b) if Registered Facility f is not a Scheduled Facility or Semi-Scheduled Facility:

EnablementLosses_CR(f,DI) = 0

9.10.3D. The Enablement Losses in respect of Contingency Reserve Lower for Registered Facility f in Dispatch Interval DI are:

(a) if Registered Facility f is a Scheduled Facility or Semi-Scheduled Facility:

$$\text{EnablementLosses\_CL(f,DI)} = \text{Max(0, EL\_CL\_Factor(f,DI)} \times \frac{5}{60} \times \text{LF(f,DI)}$$
$$\times \text{Max(0, EM\_CL(f,DI))} \times \text{(LFAOP(f,DI)} - \text{Energy\_MCP(DI)))}$$

where:

i. EL_CL_Factor(f,DI) is:

1. 1 if:

i. CL_EnablementQuantity(f,DI), determined in accordance with clause 9.10.10(c) for Registered Facility f in Dispatch Interval DI, is greater than zero; and

ii. IsMisPriced(f,DI), determined in accordance with clause 9.9.9 for Registered Facility f in Dispatch Interval DI, is equal to zero; and

2. zero otherwise;

ii. 5/60 represents the period of a Dispatch Interval in hours;

iii. LF(f,DI) is the Loss Factor applicable to the ~~network connection point~~ Metering Point associated with Registered Facility f in Dispatch Interval DI;

iv. EM_CL(f,DI) is the Enablement Minimum for Contingency Reserve Lower for Registered Facility f in Dispatch Interval DI as specified in the relevant Real-Time Market Submission in accordance with clause 7.4.41(d) and updated by AEMO, if applicable, under clause 7.4.52;

v. LFAOP(f,DI) is the Loss Factor Adjusted Price in the Price-Quantity Pair for energy which corresponds to the Enablement Minimum for Contingency Reserve Lower for Registered Facility f in Dispatch Interval DI, as specified in the relevant Real-Time Market Submission~~EM_CL(f,DI) in the Real-Time Market Submission for energy for Registered Facility f and Dispatch Interval DI~~; and

vi. Energy_MCP(DI) is the Final Energy Market Clearing Price for Dispatch Interval DI; and

(b) if Registered Facility f is not a Scheduled Facility or Semi-Scheduled Facility:

EnablementLosses_CL(f,DI) = 0

9.10.3E. The Enablement Losses in respect of RoCoF Control Service for Registered Facility f in Dispatch Interval DI are:

(a) if Registered Facility f is a Scheduled Facility or Semi-Scheduled Facility:

$$\text{EnablementLosses\_RCS(f,DI)} = \text{Max}(0, \text{EL\_RCS\_Factor(f,DI)} \times \frac{5}{60} \times \text{LF(f,DI)}$$
$$\times \text{Max}(0, \text{EM\_RCS(f,DI)}) \times (\text{LFAOP(f,DI)} - \text{Energy\_MCP(DI)}))$$

where:

i. EL_RCS_Factor(f,DI) is:

1. 1 if:

i. RCS_EnablementQuantity(f,DI), determined in accordance with clause 9.10.14(c) for Registered Facility f in Dispatch Interval DI, is greater than zero;

and

ii. IsMisPriced(f,DI), determined in accordance with clause 9.9.9 for Registered Facility f in Dispatch Interval DI, is equal to zero; and

2. zero otherwise;

ii. 5/60 represents the period of a Dispatch Interval in hours;

iii. LF(f,DI) is the Loss Factor applicable to the ~~network connection point~~ Metering Point associated with Registered Facility f in Dispatch Interval DI;

iv. EM_RCS(f,DI) is the Enablement Minimum for RoCoF Control Service for Registered Facility f in Dispatch Interval DI as specified in the relevant Real-Time Market Submission in accordance with clause 7.4.42(b) and updated by AEMO, if applicable, under clause 7.4.52;

v. LFAOP(f,DI) is the Loss Factor Adjusted Price in the Price-Quantity Pair for energy which corresponds to the Enablement Minimum for Contingency Reserve Lower for Registered Facility f in Dispatch Interval DI, as specified in the relevant Real-Time Market Submission~~EM_RCS(f,DI) in the Real-Time Market Submission for energy for Registered Facility f and Dispatch Interval DI~~; and

vi. Energy_MCP(DI) is the Final Energy Market Clearing Price for Dispatch Interval DI; and

(b) if Registered Facility f is not a Scheduled Facility or Semi-Scheduled Facility:

EnablementLosses_RCS(f,DI) = 0

9.10.3F. The Enablement Losses in respect of Regulation Raise for Registered Facility f in Dispatch Interval DI are:

(a) if Registered Facility f is a Scheduled Facility or Semi-Scheduled Facility:

$$\text{EnablementLosses\_RR}(f,DI) = \text{Max}(0, \text{EL\_RR\_Factor}(f,DI) \times \frac{5}{60} \times \text{LF}(f,DI)$$

$$\times \text{Max}(0, \text{EM\_RR}(f,DI)) \times (\text{LFAOP}(f,DI) - \text{Energy\_MCP}(DI)))$$

where:

i. EL_RR_Factor(f,DI) is:

1. 1 if:

i. RR_EnablementQuantity(f,DI), determined in accordance with clause 9.10.22(c) for Registered Facility f in Dispatch Interval DI, is greater than zero; and

ii. IsMisPriced(f,DI), determined in accordance with clause 9.9.9 for Registered Facility f in Dispatch Interval DI, is equal to zero; and

2. zero otherwise;

ii. 5/60 represents the period of a Dispatch Interval in hours;

iii. LF(f,DI) is the Loss Factor applicable to the ~~network connection point~~ Metering Point associated with Registered Facility f in Dispatch Interval DI;

iv. EM_RR(f,DI) is the Enablement Minimum for Regulation Raise for Registered Facility f in Dispatch Interval DI as specified in the relevant Real-Time Market Submission in accordance with clause 7.4.41(d) and updated by AEMO, if applicable, under clause 7.4.52;

v. LFAOP(f,DI) is the Loss Factor Adjusted Price in the Price-Quantity Pair for energy which corresponds to the Enablement Minimum for Contingency Reserve Lower for Registered Facility f in Dispatch Interval DI, as specified in the relevant Real-Time Market Submission~~EM_RR(f,DI) in the Real-Time Market Submission for energy for Registered Facility f and Dispatch Interval DI~~; and

vi. Energy_MCP(DI) is the Final Energy Market Clearing Price for Dispatch Interval DI; and

(b) if Registered Facility f is not a Scheduled Facility or Semi-Scheduled Facility:

EnablementLosses_RR(f,DI) = 0

9.10.3G. The Enablement Losses in respect of Regulation Lower for Scheduled Facility or Semi-Scheduled Facility f in Dispatch Interval DI are:

(a) if Registered Facility f is a Scheduled Facility or Semi-Scheduled Facility:

$$\text{EnablementLosses\_RL(f,DI)} = \text{Max}(0, \text{EL\_RL\_Factor(f,DI)} \times \frac{5}{60} \times \text{LF(f,DI)}$$
$$\times \text{Max}(0, \text{EM\_RL(f,DI)}) \times (\text{LFAOP(f,DI)} - \text{Energy\_MCP(DI)}))$$

where:

i. EL_RL_Factor(f,DI) is:

1. 1 if:

i. RL_EnablementQuantity(f,DI), determined in accordance with clause 9.10.23(c) for Registered Facility f in Dispatch Interval DI, is greater than zero; and

ii. IsMisPriced(f,DI), determined in accordance with clause 9.9.9 for Registered Facility f in Dispatch Interval DI, is equal to zero; and

2. zero otherwise;

ii. 5/60 represents the period of a Dispatch Interval in hours;

iii. LF(f,DI) is the Loss Factor applicable to the ~~network connection point~~ Metering Point associated with Registered Facility f in Dispatch Interval DI;

iv. EM_RL(f,DI) is the Enablement Minimum for Regulation Lower for Registered Facility f in Dispatch Interval DI as specified in the relevant Real-Time Market Submission in accordance with clause 7.4.41(d) and updated by AEMO, if applicable, under clause 7.4.52;

v. LFAOP(f,DI) is the Loss Factor Adjusted Price in the Price-Quantity Pair for energy which corresponds to the Enablement Minimum for Contingency Reserve Lower for Registered Facility f in Dispatch Interval DI, as specified in the relevant Real-Time Market Submission ~~EM_RL(f,DI) in the Real-Time Market Submission for energy for Registered Facility f and Dispatch Interval DI~~; and

vi. Energy_MCP(DI) is the Final Energy Market Clearing Price for Dispatch Interval DI; and

(b) if Registered Facility f is not a Scheduled Facility or Semi-Scheduled Facility:

EnablementLosses_RL(f,DI) = 0

…

10.4. Managing Market Information

…

Managing disclosure of Confidential Information

…

Explanatory Note The current framework under Chapter 10 does not explicitly enable AEMO to proactively share Market Information with EPWA or the ERA, unless it has received a formal request under clause 10.4.6 or it is included in the MSDC. This has led to delays in communicating information related to critical market effectiveness or compliance issues. New clause 10.4.4A is inserted to enable AEMO to use its discretion to share information with the Coordinator or the ERA where necessary.

10.4.4A. AEMO may, at its discretion, disclose Confidential Information without being requested under clause 10.4.6, if the party receiving the Confidential Information is the Coordinator or the Economic Regulation Authority.

…

11. Glossary

…

Explanatory Note The *Government Trading Enterprises Act 2023* superseded and deleted the definition of “executive officer” in the *Electricity Corporations Act 2005*. The definition of Authorised Officer is amended to align with the definition of “executive officer” in the Government Trading Enterprises Act 2023.

Authorised Officer: In respect of a Rule Participant, means:

(a) “Officer” as defined in Section 9 of the Corporations Act;

~~(b) “executive officer” as defined in section 3(1) of the Electricity Corporations Act; or~~

(b) a person designated as an “executive officer” of the Rule Participant under section 43 of the Government Trading Enterprises Act 2023; or

(c) for a Rule Participant that is not a body corporate, a person who is legally able to bind that Rule Participant.

…

Explanatory Note The definitions of Connection Point is included to increase clarity of the WEM Rules, following the inclusion of ‘Metering Points’.

Connection Point: Means a point on a Network identified in, or to be identified in, a contract for network services as an entry point, exit point or bidirectional point.

…

Explanatory Note The definitions of Electric Storage Resource Obligation Duration and Electric Storage Resource Obligation Interval are inserted. These definitions appeared in previous versions of the WEM Rules but were removed in the RCM Reform Amending Rules by mistake.

Electric Storage Resource Obligation Duration: Means Peak Electric Storage Resource Obligation Duration.

Electric Storage Resource Obligation Interval: Means Peak Electric Storage Resource Obligation Interval.

…

Explanatory Note The definitions of Enablement Maximum and Enablement Minimum are amended to improve the clarity and ensure that the Enablement Limits accurately reflect the capability of a Facility.

Enablement Maximum: In relation to a Real-Time Market Offer for a Frequency Co-optimised Essential System Service, the level of Injection or Withdrawal above which no response is ~~specified as~~ capable of being ~~available~~ provided.

Enablement Minimum: In relation to a Real-Time Market Offer for a Frequency Co-optimised Essential System Service, the level of Injection or Withdrawal below which no response is ~~specified as~~ capable of being ~~available~~ provided.

…

Explanatory Note The definition of Energy Producing System is amended because registration of a Facility is proposed to be defined at the Metering Point in clause 2.29.1B, as opposed to the connection point.

Energy Producing System: One or more electricity producing units, such as generation systems or Electric Storage Resources, located behind a single Metering Point ~~connection point~~ or electrically connected behind two or more shared Metering Points~~network connection points~~.

…

Explanatory Note The definition of Estimated FCESS Uplift Payment is updated for consistency with the calculation of the FCESS Uplift Payment as per Section 9.10.3.

Estimated FCESS Uplift Payment: For a Scheduled Facility or Semi-Scheduled Facility in a Dispatch Interval is:

$$\text{EstimatedFCESSUpliftPayment} = \text{Max}\left(0, \frac{5}{60} \times \text{LF} \times \text{Max}(0, \text{EM}) \times (\text{LFAOP} - \text{MCP})\right)$$

where:

(a) 5/60 represents the period of a Dispatch Interval in hours;

(b) LF is the Loss Factor for the Registered Facility;

(c) EM is the greatest Enablement Minimum in a Real-Time Market Submission, as updated by AEMO (as applicable) under clause 7.4.52, for a Frequency Co-optimised Essential System Service for the Registered Facility in the Dispatch Interval for which the Registered Facility had an Essential System Service Enablement Quantity greater than zero;

(d) LFAOP is the Loss Factor Adjusted Price in the Price-Quantity Pair for energy which corresponds to the greatest Enablement Minimum for a Frequency Co-optimised Essential System Service for which the Registered Facility had an Essential System Service Enablement Quantity greater than zero, as specified ~~EM~~ in the Real-Time Market Submission ~~for energy~~ for the Registered Facility in the Dispatch Interval; and

(e) MCP is the Energy Market Clearing Price in the Dispatch Interval based on the Market Schedules published by AEMO.

…

Explanatory Note
The definition of FCESS Clearing Price Ceiling is amended to correct a typographical error.

FCESS Clearing Price Ceiling: The maximum Market Clearing Price in dollars per MW per hour or dollars per MWs per hour as applicable for a Frequency Co-optimised Essential System Service in a Dispatch Interval, is equal to:

(a) from 8:00 AM on 22 May 2024 to 8:00 AM on 20 November 2024, $500; and

(b) at all other times,

~~EPOC - EOPF + FCESSOPC~~

EOPC - EOPF + FCESSOPC

where:

i. EOPC is the Energy Offer Price Ceiling in the Dispatch Interval;

ii. EOPF is the Energy Offer Price Floor in the Dispatch Interval; and

iii. FCESSOPC is the relevant FCESS Offer Price Ceiling in the Dispatch Interval.

…

Explanatory Note
The definition of the Indicative Peak Electric Storage Resource Obligation Intervals is amended to allow the dispatch of Electric Storage Resources to minimise daily peak demand for the Availability Duration Gap Load Scenario, thereby keeping the Availability Duration Gap at the lowest possible level. This change aligns with AEMO's operational flexibility in dispatching Electric Storage Resources.

Indicative Peak Electric Storage Resource Obligation Intervals: For a Trading Day in a Capacity Year, the set of contiguous Trading Intervals, ~~which has the Mid Peak Electric Storage Resource Obligation Interval in the middle for that Trading Day, and including~~ where the number of Trading Intervals equals the ESR Duration Requirement for the previous Reserve Capacity Cycle~~.~~, which minimises the daily peak demand for that Trading Day by discharging each Electric Storage Resource evenly across those Trading Intervals. ~~If the ESR Duration Requirement for the previous Reserve Capacity Cycle is an even number, then the last Trading Interval of the first half of the Indicative Peak Electric Storage Resource Obligation Intervals must be the Mid Peak Electric Storage Resource Obligation Interval.~~

…

…

> **Explanatory Note**
>
> The definition of Injection is amended because registration of a Facility is proposed to be defined at the Metering Point in clause 2.29.1B, as opposed to the connection point.

Injection: The quantity of power or energy sent into a Network, as measured at:

(a) for a Registered Facility with a single defined ~~network connection point~~ Metering Point, the ~~network connection point~~ Metering Point;

(b) for a Registered Facility with multiple ~~network connection points~~ Metering Points with the same Electrical Location, the Electrical Location; and

(c) for a Registered Facility with ~~network connection points~~ Metering Points at more than one Electrical Location, the Reference Node,

which is measured in instantaneous MW unless specified as MWh over a time period, and represented as a positive number or zero.

…

> **Explanatory Note**
>
> New definition of Metering Point is added to allow definition of a Facility at the Metering Point, rather than the connection point.
>
> There is currently inconsistency with this definition and the *Electricity Industry (Metering) Code 2012*. EPWA may consider amending the Metering Code in a future review.

Metering Point: Means, for a Facility, the point at which the Network Operator measures energy Injection and Withdrawal using a revenue quality metering device.

…

> **Explanatory Note**
>
> The definition of National Metering Identifier is amended because registration of a Facility is proposed to be defined at the Metering Point in clause 2.29.1B, as opposed to the connection point.
>
> There is currently inconsistency with this definition and the *Electricity Industry (Metering) Code 2012*. EPWA may consider amending the Metering Code in a future review.

National Metering Identifier: The unique identifier for a ~~connection point~~ Metering Point.

…

> **Explanatory Note**
>
> The new definition of Separate Facility is added to define a Facility which can be registered under clause 2.29.2B.

Separate Facility: A Facility for which the Metering Points are not, or are not intended to be, electrically equivalent to the network connection point or shared network connection points.

…

Explanatory Note The definitions of Standing Enablement Maximum and Standing Enablement Minimum are amended to improve the clarity and ensure that they accurately reflect the capability of a Facility.

Standing Enablement Maximum: In relation to a Facility and a Frequency Co-optimised Essential System Service, the maximum level of Injection or Withdrawal for which a response ~~will be available~~ is capable of being provided for a Frequency Co-optimised Essential System Service.

Standing Enablement Minimum: In relation to a Facility and a Frequency Co-optimised Essential System Service, the minimum level of Injection or Withdrawal for which a response ~~will be available~~ is capable of being provided for a Frequency Co-optimised Essential System Service.

…

Explanatory Note The definition of Withdrawal is amended because registration of a Facility is proposed to be defined at the Metering Point in clause 2.29.1B, as opposed to the connection point.

Withdrawal: The quantity of power or energy received from a Network, as measured:

(a) for a Scheduled Facility, Semi-Scheduled Facility or Non-Scheduled Facility with a single defined ~~network connection point~~ Metering Point, at the ~~network connection point~~ Metering Point;

(b) for a Scheduled Facility, Semi-Scheduled Facility or Non-Scheduled Facility with multiple ~~network connection points~~ Metering Point with the same Electrical Location, at the Electrical Location;

(c) for a Scheduled Facility, Semi-Scheduled Facility or Non-Scheduled Facility with ~~network connection points~~ Metering Point points at more than one Electrical Location, at the Reference Node;

(d) for a Non-Dispatchable Load, at the ~~network connection point~~ Metering Point; and

(e) for a Demand Side Programme, as the sum of the Withdrawal quantities of each Associated Load of the Demand Side Programme,

which is measured in instantaneous MW unless specified as MWh over a time period, and is represented as a negative number or zero.

…

Appendix 1: Standing Data

…

Explanatory Note

Appendix 1 is amended because registration of a Facility is proposed to be defined at the Metering Point in clause 2.29.1B, as opposed to the connection point.

(b) For a Scheduled Facility:

…

xxiv. the minimum load at the ~~connection point~~ Metering Point of the Facility that will automatically trip off if the Facility fails, expressed in MW;

…

(c) For a Semi-Scheduled Facility:

…

xxiii. the minimum load at the ~~connection point~~ Metering Point of the Facility that will automatically trip off if the Facility fails, expressed in MW;

…

(d) for a Non-Scheduled Facility:

…

xi. the minimum load at the ~~connection point~~ Metering Point of the Facility that will automatically trip off if the Facility fails, expressed in MW;

…

…

Appendix 5A: Non-Temperature Dependent Load Requirements

…

Explanatory Note

Appendix 5A is amended because registration of a Facility is proposed to be defined at the Metering Point in clause 2.29.1B, as opposed to the connection point.

For the purpose of this Appendix:

- AEMO must use the current set of meter data (as at the time when it commences its calculations);
- the 4 Peak SWIS Trading Intervals in a Trading Month are the 4 Peak SWIS Trading Intervals determined and published by AEMO under clause 4.1.23B for that Trading Month; and

AEMO must treat each ~~connection point~~ Metering Point measured by an interval meter measuring a Scheduled Facility, Semi-Scheduled Facility or Non-Scheduled Facility as if it were a separate Non-Dispatchable Load.

…

Part 2: Amending Rules to commence (TBA)

Explanatory Note

Part 2 of this exposure draft includes Amending Rules to:

- encourage participation of aggregated Demand Side Programmes (DSP) in the RCM; and
- allow AEMO to recover additional capacity procured under NCESS contracts to meet Peak Capacity for a relevant Reserve Capacity Cycle, using the Reserve Capacity Settlement scheme.

Energy Policy WA (EPWA) has reviewed the WEM Rules to identify and address gaps that would prevent recent Supplementary Reserve Capacity (SRC) and Non-Cooptimised Essential System Services (NCESS) providers from participating as DSPs through the Reserve Capacity Mechanism RCM.

An overview of the draft changes to the WEM Rules is outlined below.

The changes below reflect short-term changes to enable DER participation in the RCM. There is significant ongoing work looking at integrating DER into the WEM and the SWIS. This work will result in medium and long-term changes that will enable DER to participate more fully in available markets.

Policy Decision 1: DSPs to be allowed to inject into the SWIS and be a net exporter

Traditionally DSPs have comprised Associated Loads that only curtail a load to minimum consumption levels. The advent of behind-the-meter (BTM) batteries means Associated Loads can contribute to reliability by curtailing load **and** injecting into the SWIS during peak events. One of the SRC providers provided exactly this type of service in 2023.

Allowing DSPs to inject into the SWIS and be a net exporter will enable value to be extracted from batteries and to give aggregators greater flexibility on how they meet their Reserve Capacity obligations. The following amendments are proposed to the WEM Rules to enable DSPs to inject and be net exporters:

- Introduction of DSP Injection Cap that limits the quantity of energy the Associated Loads of a DSP can inject at any given TNI.
- Amendments to DSP Load (Metered Schedule) calculations to allow DSP Load to be positive (Withdrawing) and negative (Injecting).
- Changes to Peak Reserve Capacity Deficit (clause 4.26.1A(a)(ii)(5)) and Flexible Reserve Capacity Deficit (clause 4.26.4(a)(ii)(4)) to remove the requirement for DSPs to hold sufficient capacity relative to their Minimum Consumption in all Trading Intervals with a non-zero Reserve Capacity Obligation Quantity. Instead, the Reserve Capacity Deficit will now only measure Reserve Capacity Test shortfalls and delivery shortfalls (the latter occurring when a DSP fails to deliver in response to a Dispatch Instruction).
- Modifications to the previously consulted Relevant Demand method so that both negative and positive DSP Load values can be incorporated. See Appendix 10 for more details on this change.
- Consequential changes to DSP submission requirements (Section 7.4A) and DSP Market Schedules (Section 7.8A).

Policy Decision 2: Further refinements to certification of DSPs with Associated Loads at multiple TNIs

Aggregators do not necessarily know the location of their Associated Loads two years ahead of when their Reserve Capacity Obligations commence. This means they cannot specify Transmission Node Identifers (TNI) at which their Associated Loads will be located for certification purposes. EPWA recently consulted Transitional Amendments to allow DSPs to be exempt from providing TNI locations during the certification process as long as the expected quantity of Peak Reserve Capacity is less than 5 MW for each Associated Load in that DSP. In effect, these DSPs are treated as unconstrained in the Network Access Quantity (NAQ) model (‘unconstrained DSP’). Changes are needed to the

WEM Rules to ensure that the dispatch of these 'unconstrained DSPs' do not result in adverse PSSR outcomes if they end up locating their Associated Loads at congested TNIs with little spare capacity.

The following refinements have been proposed:

- Transitional clause 4.10.1B will now extend to the 2025 Reserve Capacity Cycle.
- New requirement for AEMO to publish a list of TNIs as part of the Request for Expressions of Interest for Reserve Capacity process at which Dispatch of the 'unconstrained DSPs' during operational timeframes is likely to restrict the ability of energy producing Facilities to inject up to its NAQ.
- 'Unconstrained DSPs' subject to clause 4.10.1B will be certified in aggregate and will not be constrained via the NAQ model (as their locations are unknown). However:
    - They will be required to register multiple DSPs so that there is a single Facility at each TNI at which the DSP has Associated Loads. To reduce registration costs, amendments to Facility registration rules are proposed to enable 'unconstrained DSPs' to register multiple Facilities under a single registration application.
    - They will not be allowed to register at any of the TNIs published by AEMO above.

For avoidance of doubt:

- DSPs whose expected Peak Reserve Capacity is greater than or equal to 5MW for each Associated Load will continue to be treated as constrained for the purposes of NAQ determination and must specify TNIs for their Associated Load when they are certified. These DSPs are not affected by Policy Decision 1.
- DSP registration across multiple TNIs will not be allowed.

Policy Decision 3: Allowing DSPs more flexibility in selecting a Relevant Demand method

DSPs have traditionally comprised large industrial loads with predictable load patterns and controllability. Aggregations of residential loads do not have the same level of predictability or controllability:

- Residential loads are by nature more volatile and highly temperature dependent
- Will not necessarily be controllable (i.e. smart demand flexible devices are not yet the norm)

The above can result in inaccuracies when baselining a residential load.

EPWA recently consulted on a dynamic baseline method to calculate Relevant Demand. To give Market Participants more flexibility and choice in how their Relevant Demand is calculated, the following amendments are proposed:

- DSPs can choose to set their Relevant Demand using either unadjusted or adjusted baseline values calculated in Appendix 10.

EPWA is investigating future amendments to enable Market Participants to propose their own methodology to determine Relevant Demand. Due to the complexity of implementation of this option, EPWA will defer the ability for Market Participants to propose their own methods.

Correction error in DSP Reserve Capacity Price for refund calculations.

Clauses 4.26.1(b)(v) and 4.26.1(i)(v) are amended to correct an error in the way the Trading Interval Reserve Capacity Price is calculated for DSPs for refund calculations.

…

2.29. Facility Registration Classes

…

Non-Dispatchable Loads and the association and disassociation with Demand Side Programmes and Interruptible Loads

…

> **Explanatory Note**
>
> Injecting DSPs can adversely impact Power System Security and Power System Reliability if allowed to inject with no restrictions under the existing 'dispatch light' arrangements for DSPs.
>
> For this reason, a DSP Injection Cap is proposed that would limit the injection of Associated Loads at any given TNI to 10MW in the first instance. AEMO can revise the cap downwards at any TNIs if they deem that retaining the default cap of 10MW would adversely impact Power System Security and Power System Reliability.
>
> This approach is aligned with existing registration rules that:
>
> - require energy producing Facilities with System Size greater than or equal to 10MW to register their Facility as either a Scheduled Facility or a Semi-Scheduled Facilities; and
> - allow energy producing Facilities with a System Size less than 10MW to be exempt from registration or register as a Non-Scheduled Facility. However, AEMO has the ability to revoke such exemptions to re-assess the Facility Class of a Non-Scheduled Facility to support Power System Security and Power System Reliability.
>
> AEMO will publish Injection Caps at each TNI in the Request for EOI for Reserve Capacity, so that Market Participants have visibility of any changes AEMO may make under new clause 2.29.5AC below – see changes to Section 4.3.

2.29.5AB. A Market Participant that has registered a Demand Side Programme with Associated Loads that contain one or more Energy Producing Systems must ensure that the total quantity of energy injected by its Associated Loads at any Transmission Node Identifier is less than the DSP Injection Cap at that Transmission Node Identifier as determined by AEMO under clause 2.29.5AC.

2.29.5AC. AEMO must set the DSP Injection Cap at a TNI to be 10MW, unless it determines a lower cap is required at the TNI to support Power System Security and Reliability.

> **Explanatory Note**
>
> The following changes are made to the DSP load association process to support:
>
> **Policy Decision 1 (allowing DSPs to inject):**
>
> Given the changes to Reserve Capacity Deficit calculations (see amended clauses 4.26.1A(a)(ii)(5) and 4.26.4(a)(ii)(4), the Minimum Consumption values of a DSP will now only be used to calculate DSP Forecast Capacity for the purposes of DSP Market Schedules.
>
> Historically, DSPs have comprised industrial loads with static Minimum Consumption values that are unlikely to change over time or even by Trading Interval. DSPs comprising residential loads will have Minimum Consumption values that vary by Trading Interval and season.
>
> Under existing Rules, Market Participants are required to submit Minimum Consumption when they associate a Non-Dispatchable Load (existing clause 2.29.5BC). However, there is no explicit requirement on the Market Participant to:
>
> - Provide values for each Trading Interval and Trading Day
> - Update the value if they have better information.

The following amendments are made to ensure AEMO has access to reasonably accurate Minimum Consumption values for dispatch planning purposes and to put the onus on the Market Participant to maintain accurate values.

- Clause 2.29.5B(c) is amended to remove the requirement for DSPs to provide Minimum Consumption values as part of the load association process.
- A new clause (yet un-numbered) is added to explicitly require a DSP to provide the Minimum Consumption of its Associated Loads for each Trading Interval in each Trading Day for which it has a non-zero RCOQ. This should not prevent DSPs from submitting a single value for an Associated Load with a static Minimum Consumption level. However, it enforces the requirement on DSPs with dynamic residential loads to provide more granular information.
- A new clause (un-numbered) is added to require a DSP to update its Minimum Consumption values to reflect any changes (e.g., improvements in forecasting ability).

The above clauses are un-numbered as EPWA is still working through the implementation impacts of the above changes with AEMO.

Policy Decision 2 (allowing DSPs to be certified without providing TNI locations)

1. New clause 2.29.5AD is added to:
   - Require a DSP that was certified without a TNI location to register multiple Demand Side Programmes at individual TNIs (as multi-TNI registration will not be allowed)
   - Ensure the total quantity of Capacity Credits associated with Demand Side Programmes registered above is equal to the quantity of Capacity Credits that the certified Demand Side Programme was assigned.
   - Ensure that the DSPs register the separate DSPs at least three months prior to the start of the Capacity Year to provide AEMO sufficient time to process the applications.
2. New clause 2.29.5AE is added to prevent a Demand Side Programme from registering at a TNI that AEMO has deemed to be 'congested' – see changes to Section 4.15 for more details on this.

Policy Decision 3 (allowing DSPs more flexibility in selecting a Relevant Demand method)

New clause 2.29.5AF is added to require DSPs to nominate their preferred method for calculating Relevant Demand. DSPs can choose from either the adjusted or unadjusted baseline approach (in Appendix 10).

It is intended that proposed clause 2.29.5AD will be nominated as a civil penalty provision in Schedule 1 of the Electricity Industry (Wholesale Electricity Market) Regulations 2004.

2.29.5AD. A Market Participant who intends to operate or control one or more Demand Side Programmes that were subject to clause 4.10.1B in Year 1 of the relevant Reserve Capacity Cycle, must register one or more Demand Side Programmes no later than three months prior to the start of the relevant Capacity Year such that:

(a) the Associated Loads if each individual registered Demand Side Programme is located at single Transmission Node Identifier; and

(b) the sum of the Capacity Credits associated with all Demand Side Programmes registered under this clause equals the total Capacity Credits assigned to the certified Demand Side Programme.

2.29.5AE. A Market Participant registering Demand Side Programmes under clause 2.29.5AD for a Capacity Year, may not register a Demand Side Programme at a Transmission Node Identifier that is included in the list of Transmission Identifiers published by AEMO under clause 4.3.1(n) in Year 1 of the relevant Reserve Capacity Cycle.

2.29.5AF. A Market Participant registering a Demand Side Programme must nominate one of the following methods to determine the Relevant Demand of the Demand Side Programme:

(a) the Adjusted Baseline Method; or

(b) the Unadjusted Baseline Method.

2.29.5B. A Market Participant may apply to AEMO to associate a Non-Dispatchable Load with a Demand Side Programme or an Interruptible Load. The Market Participant must provide the following information to AEMO in support of the application:

(a) if applicable, evidence satisfactory to AEMO that the Market Participant owns the Non-Dispatchable Load or has entered into a contract with the person who owns, operates or controls the Non-Dispatchable Load to provide curtailment on request by the Market Participant;

(b) the network connection point of the Non-Dispatchable Load;

(bA) the Transmission Node Identifier for the Non-Dispatchable Load;

(c) ~~the expected Minimum Consumption of the Non-Dispatchable Load in units of MW~~[Blank]

(d) if the Market Participant requesting the association owns, controls or operates the relevant Non-Dispatchable Load, then the start date and end date of the Non-Dispatchable Load association proposed by the Market Participant; and

(e) if the Market Participant requesting the association has entered into a contract with a person who owns, controls or operates the relevant Non-Dispatchable Load, then the contract start date and contract end date.

Explanatory Note

New clause 2.29.5BA is added to require the Network Operator to install, on request, interval metering at any Non-Dispatchable Load that a Market Participant intends to associate with their Demand Side Programme.

This will enable aggregators to aggregate Non-Contestable Customers who do not yet have interval metering as part of Western Power's AMI rollout.

2.29.5BA. A Network Operator must, at the request of a Market Participant, install and operate an interval meter at any Non-Dispatchable Load that the Market Participant intends to associate under clause 2.29.5B.

Explanatory Note

Two new (un-numbered clauses) are added to require DSPs to provide Minimum Consumption data that is more dynamic to AEMO and to require DSPs to keep the information up to date and accurate.

These clauses are currently un-numbered as EPWA is still determining where in the WEM Rules these are best located. We will finalise the clause numbering post-consultation.

It is intended that proposed un-numbered clauses XX.XX and YY.YY will be nominated as a civil penalty provision in Schedule 1 of the Electricity Industry (Wholesale Electricity Market) Regulations 2004.

XX.XX. A Market Participant must submit the expected Minimum Consumption of each of its Associated Loads in units of MW for each Trading Interval in each Trading Day in which the Demand Side Programme has a non-zero Peak Reserve Capacity Obligation Quantity or a non-zero Flexible Reserve Capacity Obligation Quantity, and that Minimum Consumption value must be less than zero in any Trading Interval that the Associated Load is likely to Inject into the Network when the relevant Demand Side Programme is not subject to a Dispatch Instruction with a non-zero quantity.

YY.YY. A Market Participant must provide updated values of the Minimum Consumption of the Associated Loads of its Demand Side Programmes if it reasonably believes the information submitted under clause XX.XX or resubmitted under this clause is no longer accurate.

…

2.33. The Registration Application Forms

…

Explanatory Note

To support Policy Decision 2, clause 2.33.3(a) is amended to enable AEMO to charge a different registration fee for DSPs that were certified without TNI locations but must register multiple Demand Side Programmes.

2.33.3. AEMO must prescribe a Facility registration application form that requires an applicant to provide the following:

(a) the relevant non-refundable Application Fee where this Application Fee ~~may differ for different Facility Classes~~;

(i) may differ for different Facility Classes;

(ii) must be a single Application Fee for multiple Demand Side Programmes being registered under clause 2.29.5AD;

…

…

Explanatory Note

The following amendments are made to the EOI Rules to support the policy decision to support Policy Decision to allow multi-TNI certification of DSPs and to allow DSPs to inject:

- AEMO must publish a list of TNIs in the Request for Expressions of Interest at which DSPs subject to clause 4.10.1B will not be allowed to locate their Associated Loads. This will mitigate the risk of the dispatch of these DSPs locating in congested areas and adversely affecting Power System Security and Reliability. See Section 4.15 for more details on how the list of TNIs will be determined.
- AEMO in the Request for EOI must publish the DSP Injection Cap of each TNI as determined in new clause 2.29.5AB.

4.3. Information to be Included in a Request for Expression of Interest

4.3.1. A Request for Expression of Interest for a Reserve Capacity Cycle must include the following information:

…

(l) who to contact with questions and responses to the Expression of Interest, including that person's contact details; ~~and~~

(m) the information specified in clause 4.4A.2 in respect of any Facility where the expected closure date of the Facility has not yet occurred~~.~~;

(n) the list of Transmission Node Identifiers determined in accordance with clause 4.15.16A at which Market Participants seeking certification of Demand Side Programmes subject to clause 4.10.1B in the current Reserve Capacity Cycle will not be allowed to locate Associated Loads during the relevant Capacity Year; and

(o) the DSP Injection Cap that will apply in Year 3 and Year 4 of the current Reserve Capacity Cycle as determined under clause 2.29.5AC.

4.4. Information to be Included in an Expression of Interest

Explanatory Note

Clause 4.4.1 is amended to require Demand Side Programmes to indicate whether they plan to Inject or Withdraw when subject to a Dispatch Instruction. This information is required as it will affect the constraint coefficients of large DSPs in the NAQ model (i.e. DSPs not subject to clause 4.10.1B).

4.4.1. An Expression of Interest for a Reserve Capacity Cycle must include the following information:

…

(b) subject to clause 4.10.1B, for each Facility covered by the Expression of Interest, its name and location and whether it contains:

i. an Intermittent Generating System;

ii. a Non-Intermittent Generating System;

iii. an Electric Storage Resource;

iv. a Demand Side Programme; and

v. a Small Aggregation;

(bA) if the Facility contains an Energy Producing System and is not a Demand Side Programme:

i. the expected nameplate capacity for each technology; and

ii. the maximum Peak Capacity and Flexible Capacity anticipated to be available from each technology;

(bAA) if the Facility contains an Energy Producing System and is a Demand Side Programme, whether or not the relevant Market Participant intends to Inject or Withdraw when subject to a Dispatch Instruction under clause 7.6.5A;

…

…

4.15. Network Access Quantity

…

Explanatory Note

Recent transitional amendments enable DSPs that do not know the location of its Associated Loads to be treated as unconstrained in the NAQ Model.

When these DSPs register in Year 3 of the relevant Reserve Capacity Cycle, they will be required to register separate Facilities at each TNI that they have Associated Loads. If these DSPs locate Associated Loads in constrained areas of the network, then their dispatch may result in injecting Facilities being curtailed below their NAQ which may adversely impact PSSR. For this reason, Policy Decision 3 will prohibit DSPs from registering in “constrained areas”.

This will require AEMO to identify TNIs at which the following may occur during operational timeframes:

- DSPs certified without appearing in NAQ constraints have to be dispatched at a lower level than what they were certified for to maintain PSSR; and/or
- Other Facilities that were treated as constrained in the NAQ Model, are curtailed below their NAQ to enable the above DSPs to be dispatched.

New clause 4.15.16A is added to require AEMO to identify ‘constrained’ TNIs as part of the Request for EOI process by using NAQ model outcomes from the immediately preceding Reserve Capacity Cycle. This clause is drafted at a high level with the methodological detail deferred to the WEM Procedure in clause 4.15.17, which has been amended to require AEMO to document the approach it will use to implement clause 4.15.16A.

…

4.15.16A. AEMO must, no later than the date specified in clause 4.1.4, determine the set of Transmission Node Identifiers at which Market Participants seeking certification of Demand Side Programmes will not be allowed to locate Associated Loads for those Demand Side Programmes. In doing so, AEMO must utilise the Network Access Quantity Model outcomes from the immediately preceding Reserve Capacity Cycle to identify Transmission Node Identifiers at which the dispatch of Demand Side Programmes subject to clause 4.10.1B may result in:

(a) the reduction to the withdrawal of the Associated Loads of the Demand Side Programmes being kept below the level of Capacity Credits held by the Market Participant in respect of those Demand Side Programmes; or

(b) the injection of Facilities that were assigned Capacity Credits in the immediately preceding Reserve Capacity Cycle being curtailed below the level of Capacity Credits held by those Facilities.

4.15.17. AEMO must document in a WEM Procedure:

(a) the processes, methodologies, inputs, parameters and assumptions to be applied in the Network Access Quantity Model for modelling the prioritisation and determination of Network Access Quantities for Facilities under Appendix 3;

(b) the processes to be followed by AEMO in determining the facility dispatch scenarios under clause 4.15.5;

(c) the processes AEMO must follow when determining Network Access Quantities for a Reserve Capacity Cycle, including how Network Access Quantities are determined for Facilities;

(d) the processes to be followed by AEMO for publishing the information under clause 4.15.16;

(e) without limiting any other provision of these WEM Rules, information that a Market Participant or Network Operator must provide to AEMO and the format it must be provided in, for the purposes of operating the Network Access Quantity Model and determining Network Access Quantities for Facilities under Appendix 3;~~ and~~

(eA) the processes, methodologies, inputs, parameters and assumptions to be applied to the Network Access Quantity Model from the immediately preceding Reserve Capacity Cycle for making the determination under clause 4.15.16A; and

(f) any other matters that AEMO reasonably deems relevant to performing its functions under this section 4.15.

…

4.25. Reserve Capacity Testing

…

Explanatory Note Policy Decision 1 has resulted in changes to the Peak Reserve Capacity Deficit (clause 4.26.1A(a)(ii)(5)) and Flexible Reserve Capacity Deficit (clause 4.26.4(a)(ii)(4)) calculations so that

DSPs no longer have to hold sufficient capacity relative to their Minimum Consumption levels. To provide greater certainty around DSP availability, the Reserve Capacity Testing rules must be amended to enable AEMO to trigger a Reserve Capacity Test when a DSP fails to deliver the full quantity requested by AEMO under a Dispatch Instruction.

Clauses 4.25.2B and 4.25.2BA are amended to empower AEMO to conduct a Reserve Capacity Test on a Demand Side Programme that has failed to deliver the full quantity requested by AEMO in a Dispatch Instruction calling on Peak or Flexible Capacity.

4.25.2B. AEMO must subject a Facility or Separately Certified Component to a Reserve Capacity Test under clauses 4.25.2(a)(ii) or 4.25.2(e)(ii) if:

(a) the Market Participant for the Facility, has not provided meter data, recorded by the Facility Sub-Metering to AEMO, if applicable, in accordance with and by the time specified in clause 4.25.2A;

(b) AEMO has determined, in accordance with clauses 4.25.2(a)(i) or 4.25.2(e)(i), that the Facility or Separately Certified Component of the Facility, as applicable, did not operate at the level specified in clause 4.25.1(a) by:

i. 31 January, in respect of the immediately preceding period 1 October to 31 January; and

ii. 31 July, in respect of the immediately preceding period 1 April to 31 July; or

(c) AEMO is conducting a re-test in accordance with clause 4.25.4, 4.25.6(a)(i), 4.25.6(b)(i) or 4.25.6(c)(i)~~.~~;

(d) a Demand Side Programme has failed to deliver the Peak Capacity quantity instructed by AEMO under clause 7.13.5.

4.25.2BA. AEMO must subject a Facility or Separately Certified Component to a Reserve Capacity Test under clause 4.25.1C(a)(ii) or 4.25.1C(c)(ii) if:

(a) the Market Participant for the Facility has not provided meter data, recorded by the Facility Sub-Metering to AEMO, if applicable, in accordance with and by the time specified in clause 4.25.2A;

(b) AEMO has determined, in accordance with clauses 4.25.1C(a)(i) or 4.25.1C(c)(i), that the Facility or Separately Certified Component of the Facility, as applicable, did not demonstrate the capability specified in clause 4.25.1B(a):

i. in respect of the period 1 October to 31 January, by 31 January; or

ii. in respect of the period 1 April to 31 July, by 31 July; or

(c) AEMO is conducting a re-test in accordance with clause 4.25.3F, 4.25.6(a)(ii), 4.25.6(b)(ii) or 4.25.6(c)(ii)~~.~~;

(d) a Demand Side Programme has failed to deliver the Flexible Capacity quantity instructed by AEMO under clause 7.13.5

4.25.4G. A Market Participant may, for a Demand Side Programme that failed a Reserve Capacity Test requested by AEMO under clause 4.25.1C or clause 4.25.2, elect not to subject the relevant Demand Side Programme to a second Reserve Capacity Test in accordance with clause 4.25.3F or clause 4.25.4 by providing notice to AEMO in accordance with clause 4.25.4H.

4.25.4H. A notification provided under clause 4.25.4G must be given to AEMO by 5:00 PM on the second Business Day after receiving notification from AEMO that the relevant Demand Side Programme failed the Reserve Capacity Test requested by AEMO under clause 4.25.1C or clause 4.25.2.

…

4.26. Financial Implications of Failure to Satisfy Reserve Capacity Obligations

Explanatory Note

Clauses 4.26.1(b)(v) and 4.26.1(i)(iv) are amended to correct an error in the calculation of the Per Interval Trading Interval prices for Peak and Flexible Reserve Capacity used to calculate refunds for DSPs (PY(f,t) and FY(f,t) respectively).

As previously drafted, clauses 4.26.1(b)(v) and 4.26.1(i)(iv) apply Trading Interval refunds using the daily Reserve Capacity Price instead of the Trading Interval price. To correct this, the calculations for PY(f,t) and FY(f,t) is amended by multiplying the daily prices by 1/48 to convert them to Trading Interval prices.

4.26.1. If a Market Participant holding Capacity Credits associated with a Facility fails to comply with its Reserve Capacity Obligations applicable to any given Trading Interval then the Market Participant must pay a refund to AEMO calculated in accordance with the following provisions.

…

(b) For a Facility f, for which a Market Participant holds Capacity Credits, in the Trading Interval t, PY(f,t) is determined as follows:

…

v. if Facility f is a Demand Side Programme:

$$\mathrm{PY(f,t)} = \mathrm{EDPRCP(f,t)} \times \frac{1}{48} \times \frac{\mathrm{TICY(t)}}{\mathrm{DSPTICY(f,t)}}$$

where:

1. EDPRCP(f,t) is the Entity Daily Peak Reserve Capacity Price for Facility f in Trading Interval t;

2. TICY(t) is the number of Trading Intervals in the Capacity Year in which Trading Interval t falls; and

3. DSPTICY(f,t) is the number of Trading Intervals in the Capacity Year in which Trading Interval t falls which fall in

the period specified under clause 4.10.1(f)(vi) for Demand Side Programme f;

…

(i) For a Facility f, for which a Market Participant holds Flexible Capacity Credits, in the Trading Interval t, FY(f,t) is zero if Trading Interval t falls in the Hot Season, and is otherwise determined as follows:

…

iv. if Facility f is a Demand Side Programme:

$$\text{FY(f,t)} = \frac{12}{8} \times \text{EDFRCP}(\text{f}, \text{t}) \times \frac{1}{48} \times \frac{\text{TICY}(\text{t})}{\text{DSPTICY}(\text{f}, \text{t})}$$

where:

1. EDFRCP(f,t) is the Entity Daily Flexible Reserve Capacity Price for Facility f in Trading Interval t;

2. TICY(t) is the number of Trading Intervals in the Capacity Year in which Trading Interval t falls; and

3. DSPTICY(f,t) is the number of Trading Intervals in the Capacity Year in which Trading Interval t falls which fall in the period specified under clause 4.10.1(f)(vi) for Demand Side Programme f;

…

…

Explanatory Note

Clauses 4.26.1A(a)(ii)(5) and 4.26.4(a)(ii)(4) (amended during the RCM review) require DSPs to pay refunds if they do not have enough capacity relative to their Minimum Consumption levels in all Trading Intervals with non-zero PRCOQs and FRCOQs.

Given the policy decision to allow DSPs to net export (Policy Decision 1), these equations were reviewed to ensure they worked if the DSPLoad is either positive or negative. The RCM review amended Reserve Capacity Deficit calculations work for either positive or negative DSP Load as long as Minimum Consumption is set to a negative value if the DSP intends to export in a given Trading Interval. However, Minimum Consumption levels will be challenging to forecast accurately for DSPs aggregating volatile residential loads. This may result in DSPs unnecessarily paying refunds or setting the Minimum Consumption at values to deliberately avoid refunds.

Reserve Capacity Deficit refunds are a means of incentivising Scheduled and Semi-Scheduled Facilities to ensure they offer their full RCOQ. DSPs do not have offer obligations, although they are required to submit Withdrawal Profiles under the existing Rules. Instead, Reserve Capacity Refunds for DSPs are a means of ensuring they are ready and available if called upon.

To avoid DSPs paying unnecessary refunds while ensuring AEMO has assurance that the DSP has the ability to deliver, the following changes are made:

- Two new quantities are introduced:
    - New clause 4.26.1AA: Peak DSP Delivery Shortfall for a DSP Facility on a Trading Day.

- New clause 4.26.4A: Flexible DSP Delivery Shortfall for a DSP Facility on a Trading Day.
- Clauses 4.26.1A(a)(ii)(5) and 4.26.4(a)(ii)(4) (previously amended under the RCM review) are amended so that DSPs only face Reserve Capacity Deficit Refunds if:
  - They have a non-zero Peak or Flexible DSP Test Shortfall as a result of failing a Reserve Capacity Test; or
  - They have a non-zero Peak or Flexible DSP Delivery Shortfall as a result of failing to deliver their dispatch quantity.
- DSPs will therefore no longer be required to hold sufficient capacity relative to their Minimum Consumption levels.

To support Policy Decision 1, DSPs no longer have to hold sufficient capacity relative to their Minimum Consumption levels. Instead, they will only pay refunds if they have a non-zero Peak DSP Test Shortfall quantity or a non-zero Peak DSP Delivery Shortfall quantity.

Clause 4.26.1A(a)(ii)(5) is therefore amended so that Peak Reserve Capacity Deficit is the larger of the Peak DSP Test Shortfall and the Peak DSP Delivery Shortfall.

4.26.1A. AEMO must calculate the Peak Reserve Capacity Deficit refund for each Facility f, for which a Market Participant holds Peak Capacity Credits, ("**Peak Facility Reserve Capacity Deficit Refund**") in each Trading Interval t as the lesser of:

(a) the product of:

i. the Peak Trading Interval Refund Rate, calculated under clause 4.26.1(a), applicable to Facility f in Trading Interval t; and

ii. the Peak Reserve Capacity Deficit for Facility f in Trading Interval t, where the Peak Reserve Capacity Deficit for Facility f in Trading Interval t is equal to whichever of the following applies:

…

5. if Facility f is a Demand Side Programme, the capacity shortfall calculated as zero if DSPConstrainedFlag = 1, and otherwise:

~~max (0, PRCOQ(f,t) – max(0, (2xDSPLoad(f,t) – (DSPMinLoad(f,t)+ PDSPTS(f,t)))))~~

max(PDSPTS(f,t), PDSPDS(f,t))

where:

i. ~~PRCOQ(f,t) is the Peak Reserve Capacity Obligation Quantity determined for Facility f in Trading Interval t;~~ [Blank]

ii. ~~DSPLoad(f,t) is the Demand Side Programme Load in MWh for the Demand Side Programme f in the Trading Interval t as determined under clause 9.5.4;~~ [Blank]

iii. ~~DSPMinLoad is the sum of the MW quantities of Minimum Consumption for Facility f's Associated~~

~~Loads in Trading Interval t;~~[Blank]

iv. PDSPTS(f,t) is the Peak DSP Test Shortfall in MW determined by AEMO under clause 4.25.3D, clause 4.25.4(b) or clause 4.25.6(b)(i), or zero if AEMO has not determined a Peak DSP Test Shortfall;~~ and~~

ivA. PDSPDS(f,t) is the Peak DSP Delivery Shortfall in MW determined by AEMO under clause 4.26.1AA; and

v. DSPConstrainedFlag is equal to zero, except that it is equal to one if the Demand Side Programme was responding to a Dispatch Instruction, or if one of its Associated Loads was unable to withdraw due to a Network limitation, or if one of its Associated Loads that is also associated with an Interruptible Load was responding to a Contingency Event; and

(b) the Maximum Peak Facility Refund for the Facility in the relevant Capacity Year, less all Peak Facility Reserve Capacity Deficit Refunds applicable to the Facility in previous Trading Intervals falling in the same Capacity Year.

Explanatory Note

Clause 4.26.1AA introduces the Peak DSP Delivery Shortfall quantity used in clause 4.26.1A(a)(ii)(v) above.

The quantity is the average of all Trading Interval Peak Capacity Shortfall values (calculated under clause 4.26.2D) occurring up to and including Trading Day d, but excluding Trading Intervals in which the DSP had previously failed to deliver, but has since undergone a Reserve Capacity Test.

The above changes mean that if a DSP that has failed to deliver in at least one Trading Interval, they will be subject to a Reserve Capacity Test and will face refunds until that they have passed the test. That is, if the DSP fails to deliver its quantity in one Trading Interval, but delivers fully in subsequent Trading Intervals on the same or subsequent Trading Days, they will still face a refund until they have passed a test. However, as the shortfall is calculated as an average of all capacity shortfall quantities, the refund quantity should be low if the DSP has only failed to deliver in one Trading Interval.

To understand the interaction between the Peak DSP Test Shortfall and Peak DSP Delivery Shortfall quantities, consider the example below.

Example

A DSP was dispatched on Trading day for four Trading Intervals and had delivery shortfalls of 5MW in two of the Trading Intervals. The Peak DSP Delivery Shortfall is therefore 2.5MW. This quantity will remain at 2.5MW until the DSP undergoes a Reserve Capacity Test and will be part of the Peak Reserve Capacity Deficit calculation in the clause above. A week later, the DSP undergoes a Reserve Capacity Test:

- The Peak DSP Delivery Shortfall for Trading Day t+7 will be zero as the DSP has now undergone a test.
- If the DSP passes a test then it will have a zero Peak DSP Test Shortfall quantity and will stop paying refunds.

- If the DSP fails the test, then AEMO will calculate a non-zero Peak DSP Test Shortfall quantity that will continue to apply until the DSP passes a second test.

Note, if the DSP failed a test prior to also failing to deliver its dispatch quantity, then the Peak Reserve Capacity Deficit will equal the larger of the Peak DSP Test Shortfall and Peak DSP Delivery Shortfall quantities.

4.26.1AA AEMO must determine the Peak DSP Delivery Shortfall for a Demand Side Programme on Trading Day d as the average of all Trading Interval Peak Capacity Shortfall values calculated under clause 4.26.2D occurring up to and including Trading Day d, but excluding all Trading Intervals on Trading Days in which the Demand Side Programme had previously failed to deliver, but has since undergone a Reserve Capacity Test under clause 4.25.2B(d).

…

Explanatory Note

New clause 4.26.2CA is added as Market Participants are proposed to be able to select either the adjusted baseline or unadjusted baseline methodology to calculate Relevant Demand.

…

4.26.2CA. The Relevant Demand of a Demand Side Programme for a Trading Interval in a Capacity Year is the value determined for the Demand Side Programme using either the methodology nominated in clause 2.29.5AD(a) or clause 2.29.5AD(b).

…

Explanatory Note

Clause 4.26.2D is amended to reflect the fact that the DIMW quantity calculations (Dispatch Instruction quantity) can be achieved either by increasing the absolute value of the DSP's Withdrawal or by increasing its Injection.

4.26.2D. AEMO must determine the shortfall in Peak Capacity ("**Peak Capacity Shortfall**") supplied by each Market Participant holding Peak Capacity Credits associated with a Demand Side Programme f in each Trading Interval t relative to its Peak Reserve Capacity Obligation Quantity as:

(a) if AEMO has issued a Dispatch Instruction with a non-zero MW quantity under section 7.6 to the Demand Side Programme f for the Trading Interval:

max(0, min(PRCOQ(f,t), DIMW(f,t)) – max (0, RD(f,t) – DSPLMW(f,t)))

where:

i. PRCOQ(f,t) is the Peak Reserve Capacity Obligation Quantity of the Demand Side Programme f for Trading Interval t (in MW);

ii. DIMW(f,t) is the quantity by which the Demand Side Programme f was instructed by AEMO to curtail the absolute value of its Withdrawal or increase its Injection (as relevant) in Trading Interval t as specified by AEMO in accordance with clause 7.13.5;

iii. RD(f,t) is the Relevant Demand of the Demand Side Programme f for Trading Interval t, determined by AEMO in accordance with clause 4.26.2CA; and

iv. DSPLMW(f,t) is the Demand Side Programme Load of the Demand Side Programme f in Trading Interval t, multiplied by two to convert to units of MW; and

(b) zero, if AEMO has issued a Dispatch Instruction with a zero MW quantity under section 7.6 to the Demand Side Programme f for Trading Interval t.

…

Explanatory Note
To support Policy Decision 1, DSPs no longer have to hold sufficient capacity relative to their Minimum Consumption levels. Instead, they will only pay refunds if they have a non-zero Flexible DSP Test Shortfall quantity or a non-zero Flexible DSP Delivery Shortfall quantity.
Clause 4.26.4(a)(ii)(4) is therefore amended so that Flexible Reserve Capacity Deficit is the larger of the Flexible DSP Test Shortfall and the Flexible DSP Delivery Shortfall.

4.26.4. AEMO must calculate the Flexible Reserve Capacity Deficit refund for each Facility f for which a Market Participant holds Flexible Capacity Credits ("**Flexible Facility Reserve Capacity Deficit Refund**") in each Trading Interval t as the lesser of:

(a) the product of:

i. the Flexible Trading Interval Refund Rate, calculated under clause 4.26.1(h), applicable to Facility f in Trading Interval t; and

ii. the Flexible Reserve Capacity Deficit for Facility f in Trading Interval t, which is zero if Trading Interval t is in the Hot Season, and otherwise equal to:

…

4. if Facility f is a Demand Side Programme, the capacity shortfall calculated as zero if DSPConstrainedFlag = 1, and otherwise:

~~max (0, FDSPTS(f,t), FRCOQ(f,t) − max(0, (2xDSPLoad(f,t) − DSPMinLoad(f,t))))~~

max(FDSPTS(f,t), FDSPDS(f,t))

where:

i. [Blank]~~FRCOQ(f,t) is the Flexible Reserve Capacity Obligation Quantity determined for Facility f in Trading Interval t;~~

ii. FDSPTS(f,t) is the Flexible DSP Test Shortfall determined by AEMO under clause 4.25.3E, clause 4.25.3G(b) or clause 4.25.6(b)(ii);

iiA. FDSPDS(f,t) is the Flexible DSP Delivery Shortfall in MW determined by AEMO under clause 4.26.4A; and

iii. [Blank]~~DSPLoad(f,t) is the Demand Side Programme Load for the Demand Side Programme f in the Trading Interval t as determined under clause 9.5.4;~~

iv. [Blank]~~DSPMinLoad is the sum of the MW quantities of Minimum Consumption for Facility f's Associated Loads in Trading Interval t; and~~

v. DSPConstrainedFlag is equal to zero, except if the Demand Side Programme was responding to a Dispatch Instruction, or if one of its Associated Loads was unable to withdraw due to a Network limitation, or if one of its Associated Loads that is also associated with an Interruptible Load was responding to a Contingency Event, when it is equal to one; and

(b) the Maximum Flexible Facility Refund for the Facility in the relevant Capacity Year, less all Flexible Facility Reserve Capacity Deficit Refunds applicable to the Facility in previous Trading Intervals falling in the same Capacity Year.

Explanatory Note

Clause 4.26.4A introduces the Flexible DSP Delivery Shortfall quantity used in clause 4.26.4 (a)(ii)(iv) above.

The quantity is the average of all Trading Interval Flexible Capacity Shortfall values (calculated under clause 4.26.14) occurring up to and including Trading Day d, but excluding Trading Intervals in which the DSP had previously failed to deliver, but has since undergone a Reserve Capacity Test.

4.26.4A AEMO must determine the DSP Flexible Delivery Shortfall for a Demand Side Programme on Trading Day d as the average of all Trading Interval Flexible Capacity Shortfall values calculated under clause 4.26.14 occurring up to and including Trading Day d, but excluding all Trading Intervals in which the Demand Side Programme had previously failed to deliver, but has since passed a Reserve Capacity Test under clause 4.25.2BA(d).

…

Explanatory Note

Clause 4.26.14 is amended to reflect the fact that the DIMW quantity calculations (Dispatch Instruction quantity) can be achieved either by increasing the absolute value of the DSP's Withdrawal or by increasing its Injection.

See also consequential change to clause 7.13.5.

4.26.14. AEMO must determine the Flexible Capacity shortfall ("**Flexible Capacity Shortfall**") supplied by each Market Participant holding Flexible Capacity Credits associated with a Demand Side Programme f in each Trading Interval t outside the Hot Season relative to its Reserve Capacity Obligation Quantity as:

(a) if AEMO has issued a Dispatch Instruction with a non-zero MW quantity under section 7.6 to the Demand Side Programme f for the Trading Interval:

max(0, min(RCOQ(f,t), DIMW(f,t)) – max (0, RD(f,t) – DSPLMW(f,t)))

where:

i. FRCOQ(f,t) is the Reserve Capacity Obligation Quantity of the Demand Side Programme f for Trading Interval t (in MW);

ii. DIMW(f,t) is the quantity by which the Demand Side Programme f was instructed by AEMO to curtail the absolute value of its Withdrawal or increase its Injection (as relevant) in Trading Interval t as specified by AEMO in accordance with clause 7.13.5;

iii. RD(f,t) is the Relevant Demand of the Demand Side Programme f for the Trading Day the Trading Interval t falls on, determined by AEMO in accordance with clause 4.26.2CA; and

iv. DSPLMW(f,t) is the Demand Side Programme Load of the Demand Side Programme f in Trading Interval t, multiplied by two to convert to units of MW; and

(b) zero, if AEMO has issued a Dispatch Instruction with a zero MW quantity under section 7.6 to the Demand Side Programme f for Trading Interval t.

…

4.28. Funding Reserve Capacity Purchased by AEMO

…

Explanatory Note Clause 4.28.2 is amended to improve clarity.

4.28.2. For the purposes of clause 4.28.1:

(a) AEMO is taken to have acquired a Capacity Credit held by a Market Participant in respect of a Facility for a Trading Day if that Capacity Credit has not been allocated by that Market Participant to another Market Participant for settlement purposes under sections 4.30 and 4.31;

(b) any Capacity Credits that have been allocated to a Market Participant in excess of that Market Participant's Individual Reserve Capacity Requirement must be:

i. deemed to be Capacity Credits acquired by AEMO from the Market Participant; and

ii. not counted as Capacity Credits traded bilaterally;

(c) [Blank]

(cA) [Blank]

(cB) the cost of a Capacity Credit deemed to be acquired by AEMO from a Market Participant under clause 4.28.2(b)(i) is equivalent to the Excess Allocation Price for that Market Participant in that Trading Day; and

(d) the cost of each other Capacity Credit acquired by AEMO from a Facility is equivalent to the Facility Daily Reserve Capacity Price for that Facility in that Trading Day.

4.28.3. For each Trading Day, AEMO must calculate the Targeted Reserve Capacity Cost and must allocate this cost to Market Participants in accordance with section 9.8.

Explanatory Note

New clauses 4.28.4(aA) and 4.28.4A are introduced to allow AEMO to recover additional capacity procured under NCESS contracts to maintain Power System Security and Reliability to meet Peak Capacity for a relevant Reserve Capacity Cycle using the Reserve Capacity Settlement scheme.

4.28.4. For each Trading Day, AEMO must calculate a Shared Reserve Capacity Cost being the sum of:

(a) the cost defined under clause 4.28.1(b); and

(aA) the sum of the costs determined under 4.28.4A for that Trading Day; and

(b) the net payments to be made by AEMO under Supplementary Capacity Contracts less any amount drawn under a Reserve Capacity Security or a DSP Reserve Capacity Security by AEMO and distributed in accordance with clauses 4.13.11A(a) or 4.13A.16(a) for that Trading Day; less

(c) the sum of all Intermittent Load Refunds, calculated under clause 4.28A.1, paid by all Market Participants for that Trading Day; less

(cA) the sum of all Capacity Cost Refunds, calculated under clause 4.26.2E, paid by all Market Participants for that Trading Day; less

(d) any amount drawn under a Reserve Capacity Security or a DSP Reserve Capacity Security by AEMO and distributed in accordance with clauses 4.13.11A(b) or 4.13A.16(b) for that Trading Day,

and AEMO must allocate this total cost to Market Participants in proportion to each Market Participant's Individual Reserve Capacity Requirement.

4.28.4A. For each Trading Interval, AEMO must determine the sum of the payments to be made by AEMO under NCESS Contracts for capacity procured by AEMO to meet Peak Capacity for the relevant Reserve Capacity Cycle set under clause 4.6.1.

...

7.4A. DSP ~~Withdrawal~~ Profile Submissions

Explanatory Note
Policy Decision 1 allowing DSPs to be net exporters means that market submissions made by DSPs will need to reflect both Injections and Withdrawal. This is implemented as follows: • DSP Withdrawal Profile Submissions are renamed to DSP Profile Submissions (as DSPs may now be injecting as well) • DSP Constrained Withdrawal Quantities are renamed to DSP Constrained Quantities and can be either indicate Withdrawal (positive value) or an Injection (negative value). Under current rules this quantity is given by the absolute value of the average MW Withdrawal of a DSP in a Dispatch Interval, so that Withdrawal is treated as a positive value in the submission. We propose continuing with this convention and treating Injection submission as negative. • DSP Unconstrained Withdrawal Quantities are renamed to DSP Unconstrained Quantities and, as above, can be either indicate Withdrawal (positive value) or an Injection (negative value). See amendments to Chapter 11 (Glossary) to see how the above quantities have been redefined.

7.4A.1. A Market Participant must ensure that it has made a DSP ~~Withdrawal~~ Profile Submission or Standing DSP ~~Withdrawal~~ Profile Submission in accordance with this section 7.4A for each Dispatch Interval in the Week-Ahead Schedule Horizon for each of its Demand Side Programmes.

7.4A.2. If AEMO has not accepted a DSP ~~Withdrawal~~ Profile Submission for a Demand Side Programme and Dispatch Interval under clause 7.4A.15(a), but has accepted an applicable Standing DSP ~~Withdrawal~~ Profile Submission, then the Standing DSP ~~Withdrawal~~ Profile Submission is deemed to be the DSP ~~Withdrawal~~ Profile Submission for the Demand Side Programme and Dispatch Interval.

7.4A.3. A DSP ~~Withdrawal~~ Profile Submission for a Demand Side Programme and Dispatch Interval that AEMO accepts under clause 7.4A.15(a) replaces any previously accepted DSP ~~Withdrawal~~ Profile Submission for, and has effect in relation to, the Demand Side Programme and Dispatch Interval.

7.4A.4. If:

(a) AEMO has not yet accepted a DSP ~~Withdrawal~~ Profile Submission for a Demand Side Programme and Dispatch Interval under clause 7.4A.15(a); and

(b) AEMO accepts a Standing DSP ~~Withdrawal~~ Profile Submission for the Demand Side Programme that is applicable to the Dispatch Interval,

then the Standing DSP ~~Withdrawal~~ Profile Submission replaces any previously accepted Standing DSP ~~Withdrawal~~ Profile Submission as the deemed DSP ~~Withdrawal~~ Profile Submission for the Demand Side Programme and Dispatch Interval.

7.4A.5. If AEMO identifies a Demand Side Programme in a Market Advisory under clause 7.11.6(cA)(i), then the relevant Market Participant must:

(a) as soon as practicable review, and if necessary update, the DSP ~~Withdrawal~~ Profile Submissions for the Demand Side Programme for, subject to clause 7.4A.9A, each future Dispatch Interval before the end of the Trading Day in which the period specified under clause 7.11.6(cA)(ii) falls; and

(b) for the purposes of determining DSP Constrained ~~Withdrawal~~ Quantities, assume the Demand Side Programme will be subject to Dispatch Instructions that curtail the Withdrawal or increase its Injection (as relevant) of the Demand Side Programme by the maximum quantity consistent with its Reserve Capacity Obligations for the period specified under clause 7.11.6(cA)(ii).

7.4A.6. If AEMO issues a Dispatch Instruction with a non-zero MW quantity to a Demand Side Programme under clause 7.6.15, then the Market Participant must:

(a) as soon as practicable and no later than one hour before the Dispatch Interval from which the Dispatch Instruction applies, review, and if necessary update, the DSP ~~Withdrawal~~ Profile Submissions for the Demand Side Programme for, subject to clause 7.4A.9A, each future Dispatch Interval before the end of the Trading Day in which the Dispatch Interval specified under clause 7.6.11A(c) falls; and

(b) for the purposes of determining the applicable DSP Constrained ~~Withdrawal~~ Quantities, take into account the timeframes and quantities in the Dispatch Instructions that have been issued to the Demand Side Programme and assume that AEMO will issue a Dispatch Instruction with a zero MW quantity that will apply from the Dispatch Interval specified under clause 7.6.11A(e).

7.4A.7. If AEMO issues a Dispatch Instruction with a zero MW quantity to a Demand Side Programme under clause 7.6.15, then the Market Participant must:

(a) as soon as practicable and no later than one hour before the Dispatch Interval from which the Dispatch Instruction applies, review, and if necessary update, the DSP ~~Withdrawal~~ Profile Submissions for the Demand Side Programme for, subject to clause 7.4A.9A, each future Dispatch Interval in the Trading Day in which the Dispatch Interval specified under clause 7.6.11A(c) falls; and

(b) for the purposes of determining the applicable DSP Constrained ~~Withdrawal~~ Quantities, take into account the time from which the Dispatch Instruction will apply.

7.4A.8. If a Market Participant receives a notification relating to a Reserve Capacity Test of a Demand Side Programme under clause 4.25.9(h), the Market Participant must:

(a) as soon as practicable and no later than one hour before the Reserve Capacity Test is due to commence, review and update the DSP ~~Withdrawal~~ Profile Submissions for the Demand Side Programme for, subject to clause 7.4A.9A, each future Dispatch Interval in the Trading Day in which Reserve Capacity Test will be conducted; and

(b) take the information provided in the notification under clause 4.25.9(h) into account in determining the relevant DSP Constrained ~~Withdrawal~~ Quantities.

7.4A.9. A Market Participant must make reasonable endeavours to ensure that when any of the conditions specified in clauses 7.4A.5, 7.4A.6, 7.4A.7 or 7.4A.8 apply, the DSP Unconstrained ~~Withdrawal~~ Quantities and DSP Constrained ~~Withdrawal~~ Quantities in its DSP ~~Withdrawal~~ Profile Submissions for the Demand Side Programme accurately reflect the Market Participant's reasonable expectation of the Withdrawal or Injection (as relevant) of the Demand Side Programme during the applicable Dispatch Intervals under the required assumptions.

7.4A.9A. For the purposes of updating DSP ~~Withdrawal~~ Profile Submissions under clauses 7.4A.5, 7.4A.6, 7.4A.7 or 7.4A.8, a Market Participant must not include a future Dispatch Interval in its updated DSP ~~Withdrawal~~ Profile Submissions, where the Market Participant reasonably determines that despite its best endeavours, its updated DSP ~~Withdrawal~~ Profile Submissions for the Dispatch Interval will not be received by AEMO before the start of the Dispatch Interval.

DSP ~~Withdrawal~~ Profile Submissions – Timing

7.4A.10. A Market Participant may submit a DSP ~~Withdrawal~~ Profile Submission for a Dispatch Interval at any time:

(a) on or after the Real-Time Market Submission Acceptance Horizon for the Dispatch Interval; and

(b) before the start of the Dispatch Interval.

7.4A.11. AEMO must use the most recent DSP ~~Withdrawal~~ Profile Submission (as determined in accordance with clauses 7.4A.2, 7.4A.3 and 7.4A.4) in the scheduling and dispatch of Demand Side Programmes in accordance with this Chapter 7.

DSP ~~Withdrawal~~ Profile Submissions – Format

7.4A.12. AEMO must document in a WEM Procedure the format and methodology to be followed by Market Participants for making DSP ~~Withdrawal~~ l Profile Submissions, including the options to submit multiple DSP ~~Withdrawal~~ Profile Submissions to AEMO in a single electronic submission.

7.4A.13. A DSP ~~Withdrawal~~ Profile must specify:

(a) the Demand Side Programme;

(b) the Dispatch Interval;

(c) a DSP Unconstrained ~~Withdrawal~~ Quantity;

(d) a DSP Constrained ~~Withdrawal~~ Quantity; and

(e) any other information specified in the WEM Procedure to be documented by AEMO under clause 7.4A.12.

DSP ~~Withdrawal~~ Profile Submissions – Validation

7.4A.14. On receipt of an electronic submission containing one or more DSP ~~Withdrawal~~ Profile Submissions in accordance with this section 7.4A, AEMO must as soon as practicable:

(a) acknowledge receipt of the electronic submission to the submitting Market Participant; and

(b) determine whether the DSP ~~Withdrawal~~ Profile Submissions in the electronic submission comply with the following requirements, as applicable:

i. the content requirements in clause 7.4A.13; and

ii. the timing requirements in clause 7.4A.10.

7.4A.15. Where AEMO:

(a) determines that an electronic submission complies with the requirements in clause 7.4A.14(b), AEMO must accept the DSP ~~Withdrawal~~ Profile Submissions and notify the submitting Market Participant that the DSP ~~Withdrawal~~ Profile Submissions have been accepted, or

(b) determines that the electronic submission, or any part of it, does not comply with the requirements referred to in clause 7.4A.14(b), AEMO must:

i. reject the electronic submission and notify the submitting Market Participant that it has been rejected, and

ii. provide details of the reasons the electronic submission was rejected.

DSP ~~Withdrawal~~ Profile Submissions – Standing Submissions

7.4A.16. A Market Participant may submit Standing DSP ~~Withdrawal~~ Profile Submissions for a Demand Side Programme at any time up to two hours before the first Dispatch Interval to which the submissions apply.

7.4A.17. The Standing DSP ~~Withdrawal~~ Profile Submissions in an electronic submission to AEMO for a Demand Side Programme must, in combination, uniquely specify the default DSP ~~Withdrawal~~ Profile Submission to apply for each Dispatch Interval in a generic Trading Week.

7.4A.18. An electronic submission containing Standing DSP ~~Withdrawal~~ Profile Submissions must specify the first Dispatch Interval to which the submissions apply.

7.4A.19. Subject to clause 7.4A.17, a Market Participant may specify the type of Trading Day to which a Standing DSP ~~Withdrawal~~ Profile Submission applies as:

(a) all Trading Days starting on a specific day of the week;

(b) all Trading Days starting on a weekday;

(c) all Trading Days starting on a weekend;

(d) all Trading Days starting on a Business Day;

(e) all Trading Days starting on a non-Business Day; or

(f) all Trading Days.

7.4A.20. AEMO must document in a WEM Procedure the format and methodology to be followed by Market Participants for making Standing DSP ~~Withdrawal~~ Profile Submissions, including the options to submit Standing DSP ~~Withdrawal~~ Profile Submissions for multiple Demand Side Programmes in a single electronic submission.

7.4A.21. On receipt of an electronic submission containing one or more Standing DSP ~~Withdrawal~~ Profile Submissions, AEMO must, as soon as practicable:

(a) acknowledge receipt of the electronic submission to the submitting Market Participant; and

(b) determine whether the Standing DSP ~~Withdrawal~~ Profile Submissions in the electronic submission comply with the following requirements:

i. the content requirements in clauses 7.4A.17, 7.4A.18 and 7.4A.19;

ii. the timing requirement in clause 7.4A.16; and

iii. for each Standing DSP ~~Withdrawal~~ Profile Submission in the electronic submission, the content requirements in clause 7.4A.13.

7.4A.22. Where AEMO:

(a) determines that an electronic submission complies with the requirements in clause 7.4A.21(b), AEMO must accept the Standing DSP ~~Withdrawal~~ Profile Submissions and notify the submitting Market Participant that the Standing DSP ~~Withdrawal~~ Profile Submissions have been accepted; or

(b) determines that the electronic submission, or any part of it, does not comply with the requirements referred to in clause 7.4A.21(b), AEMO must:

i. reject the electronic submission and notify the submitting Market Participant that it has been rejected, and

ii. provide details of the reasons the electronic submission was rejected.

7.4A.23. A Standing DSP ~~Withdrawal~~ Profile Submission for a Demand Side Programme that AEMO accepts under clause 7.4A.22(a) replaces any previously accepted Standing DSP ~~Withdrawal~~ l Profile Submission for Dispatch Intervals from the Dispatch Interval specified in clause 7.4A.18.

DSP ~~Withdrawal~~ Profile Submissions and Standing DSP ~~Withdrawal~~ Profile Submissions – Process Documentation

7.4A.24. AEMO must document in a WEM Procedure the processes it must follow when:

(a) acknowledging receipt of a DSP ~~Withdrawal~~ Profile Submission under clause 7.4A.14(a) or a Standing DSP ~~Withdrawal~~ Profile Submission under clause 7.4A.21(a);

(b) validating a DSP ~~Withdrawal~~ Profile Submission in accordance with clause 7.4A.14(b) or a Standing DSP ~~Withdrawal~~ Profile Submission in accordance with clause 7.4A.21(b); and

(c) accepting or rejecting a DSP ~~Withdrawal~~ Profile Submission in accordance with clause 7.4A.15 or a Standing DSP ~~Withdrawal~~ Profile Submission in accordance with clause 7.4A.22.

…

7.8A. DSP Schedules

Explanatory Note

Section 7.8A is amended as follows:

- Reflect the following amended terms: DSP ~~Withdrawal~~ Profile, DSP Unconstrained ~~Withdrawal~~ Quantity, and DSP Constrained ~~Withdrawal~~ Quantity.
- Require AEMO to calculate Relevant Demand for the purposes of determining the DSP Forecast Capacity using the Unadjusted Baseline Energy calculated in accordance with Appendix 10.

7.8A.1. A DSP Pre-Dispatch Schedule or DSP Week-Ahead Schedule is a schedule that includes, for each Demand Side Programme, for each Dispatch Interval in the Pre-Dispatch Schedule Horizon or Week-Ahead Schedule Horizon (as applicable):

(a) the DSP Unconstrained ~~Withdrawal~~ Quantity and DSP Constrained ~~Withdrawal~~ Quantity provided by the Market Participant in its DSP ~~Withdrawal~~ Profile Submission;

(b) AEMO's reasonable estimate based on the information available to AEMO of:

i. the Demand Side Programme's Relevant Demand in the applicable Trading Interval;

ii. the sum of the Minimum Consumption of each Associated Load of the Demand Side Programme in the applicable Trading Interval; and

iii. the Reserve Capacity Obligation Quantity of the Demand Side Programme in the Dispatch Interval;

(c) the DSP Forecast Capacity, determined by AEMO in accordance with clause 7.8A.3; and

(d) the DSP Forecast Reduction, determined by AEMO in accordance with clause 7.8A.4.

7.8A.2. AEMO must determine, make available to Market Participants and publish on the WEM Website the following DSP Schedules in accordance with the Real-Time Market Timetable:

(a) DSP Week-Ahead Schedules; and

(b) DSP Pre-Dispatch Schedules.

Explanatory Note
AEMO must use the Unadjusted Baseline Energy calculated in accordance with Step 5.1(b) of Appendix 10, when calculating DSP Forecast Capacity.

7.8A.3. The DSP Forecast Capacity for a Demand Side Programme in a Dispatch Interval is:

DSPForecastCapacity = max(0, DSPU~~W~~Q – max(MinLoad, RD – RCOQ))

where:

DSPU~~W~~Q is the Unconstrained ~~Withdrawal~~ Quantity provided by the Market Participant in its DSP ~~Withdrawal~~ Profile Submission for the Demand Side Programme and Dispatch Interval;

MinLoad is AEMO's reasonable estimate, based on the information available to it, of the sum of Minimum Consumption of each Associated Load of the Demand Side Programme in the applicable Trading Interval;

RD is AEMO's ~~reasonable~~ estimate~~, based on the information available to it,~~ of the Relevant Demand of the Demand Side Programme in the applicable Trading Interval calculated under Step 5.1(b) of Appendix 10; and

RCOQ is AEMO's reasonable estimate, based on the information available to it, of the Reserve Capacity Obligation Quantity of the Demand Side Programme in the Dispatch Interval.

7.8A.4. The DSP Forecast Reduction for a Demand Side Programme in a Dispatch Interval is:

DSPForecastReduction = DSPU~~W~~Q – DSPC~~W~~Q

where:

DSPU~~W~~Q is the Unconstrained ~~Withdrawal~~ Quantity provided by the Market Participant in its DSP ~~Withdrawal~~ Profile Submission for the Demand Side Programme and Dispatch Interval; and

DSPC~~W~~Q is the Constrained ~~Withdrawal~~ Quantity provided by the Market Participant in its DSP ~~Withdrawal~~ Profile Submission for the Demand Side Programme and Dispatch Interval.

...

7.11B. Determination of Market Clearing Prices

…

Explanatory Note:

Clause 7.11B.1B is amended to allow AEMO to utilise counterfactual scenarios to determine replacement Market Schedules where a suitable Dispatch or Pre-Dispatch Schedule is not available. This may include scenarios where a manifestly incorrect input was present in all previous Market Schedules.

AEMO will be required to provide details of the conditions and circumstances behind the use of this process in the WEM Procedure referenced in clause 7.11C.1.

7.11B.1B. For the purposes of clauses 7.11B.1A and 7.11C.2, AEMO must identify a replacement Market Schedule containing the Dispatch Interval as follows:

(a) if the Dispatch Interval has been included in a previous Dispatch Schedule, then AEMO must identify the most recent Dispatch Schedule, if available, that contains the Dispatch Interval and which AEMO reasonably considers does not include manifestly incorrect data;

(b) if AEMO is unable to identify a Dispatch Schedule in accordance with clause 7.11B.1B(a), then AEMO must identify the most recent Pre-Dispatch Schedule, if available, that contains the Dispatch Interval and which AEMO reasonably considers does not include manifestly incorrect data;~~ and~~

(bA) if AEMO is unable to identify a Market Schedule under clauses 7.11B.1B(a) or 7.11B.1B(b), then AEMO must, if it has sufficient information, use the Dispatch Algorithm with corrected Dispatch Inputs to determine a replacement Market Schedule for the relevant Dispatch Interval that does not include manifestly incorrect data, in accordance with the WEM Procedure referred to in clause 7.11C.1; and

(c) if AEMO is unable to identify a Market Schedule under clauses ~~7.11B.1B(a) or 7.11B.1B(b)~~ 7.11B.1B(a), 7.11B.1B(b) or 7.11B.1B(c), then AEMO must identify the most recently determined Dispatch Schedule or Pre-Dispatch Schedule that contains the Dispatch Interval.

…

7.11C. Corrections to Price Determinations and Intervention Pricing

7.11C.1. AEMO must develop procedures for the identification of Affected Dispatch Intervals within the timeframes contemplated under clause 7.11C.2, and must document in a WEM Procedure ~~the conditions or circumstances that would identify a Dispatch Interval as an Affected Dispatch Interval.~~:

(a) the conditions or circumstances that would identify a Dispatch Interval as an Affected Dispatch Interval;

(b) the conditions and circumstances that would require AEMO to determine a replacement Market Schedule under clause 7.11B.1B(bA); and

(c) the process AEMO must follow to determine a replacement Market Schedule under clause 7.11B.1B(bA).

…

7.13. Settlement and Monitoring Data

…

Explanatory Note: Clause 7.13.5 is amended to indicate that DSPs may be required to either reduce Withdrawal or increase Injection (to support Policy Decision 1).

7.13.5. AEMO must, for the purposes of clauses 7.13.1E(d) and 4.26.2D, calculate, for each Demand Side Programme for each Trading Interval, the quantity, in MW, by which the Facility was requested by the applicable Dispatch Instruction to curtail the absolute value of its Withdrawal or increase its Injection (as relevant) during that Trading Interval, where the quantity:

(a) must be measured as a requested decrease from the Facility's Relevant Demand (and so must not include any quantity above the Relevant Demand); and

(b) must not take account of the Facility's actual performance in response to the Dispatch Instruction.

…

9.5. The Metered Schedule

…

Explanatory Note To support Policy Decision 1, amendments are made to the DSP Metered Schedule calculations (used to calculate DSP Load in refund calculations) so that DSP Load can be positive (Withdrawing) and negative (Negative). Note, for normal Metered Schedules (clause 9 .5.2 and 9.5.3), negative values indicate Withdrawal and positive values indicate Injection. We have retained the inverse of this for

the DSP Metered Schedule calculation as refund calculations assume consumption to be positive.

9.5.4. AEMO must determine the Demand Side Programme Load for a Demand Side Programme for a Trading Interval as the total net MWh quantity of energy consumed or produced by the Associated Loads of that Demand Side Programme during the Trading Interval, determined from Meter Data Submissions and expressed as: ~~a positive non-Loss Factor adjusted value.~~

(a) a positive non-Loss Factor adjusted value if the total net MWh quantity of energy determined above indicates the DSP was withdrawing or consuming energy; or

(b) a negative non-Loss Factor adjusted value if the total net MWh quantity of energy determined above indicates the DSP was injecting or producing energy.

…

9.10. Settlement Calculations - Essential System Services

…

Explanatory Note Clauses 9.10.27D and 9.10.45 are amended to remove from the Essential System Service Settlements Calculations any NCESS contracts procured and recovered under the Reserve Capacity Mechanism, in accordance with the new clauses 4.28.4(aA) and 4.28.4A.

9.10.27D. The ~~total~~ residual cost of procuring NCESS in Trading Interval t is:

$$\text{NCESS\_Payable}(t) = \sum_{p \in P} \text{NCESS\_Payable}(p,t) - \sum_{p \in P} \text{NCESS\_Shared}(p,t)$$

where:

(a) NCESS_Payable(p,t) is the NCESS amount payable to Market Participant p for NCESS in Trading Interval t as calculated in accordance with clause 9.10.27B; ~~and~~

(b) p∈P denotes all Market Participants~~.~~; and

(c) NCESS_Shared(p,t) is the NCESS amount payable to Market Participant p for NCESS in Trading Interval t calculated under clause 4.28.4A.

…

9.10.45. The NCESS amount recoverable from Market Participant p for Trading Interval t is:

$$\text{NCESS\_Recoverable}(p,t) = \text{NCESS\_Payable}(t) \times \text{ConsumptionShare}(p,t)$$

where:

(a) NCESS_Payable(t) is the ~~total~~ residual cost of procuring NCESS in Trading Interval t as calculated in accordance with clause 9.10.27D; and

(b) ConsumptionShare(p,t) is the Consumption Share for Market Participant p in Trading Interval t as calculated in accordance with clause 9.5.6.

…

11. Glossary

Explanatory Note

To support Policy Decision 3, the terms Adjusted Baseline Method and Unadjusted Baseline Method are introduced to differentiate the two ways Relevant Demand could be calculated under Appendix 10.

Adjusted Baseline Method: A variant of the Relevant Demand methodology in Appendix 10 where the Relevant Demand of a Demand Side Programme is calculated under step 4.5 of Appendix 10.

Unadjusted Baseline Method: A variant of the Relevant Demand methodology in Appendix 10 where the Relevant Demand of a Demand Side Programme is calculated under step 3.1 of Appendix 10.

Explanatory Note

To support Policy Decision 1, the term DSP Injection Cap is introduced so that injecting DSPs cannot Inject above this level.

DSP Injection Cap: The quantity determined by AEMO under clause 2.29.5AB for each Transmission Node Identifier.

Explanatory Note

Do support Policy Decision 1, the following definitions are amended to reflect that DSPs can now Withdraw and Inject.

DSP Constrained ~~Withdrawal~~ Quantity: A Market Participant's estimate of the output ~~absolute value of the average MW Withdrawal~~ of its Demand Side Programme in a Dispatch Interval, taking into account any information about the potential or actual dispatch of the Demand Side Programme that is provided by AEMO in Market Advisories under clause 7.11.6(cA), Dispatch Instructions under clause 7.6.15 or notifications under clause 4.25.9(h)~~.~~, where:

(a) the output of a Demand Side Programme that expects to Inject during the Dispatch Interval should denote the Market Participants estimate of the average MW Injection of its Demand Side Programme, multiplied by negative one; and

(b) the output of a Demand Side Programme that expects to Withdraw during the Dispatch Interval should denote the Market Participants estimate of the absolute value of the average MW Withdrawal of its Demand Side Programme in a Dispatch Interval.

DSP Forecast Reduction: An estimate of the expected reduction in the absolute value of Withdrawal or increase in the Injection (as relevant) of a Demand Side Programme in a Dispatch Interval based on DSP ~~Withdrawal~~ Profile Submissions provided by the Market Participant, determined by AEMO in accordance with clause 7.8A.4.

DSP Unconstrained ~~Withdrawal~~ Quantity: A Market Participant's estimate of the output ~~absolute value of the average MW Withdrawal~~ of its Demand Side Programme in a Dispatch Interval, assuming that the Demand Side Programme does not receive a notification under clause 4.25.9(h) or Dispatch Instruction under clause 7.6.15 that affects its Withdrawal or Injection in the Dispatch Interval~~.~~, where:

(a) the output of a Demand Side Programme that expects to Inject during the Dispatch Interval should denote the Market Participants estimate of the average MW Injection of its Demand Side Programme, multiplied by negative one; and

(b) the output of a Demand Side Programme that expects to Withdraw during the Dispatch Interval should denote the Market Participants estimate of the absolute value of the average MW Withdrawal of its Demand Side Programme in a Dispatch Interval.

..

DSP ~~Withdrawal~~ Profile Submission: A submission made by a Market Participant to AEMO which provides a DSP Unconstrained ~~Withdrawal~~ Quantity and DSP Constrained ~~Withdrawal~~ Quantity for a Demand Side Programme for a Dispatch Interval.

Explanatory Note To support Policy Decision 1, the terms Flexible DSP Delivery Shortfall and Peak DSP Delivery Shortfall are introduced so that DSPs pay Reserve Capacity Deficit Refunds if they fail to deliver their full dispatch quantity (unless they have undergone a test). See also changes to Section 4.26.

Flexible DSP Delivery Shortfall: For a Trading Day, denotes the average of all Trading Interval Flexible Capacity Shortfall values (calculated under clause 4.26.14) occurring up to and including Trading Day d, but excluding Trading Intervals in which the DSP had previously failed to deliver, but has since undergone a Reserve Capacity Test, as calculated in accordance with clause 4.26.4A.

Peak DSP Delivery Shortfall: For a Trading Day, denotes the average of all Trading Interval Peak Capacity Shortfall values (calculated under clause 4.26.2D) occurring up to and including Trading Day d, but excluding Trading Intervals in which the DSP had previously failed to deliver, but has since undergone a Reserve Capacity Test, as calculated in accordance with clause 4.26.1AA.

Appendix 10: Relevant Demand Determination

Explanatory Note

The following changes are made to Appendix 10 (previously consulted on as part of the Demand Side Review (DSR))

Policy Decision 1

The Baseline Adjustment calculation has been amended so that it can handle both positive and negative values for Average Metered Energy and Average Unadjusted Baseline Energy. Additionally a floor of -20% is introduced to the Baseline Adjustment formula to prevent DSPs with very small Average Unadjusted Baseline Energy valus from receiving very large negative adjustments.

Policy Decision 3

Appendix 10 has been amended to indicate that the Relevant Demand of a DSP can be determined either using the (adjusted) Baseline Energy value or the Unadjusted Baseline Energy value or using an alternative methodology approved by AEMO (see changes in Section 4.26).

Other changes

Amendments are also made in response to submissions made as part of the DSR consultation

- The calculations in Appendix 10 are now performed on the Demand Side Programme's load in aggregate (instead of calculating it for each Associated Load and then summing it at the end).
- Equations are introduced to make the intent of the calculations clearer
- Minor changes to the text to make the intent of Appendix 10 clearer.
- The Baseline Adjustment formula is further adjusted to handle divide by zero errors.

This Appendix sets out the dynamic baseline method for determining the Relevant Demand for each Demand Side Programme in Trading Interval t, for use in clause 4.26.2CA.

A "**DSP Dispatch Event**" is a contiguous number of Trading Intervals comprising all Trading Intervals starting from and including the Trading Interval in which a Demand Side Programme receives a dispatch instruction under clause 7.6.5A and ending with the last Trading Interval in which AEMO requires the Demand Side Programme to be activated under the dispatch instruction received under clause 7.6.5A.

An "**Event Day**" is a Trading Day in which one or more DSP Dispatch Events occur.

~~"**Trading Day**" d is the Trading Day that contains Trading Interval t.~~

The "**Baseline Window**" for Trading Day d is the 50 Trading Days from Trading Day d-50 to Trading Day d-1.

1. Determine Selected Days

Determine the "**Selected Days**" for Trading Day d using the following steps:

If Trading Day d is a Business Day:

1.1 Select the ten most recent Trading Days in the Baseline Window that are a Business Day and not an Event Day.

1.2 If between five and ten Trading Days (inclusive) have been selected, go to 1.4.

1.3 If fewer than five Trading Days have been selected in step 1.1, then keep adding the next most recent Trading Day(s) in the Baseline Window that is (or are) a Business Day and an Event Day until a total of five days has been selected.

1.4 Trading Days selected under steps 1.2 or 1.3, as applicable, are the Selected Days for Trading Day d.

If Trading Day d is a non-Business Day:

1.5 Select the four most recent Trading Days in the Baseline Window that are non-Business Days and not an Event Days.

1.6 If four Trading Days have been selected, go to step 1.8.

1.7 If fewer than four Trading Days have been selected in step 1.5, then keep adding the next most recent Trading Day(s) in the Baseline Window that is (or are) a Non-Business Day and an Event Day until a total of four days has been selected.

1.8 Trading Days selected under steps 1.6 or 1.7, as applicable, are the Selected Days for Trading Day d.

Explanatory Note
The Unadjusted Baseline Energy is the average energy consumed if generated during each Trading Interval over the set of Selected Days as determined in Step 1.4 or 2.4 as relevant.

3. Determine Unadjusted Baseline Energy

3.1 The Unadjusted Baseline Energy(f,t) of Demand Side Programme Facility f for Trading Interval t in Trading Day d is given by:

$$\text{Unadjusted Baseline Energy}(f,t,d) = \frac{1}{N(f,t,d)} \times \sum_{i \in \text{Selected Days}(d)} \text{DSPLoad}(f,i,d)$$

Where:

(a) $N_{(f,t,d)}$ is the number of Selected Days for Demand Side Programme f on Trading Day d that contains Trading Interval t as determined in step 1.4 or 1.8 as relevant; and

(b) $DSPLoad_{i(d)}$ is the Demand Side Programme Load of Demand Side Programme f determined using:

i. The Demand Side Programme Load determined under clause 9.5.4

ii. If the Demand Side Programme Load determined under clause 9.5.4 is not available, or is considered by AEMO or the relevant Market Particiapnt to be inappropriate, an alternative quantity determined by AEMO based on:

1. available Meter Data Submissions; or

2. Load information provided by the Market Participant; or

3. other relevant information.

4. Determine Adjustment

4.1 The "**Adjustment Window**" for Trading Interval t is the two Trading Intervals immediately before the Trading Interval in which AEMO issues a dispatch instruction to the Demand Side Programme in accordance with clause 7.6.5A for activation in Trading Interval t.

Explanatory Note
Average Metered Energy is the average of the actual consumption over the two Trading Intervals during the hour prior to the DSP receiving a Dispatch Instruction (the adjustment window)

4.2 The **Average Metered Energy(f,t)** is the average Demand Side Programme Load (as determined in accordance with clause 9.5.4) of the Demand Side Programme, during the Adjustment Window, determined as:

$$\text{Average Metered Energy(f,t)} = \frac{1}{2} \sum_{\text{i∈Adjustment Window(f,t)}} \text{DSPLoad(f, i)}$$

where:

(a) DSPLoad(f, i) is the Demand Side Programme Load of Demand Side Programme f in Trading Interval i, determined under clause 9.5.4; and

(b) Adjustment Window(f,t) denotes the Adjustment Window for Demand Side Programme f in Trading Interval t determined in step 4.1.

Explanatory Note
Average Unadjusted Baseline Energy is the average of the Unadjusted Baseline Energy quantities (calculated in Step 3.1) for the two Trading Intervals preceding the Trading Interval in which the DSP receives a Dispatch Instruction (i.e. the adjustment window).

4.3 The **Average Unadjusted Baseline Energy(f,t)** is the average Unadjusted Baseline Energy of the Demand Side Programme, during the Adjustment Window, determined as:

Average Unadjusted Baseline Energy(f,t)

$$= \frac{1}{2} \sum_{i \in \text{Adjustment Window(f,t)}} \text{Unadjusted Baseline Energy}(f,i)$$

where:

(a) $\text{Unadjusted Baseline Energy}(f,t)$ is the Unadjusted Baseline Energy of the Demand Side Programme f in Trading Interval t as determined step 3.1; and

(b) Adjustment Window(f,t) denotes the Adjustment Window for Demand Side Programme f in Trading Interval t determined in step 4.1.

Explanatory Note

The Baseline Adjustment is amended as follows:

- The relative difference between the Average Metered Energy and Average Unadjusted Baseline Energy is calculated relative to the Average Unadjusted Baseline Energy (i.e. the denominator in the formula has been changed from Average Metered Energy to Average Unadjusted Baseline Energy).
- The adjustment is multiplied by negative one if the sign of Average Unadjusted Baseline Energy is different to that of the Unadjusted Baseline Energy – this change is made to ensure the adjustment works if either Average Metered Energy or Average Unadjusted Baseline Energy indicates injection into the network. Further details are provided below.
- The adjustment is set to the cap of 20%, if the Average Unadjusted Baseline Energy equals exactly zero to prevent divide by zero errors. Further details are provided below.
- There is also a very conservative floor of -300% to cap the level of negative adjustments.

Changes to enable DSPs to inject

In the previously consulted version of Appendix 10, the Baseline Adjustment was calculated as follows:

$$\text{Baseline Adjustment(f, t)} \\ = \text{Min}\left(20\%,\ \frac{\text{Average Metered Energy(f,t)} - \text{Average Unadjusted Baseline Energy(f,t)}}{\text{Average Unadjusted Baseline Energy(f,t)}}\right)$$

The above adjustment produces correct outcomes for injecting DSPs as long as the sign of the denominator (Average Unadjusted Baseline Energy) is the same as the sign of the Unadjusted Baseline Energy value (that will be adjusted). Consider the two examples below:

Example 1

In this example the Average Metered Energy (AME) and the Average Unadjusted Baseline Energy (AUBE) are both negative indicating injection or spilling:

- AME = -0.45 MWh
- AUBE = -0.5 MWh

If we apply the above formula, we get an adjustment of -10%. Even though AME>AUBE we get a negative adjustment, as AUBE has a negative sign (as it indicates injection).

Let us say that the Trading Interval in which the DSP is activated, it has an Unadjusted Baseline Energy (UBE) value of -0.1. That is, during the previous 10 (or 4 as relevant) days, the DSP was, on average, spilling in that Trading Interval.

The Baseline Energy (adjusted) in that Trading Interval will equal -0.1 x (1-10%) = -0.09 MWh. That is, the UBE value is reduced by 10% indicating less injection. This is the correct outcome, as AME is larger than AUBE, which indicates higher consumption (and less spilling) on the day of the Dispatch Event.

Explanatory Note contd

Example 2

Now consider the same example as above, but where the DSP is activated during a Trading Interval with a positive UBE value of +0.1 indicating that the DSP has (over the previous days), consumed or withdrawn energy from the network during this Trading Interval.

The Baseline Energy (adjusted) in the Trading Interval will now equal +0.1 x (1-10%) = -0.9 MWh. That is, after applying the adjustment, we have lowered the consumption of the DSP. This is an incorrect outcome as AME > AUBE indicating that we would expect the consumption to be increased during the Trading Interval. The reason this error did not occur in Example 1 is that UBE was a negative value or an injection. Applying a negative adjustment to a negative value results in **increasing** that value. However, applying a negative adjustment to a positive value will result in decreasing that value incorrectly.

The above error can be rectified by instead increasing the UBE by 10% (instead of decreasing it). That is, the Baseline Energy should equal +0.1 x (1+10%) = 0.11MWh.

The Baseline Adjustment formula is therefore adjusted to ensure that the adjustment occurs in the correct direction if the signs of UBE and AUBE differ. This is implemented by multiplying the adjustment formula by negative one if the signs of UBE and AUBE are different.

Changes to prevent large negative adjustments

The Baseline Adjustment formula can result in very negative or positive adjustment if the Average Unadjusted Baseline Energy (AUBE) value is very close to zero. The adjustment is capped in the upwards direction but not in the downwards direction. For example, if AME equals 0.5 and AUBE is -0.01, the adjustment will equal -5,100%. To prevent large negative errors (and to enable an adjustment when AUBE is zero – see below), a floor of -200% is introduced,

Changes to prevent divide by zero errors

The Baseline Adjustment formula will result in a divide by zero error if the Average Unadjusted Baseline Energy (AUBE) value is zero. Amendments are introduced to enable an adjustment to be calculated when AUBE is zero. The following amendments are made to calculate the Baseline Adjustment when AUBE is zero:

- If AME > 0, then the Baseline Adjustment is set by the cap of 20%; this is what a DSP with a positive AUBE that is very close to zero would also get as an adjustment as well.
- If AME <0, then the Baseline Adjustment is set by the floor of -200%; this is what a DSP with a negative AUBE that is very close to zero would get an adjustment as well.
- If AME equals 0 then the Baseline Adjustment equals 0.

4.4 The **Baseline Adjustment$_{f,t}$** of Demand Side Programme f in Trading Interval t is equal to:

(a) $\text{Baseline Adjustment}(f,t) = \text{Min}\left(20\%,\ \text{Max}\left\{-200\%, \frac{\text{Average Metered Energy}(f,t) - \text{Average Unadjusted Baseline Energy}(f,t)}{\text{Average Unadjusted Baseline Energy}(f,t)}\right\}\right)$, if:

(i) Unadjusted Baseline Energy(f,t) >0 and Average Unadjusted Baseline Energy(f,t)>0; or

(ii) Unadjusted Baseline Energy(f,t) <0 and Average Unadjusted Baseline Energy(f,t)<0; or

(b) $\text{Baseline Adjustment}(f,t) = -1 \times \text{Min}\left(20\%,\ \text{Max}\left\{-200\%, \frac{\text{Average Metered Energy}_{f,t} - \text{Average Unadjusted Baseline Energy}(f,t)}{\text{Average Unadjusted Baseline Energy}(f,t)}\right\}\right)$, if:

(i) Unadjusted Baseline Energy(f,t)< 0 and Average Unadjusted Baseline Energy(f,t) > 0; or

(ii) Unadjusted Baseline Energy(f,t) > 0 and Average Unadjusted Baseline Energy(f,t) < 0; or

(c) if Average Unadjusted Baseline Energy(f,t) = 0, then:

(i) If $\text{Average Metered Energy}(f,t) > 0, \text{Baseline Adjustment}(f,t) = 20\%$; or

(ii) If $\text{Average Metered Energy}(f,t) < 0, \text{Baseline Adjustment}(f,t) = -200\%$; or

(iii) If $\text{Average Metered Energy}(f,t) = 0, \text{Baseline Adjustment}(f,t) = 0\%$.

If more than one DSP Dispatch Event occurs in the same Event Day, the same Baseline Adjustment is applied to those further DSP Dispatch Events.

4.5 The **Baseline Energy(f,t)** for the Demand Side Programme in Trading Interval t is:

$$\text{Baseline Energy}(f,t) = \text{Unadjusted Baseline Energy}(f,t) \times (1 + \text{Baseline Adjustment}(f,t))$$

Where:

(a) $\text{Unadjusted Baseline Energy}(f,t)$ is the Unadjusted Baseline Energy of the Demand Side Programme f in Trading Interval t as determined in step 3.1; and

(b) $\text{Baseline Adjustment}(f,t)$ is the adjustment applied to Demand Side Programme f in Trading Interval t as calculated in step 4.4.

Explanatory Note

To support Policy Decision 3, Market Participants can choose either the Adjusted Baseline Method or the Unadjusted Baseline Method. Amendments are made to Appendix 10 to reflect this.

Appendix 10 is also amended to require AEMO to use the Unadjusted Baseline Method when calculating Relevant Demand for the purposes of determining the DSP Forecast Capacity quantity in DSP Market Schedules.

5. Calculate Relevant Demand

5.1 The **Relevant Demand$_{f,t}$** for the Demand Side Programme f in Trading Interval t is:

a) If AEMO has issued a Dispatch Instruction with a non-zero MW quantity under section 7.6 to the Demand Side Programme f for the Trading Interval t, then:

i. if the Market Participant to whom Demand Side Programme f is registered, nominated the Adjusted Baseline Method under clause 2.29.5AD(a) or clause 4.26.2CG(b), the $\text{Baseline Energy}_{f,t}$ calculated in step 4.5; or

ii. if the Market Participant to whom Demand Side Programme f is registered, nominated the Unadjusted Baseline Method under clause 2.29.5AD(b) or clause 4.26.2CG(b), the $\text{Unadjusted Baseline Energy}(f, t)$ calculated under step 3.1;

(b) If AEMO is estimating the Relevant Demand of a Demand Side Programme f, to calculate the DSP Forecast Capacity under clause 7.8A.3, the $\text{Unadjusted Baseline Energy}(f, t)$ calculated under step 3.1.

Part 3: Contingency Reserve Raise and the Additional RoCoF Requirement of RoCoF Control Service cost allocation - Amending Rules to commence TBA

…

7.5. Dispatch Algorithm

…

7.5.14. AEMO must determine and publish on the WEM Website the RoCoF Upper Limit at least annually.

> **Explanatory Note**
>
> Under the proposed changes to the cost allocation method for Contingency Reserve Raise, AEMO will determine the method for calculating Single Facility Raise Risks (previously Facility Risks) on a case-by-case basis, to more accurately reflect the actual risk posed by the failure of a Facility.
>
> New clause 7.5.15 requires AEMO to document how it determines Facility Raise Contingencies, Facility Raise Contingency Risks, Single Facility Raise Risks and Secondary Facility Raise Risks in a WEM Procedure.
>
> New clause 7.5.16 specifies information that AEMO must consider when determining Facility Raise Contingencies, Facility Raise Contingency Risks and Single Facility Raise Risks for Facilities that contain an Intermittent Load.

Facility Raise Contingencies

7.5.15. AEMO must document in a WEM Procedure the method it uses and the factors it takes into account when determining:

(a) Facility Raise Contingencies;

(b) Facility Raise Contingency Risks;

(c) Single Facility Raise Risks; and

(d) Secondary Facility Raise Risks.

7.5.16. AEMO must take the following information into account when determining Facility Raise Contingencies, Facility Raise Contingency Risks and Single Facility Raise Risks for a Facility that contains an Intermittent Load:

(a) any information provided by the Market Participant for the Facility under clause 2.30B.3(g);

(b) the Dispatch Target or Dispatch Forecast for the Facility, if applicable;

(c) for Non-Dispatchable Loads, AEMO's estimate of the Facility's MW Injection or Withdrawal level for the Dispatch Interval; and

(d) the output of each energy producing unit in the Energy Producing System supplying the Intermittent Load, if applicable.

…

7.13. Settlement and Monitoring Data

…

Explanatory Note

Clause 7.13.1EA is amended to:

- update the terminology used around Contingency Events that result in a decrease in the SWIS Frequency;
- require AEMO to prepare and publish, for each Dispatch Interval, the contingency risk values required by Appendix 2A, which include:
  - the Single Facility Raise Risk for each CR Facility (i.e. each Non-Dispatchable Load containing an Intermittent Load, and each Scheduled Facility, Semi-Scheduled Facility and Non-Scheduled Facility);
  - for each Facility Raise Contingency considered when setting the Contingency Reserve Raise Requirement, the Facility Contingency Raise Risk (which may be different from the Single Facility Raise Risk of the initiating CR Facility due to the consequential responses of other Facilities) and the MW contribution to that risk from other CR Facilities (Secondary Facility Raise Risks); and
  - for each Network Raise Contingency considered when setting the Contingency Reserve Raise Requirement, the Network Raise Contingency Risk and the MW contribution to that risk of each contributing CR Facility (Network Facility Raise Risk).

Note that the Network Facility Raise Risk of a CR Facility for a Network Raise Contingency may be different from the Single Facility Raise Risk of that CR Facility, for example because the risk associated with the auxiliary loads of a CR Facility may be different for a Facility Raise Contingency and a Network Raise Contingency.

The drafting assumes that other changes proposed to clause 7.13.1EA(c) to support the implementation of new Appendix 2E (Contingency Reserve Lower Cost Share Allocation Method) have been implemented.

7.13.1EA. Subject to clause 7.11D.5, AEMO must prepare and publish on the WEM Website the following data for a Trading Day by noon on the first Business Day following the day on which the Trading Day ends:

(a) details of each Real-Time Market Submission used as an input to the Dispatch Algorithm for the purposes of the Central Dispatch Process, or revised in accordance with clauses 7.11B.1A(b) or 7.11C.2(c), for Dispatch Intervals in that Trading Day, including, as applicable:

i. the Registered Facility ID;

iA. the Market Service;

ii. Price-Quantity Pairs;

iii. In-Service Capacity for Injection;

iv. Available Capacity for Injection;

v. In-Service Capacity for Withdrawal;

vi. Available Capacity for Withdrawal;

vii. the Maximum Upwards Ramp Rate;

viii. the Maximum Downwards Ramp Rate;

ix. Enablement Minimums;

x. Enablement Maximums;

xi. Low Breakpoints;

xii. High Breakpoints;

xiii. Dispatch Inflexibility Profiles;

xiv. any reasons for revisions in accordance with clauses 7.4.26(a) or 7.4.27(a);

xv. if the Registered Facility is Inflexible;

xvi. the Unconstrained Injection Forecast; and

xvii. the Unconstrained Withdrawal Forecast;

(b) where applicable, for each Scheduled Facility or Semi-Scheduled Facility and each Dispatch Interval of the Trading Day, the Congestion Rental, generated by the Dispatch Algorithm for the purposes of the Central Dispatch Process, or revised in accordance with clauses 7.11B.1A(b) or 7.11C.2(c), calculated under clause 7.14.1;

(c) for each Dispatch Interval of the Trading Day, information used in the Dispatch Algorithm for the purposes of the Central Dispatch Process, or revised in accordance with clauses 7.11B.1A(b) or 7.11C.2(c):

~~i. all Facility Risks for that Dispatch Interval;~~

~~ii. for each Network Contingency which is a Credible Contingency Event that is taken into account when setting the Contingency Reserve Raise requirement under clause 7.2.4 in that Dispatch Interval:~~

~~1. the Network Risk associated with that Network Contingency; and~~

~~2. the Registered Facilities whose Facility Risks are included in the Network Risk associated with that Network Contingency;~~

i. for each CR Facility, the Single Facility Raise Risk for the Dispatch Interval;

ii. for each Facility Raise Contingency which is a Credible Contingency Event that is taken into account when setting the Contingency Reserve Raise requirement under clause 7.2.4 in the Dispatch Interval:

1. the Facility Raise Contingency Risk associated with the Dispatch Interval; and

2. the Secondary Facility Raise Risk of each Secondary CR Facility that contributes to the Facility Raise Contingency in the Dispatch Interval;

iiA. for each Network Raise Contingency which is a Credible Contingency Event that is taken into account when setting the Contingency Reserve Raise requirement under clause 7.2.4 in the Dispatch Interval:

1. the Network Raise Risk associated with the Network Supply Contingency; and

2. the Network Facility Raise Risk of each CR Facility that contributes to the Network Raise Contingency in the Dispatch Interval;

iii. the Largest Credible Supply Contingency;

iv. the Largest Credible Load Contingency;

v. all Facility Lower Risks for that Dispatch Interval; and

vi. for each Network Lower Contingency which is a Credible Contingency Event that is taken into account when setting the Contingency Reserve Lower requirement for that Dispatch Interval:

1. the Network Lower Risk associated with that Network Lower Contingency; and

2. the Network Facility Lower Risk of each CL Facility that contributes to that Network Lower Contingency in the Dispatch Interval;

(d) for each Dispatch Interval of the Trading Day, for each Semi-Scheduled Facility and Non-Scheduled Facility, any alternative forecast quantities to the Unconstrained Injection Forecast and Unconstrained Withdrawal Forecast provided by the Market Participant in its Real-Time Market Submission that were determined and used by AEMO as an input to the Dispatch Algorithm for the purposes of the Central Dispatch Process under clause 7.2.4A, or revised in accordance with clauses 7.11B.1A(b) or 7.11C.2(c); and

(e) where applicable, for each Scheduled Facility or Semi-Scheduled Facility and each Dispatch Interval, the Energy Uplift Price and the Uplift Payment Mispricing Trigger as determined by the Dispatch Algorithm, or revised in accordance with clauses 7.11B.1A(b) or 7.11C.2(c).

…

9.10. Settlement Calculations - Essential System Services

…

9.10.29. The Contingency Reserve Raise amount recoverable from Market Participant p for Trading Day d is:

$$CR\_Recoverable(p,d) = \sum_{t \in d} CR\_Recoverable(p,t)$$

where:

(a) CR_Recoverable(p,t) is the Contingency Reserve Raise amount recoverable from Market Participant p for Trading Interval t calculated in accordance with clause 9.10.30; and

(b) t∊d denotes all Trading Intervals t in Trading Day d.

9.10.30. The Contingency Reserve Raise amount recoverable from Market Participant p for Trading Interval t is:

$$\cancel{CR\_Recoverable(p,t) = \sum_{DI \in t} \begin{cases} CR\_Payable(DI) \times RTMSuspShare(p,DI), \text{ if } RTMSuspFlag(DI)=1 \\ CR\_Payable(DI) \times TotalRunwayShare(p,DI), \text{ otherwise} \end{cases}}$$

$$CR\_Recoverable(p,t) = \sum_{DI \in t} \begin{cases} CR\_Payable(DI) \times RTMSuspShare(p,DI), \text{ if } RTMSuspFlag(DI)=1 \\ CR\_Payable(DI) \times CR\_Cost\_Share(p,DI), \text{ otherwise} \end{cases}$$

where:

(a) CR_Payable(DI) is the total cost of procuring Contingency Reserve Raise in Dispatch Interval DI calculated in accordance with clause 9.10.7;

(b) ~~TotalRunwayShare(p,DI)~~ CR_Cost_Share(p,DI) is Market Participant p's share of the total cost of procuring Contingency Reserve Raise in Dispatch Interval DI as calculated following the steps set out in Appendix 2A and as finally calculated in ~~clause 5.3~~ clause 5.2 of Appendix 2A;

(c) RTMSuspFlag(DI) is the RTM Suspension Flag for Dispatch Interval DI;

(d) RTMSuspShare(p,DI) is Market Participant p’s share of the total cost of procuring Contingency Reserve Raise when AEMO has suspended the Real-Time Market under clause 7.11D.1 for Dispatch Interval DI as calculated in clause 9.10.30A; and

(e) DI∊t denotes all Dispatch Intervals DI in Trading Interval t.

…

9.10.43. The cost of procuring the Additional RoCoF Control Requirement component of RoCoF Control Service recoverable from Rule Participant p in Dispatch Interval DI is:

$$\cancel{AdditionalRCS\_Recoverable(p,DI) = \begin{cases} AdditionalRCS\_Payable(DI) \times RTMSuspShare(p,DI), \text{ if } RTMSuspFlag(DI)=1 \\ AdditionalRCS\_Payable(DI) \times TotalRunwayShare(p,DI), \text{ otherwise} \end{cases}}$$

$$AdditionalRCS\_Recoverable(p,DI) = \begin{cases} AdditionalRCS\_Payable(DI) \times RTMSuspShare(p,DI), \text{ if } RTMSuspFlag(DI)=1 \\ AdditionalRCS\_Payable(DI) \times CR\_Cost\_Share(p,DI), \text{ otherwise} \end{cases}$$

where:

(a) AdditionalRCS_Payable(DI) is the total cost of procuring the Additional RoCoF Control Requirement component of RoCoF Control Service in Dispatch Interval DI as calculated in accordance with clause 9.10.19;

(b) RTMSuspShare(p,DI) is Market Participant p's share of procuring the SESSM Awards for RoCoF Control Service in Dispatch Interval DI where AEMO has suspended the Real-Time Market under clause 7.11D.1, as calculated in accordance with clause 9.10.30A;

(c) RTMSuspFlag(DI) is the RTM Suspension Flag for Dispatch Interval DI; and

(d) ~~TotalRunwayShare(p,DI)~~ CR_Cost_Share(p,DI) is Market Participant p's share of procuring the Additional RoCoF Control Requirement component of RoCoF Control Service in Dispatch Interval DI as calculated following the steps set out in Appendix 2A and as finally calculated in ~~clause 5.3~~ clause 5.2 of Appendix 2A.

…

11. Glossary

…

CR Facility: A Facility that is a:

(a) Scheduled Facility;

(b) Semi-Scheduled Facility;

(c) Non-Scheduled Facility; or

(d) Non-Dispatchable Load containing an Intermittent Load, if the Energy Producing System supplying the Intermittent Load is not also part of a Scheduled Facility, Semi-Scheduled Facility or Non-Scheduled Facility.

…

Contingency Event: Has the meaning given in clause 3.8A.1.

…

Credible Contingency Event: Has the meaning given in clause 3.8A.2.

…

Facility Contingency: Means a Credible Contingency Event associated with the unexpected automatic or manual disconnection of, or the unplanned change in output of, one or more operating energy producing units or Facilities.

…

Facility Raise Contingency: For a CR Facility, a Credible Contingency Event resulting in a decrease in the SWIS Frequency associated with the unexpected automatic or manual disconnection of, or the unplanned change in the output of, one or more operating energy producing units within the Facility.

Facility Raise Contingency Risk: For a CR Facility in a Dispatch Interval or Pre-Dispatch Interval, the maximum estimated net MW change resulting in a decrease in SWIS Frequency due to a Facility Raise Contingency for the CR Facility, taking into account the output of the Dispatch Algorithm (and expressed as a non-negative number).

…

~~**Facility Risk**: Means, for a Facility, the sum of energy and Regulation Raise cleared from the relevant Facility in that Dispatch Interval.~~

…

Largest Credible Supply Contingency: Means the maximum possible net MW change resulting in a decrease in SWIS frequency that could occur in a Dispatch Interval or Pre-

Dispatch Interval due to a single Credible Contingency Event taking into account the output of the Dispatch Algorithm, accounting for any associated change in overall demand as a result of the same Credible Contingency Event.

~~**Largest Network Risk**: Means, for a Dispatch Interval, the maximum MW value across all Network Risks.~~

…

Network Facility Raise Risk: For a Network Raise Contingency and a CR Facility, in a Dispatch Interval or Pre-Dispatch Interval, the estimated MW contribution of the Facility to the Network Raise Risk for the Network Raise Contingency in that Dispatch Interval or Pre-Dispatch Interval (as applicable), taking into account the output of the Dispatch Algorithm.

…

Network Raise Contingency: A Credible Contingency Event resulting in a decrease in SWIS Frequency associated with the unexpected disconnection of one or more major items of Network equipment, but excludes from that meaning a Credible Contingency Event resulting in a loss of output from a Facility arising from a failure of equipment at that Facility or the loss of the network connection point associated with that Facility.

…

Network Raise Risk: For a Network Raise Contingency in a Dispatch Interval or Pre-Dispatch Interval, the estimated net MW change resulting in a decrease in SWIS Frequency due to the Network Raise Contingency, taking into account the output of the Dispatch Algorithm (and expressed as a non-negative number).

…

~~**Network Risk**: Means, for a Network Contingency in a Dispatch Interval, the sum in MW of the Facility Risks for any Registered Facilities less the forecast consumption of any relevant Loads that are connected to the part of the Network affected by that Network Contingency, and that would lose the ability to Inject or Withdraw from the Network as a result of that Network Contingency.~~

…

Single Facility Raise Risk: For a CR Facility in a Dispatch Interval or Pre-Dispatch Interval, the maximum estimated MW change resulting in a decrease in SWIS Frequency due to a Facility Raise Contingency for the CR Facility, excluding any consequential changes to the Injection or Withdrawal of other Facilities and taking into account the output of the Dispatch Algorithm (and expressed as a non-negative number).

…

__**Secondary CR Facility**: For a Facility Raise Contingency in a Dispatch Interval, a CR Facility that does not initiate the Facility Raise Contingency but whose subsequent response increases the size of the associated Facility Raise Contingency Risk.__

__**Secondary Facility Raise Risk**: For a Facility Raise Contingency in a Dispatch Interval and a Secondary CR Facility, the expected MW contribution of the Secondary CR Facility to the Facility Raise Contingency Risk.__

…

Explanatory Note:

The current cost allocation method for Contingency Reserve Raise and the Additional RoCoF Requirement component of RoCoF Control Service does not appropriately deal with the following situations:

- where a Registered Facility contains independently dispatchable energy producing units with separate network connections, so that the credible contingency risk associated with the Facility is less than its Dispatch Target/Dispatch Forecast;
- where the credible contingency risk associated with a Scheduled Facility exceeds its Dispatch Target due to an additional risk from auxiliary load at the site;
- where the sudden loss of part or all of a registered energy-producing Facility triggers the loss of output from Distributed Energy Resources in Non-Dispatchable Loads or, in rare cases, another registered energy-producing Facility, increasing the size of the Facility contingency; and
- where some or all of the Injection lost in a Network Raise Contingency comes from Distributed Energy Resources in Non-Dispatchable Loads.

Additionally:

- the quantities used in the facility runway method for Facilities with Intermittent Loads may not reflect the actual risks posed by the Facilities, leading to over or under allocation of costs to those Facilities; and
- the "network" component of the cost is allocated using a runway method, which is inappropriate because the contributors to a Network Contingency do not share the MW they contribute to the associated risk, i.e. if a Network Contingency occurs then the Injection of all the contributing Facilities will be lost, not just one of them.

Appendix 2A has been updated to address these concerns and several other minor issues.

Under the revised approach, AEMO determines a Single Facility Raise Risk for each CR Facility (which may be a Non-Dispatchable Load containing an Intermittent Load, a Scheduled Facility, a Semi-Scheduled Facility or a Non-Scheduled Facility) for each Dispatch Interval. AEMO will determine how to calculate the Single Facility Raise Risk for a CR Facility on a case-by-case basis. For Facilities that contain an Intermittent Load, AEMO must take into account the information listed in new clause 7.5.16. For other CR Facilities, the Single Facility Raise Risk will usually be equal to the Facility's Dispatch Target/Dispatch Forecast, but for some CR Facilities may be higher (e.g. to account for auxiliary loads) or lower (e.g. if the Facility contains independently dispatchable energy producing units with separate network connections). Importantly, the Single Facility Raise Risk will not include any loss of output from other Facilities that may occur in response to the failure of the CR Facility.

For the purposes of this appendix, the total cost of procuring Contingency Reserve Raise and the Additional RoCoF Requirement component of RoCoF Control Service in a Dispatch Interval is divided into two components – a "runway" component and a "non-runway" component – based on the relative sizes of the following variables:

- RunwayComponentMW(DI), which is set to the size of the largest Single Facility Raise Risk; and
- NonRunwayComponentMW(DI), which is set to the quantity by which the Largest Credible Supply Contingency exceeds the size of the largest Single Facility Raise Risk.

In section 3, CR Facilities with a Single Facility Raise Risk greater than 10 MW are assigned individual shares of the runway component using the runway method.

If the Largest Credible Supply Contingency is greater than the largest Single Facility Raise Risk (i.e. NonRunwayComponent(DI) > 0), then it must be set by one or more Credible Contingencies that are either:

- Facility Raise Contingencies for a CR Facility that involve the consequential loss of output from other Facilities (which may include CR Facilities and Non-Dispatchable Loads); or
- Network Raise Contingencies.

Section 4 identifies these contingencies and uses them to allocate shares of the non-runway component on a pro-rata basis.

For Facility Raise Contingencies, a share is allocated to each CR Facility (if any) that suffers a consequential loss of output. Any remaining share is allocated to Synergy, as the Market Participant responsible for the overwhelming majority of the Non-Dispatchable Loads that cause the additional risk. The initiating CR Facility is not allocated a share of the non-runway component because its risk contribution is already accounted for through the runway component.

For Network Raise Contingencies, a share is allocated to each CR Facility affected by the contingency in proportion to its contribution to the overall risk. Any remaining risk, which is related to the loss of Injection from Non-Dispatchable Loads, is allocated to Synergy. It should be noted that a CR Facility's MW contribution to a Network Raise Risk may be different from its Single Facility Raise Risk.

Section 5 uses the values determined in sections 3 and 4 to calculate the CR_Cost_Share(p,DI) values for each Market Participant that, in turn, are used to calculate CR_Recoverable(p,t) amounts under clause 9.10.30 and AdditionalRCS_Recoverable(p,DI) amounts under clause 9.10.43.

Appendix 2A: ~~Runway share calculation method~~ Contingency Reserve Raise and Additional RoCoF Requirement Cost Share Calculation Method

1. Interpretation ~~and calculation of a Market Participant's Total Runway Share~~

1.1 Where anything is to be determined, calculated or done in this Appendix 2A, then except where otherwise stated, AEMO will determine, calculate or do, as the case may be, those things.

1.2 AEMO must calculate a Market ~~Participant's~~ Participant p's total ~~runway~~ share of procuring Contingency Reserve Raise and the Additional RoCoF Requirement component of RoCoF Control Service in Dispatch Interval DI by following each of the steps set out in the rest of this Appendix 2A.

~~1.3 Each electricity producing unit in an Energy Producing System supplying an Intermittent Load to which clause 2.1(c) of this Appendix 2A applies is treated as a separate Facility for the purposes of this Appendix 2A.~~

1.3 In this Appendix 2A, "CR Facility Name" means:

(a) for a CR Facility that is a Scheduled Facility, Semi-Scheduled Facility or Non-Scheduled Facility, the name of the Facility recorded by AEMO in accordance with clause 2.34B.1(e); and

(b) for a CR Facility that is a Non-Dispatchable Load containing an Intermittent Load, the name of the Intermittent Load recorded by AEMO in accordance with clause 2.34B.1(f).

2. Define Facility Sets and Facility Contingencies

2.1 Determine ~~Facilities(DI)~~ CRFacilities(DI) as the set of all~~:~~ CR Facilities in Dispatch Interval DI.

~~(a) Scheduled Facilities and Semi-Scheduled Facilities that do not contain an Intermittent Load in Dispatch Interval DI;~~

~~(b) Scheduled Facilities, Semi-Scheduled Facilities, Non-Scheduled Facilities and Non-Dispatchable Loads that contain an Intermittent Load in Dispatch Interval DI, where:~~

~~i. in AEMO's reasonable opinion, the information provided under clause 2.30B.3(g) establishes that if a Contingency Event or an event behind the relevant connection point affects the Energy Producing System supplying the Intermittent Load, the net Injection or Withdrawal of the Facility will change by less than 10 MW; or~~

~~ii. the Facility Risk for the Facility in Dispatch Interval DI as published under clause 7.13.1EA(c)(i) is greater than the highest instantaneous output (in MW) of any electricity producing unit in the Energy Producing System supplying the Intermittent Load as provided under clause 2.30B.3(h); and~~

~~(c) electricity producing units in Energy Producing Systems supplying Intermittent Loads which are not part of a Facility included in Facilities(DI) under clause 2.1(b) of this Appendix 2A, and for which, in AEMO's reasonable opinion, the information provided under clause 2.30B.3(g) does not establish that if a Contingency Event or an event behind the relevant connection point affects the Energy Producing System the net Injection or Withdrawal of the Facility will change by less than 10 MW.~~

Explanatory Note
Clause 2.1A is no longer required because the MW Facility contribution to a Network Raise Risk is no longer based on its Facility Risk.

~~2.1A Determine AdditionalIMLFacilities(DI) as the set of all Scheduled Facilities, Semi-Scheduled Facilities, Non-Scheduled Facilities and Non-Dispatchable Loads that contain an Intermittent Load in Dispatch Interval DI and are not included in Facilities(DI).~~

~~2.2 For each member in Facilities(DI) or AdditionalIMLFacilities(DI), f, calculate the FacilityRisk(f,DI) to be:~~

~~(a) where f is a member of AdditionalIMLFacilities(DI) or was included in Facilities(DI) under clauses 2.1(a) or 2.1(b) of this Appendix 2A, the Facility Risk for f in Dispatch Interval DI as published under clause 7.13.1EA(c)(i); or~~

~~(b) where f was included in Facilities(DI) under clause 2.1(c) of this Appendix 2A, the MWh output or consumption of the electricity producing unit in the Dispatch Interval immediately prior to Dispatch Interval DI as published under clause 7.13.1E(a)(v), multiplied by 12 to convert to MW.~~

2.2 For each member f of CRFacilities(DI), determine SingleFacilityRisk(f,DI) as the Single Facility Raise Risk for CR Facility f in Dispatch Interval DI as published under clause 7.13.1EA(c)(i).

2.3 Determine ~~ApplicableFacilities(DI)~~ CRApplicableFacilities(DI), which comprises those members f of ~~Facilities(DI)~~ CRFacilities(DI) for which:

$$\cancel{FacilityRisk(f,DI) \geq 10MW}$$

SingleFacilityRisk(f,DI)≥10MW

~~2.4 Determine AdditionalApplicableFacilities(DI), which comprises those members f of AdditionalIMLFacilities(DI) for which:~~

$$\cancel{FacilityRisk(f,DI) \geq 10MW}$$

3. Applicable Facility Shares

Explanatory Note

The runway method assesses Single Facility Raise Risks for CR Facilities, i.e. it ignores any risks relating to secondary responses from Distributed Energy Resources in Non-Dispatchable Loads or other CR Facilities.

3.1 Rank the CR Facilities in the set CRApplicableFacilities(DI) in Dispatch Interval DI in the ascending order of the value of SingleFacilityRisk(f,DI) as determined in clause 2.2 of this Appendix 2A. If two or more CR Facilities in that set have the same SingleFacilityRisk(f,DI) value, AEMO shall rank those CR Facilities, as between each other, in ascending ~~alphabetical order of the name of the Facilities recorded by AEMO in accordance with clause 2.34B.1(f)~~ alphanumeric order of CR Facility Name. The CR Facility with the lowest SingleFacilityRisk(f,DI) value will have rank(f, DI) = 1, and the CR Facility with the highest

SingleFacilityRisk(f,DI) value will have rank(f, DI) = n, where n is the number of CR Facilities in the set CRApplicableFacilities(DI).

3.2 Calculate ~~LargestFacilityRisk(DI)~~ RunwayComponentMW(DI), which is the SingleFacilityRisk(f,DI) of the Facility which has the rank(f,DI) = n as determined in clause 3.1 of this Appendix 2A.

3.3 Determine for each ~~Registered Facility f~~ CR Facility f in CRApplicableFacilities(DI), its runway share of the ~~FacilityComponent(DI))~~ runway component of procuring Contingency Reserve Raise and the Additional RoCoF Control Requirement of RoCoF Control Service as follows:

$$\cancel{\text{FacilityRunwayShare(f,DI)} = \sum_{i=1}^{\text{Rank(f,DI)}} \frac{\text{FacilityMW(i,DI)} - \text{FacilityMW(i} - 1\text{, DI)}}{\text{FacilityMW(n,DI)} \times (n + 1 - i)}}$$

$$\text{CRFacilityRunwayShare(f,DI)} = \sum_{i=1}^{\text{rank(f,DI)}} \frac{\text{CRFacilityMW(i,DI)} - \text{CRFacilityMW(i} - 1\text{, DI)}}{\text{CRFacilityMW(n,DI)} \times (n + 1 - i)}$$

where:

(a) CRFacilityMW(i,DI) is the SingleFacilityRisk(x,DI) value of CR Facility x with rank(x,DI) = i in Dispatch Interval DI, where CRFacilityMW(0,DI)=0, and ~~x∈ApplicableFacilities(DI)~~ x∈CRApplicableFacilities(DI);

(b) ~~Rank(f,DI)~~ rank(f,DI) is the rank of CR Facility f in Dispatch Interval DI as determined in clause 3.1 of this Appendix 2A; and

(c) n is the number of CR Facilities in the set CRApplicableFacilities(DI) in Dispatch Interval DI.

~~4. Network Contingency Shares~~

~~4.1 Determine NetworkContingencies(DI), which is the set of Network Contingencies that are taken into account when setting the Contingency Reserve Raise requirement under clause 7.2.4 in Dispatch Interval DI.~~

~~4.2 For each member in NetworkContingencies(DI), nc, calculate NetworkRisk(nc,DI) in Dispatch Interval DI as follows:~~

~~(a) NetworkRisk(nc,DI) equals the Network Risk in Dispatch Interval DI as published by AEMO in clause 7.13.1EA(c)(ii)(1), if nc sets the Largest Credible Supply Contingency in Dispatch Interval DI; and~~

~~(b) NetworkRisk(nc,DI) = 0 otherwise.~~

~~4.3 Determine ApplicableNetworkContingencies(DI), which comprises those members nc of NetworkContingencies(DI) for which:~~

~~NetworkRisk(nc,DI) > 0MW~~

~~4.4 Calculate m(DI), as the number of members of ApplicableNetworkContingencies(DI).~~

~~4.5 For each member in ApplicableNetworkContingencies(DI), nc, perform the following steps:~~

~~(a) from the information published under clause 7.13.1EA(c)(ii), determine the set of Registered Facilities whose Facility Risks are included in the Network Risk associated with Network Contingency nc as CauserFacilities(nc,DI), where CauserFacilities(nc,DI) is a subset of the union of ApplicableFacilities(DI) and AdditionalApplicableFacilities(DI) as defined in clauses 2.3 and 2.4 of this Appendix 2A;~~

~~(b) rank the Registered Facilities in CauserFacilities(nc,DI) in the ascending order of the value of FacilityRisk(f,DI) as determined in clause 2.2 of this Appendix 2A. If two or more Registered Facilities in CauserFacilities(nc,DI) have the same FacilityRisk(f,DI) value in Dispatch Interval DI, AEMO shall rank those Registered Facilities, as between each other, in ascending alphabetical order of the name of the Registered Facility recorded by AEMO in accordance with clause 2.34B.1(f). The Registered Facility with the lowest FacilityRisk(f,DI) value will have rank(nc,f,DI) = 1, and the Registered Facility with the highest FacilityRisk(f,DI) value will have a rank(nc,f,DI) =~~ ~~n_{nc}, where n_{nc} is the number of Registered Facilities in the set CauserFacilities(nc,DI); and~~

~~(c) determine for each Registered Facility f, which is a member of CauserFacilities(nc,DI), its runway share of the Network Contingency component (attributable to Network Contingency nc) of procuring Contingency Reserve Raise and the Additional RoCoF Control Requirement component of RoCoF Control Service in Dispatch Interval DI as follows:~~

$$\cancel{\text{NetworkRunwayShare}(nc,f,DI) = \sum_{i=1}^{\text{Rank}(nc,f,DI)} \frac{\text{NetworkMW}(nc,i,DI) - \text{NetworkMW}(nc,i-1,DI)}{\text{NetworkMW}(nc,n_{nc},DI) \times (n_{nc}+1-i)}}$$

~~where:~~

~~i. NetworkMW(nc,i,DI) is the FacilityRisk(x,DI) value of Registered Facility x with rank(nc,x,DI) = i in Dispatch Interval DI, where NetworkMW(nc,0,DI) =0, and x∈CauserFacilities(nc,DI);~~

~~ii. Rank(nc,f,DI) is the rank of Registered Facility f∈CauserFacilities(nc,DI) as determined in clause 4.5(b) of this Appendix 2A; and~~

~~iii.~~ ~~n_{nc} is the number of Registered Facilities in the set CauserFacilities(nc,DI) as determined in clause 4.5(b) of this Appendix 2A.~~

4. Non-Runway Contingency Shares

4.1 Calculate NonRunwayComponentMW(DI) as follows:

NonRunwayComponentMW(DI) = max(0,LargestSupplyContingencyMW(DI) – RunwayComponentMW(DI))

where:

(a) LargestSupplyContingencyMW(DI) is the Largest Credible Supply Contingency in Dispatch Interval DI; and

(b) RunwayComponentMW(DI) is the quantity determined in clause 3.2 of this Appendix 2A.

Explanatory Note

If the Largest Credible Supply Contingency does not exceed RunwayComponentMW(DI) then the non-runway component will be zero and no allocation of the non-runway component to CR Facilities is required.

4.2 If NonRunwayComponentMW(DI) is equal to zero then go to clause 5.1 of this Appendix 2A.

4.3 Determine ApplicableFRContingencies(DI), which is the set of Facility Raise Contingencies which set the Largest Credible Supply Contingency in Dispatch Interval DI.

4.4 Determine ApplicableNRContingencies(DI), which is the set of Network Raise Contingencies which set the Largest Credible Supply Contingency in Dispatch Interval DI.

4.5 Calculate rm(DI) as the sum of the number of members in ApplicableFRContingencies(DI) and the number of members in ApplicableNRContingencies(DI).

4.6 For each member fc of ApplicableFRContingencies(DI), perform the following steps:

(a) from the information published under clause 7.13.1EA(c)(ii)(2), determine SecFacilities(fc,DI), which is the set of Secondary CR Facilities for Facility Raise Contingency fc in Dispatch Interval DI;

Explanatory Note

The calculation of FCTotalApplicableRisk(fc,DI) accounts for the possibility that the size of the MW risk contributions to a Facility Raise Contingency may exceed the Facility Raise Contingency Risk, due to offsetting factors (e.g. the consequential loss of a Withdrawing Facility).

(b) determine FCTotalApplicableRisk(fc,DI) as follows:

$$\text{FCTotalApplicableRisk(fc,DI)} = \max\left(\text{FRContingencyRisk(fc,DI)} - \text{MainFacilityRisk(fc,DI)}, \sum_{f \in \text{SecFacilities(fc,DI)}} \text{SecondaryRisk(f,fc,DI)}\right)$$

where:

i. FRContingencyRisk(fc,DI) is the Facility Raise Contingency Risk for Facility Raise Contingency fc in Dispatch Interval DI as published under clause 7.13.1EA(c)(ii)(1);

ii. MainFacilityRisk(fc,DI) is the Single Facility Raise Risk for the CR Facility that initiates Facility Raise Contingency fc in Dispatch Interval DI as published under clause 7.13.1EA(c)(i);

iii. SecondaryRisk(f,fc,DI) if the Secondary Facility Raise Risk for Secondary CR Facility f in Dispatch Interval DI, as published under clause 7.13.1EA(c)(ii)(2); and

iv. f∈SecFacilities(fc,DI) denotes all Secondary CR Facilities f in SecFacilities(fc, DI); and

(c) determine for each Secondary CR Facility f in SecFacilities(fc,DI), its share of the non-runway component (attributable to Facility Raise Contingency fc) of procuring Contingency Reserve Raise and the Additional RoCoF Control Requirement component of RoCoF Control Service in Dispatch Interval DI as follows:

$$\text{FCFacilityShare}(f,fc,DI) = \frac{\text{SecondaryRisk}(f,fc,DI)}{\text{FCTotalApplicableRisk}(fc,DI)} \times \frac{1}{\text{rm}(DI)}$$

where:

i. SecondaryRisk(f,fc,DI) is the Secondary Facility Raise Risk for Secondary CR Facility f in Dispatch Interval DI, as published under clause 7.13.1EA(c)(ii)(2);

ii. FCTotalApplicableRisk(fc,DI) is the quantity determined for Facility Raise Contingency fc in Dispatch Interval DI in clause 4.6(b) of this Appendix 2A; and

iii. rm(DI) is the number determined for Dispatch Interval DI in clause 4.5 of this Appendix 2A.

4.7 For each member nc of ApplicableNRContingencies(DI), nc, perform the following steps:

(a) from the information published under clause 7.13.1EA(c)(iiA)(2), determine CauserCRFacilities(nc,DI), which is the set of CR Facilities f for which:

NCFacilityRaiseRisk(f,nc,DI) > 0

where:

i. NCFacilityRaiseRisk(f,nc,DI) is the Network Facility Raise Risk for CR Facility f and Network Raise Contingency nc in Dispatch Interval DI as published under clause 7.13.1EA(c)(iiA)(2);

(b) determine NCTotalApplicableRisk(nc,DI) as follows:

NCTotalApplicableRisk(nc,DI)=

$$\max\left(NRRisk(nc,DI), \sum_{f \in CauserCRFacilities(nc,DI)} NCFacilityRaiseRisk(f,nc,DI)\right)$$

where:

i. NRRisk(nc,DI) is the Network Raise Risk for Network Raise Contingency nc in Dispatch Interval DI as published under clause 7.13.1EA(c)(iiA)(1);

ii. NCFacilityRaiseRisk(f,nc,DI) is the Network Facility Raise Risk for CR Facility f and Network Raise Contingency nc in Dispatch Interval DI as published under clause 7.13.1EA(c)(iiA)(2); and

iii. f∈CauserCRFacilities(nc,DI) denotes all CR Facilities f in CauserCRFacilities(nc,DI); and

(c) determine for each CR Facility f, which is a member of CauserCRFacilities(nc,DI), its share of the non-runway component (attributable to Network Raise Contingency nc) of procuring Contingency Reserve Raise and the Additional RoCoF Control Requirement component of RoCoF Control Service in Dispatch Interval DI as follows:

$$NCFacilityShare(f,nc,DI) = \frac{NCFacilityRaiseRisk(f,nc,DI)}{NCTotalApplicableRisk(nc,DI)} \times \frac{1}{rm(DI)}$$

where:

i. NCFacilityRaiseRisk(f,nc,DI) is the Network Facility Raise Risk for CR Facility f and Network Raise Contingency nc in Dispatch Interval DI as published under clause 7.13.1EA(c)(iiA)(2);

ii. NCTotalApplicableRisk(nc,DI) is the quantity determined for Network Raise Contingency nc in Dispatch Interval DI in clause 4.7(b) of this Appendix 2A; and

iii. rm(DI) is the number determined for Dispatch Interval DI in clause 4.5 of this Appendix 2A.

Explanatory Note

Any remaining share of the non-runway component (i.e. which has not been allocated to a CR Facility) will be related to the loss of output from Distributed Energy Resources of Non-Dispatchable Loads, and is assigned to Synergy.

4.8 Determine the cost share of procuring the non-runway component of Contingency Reserve Raise and the Additional RoCoF Control Requirement of RoCoF Control Service in Dispatch Interval DI that is allocated to Synergy's Non-Dispatchable Loads as follows:

$$NDLNonRunwayShare(DI) =$$

$$1 - \sum_{fc \in ApplicableFRContingencies(DI)} \sum_{f \in SecFacilities(fc,DI)} FCFacilityShare(f,fc,DI)$$

$$- \sum_{nc \in ApplicableNRContingencies(DI)} \sum_{f \in CauserCRFacilities(nc,DI)} NCFacilityShare(f,nc,DI)$$

where:

(a) FCFacilityShare(f,fc,DI) is CR Facility f's cost share associated with Facility Raise Contingency fc in Dispatch Interval DI as calculated in clause 4.6(c) of this Appendix 2A;

(b) fc∈ApplicableFRContingencies(DI) denotes all Facility Raise Contingencies fc in ApplicableFRContingencies(DI);

(c) f∈SecFacilities(fc,DI) denotes all CR Facilities f in SecFacilities(fc,DI);

(d) NCFacilityShare(f,nc,DI) is CR Facility f's cost share associated with Network Raise Contingency nc in Dispatch Interval DI as calculated in clause 4.7(c) of this Appendix 2A;

(e) nc∈ApplicableNRContingencies(DI) denotes all Network Raise Contingencies nc in ApplicableNRContingencies(DI); and

(f) f∈CauserCRFacilities(nc,DI) denotes all CR Facilities f in CauserCRFacilities(nc,DI).

5. Cost Shares

5.1 Calculate the cost shares associated with the ~~Network Contingency~~ non-runway and ~~Facility Contingency~~ runway components of procuring Contingency Reserve Raise and the Additional RoCoF Control Requirement of RoCoF Control Service as follows:

(a) calculate the cost share associated with the ~~Network Contingency~~ non-runway component in Dispatch Interval DI as follows:

$$\cancel{NetworkComponent(DI) = \frac{Max(0, LargestNetworkRisk(DI) - LargestFacilityRisk(DI))}{LargestNetworkRisk\ (DI)}}$$

$$NonRunwayComponent(DI) = \frac{NonRunwayComponentMW(DI)}{LargestSupplyContingencyMW(DI)}$$

where:

~~i. LargestNetworkRisk(DI) is the Largest Network Risk in Dispatch Interval DI; and~~

~~ii. LargestFacilityRisk(DI) is the largest Facility Risk in Dispatch Interval DI as calculated in clause 3.2 of this Appendix 2A; and~~

i. NonRunwayComponentMW(DI) is the quantity determined for Dispatch Interval DI in clause 4.1 of this Appendix 2A; and

ii. LargestSupplyContingencyMW(DI) is the Largest Credible Supply Contingency in Dispatch Interval DI; and

(b) calculate the cost share associated with the ~~Facility Contingency~~ runway component in Dispatch Interval DI as follows:

$$\cancel{FacilityComponent(DI)=1 - NetworkComponent(DI)}$$

RunwayComponent(DI)=1 – NonRunwayComponent(DI)

where:

i. NonRunwayComponent(DI) is the quantity determined in clause 5.1(a) of this Appendix 2A.

~~5.2 Determine for each Registered Facility f associated with each Applicable Network Contingency nc its cost share of procuring the Network Contingency component of Contingency Reserve Raise and the Additional RoCoF Control Requirement of RoCoF Control Service (attributable to Network Contingency nc) in Dispatch Interval DI as follows:~~

$$\cancel{NetworkShare(nc,f,DI) = \frac{1}{m(DI)} \times NetworkRunwayShare(nc,f,DI)}$$

~~where:~~

~~(a) m(DI) is determined in clause 4.4 of this Appendix 2A; and~~

~~(b) NetworkRunwayShare(nc, f, DI) is determined in clause 4.5(c) of this Appendix 2A.~~

~~5.3 Determine Market Participant p's total runway share of procuring Contingency Reserve Raise and the Additional RoCoF Requirement component of RoCoF Control Service in Dispatch Interval DI as follows:~~

~~TotalRunwayShare(p,DI) = FacilityComponentShare(p,DI) +~~

~~NetworkComponentShare(p,DI)~~

~~where:~~

~~(a) FacilityComponentShare(p,DI) is calculated as follows:~~

~~FacilityComponentShare(p,DI)=FacilityComponent(DI) ×~~

$$\cancel{\sum_{f \in ApplicableFacilities(p,DI)} FacilityRunwayShare(f,DI)}$$

~~where:~~

~~i. FacilityComponent(DI) is the cost share associated with the Facility Contingency component of procuring Contingency Reserve Raise and the Additional RoCoF Requirement component of RoCoF Control Service in Dispatch Interval DI calculated in clause 5.1(b) of this Appendix 2A;~~

~~ii. ApplicableFacilities(p,DI) is a subset of ApplicableFacilities(DI) defined in clause 2.3 of this Appendix 2A, which denotes Registered Facilities in ApplicableFacilities(DI) which are registered to Market Participant p and electricity producing units in ApplicableFacilities(DI) which are in Energy Producing Systems supplying Intermittent Loads for which Market Participant p is responsible; and~~

iii. ~~FacilityRunwayShare(f,DI) is Facility f's runway share of the Facility Contingency component of procuring Contingency Reserve Raise and the Additional RoCoF Control Requirement component of RoCoF Control Service in Dispatch Interval DI as calculated in clause 3.3 of this Appendix 2A; and~~

~~(b) NetworkComponentShare(p,DI) is calculated as follows:~~

$$\cancel{\text{NetworkComponentShare}(p,DI) = \text{NetworkComponent}(DI) \times \left(\text{NDLNetworkShare}(DI) + \sum_{nc \in \text{ApplicableNetworkContingencies}(DI)} \; \sum_{f \in \text{CauserFacilities}(nc,p,DI)} \text{NetworkShare}(f,nc,DI) \right)}$$

~~where:~~

i. ~~NetworkComponent(DI) is the cost share associated with the Network Contingency component of procuring Contingency Reserve Raise and the Additional RoCoF Requirement component of RoCoF Control Service in Dispatch Interval DI calculated in clause 5.1(a) of this Appendix 2A;~~

ii. ~~ApplicableNetworkContingencies(DI) is the subset of Network Contingencies determined in clause 4.3 of this Appendix 2A;~~

iii. ~~CauserFacilities(nc,p,DI) is a subset of CauserFacilities(nc,DI) identified in clause 4.5(a) of this Appendix 2A, which denotes Registered Facilities in CauserFacilities(nc,DI) registered to Market Participant p; and~~

iv. ~~NetworkShare(nc,f,DI) is Registered Facility f's cost share associated with Network Contingency nc in Dispatch Interval DI as calculated in clause 5.2 of this Appendix 2A.~~

5.2 Calculate Market Participant p's total share of the cost of procuring Contingency Reserve Raise and the Additional RoCoF Requirement component of RoCoF Control Service in Dispatch Interval DI as follows:

$$\text{CR\_Cost\_Share}(p,DI) = \begin{cases} \text{CRRunwayShare}(p,DI), & \text{if NonRunwayComponent}(DI) = 0 \\ \cancel{\text{CRRunwayShare}(p,DI) + \text{CRNonRunwayShare}(p,DI),} & \cancel{\text{otherwise}} \end{cases}$$

where:

(a) CRRunwayShare(p,DI) is calculated as follows:

$$\text{CRRunwayShare}(p,DI) = \text{RunwayComponent}(DI) \times \sum_{f \in \text{CRApplicableFacilities}(p,DI)} \text{CRFacilityRunwayShare}(f,DI)$$

where:

i. RunwayComponent(DI) is the cost share associated with the runway component of procuring Contingency Reserve Raise and the Additional RoCoF Requirement component of RoCoF Control Service in Dispatch Interval DI calculated in clause 5.1(b) of this Appendix 2A;

ii. f∈CRApplicableFacilities(p,DI) denotes each CR Facility f in CRApplicableFacilities(DI) that belongs to Market Participant p in Dispatch Interval DI; and

iii. CRFacilityRunwayShare(f,DI) is Facility f's runway share of the runway component of procuring Contingency Reserve Raise and the Additional RoCoF Control Requirement component of RoCoF Control Service in Dispatch Interval DI as calculated in clause 3.3 of this Appendix 2A;

(b) NonRunwayComponent(DI) is the cost share associated with the non-runway component of procuring Contingency Reserve Raise and the Additional RoCoF Requirement component of RoCoF Control Service in Dispatch Interval DI calculated in clause 5.1(a) of this Appendix 2A; and

(c) CRNonRunwayShare(p,DI) is calculated as follows:

$$\mathrm{CRNonRunwayShare(p,DI)} = \mathrm{NonRunwayComponent(DI)} \times \left(\mathrm{NDLPNonRunwayShare(p,DI)} + \sum_{\mathrm{fc \in ApplicableFRContingencies(DI)}} \; \sum_{\mathrm{f \in SecFacilities(p,fc,DI)}} \mathrm{FCFacilityShare(f,fc,DI)} + \sum_{\mathrm{nc \in ApplicableNRContingencies(DI)}} \; \sum_{\mathrm{f \in CauserCRFacilities(p,nc,DI)}} \mathrm{NCFacilityShare(f,nc,DI)} \right)$$

where:

i. NonRunwayComponent(DI) is the cost share associated with the non-runway component of procuring Contingency Reserve Raise and the Additional RoCoF Requirement component of RoCoF Control Service in Dispatch Interval DI calculated in clause 5.1(a) of this Appendix 2A;

ii. NDLPNonRunwayShare(p,DI) is:

1. the quantity determined for Dispatch Interval DI in clause 4.8 of this Appendix 2A, if Market Participant p is Synergy; and

2. zero, otherwise;

iii. fc∈ApplicableFRContingencies(DI) denotes all Facility Raise Contingencies fc in ApplicableFRContingencies(DI);

iv. f∈SecFacilities(p,fc,DI) denotes each CR Facility f in SecFacilities(fc,DI) that belongs to Market Participant p in Dispatch Interval DI;

v. FCFacilityShare(f,fc,DI) is CR Facility f's cost share associated with Facility Raise Contingency fc in Dispatch Interval DI as calculated in clause 4.6(c) of this Appendix 2A;

vi. nc∈ApplicableNRContingencies(DI) denotes all Network Raise Contingencies nc in ApplicableNRContingencies(DI);

vii. f∈CauserCRFacilities(p,nc,DI) denotes each CR Facility f in CauserCFFacilities(nc,DI) that belongs to Market Participant p in Dispatch Interval DI; and

viii. NCFacilityShare(f,nc,DI) is CR Facility f's cost share associated with Network Raise Contingency nc in Dispatch Interval DI as calculated in clause 4.7(c) of this Appendix 2A.

…