CONSOLIDATED DRAFT AMENDING RULES FOR WEM REFORMS "TRANCHE 1"

PLEASE NOTE

This document contains the draft Amending Rules for:

- the new framework for Essential System Service;
- the new Frequency Operating Standards;
- the new framework for Operating States and Contingency Events;
- the new framework for Scheduling and Dispatch of energy and Essential System Services, based on the fully co-optimised security constrained economic dispatch market design approved by the Taskforce;
- the Short Term Energy Market; and
- Generator Performance Standards.

Other amendments that are being progressed in other workstreams include (**Administrative Amendments**):

- Removing references to System Management (including merging relevant System Management Functions into AEMO functions in section 2.1A, and removing or modifying the System Operator framework in section 2.2). However, references to System Management in clauses proposed to be amended in these draft Amending Rules have been replaced with AEMO.
- Replacing Market Procedure and Power System Operation Procedure with WEM Procedure. However, references to these terms in clauses proposed to be amended in these draft Amending Rules have been replaced with WEM Procedure.
- Replacing Market Rules with WEM Rules. However, references to this term in clauses proposed to be amended in these draft Amending Rules have been replaced with WEM Rules.
- Replacing Market Web Site with WEM Website. However, references to this term in clauses proposed to be amended in these draft Amending Rules have been replaced with WEM Website.
- Transitional arrangements, including the various preparatory activities required to be undertaken in advance of commencement of the new frameworks contained in these draft Amending Rules. A consolidated package of draft Amending Rules setting out the transitional obligations and requirements is being progressed separately to these draft Amending Rules. However, some placeholder transitional provisions have been included to give context to certain proposed changes, and for completeness.

In many cases, these draft Amending Rules refer to “Facility” and “Registered Facility” interchangeably. The intent is for all references, unless the context otherwise requires, to be to “Registered Facility”. Accordingly, the relevant references in each clause will be further reviewed and addressed in due course.

The baseline clauses in these draft Amending Rules reflect the latest version of the WEM Rules published by the Rule Change Panel, and any changes contained in Amending Rules made by the Minister (including Amending Rules with a deferred commencement date).

Various sections in these draft Amending Rules overlap or interface with other draft Amending Rules, notably the Outage Management Framework (reporting of available capacity instead of unavailable capacity); and the new Monitoring and Compliance Framework, including specifying the compliance requirements with respect to obligations such as, for example, Real-Time Market Submissions and any proposal to require the submissions to be made in good faith, and designating obligations as civil penalty provisions. As the drafting in those other workstreams progresses, further amendments to these draft Amending Rules may be required.

Finally, there are many clauses in the WEM Rules that refer to deleted or amended clauses and definitions in these draft Amending Rules. Those consequential amendments, including where they appear in the draft Amending Rules for other workstreams, will be addressed once these draft Amending Rules have progressed further, including after initial industry consultation.

Explanatory Note

Clause 1.1.2 is a consequential amendment resulting from the new Essential System Services framework.

1.1. Authority of ~~Market~~ WEM Rules

…

1.1.2. These ~~Market~~ WEM Rules govern the market and the operation of the South West interconnected system, including the wholesale sale and purchase of electricity, Reserve Capacity, and ~~Ancillary~~ Essential System Services.

…

Explanatory Note

Gate Closure is to be 15 minutes before the start of the Trading Interval for the first 6 months of the new Real-Time Market. Thereafter, Gate Closure will be the period published by AEMO on the WEM Website, which will be zero unless there is expected to be a significant and quantifiable impact on power system security and reliability. AEMO could choose to leave the Gate Closure period at 15 minutes or reduce it to a period less than 15 minutes and as close to real-time as possible (i.e. allowing AEMO sufficient time to process Real-Time Market Submission and issue Dispatch Instructions, etc).

As mentioned in the covering note to these draft Amending Rules, transitional provisions are being collated in a separate workstream. It is expected key transitional provisions for this workstream will include:

- publication of market information such as, for example, Reference Scenarios and other information to enable Market Participants to construct their Real-Time Market Submissions; and
- lodgement of Real-Time Market Submissions.

[1.AA.] Specific Transitional Provisions – Gate Closure

[1.AA.1.] Notwithstanding clause 7.4.24, Gate Closure is 15 minutes for each Dispatch Interval in the New WEM Commencement Month and each of the subsequent five Trading Months.

[1.AA.2.] After the period referred to in clause [1.AA.1], Gate Closure is the period published by AEMO in accordance with clause 7.4.24.

Explanatory Note

Chapter 3A will apply to Western Power but there is not a need at this stage for it to apply to other network operators. The below transitional provision exempts other Network Operators from the application of Chapter 3A until such time as determined appropriate by AEMO.

The transitional rules below only concern Network Operators and WEM Procedures. Further transitional rules which concern the application of the regime to Transmission Connected Generating Systems which are currently connected to a transmission system in the SWIS will be set out at a later date.

[1.BB.] Specific Transitional Provisions – Application of Chapter 3A to Network Operators

[1.BB.1.] Notwithstanding the requirements of Chapter 3A, a Network Operator, other than Western Power, is exempt from the requirement to comply with Chapter 3A and Appendix 12 until such time as it is notified by AEMO, in writing, that it must comply with Chapter 3A and Appendix 12.

[1.BB.2.] AEMO may issue a notice to a Network Operator that it must comply with Chapter 3A and Appendix 12, where:

(a) AEMO has consulted with the Network Operator in respect of the Network Operator's ability to comply with Chapter 3A and Appendix 12; and

(b) AEMO reasonably considers that the Network Operator can comply with Chapter 3A and Appendix 12 on and from the date of the notification.

[1.BB.3.] A notice issued pursuant to clause [1.BB.2] must specify the time by which the Network Operator is required to comply with Chapter 3A and Appendix 12 which must be no less than 6 months from the date of the notice.

> **Explanatory Note**
>
> To ensure that there are WEM Procedures in place when this package of Amending Rules commences, the below transitional provision will allow Western Power and AEMO to develop initial WEM Procedures as required under the Amending Rules outside of the Procedure Change Process.
>
> GPS Commencement Date is proposed to be a defined term in Chapter 11 as it will be used for the GPS transitional regime (which is the subject of a separate workstream). It is defined as:
>
> **GPS Commencement Date:** Means the Trading Day commencing at 8.00 AM on [1 February 2021].

[1.CC.] Specific Transitional Provisions – WEM Procedures for [WEM Reforms Tranche 1]

[1.CC.1.] In this section 1.CC:

(a) [WEM Reforms Tranche 1 Amending Rules] means the Amending Rules made by the Minister pursuant to [WEM Reforms Tranche 1].

(b) [WEM Reforms Tranche 1 Commencement Date] means the Trading Day commencing at 8.00 AM on [insert].

[1.CC.2.] AEMO must, without limiting clause 1.CC.5:

(a) develop each of the procedures it is responsible for in accordance with the [WEM Reforms Tranche 1 Amending Rules] prior to the [WEM Reforms Tranche 1 Commencement Date] other than the procedures it is responsible for under Chapter 3A and section 3.8A of the [WEM Reforms Tranche 1 Amending Rules] which must be developed prior to the GPS Commencement Date; and

(b) consult with Rule Participants and other relevant stakeholders in developing the procedures it is responsible for in accordance with the [WEM Reforms Tranche 1 Amending Rules].

[1.CC.3.] Each Network Operator must, without limiting clause 1.CC.5:

(a) develop each of the procedures it is responsible for in accordance with the [WEM Reforms Tranche 1 Amending Rules] prior to the [WEM Reforms Tranche 1 Commencement Date] other than the procedures it is responsible for under Chapter 3A of the [WEM Reforms Tranche 1 Amending Rules] which must be developed prior to the GPS Commencement Date; and

(b) consult with Rule Participants and other relevant stakeholders in developing the procedures it is responsible for in accordance with the [WEM Reforms Tranche 1 Amending Rules].

[1.CC.4.] The Economic Regulation Authority:

(a) must develop each of the procedures it is responsible for in accordance with the [WEM Reforms Tranche 1 Amending Rules] prior to the [WEM Reforms Tranche 1 Commencement Date;

(b) must consult with Rule Participants and other relevant stakeholders in developing the procedures it is responsible for in accordance with the [WEM Reforms Tranche 1 Amending Rules]; and

(c) may do anything reasonably necessary or desirable to prepare for its function of monitoring compliance in accordance with its obligations in the [WEM Reforms Tranche 1 Amending Rules].

[1.CC.5.] Each WEM Procedure that is required to be developed under clauses 1.CC.2(a), 1.CC.3(a) and 1.CC.4(a):

(a) without limiting clauses 1.CC.2(b), 1.CC.3(b) and 1.CC.4(b), may, but is not required to, be developed in accordance with the Procedure Change Process; and

(b) is, from the [WEM Reforms Tranche 1 Commencement Date] or GPS Commencement Date (as relevant), deemed to be the relevant WEM Procedure required to be developed under the relevant clause in the [WEM Reforms Tranche 1 Amending Rules].

…

Explanatory Note

Section 2.1A describes AEMO's functions.

Clause 2.1A.2 is to be amended to reflect the name of the new Real-Time Market and AEMO's new functions with respect to the new Essential System Services framework and in respect of Chapter 3A and generator performance standards generally.

It is expected that section 2.1A will be further amended to reflect changes to the market design being progressed in other workstreams for example, the monitoring and compliance framework workstream, and the Administrative Amendments referred to in the opening Note to these draft

Amending Rules. This work includes merging the relevant System Management Functions described in section 2.2 into section 2.1A.

Further details regarding the obligations AEMO will be required to monitor with respect to dispatch in accordance with clause 2.1A.2(eB) will be provided with the draft Amending Rules implementing the new Monitoring and Compliance Framework for the Wholesale Electricity Market.

The proposed amendment to clause 2.1A.2(j) is to reflect the drafting style of the WEM Rules.

2.1A. Australian Energy Market Operator

2.1A.1. AEMO is conferred functions in respect of the Wholesale Electricity Market under the WEM Regulations and AEMO Regulations.

2.1A.2. The WEM Regulations also provide for the ~~Market~~ WEM Rules to confer additional functions on AEMO. The functions conferred on AEMO are:

(a) to operate the Reserve Capacity Mechanism, the Short Term Energy Market~~, the LFAS Market,~~ and the ~~Balancing~~ Real-Time Market;

(b) to settle such transactions as it is required to under these ~~Market~~ WEM Rules;

(c) to carry out a Long Term PASA study and to publish the Statement of Opportunities Report;

(d) to do anything that AEMO determines to be conducive or incidental to the performance of the functions set out in this clause 2.1A.2;

(e) to process applications for participation, and for the registration, de-registration, ~~and~~ transfer and Essential System Services accreditation of facilities;

(eA) to schedule and dispatch Essential System Services to meet the Essential System Service Standards;

(eB) to monitor Rule Participants' compliance with the WEM Rules relating to dispatch and Power System Security and Power System Reliability;

…

(j) to ~~support—~~ support:

i. the Economic Regulation Authority's monitoring of other Rule Participants' compliance with the ~~Market~~ WEM Rules;

ii. the Economic Regulation Authority's investigation of potential breaches of the ~~Market~~ WEM Rules (including by reporting potential breaches to the Economic Regulation Authority); and

iii. any enforcement action taken by the Economic Regulation Authority under the Regulations and these ~~Market~~ WEM Rules;

…

(IE) to support each Network Operator in relation to Generator Performance Standards applicable to Transmission Connected Generating Systems and perform the associated functions set out in Chapter 3A of these WEM Rules;

(lF) to advise and consult with each Network Operator in respect of AEMO's System Management Functions as contemplated under the Technical Rules applicable to the Network; and

(m) to carry out any other functions conferred, and perform any obligations imposed, on it under these ~~Market~~ WEM Rules.

Explanatory Note

Section 2.2 describes System Management's functions and contains a framework for the delegation of these functions to a System Operator.

Amendments to section 2.2 will be made in a separate workstream that has been tasked with removing the references to System Management in the WEM Rules. This work will include merging the relevant System Management Functions described in section 2.2 into section 2.1A (AEMO's functions).

As the draft Amending Rules giving effect to these changes are being progressed separately, section 2.2 does not contain any proposed modifications, including with respect to the new Essential System Services framework, but has been included in these draft Amending Rules for completeness.

2.2. System Management Functions

2.2.1. The function of ensuring that the SWIS operates in a secure and reliable manner for the purposes of regulation 13(1) of the WEM Regulations is conferred on AEMO.

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2.2.1. The function of ensuring that the SWIS operates in a secure and reliable manner for the purposes of regulation 13(1) of the WEM Regulations is conferred on AEMO.

2.2.2. The other functions of System Management in relation to the Wholesale Electricity Market are:

(a) to procure adequate Ancillary Services where Synergy cannot meet the Ancillary Service Requirements;

(b) [Blank]

(c) to develop Market Procedures relevant to System Management (including the Power System Operation Procedures), and amendments and replacements for them, where required by these Market Rules;

(d) to release information required to be released by System Management under these Market Rules;

(e) to monitor Rule Participants' compliance with Market Rules relating to dispatch and Power System Security and Power System Reliability; and

(f) to carry out any other functions or responsibilities conferred, and perform any obligations imposed, on System Management under these Market Rules.

2.2.3. System Management may—

(a) engage a person as an agent, or appoint a person as a delegate, (including, without limitation, a Network Operator) as it considers competent to exercise, on its behalf, any of or all of its System Management Functions (other than the power to do the things indicated as not able to be delegated in the Regulations) or engage a person it considers competent to provide it with services it requires to enable or assist it to perform System Management Functions (that person being a System Operator); or

(b) organise, enter into and manage any contractual arrangements with any service provider (including, without limitation, a Network Operator) as it considers competent.

A System Management Function performed by a System Operator as an agent or delegate of System Management, or a service provided by a System Operator to System Management to enable or assist it to perform a System Management Function, is deemed to be a System Management Function conferred on that System Operator under these Market Rules. A System Operator performing such a System Management Function is to be taken to do so in accordance with the terms of the delegation or engagement under which it is undertaken, unless the contrary is shown. Nothing in this clause 2.2.3 limits the ability of System Management to perform a function through an officer, employee or agent.

2.2.4. System Management must publish on the Market Web Site information as to—

(a) the engagement or appointment of any System Operator;

(b) the identity of that System Operator or service provider; and

(c) the scope of the engagement or appointment, including without limitation, the activities in relation to which the engagement or appointment applies.

2.2.5. A Market Participant must ensure that, where System Management has engaged or appointed a System Operator or service provider under clause 2.2.3, any communications from the Market Participant to System Management under these Market Rules concerning the System Management Functions within the scope of the System Operator's or service provider's engagement or appointment are made through that System Operator or service provider to the extent notified to the Market Participant by System Management.

2.2.6. A System Operator must carry out the System Management Functions, and other rights and obligations, in respect of which it has been engaged or appointed by System Management in accordance with the provisions of the Market Rules, Market Procedures, and the instrument of appointment or delegation.

2.2.7. A System Operator is a "system management participant" for the purposes of section 126 of the Electricity Industry Act to the extent that it performs a System Management Function conferred on it under clause 2.2.3.

2.2.8. Notwithstanding that AEMO may have engaged or appointed a System Operator or service provider under clause 2.2.3 to carry out a System Management Function, System Management remains liable under these Market Rules for performance of that right, function or obligation.

…

Explanatory Note

Functions of Network Operators were inserted as part of the *Wholesale Electricity Market Amendment (Constraints Framework and Governance) Rules 2020*. The functions are amended to include the new functions under Chapter 3A for Network Operators.

2.2C. Network Operators

2.2C.1. The WEM Regulations provide for the ~~Market~~ WEM Rules to confer functions on registered participants of a specified class. The functions conferred on each Network Operator are to:

…

(ca) perform the functions in relation to Generator Performance Standards applicable to Transmission Connected Generating Systems that form part of the Network the Network Operator operates as set out in Chapter 3A of these WEM Rules;

…

Explanatory Note

The compliance and enforcement regime under Chapter 3A is bespoke to Chapter 3A. As such, the existing general monitoring and compliance provisions will be amended to recognise the regime under Chapter 3A.

2.13. ~~Market~~ WEM Rule Compliance Monitoring and Enforcement

…

2.13.9C. If AEMO becomes aware of an alleged breach of the ~~Market~~ WEM Rules (other than a provision of the ~~Market~~ WEM Rules referred to in clause 2.13.9) or the ~~Market~~ WEM Procedures developed by AEMO then, subject to clauses 3A.10.6, 3A.11.21(a), 3A.11.21(b), 3A.11.21(c) and 3A.12.2, it must notify the Economic Regulation Authority in accordance with the ~~Market~~ WEM Procedure specified in clause 2.15.6A developed by AEMO.

…

2.13.10 If the Economic Regulation Authority becomes aware of an alleged breach of the ~~Market~~ WEM Rules or ~~Market~~ WEM Procedures, then, subject to section 3A.12:

…

Monitoring, Enforcement and Audit

…

Explanatory Note

Section 2.16 is proposed to be amended to reflect:

- the role of the Economic Regulation Authority in monitoring the acquisition of Essential System Services, including through the Supplementary Essential System Service Mechanism in section 3.15A, and the transition from Ancillary Service Contracts to the Essential System Services Framework;
- the new Essential System Services framework (for example, Ancillary Service Declarations are not required in the new framework); and
- reflect the removal of Operating Instructions. All circumstances in which AEMO currently issues Operating Instructions will be managed by inputs into the Market Clearing Engine.

It is expected that section 2.16 will be further amended to incorporate changes to reflect the new Monitoring and Compliance Framework, and the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

2.16. Monitoring the Effectiveness of the Market

2.16.2. AEMO must develop a Market Surveillance Data Catalogue, which identifies data to be compiled concerning the market. The Market Surveillance Data Catalogue must identify the following data items:

…

(gC) [Blank]~~all Ancillary Service Declarations~~;

(gD) Offers of Frequency Co-optimised Essential System Services in the Real-Time Market;

…

(j) the frequency and nature of Dispatch Instructions~~ and Operating Instructions~~ to Market Participants;

…

(m) details of any System Restart Service Contracts~~ Ancillary Service Contracts that it enters into as System Management~~;

…

2.16.4. AEMO must undertake the following analysis of the data identified in the Market Surveillance Data Catalogue to calculate relevant summary statistics:

(a) where applicable, calculation of the means and standard deviations of values in the Market Surveillance Data Catalogue;

(b) monthly, quarterly and annual moving averages of STEM Clearing Prices, Balancing Prices and LFAS Prices;

(c) statistical analysis of the volatility of STEM Clearing Prices, Balancing Prices and LFAS Prices;

(cA) any consistent or significant variations between the Fuel Declarations~~,~~ and Availability Declarations~~, and Ancillary Service Declarations~~ for, and the actual operation of, a Market Participant facility in real-time;

…

…

2.16.9. The Economic Regulation Authority is responsible for monitoring the effectiveness of the market in meeting the Wholesale Market Objectives and must investigate any market behaviour if it considers that the behaviour has resulted in the market not functioning effectively. The Economic Regulation Authority, with the assistance of AEMO, must monitor:

(a) the criteria and processes used by AEMO for the procurement of Essential System Services through the Real-Time Market, the Supplementary Essential System Service Mechanism, and under any contracts entered into by AEMO~~Ancillary Service Contracts that System Management enters into and the criteria and process that System Management uses to procure Ancillary Services from other persons~~;

(b) inappropriate and anomalous market behaviour, including behaviour related to market power and the exploitation of shortcomings in the ~~Market~~ WEM Rules or ~~Market~~ WEM Procedures by Rule Participants including, but not limited to:

…

v. [Blank]~~Ancillary Service Declarations that may not reflect the reasonable expectation of the Ancillary Services to be provided by a Facility~~; and

…

…

2.16.12. A report referred to in clause 2.16.11 must contain but is not limited to the following:

(a) a summary of the information and data compiled by AEMO and the Economic Regulation Authority under clause 2.16.1;

(b) the Economic Regulation Authority's assessment of the effectiveness of the market, including the effectiveness of AEMO ~~(including in its capacity as System Management)~~ in carrying out its functions, with discussion of each of:

i. the Reserve Capacity Mechanism;

ii. the market for bilateral contracts for capacity and energy;

iii. the STEM;

iv. the ~~Balancing~~ Real-Time Market;

v. the dispatch process;

vi. planning processes;

vii. the administration of the market, including the Market Rule change process; and

viii. [Blank]~~Ancillary Services~~

ix. Essential System Services, including the Supplementary Essential System Service Mechanism;

(c) an assessment of any specific events, behaviour or matters that impacted on the effectiveness of the market; and

(d) any recommended measures to increase the effectiveness of the market in meeting the Wholesale Market Objectives to be considered by the Minister.

Explanatory Note

In order not to unnecessarily delay processes or introduce a decision maker other than AEMO and the relevant Network Operator in respect of Generator Performance Standards, certain parts of Chapter 3A will not be subject to the general ability to raise a dispute under the WEM Rules. These are:

- a decision to exempt generating works connected to a transmission system;
- a decision to refuse to renegotiate a Registered Generator Performance Standard;
- a decision in respect of a Rectification Plan; and
- a decision to declare a Potential Relevant Generation Modification to be a Relevant Generator Modification.

Disputes

2.18.1. The dispute process set out in clauses 2.18, 2.19 and 2.20 applies to any dispute concerning:

(a) the application or interpretation of these ~~Market~~ WEM Rules;

(b) the failure of Rule Participants to reach agreement on a matter where these ~~Market~~ WEM Rules require agreement or require the Rule Participants to negotiate in good faith with a view to reaching agreement;

(c) payment of moneys under, or the performance of any obligation under, these ~~Market~~ WEM Rules,

but does not apply to:

(d) any matter that is identified as a Reviewable Decision or is subject to Procedural Review; ~~or~~

(e) a matter that arises under a contract between Rule Participants, unless AEMO is a party to the contract and the contract provides that the dispute process applies~~.~~; or

(f) a dispute that arises in relation to:

i. a decision to exempt or not to exempt a Transmission Connected Generating System under section 3A.3;

ii. a decision by the Network Operator to refuse to renegotiate a Registered Generator Performance Standard under clause 3A.8.8;

iii. a decision in respect of a Rectification Plan under section 3A.11; or

iv. a decision to declare a Potential Relevant Generation Modification to be a Relevant Generation Modification under section 3A.13.

…

Budgets and Fees

…

Explanatory Note

Section 2.22A.1 describes the services provided by AEMO for the purposes of section 2.22A (Determination of AEMO's budget). This clause is proposed to be amended to reflect the name of the new Real-Time Market, and to describe certain AEMO functions with respect to the new Essential System Services framework.

It is expected that further changes will be made to section 2.22A to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules

Please note that clauses 2.22A.1(c) and 2.22A.1(d) incorporate amendments to the WEM Rules that will commence on 1 January 2021.

2.22A. Determination of AEMO's budget

2.22A.1. For the purposes of this section 2.22A, the services provided by AEMO are:

(a) market operation services, including AEMO's operation of the Reserve Capacity Mechanism, STEM, ~~Balancing~~ Real-Time Market and ~~LFAS Market and~~ settlement and information release functions;

(b) system planning services, including AEMO's performance of the Long Term PASA function;

(c) market administration services, including AEMO's performance of the Procedure Change Process, support for the Rule Change Panel in carrying out its functions under these ~~Market~~ WEM Rules, participation in the Market Advisory Committee and other consultation, participation in the Technical Rules Committee as required by the Access Code, provision of advice on Technical Rules Change Proposals as required by the Economic Regulation Authority under the Access Code, provision of submissions as part of the public consultation process in respect of Technical Rules Change Proposals, support for monitoring and reviews by the Economic Regulation Authority, audit, registration related functions and other functions under these ~~Market~~ WEM Rules;

(d) system management services, being AEMO's ~~(in its capacity as System Management)~~ performance of System Management Functions, including its functions in respect to the Supplementary Essential System Services Mechanism, support for each Network Operator in relation to Generator Performance Standards applicable to Transmission Connected Generating Systems and performance of the associated functions set out in Chapter 3A of these WEM Rules, to advise and consult with each Network Operator in respect of AEMO's System Management Functions as contemplated under the Technical Rules for each Network and the development and submission of Technical Rules Change Proposals relating to System Management Functions; and

(e) Constraint-related and Network congestion services, including AEMO maintaining a Congestion Information Resource.

…

Explanatory Note

Clause 2.26.3 is proposed to be amended to reflect the name of the new Real-Time Market.

2.26.3. The Economic Regulation Authority must review the methodology for setting the Benchmark Reserve Capacity Price and the Energy Price Limits not later than the fifth anniversary of the first Reserve Capacity Cycle and, subsequently, not later than the fifth anniversary of the completion of the preceding review under this clause 2.26.3. A review must examine:

…

(h) the performance of Reserve Capacity Auctions, STEM Auctions and the ~~Balancing~~ Real-Time Market in meeting the Wholesale Market Objectives; and

…

…

Explanatory Note

The *Wholesale Electricity Market Amendment (Constraints Framework and Governance) Rules 2020*, that commenced on 1 July 2020, formalised the framework for the conferral of functions on Network Operators. One of those functions is to develop WEM Procedures, and amendments to and replacements for them, as required by the WEM Rules.

Currently, AEMO is responsible for the Loss Factors WEM Procedure referred to in 2.27.17 with the assistance of Network Operators. However, as the WEM Procedure sets out how Network Operators determine Loss Factors, it is more appropriate for each Network Operator to be responsible for the WEM Procedure. Accordingly, clause 2.27.17 is proposed to be amended to make Network Operators responsible for documenting and maintaining a WEM Procedure for Loss Factors.

2.27.17. ~~AEMO must, with the assistance of Network Operators,~~ Each Network Operator must document the standards, methodologies, classification systems and procedures to be used in determining Loss Factors in a ~~Market~~ WEM Procedure.

…

Explanatory Note

Clause 2.27A.10 (which is part of the *Wholesale Electricity Market Amendment (Constraints Framework and Governance) Rules 2020* that commenced on 1 July 2020) sets out the matters to be documented by AEMO in a WEM Procedure.

Clause 2.27A.10 is proposed to be amended to make provision for AEMO to document further matters relating to Constraint Equations in the WEM Procedure referred to in clause 2.27A.10

2.27A.10. AEMO must document in a ~~Market~~ WEM Procedure:

…;

(b) the processes to be followed by AEMO and the matters it must consider in formulating and updating Constraint Equations, including:

i. the approach to be taken by AEMO in applying:

1. an Operating Margin; and

2. the principles described in clause 2.27A.9; and

ii. the conventions for assigning a unique identifier to Constraint Equations and Constraint Sets;

(c) the processes to be followed by AEMO in developing and updating the Constraints Library and notifying Market Participants of updates to the Constraints Library; ~~and~~

(cA) the processes to be followed and the methodology to be used by AEMO in determining Constraint Equation terms and coefficients for Network Constraints, including the methodology for determining whether the exclusion of a variable from a Fully Co-optimised Network Constraint Equation would have a material effect on Power System Security due to the size of its coefficient;

(cB) the processes to be followed and the methodology to be used by AEMO in selecting one or more Constraint Equations to respond to a Network Constraint, including in respect of the location of terms on each side of the Constraint Equation;

(cC) the processes and timeframes to be followed by AEMO for creating new Constraint Equations and Constraint Sets in response to a Non-Credible Contingency Event; and

(d) any other processes or procedures relating to Constraints or Network congestion that AEMO considers are reasonably required to enable it to carry out its functions under the ~~Market~~ WEM Rules.

…

Explanatory Note

Clause 2.27B.3 (which is part of the *Wholesale Electricity Market Amendment (Constraints Framework and Governance) Rules 2020* that commenced on 1 July 2020) sets out the matters to be contained the Congestion Information Resource. This clause is proposed to be amended to include a requirement for any reports prepared by AEMO in accordance with clause 7.2.9(b) – relaxation of Constraints – to be included in the Congestion Information Resource, and to refer to Dispatch Interval in subclause (b).

2.27B.3. The Congestion Information Resource must include:

(a) the Constraints Library;

(b) as soon as practicable after a ~~Trading~~ Dispatch Interval, each Constraint Equation that bound during the ~~Trading~~ Dispatch Interval;

(c) each report described in ~~clause~~ clauses 2.27B.6 and 7.2.10(b);

(d) any other information that AEMO, in its reasonable opinion, considers relevant to implement the Congestion Information Resource Objective; and

(e) any other information specified in the ~~Market~~ WEM Procedure referred to in clause 2.27B.8.

…

Explanatory Note

Clause 2.27B.6(a)(i) (which is part of the *Wholesale Electricity Market Amendment (Constraints Framework and Governance) Rules 2020* that commenced on 1 July 2020) is proposed to be amended to refer to Dispatch Interval.

2.27B.6. AEMO must prepare and publish an annual congestion report by 31 March each year. A report must contain:

(a) information on Network congestion for at least the period of 12 months commencing at the start of the Trading Day which commences on 1 October and ending at the end of the Trading Day ending on 1 October of the following calendar year immediately preceding the due date of the report specified in this clause 2.27B.6, including:

i. analysis of the Constraint Equations that bound during a ~~Trading~~ Dispatch Interval, including the duration and frequency; and

ii. assessment of the market impact of Network congestion;

...

…

Explanatory Note

Section 2.28 sets out the classes of Rule Participants and registration requirements.

Clause 2.28.1 is proposed to be amended to remove the Ancillary Services Provider class, resulting in the proposed deletion of clauses 2.28.11A and 2.28.11B. However, it is expected that further changes to section 2.28 will be made to clarify the framework in so far at it applies to persons providing Non-Co-optimised Essential System Services under contracts entered into with AEMO.

It is expected that further changes will be made to section 2.28 in the Registration and Participation workstream, and to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

2.28. Rule Participants

2.28.1. The classes of Rule Participant are:

(a) Network Operator;

(b) Market Generator;

(c) Market Customer;

~~(cA) Ancillary Service Providers;~~

(d) [Blank]~~System Management~~;

(dA) System Operator; and

(e) [Blank]

(f) AEMO.

…

~~2.28.11A. A person who intends to enter into an Ancillary Service Contract with System Management and who is not registered in any other Rule Participant Class must register as an Ancillary Service Provider;~~

~~2.28.11B. A person who is registered in a Rule Participant Class other than the Ancillary Service Provider class, or who does not intend to enter into an Ancillary Service Contract with System Management may not register as an Ancillary Service Provider.~~

…

Explanatory Note

Clause 2.30.5 is a consequential amendment as a result of the new Essential System Services framework, which does not use the term 'Ancillary Service Contract'. However, depending on the framework that will apply to persons providing Non-Co-optimised Essential System Services under contracts entered into with AEMO, further changes to clause 2.30.5 may be required.

2.30. Facility Aggregation

…

2.30.5. AEMO must only allow the aggregation of facilities if, in its opinion:

…

(c) none of the Facilities within the aggregated Facility are subject to ~~an Ancillary Service Contract or~~ a Network Control Service Contract that requires that Facility not be part of an aggregated Facility;

…

…

Explanatory Note

Section 2.30A deals with exemptions from the requirement to fund Spinning Reserve Costs.

Existing exemptions for Intermittent Generators and Non-Scheduled Generators are to be removed, and those facilities will be required to contribute to the costs of Essential System Services in the new framework. Distributed Energy Resources may be exempt from funding these costs, but that policy decision has not yet been made.

This section has been struck through as a placeholder only. Amendments to this section (and Appendix 2 – Spinning Reserve Cost Allocation) will be made in the Settlement workstream. Amendments will also be made to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

2.30A. Exemption from Funding ~~Spinning Reserve~~ Essential System Service Costs

~~2.30A.1. When registering an Intermittent Generator as a Non-Scheduled Generator, a Rule Participant, or an applicant for rule participation, may apply to AEMO for that Intermittent Generator to be exempted from funding Spinning Reserve cost.~~

~~2.30A.2 Where an application is received in accordance with clause 2.30A.1, AEMO must exempt the Intermittent Generator from funding Spinning Reserve costs where the applicant demonstrates to the satisfaction of AEMO that the shut down of the facility is a gradual process not exceeding a maximum ramp down rate (MW/minute) equal to the Facility's installed MW capacity divided by 15.~~

~~2.30A.3 [Blank]~~

~~2.30A.4 If AEMO approves the application for exempting an Intermittent Generator from funding Spinning Reserve costs then that facility must be excluded from the set of applicable facilities described in Appendix 2.~~

~~2.30A.5 Where AEMO considers that a change in the nature of an Intermittent Generator means that it should no longer be exempted from funding Spinning Reserve costs, it must:~~

~~(a) inform the relevant Market Participant of the first Trading Month from which the facility will cease to be exempted; and~~

~~(b) include that facility in the list of applicable facilities described in Appendix 2 from the commencement of that Trading Month.~~

~~2.30A.6. AEMO must document the Spinning Reserve costs exemption process in a Market Procedure.~~

…

Explanatory Note

Section 2.34 sets out the obligations and associated processes with respect to Standing Data.

Clause 2.34.7A is proposed to be deleted as accreditation of Facilities for providing Frequency Co-optimised Essential System Services (**FCESS**) is dealt with in new section 2.34A.

Clauses 2.34.7B and 2.34.7C are proposed to be deleted as a consequence of clause 2.34.7A being deleted.

2.34. Standing Data

…

~~2.34.7A. AEMO must—~~

~~(a) consider whether it is satisfied that a proposed change in LFAS Standing Data meets the LFAS Facility Requirements within ten Business Days; and~~

~~(b) [Blank]~~

~~(c) where AEMO rejects the proposed change, advise the Market Participant of the rejection.~~

~~2.34.7B. [Blank]~~

~~2.34.7C. [Blank]~~

…

Explanatory Note New proposed section 2.34A sets out the regime for accreditation of facilities for providing FCESS. Transitional rules and procedures are separately under development to give effect to the Taskforce decision that all Registered Facilities which are participating in Ancillary Services provision in the 2020 Capacity Year must be accredited to provide the equivalent FCESS from new WEM commencement in October 2022. The transitional arrangements will also provide information to industry on how the Essential System Service accreditation will be implemented, allowing other interested Market Participants to accredit their Registered Facilities in accordance with the relevant rules well-ahead of new WEM commencement. Facilities providing Non-Co-optimised Essential System Services will not be required to be accredited in accordance with the regime set out in section 2.34A. However, it is expected that those Facilities will need to meet certain requirements that will be reflected in draft Amending Rules when the framework for all Non-Co-optimised Essential System Services is finalised.

2.34A. Essential System Service Accreditation

2.34A.1. AEMO may accredit a Facility to provide one or more of the following Frequency Co-optimised Essential System Services:

(a) Regulation Raise;

(b) Regulation Lower;

(c) Contingency Reserve Raise;

(d) Contingency Reserve Lower; and

(e) RoCoF Control Service.

2.34A.2. A Market Participant may apply to AEMO for accreditation of a Facility to provide one or more Frequency Co-optimised Essential System Services referred to in clause 2.34A.1.

2.34A.3. Unless the relevant information is included as part of Standing Data, an application for accreditation of a Facility made pursuant to clause 2.34A.2 to provide one or more Frequency Co-optimised Essential System Services referred to in clause 2.34A.1 must include:

(a) the identity of the Facility;

(b) the maximum quantity of each applicable Frequency Co-optimised Essential System Service that the Facility intends to provide and where that value would differ under different Facility operating configurations;

(c) the Standing Enablement Minimum and Standing Enablement Maximum for the Facility for each applicable Frequency Co-optimised Essential System Service and where those values would differ under different Facility operating configurations;

(d) the Standing Low Breakpoint and Standing High Breakpoint for the Facility for each applicable Frequency Co-optimised Essential System Service and where those values would differ under different Facility operating configurations;

(e) for a Facility that is an Interruptible Load, the Restoration Profile of the Interruptible Load if applicable;

(f) for an application to provide a Contingency Reserve Raise, whether the Facility will provide a Contingency Reserve Raise response in a block or continuous manner if applicable; and

(g) any other information that may be specified in the WEM Procedure referred to in clause 2.34A.13.

2.34A.4. AEMO must approve or reject an application for accreditation of a Facility made pursuant to clause 2.34A.2 in accordance with the WEM Procedure referred to in clause 2.34A.13, within 20 Business Days of the later of:

(a) receipt of the application under clause 2.34A.2; and

(b) receipt of all information required to be provided under clauses 2.34A.3 and as may be specified in the WEM Procedure referred to in clause 2.34A.13, including the results of any required Facility tests and re-tests.

2.34A.5. If AEMO rejects an application for accreditation of a Facility made pursuant to clause 2.34A.2, AEMO must provide reasons for the rejection to the Market Participant.

2.34A.6. If AEMO approves an application for accreditation of a Facility made pursuant to clause 2.34A.2, the Market Participant must include the following information in its Standing Data for the Facility in respect of each Frequency Co-optimised Essential System Service referred to in clause 2.34A.1 that the Facility is accredited to provide:

(a) the Standing Enablement Minimum and Standing Enablement Maximum for each relevant Facility operating configuration;

(b) the Standing Low Breakpoint and Standing High Breakpoint for each relevant Facility operating configuration;

(c) where the Facility is accredited to provide Contingency Reserve:

i. the Speed Factor (which must be based on the Facility's actual or modelled response to a local frequency excursion determined in accordance with the WEM Procedure referred to in clause 2.34A.13); and

ii. whether the Facility is subject to the Maximum Contingency Reserve Block Size; and

(d) where the Facility is accredited to provide Regulation or RoCoF Control Service, the Performance Factor for each of these Essential System Services, which is 1.

2.34A.7. If requested by AEMO, a Market Participant must promptly provide AEMO with any information to clarify or support the information referred to in clause 2.34A.6.

> **Explanatory Note**
>
> Where a Market Participant requests AEMO to amend the Frequency Co-optimised Essential System Service Accreditation Parameters, AEMO may require the Facility to undergo a test that may, potentially, result in a reduction to the Facility's accredited quantity of relevant FCESS. AEMO would conduct the re-assessment taking into account the effect of any outages.
>
> Clause 2.34A.8 is intended to be a civil penalty provision.

2.34A.8. Where, in the Market Participant's reasonable opinion, the performance of the Facility is varying significantly, or is likely to vary significantly, from Frequency Co-optimised Essential System Service Accreditation Parameters for the Facility in the future, the Market Participant must provide the information in respect of those matters to AEMO as soon as possible and request AEMO to amend the Frequency Co-optimised Essential System Service Accreditation Parameters for the Facility to reflect the actual or likely varied performance.

> **Explanatory Note**
>
> AEMO is unlikely to decline a request to change the Frequency Co-optimised Essential System Service Accreditation Parameters. However, AEMO may require the Facility to undergo further testing to verify whether the Facility is able to perform in accordance with the reduced Frequency Co-optimised Essential System Service Accreditation Parameters.

2.34A.9. Clause 2.34A.8 does not apply to the extent that the performance of the Facility is impacted by an approved Outage.

2.34A.10. Where a request to amend the Frequency Co-optimised Essential System Service Accreditation Parameters for a Facility pursuant to clause 2.34A.8:

(a) is made at least 12 months after AEMO's most recent assessment of the Frequency Co-optimised Essential System Service Accreditation Parameters for the Facility, AEMO must consider the information and assess whether the Frequency Co-optimised Essential System Service Accreditation Parameters should be amended; or

(b) is made less than 12 months after AEMO's most recent assessment of the Frequency Co-optimised Essential System Service Accreditation Parameters for the Facility, AEMO may decline the request or may consider the information and assess whether the Frequency Co-optimised Essential System Service Accreditation Parameters should be amended.

2.34A.11. If AEMO becomes aware 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, AEMO may 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.

2.34A.12. Where AEMO amends the Frequency Co-optimised Essential System Service Accreditation Parameters pursuant to clause 2.34A.11, the Market Participant must, within 5 Business Days of receiving notification from AEMO in accordance with clause 2.34A.11, update its Standing Data for the Facility to reflect the amended Frequency Co-optimised Essential System Service Accreditation Parameters.

2.34A.13. AEMO must document in a WEM Procedure the processes to be followed by AEMO and Market Participants in respect of the accreditation of a Facility to provide a Frequency Co-optimised Essential System Service. The WEM Procedure must include:

(a) the format of information which Market Participants must submit;

(b) the performance parameters and requirements which must be satisfied in order for a Facility to be accredited to provide a particular Frequency Co-optimised Essential System Service (for example, minimum quantity, maximum response time, control facilities, measurement facilities);

(c) the manner and form of control system or communication arrangements required for the provision, and monitoring, of the Frequency Co-optimised Essential System Service;

(d) the format and nature of data to be provided as evidence of performance after each Contingency Event;

(e) how AEMO will monitor and verify Facility performance against the Frequency Co-optimised Essential System Service Accreditation Parameters for the Facility including modelling and testing requirements;

(f) how AEMO will determine a Speed Factor for the Facility (so that it is possible for a Market Participant to estimate the Speed Factor likely to be applied to its Facility);

(g) the process for a Market Participant to seek to amend the Frequency Co-optimised Essential System Service Accreditation Parameters for a Facility;

(h) the process AEMO will follow in considering whether to amend the Frequency Co-optimised Essential System Service Accreditation

Parameters for a Facility, including examples of changes to Facility performance that would lead to an adjustment of the Frequency Co-optimised Essential System Service Accreditation Parameters;

(i) the processes to be followed by AEMO and Market Participants for any tests and re-tests of a Facility for the accreditation of a Facility to provide a Frequency Co-optimised Essential System Service;

(j) timeframes for notification requirements and provision of information; and

(k) any other processes or requirements relating to the accreditation of a Facility to provide a Frequency Co-optimised Essential System Service that AEMO considers are reasonably required to enable it to perform its functions under this section 2.34A.

…

Explanatory Note

Clause 2.35.4 is proposed to be amended to require AEMO to document the backup processes to be followed where the primary communication and control system requirements are not available.

2.35. Dispatch Systems Requirements

…

2.35.4. AEMO~~System Management~~ must document the communications and control system requirements, including backup communication and control requirements where the primary methods are unavailable, necessary to support the dispatch process described in these ~~Market~~ WEM Rules in a ~~Power System Operation~~ WEM Procedure, including for issuing Dispatch Instructions.

Explanatory Note

Clause 2.36.1 is proposed to be amended to replace the specific list of calculations with more generic wording that will capture all calculations performed by AEMO via software systems.

This will ensure AEMO applies software management processes for all market systems which perform calculations that affect market outcomes.

2.36. Market Systems Requirements

2.36.1. Where AEMO uses software systems to ~~determine Balancing Prices, to determine Non-Balancing Facility Dispatch Instruction Payments, to determine LFAS Prices, in the Reserve Capacity Auction, in the STEM Auction or for settlement processes~~ calculate prices, quantities and amounts, it must:

(a) maintain a record of which version of software was used in producing each set of results, and maintain records of the details of the differences between each version and the reasons for the changes between versions;

(b) maintain each version of the software in a state where results produced with that version can be reproduced for a period of at least one year from the release date of the last results produced with that version;

(c) ensure that appropriate testing of new software versions is conducted;

(d) ensure that any versions of the software used by AEMO have been certified as being in compliance with the ~~Market~~ WEM Rules by an independent auditor; and

(e) require vendors of software audited in accordance with clause 2.36.1(d) to make available to Rule Participants explicit documentation of the functionality of the software adequate for the purpose of audit.

…

Explanatory Note

The proposed amendments to section 2.36A allow AEMO to require provision of SCADA data from Rule Participants, including high-speed data recorder readings provided by Network Operators for investigations and incident response, and to oblige Network Operators to install this measuring equipment for new facilities. Further amendments to this section may be required pending further discussion on aspects such as ownership of equipment and responsibility for the accuracy of data and measuring equipment.

2.36A. ~~Network Systems and SCADA~~Communication and Measuring Equipment

2.36A.1. ~~System Management~~AEMO must develop a ~~Market~~ WEM Procedure prescribing the reasonable arrangement by which ~~Network Operators~~ Rule Participants and AEMO must, subject to clause 2.36A.2, provide each other with information under these ~~Market~~ WEM Rules, including:

(a) the format, form and manner in which that information must be provided; and

(b) where the ~~Market~~ WEM Rules do not provide a timeframe for the provision of the information, the time by which such information must be provided.

2.36A.2. Where the ~~Market~~ WEM Procedure specified in clause 2.36A.1 is inadequate to enable either ~~System Management~~ AEMO or a ~~Network Operator~~ Rule Participant to comply with an obligation to provide information to the other under these ~~Market~~ WEM Rules, and such information is required in a timely manner for the efficient performance of ~~System Management's~~ AEMO's functions, then the following process applies until such time as the ~~Market~~ WEM Procedure is amended to correct the inadequacy:

(a) a senior manager from each of ~~System Management~~ AEMO and the ~~Network Operator~~ Rule Participant must meet as soon as possible after the inadequacy in the ~~Market~~ WEM Procedure is identified and seek to agree an amendment to the ~~Market~~ WEM Procedure that addresses the inadequacy and which is consistent with these ~~Market~~ WEM Rules;

(b) if agreement is reached under clause 2.36A.2(a) within five Business Days of the first meeting, then ~~System Management~~ AEMO must seek to develop a Procedure Change Proposal accordingly and, in the interim, act in accordance with that agreement;

(c) if no agreement is reached under clause 2.36A.2(a), then ~~System Management~~ AEMO and the ~~Network Operator~~ Rule Participant must meet as soon as possible and seek to agree an amendment to the ~~Market~~ WEM Procedure that addresses the inadequacy and which is consistent with these ~~Market~~ WEM Rules, and develop a Procedure Change Proposal accordingly;

(d) if agreement is reached under clause 2.36A.2(c) within five Business Days of the first meeting, then ~~System Management~~ AEMO and the ~~Network Operator~~ Rule Participant must seek to develop a Procedure Change Proposal accordingly and, in the interim, act in accordance with that agreement; and

(e) if no agreement is reached under clause 2.36A.2(c) within five Business Days of the first meeting, then ~~System Management~~ AEMO, acting reasonably, must, as soon as practicable, develop and draft a Procedure Change Proposal seeking an amendment to the ~~Market~~ WEM Procedure that addresses the inadequacy and which is consistent with these ~~Market~~ WEM Rules.

2.36A.3. ~~Where reasonably necessary for System Management to discharge its System Management Functions, System Management may direct a Network Operator to—~~ AEMO may direct a Rule Participant to, in accordance with the WEM Procedure referred to in clause 2.36A.5:

(a) install communications or control systems (including to provide access to the Network Operator's SCADA system) which, in ~~System Management's~~ AEMO's reasonable opinion, is adequate to enable it to remotely monitor the performance of ~~a Network~~ the SWIS (including its dynamic performance); ~~and~~

(b) upgrade, modify or replace any communications or control systems already installed in a Facility providing the existing communications or control systems are, in the reasonable opinion of ~~System Management~~ AEMO, no longer fit for the intended purpose~~.~~; and

(c) install measurement equipment for a new Facility which, in AEMO's reasonable opinion, will enable AEMO to perform or better perform its functions under these WEM Rules.

2.36A.4. If ~~System Management~~ AEMO issues a direction under clause ~~2.36A.3—~~ 2.36A.3,

~~(a)~~ the Rule Participant ~~Network Operator~~ must comply with the direction within the period reasonably specified by ~~System Management~~ AEMO.~~; and~~

~~(b) the Network Operator is deemed to be a System Operator to the extent that it complies with a direction in good faith.~~

2.36A.5. ~~System Management~~AEMO must document in a ~~Power System Operation~~ WEM Procedure the communications and control system requirements necessary to enable it to remotely monitor the performance of ~~a Network described in these Market Rules~~ the SWIS as required under clause 2.36A.3.

2.36A.6. Rule Participants must operate and maintain equipment in order to meet and comply with the requirements specified in the WEM Procedure referred to in clause 2.36A.5.

…

Explanatory Note

The proposed amendments to clause 2.37.5 are consequential changes resulting from the new framework for Essential System Services. No changes are expected to be made to the calculation of a Market Participant's Credit Limit.

2.37. Credit Limit

…

2.37.5. When determining a Market Participant's Credit Limit AEMO must take into account:

…

(e) the Market Participant's historical level of ~~Balancing~~ Real-Time Market Settlement payments under clause 9.8.1, or an estimate of the Market Participant's future level of ~~Balancing~~ Real-Time Market Settlement payments based on its expected transactions in the ~~Balancing~~ Real-Time Market where no historical ~~Balancing~~ Real-Time Market Settlement payment data is available;

(f) the Market Participant's historical level of ~~Ancillary~~ Essential System Service settlement payments under clause 9.9.1, or an estimate of the Market Participant's future level of ~~Ancillary~~ Essential System Service settlement payments based on its expected ~~Ancillary~~ Essential System Service provision where no historical ~~Ancillary~~ Essential System Service settlement payment data is available;

…

…

3 Power System Security and Reliability

Security and Reliability

Explanatory Note

The proposed amendments to section 3.1 recognise that the SWIS frequency operating standards are being moved from the Technical Rules to the WEM Rules.

3.1. SWIS Operating Standards

3.1.1. The frequency and time error standards for the SWIS ~~a Network in the SWIS~~ are as defined in Chapter 3B and ~~the Technical Rules that apply to that Network~~ Appendix 13.

3.1.2. The voltage standards for a Network in the SWIS are as defined in the Technical Rules that apply to that Network.

> **Explanatory Note**
>
> Security Limits are now addressed as part of the Constraints framework.

3.2. Technical Envelope, Security and Equipment Limits

3.2.1. An Equipment Limit means any limit on the operation of a Facility's equipment that is provided as Standing Data for the Facility, or otherwise provided to AEMO by a Rule Participant for its Facility's equipment.

3.2.2. ~~System Management~~AEMO must record Equipment Limit information in accordance with the ~~Power System Operation~~ WEM Procedure specified in clause 3.2.7.

3.2.3. [Blank]~~A Security Limit means any technical limit on the operation of the SWIS as a whole, or on a region of the SWIS, necessary to maintain Power System Security, including both static and dynamic limits, and including limits to allow for and to manage contingencies~~.

3.2.4. [Blank]~~Network Operators, in consultation with System Management, must determine any Security Limit in accordance with the Power System Operation Procedure specified in clause 3.2.7, and System Management must record Security Limit information in accordance with that Power System Operation Procedure.~~

> **Explanatory Note**
>
> The definition of 'Technical Envelope' is proposed to be amended to include all the components necessary to practically assess power system security and reliability. The concept of Equipment Limits is expanded to cover normal operating limits, variations in operating limits made through facility offers and overload limits. The intent is that AEMO must respect the relevant limits when maintaining power system security and reliability.

3.2.5. The Technical Envelope represents the limits within which the SWIS can be operated in each SWIS Operating State. In establishing and modifying the Technical Envelope under clause 3.2.6, ~~System Management~~ AEMO must:

(a) respect the relevant Equipment Limits;

(b) [Blank]~~respect all Security Limits;~~

(c) respect all SWIS Operating Standards;

(d) respect all ~~Ancillary~~ Essential System Service ~~standards~~ Standards; ~~and~~

(e) take into account those parts of the SWIS which are not designed to be operated to the planning criteria in the relevant Technical Rules~~.~~;

(f) respect any applicable Inertia Requirements;

(g) respect any applicable System Strength Requirements; and

(h) take into account all other matters AEMO considers relevant to assessing Power System Security and Power System Reliability.

3.2.6. ~~System Management~~AEMO must establish and modify the Technical Envelope in accordance with clause 3.2.5 and the ~~Power System Operation~~ WEM Procedure specified in clause 3.2.7.

3.2.7. ~~System Management~~AEMO must develop a ~~Power System Operation~~ WEM Procedure documenting:

(a) the process to be followed by ~~System Management~~ Rule Participants in providing Equipment Limit information to AEMO;

(b) [Blank]~~the process to be followed by Network Operators and System Management in determining the Security Limits and maintaining Security Limit information~~;

(c) the process to be followed by ~~System Management~~ AEMO in establishing and modifying the Technical Envelope, including how AEMO will utilise Equipment Limit information;

(d) the processes to be followed by ~~System Management~~ AEMO to enable it to ensure the SWIS operates according to the Technical Envelope applicable to each SWIS Operating State;

(e) the process to be followed by AEMO to determine Inertia Requirements; and

(f) the process to be followed by AEMO to assess and maintain System Strength.

3.2.8. ~~System Management~~AEMO must ensure the SWIS operates in accordance with the ~~Power System Operation~~ WEM Procedure specified in clause 3.2.7 and the Technical Envelope for the applicable SWIS Operating State.

Explanatory Note

The operating states of the SWIS are proposed to be amended to separate the power system reliability standards in the SWIS.

A new 'reliable operating state' is inserted as part of the new framework. New power system reliability principles are also included.

The adoption of a Reliable Operating State in the SWIS will clarify AEMO's requirements in terms of identifying and mitigating risks to power system reliability in the SWIS.

Assessment of reliability is complex because it varies over different timeframes. For this reason, the framework will be more flexible and the reliability standard implementation process, assessments and criteria which will be used to determine reliability risks, will be set out in a new WEM Procedure.

3.3. ~~Normal~~Reliable Operating State

3.3.1. The SWIS is in a Reliable Operating State when AEMO has not initiated any manual load shedding instructions, and does not reasonably expect to initiate any manual load shedding instructions, in accordance with the WEM Procedure referred to in clause 3.3.2. ~~The SWIS is in a Normal Operating State when System Management considers that all of the following circumstances apply:~~

~~(a) the voltage magnitudes at all energised busbars at every switchhouse, switchyard or substation of the SWIS are within the applicable Security Limits;~~

~~(b) the MVA flows on all Registered Facilities are within the applicable Security Limits;~~

~~(c) all other electric plant forming part of, or having or likely to have a material impact on the operation of, the SWIS is being operated within any applicable Equipment Limits and Security Limits;~~

~~(d) the configuration of the SWIS is such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment;~~

~~(e) the frequency at all energised busbars at every switchhouse, switchyard or substation of the SWIS is within the normal operating frequency band of the SWIS Operating Standards;~~

~~(f) the levels of all Ancillary Services being provided meet the Ancillary Service Requirements; and~~

~~(g) conditions on the SWIS are secure in accordance with the requirements of the Technical Envelope.~~

~~3.3.2. When the SWIS is in a Normal Operating State, System Management must:~~

~~(a) not require a Registered Facility to be operated inconsistently with:~~

~~i. the Security Standards; or~~

~~ii. its Equipment Limits but only to the extent those limits are not inconsistent with the dispatch of Balancing Facilities that, but for the Equipment Limits, would be dispatched under clause 7.6.1C, for the Normal Operating State;~~

~~(b) ensure the overload capacity of Scheduled Generators (as indicated in Standing Data) is not utilised;~~

~~(c) schedule and dispatch (or cause to be scheduled and dispatched) Ancillary Services in accordance with the Ancillary Service Requirements;~~

~~(d) subject to clause 3.19, accept applications for the scheduling of outages unless System Management considers that these would endanger Power System Security or Power System Reliability; and~~

~~(e) ensure no actions are taken that in its opinion would be reasonably likely to lead to a High Risk Operating State.~~

Explanatory Note

AEMO will be required to develop a new WEM Procedure to assess power system reliability. Until policy positions are developed on the reliability concepts for the SWIS, the reference to Long Term PASA in the WEM Procedure will largely reflect the process outlined in existing Chapter 4 of the WEM Rules.

3.3.2. AEMO must develop and maintain a WEM Procedure which:

(a) sets out how AEMO assesses reliability in relation to the following:

i. the Long Term PASA;

ii. the Medium Term PASA;

iii. the Short Term PASA;

iv. Pre-Dispatch Intervals and Dispatch Intervals; and

v. Outage assessment and approval; and

(b) describes the events that are included or not included in measuring Unserved Energy in relation to maintaining Power System Reliability and Power System Adequacy.

~~3.3.3. System Management may include in the Power System Operation Procedure specified in clause 3.2.7 guidelines describing matters it will take into account in making a determination under clause 3.3.1.~~

Explanatory Note

The WEM Rules will include 'Power System Reliability Principles'. The SWIS is considered to be operating reliably when it is operating in accordance with the Power System Reliability Principles.

3.3.3. The Power System Reliability Principles are:

(a) the SWIS should be operated such that it is in a Reliable Operating State to the extent practicable;

(b) subject to maintaining Power System Security, where the SWIS is not in a Reliable Operating State, or is not forecast to be in a Reliable Operating State, AEMO must take all reasonable actions to restore or maintain a Reliable Operating State as soon as practicable; and

(c) AEMO must assess risks to Power System Adequacy and act to minimise any risks to Power System Adequacy in accordance with the WEM Procedure referred to in clause 3.3.2.

Explanatory Note

The cascading 'Normal' and 'High Risk' operating states are proposed to be removed. Two new operating states being 'satisfactory operating state' and 'secure operating state' are to be introduced.

3.4. ~~High Risk~~ Satisfactory and Secure Operating ~~State~~ States

~~3.4.1. The SWIS is in a High Risk Operating State when System Management considers that any of the following circumstances exist, or are likely to exist within the next fifteen minutes, or are likely to exist at a time beyond the next fifteen minutes; and actions other than those allowed under the Normal Operating State must be implemented immediately by System Management so as to moderate or avoid the circumstance:~~

~~(a) there is a violation of the Spinning Reserve requirements determined in accordance with clause 3.11;~~

~~(b) insufficient Load Following range is available to meet the requirements determined in accordance with clause 3.11;~~

~~(c) there is a voltage deviation of greater than ±6% from the values determined in accordance with clause 3.1.2;~~

~~(d) there is a frequency deviation of greater than ±0.12 Hz from the values determined in accordance with clause 3.1.1 at an energised busbar at any switchyard or substation of the SWIS;~~

~~(e) a transmission line is overloaded but the overload can be managed for the timeframe during which the overload is expected to be rectified;~~

~~(f) there is a short circuit condition that could result in equipment fault levels being exceeded;~~

~~(g) there would be an overload, under-voltage situation or threat to the stability of the power system if a credible contingency occurred;~~

~~(h) System Management is aware that one or more Market Participants have been notified by fuel suppliers and/or fuel transporters that a fuel shortfall is likely in relation to one or more Registered Facilities, where such fuel shortfall will limit the availability of generation during the next 24 hours, and where this might affect Power System Security or Power System Reliability;~~

~~(i) imminent generator unavailability that would cause supply to fall below load;~~

~~(j) significant SCADA system degradation is occurring which limits System Management's ability to control the power system (including by issuing instructions to a Network Operator) or a Network Operator's ability to control the power system;~~

~~(k) there is a major bushfire or storm near, or forecast to be near, elements of the SWIS; and~~

~~(l) any other circumstance which would, in the reasonable opinion of System Management, threaten Power System Security or Power System Reliability.~~

3.4.1. The SWIS is in a Satisfactory Operating State when the SWIS is operating in accordance with all relevant Frequency Operating Standards, Equipment Limits and is Stable.

~~3.4.2. When the SWIS is in a High Risk Operating State, System Management must:~~

~~(a) not require Registered Facilities to operate inconsistently with the Security Standards or their Equipment Limits for the High Risk Operating State; and~~

~~(b) schedule and dispatch (or cause to be scheduled and dispatched) Ancillary Services appropriate for the High Risk Operating State in accordance with Ancillary Service Requirements.~~

3.4.2. The SWIS is in a Secure Operating State when the SWIS is able to return to a Satisfactory Operating State following a Credible Contingency Event in accordance with the Power System Security Principles and the requirements of the Technical Envelope.

~~3.4.3. When the SWIS is in a High Risk Operating State, System Management may:~~

~~(a) cancel or defer Planned Outages that have not yet commenced;~~

~~(b) require the return to service in accordance with the relevant Outage Contingency Plan of Network equipment undergoing Planned Outages, or take other measures contained in the relevant Outage Contingency Plan for any Registered Facility; and~~

~~(c) utilise the overload capacity of Scheduled Generators (as indicated in Standing Data).~~

Explanatory Note

There are currently no specified principles in the WEM Rules that AEMO must follow when maintaining Power System Security. The WEM Rules will be amended to include operational processes to ensure Power System Security.

The WEM Rules will include Power System Security Principles. The introduction of these principles provide a framework for AEMO to provide information to Market Participants regarding the actions it may take under different conditions, and periodically report to the Economic Regulation Authority on its ability to meet the timeframe for returning to a Secure Operating State.

The concept of 'Lack of Reserve' will be defined in the PASA workstream.

3.4.3. The Power System Security Principles are:

(a) the power system should be operated such that it is and will remain in a Secure Operating State to the extent practicable;

(b) following a Contingency Event, AEMO should take all reasonable actions to return to a Secure Operating State as soon as possible, and in any case within 30 minutes, other than during conditions of Lack of Reserve or when in an Emergency Operating State;

(c) sufficient Inertia should be available to meet applicable Inertia Requirements; and

(d) sufficient capability should be maintained at applicable locations in the SWIS to meet the applicable System Strength Requirements.

3.4.4. [Blank]~~System Management may take any other actions as it considers are required, consistent with good electricity industry practice, to ensure the SWIS returns to a Normal Operating State provided it acts with as little disruption to electricity supply and seeks to return to issuing Dispatch Instructions in the priority set out in clause 7.6.1C as soon as is reasonably practicable in the circumstances.~~

3.4.5. [Blank] ~~System Management must ensure the SWIS returns from a High Risk Operating state to a Normal Operating State as soon as practicable.~~

~~3.4.6. When the SWIS is in a High Risk Operating State, Rule Participants must:~~

~~(a) subject to clause 3.4.7, comply with directions issued by System Management in accordance with clauses 3.4.3 and 3.4.4; and~~

~~(b) otherwise, use reasonable endeavours to assist System Management to ensure the SWIS returns to a Normal Operating State.~~

3.4.6. In order to maintain Power System Security or Power System Reliability, AEMO may:

(a) reject Planned Outages that have not yet commenced;

(b) require the return to service, in accordance with the relevant Outage Contingency Plan, of Network equipment undergoing Planned Outages, or take other measures contained in the relevant Outage Contingency Plan for any Registered Facility;

(c) utilise the overload capacity of Scheduled Facilities (as indicated in Standing Data); or

(d) direct Facilities to adjust output or operate in a particular way, in accordance with the Registered Generator Performance Standards applicable to the Facility.

~~3.4.7. A Rule Participant is not required to comply with directions issued by System Management, issued in accordance with clauses 3.4.3 or 3.4.4, if such compliance would endanger the safety of any person, damage equipment, or breach any applicable law.~~

3.4.7. AEMO may take any other actions it considers are required, consistent with good electricity industry practice, in order to maintain Power System Security or Power System Reliability, while seeking to follow the principles set out in clause 7.2.5.

~~3.4.8. Where a Rule Participant cannot comply with a direction issued by System Management it must inform System Management immediately.~~

Explanatory Note
Clause 3.4.8(a) is intended to be a civil penalty provision.

3.4.8. Rule Participants must:

(a) subject to clause 3.4.9, comply with directions issued by AEMO in accordance with clause 3.4.6; and

(b) otherwise, use reasonable endeavours to assist AEMO to ensure the SWIS remains in a Satisfactory Operating State or Secure Operating State.

~~3.4.9. System Management may include in the Power System Operation Procedure specified in clause 3.2.7 guidelines describing matters it will consider in making a determination under clause 3.4.1.~~

3.4.9. A Rule Participant is not required to comply a direction issued by AEMO, in accordance with clause 3.4.6, if such compliance would endanger the safety of any person, damage equipment, or breach any applicable law.

3.4.10. Where a Rule Participant cannot comply with a direction issued by AEMO in accordance with clause 3.4.6 it must notify AEMO immediately and provide the reasons why it cannot comply with the direction which must be a reason described in clause 3.4.9.

3.4.11. AEMO must develop and maintain a WEM Procedure which sets out the method by which it assesses whether the SWIS is Stable.

Explanatory Note

The 'emergency operating state' is retained but modified to take into account the new 'Satisfactory' and 'Secure' operating states, including making the Emergency Operating State less prescriptive and including more detail in a WEM Procedure.

3.5. Emergency Operating State

~~3.5.1. The SWIS is in an Emergency Operating State when System Management considers that any of the following circumstances exist, or are likely to exist within the next 15 minutes, or are likely to exist after 15 minutes; and actions other than those allowed under the Normal Operating State or High Risk Operating State must be implemented immediately by System Management so as to moderate or avoid the circumstance:~~

~~(a) there is a frequency deviation of greater than ±0.5 Hz from the values determined in accordance with clause 3.1.1 for more than five minutes at any energised busbar at any switch-yard or substation of the SWIS;~~

~~(b) there is a voltage deviation of greater than ±10% from the values determined in accordance with clause 3.1.2 for more than five minutes;~~

~~(c) circuit currents exceed hard circuit ratings;~~

~~(d) System Management expects a significant generation shortfall;~~

~~(e) significant involuntary load interruption is occurring;~~

(eA) ~~operation under a Normal Operating State or a High Risk Operating State would pose a significant risk to the physical safety of the public or field personnel;~~

(f) ~~significant primary SCADA system failure is occurring which has forced System Management to move power system control away from its (or a relevant Network Operator's) primary control centre;~~

(g) ~~significant transmission separation is occurring, or is imminent, resulting in limited power transfer and power system instability; or~~

(h) ~~any other circumstance which would, in the reasonable opinion of System Management, significantly threaten Power System Security or Power System Reliability.~~

3.5.1. The SWIS is in an Emergency Operating State when AEMO considers that circumstances exist on the SWIS that impact the ability of AEMO to operate the power system in accordance with these WEM Rules.

3.5.1A. AEMO must develop a WEM Procedure which sets out conditions under which AEMO may declare an Emergency Operating State. To avoid doubt, the WEM Procedure referred to in this clause 3.5.1A does not limit the ability of AEMO to declare an Emergency Operating State.

3.5.2. An Emergency Operating State as defined in these ~~Market~~ WEM Rules does not necessarily correspond to a civil emergency, or emergencies as defined in legislation but may commence as a result of these.

3.5.3. ~~System Management~~AEMO must ensure that ~~no actions are taken~~ when it becomes aware of any actions by a Rule Participant that in its opinion would be reasonably likely to lead to an Emergency Operating State, AEMO takes all actions necessary and within its control to prevent the Rule Participant engaging in such actions.

3.5.4. When the SWIS is in an Emergency Operating State, ~~System Management~~ AEMO must not require Registered Facilities to operate inconsistently with ~~the Security Standards or~~ their Equipment Limits for the Emergency Operating State.

~~3.5.5. When the SWIS is in an Emergency Operating State, System Management may:~~

(a) ~~direct any Rule Participant to provide Ancillary Services, whether that Rule Participant has an Ancillary Services Contract in relation to the relevant Facility or not;~~

(b) ~~utilise the overload capacity of Scheduled Generators (as indicated by Standing Data);~~

(c) ~~cancel or defer Planned Outages, require the return to service in accordance with the relevant Outage Contingency Plan of Registered Facilities undergoing Planned Outages or take other measures contained in the relevant Outage Contingency Plans;~~

~~(d) issue directions to Rule Participants to operate their Registered Facilities in specific ways; and~~

~~(e) ensure that such other actions as it considers are required are taken, consistent with good electricity industry practice, to ensure the SWIS is restored to a Normal Operating State, or to ensure the SWIS is restored to a High Risk Operating State where a Normal Operating State is not immediately achievable.~~

3.5.5. When the SWIS is in an Emergency Operating State, AEMO may in addition to any other ability AEMO has:

(a) direct any Rule Participant to provide Essential System Services;

(b) issue directions to Rule Participants to operate Registered Facilities at a particular level or in a particular way; and

(c) take other actions as considered necessary, consistent with good electricity industry practice, in order to return the SWIS to a Satisfactory Operating State, Secure Operating State or Reliable Operating State.

3.5.6. ~~System Management~~AEMO must ensure the SWIS returns from an Emergency Operating State to a Satisfactory ~~Normal~~ Operating State as soon as ~~practicable~~ possible.

3.5.7. Subject to clause 3.5.6, while operating under an Emergency Operating State, ~~System Management~~ AEMO must attempt to ensure the SWIS operates according to the principles set out in clause 7.2.5 ~~in such a way as to, first minimise the disruption to electricity supply, and then, to seek to return to issuing Dispatch Instructions in the priority set out in clause 7.6.1C~~, to the extent that is reasonably practicable to do so in the circumstances.

3.5.8. When the SWIS is in an Emergency Operating State, Rule Participants must:

(a) subject to clause 3.5.9, comply with directions issued by ~~System Management~~ AEMO in accordance with ~~clause~~ clauses 3.4.6 and 3.5.5; and

(b) otherwise, use their best endeavours to assist ~~System Management~~ AEMO to ensure the SWIS returns to a Satisfactory ~~Normal~~ Operating State.

3.5.9. A Rule Participant is not required to comply with any directions issued by ~~System Management~~ AEMO~~, issued~~ in accordance with clause 3.5.5, if such compliance would endanger the safety of any person, damage equipment, or breach any applicable law.

3.5.10. Where a Rule Participant cannot comply with a direction issued by ~~System Management~~ AEMO in accordance with clause 3.5.5, it must notify ~~inform System Management~~AEMO immediately and provide AEMO with the reasons why it cannot comply with the direction which must be a reason described in clause 3.5.9.

3.5.11. [Blank]~~System Management may include in the Power System Operation Procedure specified in clause 3.2.7 guidelines describing matters it will consider in making determination under clause 3.5.1~~

Explanatory Note

Section 3.6 deals with Demand Control, including the planning and operation of under frequency load shedding schemes.

This section has been included as a placeholder only, and is expected to be amended separately.

3.6. Demand Control

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

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

3.6.3. [Blank]

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

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

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

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

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

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

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

3.6.6B. Network Operators must comply with any manual disconnection directions received from System Management.

Explanatory Note

Section 3.7 deals with System Restart, including determining the System Restart Standard and procurement of System Restart Service requirements.

System Restart service is an Essential System Service that allows the SWIS to be restored by black start equipped capacity – i.e. capacity that does not require energy from the Network to start – following a blackout.

This section has been included as a placeholder only, and is expected to be amended separately.

3.7. System Restart

3.7.1. System Management must make operational plans and preparations to restart the SWIS in the event of system shutdown.

3.7.2. System Management must use its reasonable endeavours to ensure the SWIS is restarted in the event of system shutdown.

3.7.3 System Management must publish guidelines for the preparation of Local Black Start Procedures and may amend the guidelines from time to time.

3.7.4 Each Scheduled Generator and Non-Scheduled Generator must develop Local Black Start Procedures in accordance with the guidelines published under clause 3.7.3.

3.7.5 Local Black Start Procedures must provide sufficient information to enable System Management to understand the likely condition and capabilities of Facilities following any major supply disruption or system shutdown such that System Management is able to make the operational plans and preparations referred to in clause 3.7.1.

3.7.6 System Management may require any Scheduled Generator or Non-Scheduled Generator to submit its Local Black Start Procedures to System Management for review and to amend its Local Black Start Procedures to take into account the results of the review.

Explanatory Note

Clause 3.8.1 is proposed to be amended to refer to the new Central Dispatch process in section 7, and for consistency with the drafting style of the WEM Rules.

It is expected that section 3.8 will be further amended to reflect changes in other workstreams, and the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

3.8. Investigating Incidents in the SWIS

3.8.1. AEMO must investigate any incidents in the operation of equipment comprising the SWIS ~~that—~~ that:

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

(b) causes significant disruption to the operation of the Central Dispatch ~~dispatch~~ process set out in ~~clauses~~ section 7.6 ~~and 7.7~~; and

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

3.8.2. Where an incident referred to in clause 3.8.1 occurs:

(a) [Blank]

(b) AEMO may require the Rule Participants involved in the incident to provide data, information or a report on the incident within a reasonable time period specified by AEMO~~.~~;

(bA) AEMO may require a Network Operator to provide data, information or a report (including, without limitation, from any measuring equipment) in respect of the incident within a reasonable time period specified by AEMO;

(c) ~~A~~a Rule Participant must comply with any request by AEMO for data, information or a report under ~~paragraph~~ clause 3.8.2(b) or clause 3.8.2(bA)~~.~~; and

(d) AEMO may conduct its own investigation of, or engage independent experts to report on, the incident.

3.8.2A. Following the investigation, AEMO must provide a report detailing its findings to 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.

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

(a) any reports provided in accordance with clause 3.8.2(d) after AEMO has removed any information that cannot be made public under these ~~Market~~ WEM Rules or which AEMO considers should not be released; and

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

3.8.4. Where AEMO considers that changes in the ~~Market~~ WEM Rules are necessary, it must draft a suitable Rule Change Proposal and submit it using the rule change process in ~~clauses~~ sections 2.5 to 2.8.

3.8.5. Where AEMO considers that changes in a ~~Market~~ WEM Procedure which these ~~Market~~ WEM Rules contemplate will be developed by AEMO are necessary, it must draft a suitable Procedure Change Proposal and progress it using the Procedure change process in ~~clause~~ section 2.10.

3.8.5A. Where AEMO has recommended any changes to the ~~Market~~ WEM Procedures which these ~~Market~~ WEM Rules contemplate will be developed by the Economic Regulation Authority, then if the Economic Regulation Authority considers they are necessary, it must draft a suitable Procedure Change Proposal and progress it using the Procedure Change Process in ~~clause~~ section 2.10.

3.8.6. ~~[Blank]~~Where AEMO has recommended any changes to the WEM Procedures which these WEM Rules contemplate will be developed by a Network Operator, then if the Network Operator considers they are necessary, it must draft a suitable Procedure Change Proposal and progress it using the Procedure Change Process in section 2.10.

Explanatory Note

This section outlines a new framework for contingency events. It introduces new definitions for a Contingency Event, Non-credible Contingency Event and Credible Contingency Event. It also introduces a mechanism for AEMO to:

- reclassify Non-credible Contingency Events to Credible Contingency Events; and
- reclassify Credible Contingency Events back to Non-credible Contingency Events when the conditions that gave rise to it are no longer relevant.

Section 3.8A is intended to commence on 1 February 2021.

The Taskforce Paper recommends the framework includes "*[a] requirement for AEMO to provide periodic performance reports to the Economic Regulation Authority (Authority) to include reclassification events.*" This will be further considered as part of the Monitoring and Compliance workstream.

3.8A. Contingency Events

3.8A.1. A Contingency Event is an event affecting the SWIS which AEMO expects would be likely to involve:

(a) the failure or removal from operational service of one or more generating units, Facilities and/or Network elements; or

(b) an unplanned change in load, Intermittent Generation [subject to Registration rules] or other elements of the SWIS not controlled by AEMO.

3.8A.2. A Credible Contingency Event means one or more Contingency Events, the occurrence of which AEMO considers in accordance with the WEM Procedure referred to in clause 3.8A.5 to be reasonably possible in the prevailing circumstances, taking into account the Technical Envelope. Without limitation, examples of Credible Contingency Events include:

(a) the unexpected automatic or manual disconnection of, or the unplanned change in output of, one or more operating energy producing units or Facilities;

(b) the unexpected disconnection of one or more major items of Network equipment; or

(c) Non-credible Contingency Events reclassified as Credible Contingency Events in accordance with the WEM Procedure referred to in clause 3.8A.5.

3.8A.3. A Non-credible Contingency Event means a Contingency Event other than a Credible Contingency Event. Without limitation, examples of Non-credible Contingency Events include simultaneous disruptive events such as:

(a) multiple Facility failures; or

(b) failure of multiple items of Network equipment.

3.8A.4. A Multiple Contingency Event means two or more of a Contingency Event or Separation Event, or a combination of both, which occur within the time it takes to Recover.

3.8A.5. AEMO must develop and maintain a WEM Procedure which sets out:

(a) the process for determination and classification of Credible Contingency Events;

(b) the Contingency Reclassification Conditions;

(c) the factors that AEMO may take into account in reclassifying a Contingency Event in accordance with this section 3.8A;

(d) the process for reclassifying a Non-credible Contingency Event as a Credible Contingency Event; and

(e) the procedures for notifying affected Rule Participants under clause 3.8A.7, including the time by which a notification must be given.

3.8A.6. AEMO must:

(a) determine a Credible Contingency Event; and

(b) reclassify a Non-credible Contingency Event as a Credible Contingency Event,

in accordance with the WEM Procedure referred to in clause 3.8A.5.

3.8A.7. Where AEMO determines a new Credible Contingency Event, or reclassifies a Non-credible Contingency Event as a Credible Contingency Event, AEMO must:

(a) publish the determination or reclassification on the WEM Website; and

(b) notify affected Rule Participants in accordance with the WEM Procedure referred to in clause 3.8A.5 of all relevant information, including but not limited to:

i. the name of the new Credible Contingency Event;

ii. a description of the new Credible Contingency Event;

iii. any relevant timeframes in respect of the new Credible Contingency Event; and

iv. if applicable, the Contingency Reclassification Conditions that gave rise to the reclassification of a Non-credible Contingency Event as a Credible Contingency Event.

3.8A.8. If any of the information provided to Rule Participants in accordance with clause 3.8A.7 changes in any material respect, AEMO must publish the changes on the WEM Website and notify the affected Rule Participants in accordance with the WEM Procedure referred to in clause 3.8A.5.

…

Explanatory Note

The proposed amendments to section 3.9 are to set out the new definitions for Essential System Services. Essential System Services encompasses all of FCESS and Non-Co-optimised Essential System Services. The definitions for, and location of, System Restart Services and Non-Co-optimised Essential System Services may be further revised as those work packages progress.

~~Ancillary~~Essential System Services

3.9. Definitions of ~~Ancillary~~ Essential System Services

~~3.9.1. Load Following Service is the service of frequently adjusting:~~

~~(a) the output of one or more Scheduled Generators; or~~

~~(b) the output of one or more Non-Scheduled Generators,~~

~~within a Trading Interval so as to match total system generation to total system load in real time in order to correct any SWIS frequency variations.~~

~~3.9.2. Spinning Reserve Service is the service of holding capacity associated with a synchronised Scheduled Generator or Interruptible Load in reserve so that the relevant Facility is able to respond appropriately in any of the following situations:~~

~~(a) to retard frequency drops following the failure of one or more generating works or transmission equipment; and~~

~~(b) in the case of Spinning Reserve Service provided by Scheduled Generators to supply electricity if the alternative is to trigger involuntary load curtailment.~~

~~3.9.3. Spinning Reserve response is measured over three time periods following a contingency event. A provider of Spinning Reserve Service must be able to ensure the relevant Facility can:~~

~~(a) respond appropriately within 6 seconds and sustain or exceed the required response for at least 60 seconds; or~~

~~(b) respond appropriately within 60 seconds and sustain or exceed the required response for at least 6 minutes; or~~

~~(c) respond appropriately within 6 minutes and sustain or exceed the required response for at least 15 minutes,~~

~~for any individual contingency event.~~

~~3.9.4. [Blank]~~

~~3.9.5. [Blank]~~

~~3.9.6. Load Rejection Reserve Service is the service of holding capacity associated with a Scheduled Generator in reserve so that the Scheduled Generator can reduce output rapidly in response to a sudden decrease in SWIS load.~~

~~3.9.7. Load Rejection Reserve response is measured over two time periods following a contingency event. A provider of Load Rejection Reserve Service must be able to ensure that the relevant Facility can:~~

~~(a) respond appropriately within 6 seconds and sustain or exceed the required response for at least 6 minutes; or~~

~~(b) respond appropriately within 60 seconds and sustain or exceed the required response for at least 60 minutes,~~

~~for any individual contingency event.~~

~~3.9.8. System Restart Service is the ability of a Registered Facility which is a generation system to start without requiring energy to be supplied from a Network to assist in the re-energisation of the SWIS in the event of system shut-down.~~

~~3.9.9. Dispatch Support Service is any other ancillary service that is needed to maintain Power System Security and Power System Reliability that are not covered by the other Ancillary Service categories. Dispatch Support Service is to include the service of controlling voltage levels in the SWIS, where that service is not already provided under any Arrangement for Access or Network Control Service Contract.~~

3.9.1. Regulation is the service, measured in MW, of frequently adjusting the Injection or Withdrawal of a Facility in accordance with an AEMO centralised control scheme in order to assist in maintaining the SWIS frequency according to the Frequency Operating Standards.

3.9.2. Regulation Raise is a Regulation service, measured in MW of response capability, that operates to raise the SWIS frequency.

3.9.3. Regulation Lower is a Regulation service, measured in MW of response capability, that operates to lower the SWIS frequency.

3.9.4. Contingency Reserve is the service, measured in MW, of holding response capability associated with a Facility in reserve so that the relevant Facility can rapidly adjust Injection or Withdrawal in order to assist in maintaining the SWIS frequency according to the Frequency Operating Standards after a Contingency Event.

3.9.5. Contingency Reserve Raise is a Contingency Reserve service, measured in MW of response capability, that enables a Facility to adjust Injection or Withdrawal to raise the SWIS frequency.

3.9.6. Contingency Reserve Lower is a Contingency Reserve service, measured in MW of response capability, that enables a Facility to adjust Injection or Withdrawal to lower the SWIS frequency.

3.9.7. Rate of Change of Frequency Control Service (“RoCoF Control Service”) is the service, measured in MWs, of providing Inertia which provides instantaneous response to slow down the rate of change of the SWIS frequency.

3.9.8. System Restart Service is the service of an energy producing system starting without requiring energy to be supplied from a Network to assist in the re-energisation of the SWIS in the event of system shutdown, or a major supply disruption.

3.9.9. Non-Co-optimised Essential System Service is an Essential System Service that is not a Frequency Co-optimised Essential System Service.

> **Explanatory Note**
>
> The proposed amendments to section 3.10 are to set out the new Essential System Services Standards. At present, this section refers only to FCESS, however, as work progresses, this section will be expanded to include Non-Co-optimised Essential System Services and the System Restart Standard.

3.10. ~~Ancillary~~Essential System Service Standards

~~3.10.1. The standard for Load Following Service is a level which is sufficient to:~~

~~(a) provide Minimum Frequency Keeping Capacity, where the Minimum Frequency Keeping Capacity is the greater of:~~

~~i. 30 MW; and~~

~~ii. the capacity sufficient to cover 99.9% of the short term fluctuations in load and output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average.~~

~~(b) [Blank]~~

~~3.10.2. The standard for Spinning Reserve Service is a level which satisfies the following principles:~~

~~(a) the level must be sufficient to cover the greater of:~~

~~i. 70% of the total output, including Parasitic Load, of the generation unit synchronised to the SWIS with the highest total output at that time; and~~

~~ii. the maximum load ramp expected over a period of 15 minutes;~~

~~(b) the level must include capacity utilised to meet the Load Following Service standard under clause 3.10.1, so that the capacity provided to meet the Load Following requirement is counted as providing part of the Spinning Reserve requirement;~~

~~(c) the level may be relaxed by up to 12% by System Management where it expects that the shortfall will be for a period of less than 30 minutes; and~~

~~(d) the level may be relaxed following activation of Spinning Reserve and may be relaxed by up to 100% if all reserves are exhausted and to maintain reserves would require involuntary load shedding. In such situations the levels must be fully restored as soon as practicable.~~

~~3.10.3. [Blank]~~

~~3.10.4. The standard for Load Rejection Reserve Service is a level which satisfies the following principles:~~

~~(a) the level sufficient to keep over-frequency below 51 Hz for all credible load rejection events;~~

~~(b) may be relaxed by up to 25% by System Management where it considers that the probability of transmission faults is low.~~

~~3.10.5. The level of Load Following Service, Spinning Reserve Service and Load Rejection Reserve Service may be reduced:~~

~~(a) following relevant contingencies; or~~

~~(b) where System Management considers the standard cannot be met without shedding load, providing that System Management considers that reducing the level is not inconsistent with maintaining Power System Security.~~

~~3.10.6. The standard for System Restart Service is a level which is sufficient to meet System Management's operational plans as developed in accordance with clause 3.7.1.~~

3.10.1. Subject to clause 3.12.2, AEMO must schedule and dispatch sufficient Regulation to ensure that the frequency in the SWIS is maintained within the Normal Operating Frequency Band and the Normal Operating Frequency Excursion Band in accordance with Chapter 3B.

3.10.2. When determining the quantity of Regulation to schedule and dispatch in accordance with clause 3.10.1, AEMO must take into account the historic and expected variability of the frequency in the SWIS.

3.10.3. Subject to clause 3.12.2, AEMO must schedule and dispatch sufficient Contingency Reserve and RoCoF Control Service to ensure that, in combination, following a Credible Contingency Event the frequency in the SWIS is maintained within:

(a) the relevant Frequency Band; and

(b) the RoCoF Safe Limit.

3.10.4. A Facility accredited to provide Contingency Reserve must be capable of responding according to its accredited capability (including Speed Factor), and sustain the required response for a period of at least 15 minutes following any Contingency Event.

3.10.5. Where a Market Participant receives a Dispatch Instruction to enable a Facility to provide a quantity of Regulation Raise or Regulation Lower in a Dispatch Interval, the Market Participant must ensure that the Facility (subject to the Facility's maximum ramp rates in relation to the provision of the relevant Essential System Service) is able to provide the full enabled MW quantity of response at any time during the Dispatch Interval, according and subject to instructions from AEMO's centralised control scheme.

> **Explanatory Note**
>
> Section 3.11 sets out the mechanism by which AEMO will determine the FCESS Requirements for the SWIS. It also sets out the circumstances which require AEMO to trigger the Supplementary Essential System Service Mechanism (**SESSM**).

3.11. Determining & Procuring ~~Ancillary~~ Frequency Co-optimised Essential System Service Requirements

~~3.11.1. System Management must determine all Ancillary Service Requirements in accordance with the SWIS Operating Standards and the Ancillary Service Standards.~~

~~3.11.2. System Management must update Ancillary Service Requirements on an annual basis. The Ancillary Service Requirements must be set based on the facilities and configuration expected for the SWIS in the coming year.~~

~~3.11.3. If it considers that a considerable shortfall of any Ancillary Service relative to the applicable Ancillary Service Standard is occurring, or is likely to occur before the next update under clause 3.11.2, System Management may reassess the level of the Ancillary Service Requirements for that Ancillary Service at that time.~~

~~3.11.4. System Management must determine the Ancillary Service Requirements in accordance with clause 3.11.1 and 3.11.5 for the:~~

~~(a) Load Following Service;~~

~~(b) Spinning Reserve Service;~~

~~(c) [Blank]~~

~~(d) Load Rejection Reserve Service;~~

~~(e) each Dispatch Support Service; and~~

~~(f) System Restart Service~~

~~3.11.5. The Ancillary Service Requirements may:~~

~~(a) be location specific;~~

~~(b) vary for different SWIS load levels or other scenarios;~~

~~(c) vary by the type of day and time of day; and~~

~~(d) vary across the year.~~

~~3.11.6. System Management must submit the Ancillary Service Requirements to the Economic Regulation Authority for approval. The Economic Regulation Authority must audit System Management's determination of the Ancillary Service Requirements and may require System Management to redetermine the Ancillary Service Requirements, in which case this clause 3.11.6 applies to any recalculated requirements.~~

Explanatory Note

Clauses 3.11.1 to 3.11.6 specify the conditions under which AEMO will trigger the Supplementary Essential System Service Mechanism due to a shortfall. Accreditation shortfalls will trigger the SESSM when the PASA indicates a shortfall but no new entry will occur. Participation shortfalls will trigger the SESSM where AEMO regularly directs Market Participants to commit Facilities to provide a FCESS.

Clauses 3.11.1 and 3.11.2 may need to be reviewed further pending the development of the PASA draft Amending Rules and the related Reliability Standard implementation procedure.

3.11.1. Where the quantities of any Frequency Co-optimised Essential System Service expected to be required in a Dispatch Interval, or the combined quantities of more than one Frequency Co-optimised Essential System Service which are to be provided by the same accredited Facility, is greater than 100% of the accredited Essential System Service capacity for that Frequency Co-optimised Essential System Service under the appropriate load forecast as determined in accordance with the WEM Procedure referred to in [PASA procedure clause], AEMO must identify:

(a) the times of the affected Dispatch Intervals; and

(b) the maximum incremental Frequency Co-optimised Essential System Service requirement for each of the affected Dispatch Intervals.

3.11.2. AEMO must identify, record and publish on the WEM Website by no later than noon on the first Business Day following the day on which the Trading Day ends:

(a) the number of Dispatch Intervals in the previous 90 days for which, four hours ahead of the relevant Dispatch Interval, AEMO has scheduled a shortfall in each Frequency Co-optimised Essential System Service, as a result of AEMO's obligations under clauses 3.12.1 and 3.12.2, in the Reference Scenario; and

(b) the number of Dispatch Intervals in the previous 90 days for which AEMO directed a Market Participant to commit a Facility to provide a Frequency Co-optimised Essential System Service due to a forecast real-time shortfall not being resolved in response to a market notice issued under [PASA 'lack of reserve' notice clause].

3.11.3. Where the number of Dispatch Intervals identified in clause 3.11.2(b) is greater than the threshold specified in the WEM Procedure referred to in clause 3.11.4 for each Dispatch Interval identified in clause 3.11.2(b), AEMO must identify and publish on the WEM Website within 15 Business Days:

(a) the times of each of the Dispatch Intervals;

(b) the total quantity of the Frequency Co-optimised Essential System Service required in each Dispatch Interval; and

(c) the difference between the Market Clearing Price for the Dispatch Interval and the Market Clearing Price which was initially calculated for the Dispatch Interval before AEMO applied the intervention pricing procedure described in the WEM Procedure referred to in clause 7.11C.11.

3.11.4. AEMO must document in a WEM Procedure the process and basis to determine the number of Dispatch Intervals in a 90 day period in which it issues directions under clause 7.7.5 that, once reached, requires AEMO to trigger the Supplementary Essential System Service Mechanism in accordance with section 3.15A.

Explanatory note

Clause 3.11.4 requires AEMO to determine a threshold number of participation shortfall intervals that would trigger the SESSM.

Clause 3.11.5 seeks to ensure that the threshold is set high enough that the benefits of avoiding the shortfall will be worth the cost of running the SESSM process, but low enough to avoid significant AEMO intervention distorting market outcomes.

While a shortfall in Essential System Service is generally undesirable, in setting a trigger threshold we seek to avoid building new capacity to avoid an infrequent or unlikely event where the cost of pre-emptive manual load shedding would be less than the cost of building the new Essential System Service capability.

3.11.5. In developing the WEM Procedure referred to in clause 3.11.4, AEMO must have regard to:

(a) the impact of the intervention on AEMO's dispatch process; and

(b) the cost of ongoing directions to Market Participants made pursuant to clause 7.7.5 (including in the form of Intervention Pricing).

3.11.6. Where:

(a) AEMO identifies a Frequency Co-optimised Essential System Service Accreditation Shortfall and, in its reasonable opinion, the Frequency Co-optimised Essential System Service Accreditation Shortfall will not be met by Market Participant activity; or

(b) the number of Dispatch Intervals in any 90 day period referred to in clause 3.11.4 is reached,

AEMO must trigger the Supplementary Essential System Service Mechanism in accordance with section 3.15A.

3.11.7. [Blank]~~System Management must make an annual Ancillary Services plan describing how it will ensure that the Ancillary Service Requirements are met.~~

3.11.7A. [Blank]~~Synergy must make its capacity to provide Ancillary Services from its Facilities available to System Management to a standard sufficient to enable System Management to meet its obligations in accordance with these Market Rules.~~

~~3.11.8. System Management may enter into an Ancillary Service Contract with a Rule Participant other than Synergy for Spinning Reserve Ancillary Services, where:~~

~~(a) it does not consider that it can meet the Ancillary Service Requirements with Synergy's Registered Facilities; or~~

~~(b) the Ancillary Service Contract provides a less expensive alternative to Ancillary Services provided by Synergy's Registered Facilities.~~

3.11.8. AEMO must document in a WEM Procedure the methodologies and processes to be followed by AEMO in determining, for each Pre-Dispatch Interval and Dispatch Interval:

(a) the quantity of Regulation to schedule and dispatch, including:

i. the identification and measurement of sources of variability; and

iii. the method by which the quantity of Regulation required is calculated;

(b) the combination of Contingency Reserve and RoCoF Control Service required to maintain the frequency of the SWIS within the Credible Contingency Event Frequency Band, including the use of Speed Factors for a Facility; and

(c) the expected quantities of any other Frequency Control Essential System Services required in each Dispatch Interval or Pre-Dispatch Interval to meet the Essential System Service Standards.

~~3.11.8A. System Management may enter into an Ancillary Service Contract with a Rule Participant for the provision of a Load Rejection Reserve Service, System Restart Service or Dispatch Support Service.~~

~~3.11.8B System Management must obtain the approval of the Economic Regulation Authority before entering into an Ancillary Service Contract for Dispatch Support Ancillary Services.~~

~~3.11.8C The Economic Regulation Authority must only review whether an Ancillary Service Contract, to which 3.11.8B applies, would achieve the lowest practicably sustainable cost of delivering the services.~~

~~3.11.8D The Economic Regulation Authority may undertake a public consultation process in determining whether to approve the Ancillary Service Contract for Dispatch Support Service. In determining whether to undertake a public consultation process, the Economic Regulation Authority must have regard to the terms of the Ancillary Service Contract, including the length of its intended operation and whether a need exists to expedite the approval process.~~

~~3.11.8E The scope of any Ancillary Services Contract entered into by System Management for the purposes of clause 3.11.8 must:~~

~~(a) not include components for the payment of energy; and~~

~~(b) only include the availability of the service based on a proportion of the values determined under clause 3.13.3.~~

~~3.11.9. Where it intends to enter into an Ancillary Service Contract, System Management must:~~

~~(a) seek to minimise the cost of meeting its obligations under clause 3.12.1; and~~

~~(b) give consideration to using a competitive tender process, unless System Management considers that this would not meet the requirements of clause 3.11.9(a).~~

~~3.11.10. Where System Management has entered into an Ancillary Service Contract, System Management must report the capacity of each Ancillary Service contracted, and the prices and terms for calling on the relevant Facility to provide that capacity to the Economic Regulation Authority.~~

~~3.11.11. By 1 June each year, System Management must submit to the Economic Regulation Authority a report containing information on:~~

~~(a) the quantities of each of the Ancillary Services provided in the preceding year, including Ancillary Services provided under Ancillary Service Contracts, and the adequacy of these quantities;~~

~~(b) the total cost of each of the categories of Ancillary Services provided, including Ancillary Services provided under Ancillary Service Contracts, in the preceding year; and~~

~~(c) the Ancillary Service Requirements for the coming year and the Ancillary Services plan to meet those requirements.~~

~~3.11.12. The Economic Regulation Authority must audit System Management's determination of the Ancillary Services plan submitted to the Economic Regulation Authority under clause 3.11.11. The Economic Regulation Authority may require System Management to amend the Ancillary Services plan and resubmit it to the Economic Regulation Authority, in which case this clause 3.11.12 applies to any amended plan.~~

~~3.11.13. By 1 July each year, System Management must publish the report prepared under clause 3.11.11 or 3.11.12 as soon as practicable.~~

~~3.11.14. System Management must document in a Power System Operation Procedure the procedure to be followed when:~~

~~(a) determining Ancillary Service Requirements; and~~

~~(b) entering into Ancillary Service Contracts, including the process for conducting competitive tender processes utilised for the awarding of Ancillary Service Contracts.~~

~~3.11.15. System Management must document in a Power System Operation Procedure the procedure to be followed where the Market Rules require Ancillary Services to be provided.~~

Explanatory Note Section 3.12 ensures that if there is insufficient capacity to dispatch energy and Essential System Service, AEMO must dispatch Facilities for energy first. In such a situation, AEMO is likely to also

consider shedding load under clause 3.6.6A. This is subject to available capacity determined in accordance with Chapter 7.

3.12. ~~Ancillary~~ Frequency Co-optimised Essential System Service Dispatch

3.12.1. ~~System Management~~AEMO must schedule and dispatch ~~facilities~~ Registered Facilities (or cause them to be scheduled and dispatched) to meet the ~~Ancillary~~ Essential System Service ~~Requirements~~ Standards in each ~~Trading~~ Dispatch Interval in accordance with Chapter 7.

3.12.2. AEMO must schedule or dispatch Registered Facilities for energy in preference to Frequency Co-optimised Essential System Service.

Explanatory Note

The proposed deletion of section 3.13 is a placeholder only. Any amendments are to be made in the Settlement workstream.

3.13. ~~Payment for Ancillary Services~~[Blank]

~~3.13.1. The total payments by AEMO for Ancillary Services in accordance with Chapter 9 comprise:~~

~~(a) [Blank]~~

~~(aA) for Load Following Service for each Trading Month:~~

~~i. a capacity payment LF_Capacity_Cost, calculated in accordance with clause 9.9.2(q) for that Trading Month; and~~

~~ii. an amount LF_Market_Cost calculated in accordance with clause 9.9.2(o) for that Trading Month;~~

~~(b) an amount SR_Availability_Cost for Spinning Reserve Service for each Trading Month, which is calculated in accordance with clause 9.9.2(m) for that Trading Month; and~~

~~(c) Cost_LRD, the monthly amount for Load Rejection Reserve Service and System Restart Service, determined in accordance with the process described in clauses 3.13.3B and 3.13.3C; and Dispatch Support Service determined in accordance with clause 3.11.8B.~~

~~3.13.1A. [Blank]~~

~~3.13.2. Market Participants pay for the use of Ancillary Services through the operation of the Ancillary Service settlement process in section 9.9.~~

~~3.13.3. The parameters Margin_Peak and Margin_Off-Peak to be used in the settlement calculation described in clause 9.9.2 are:~~

~~(a) where the Economic Regulation Authority has not completed its first assessment in accordance with clause 3.13.3A:~~

~~i. 15% for Margin_Peak; and~~

~~ii. 12% for Margin_Off-Peak; and~~

~~(b) determined by the Economic Regulation Authority, where the Economic Regulation Authority has completed its first assessment in accordance with clause 3.13.3A.~~

~~3.13.3A. For each Financial Year, by 31 March prior to the start of that Financial Year, the Economic Regulation Authority must determine values for the parameters Margin_Peak and Margin_Off-Peak, taking into account the Wholesale Market Objectives and in accordance with the following:~~

~~(a) by 30 November prior to the start of the Financial Year, AEMO must submit a proposal for the Financial Year to the Economic Regulation Authority:~~

~~i. for the reserve availability payment margin applying for Peak Trading Intervals, Margin_Peak, AEMO must take account of:~~

~~1. the margin Synergy could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve Service during Peak Trading Intervals; and~~

~~2. the loss in efficiency of Synergy's Scheduled Generators that System Management has scheduled (or caused to be scheduled) to provide Spinning Reserve Service during Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves;~~

~~ii. for the reserve availability payment margin applying for Off-Peak Trading Intervals, Margin_Off-Peak, AEMO must take account of:~~

~~1. the margin Synergy could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve Service during Off-Peak Trading Intervals; and~~

~~2. the loss in efficiency of Synergy's Scheduled Generators that System Management has scheduled (or caused to be scheduled) to provide Spinning Reserve Service during Off-Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves; and~~

~~(b) the Economic Regulation Authority must undertake a public consultation process, which must include publishing an issues paper and issuing an invitation for public submissions.~~

~~3.13.3B. For each Review Period, by 31 March of the year in which the Review Period commences, the Economic Regulation Authority must determine values for Cost_LR, taking into account the Wholesale Market Objectives and in accordance with the following:~~

~~(a) by 30 November of the year prior to the start of the Review Period, System Management must submit a proposal for the Cost_LR parameter for the~~

~~Review Period to the Economic Regulation Authority. Cost_LR must cover the costs for providing the Load Rejection Reserve Service and System Restart Service and Dispatch Support Service except those provided through clause 3.11.8B;~~

~~(b) the Economic Regulation Authority must undertake a public consultation process, which must include publishing an issues paper and issuing an invitation for public submissions.~~

~~3.13.3C. For any year within a Review Period if System Management determines Cost_LR for the following Financial Year to be materially different than the costs provided under clause 3.13.3B, then the Economic Regulation Authority must determine the revised values for Cost_LR, taking into account the Wholesale Market Objectives and in accordance with the following:~~

~~(a) by 30 November of the year prior to the start of the relevant Financial Year, System Management must submit an updated proposal for the Cost_LR parameter to the Economic Regulation Authority. Cost_LR must cover the costs for providing the Load Rejection Reserve Service and System Restart Service and Dispatch Support Service except those provided through clause 3.11.8B;~~

~~(b) the Economic Regulation Authority may undertake a public consultation process and:~~

~~i. if a public consultation process is undertaken, the Economic Regulation Authority must publish an issues paper and issue an invitation for public submissions; and~~

~~ii. if a public consultation process is not undertaken, the Economic Regulation Authority must publish the reasons behind the decision.~~

Explanatory Note The proposed deletion of section 3.14 is a placeholder only. Any amendments are to be made in the Settlement workstream.

3.14. ~~Ancillary Service Cost Recovery~~[Blank]

~~3.14.1. Market Participant p's share of the Load Following Service payment cost in each Trading Month m is LF_Share(p,m) which equals:~~

~~(a) the Market Participant's contributing quantity; divided by~~

~~(b) the total contributing quantity of all Market Participants,~~

~~where a Market Participant's contributing quantity for Trading Month m is the sum of:~~

~~i. the absolute value of the sum of the Metered Schedules for the Non-Dispatchable Loads and Interruptible Loads registered by the Market Participant for all Trading Intervals during Trading Month m; and~~

~~ii. the sum of the Metered Schedules for Non-Scheduled Generators registered by the Market Participant for all Trading Intervals during Trading Month m.~~

~~iii. [Blank]~~

~~3.14.2. Market Participant p's share of the Spinning Reserve Service payment costs in each Trading Interval t is SR_Share (p,t) which equals the amount determined in Appendix 2.~~

~~3.14.3. Market Participant p's share of the Load Rejection Reserve Service, System Restart Service and Dispatch Support Service payment costs in each Trading Month m is Consumption_Share(p,m) determined in accordance with clause 9.3.7.~~

Explanatory Note
The proposed amendments to section 3.15 are to reflect the new arrangements for reviews of the processes and standards of Essential System Services, and in particular to include economic analysis of the underlying technical settings. The review will encompass all Essential System Services, not only FCESS.

3.15. Review of ~~Ancillary~~ Essential System Service ~~Requirements~~ Process and Standards

3.15.1. ~~From time to time, and at least once in every five year period starting from Energy Market Commencement, the~~The Economic Regulation Authority, with the assistance of AEMO, must carry out a ~~study~~ review on the ~~Ancillary~~ Essential System Service Standards and the basis for setting ~~Ancillary~~ Essential System Service ~~Requirements~~ requirements. ~~The study must include:~~

~~(a) technical analyses determining the relationship between the level of Ancillary Services provided and the SWIS Operating Standards set out in clause 3.1;~~

~~(b) identification of the expected costs that would result from an increase in the requirements for Ancillary Services due to additional Facilities connecting to the SWIS;~~

~~(c) a cost-benefit study on the effects on stakeholders of providing and using a variety of levels of each Ancillary Service; and~~

~~(d) a public consultation process.~~

3.15.1A. The Economic Regulation Authority must conduct the first review under clause 3.15.1 within two and a half years of the New WEM Commencement Day and then, subject to clause 3.15.1B, at least once in every three year period from completion of the previous review.

3.15.1B. The Economic Regulation Authority may conduct a review contemplated by clause 3.15.1 earlier than the time referred to in clause 3.15.1A if it reasonably forms the opinion that any of the metrics developed under clause 3.15.2 are significantly departing from the targets set in the previous review.

3.15.1C. A review conducted pursuant to clause 3.15.1A or clause 3.15.1B must include:

(a) technical analyses determining the relationship between the quantity of Essential System Service scheduled and dispatched against the technical parameters in the Frequency Operating Standards;

(b) economic analyses determining the relationship between technical parameters (including, without limitation, frequency operating bands) and overall cost of supply of energy and Essential System Services;

(c) a cost-benefit study on the effects on the Network and Market Participants of providing and using higher or lower levels of each Essential System Service;

(d) identification of the costs and benefits of changing technical parameters, including the potential for increasing or decreasing the overall cost to supply energy and Essential System Services; and

(e) a public consultation process.

3.15.2. As part of each review under clause 3.15.1A or clause 3.15.1B, the Economic Regulation Authority, with the support of AEMO, must determine and publish a set of metrics to be used for ongoing monitoring of Essential System Services, which must include:

(a) technical outcomes, such as dispatched Essential System Service quantities, number of accredited Facilities, number of capable Facilities and the historical performance of those Facilities;

(b) financial outcomes, such as Market Clearing Prices and Essential System Service costs; and

(c) economic outcomes, such as the overall electricity costs faced by consumers.

3.15.~~2~~3. The Economic Regulation Authority must publish a report containing:

(a) the inputs and results of the technical reviews conducted pursuant to clause 3.15.1A and clause 3.15.1B and cost-benefit studies;

(b) the submissions received by the Economic Regulation Authority in the consultation process, a summary of those submissions, and any responses to issues raised in those submissions; ~~and~~

(c) any recommendations for the inclusion of a new Essential System Service, ~~recommended~~ changes to ~~Ancillary~~ Essential System Service Standards and the basis for setting ~~Ancillary~~ Essential System Service ~~Requirements~~ requirements~~.~~; and

(d) the metrics and targets to be used for ongoing monitoring of Essential System Services.

3.15.4. The Economic Regulation Authority must publish the report referred to in clause 3.15.3 no later than:

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(a) for the first report, two and a half years of the New WEM Commencement Day; and

(b) thereafter, three years after publishing the previous review.

3.15.~~3~~5. If the Economic Regulation Authority recommends any changes in a ~~the~~ report published under ~~in~~ clause ~~3.15.2~~ 3.15.3, the Economic Regulation Authority must make a Rule ~~Charge~~ Change Proposal in accordance with clause 2.5.1 to implement those changes.

Explanatory Note

New proposed section 3.15A sets out the regime for the new SESSM for procuring FCESS. This new regime replaces the current contract-based mechanism.

Set out below is an extract from the Taskforce's Information Paper *Supplementary ESS Procurement Mechanism* to provide some background to the new regime. You should refer to the Information Paper for further details.

FCESS will be primarily procured via real-time markets, with participation from all capable and accredited facilities enabled, but not mandatory. Nevertheless, to protect against the risk of market failure in what will be relatively small and concentrated markets, the Taskforce has endorsed the SESSM to provide a means for longer-term contractual arrangements to increase certainty, mitigate inefficient market outcomes, support new market entry, and avoid a shortfall in ESS accreditation and participation. Contrasting with current arrangements, the SESSM will be implemented through a transparent tender process in the WEM Rules, rather than through individually negotiated bilateral contracts

The broad objectives of the SESSM are to:

- incentivise new FCESS providers to enter the market;
- mitigate scarcity in FCESS markets, manifesting either as a shortfall of accredited facilities, or shortfall of participation; and
- mitigation of market power by:
  - the threat of competitive entry; and
  - a mechanism of ex-ante review of the operating costs of ESS providers by the Economic Regulation Authority.

The procurement of SESSM broadly consists of seven stages: Triggering, SESSM Service Specification, Veto of Procurement, Procurement Process, Selection, Veto of Award, and SESSM awarded.

Section 3.15A contains proposed subheadings to assist the user. Please note, however, that as is the case for all headings in the WEM Rules (including those in brackets at the beginning of a paragraph), they are for convenience only and do not affect the interpretation of the WEM Rules (clause 1.4.1(f)).

3.15A. Supplementary Essential System Service Mechanism

Triggering the mechanism

Explanatory Note

The SESSM may be triggered by AEMO or it may be triggered by the Economic Regulation Authority in accordance with the trigger events set out below. Depending on which body triggers the SESSM will affect the process.

3.15A.1. AEMO may only trigger the Supplementary Essential System Service Mechanism in accordance with clause 3.11.6.

3.15A.2. The Economic Regulation Authority may only trigger the Supplementary Essential System Service Mechanism when, pursuant to a review under clauses 3.15.1A or 3.15.1B or its monitoring pursuant to clause 2.16.9, it reasonably considers that Real-Time Market outcomes are not consistent with the efficient operation of the Real-Time Market in respect of Frequency Co-optimised Essential System Services or the Wholesale Market Objectives.

3.15A.3. Where AEMO is required to trigger the Supplementary Essential System Service Mechanism, AEMO must submit to the Economic Regulation Authority:

(a) the reasons why it is required to trigger the Supplementary Essential System Service Mechanism;

(b) the Frequency Co-optimised Essential System Services it proposes to be procured through the Supplementary Essential System Service Mechanism;

(c) where AEMO identifies an expected shortfall in the accredited Frequency Co-optimised Essential System Service capacity in accordance with clause 3.11.2, the additional quantity of the relevant Frequency Co-optimised Essential System Services which would be expected to rectify the shortfall;

(d) the SESSM Service Specification, prepared in accordance with clause 3.15A.6, for each Frequency Co-optimised Essential System Service to be procured under the Supplementary Essential System Service Mechanism; and

(e) where the number of Dispatch Intervals in any 90 day period referred to in clause 3.11.4 is reached, the number of Dispatch Intervals where AEMO was required to give a direction pursuant to clause 7.7.5 that otherwise would not have been required if Frequency Co-optimised Essential System Services had been procured pursuant to the Supplementary Essential System Service Mechanism for that 90 day period.

3.15A.4. When the Economic Regulation Authority proposes to trigger the Supplementary Essential System Service Mechanism pursuant to clause 3.15A.2 it must publish:

(a) the reasons why it proposes to trigger the Supplementary Essential System Service Mechanism;

(b) the Frequency Co-optimised Essential System Services it proposes to be procured through the Supplementary Essential System Service Mechanism;

(c) whether the Frequency Co-optimised Essential System Services are required for certain time intervals only (for example, day of week, time of year), or are required more generally; and

(d) an estimate of the difference between the cost of Frequency Co-optimised Essential System Services in the Real-Time Market and the Economic Regulation Authority's reasonable estimate of the cost of those Frequency Co-optimised Essential System Services if they were procured in an efficient Real-Time Market.

Explanatory Note

The heads of power for the FCESS offer construction guidelines will be set out in the Compliance and Monitoring workstream.

3.15A.5. The Economic Regulation Authority must document in a WEM Procedure the process it will undertake to identify inefficient Real-Time market outcomes pursuant to clause 3.15A.2, which may include, but is not limited to:

(a) comparing individual Facility offers of Frequency Co-optimised Essential System Services with:

i. offers of Frequency Co-optimised Essential System Services from similar Facilities;

ii. expected or known costs for that Facility;

iii. offers from the same Facility in different time periods;

iv. historic offers of Frequency Co-optimised Essential System Services in the Real-Time Market; and

v. the Frequency Co-optimised Essential System Services offer construction guidelines published by the Economic Regulation Authority under [clause reference in Compliance and Monitoring drafting instructions];

(b) comparing existing Facility costs with potential new facility entrant costs;

(c) an analysis of the information received from expressions of interest forms submitted in accordance with section 3.15B; and

(d) comparing Frequency Co-optimised Essential System Services market outcomes with other relevant jurisdictions.

SESSM Service specification

Explanatory Note

AEMO will be responsible for the service specification for each FCESS but it must align with the relevant shortfall identified.

To allow the market to develop, there will be a transitional rule which, in the first three years of operation of the market, restricts the proposed SESSM Award Duration to a maximum of one year.

3.15A.6. When the Supplementary Essential System Service Mechanism is triggered under clause 3.15A.1 or clause 3.15A.2, AEMO must prepare a SESSM Service Specification for each Frequency Co-optimised Essential System Service being procured under the Supplementary Essential System Service Mechanism which must include the:

(a) name of the Frequency Co-optimised Essential System Service or services;

(b) SESSM Service Commencement Date;

(c) SESSM Service Timing;

(d) proposed SESSM Award Duration;

(e) SESSM Service Quantity Profile; and

(f) SESSM Minimum Availability Requirement.

3.15A.7. Where the Supplementary Essential System Service Mechanism has been triggered by AEMO, the SESSM Service Timing and SESSM Service Quantity Profile must align with the relevant quantities and times identified by AEMO under clause 3.11.6.

Explanatory Note
Where the Economic Regulation Authority triggers the SESSM, the quantities of FCESS will include the full forecast quantity, to enable new providers to compete in the process alongside any Facilities designated to participate in the process by the Economic Regulation Authority (based on the Market Participant's capability of exercising market power in respect the Facility), and any other existing facilities who wish to participate.

3.15A.8. Where the Supplementary Essential System Service Mechanism has been triggered by the Economic Regulation Authority, the SESSM Service Timing must align with the relevant times identified by the Economic Regulation Authority under clause 3.15A.4 and the SESSM Service Quantity Profile must align with the quantities of the relevant Frequency Co-optimised Essential System Service identified by AEMO in the most recent Medium Term PASA.

Economic Regulation Authority veto

Explanatory Note
The Economic Regulation Authority will have the power to veto the SESSM process in specified circumstances. This provides a check on the process.

3.15A.9. The Economic Regulation Authority must, within 10 Business Days of the receipt of information from AEMO under clause 3.15A.3, review the information provided by AEMO under clause 3.15A.3 and determine whether or not to veto the Supplementary Essential System Service Mechanism process pursuant to clause 3.15A.10.

3.15A.10. If, following the review of the information provided by AEMO under clause 3.15A.3, the Economic Regulation Authority reasonably considers:

(a) the requirements in clause 3.11.6 were not satisfied; or

(b) AEMO has not provided sufficient information in accordance with clause 3.15A.3; or

(c) the SESSM Service Specification does not comply with clause 3.15A.6 or clause 3.15A.7,

the Economic Regulation Authority may veto the Supplementary Essential System Service Mechanism process.

3.15A.11. Where the Economic Regulation Authority has vetoed the process:

(a) under clause 3.15A.10(b), AEMO must revise and resubmit the information under clause 3.15A.3; or

(b) under clause 3.15A.10(c), AEMO must revise and resubmit the information under clause 3.15A.6 and clause 3.15A.7.

3.15A.12. The Economic Regulation Authority must, within the time specified in clause 3.15A.9:

(a) notify AEMO:

i. if it does not exercise its veto under clause 3.15A.10; or

ii. if it exercises its veto under clause 3.15A.10:

1. whether its veto is exercised under clause 3.15A.10(a), clause 3.15A.10(b) or 3.15A.10(c); and

2. the reasons for exercising its veto; and

(b) publish the information notified to AEMO pursuant to clause 3.15A.12(a) on its website.

Participation

Explanatory Note

The intention is for new providers or new capacity for Essential System Services to participate in the SESSM.

A Facility does not need to be registered to participate in SESSM procurement. However, if the facility is successful then it will be required to register and be accredited pursuant to clause 3.15A.41. Clause 3.15A.41 states:

3.15A.41. A Market Participant that is granted a SESSM Supplementary ESS Award for a Facility that is yet to commence operation must, within any timeframe specified by AEMO:

(a) if the Facility is not already registered, register the Facility in accordance with these WEM Rules; and

(b) if the Facility is not already accredited, ensure the Facility is accredited to provide the relevant Frequency Co-optimised Essential System Service in accordance with clause 2.34A.1, where the accredited capability for each Dispatch Interval in the SESSM Award Duration must be at least the sum of the Base ESS Quantity and the Availability Quantity.

3.15A.13. A Facility:

(a) that is not accredited to provide a Frequency Co-optimised Essential System Service under clause 2.34A.1; or

(b) that is not registered under the WEM Rules,

may participate in a Supplementary Essential System Service Mechanism procurement.

Explanatory Note

Clause 3.15A.14 intends that an existing accredited Facility can only participate in an AEMO triggered SESSM if it is seeking to increase its accredited capacity through incremental capital upgrades. For example, by installing new equipment that enables it to provide more of the FCESS.

3.15A.14. Where AEMO has identified a shortfall of Frequency Co-optimised Essential System Services under clause 3.11.2, then a Facility that is accredited under clause 2.34A.1 to provide a Frequency Co-optimised Essential System Service may only participate in a Supplementary Essential System Service Mechanism procurement for that Frequency Co-optimised Essential System Service by proposing an increase in its accredited capability to provide that Frequency Co-optimised Essential System Service.

Explanatory Note

The Economic Regulation Authority will have the power to designate facilities to participate in the SESSM, where the Market Participant is expected to have, or be able to exercise, market power in respect to any of its facilities.

3.15A.15. Where the Economic Regulation Authority triggers the Supplementary Essential System Service Mechanism, subject to clause 3.15A.16, the Economic Regulation Authority may designate one or more Facilities that must participate in the Supplementary Essential System Service Mechanism.

3.15A.16. The Economic Regulation Authority may only designate a Facility pursuant to clause 3.15A.15:

(a) that is registered under these WEM Rules;

(b) that the Economic Regulation Authority reasonably considers is able to meet the SESSM Service Specification;

(c) that is accredited for that Frequency Co-optimised Essential System Service under clause 2.34A.1;

(d) if the Facility has available accredited capability in excess of any existing SESSM Supplementary ESS Award for the applicable Frequency Co-optimised Essential System Service; and

(e) if, in the Economic Regulation Authority's opinion, the Market Participant for the designated facility has, or is expected to be able to exercise, market power in respect of the designated facility, either alone or in combination with any one or more of the Market Participant's other facilities, for the applicable Frequency Co-optimised Essential System Service.

To avoid doubt, the Economic Regulation Authority may, but is not obliged to, consult with AEMO in respect of designating a Facility pursuant to clause 3.15A.15.

3.15A.17. Where the Economic Regulation Authority has designated a Facility pursuant to clause 3.15A.15, the Economic Regulation Authority must notify:

(a) AEMO, and provide details of the Facility; and

(b) the relevant Market Participant responsible for the Facility.

3.15A.18. A Facility that has not been designated by the Economic Regulation Authority pursuant to clause 3.15A.15 may still participate in a Supplementary Essential System Service Mechanism triggered by the Economic Regulation Authority.

Procurement notice

Explanatory Note AEMO will be required to advertise the particulars of the Supplementary Essential System Service Mechanism to maximise participation.

3.15A.19. Where the Economic Regulation Authority has notified AEMO that it will not veto the Supplementary Essential System Service Mechanism then AEMO must advertise a call for Supplementary Essential System Service Submissions, no later than 20 Business Days prior to the proposed closing date for Supplementary Essential System Service Submissions.

3.15A.20. In advertising the call for Supplementary Essential System Service Submissions in accordance with clause 3.15A.19, AEMO must:

(a) publish a notice on the WEM Website;

(b) publish a notice on at least one major tender portal; and

(c) directly contact any Market Participants designated by the Economic Regulation Authority pursuant to clause 3.15A.15.

3.15A.21. AEMO must include in each notice referred to in clause 3.15A.20:

(a) the date and time for lodgement of Supplementary Essential System Service Submissions, which must be in accordance with the form referred to in clause 3.15A.22;

(b) contact details for AEMO;

(c) a description of the quantity, type and timing of the required Frequency Co-optimised Essential System Service;

(d) the location on the WEM Website of the Supplementary Essential System Service Submission form referred to in clause 3.15A.22; and

(e) the location on the WEM Website of the SESSM Service Specification for the Frequency Co-optimised Essential System Service referred to in clause 3.15A.6.

Response requirements

Explanatory Note The requirements for responses to the SESSM are set out in clauses 3.15A.22 to 3.15A.25.

3.15A.22. AEMO must develop and publish a Supplementary Essential System Service Submission form which must include the following fields for the Supplementary Essential System Service Mechanism procurement:

(a) the Availability Quantity for each Dispatch Interval in the SESSM Award Duration up to the quantity set out in the SESSM Service Specification for the Facility which may vary according to the time periods set out in the SESSM Service Specification;

(b) the proposed Availability Payment, which:

i. is the total amount payable across the SESSM Award Duration for offering the Availability Quantity into the Real-Time Market; and

ii. must be equal to or less than the incremental fixed costs, if any, that are not already covered by any Capacity Credit payments, which would otherwise be incurred to make available the Availability Quantity of the Frequency Co-optimised Essential System Service in addition to any Base ESS Quantity of that Frequency Co-optimised Essential System Service;

(c) the proposed Offer Cap, which must be the variable costs of providing the relevant Frequency Co-optimised Essential System Service, and which:

i. is the highest price which the Market Participant will offer the applicable Frequency Co-optimised Essential System Service into the Real-Time Market (excluding Enablement Losses); and

ii. may vary according to the time periods set out in the SESSM Service Specification;

(d) the SESSM Award Duration; and

(e) where the Supplementary Essential System Service Mechanism includes more than one Frequency Co-optimised Essential System Service, whether the Supplementary Essential System Service Submission is contingent on holding a SESSM Supplementary ESS Award for more than one Frequency Co-optimised Essential System Service that is also included in the Supplementary Essential System Service Mechanism and, if so, which ones.

Explanatory Note The requirement to make a Supplementary Essential System Service Submission in good faith will be a civil penalty provision.

3.15A.23. A Supplementary Essential System Service Submission submitted by a Market Participant in response to a call for submissions under clause 3.15A.19 must:

(a) be made in good faith;

(b) be in the form published by AEMO in accordance with clause 3.15A.22; and

(c) include the cost information and any assumptions used to calculate the proposed Offer Cap and Availability Payment.

3.15A.24. Where a Market Participant submits a Supplementary Essential System Service Submission under clause 3.15A.23 in respect of an accredited Facility, the Supplementary Essential System Service Submission must also include:

(a) a comparison of the proposed Availability Quantity of the Facility to its historic quantities offered in the Real-Time Market over the past 12 months in Dispatch Intervals within the SESSM Service Timing;

(b) information on the proportion of the Frequency Co-optimised Essential System Service offers into the Real-Time Market that related to Enablement Losses of the Facility over the past 12 months in Dispatch Intervals within the SESSM Service Timing; and

(c) a comparison of the proposed Offer Cap for the Facility to its historic offer prices offered in the Real-Time Market (excluding Enablement Losses) over the past 12 months.

3.15A.25. Where a Market Participant submits a Supplementary Essential System Service Submission under clause 3.15A.23 in respect of a new Facility which is:

(a) not accredited for the relevant Frequency Co-optimised Essential System Service; or

(b) accredited for the relevant Frequency Co-optimised Essential System Service and which is proposing to increase the quantity of the relevant Frequency Co-optimised Essential System Service for which it is accredited,

the Supplementary Essential System Service Submission must also include:

(c) whether or not the Facility has applied for, or been granted, Certified Reserve Capacity or Capacity Credits in respect of the capacity that would provide the Frequency Co-optimised Essential System Service;

(d) if the Facility, or relevant part of the Facility, has not applied for or been granted Certified Reserve Capacity or Capacity Credits, the information listed in clause 4.10.1(c), and any other information required under the relevant WEM Procedure;

(e) the expected Standing Enablement Minimum;

(f) the expected generation cost at the Standing Enablement Minimum; and

(g) expected start-up costs for the Facility.

Explanatory Note

A person may make more than one Supplementary Essential System Service Submission and may set out alternative offers. In addition, a person may make contingent offers for multiple services. AEMO will only select one offer, or combination, but the intention is to provide as much choice and flexibility to the market, while ensuring offers can be compared on a consistent basis. A person must make compliant offers under clause 3.15A.26 to be permitted to make a contingent offer for multiple services to AEMO as well.

3.15A.26. A Market Participant wishing to participate in the Supplementary Essential System Service Mechanism may make one or more Supplementary Essential System Service Submissions in respect of a single Facility which:

(a) comply with the requirements of Supplementary Essential System Service Submissions specified in clauses 3.15A.23 to 3.15A.25 as applicable;

(b) comply with the SESSM Service Specification;

(c) are binding for the SESSM Award Duration as specified in the SESSM Service Specification;

(d) may have different Availability Quantities; and

(e) are not contingent on being awarded a SESSM Supplementary ESS Award for more than one Essential System Service.

3.15A.27. Where a Market Participant has made a Supplementary Essential System Service Submission under clause 3.15A.26, it may make one or more additional Supplementary Essential System Service Submissions in respect of the same Facility which:

(a) have the same Availability Quantity and Offer Cap but have a different SESSM Award Duration and Availability Payment; or

(b) have the same Availability Quantity, Offer Cap and SESSM Award Duration but have a different Availability Payment and are contingent on the Facility being selected for more than one SESSM Supplementary ESS Award.

Selection and approval

Explanatory Note

AEMO will select the submissions which meet the SESSM Service Specification and result in the lowest cost of providing the FCESS to the market. The Economic Regulation Authority will have a review role in order to ensure that the process has been followed, but is not expected to perform a parallel assessment.

3.15A.28. Within 20 Business Days of the date and time for lodgement of Supplementary Essential System Service Submissions specified in clause 3.15A.21(a), AEMO must:

(a) select the Supplementary Essential System Service Submissions which meet the SESSM Service Specification which, taken together, in AEMO's opinion will result in the lowest cost of providing the Frequency Co-optimised Essential System Service in accordance with clause 3.15A.29;

(b) identify the Market Participants and the Facilities who it approves and intends to grant a SESSM Supplementary ESS Award; and

(c) notify the Economic Regulation Authority in accordance with clause 3.15A.31.

3.15A.29. When selecting the lowest cost combination of Supplementary Essential System Service Submissions in accordance with clause 3.15A.28(a), AEMO must:

(a) exclude Supplementary Essential System Service Submissions that do not comply with the SESSM Service Specification;

(b) exclude Supplementary Essential System Service Submissions for new facilities where the Market Participant has not provided sufficient evidence to support the Key Project Dates or that all necessary Environmental Approvals have been granted;

(c) identify historical Dispatch Intervals matching the SESSM Service Specification (date, time, load);

(d) calculate energy price profiles for energy matching the SESSM Service Timing for those Dispatch Intervals on the basis of three categories being average cost, high cost and low cost;

(e) calculate effective Frequency Co-optimised Essential System Service offer prices for each Supplementary Essential System Service Submission comprising:

i. proposed Availability Payment divided by the sum of all Availability Quantities within the SESSM Award Duration;

ii. proposed Offer Cap; and

iii. Expected Enablement Losses based on:

1. Standing Enablement Minimum;

2. start-up costs; and

3. minimum running costs; and

(f) calculate the lowest cost combination of Supplementary Essential System Service Submissions to deliver the requirement under each of the three energy price profiles referred to in clause 3.15A.29(d).

3.15A.30. If AEMO is selecting Facilities to meet more than one SESSM Service Specification in a single Supplementary Essential System Service procurement process, AEMO must:

(a) identify where the Supplementary Essential System Service Submissions from a Facility for the provision of different Frequency Co-optimised Essential System Services would be provided from the same portion of the Facility's capacity;

(b) determine the order of selection for the affected Frequency Co-optimised Essential System Services;

(c) in selecting Facilities to provide each of the Frequency Co-optimised Essential System Services, exclude any Supplementary Essential System Service Submissions for the Facility's capacity that has already been selected for a SESSM Supplementary ESS Award under a previous selection; and

(d) ensure that proposed SESSM Supplementary ESS Awards will deliver the total Essential System Service requirement.

3.15A.31. AEMO must notify the Economic Regulation Authority of the outcome of the Supplementary Essential System Service Mechanism, including providing the Economic Regulation Authority with the following information:

(a) the names of the parties and the facility details (including, if already registered, the identity of the Market Participants and the Facilities), it intends to grant a SESSM Supplementary ESS Award to;

(b) the estimated aggregated cost of all SESSM Supplementary ESS Awards it intends to grant;

(c) the proposed SESSM Service Commencement Date;

(d) AEMO's reasonable estimate of the cost of procuring the Frequency Co-optimised Essential System Services based on the historic costs of the Frequency Co-optimised Essential System Services (as if the SESSM Supplementary ESS Awards it intends to grant were not made); and

(e) a comparison of the calculated effective Frequency Co-optimised Essential System Service offer prices to the prices for the Frequency Co-optimised Essential System Service in the Real-Time Market within the SESSM Service Timing for the relevant Frequency Co-optimised Essential System Service over the previous 12 months.

3.15A.32. The Economic Regulation Authority may request AEMO to provide it with any information and data provided by a Market Participant as part of a Supplementary Essential System Service Submission. AEMO must comply with any request under this clause 3.15A.32 within 5 Business Days of the request or such later time as agreed. To avoid doubt, a request by the Economic Regulation Authority under this clause 3.15A.32 will not affect the veto timeline under clause 3.15A.33.

Explanatory Note Where AEMO triggers the SESSM, the Economic Regulation Authority will review the process and may veto the Supplementary Essential System Service awards and require AEMO to redo the selection process.

3.15A.33. Where AEMO triggered the Supplementary Essential System Service Mechanism, the Economic Regulation Authority must, within 10 Business Days of AEMO notifying it pursuant to clause 3.15A.31, review the proposed SESSM Supplementary ESS Awards AEMO intends to grant and determine whether or not to veto the SESSM Supplementary ESS Awards AEMO intends to grant pursuant to clause 3.15A.34.

3.15A.34. If, following the review pursuant to clause 3.15A.33, the Economic Regulation Authority reasonably considers that AEMO has not followed the processes in clause 3.15A.28 and clause 3.15A.29, the Economic Regulation Authority may veto the SESSM Supplementary ESS Awards AEMO intends to grant, and may ask AEMO to revise its selection assessment and approval according to the process in clause 3.15A.28 and clause 3.15A.29.

Explanatory Note

Where the Economic Regulation Authority triggers the SESSM, the Economic Regulation Authority will review the Supplementary Essential System Service awards and if it considers they will not lower the cost to the market it may veto any or all of the proposed awards. It may also veto an individual award where it was not made in good faith or was incorrect. In the interests of time, the Economic Regulation Authority will only have a short period to review awards, but can use information provided through the SESSM process in its wider market surveillance and compliance activities.

3.15A.35. Where the Economic Regulation Authority triggered the Supplementary Essential System Service Mechanism, the Economic Regulation Authority must, within 20 Business Days of AEMO notifying it pursuant to clause 3.15A.31, review the proposed SESSM Supplementary ESS Awards AEMO intends to grant and determine whether or not to veto the SESSM Supplementary ESS Awards AEMO intends to grant pursuant to clause 3.15A.36.

3.15A.36. If, following a review pursuant to clause 3.15A.35, the Economic Regulation Authority reasonably considers that:

(a) the SESSM Supplementary ESS Awards AEMO intends to grant will not reduce the cost to the market of the relevant Frequency Co-optimised Essential System Service, the Economic Regulation Authority may, within 20 Business Days of AEMO notifying it pursuant to clause 3.15A.31, veto any or all of the SESSM Supplementary ESS Awards AEMO intends to grant; or

(b) a Market Participant's Supplementary Essential System Service Submission does not reflect the costs and assumptions referred to in clause 3.15A.22(b) or clause 3.15A.22(c) or was not provided in good faith in accordance with clause 3.15A.23, the Economic Regulation Authority may, within 20 Business Days of AEMO notifying it pursuant to clause 3.15A.31, veto the SESSM Supplementary ESS Award AEMO intends to grant to the Market Participant.

Explanatory Note

The Economic Regulation Authority will have enforcement powers in respect of submissions not made in good faith including seeking a civil penalty or adjusting the terms of the award. In either case the participant should be able to challenge the decision in accordance with the existing dispute resolution clauses.

3.15A.37. Where the Economic Regulation Authority reasonably considers that a Market Participant has breached the obligation to make a Supplementary Essential System Service Submission in good faith in accordance with clause 3.15A.23, then in addition to its powers under clause 3.15A.36(b), the Economic Regulation Authority may:

(a) issue a warning to the Market Participant pursuant to clause 2.13.10(d);

(b) adjust the Availability Payment and / or Offer Cap for the SESSM Supplementary ESS Award AEMO intends to grant to reflect the costs that the Economic Regulation Authority determines should have been submitted if the Supplementary Essential System Service Submission was made in good faith; or

(c) determine that a breach has taken place, in which case the Economic Regulation Authority may issue a penalty notice in accordance with the WEM Regulations.

Notification

Explanatory Note AEMO will be required to publish certain details of Supplementary Essential System Service Awards but otherwise the information in a submission will be confidential.

3.15A.38. If the Economic Regulation Authority does not veto a SESSM Supplementary ESS Award AEMO intends to grant in accordance with clause 3.15A.36, AEMO must grant the SESSM Supplementary ESS Award as submitted to the Economic Regulation Authority in accordance with clause 3.15A.31 and:

(a) notify the relevant Market Participants or persons responsible for the Facilities who it has selected to grant a SESSM Supplementary ESS Award;

(b) publish information about the Supplementary Essential System Service Mechanism process including:

i. the number and identity of respondents; and

ii. the information on the SESSM Supplementary ESS Awards as notified to the Economic Regulation Authority in accordance with clause 3.15A.31, but excluding any information the Economic Regulation Authority may have received under clause 3.15A.32; and

(c) publish the terms of each SESSM Supplementary ESS Award granted including details of:

i. each Facility that was granted a SESSM Supplementary ESS Award;

ii. the SESSM Service Specification;

iii. the duration of the SESSM Supplementary ESS Award;

iv. the Availability Payment;

v. the Offer Cap;

vi. where the Availability Payment is greater than zero, the Base ESS Quantity for each Dispatch Interval in the SESSM Award Duration; and

vii. the Per-Dispatch Interval Availability Payment.

3.15A.39. Subject to the obligation to publish the information in clause 3.15A.38 the information contained in any Supplementary Essential System Service

Submissions received pursuant to the Supplementary Essential System Service Mechanism are AEMO Confidential.

Obligation to comply

Explanatory Note Clause 3.15A.40 is intended to be a civil penalty provision.

3.15A.40. A Facility that was granted a SESSM Supplementary ESS Award must comply with the SESSM Service Specification for that Frequency Co-optimised Essential System Service.

Supplementary Essential System Service Mechanism new entrants

Explanatory Note The SESSM will be open to new participants that are not registered under the WEM Rules. As such there will be requirements on those participants to report key progress dates to AEMO, in the same way as new Facilities holding capacity credits.

3.15A.41. A Market Participant that is granted a SESSM Supplementary ESS Award for a Facility that is yet to commence operation must, within any timeframe specified by AEMO:

(a) if the Facility is not already registered, register the Facility in accordance with these WEM Rules; and

(b) if the Facility is not already accredited, ensure the Facility is accredited to provide the relevant Frequency Co-optimised Essential System Service in accordance with clause 2.34A.1, where the accredited capability for each Dispatch Interval in the SESSM Award Duration must be at least the sum of the Base ESS Quantity and the Availability Quantity.

3.15A.42. Market Participants who are granted a SESSM Supplementary ESS Award for Facilities that are yet to commence operation and for which they are not required to submit a report pursuant to clause section 4.27.10 must file a report on progress with AEMO:

(a) at least once every three months from the date the SESSM Supplementary ESS Award is confirmed under clause 3.15A.38; and

(b) at least once every month commencing on the date that is six months prior to the SESSM Service Commencement Date,

or as otherwise agreed with AEMO.

3.15A.43. Each report provided pursuant to clause 3.15A.42 must include any changes to Key Project Dates.

Explanatory Note Where AEMO is of the view that a new participant will not be ready to provide the Essential System Service in the required timeframe then AEMO may require further reporting to be satisfied, revise the service date or cancel the award.

3.15A.44. Within 10 Business Days of receiving a report provided pursuant to clause 3.15A.42, clause 4.27.10 or this clause 3.15A.44, as applicable, AEMO:

(a) must:

i. determine whether, in its reasonable opinion, the Facility, or part of the Facility, is unlikely to have completed all Commissioning Tests by the SESSM Service Commencement Date; and

ii. notify the Market Participant of its decision and provide reasons why the dates have been rejected; and

(b) may:

i. require the Market Participant to provide additional information;

ii. require the Market Participant to submit further reports or revise the Key Project Dates; and

iii. revise the SESSM Service Commencement Date or cancel the SESSM Supplementary ESS Award and, where it does so, must notify the Economic Regulation Authority. To avoid doubt, the Economic Regulation Authority may trigger the Supplementary Essential System Service Mechanism if, as a result of being notified by AEMO, it reasonably considers that Real-Time Market outcomes are not consistent with the efficient operation of the Real-Time Market in respect of Frequency Co-optimised Essential System Services or the Wholesale Market Objectives.

Supplementary Essential System Service Mechanism performance monitoring

3.15A.45. During the SESSM Service Timing, AEMO must monitor the quantity of Frequency Co-optimised Essential System Service offered by a Facility that was granted a SESSM Supplementary ESS Award.

Explanatory Note It is to be expected that AEMO will not exercise its discretion under this clause unless AEMO considered the breach was material or important. This is a secondary measure as the Facility will be paying refunds.

3.15A.46. Where a Facility that was granted a SESSM Supplementary ESS Award consistently fails to offer at least the sum of the Availability Quantity and the Base ESS Quantity for Dispatch Intervals within the SESSM Service Timing, AEMO may:

(a) revise the Availability Quantity to reflect the average quantity offered in Dispatch Intervals with adjustments for the effect of any Facility Outage; and

(b) revise the Per-Dispatch Interval Availability Payment by the same ratio as the adjustment to the Availability Quantity.

WEM Procedure

3.15A.47. AEMO must document in a WEM Procedure the process to be followed by AEMO and Market Participants in the Supplementary Essential System Service Mechanism. The WEM Procedure must include:

(a) the format and content of SESSM Service Specifications;

(b) the format and content of any information required to be provided in the Supplementary Essential System Service Submission form which is not set out in clause 3.15A.22 (if any);

(c) the evidence to be provided by new entrant Facilities about the viability of their proposed facility to support the Key Project Dates provided under clause 3.15A.42 or clause 4.10.1(c);

(d) the methodology used to approve and grant SESSM Supplementary ESS Awards;

(e) the process for monitoring progress of new entrant Facilities that are granted a SESSM Supplementary ESS Award;

(f) the circumstances in which it would cancel the granted a SESSM Supplementary ESS Award to a new entrant Facility that is unlikely to have completed all Commissioning Tests by the SESSM Service Commencement Date;

(g) the process for monitoring the performance of Facilities that are granted a SESSM Supplementary ESS Award; and

(h) the process for reducing Availability Quantity and the Per-Dispatch Interval Availability Payment under clause 3.15A.46.

Explanatory Note New proposed section 3.15B sets out the regime for a new periodic expressions of interest process to provide a benchmark for market pricing of Essential System Service. It sets out a market sounding process in order for AEMO to test the market. It will not result in the award of Supplementary Essential System Service but it will assist the Economic Regulation Authority to determine whether the current market price is appropriate and whether there is a need to trigger the SESSM. Additionally, the process provides engagement with new facilities to understand the accreditation process and allows participants to prepare submissions in readiness for a short lead-time SESSM procurement.

3.15B. Expressions of Interest for Essential System Services

3.15B.1. At least once every two years, AEMO must conduct a Frequency Co-optimised Essential System Service expression of interest process.

3.15B.2. In conducting an expression of interest process pursuant to clause 3.15B.1, AEMO must advertise the call for expressions of interest no later than 20 Business Days prior to the proposed closing date for the expressions of interest.

3.15B.3. In advertising the call for expressions of interest under clause 3.15B.2, AEMO must:

(a) publish a notice on the WEM Website; and

(b) publish a notice on at least one major tender portal.

3.15B.4. AEMO must include in each notice referred to in clause 3.15B.3:

(a) the date and time for lodgement of an expression of interest, which must be in accordance with the form referred to in clause 3.15B.5;

(b) contact details for AEMO;

(c) a description of the quantity, type and timing of the historic requirements for the Frequency Co-optimised Essential System Services;

(d) the location on the WEM Website of detailed historic data on the timing and quantity of the Frequency Co-optimised Essential System Services in accordance with clauses 10.5.1(y) and 10.5.1(z); and

(e) the location on the WEM Website of the expression of interest form referred to in clause 3.15B.5.

3.15B.5. AEMO must develop and publish an expression of interest form, which must include the following fields:

(a) the type of the facility;

(b) the likely lead time required to develop and commission the facility;

(c) the likely network location of the facility;

(d) the quantity of each Frequency Co-optimised Essential System Service which could be made available from the facility, which may vary by time of day or year;

(e) the fixed costs of being available to offer the relevant Frequency Co-optimised Essential System Service;

(f) the variable costs of providing each relevant Frequency Co-optimised Essential System Service;

(g) any likely Standing Enablement Minimum limit;

(h) the likely cost per MWh of Injecting energy when operating at any Standing Enablement Minimum limit; and

(i) the start-up costs of the facility.

3.15B.6. The information contained in any expression of interest form submitted in accordance with this section 3.15B must be provided in good faith but is not binding on the respondent.

3.15B.7. Subject to clause 3.15B.8, the information contained in any expression of interest form submitted in accordance with this section 3.15B is AEMO Confidential.

3.15B.8. The Economic Regulation Authority may use any information provided in expressions of interest forms submitted in accordance with this section 3.15B in its monitoring and review functions under these WEM Rules, including in a review under clauses 3.15.1A or 3.15.1B or its monitoring pursuant to clause 2.16.9, and in deciding whether to trigger the Supplementary Essential System Service Mechanism in accordance with clause 3.15A.2.

Explanatory Note

Amendments to section 3.16, including consequential amendments as a result of the new Essential System Services framework, will be made in the PASA workstream. The section will incorporate the Medium Term PASA Essential System Services forecasting requirements. The PASA will be used to forecast all Essential System Services requirements, and not only FCESS.

Amendments will also be made to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

Medium and Short Term Planning

3.16.1. System Management must carry out a Medium Term PASA study by the 15th day of each month.

3.16.2. The Medium Term PASA study must consider each week of a three year planning horizon, starting from the month following the month in which the Medium Term PASA study is performed.

3.16.3. System Management must use the assembled data to assist it with respect to:

(a) setting Ancillary Service Requirements over the year; and

(b) outage planning for Registered Facilities; and

(c) assessing the availability of Facilities providing Capacity Credits, and the availability of other capacity.

3.16.4. Unless otherwise directed by System Management, Rule Participants must provide the following data to System Management in respect of each week in the medium term planning horizon described in clause 3.16.2 by the time specified in the Power System Operation Procedure specified in clause 3.16.10:

(a) for Network Operators:

i. future changes to transmission capacities and ratings of equipment, to the extent that these have been planned at the time of providing the data;

ii. in accordance with clause 3.18, confirmation of previous outage plans and any new outage plans; and

iii. future access quantities at entry and exit point to its Network;

(b) for Market Generators:

i. planned future changes to generating facility capabilities and Ancillary Service capabilities;

ii. in accordance with section 3.18, confirmation of previous outage plans and any new outage plans;

iii. any proposed closure of a Registered Facility with a rated capacity of less than 10 MW;

iv. any energy constraints for any week in the Medium Term Planning horizon described in clause 3.16.2; and

v. estimated weekly output for Non-Scheduled Generators; and

(c) for Market Customers:

i. [Blank]

ii. in accordance with section 3.18, confirmation of previous outage plans and any new outage plans; and

iii. availability of Demand Side Management capacity.

3.16.5. In conducting a Medium Term PASA study, System Management may use information developed by System Management in relation to:

(a) SWIS Operating Standards;

(b) Ancillary Service Requirements;

(c) Ancillary Service Contracts.

3.16.6. In conducting a Medium Term PASA study, System Management may, in place of information provided in accordance with clause 3.16.4, use information developed by System Management.

3.16.7. Rule Participants must provide the information System Management requests, and any other data they are aware of that might be relevant to a Medium Term PASA study, within the timeframe specified in the Power System Operation Procedure specified in clause 3.16.10.

3.16.8. System Management must review the information provided by Rule Participants, and where necessary, seek additional information or clarifications.

3.16.8A. Rule Participants must provide any additional information or clarifications requested by System Management, within the time frame specified in the Power System Operation Procedure specified in clause 3.16.10.

3.16.9. On the first Business Day falling on or following the 15th day of each month, System Management must publish the following information developed as a result of System Management's Medium Term PASA for each week in the medium term planning horizon described in clause 3.16.2:

(a) peak load forecasts for the following scenarios:

i. mean;

ii. mean plus one standard deviation; and

iii. mean plus two standard deviations.

(b) forecast total available generation capacity by constrained region;

(c) System Management's reasonable forecast of the total available Demand Side Management capacity by week and by constrained region;

(d) the amount equal to:

i. the load forecast referred to in clause 3.16.9(a)(iii); minus

ii. the total forecast available generation capacity; minus

iii. System Management's reasonable forecast of the total available Demand Side Management capacity;

(e) any weeks where there is expected to be a shortfall of capacity, including a shortfall of Ancillary Services or an inability to satisfy the Ready Reserve Standard;

(f) transmission outages of which System Management is aware, forecast transmission capacity between potentially constrained regions, under normal conditions and some contingency scenarios, and any constraints that are likely under these scenarios;

(g) possible security problems that could affect market or dispatch outcomes;

(h) potential fuel supply, transport or storage limitations that could affect generation capacity of which System Management is aware;

(i) the details of any use by System Management of its own data in place of data provided in accordance with clause 3.16.6, and the reasons why System Management's data was substituted; and

(j) for each approved Commissioning Test the Facility to be tested and the dates and times during which the Commissioning Test will be conducted.

3.16.10. System Management must document the procedure it follows in conducting Medium Term PASA studies in a Power System Operation Procedure.

Explanatory Note

Amendments to section 3.17, including consequential amendments as a result of the new Essential System Services framework, will be made in the PASA workstream. The section will incorporate the new Short Term PASA Essential System Services forecasting requirements. The PASA will be used to forecast all Essential System Services requirements, and not only FCESS.

Amendments will also be made to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

3.17. Short term PASA

3.17.1. System Management must carry out a Short Term PASA study—

(a) every Thursday, and publish the Short Term PASA results referred to in clause 3.17.9 by 4:30 PM; and

(b) on any other day if it determines that changes have occurred that would materially affect market outcomes during the first week of the period covered by the previous Short Term PASA study, and publish the Short Term PASA results referred to in clause 3.17.9 as soon as practicable.

3.17.2. [Blank]

3.17.3. The Short Term PASA study must consider each six-hour period of a three week planning horizon ("**Short Term PASA Planning Horizon**"), starting from 8 AM on the day following the day on which the Short Term PASA study is performed.

3.17.4. System Management must use the Short Term PASA study to assist it in:

(a) setting Ancillary Service Requirements in each six-hour period during the Short Term PASA Planning Horizon;

(b) assessing final approval of Planned Outages; and

(c) assessing the availability of capacity holding Capacity Credits in each six-hour period during the Short Term PASA Planning Horizon.

3.17.5. Unless otherwise directed by System Management, Rule Participants must, before 10 AM every Thursday, submit information to System Management, consisting of:

(a) for a Network Operator, availability over the next Short-Term PASA Horizon of all Registered Facilities;

(b) for a Market Generator, availability over the next Short-Term PASA Horizon of all its Registered Facilities which are generating works; and

(c) for a Market Customer, information about the availability over the next Short-Term PASA Horizon of all its Registered Facilities that are Loads or Demand Side Programmes and demand forecasts for any other load facilities designated as significant by System Management.

3.17.6. Where a Rule Participant becomes aware that the information it submitted in accordance with clause 3.17.5 has materially changed during the first week of the period covered by the previous Short Term PASA study, then it must re-submit the relevant data to System Management as soon as practicable, and in any case within 24 hours.

3.17.7. In conducting the Short Term PASA study, System Management may, use information developed by System Management in relation to:

(a) SWIS Operating Standards;

(b) Ancillary Service Requirements;

(c) Ancillary Service Contracts;

(d) load forecasts.

3.17.8. In conducting a Short Term PASA study, System Management may, in place of information provided in accordance with clause 3.17.5, use information developed by System Management.

3.17.9. System Management must ensure that the results of a Short Term PASA study include for the Short Term PASA Planning Horizon:

(a) peak load forecasts for the following scenarios:

i. mean;

ii. mean plus one standard deviation; and

iii. mean plus two standard deviations;

(b) forecast total available generation capacity by six-hour period;

(c) System Management's reasonable forecast of the total available Demand Side Management capacity by six-hour period;

(d) by six-hour period, the amount equal to:

i. the load forecast referred to in clause 3.17.9(a)(iii); minus

ii. the total forecast available generation capacity; minus

iii. System Management's reasonable forecast of the total available Demand Side Management capacity;

(e) any six-hour periods where a shortfall of capacity is forecast, including a shortfall of Ancillary Services or an inability to satisfy the Ready Reserve Standard;

(f) transmission outages of which System Management is aware, forecast transmission capacity between potentially constrained regions, and any constraints that are likely;

(g) possible security problems that could affect market or dispatch outcomes;

(h) [Blank]

(i) the details of any use by System Management of its own data in place of data provided in accordance with clause 3.17.8, and the reasons why System Management's data was substituted; and

(j) for each approved Commissioning Test the Facility to be tested and the dates and times during which the Commissioning Test will be conducted.

3.17.10. System Management must document the procedure it follows in conducting Short Term PASA studies in a Power System Operation Procedure.

Explanatory Note

Amendments to section 3.18, including consequential amendments as a result of the new Essential System Services framework, will be made in the Outages workstream.

Amendments will also be made to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

3.18. Outage Scheduling

3.18.1. Where a reference is made to an outage of a Facility or item of equipment in this section 3.18 and sections 3.19, 3.20 and 3.21, this includes partial and complete outages and de-ratings of the Facility or item of equipment.

3.18.1A. The obligations specified in this section 3.18 and sections 3.19 and 3.21 to request or report Outages do not apply to Market Participants in respect of an outage of a Non-Scheduled Generator if the average MW de-rating over the relevant Trading Interval is less than:

$$\min(0.1 \times \text{Nameplate\_Capacity}, 10)$$

where Nameplate_Capacity is the MW quantity provided for the Non-Scheduled Generator under Appendix 1(e)(ii).

3.18.1B. For the purposes of this section 3.18 and section 3.19, capacity or capability associated with an Outage Facility is deemed to be unavailable for service in a Trading Interval if the capacity or capability could not, in response to an instruction or direction to the Market Participant or Network Operator from System Management that was consistent with:

(a) the Outage Facility's Equipment Limits;

(b) any relevant limits or information relating to the capacity or capability of an Outage Facility provided to System Management in accordance with the Power System Operation Procedure referred to in clause 2.28.3A(a); or

(c) any relevant limits specified in an Ancillary Service Contract,

(as applicable), be used to provide the relevant service expected from the capacity or capability of the Outage Facility. To avoid doubt, capacity of a Non-Scheduled Generator is not deemed to be unavailable for service because of a shortfall of the intermittent energy source used by the Non-Scheduled Generator to generate electricity.

3.18.2.

(a) System Management must maintain and publish on the Market Web Site a list of all equipment on the SWIS that it determines should be subject to outage scheduling in accordance with this section 3.18 and sections 3.19, 3.20 and 3.21 ("**Equipment List**").

(b) System Management must, as soon as practicable after it becomes aware of an error relating to the Equipment List, or otherwise determines that a change is required to the Equipment List, update the Equipment List to address the error or reflect the change and publish the updated Equipment List on the Market Web Site.

(c) The Equipment List must include:

i. any part of a transmission system (however defined by System Management) that could limit the output of a generation system that System Management has included on the Equipment List;

ii. all Scheduled Generators holding Capacity Credits;

iii. all Non-Scheduled Generators holding Capacity Credits with a Standing Data nameplate capacity that equals or exceeds 10 MW;

iv. all generation systems to which clause 2.30B.2(a) relates with a nameplate capacity that equals or exceeds 10 MW;

v. all Registered Facilities subject to an Ancillary Service Contract; and

vi. any other equipment that System Management determines must be subject to outage scheduling to maintain Power System Security and Power System Reliability.

(d) The Equipment List may specify that an Equipment List Facility is subject to outage scheduling by System Management only at certain times of the year.

(e) [Blank]

(f) A Market Participant or a Network Operator must schedule outages for each of its Equipment List Facilities in accordance with this section 3.18 and sections 3.19, 3.20 and 3.21.

(g) A Market Generator who provides an Ancillary Service under an Ancillary Service Contract must schedule outages in respect of both:

i. the capacity of the Facility to provide sent out energy; and

ii. for each applicable Ancillary Service Contract, the capacity or capability of the Facility to provide the contracted Ancillary Service.

3.18.2A.

(a) If a generation system:

i. is a Scheduled Generator, a Non-Scheduled Generator or a generation system to which clause 2.30B.2(a) relates; and

ii. is not required to be included on the Equipment List under clause 3.18.2(c),

then the relevant Market Participant is not required to schedule outages in accordance with this section 3.18 and sections 3.19 and 3.20 for that generation system ("**Self-Scheduling Outage Facility**") other than as required by this clause 3.18.2A.

(b) Subject to clause 3.18.2A(i), a Market Participant must notify System Management of a proposed Planned Outage of its Self-Scheduling Outage Facility if, and only if, the Market Participant intends that some or all of the capacity of its Self-Scheduling Outage Facility will be unavailable for service for a period for the purpose of Outage Facility Maintenance.

(c) The notice under clause 3.18.2A(b) must be given:

i. for an outage exceeding 24 hours in duration, no later than 10:00 AM on the day prior to the Scheduling Day for the Trading Day in which the proposed Planned Outage is due to commence; and

ii. for an outage of up to 24 hours in duration, no later than 30 minutes before Balancing Gate Closure for the Trading Interval in which the proposed Planned Outage is due to commence.

(d) The notice under clause 3.18.2A(b) must include the information specified in clause 3.18.6.

(e) System Management is deemed to have approved each proposed Planned Outage for a Self-Scheduling Outage Facility that is notified under clauses 3.18.2A(b) or 3.18.2A(g) and in accordance with clauses 3.18.2A(c) and 3.18.2A(d). The deemed approval takes effect when System Management receives the notice.

(f) Where a Market Participant no longer intends that the relevant capacity of its Self-Scheduling Outage Facility will be unavailable for service for the purpose of Outage Facility Maintenance it must inform System Management and withdraw the notice of the proposed Planned Outage as soon as practicable.

(g) Subject to clause 3.18.2A(h), if a Market Participant becomes aware of any changes to the information provided to System Management in a notice of a proposed Planned Outage for a Self-Scheduling Outage Facility, then the Market Participant must, as soon as practicable, submit a revised notice to System Management for the Self-Scheduling Outage Facility that complies with the requirements of a notice of a proposed Planned Outage for a Self-Scheduling Outage Facility in this clause 3.18.2A.

(h) A Market Participant must not submit a revised notice of a proposed Planned Outage to System Management for a Self-Scheduling Outage Facility that proposes:

i. a new start time for the proposed Planned Outage that is earlier than the previous proposed start time;

ii. a new end time for the proposed Planned Outage that is later than the previous proposed end time; or

iii. an increase in the quantity of de-rating.

(i) Subject to clause 3.19.2G, a Market Participant must not notify System Management of a proposed Planned Outage of its Self-Scheduling Outage Facility in accordance with clause 3.18.2A(b) if the Market Participant is aware, or ought to be aware in the circumstances that, if the proposed Planned Outage did not proceed, any of the relevant capacity would be unavailable for service for any part of the proposed outage period for any reason other than that a deadline for completion of Mandatory Routine Maintenance would pass before the end of the proposed outage period.

3.18.3.

(a) If a Market Participant's or Network Operator's Facility (or an item of equipment forming part of a Facility or an item of equipment which is a generation system to which clause 2.30B.2(a) relates) is on the Equipment List, then the Market Participant or Network Operator may request that the Economic Regulation Authority reassess the inclusion of the Facility or item of equipment on the Equipment List in accordance with this clause 3.18.3.

(b) Following a request by a Market Participant or Network Operator under clause 3.18.3(a), the Economic Regulation Authority must consult with System Management and the Market Participant or Network Operator concerning whether the Equipment List Facility should remain on the Equipment List.

(c) The Economic Regulation Authority may give a direction to System Management that an Equipment List Facility should not remain on the Equipment List where it finds that:

i. System Management has not followed the Market Rules or the Power System Operation Procedure specified in clause 3.18.21 in determining the Equipment List; and

ii. if the Market Rules and the Power System Operation Procedure specified in clause 3.18.21 had been followed, then the Equipment List Facility would not have been on the Equipment List.

(d) If the Economic Regulation Authority gives a direction to System Management under clause 3.18.3(c), then System Management must, as soon as practicable, remove the relevant Equipment List Facility from the Equipment List and publish the updated Equipment List on the Market Web Site.

3.18.4. System Management must maintain an outage schedule that contains details of each Outage Plan:

(a) that System Management has accepted under clause 3.18.13; or

(b) that the Economic Regulation Authority has directed System Management under clause 3.18.15(f) to include in the outage schedule.

3.18.4A. A proposal submitted to System Management in accordance with this section 3.18 by a Market Participant or Network Operator in which permission is sought from System Management for some or all of the capacity or capability of an Equipment List Facility to be unavailable for service for a period is a proposed outage plan ("**Outage Plan**").

3.18.5. Market Participants:

(a) must, subject to clause 3.18.5A, submit to System Management details of a proposed Outage Plan at least one year but not more than three years in advance of the proposed outage, where:

i. the outage relates to an Equipment List Facility in respect of which a Market Participant holds Capacity Credits at any time during the proposed outage;

ii. the Equipment List Facility has a nameplate capacity greater than 10 MW; and

iii. the proposed outage has a duration of more than one week; and

(b) otherwise may submit an Outage Plan to System Management not more than three years and not less than two days in advance of the proposed outage.

3.18.5A. Market Participants may submit an Outage Plan to which clause 3.18.5(a) relates to System Management less than one year, but not less than two days, in advance of the proposed outage, but in such instances:

(a) System Management must give priority to Outage Plans to which clause 3.18.5(a) relate and which were received more than one year in advance of the commencement of the proposed outage;

(b) System Management must give priority to Outage Plans to which this clause 3.18.5A relates in the order they are received; and

(c) System Management must give no special priority to Outage Plans to which this clause 3.18.5A relates relative to Outage Plans to which clause 3.18.5(a) does not relate.

3.18.5B. Network Operators may submit an Outage Plan to System Management not more than three years and not less than two days in advance of the proposed outage.

3.18.5C. Where a Network outage is likely to unduly impact the operation of one or more Market Participant Registered Facilities, System Management may require that in developing their Outage Plans the relevant Network Operator and affected Market Participants coordinate the timing of their outages so as to minimise the impact of the Network outage on the operation of the Market Participant Registered Facilities.

3.18.5D. Subject to clauses 3.18.5E and 3.19.2G, a Market Participant or Network Operator must not submit an Outage Plan to System Management if it is aware or ought to be aware in the circumstances that, if System Management rejected the Outage Plan, any of the capacity or capability to which the Outage Plan applies would be unavailable for service for any part of the relevant outage period.

3.18.5E. A Market Participant or Network Operator is not required to comply with clause 3.18.5D in respect of an Outage Plan provided that:

(a) the purpose of the proposed outage is to conduct Mandatory Routine Maintenance;

(b) the applicable deadline for the proposed Mandatory Routine Maintenance falls within the proposed outage period;

(c) the Market Participant or Network Operator is aware that if the Mandatory Routine Maintenance is not undertaken before or during the proposed outage period then some or all of the capacity or capability to which the Outage Plan applies will be unavailable for service for part of the proposed outage period because the applicable deadline for the Mandatory Routine Maintenance will have passed;

(d) the Market Participant or Network Operator is not aware of any other reason why, if System Management rejected the Outage Plan, any of the capacity or capability to which the Outage Plan applies would be unavailable for service for any part of the proposed outage period; and

(e) the Market Participant or Network Operator includes in the Outage Plan that the Outage Plan is submitted under this clause 3.18.5E.

3.18.6. The information submitted in an Outage Plan, a notice of a proposed Planned Outage of a Self-Scheduling Outage Facility submitted in accordance with clause 3.18.2A, or a request for approval of Opportunistic Maintenance must include:

(a) the identity of the Outage Facility that will be unavailable;

(b) the quantity of any de-rating where, if the Outage Facility is a generating system, this quantity is in accordance with clause 3.21.5;

(c) the reason for the outage;

(d) the proposed start and end times of the outage;

(e) an assessment of risks that might extend the outage;

(f) details of the time it would take the Outage Facility to return to service, if required;

(g) contingency plans for the early return to service of the Outage Facility ("**Outage Contingency Plans**"); and

(h) if a Network Operator submits either an Outage Plan or a request for approval of Opportunistic Maintenance, a confirmation that the Network Operator has used its best endeavours to inform any Market Generator with a Scheduled Generator or Non-Scheduled Generator impacted by the unavailability of the relevant Outage Facility of the proposed outage.

3.18.6A. A Market Participant or Network Operator must not submit an Outage Plan if it is aware or ought to have been aware in the circumstances that it would not be able to complete the proposed Outage Facility Maintenance and make the relevant capacity or capability available for service by the end of the proposed outage period.

3.18.7. Outage Plans submitted by a Market Participant or Network Operator must represent the good faith intention of the Market Participant or Network Operator that the relevant capacity or capability of its Equipment List Facility will be unavailable for service for the duration of the outage period described in clause 3.18.6(d) for the purpose of Outage Facility Maintenance.

3.18.7A. System Management may reject an Outage Plan first submitted within 6 weeks of the commencement time of the outage without evaluating that Outage Plan if, in the opinion of System Management, the submitting party has not allowed adequate time for the Outage Plan to be assessed.

3.18.8. Where a Market Participant or Network Operator no longer intends that the relevant capacity or capability of its Equipment List Facility will be unavailable for service for the purpose of Outage Facility Maintenance it must inform System Management and withdraw the relevant Outage Plan as soon as practicable.

3.18.9. Subject to clause 3.18.9A, if a Market Participant or Network Operator becomes aware of any changes to the information provided to System Management in an Outage Plan, then the Market Participant or Network Operator must as soon as practicable submit a revised Outage Plan to System Management for the relevant Equipment List Facility that complies with the requirements of an Outage Plan in this section 3.18.

3.18.9A. A Market Participant or Network Operator must not submit a revised Outage Plan to System Management that proposes:

(a) a new start time for the proposed outage that is earlier than the previous proposed start time;

(b) a new end time for the proposed outage that is later than the previous proposed end time; or

(c) an increase in the quantity of de-rating.

3.18.9B. Subject to clauses 3.18.10C and 3.19.2G, if a Market Participant or Network Operator becomes aware, or ought to have become aware in the circumstances, that, if System Management rejected an Outage Plan for its Equipment List Facility, any of the capacity or capability to which the Outage Plan applies would be unavailable for service for any part of the proposed outage period, then the Market Participant or Network Operator must either:

(a) as soon as practicable, submit a revised Outage Plan to System Management for the Equipment List Facility that amends the proposed outage period or reduces the quantity of de-rating (or both) to meet the requirements of clause 3.18.5D; or

(b) as soon as practicable:

i. notify System Management; and

ii. if System Management has not yet scheduled the Outage Plan for the Equipment List Facility in its outage schedule, withdraw the Outage Plan.

3.18.10. Subject to clauses 3.18.10A and 3.18.10B, System Management must use a risk assessment process using the criteria set out in clause 3.18.11 to evaluate Outage Plans:

(a) when an Outage Plan is received or revised; and

(b) on an ongoing basis as part of the Medium Term PASA and Short Term PASA studies.

3.18.10A. Subject to clauses 3.18.10C and 3.19.2G, System Management must not schedule a new Outage Plan in its outage schedule if it is aware, or ought to be aware based on information that it has and any readily available confirmatory information, that, if it rejected the Outage Plan, any of the capacity or capability to which the Outage Plan applies would be unavailable for service for any part of the proposed outage period.

3.18.10B. If, at the time System Management begins its evaluation of a new Outage Plan:

(a) the relevant capacity or capability is subject to a Planned Outage for which System Management has received a notification under clauses 3.18.9B(b)(i) or 3.19.2F(b)(i);

(b) the relevant capacity or capability is subject to a Planned Outage for which System Management is aware that it should have received a notification under clauses 3.18.9B(b)(i) or 3.19.2F(b)(i) from the Market Participant or Network Operator; or

(c) the relevant capacity or capability is subject to a Forced Outage,

then System Management must delay its evaluation of the Outage Plan until:

(d) the relevant capacity or capability is returned to service; or

(e) System Management receives evidence to its satisfaction from the Market Participant or Network Operator that the relevant capacity or capability would be capable of being made available for service before the start of the proposed outage period in the Outage Plan.

3.18.10C. If a Market Participant or Network Operator submits an Outage Plan under clause 3.18.5E then:

(a) System Management must not refuse to schedule the Outage Plan in its outage schedule under clause 3.18.10A because the Mandatory Routine Maintenance will not be completed before the applicable deadline for that Mandatory Routine Maintenance; and

(b) the Market Participant or Network Operator is not required to take action under clause 3.18.9B because the Mandatory Routine Maintenance will not be completed before the applicable deadline for that Mandatory Routine Maintenance.

3.18.11. System Management must apply the following criteria when evaluating Outage Plans:

(a) the capacity of the total generation and Demand Side Management Facilities remaining in service must be greater than the second deviation load forecast published in accordance with clause 3.16.9(a)(iii) or clause 3.17.9(a)(iii), as applicable;

(aA) the total capacity of the generation Facilities remaining in service, and System Management's reasonable forecast of the total available Demand Side Management, must satisfy the Ready Reserve Standard described in clause 3.18.11A;

(b) the transmission system and distribution system capacity or capability remaining in service must be capable of allowing the dispatch of the capacity referred to in clause 3.18.11(a);

(c) the Facilities remaining in service must be capable of meeting the applicable Ancillary Service Requirements;

(d) the Facilities remaining in service must allow System Management to ensure the power system is operated within the Technical Envelope; and

(e) notwithstanding the criteria set out in clause 3.18.11(a) to (d), System Management may allow an outage to proceed if it considers that preventing the outage would pose a greater threat to Power System Security or Power System Reliability over the long term than allowing the outage.

3.18.11A. The Ready Reserve Standard requires that the available generation and demand-side capacity at any time satisfies the following principles:

(a) Subject to clause 3.18.11A(c), the additional energy available within fifteen minutes must be sufficient to cover:

i. 30% of the total output, including Parasitic Load, of the generation unit synchronized to the SWIS with the highest total output at that time;

ii. plus the Minimum Frequency Keeping Capacity as defined in clause 3.10.1(a).

(b) Subject to clause 3.18.11A(c), and in addition to the additional energy described in clause 3.18.11A(a), the additional energy available within four hours must be sufficient to cover:

i. 70% of the total output, including Parasitic Load, of the generation unit synchronized to the SWIS with the second highest total output at that time;

ii. less the Minimum Frequency Keeping Capacity as defined in clause 3.10.1(a).

(c) System Management may relax the requirements in clause 3.18.11A(a) and (b) in the following circumstances:

i. where System Management expects that the load demand will be such that it exceeds the second standard deviation peak load forecast level, as described in clause 3.17.9(a), used in the most recently published Short Term PASA for that Trading Interval;

ii. during the four hours following an event that has caused System Management to call on additional energy maintained in accordance with clauses 3.18.11A(a) or (b).

3.18.12. Except to the extent required by the criteria in clause 3.18.11 and to the extent allowed by clause 3.18.5A, in evaluating Outage Plans, System Management must not show bias towards a Market Participant or Network Operator in regard to its Outage Plans.

3.18.13. Following an evaluation of a new Outage Plan or an Outage Plan or group of Outage Plans that System Management has previously accepted fully or subject to conditions:

(a) System Management may find that an Outage Plan, or group of Outage Plans, when considered together, are acceptable, unacceptable or are acceptable under certain circumstances. If System Management finds that a group of Outage Plans when considered together are acceptable, unacceptable or acceptable under certain circumstances, then all the Outage Plans in that group have that status.

(b) Where System Management finds that an Outage Plan is acceptable, then it must schedule the Outage Plan in System Management's outage schedule accordingly and inform the Market Participants or Network Operators that submitted the Outage Plans.

(c) Where System Management finds that an Outage Plan is acceptable under certain circumstances, then it must inform the Market Participant or Network Operator that submitted the Outage Plan of its finding and the circumstances under which the Outage Plan would be acceptable. System Management must:

  i. consult with the Market Participant or Network Operator about those circumstances;

  ii. determine a date by which it expects to have sufficient information on those circumstances to reassess the Outage Plan;

  iii. inform the Market Participant or Network Operator of the date; and

  iv. reassess the outage plan using the criteria under clause 3.18.11 following the date specified in accordance with clause 3.18.13(c)(ii);

(d) Where System Management finds that an Outage Plan is unacceptable, then System Management must inform all Market Participants and Network Operators affected and must negotiate with the affected Market Participants and Network Operators to attempt to reach agreement as to System Management's outage schedule, and:

  i. If agreement is reached, then the affected Market Participants and Network Operators must resubmit Outage Plans to System Management; or

  ii. If no agreement is reached within 15 Business Days, System Management must:

    1. decide which of the Outage Plans are acceptable and schedule these Outages Plans into System Management's outage schedule where they are not already scheduled;

    2. decide which of the Outage Plans are unacceptable and remove these Outages Plans from the System Management's outage schedule where they were previously scheduled; and

    3. notify each affected Market Participant whether its Outage Plan has been scheduled.

(e) Where, as a result of an evaluation, the status of an Outage Plan that was previously acceptable or acceptable under certain conditions changes then System Management must modify its outage schedule accordingly.

3.18.14. System Management must use the following criteria when making a decision referred to in clause 3.18.13(d)(ii), in descending order of priority:

(a) System Management must give priority to the criteria in clause 3.18.11;

(b) System Management must give priority to Outage Plans that have previously been scheduled in System Management's outage schedule, in the order in which they were entered into the schedule;

(c) System Management must have regard to the technical reasons for the requested Outage Facility Maintenance, the technical implications for the relevant equipment if the Outage Facility Maintenance is not carried out and a reasonable duration for Outage Facility Maintenance carried out for those reasons; and

(d) System Management must give priority to Outage Plans that would be more difficult to reschedule, including considering the amount of capacity or capability that would be taken out of service and the duration of the outage.

3.18.15. Where System Management informs a Market Participant or Network Operator that an Outage Plan has not been scheduled or has been removed from System Management's outage schedule under clause 3.18.13(d)(ii), the Market Participant or Network Operator may apply to the Economic Regulation Authority to reassess the decision in accordance with the following procedures:

(a) A Market Participant or Network Operator can only apply for the Economic Regulation Authority to reassess a decision on the grounds that System Management has not followed the Market Rules or the Power System Operation Procedure specified in clause 3.18.21;

(b) The Market Participant or Network Operator must submit a written application to the Economic Regulation Authority, and forward a copy to System Management, stating the reasons why it considers that System Management's decision under clause 3.18.13(d)(ii) should be reassessed and providing any supporting evidence:

i. within ten Business Days of being informed of System Management's decision; and

ii. no later than five Business Days prior to the date when the outage would have commenced.

(c) Until the Economic Regulation Authority completes its reassessment, System Management's decision continues to have effect and System Management and the Market Participant or Network Operator must continue to plan their operations on this basis.

(d) System Management must submit records relating to System Management’s outage schedule around the date of the relevant outage to the Economic Regulation Authority within two Business Days of being informed of the Market Participant’s or Network Operator’s application under clause 3.18.15(b).

(e) The Economic Regulation Authority must consult with System Management and the Market Participant or Network Operator concerning the Outage Plan, and must make a complete reassessment by the earlier of:

i. ten Business Days of receiving the application under clause 3.18.15(b); or

ii. two Business Days prior to the date when the outage would have commenced.

(f) The Economic Regulation Authority may give a direction to System Management that the Outage Plan should be scheduled in System Management’s outage schedule where it finds that:

i. System Management has not followed the Market Rules or the Power System Operation Procedure specified in clause 3.18.21; and

ii. if the Market Rules and the Power System Operation Procedure specified in clause 3.18.21 had been followed, then the Outage Plan would have been scheduled; and

(g) Where the Economic Regulation Authority gives a direction to System Management that the Outage Plan should be scheduled in System Management’s outage schedule, System Management must schedule it into the outage schedule in accordance with the direction.

3.18.16. Where System Management informs a Market Participant or Network Operator that an Outage Plan is unacceptable, and the Economic Regulation Authority does not give System Management a direction under clause 3.18.15(f), then System Management and the Market Participant or Network Operator must use their best endeavours to agree an alternative time for the relevant outage, and System Management must schedule the alternative time in its outage schedule.

3.18.17. System Management must keep records of all of its outage evaluations and decisions made in accordance with this section 3.18, together with the reasons for each outage evaluation and decision.

3.18.18. From time to time, and at least once in every five year period starting from Energy Market Commencement, the Economic Regulation Authority, with the assistance of System Management, must conduct a review of the outage planning process against the Wholesale Market Objectives. The review must include a technical study of the effectiveness of the criteria in clause 3.18.11 and a broad consultation process with Rule Participants.

3.18.19. At the conclusion of a review under clause 3.18.18, the Economic Regulation Authority must publish a report containing:

(a) the inputs and results of the technical study;

(b) the submissions made by Rule Participants in the consultation process and any responses to issues raised in those submissions;

(c) any recommended changes to the outage planning process, formulated as one or more Market Rule changes or Market Procedure changes.

3.18.20. If the Economic Regulation Authority recommends any changes in the report in clause 3.18.19, the Economic Regulation Authority must either submit a Rule Change Proposal in accordance with clause 2.5.1 or initiate a Procedure Change Process in accordance with section 2.10, as the case may be.

3.18.21. System Management must document the procedure it follows in conducting outage planning in a Power System Operation Procedure.

Explanatory Note Amendments to section 3.19, including consequential amendments as a result of the new Essential System Services framework, will be made in the Outages workstream. Amendments will also be made to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

3.19. Outage Approval

3.19.1. No later than 10:00 AM on the day prior to the Scheduling Day for the Trading Day in which a Scheduled Outage is due to commence, the relevant Market Participant or Network Operator must request that System Management approve the Scheduled Outage to proceed.

3.19.2. Subject to clause 3.19.2B, Market Participants and Network Operators may request that System Management approve an outage of an Equipment List Facility that is not a Scheduled Outage ("**Opportunistic Maintenance**"):

(a) at any time between:

i. 10:00 AM on the day prior to the Scheduling Day for the Trading Day in which the requested outage is due to commence; and

ii. 30 minutes before Balancing Gate Closure for the Trading Interval in which the requested outage is due to commence, and

(b) where:

i. the requested outage is to allow Outage Facility Maintenance to be performed;

ii. the duration of the requested outage does not exceed 24 hours;

iii. the outage period is separated by at least 24 hours from any other Opportunistic Maintenance outage period for the Equipment List Facility; and

iv. the request includes the information specified in clause 3.18.6.

3.19.2A. If:

(a) a Market Participant or Network Operator intends that some or all of an Equipment List Facility’s capacity or capability will be unavailable for service for a period for the purpose of Outage Facility Maintenance; and

(b) the Market Participant or Network Operator is not prohibited from submitting an Outage Plan under clause 3.18.5D or a request for approval of Opportunistic Maintenance under clause 3.19.2B (as applicable) for the proposed outage,

then the Market Participant or Network Operator must request approval for a Scheduled Outage or Opportunistic Maintenance from System Management in accordance with section 3.18 and this section 3.19.

3.19.2B. Subject to clause 3.19.2G, a Market Participant or Network Operator must not request approval of Opportunistic Maintenance under clause 3.19.2 if the Market Participant or Network Operator is aware or ought to be aware in the circumstances that, if System Management rejected the request, any of the capacity or capability to which the request applies would be unavailable for service for any part of the relevant outage period.

3.19.2C. Where a Market Participant or Network Operator no longer intends to proceed with Opportunistic Maintenance that was requested under this section 3.19, it must inform System Management and withdraw the request as soon as practicable.

3.19.2D. Subject to clause 3.19.2E, if a Market Participant or Network Operator becomes aware of any changes to the information provided to System Management in a request for approval of Opportunistic Maintenance, then the Market Participant or Network Operator must submit a revised request to System Management for the relevant Equipment List Facility as soon as practicable in accordance with the requirements of a request for approval of Opportunistic Maintenance in this section 3.19.

3.19.2E. A Market Participant or Network Operator must not submit a revised request for approval of Opportunistic Maintenance that proposes:

(a) a new start time for the Opportunistic Maintenance that is earlier than the previous proposed start time;

(b) a new end time for the Opportunistic Maintenance that is later than the previous proposed end time; or

(c) an increase in the quantity of de-rating.

3.19.2F. Subject to clause 3.19.2G, if a Market Participant or Network Operator becomes aware, or ought to have become aware in the circumstances, that, if System Management rejected a request for approval of Opportunistic Maintenance for its Equipment List Facility, any of the capacity or capability to which the request applies would be unavailable for service for any part of the proposed outage period, then the Market Participant or Network Operator must either:

(a) as soon as practicable, submit a revised request to System Management for the Equipment List Facility that amends the proposed outage period or reduces the quantity of de-rating (or both) to meet the requirements of clause 3.19.2B; or

(b) as soon as practicable:

i. notify System Management; and

ii. withdraw the request for approval of Opportunistic Maintenance if System Management has not yet approved it.

3.19.2G. Clauses 3.18.2A(i), 3.18.5D, 3.18.9B, 3.18.10A, 3.19.2B, 3.19.2F and 3.19.3B do not apply where:

(a) the proposed Planned Outage will immediately follow a Planned Outage of the relevant capacity or capability, and System Management has not received a notification under clauses 3.18.9B(b)(i) or 3.19.2F(b)(i) in respect of the earlier Planned Outage; or

(b) System Management or the Market Participant or Network Operator (as applicable):

i. is aware that the relevant capacity or capability would be subject to a Consequential Outage if the proposed Planned Outage did not proceed; and

ii. is not aware of any other reason why any part of the relevant capacity or capability would be unavailable for service for any part of the relevant outage period if the proposed Planned Outage did not proceed.

3.19.2H. If, at the time a Market Generator submits a request for approval of Opportunistic Maintenance for a Scheduled Generator:

(a) the Facility is not synchronised; and

(b) the proposed start time for the maintenance work that is the subject of the request is before the time when the Facility could be synchronised in accordance with its relevant Equipment Limits,

then the Market Generator may exclude from the start of the proposed outage period in its request any Trading Intervals during which the Facility could not be synchronised in accordance with its Equipment Limits, provided that the Market Generator:

(c) does not start the maintenance work that is the subject of the request until the request is approved by System Management; and

(d) immediately withdraws the request if System Management has not approved the request prior to the Trading Interval in which the maintenance work that is the subject of the request is intended to commence.

3.19.3. Subject to clauses 3.19.3A, 3.19.3B and 3.19.3C, System Management must assess the request for approval of a Scheduled Outage or Opportunistic Maintenance, based on the information available to System Management at the time of the assessment, and applying the criteria set out in clause 3.19.6.

3.19.3A. In assessing whether to grant a request for Opportunistic Maintenance, System Management:

(a) must not grant permission for Opportunistic Maintenance to begin prior to the first Trading Interval for which Opportunistic Maintenance is requested; and

(b) [Blank]

(c) [Blank]

(d) may decline to approve Opportunistic Maintenance for a facility where it considers that inadequate time is available before the proposed commencement time of the outage to adequately assess the impact of that outage.

3.19.3B. Subject to clause 3.19.2G, System Management must not approve an Opportunistic Maintenance request for an Equipment List Facility if it is aware, or ought to be aware based on information that it has and any readily available confirmatory information, that, if it rejected the request, any of the capacity or capability to which the request applies would be unavailable for service for any part of the proposed outage period.

3.19.3C. If, at the time a Market Participant or Network Operator submits a request for approval of Opportunistic Maintenance under clause 3.19.2:

(a) the relevant capacity or capability is subject to a Planned Outage for which System Management has received a notification under clauses 3.18.9B(b)(i) or 3.19.2F(b)(i);

(b) the relevant capacity or capability is subject to a Planned Outage for which System Management is aware that it should have received a notification under clauses 3.18.9B(b)(i) or 3.19.2F(b)(i) from the Market Participant or Network Operator; or

(c) the relevant capacity or capability is subject to a Forced Outage,

then System Management must delay its assessment of the request until:

(d) the relevant capacity or capability becomes available for service; or

(e) System Management receives evidence to its satisfaction from the Market Participant or Network Operator that the relevant capacity or capability would be capable of being made available for service before the start of the proposed Opportunistic Maintenance.

3.19.4. System Management must either approve or reject a request for approval of a Scheduled Outage or Opportunistic Maintenance, subject to clause 3.19.3C, and inform the Market Participant or Network Operator of its decision as soon as practicable.

3.19.4A. If System Management does not provide a Market Participant or Network Operator with its decision on a request for approval of a Scheduled Outage or Opportunistic Maintenance:

(a) for Scheduled Outages, by 2:00 PM on the day prior to the Scheduling Day for the Trading Day in which the Scheduled Outage is proposed to commence; or

(b) for Opportunistic Maintenance, by 30 minutes before Balancing Gate Closure for the Trading Interval during which the Opportunistic Maintenance is proposed to commence,

then the request for approval of the Scheduled Outage or Opportunistic Maintenance is deemed to be rejected.

3.19.5. Where a change in power system conditions after System Management has approved a Scheduled Outage or Opportunistic Maintenance means that the Scheduled Outage or Opportunistic Maintenance is no longer approvable applying the criteria in clause 3.19.6, System Management may decide to reject the Scheduled Outage or Opportunistic Maintenance. Where System Management makes such a decision, it must inform the relevant Market Participant or Network Operator of its decision immediately.

3.19.6. System Management must use the following criteria when considering approval of Scheduled Outages or Opportunistic Maintenance:

(a) the capacity of the generation Facilities remaining in service, and System Management's reasonable forecast of the total available Demand Side Management, must be greater than the load forecast for the relevant time period;

(b) the Facilities remaining in service must be capable of meeting the Ancillary Service Requirements;

(c) the Facilities remaining in service must allow System Management to ensure the power system is operated within the Technical Envelope;

(d) where a group of outages when considered together, do not meet the criteria set out in clause 3.19.6(a) to (c), then System Management should give priority:

i. to outages scheduled in System Management's outage schedule more than one month ahead; then

ii. to previously Scheduled Outages that have been deferred in accordance with clauses 3.19.4 or 3.19.5, but were originally scheduled in System Management's outage schedule more than one month ahead; then

iii. to outages scheduled in System Management's outage schedule less than one month ahead; then

iv. to previously Scheduled Outages that have been deferred in accordance with clause 3.19.4 or 3.19.5, but were originally scheduled in System Management's outage schedule less than one month ahead; then

v. to Opportunistic Maintenance; and

(e) notwithstanding the criteria set out in clause 3.19.6(a) to (d), System Management may allow a Scheduled Outage to proceed if it considers that rejecting it would pose a greater threat to Power System Security or Power System Reliability than accepting it.

3.19.7. Where System Management informs a Market Participant or Network Operator that an outage is rejected, then System Management and the Market Participant or Network Operator must use their best endeavours to find an alternative time for the relevant outage.

3.19.8. Subject to clause 3.19.9, Market Participants and Network Operators must comply with System Management's decision to reject an outage, and the relevant Market Participant or Network Operator must ensure that the outage is not taken.

3.19.9. Compliance with clause 3.19.8 is not required if such compliance would endanger the safety of any person, damage equipment, or violate any applicable law. Where a Rule Participant cannot comply with such a decision it must inform System Management as soon as practicable.

3.19.10. Where a Market Participant or Network Operator has reason to believe that System Management has not followed the Market Rules or the Power System Operation Procedure specified in clause 3.19.14 in its decision to reject an outage it may report the decision to the Economic Regulation Authority as a potential breach of the Market Rules in accordance with clause 2.13.4.

3.19.11. An outage, including a Scheduled Outage or Opportunistic Maintenance, is a Planned Outage if it is:

(a) approved by System Management under clause 3.19.4; or

(b) deemed to be approved by System Management under clause 3.18.2A(e).

3.19.12.

(a) Where System Management informs a Market Participant or Network Operator that an Outage Plan previously scheduled in System Management's outage schedule is rejected within 48 hours of the time when the outage would have commenced in accordance with the Outage Plan, the Market Participant or Network Operator may apply to AEMO for compensation.

(aA) Compensation will only be paid where details of the relevant Outage Plan have been submitted to System Management at least one year in advance of the time when the outage would have commenced.

(b) Compensation will only be paid for the additional maintenance costs directly incurred by a Market Participant or Network Operator in the deferment or cancellation of the relevant outage.

(c) Compensation will not be paid for Opportunistic Maintenance.

(d) The Market Participant or Network Operator must submit a written request for compensation to AEMO within three months of System Management's decision, including invoices and other documents demonstrating the costs referred to in clause 3.19.12(b).

(e) AEMO must determine the amount of compensation within one month of the submission of the application for compensation, and must notify the Market Participant or Network Operator of the amount determined and the reasons for its determination.

(f) The determined amount of compensation:

i. if less than or equal to $50,000, must be paid to the applicant in accordance with Chapter 9 in respect of the Trading Month during which the determination is made; and

ii. if greater than $50,000, must be paid to the applicant in accordance with Chapter 9 in equal instalments over between one and six Trading Months as determined by AEMO, where:

1. if practicable, AEMO must endeavour not to recover more than $50,000 in any Trading Month;

2. interest is to be paid to the applicant calculated by AEMO in accordance with clause 9.1.3 if the amount is recovered over two or more Trading Months; and

3. the Trading Month amounts are to be included in its Non-STEM Settlement Statement pertaining to each of the applicable Trading Months from the Trading Month during which the determination is made.

3.19.13. System Management must keep records of all of its outage evaluations and decisions made in accordance with this section 3.19, together with the reasons for each outage evaluation and decision.

3.19.14. System Management must document the procedure it follows in conducting final approval of outages in a Power System Operation Procedure.

Explanatory Note
The proposed amendment to clause 3.20.1 is a consequential amendment to the new Operating States.

It is expected that further changes will be made to section 3.20 in the Outages workstream, and to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

3.20. Outage Recall

3.20.1. ~~Where the SWIS is in an Emergency Operating State or a High Risk Operating State, System Management~~In order to maintain Power System Security or Power System Reliability, AEMO may direct a Market Participant or Network Operator to return an Outage Facility to service from a Planned Outage in accordance with the relevant Outage Contingency Plan, or take other measures contained in the relevant Outage Contingency Plan.

3.20.2. Subject to clause 3.20.3, Market Participants and Network Operators must comply with directions from System Management under clause 3.20.1.

3.20.3. Rule Participants are not required to comply with directions issued by System Management under clause 3.20.1 if such compliance would endanger the safety of any person, damage equipment, or violate any applicable law. Where a Rule Participant cannot comply with such a direction it must inform System Management as soon as practicable.

Explanatory Note

Amendments to sections 3.21, 3.21A and 3.21B are proposed to be made in other workstreams, including Outages. Amendments will also be made to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

3.21. Forced Outages and Consequential Outages

3.21.1. A Forced Outage is any outage of either a Facility or item of equipment on the list described in clause 3.18.2 or a Facility or generation system to which clause 3.18.2A relates that has not received System Management's approval, including:

(a) outages or de-ratings for which no approval was received from System Management, excluding Consequential Outages;

(aB) outages or de-ratings as a result of a direction from System Management under clause 2.28.3C;

(b) any part of a Planned Outage that exceeds its approved duration; and

(c) where the Market Participant or Network Operator does not follow a direction from System Management under clause 3.20.1 to return the equipment to service within the time specified in the appropriate contingency plan.

3.21.2. A Consequential Outage is an outage of either a Facility or item of equipment on the list described in clause 3.18.2 or a facility or generation system to which clause 3.18.2A relates for which no approval was received from System Management, but which System Management determines:

(a) was caused by a Forced Outage to another Rule Participant's equipment and would not have occurred if the other Rule Participant's equipment did not suffer a Forced Outage; or

(b) was caused by a Planned Outage to a Network Operator's equipment and would not have occurred if the Network Operator's equipment did not undertake the Planned Outage,

but excludes any outage deemed not to be a Consequential Outage in accordance with clause 3.21.10.

3.21.2A. An outage does not occur in respect of a Constrained Access Facility for the purposes of these Market Rules where the Constrained Access Facility is dispatched in accordance with a Network Control Service Contract and these Market Rules.

3.21.3. System Management must keep a record of all Forced Outages and Consequential Outages of which it is aware.

3.21.4. If a Facility or item of equipment that is on the list described in clause 3.18.2 or a Facility or generation system to which clause 3.18.2A relates suffers a Forced Outage or Consequential Outage, then the relevant Market Participant or Network Operator must inform System Management of the outage as soon as practicable. Information provided to System Management must include:

(a) the time the outage commenced;

(b) an estimate of the time the outage is expected to end;

(c) the cause of the outage;

(d) the Facility or item of equipment or Facilities or items of equipment affected; and

(e) for each affected Facility or item of equipment, the expected quantity of any de-rating by Trading Interval, where, if the Facility is a generating system, this quantity is to be submitted in accordance with clause 3.21.5.

3.21.5 The quantity of an outage notification submitted to System Management is the reduction in capacity from the relevant Facility's maximum capacity measured on a sent out basis at 41 degrees Celsius where the maximum capacity is as found in the Standing Data file for Temperature Dependence provided under Appendix 1(b) iv and converted to a sent out basis at 41 degrees Celsius. The remaining capacity, determined as the maximum capacity minus the notified outage, must be available to System Management for dispatch.

3.21.6. The following will apply for the purposes of clauses 7.3.4 and 7.13.1A (b):

(a) outage data will be entered by Market Participants in System Management's computer interface system on a sent out basis at 15 degrees Celsius. System Management will convert the outage data to a sent out basis at 41 degrees Celsius by multiplying the outage quantity at 15 degrees Celsius by the ratio of the maximum capacity at 41 degrees

Celsius to the maximum capacity at 15 degrees Celsius for the Facility as found in the Standing Data file for temperature dependence provided under Appendix 1(b) iv on a generated basis for that facility. Market Participants will submit the outage data at 41 degrees Celsius as displayed by System Management's computer interface system;

(b) System Management will calculate the Forced Outage (on a sent out basis at 41 degrees Celsius) for a Facility in a Trading Interval as the greater of:

i zero and

ii the sum of all Forced Outages notified for that Facility minus the difference of the Facility maximum capacity and its Reserve Capacity Obligation Quantity;

(c) System Management will calculate the Planned Outage (on a sent out basis at 41 degrees Celsius) for a Facility in a Trading Interval as the greater of:

i. zero and

ii. the sum of all Planned Outages minus the greater of:

1. zero and

2. the maximum capacity of the Facility minus its Reserve Capacity Obligation Quantity minus the sum of all Forced Outages notified for the Facility before the adjustment in (b) above is made by System Management; and

(d) System Management will calculate the Consequential Outage (on a sent out basis at 41 degrees Celsius) for a Facility in a Trading Interval as the greater of:

i. zero and

ii. the sum of all Consequential Outages minus the greater of:

1. zero and

2. the maximum capacity of the Facility minus its Reserve Capacity Obligation Quantity minus the sum of all Forced Outages and the sum of all Planned Outages notified for the Facility before the adjustments in (b) and (c) above are made by System Management;

(e) [Blank]

(f) the maximum capacity used in this clause is the value defined in clause 3.21.5.

3.21.7 Notwithstanding the requirements of clause 3.21.4 that a relevant Market Participant or Network Operator must inform System Management of a Forced Outage or Consequential Outage as soon as practicable, a Market Participant or Network Operator must provide full and final details of the relevant Planned

Outage, Forced Outage or Consequential Outage to System Management no later than fifteen calendar days following the Trading Day.

3.21.8 If a Market Participant considers that one of its Facilities has suffered a Consequential Outage then the Market Participant may provide System Management with a notice confirming details of the Consequential Outage no later than 15 calendar days following the Trading Day on which the Consequential Outage commenced. The notice must:

(a) be signed by an Authorised Officer of the Market Participant;

(b) confirm that a Consequential Outage has occurred; and

(c) provide details (to the best of its knowledge) of the events which resulted in the Consequential Outage.

3.21.9. In its determination of a Consequential Outage under clause 3.21.2, System Management must accept the information provided by a Market Participant under clause 3.21.8 unless the information is inconsistent with other information held by System Management.

3.21.10 If a Market Participant informs System Management of a Consequential Outage under clause 3.21.4, but does not provide System Management with a notice in accordance with clause 3.21.8, then the outage will be deemed not to be a Consequential Outage and System Management must not include the outage as a Consequential Outage in the schedule provided to AEMO in accordance with clause 7.13.1A(b).

3.21.11 System Management must retain the notices it receives under clause 3.21.8.

3.21.12. System Management must document the procedure to be followed in determining and reporting Forced Outages and Consequential Outages in a Power System Operation Procedure.

Commissioning Tests

3.21A Commissioning Tests

3.21A.1. A Commissioning Test ("Commissioning Test") is a series of activities which confirm the ability of a generating system to operate at different levels of output reliably.

3.21A.2. A Market Participant conducting a Commissioning Test for:

(a) an existing generating system that has undergone significant maintenance; or

(b) a new generating system that has yet to commence operation,

must conduct such tests under a Commissioning Test Plan approved by System Management.

3.21A.3. System Management may approve a Commissioning Test Plan only for a new generating system that is yet to commence operation, or for an existing generating system that has undergone significant maintenance.

3.21A.4. A Market Participant requesting permission for a Commissioning Test must use best endeavours to submit to System Management its Commissioning Test Plan for approval at least 7 Trading Days prior to the start of the Commissioning Test Period. A Commissioning Test Plan must contain the following information:

(a) the name and location of the facility to be tested;

(b) details of the proposed Commissioning Test Period, including start and end Trading Intervals and dates for the proposed Commissioning Tests;

(c) details of the proposed Commissioning Tests to be undertaken, including an indicative test program, fuel mix and trip risk of the facility to be tested; and

(d) contact details for the relevant contact persons at the facility to be tested, where such persons must be contactable by System Management during all Trading Intervals during the proposed Commissioning Test Period

3.21A.5. A Commissioning Test Plan submitted by a Market Participant must represent the good faith intention of the Market Participant to conduct the Commissioning Test.

3.21A.6. Where a Market Participant no longer plans to conduct a Commissioning Test it must inform System Management as soon as practicable.

3.21A.7. System Management must approve a Commissioning Test Plan, unless:

(a) in its opinion inadequate information is provided in the Commissioning Test Plan; or

(b) in its opinion conducting any of the proposed activities to be undertaken at the proposed times would pose a threat to Power System Security or Power System Reliability.

(c) [Blank]

(d) in its opinion inadequate time to properly consider the Commissioning Test Plan has been provided, where the request has been received less than 20 Trading Days prior to the start date of the proposed Commissioning Test.

3.21A.8. System Management must not show bias towards a Market Participant in regard to approving a Commissioning Test Plan.

3.21A.9. System Management must notify a Market Participant as to whether it has approved a Commissioning Test Plan as soon as practicable but in any event no later than 8:00am on the Scheduling Day for which the Commissioning Test Plan would apply.

3.21A.10. Where System Management notifies a Market Participant that:

(a) a Commissioning Test Plan has not been approved then:

i. System Management must provide an explanation for its decision;

ii. if the Commissioning Test Plan complied with clause 3.21A.7(a) but did not comply with any or all of clauses 3.21A.7(b) or 3.21A.7(d) then, System Management and the Market Participant must use their best endeavours to agree to an alternative time for the relevant Commissioning Test that is consistent with the requirements in clause 3.21A.7; and

iii. where System Management and the Market Participant agree an alternative time under clause 3.21A.10(a)(ii), the Market Participant must, as soon as practicable, submit a revised Commissioning Test Plan which reflects the agreed alternative time to System Management and System Management must approve that revised Commissioning Test Plan; or

(b) a Commissioning Test Plan has been approved then, subject to clause 3.21A.11, the Market Participant may proceed with that Commissioning Test.

3.21A.11. If, having approved a Commissioning Test Plan, System Management becomes aware that:

(a) conducting any of the activities at the proposed time would pose a threat to Power System Security or Power System Reliability, or in the case of a Facility returning to service after undergoing significant maintenance the return to service has been delayed, then it may delay the commencement of that Commissioning Test or cancel that Commissioning Test; or

(b) the Commissioning Test is no longer required then it may cancel its approval of that Commissioning Test,

and must notify the Market Participant conducting the Commissioning Test of such delay or cancellation as soon as practicable after making its decision.

3.21A.12. In conducting a Commissioning Test a Market Participant must conform to the most recent Commissioning Test Plan approved by System Management.

3.21A.13. If a Market Participant conducting a Commissioning Test cannot conform to the most recent Commissioning Test Plan approved by System Management for that Commissioning Test then it must:

(a) inform System Management as soon as practicable; and

(b) obtain System Management's approval of a Commissioning Test Plan for that Commissioning Test if it wishes to conduct that Commissioning Test.

3.21A.14. A Commissioning Test under an approved Commissioning Test Plan for an Outage Facility may cover periods in which some or all of the capacity or capability of the Outage Facility is subject to a Planned Outage or Forced Outage.

3.21A.15. System Management must document the procedure it follows in scheduling and approving Commissioning Tests in a Power System Operation Procedure.

3.21A.16. [Blank]

3.21A.17. A reference in these Market Rules to an "approved Commissioning Test" shall be interpreted to mean a "Commissioning Test specified in the most recent Commissioning Test Plan approved by System Management".

Decommitment and Reserve Capacity Obligations

3.21B. Decommitment and Reserve Capacity Obligations

3.21B.1. Except where approval for a Planned Outage has been granted, or clause 7.9.6 applies, a Market Participant must seek permission from System Management before putting a Scheduled Generator holding Capacity Credits into a state where it will take more than four hours to re-synchronise the Scheduled Generator.

3.21B.2. A Market Participant must request from System Management the permission described in clause 3.21B.1 not less than two hours prior to the facility ceasing to be able to be re-synchronised within four hours, including in that request:

(a) the identity of the Scheduled Generator;

(b) the time at which the Market Participant wants to have the Scheduled Generator enter a state where it will take more than four hours to re-synchronise; and

(c) the first time after that in (b) at which the Scheduled Generator will be able to be resynchronised with four hours notice.

3.21B.3. System Management must assess the request for permission, based on the information available to System Management at the time of the request, and applying the criteria set out in clause 3.21B.5.

3.21B.4. System Management must either approve or reject the request and inform the Market Participant of its decision as soon as practicable, but no later than one hour prior to the time described in clause 3.21B.2(b).

3.21B.5. System Management may only withhold the permission described in clause 3.21B.1 if:

(a) the request for that permission is not in compliance with clause 3.21B.2 or the Power System Operation Procedure specified in clause 3.21B.8; or

(b) granting permission would mean that System Management would be incapable of maintaining the Ready Reserve Standard.

3.21B.6. Where System Management informs a Market Participant that permission is not granted, then System Management and the Market Participant must use their best endeavours to find an alternative time for the Scheduled Generator to be put into a state where it will take more than four hours to re-synchronise the Scheduled Generator

3.21B.7. If System Management grants permission, then within the time period set out in clause 3.21B.2(b) and 3.21B.2(c), or such alternative times as are mutually agreed in accordance with clause 3.21B.6, System Management must not require that Scheduled Generator to perform in accordance with its Reserve Capacity Obligations.

3.21B.8. System Management must document the procedure it follows to grant permission in accordance with section 3.21B in a Power System Operation Procedure.

Explanatory Note

Section 3.22 is proposed to be amended as a consequence of the amendments to section 3.13. However, these are placeholder amendments only, as section 3.22 will be amended in the Settlement workstream.

Amendments will also be made to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

3.22. Settlement Data

3.22.1. AEMO must update the following information in the settlement system for each Trading Month:

(a) [Blank]

(b) [Blank]

(c) [Blank]~~Margin_Peak as described in clause 3.13.3A~~;

(d) [Blank]~~Margin_Off-Peak as described in clause 3.13.3A~~;

(e) [Blank]~~SR_Capacity_Peak, the requirement for Spinning Reserve Service for Peak Trading Intervals assumed in forming Margin_Peak~~;

(f) [Blank]~~SR_Capacity_Off-Peak, the requirement for Spinning Reserve Service for Off-Peak Trading Intervals assumed in forming Margin_Off-Peak~~;

(fA) [Blank]

(g) [Blank]~~Cost_LRD as the sum of:~~

~~i. Cost_LR (as described in clauses 3.13.3B and 3.13.3C) divided by 12 as a monthly amount; and~~

~~ii. the monthly amount for Dispatch Support Service~~; and

(h) the compensation due to changed outage plans to be paid to a Market Participant for that Trading Month as determined in accordance with clause 3.19.12(e).

3.22.2. [Blank]

3.22.3. [Blank]

3.23 LoadWatch Data

3.23.1. System Management must, by 12:00 PM on each Tuesday during a Hot Season, prepare and publish on the Market Web Site a LoadWatch Report, providing the following information for each Business Day of that week—

(a) System Management's estimate of—

i. daily maximum temperature;

ii. daily minimum temperature; and

iii. daily maximum load in MW; and

(b) other data published by System Management from time to time for the purpose of the LoadWatch Report.

Where available, System Management must also publish in the LoadWatch Report the following information for each Business Day of the previous week—

(c) maximum and minimum temperatures;

(d) total generation capacity and total Demand Side Management capacity;

(e) total MW quantity of Outages;

(f) total available generation capacity and total Demand Side Management capacity after accounting for total Outages;

(g) maximum Operational System Load Estimate; and

(h) total available generation capacity and total Demand Side Management capacity after accounting for total Outages and the maximum Operational System Load Estimate.

3.23.2. [Blank]

3.23.3. [Blank]

Market Data

3.24. Distributed Energy Resources Register

3.24.1. On and from a day no earlier than the day that is six months after the day AEMO develops the Market Procedure referred to in clause 3.24.8, AEMO must establish, maintain and update a DER Register.

3.24.2. The DER Register:

(a) must include DER Generation Information reported to AEMO by Network Operators in accordance with clause 3.24.5; and

(b) may include information of a type similar to the information referred to in clause 3.24.2(a) provided to AEMO by any person in connection with the performance of AEMO's functions under the Market Rules, Regulations or the Electricity Industry Act.

3.24.3. By no later than 30 September 2020, a Network Operator must provide AEMO with all DER Generation Information that it holds in accordance with the Market Procedure referred to in clause 3.24.8, or as otherwise agreed with AEMO.

3.24.4. AEMO will be taken to satisfy the requirement to establish and maintain a DER Register in clause 3.24.1 if it stores DER Register Information in one or more databases.

3.24.5. If a Network Operator receives DER Generation Information relating to connection points on its Network it must, in accordance with the Market Procedure referred to in clause 3.24.8, provide that information to AEMO.

3.24.6. AEMO may use DER Register Information for the purpose of the exercise of its statutory functions under the Electricity Industry Act, Regulations, and these Market Rules.

3.24.7. AEMO must publish details on the extent to which, in general terms, DER Register Information has informed AEMO's development or use of load forecasts, or the performance of its functions referred to in clause 3.24.6 and AEMO may, for this purpose, include such details as part of existing Market Procedures or other publications produced by AEMO, or by publishing details on the Market Web Site.

3.24.8. By no later than 1 July 2020, AEMO must develop and implement a Market Procedure that specifies:

(a) details of the DER Generation Information that Network Operators must provide to AEMO under clauses 3.24.3 and 3.24.5, including any minimum size of Small Generating Units or Storage Works for which a Network Operator is required to provide DER Generation Information;

(b) when Network Operators must provide and update DER Generation Information;

(c) how DER Generation Information should be provided to AEMO by Network Operators, including, for example, the format in which the information must be provided;

(d) how the information in the DER Register is stored by AEMO;

(e) the manner and form in which AEMO will publish details, in accordance with clause 3.24.7, on the extent to which DER Register Information has informed its load forecasts or its function for ensuring that the SWIS operates in a secure and reliable manner;

(f) details of how AEMO will provide Network Operators with access to DER Register Information under clause 3.24.14; and

(g) the contents, form and timing of the DER Register Report to be published by AEMO in accordance with clause 3.24.12 and how the DER Register Information to be included in that report will be aggregated.

3.24.9. In developing and amending the Market Procedure referred to in clause 3.24.8, AEMO must:

(a) have regard to the reasonable costs of efficient compliance by Network Operators with the procedure compared to the likely benefits from the use of DER Generation Information as contemplated under this section 3.24;

(b) consider any risk of unauthorised use or disclosure of confidential information or personal information that may arise from including information in the DER Register compared to the likely benefits of including that information in the register; and

(c) subject to clause 3.24.10, comply with the Procedure Change Process.

3.24.10. AEMO is not required to comply with the Procedure Change Process when making the first Market Procedure referred to in clause 3.24.8 or when making minor or administrative amendments to that Market Procedure.

3.24.11. The Market Procedure referred to in clause 3.24.8 must include a minimum period of 3 months between the date of publication and the date when the procedure commences other than when the procedure is amended under paragraph 3.24.10, in which case the procedure may commence on the date of publication.

3.24.12. AEMO must prepare and publish on the Market Web Site a report of aggregated DER Register Information in accordance with the Market Procedure referred to in clause 3.24.8.

3.24.13. The information in the DER Register Report must be aggregated such that it does not:

(a) directly or indirectly disclose confidential information; or

(b) result in a breach of applicable privacy legislation.

3.24.14. AEMO must provide or give access to DER Register Information to each Network Operator in relation to that Network Operator's Network in accordance with the Market Procedure referred to in clause 3.24.8.

3.24.15. Nothing in this clause 3.24:

(a) requires AEMO to make available DER Register Information where the collection, use or disclosure of that information by AEMO would breach applicable privacy legislation; or

(b) precludes AEMO from disclosing confidential information in the circumstances in which disclosure of confidential information is permitted under the Market Rules, Regulations or the Electricity Industry Act.

3.24.16. No less than seven days before the day the DER Register commences, AEMO must publish notice on the Market Web Site of the day the DER Register is to commence.

Explanatory Note

Chapter 3A will be inserted in its entirety and is intended to commence in February 2021.

3A. REQUIREMENTS FOR TRANSMISSION CONNECTED GENERATING SYSTEMS

Explanatory Note

Section 3A.1 sets out the general requirement for a Market Participant responsible for a Transmission Connected Generating System to comply with Chapter 3A and Appendix 12 unless it is exempted under section 3A.3. Chapter 3A will only apply to generating works connected to a transmission system.

3A.1. General

3A.1.1. A Market Participant responsible for a Transmission Connected Generating System must comply at all times with all applicable requirements for Transmission Connected Generating Systems as set out in this Chapter 3A and the relevant provisions of Appendix 12 other than in respect of Exempt Transmission Connected Generating Systems.

3A.1.2. If there is any inconsistency between the provisions of these WEM Rules (including Appendix 12) and the Technical Rules, the provisions of these WEM Rules prevail to the extent of the inconsistency.

Explanatory Note

Clause 3A.1.3 is intended to be a civil penalty provision.

3A.1.3. A Market Participant responsible for a Transmission Connected Generating System who has been issued an Approval to Generate Notification must comply with each Registered Generator Performance Standard for the Transmission Connected Generating System.

3A.1.4. A Network Operator and AEMO must document a process by which they will provide each other with information, consult with each other, or reach agreement in respect of the matters in this Chapter 3A and Appendix 12 including:

(a) the requirements for, and manner in which, they will consult with each other;

(b) the format, form and manner in which any information must be provided; and

(c) where the WEM Rules do not provide a timeframe for the provision of the information, the time by which such information must be provided.

Explanatory Note

Section 3A.2 sets out the general requirements on Market Participants to provide relevant information. Section 3A.2 includes an obligation on a Market Participant to ensure that the generation system model it provides to AEMO (required under Appendix 12) complies with the WEM Procedure developed by the Network Operator. If the WEM Procedure is amended then the Market Participant must ensure that its generation system model complies with the amended WEM Procedure. When a Network Operator amends the WEM Procedure it will also specify a time by when the Market Participant must comply with the amended WEM Procedure.

3A.2. General Requirements to Provide Relevant Information

3A.2.1 A Market Participant responsible for a Transmission Connected Generating System must provide all data and information reasonably required by a Network Operator or AEMO under this Chapter 3A to assess the impact of a Transmission Connected Generating System on the performance and security of the transmission system and distribution system.

3A.2.2. A Market Participant responsible for a Transmission Connected Generating System must ensure that the generation system model referred to in Appendix 12 complies with the requirements specified in the WEM Procedure referred to in clause 3A.4.2.

3A.2.3. Where the requirements for the generation system model are amended in the WEM Procedure referred to in clause 3A.4.2, a Market Participant responsible for a Transmission Connected Generating System must ensure that the generation system model used by the Market Participant complies with the amended requirements within the timeframes specified in the WEM Procedure for compliance with the amended requirements.

Explanatory Note

Section 3A.3 sets out a mechanism for a Network Operator to exempt a Transmission Connected Generating System from the requirements of Chapter 3A. The section recognises that the compliance costs would outweigh the benefits of applying the regime to certain generating works, such as smaller generators.

The exemption regime will exempt a generating system from section 3A.1, section 3A.2, sections 3A.5 to 3A.12 and Appendix 12. An exemption notice may only be revoked where the generating system is undertaking a relevant generation modification. An exempt generating system will still be required to comply with the Technical Rules.

3A.3. Exempt Transmission Connected Generating Systems

3A.3.1. Network Operator may, by written notice, exempt a Market Participant responsible for a Transmission Connected Generating System from all of the requirements of section 3A.1, section 3A.2, sections 3A.5 to 3A.12 and Appendix 12 in respect of a Transmission Connected Generating System (**Exempt Transmission Connected Generating System**) where the Network Operator and AEMO agree that the cost incurred by the Market Participant responsible for the Transmission Connected Generating System to comply with Chapter 3A and Appendix 12 is reasonably likely to outweigh the benefit of requiring the Market Participant to comply having regard to:

(a) the potential of the Transmission Connected Generating System to adversely affect Power System Security or Power System Reliability; and

(b) the effect the proposed exemption will, if granted, have on other Market Participants.

3A.3.2. An exemption notice issued pursuant to clause 3A.3.1 must be provided to the Market Participant responsible for a Transmission Connected Generating System and the relevant Network Operator must keep a record of each exemption notice issued.

3A.3.3. A Network Operator may revoke an exemption notice issued pursuant to clause 3A.3.1 by written notice to a Market Participant responsible for the Exempt Transmission Connected Generating System where a Relevant Generator Modification is proposed to be undertaken in respect of the Exempt Transmission Connected Generating System.

3A.3.4. Where an exemption notice issued pursuant to clause 3A.3.1 is revoked pursuant to clause 3A.3.3, section 3A.14 applies.

3A.3.5. A Network Operator must notify the Economic Regulation Authority when it issues an exemption notice pursuant to clause 3A.3.1 or revokes an exemption notice pursuant to clause 3A.3.3.

3A.3.6. The Economic Regulation Authority must publish and maintain a list of current Exempt Transmission Connected Generating Systems.

3A.3.7. An Exempt Transmission Connected Generating System must comply with any applicable requirements and obligations contained in the Technical Rules applicable to the Network.

Explanatory Note

Section 3A.4 sets out general obligations of a Network Operator. It will require a Network Operator to ensure its connection processes are consistent with Chapter 3A. It provides a head of power for a Network Operator to create a WEM Procedure in respect of the requirements for a Market Participant's generation system model.

It also creates a head of power for a Network Operator to issue guidelines as to how it will assess Generator Performance Standards.

3A.4. General Obligations of a Network Operator

3A.4.1. A Network Operator must ensure its connection process as it relates to Transmission Connected Generating Systems is consistent with this Chapter 3A.

3A.4.2. A Network Operator must develop and maintain a WEM Procedure that addresses the requirements of the generation system model referred to in Appendix 12.

3A.4.3. The WEM Procedure referred to in clause 3A.4.2, must specify the timeframes by which the Market Participant must ensure that the generation system model referred to in Appendix 12 and provided by the Market Participant to AEMO complies with each amended requirement of the generation system model as specified in the WEM Procedure.

3A.4.4. A Network Operator may publish guidelines and provide further information to Market Participants as to how Generator Performance Standards in relation to each Technical Requirement will be assessed for each type of generating unit.

Explanatory Note

Section 3A.5 requires a Market Participant that intends to connect its generating works to a transmission system to submit Proposed Generator Performance Standards.

There is currently no minimum level for the technical performance of generators below which an exemption from the Technical Rules can be sought. This results in inefficiencies for both generators and Network Operators in negotiating generator performance standards. This contrasts with the framework under the National Electricity Market which includes a performance band between an 'ideal' and a 'minimum' standard, with the range between the two extremes representing the scope for negotiation, in the event that meeting the 'ideal' standard is impractical.

A Generator Performance Guideline (GPG) was published in late 2018, outlining new proposed standards for connecting generators. The GPG has been converted into a new Appendix 12 of the WEM Rules. As part of the GPG, Western Power and AEMO proposed that such a range also apply in the SWIS. The 'minimum' range under the proposed framework within the WEM Generator Performance Guideline reflects the lowest level of exemption provided under the Technical Rules. However, the Minimum Generator Performance Standard is not the starting point of negotiation, the Ideal Generator Performance Standard is. Section 3.A.5 sets out the approval process and negotiation framework for Generator Performance Standards. The process includes an ability to reject Proposed Generator Performance Standards. Where a Market Participant proposes a standard which is below the Ideal Generator Performance Standard then it must be able to adequately justify any standard it proposes that falls below the Ideal Generator Performance Standard. Similarly, if rejecting a Proposed Generator Performance Standard, the Network Operator must provide reasons.

A Market Participant may propose a Trigger Event. If a Trigger Event occurs then the Market Participant must comply with the conditions of the Trigger Event.

Once approved the Generator Performance Standards for a Transmission Connected Generating System must be recorded on the GPS Register.

3A.5. Generator Performance Standards for Transmission Connected Generating Systems

3A.5.1. Where a Market Participant responsible for generating works intends to connect those generating works to the transmission system, the Market Participant must submit to the relevant Network Operator, Proposed Generator Performance Standards for the generating works as if the generating works were a Transmission Connected Generating System addressing each Technical Requirement.

3A.5.2. Each Proposed Generator Performance Standard submitted under clause 3A.5.1 or clause 3A.14.1(a) must meet the Common Requirements and either:

(a) be equal to or better than the Ideal Generator Performance Standard; or

(b) if a Proposed Negotiated Generator Performance Standard is submitted:

i. be no less onerous than the Minimum Performance Standard;

ii. demonstrate any applicable Negotiation Criteria have been met;

iii. meet the requirements of clause 3A.5.5; and

iv. if applicable, meet the requirements of clause 3A.5.6.

3A.5.3. The Network Operator must not approve a Proposed Generator Performance Standard that does not meet or demonstrate the applicable criteria listed in clause 3A.5.2.

3A.5.4. The Network Operator must approve a Proposed Generator Performance Standard that is equal to or better than the Ideal Generator Performance Standard for a Technical Requirement.

3A.5.5. A Proposed Negotiated Generator Performance Standard must be as consistent as practicable to the corresponding Ideal Generator Performance Standard for that Technical Requirement, having regard to:

(a) the need to protect the Transmission Connected Generating System from damage;

(b) power system conditions at the location of the connection or proposed connection; and

(c) the commercial and technical feasibility of complying with the Ideal Generator Performance Standard.

3A.5.6. A Proposed Negotiated Generator Performance Standard may include a Trigger Event which must address:

(a) the conditions for determining whether the Trigger Event has occurred;

(b) the party responsible for determining whether the Trigger Event has occurred;

(c) the actions required to be taken and any revised Generator Performance Standards which must be achieved if the Trigger Event occurs;

(d) the maximum timeframe for compliance with any action required to be taken and each revised Generator Performance Standard following the Trigger Event;

(e) any requirements to provide information and supporting evidence required by the Network Operator or AEMO to demonstrate that, if the Trigger Event occurs, the actions required will occur and will deliver the agreed outcome and level of performance required by any revised Generator Performance Standard;

(f) any testing requirements to verify compliance with each revised Generator Performance Standard; and

(g) any requirements necessary to verify that the actions required to be taken have occurred if the Trigger Event occurs.

Explanatory Note
Clause 3A.5.7 is intended to be a civil penalty provision.

3A.5.7. If a Registered Generator Performance Standard includes a Trigger Event and the Trigger Event subsequently occurs, the Market Participant responsible for the

Transmission Connected Generating System must comply with the requirements of the Trigger Event.

3A.5.8. A Trigger Event contained in a Registered Generator Performance Standard may be modified by written agreement between the Market Participant responsible for the Transmission Connected Generating System, AEMO and the relevant Network Operator.

3A.5.9. If a Market Participant responsible for a Transmission Connected Generating System submits to the Network Operator a Proposed Negotiated Generator Performance Standard pursuant to clause 3A.5.2 or clause 3A.14.1(a), the Market Participant responsible for the Transmission Connected Generating System must provide to the relevant Network Operator:

(a) the reasons and supporting evidence why the Market Participant responsible for the Transmission Connected Generating System cannot meet the Ideal Generator Performance Standard; and

(b) any information and supporting evidence required by the Network Operator setting out the reasons why the Proposed Negotiated Generator Performance Standard is appropriate, including:

i. how the Proposed Negotiated Generator Performance Standard meets the applicable criteria listed in clause 3A.5.2; and

ii. how the Market Participant responsible for the Transmission Connected Generating System has taken into account each of the matters listed in clause 3A.5.5.

3A.5.10. If, following the receipt of a Proposed Negotiated Generator Performance Standard and the information and evidence referred to in clause 3A.5.9, the Network Operator reasonably considers it will approve the Proposed Negotiated Generator Performance Standard, the Network Operator, in accordance with the process agreed pursuant to clause 3A.1.4, must:

(a) provide the information received from the Market Participant responsible for the Transmission Connected Generating System pursuant to clause 3A.5.9 to AEMO; and

(b) use best endeavours to consult with AEMO within a reasonable timeframe in relation to each Proposed Negotiated Generator Performance Standard.

3A.5.11. AEMO must use best endeavours to respond in a reasonable timeframe after being consulted in accordance with clause 3A.5.10 and provide a recommendation to the Network Operator whether a Proposed Negotiated Generator Performance Standard should be approved or rejected by the Network Operator, or whether AEMO requires further information to make the recommendation in accordance with the process agreed pursuant to clause 3A.1.4.

3A.5.12. Where AEMO requires further information that it considers necessary to make the recommendation in clause 3A.5.11, the Network Operator, in accordance with the process agreed pursuant to clause 3A.1.4, must:

(a) provide the further information that is in its possession, power or control; or

(b) use reasonable endeavours to obtain that information from the Market Participant responsible for the Transmission Connected Generating System and provide that information to AEMO.

3A.5.13. In making a recommendation whether a Proposed Negotiated Generator Performance Standard should be approved or rejected in accordance with clause 3A.5.11, AEMO is not limited to considering information provided by the Network Operator and may use any other relevant information available to it.

3A.5.14. AEMO must recommend that the Network Operator reject a Proposed Negotiated Generator Performance Standard in accordance with clause 3A.5.11 if it reasonably considers that the Proposed Negotiated Generator Performance Standard may adversely affect Power System Security or Power System Reliability.

3A.5.15. Where AEMO recommends that the Network Operator reject a Proposed Negotiated Generator Performance Standard in accordance with clause 3A.5.11, AEMO must:

(a) provide written reasons to the Network Operator; and

(b) in respect of the relevant Technical Requirement, recommend that either:

i. if applicable, an alternative Proposed Negotiated Generator Performance Standard that AEMO considers meets the requirements of clause 3A.5.2(b), which may include a Trigger Event, is adopted; or

ii. otherwise, the Ideal Generator Performance Standard is adopted.

3A.5.16. Subject to clause 3A.5.17, after a Network Operator has received the recommendation from AEMO pursuant to clause 3A.5.11, the Network Operator must determine whether to approve or reject each Proposed Negotiated Generator Performance Standard proposed by the Market Participant responsible for the Transmission Connected Generating System.

3A.5.17. A Network Operator must reject a Proposed Negotiated Generator Performance Standard in accordance with clause 3A.5.16 where:

(a) in the Network Operator's reasonable opinion:

i. one or more of the requirements in clause 3A.5.2(b); or

ii. in the case of a Relevant Generator Modification, one or more of the requirements in clause 3A.14.1,

are not met;

(b) AEMO has recommended in accordance with clause 3A.5.11 that the Network Operator reject the Proposed Negotiated Generator Performance Standard; or

(c) in the Network Operator's reasonable opinion, the Proposed Negotiated Generator Performance Standard will adversely affect:

i. Power System Security;

ii. Power System Reliability;

iii. Power Transfer Capability; or

iv. the quality of supply of electricity for other users of the Network.

3A.5.18. If a Network Operator rejects a Proposed Negotiated Generator Performance Standard in accordance with clause 3A.5.16, the Network Operator must provide to the Market Participant responsible for the Transmission Connected Generating System:

(a) written reasons for the rejection;

(b) any recommendation provided by AEMO to the Network Operator in respect of a suitable alternative Generator Performance Standard for a Technical Requirement; and

(c) if applicable, an alternative Proposed Negotiated Generator Performance Standard that the Network Operator and AEMO consider meets the requirements of clause 3A.5.2(b), which may include a Trigger Event.

3A.5.19. The Market Participant responsible for the Transmission Connected Generating System may, in relation to an alternative Proposed Negotiated Generator Performance Standard provided by the Network Operator in accordance with clause 3A.5.18(c), either:

(a) accept the alternative Proposed Negotiated Generator Performance Standard; or

(b) reject the alternative Proposed Negotiated Generator Performance Standard; and

i. propose a different alternative Proposed Negotiated Generator Performance Standard consistent with the requirements of clause 3A.5.2(b), which may include a Trigger Event, in which case the process for consideration and approval of Proposed Generator Performance Standards in section 3A.5 applies; or

ii. elect to adopt the Ideal Generator Performance Standard for the relevant Technical Requirement.

3A.5.20. When a Proposed Generator Performance Standard is approved in accordance with clause 3A.5.16, or accepted by the Market Participant under clause 3A.5.19(a), it must be recorded by the relevant Network Operator on the GPS Register and it will be a Registered Generator Performance Standard for that Transmission Connected Generating System.

Explanatory Note

Section 3A.6 sets out the submission and approval process for GPS Monitoring Plans, including AEMO's obligations and rights in approving or rejecting a GPS Monitoring Plan and the obligations for a Market Participant responsible for a Transmission Connected Generating System to:

- monitor its compliance with the Registered Generator Performance Standards for the Transmission Connected Generation System; and
- undertake testing and monitoring activities,

in accordance with the GPS Monitoring Plan proposed by the Market Participant and approved by AEMO and included in the GPS Register for the Transmission Connected Generating System.

AEMO has an obligation to develop and maintain a WEM Procedure which includes:

- a Template GPS Monitoring Plan;
- the assessment and approval process to be followed by AEMO for a proposed GPS Monitoring Plan submitted by a relevant Market Participant;
- non-compliance reporting requirements of a relevant Market Participant in relation to Registered Generator Performance Standards and the applicable GPS Monitoring Plan;
- the process and timeframe by which a relevant Market Participant must report any alleged non-compliance or suspected non-compliance with an approved Rectification Plan; and
- the process by which a relevant Market Participant must submit proposed updates and amendments to a GPS Monitoring Plan approved by AEMO and the assessment process in relation to the same.

3A.6. GPS Monitoring Plans

Explanatory Note

Clause 3A.6.1 is intended to be a civil penalty provision.

3A.6.1. A Market Participant responsible for a Transmission Connected Generating System must:

(a) monitor its compliance with the Registered Generator Performance Standards for the Transmission Connected Generation System;

(b) once issued an Approval to Generate Notification, have a GPS Monitoring Plan approved by AEMO for the Transmission Connected Generating System at all times; and

(c) comply with the GPS Monitoring Plan approved by AEMO for the Transmission Connected Generating System on and from the date specified in the GPS Monitoring Plan approved by AEMO.

3A.6.2. AEMO must develop and maintain a WEM Procedure which includes:

(a) a Template GPS Monitoring Plan which details:

i. how a Market Participant responsible for a Transmission Connected Generating System must monitor performance against the applicable Registered Generator Performance Standards including any testing and verification requirements;

ii. the record keeping obligations relating to monitoring compliance with Registered Generator Performance Standards a Market Participant responsible for a Transmission Connected Generating System must comply with; and

iii. the information and data provision obligations a Market Participant responsible for a Transmission Connected Generating System must comply with when requested by AEMO, the Network Operator or the Economic Regulation Authority, including the form and timeframes by which that information and data must be provided;

(b) the assessment and approval process to be followed by AEMO for a proposed GPS Monitoring Plan submitted by a Market Participant responsible for a Transmission Connected Generating System;

(c) the process by which a Market Participant responsible for a Transmission Connected Generating System must report any alleged non-compliance or suspected non-compliance with applicable Registered Generator Performance Standards and the applicable GPS Monitoring Plan approved by AEMO;

(d) the process and timeframe by which a Market Participant responsible for a Transmission Connected Generating System must report any alleged non-compliance or suspected non-compliance with an approved Rectification Plan; and

(e) the process by which a Market Participant responsible for a Transmission Connected Generating System must submit proposed updates and amendments to a GPS Monitoring Plan approved by AEMO and the assessment process to be followed by AEMO for such updates and amendments.

3A.6.3. AEMO must classify GPS Monitoring Plans and information relating to GPS Monitoring Plans including outcomes, reporting data and supporting evidence relating to a GPS Monitoring Plan as Rule Participant Network Restricted information.

3A.6.4. A Market Participant responsible for a Transmission Connected Generating System must submit a proposed GPS Monitoring Plan to AEMO for approval in accordance with any requirements for submission in the WEM Procedure referred to in clause 3A.6.2 for each Transmission Connected Generating System that either:

(a) meets the requirements of the Template GPS Monitoring Plan set out in the WEM Procedure referred to in clause 3A.6.2 as applicable to the Transmission Connected Generating System; or

(b) meets the requirements of the Template GPS Monitoring Plan as applicable to the Transmission Connected Generating System, other than in respect of variations that the Market Participant reasonably considers are required on the basis that compliance is not possible, or where doing so would impose unreasonable costs on the Market Participant.

3A.6.5. AEMO must approve a proposed GPS Monitoring Plan if:

(a) it meets the requirements of the Template GPS Monitoring Plan set out in the WEM Procedure referred to in clause 3A.6.2 as applicable to the Transmission Connected Generating System; or

(b) AEMO considers any variations from the Template GPS Monitoring Plan as applicable to the Transmission Connected Generating System are:

i. required on the basis that compliance is not possible, or where doing so would impose unreasonable costs on the Market Participant; and

ii. not likely to pose a safety risk or threat to Power System Security or Power System Reliability.

3A.6.6. AEMO may reject a proposed GPS Monitoring Plan if AEMO reasonably considers that:

(a) the proposed GPS Monitoring Plan does not meet the requirements of clause 3A.6.4(a);

(b) the proposed GPS Monitoring Plan is likely to pose a safety risk or threat to Power System Security or Power System Reliability; or

(c) that any proposed variations from the Template GPS Monitoring Plan as applicable to the Transmission Connected Generating System are not required under clause 3A.6.5(b).

3A.6.7. AEMO may, but is not required to, consult the relevant Network Operator in respect of a proposed GPS Monitoring Plan submitted to AEMO for approval pursuant to clause 3A.6.3 or clause 3A.14.1(b).

3A.6.8. Where AEMO rejects a proposed GPS Monitoring Plan in accordance with clause 3A.6.6, AEMO may request amendments to the proposed GPS Monitoring Plan that it considers are required to meet the requirements of clause 3A.6.4(a) or clause 3A.6.4(b) as the case may be.

3A.6.9. If the Template GPS Monitoring Plan as applicable to a Transmission Connected Generating System is amended, the Market Participant responsible for the Transmission Connected Generating System must submit an amended proposed GPS Monitoring Plan to AEMO for approval in accordance with clause 3A.6.3 within six months of the amendment to the Template GPS Monitoring Plan taking effect.

3A.6.10. A Market Participant responsible for a Transmission Connected Generating System may submit an amended proposed GPS Monitoring Plan to AEMO for approval at any time in accordance with the WEM Procedure referred to in clause 3A.6.2.

3A.6.11. Where a Market Participant responsible for a Transmission Connected Generating System submits an amended proposed GPS Monitoring Plan to AEMO for approval in accordance with clause 3A.6.9 or clause 3A.6.10, then clauses 3A.6.5 to 3A.6.8 apply.

3A.6.12. AEMO must provide the relevant Network Operator each GPS Monitoring Plan approved by AEMO and the Network Operator must update the GPS Register to include the most recent GPS Monitoring Plan approved by AEMO.

3A.6.13. Subject to clause 3A.6.14 and clause 3A.6.15, the Economic Regulation Authority, AEMO or the relevant Network Operator may request that a Market Participant responsible for a Transmission Connected Generating System provide the outcomes, reporting data and supporting evidence in respect of a GPS Monitoring Plan that has been approved by AEMO.

3A.6.14. AEMO may only request the information described in clause 3A.6.13 from a Market Participant if AEMO reasonably considers that the information will assist it to meet any of its functions or discharge any of its obligations under these WEM Rules.

3A.6.15. A Network Operator may only request the information described in clause 3A.6.13 from a Market Participant if the Network Operator reasonably considers that the information will assist it to meet any of its functions or discharge any of its obligations under these WEM Rules.

3A.6.16. A Market Participant responsible for a Transmission Connected Generating System must provide the outcomes, reporting data and supporting evidence relating to a GPS Monitoring Plan within 5 Business Days, or longer period if agreed, of a request by the Economic Regulation Authority, AEMO or the Network Operator made in accordance with clause 3A.6.13.

3A.6.17. Nothing in this Chapter 3A prevents AEMO, the Economic Regulation Authority or the relevant Network Operator from undertaking monitoring activities in respect of compliance with the Registered Generator Performance Standards for a Transmission Connected Generating System.

Explanatory Note

Section 3A.7 requires a Network Operator to maintain a register (GPS Register) of approved Generator Performance Standards for each Transmission Connected Generating System connected to its Network. GPS Registers are to be made available to AEMO, Market Participants (as relevant) and the Economic Regulation Authority.

GPS Registers will also include the approved GPS Monitoring Plan for each Transmission Connected Generating System connected to the Network Operator's Network.

Market Participants are required to provide requested information reasonably required for the purpose of a Network Operator establishing and maintaining the GPS Register and notification requirements of Market Participants to ensure the currency and accuracy of the GPS Register.

3A.7. GPS Register

3A.7.1. A Network Operator must establish and maintain a register of approved Generator Performance Standards for each Transmission Connected Generating System connected to its Network (GPS Register).

3A.7.2. A Market Participant must provide the relevant Network Operator any information requested and reasonably required by the Network Operator to establish and maintain a GPS Register in accordance with this section 3A.7.

3A.7.3. A GPS Register will include any information considered relevant by the Network Operator and must record, at a minimum, for each Transmission Connected Generating System other than an Exempt Transmission Connected Generating System:

(a) the status of connection of the generating works to the transmission system;

(b) details of the Market Participant responsible for the Transmission Connected Generating System including the registered name of the Facility and the Market Participant's registered name;

(c) full details of each Registered Generator Performance Standard for each generating unit or component of the generating works forming part of the Transmission Connected Generating System, including Trigger Events;

(d) the generating system model used and provided by the Market Participant responsible for the Transmission Connected Generating System and referred to in clause 3A.2.2; and

(e) each GPS Monitoring Plan approved by AEMO.

3A.7.4. A Network Operator must update the GPS Register:

(a) in respect of a proposed Transmission Connected Generating System after the Arrangement for Access has been executed by all relevant parties and prior to an Interim Approval to Generate Notification being issued for the proposed Transmission Connected Generating System; and

(b) as required from time to time when the information referred to in clause 3A.7.2 is updated or otherwise to ensure it remains accurate and up to date.

3A.7.5. A Market Participant responsible for a Transmission Connected Generating System must notify the relevant Network Operator as soon as reasonably practicable of any changes in respect of the generating works, the Registered Generator Performance Standards, the generating system model, the ownership of the Transmission Connected Generating System or any other information in respect of the Transmission Connected Generating System that would render the information (other than the GPS Monitoring Plan approved by AEMO), recorded in the GPS Register being inaccurate or out of date.

3A.7.6. A Network Operator must make the GPS Register available to:

(a) AEMO in accordance with the process agreed pursuant to clause 3A.1.4;

(b) a Market Participant, but only in respect of the information that relates to a Transmission Connected Generating System the Market Participant is responsible for; and

(c) the Economic Regulation Authority.

3A.7.7. AEMO must classify a GPS Register as Rule Participant Network Restricted information.

Explanatory Note

Section 3A.8 prohibits a Market Participant responsible for a Transmission Connected Generating System from generating electricity without an approved Commissioning Test Plan unless it has been issued with an Interim Approval to Generate Notification (with or without conditions) or an Approval to Generate Notification.

The section sets out the circumstances in which a Network Operator may exercise its discretion to issue an Interim Approval to Generate Notification (including to issue any conditions) with the approval of AEMO.

3A.8. Commissioning, Interim Approval to Generate Notification and Approval to Generate Notification

Explanatory Note

Clause 3A.8.1 is intended to be a civil penalty provision.

3A.8.1. A Market Participant responsible for a Transmission Connected Generating System must not generate electricity without an approved Commissioning Test Plan unless it has a valid Interim Approval to Generate Notification (with or without conditions) or an Approval to Generate Notification.

3A.8.2. A Network Operator may only issue an Interim Approval to Generate Notification without conditions to a Market Participant responsible for a Transmission Connected Generating System, where the Network Operator and AEMO consider the Transmission Connected Generating System has not demonstrated non-compliance based on observed performance with the applicable Registered Generator Performance Standards and there are no observed risks to Power System Security or Power System Reliability.

3A.8.3. Subject to clause 3A.8.4, a Network Operator may, in its discretion and with the approval of AEMO:

(a) issue an Interim Approval to Generate Notification with conditions to a Market Participant responsible for a Transmission Connected Generating System; or

(b) place conditions on an Interim Approval to Generate Notification issued pursuant to clause 3A.8.2.

3A.8.4. A Network Operator may only issue and place conditions on an Interim Approval to Generate Notification pursuant to clause 3A.8.3 where AEMO and the Network Operator:

(a) either:

i. do not consider the Transmission Connected Generating System is demonstrating compliance based on observed performance with the applicable Registered Generator Performance Standards; or

ii. consider that conditions are required to mitigate any observed risks to Power System Security or Power System Reliability; and

(b) consider the Transmission Connected Generating System is reasonably likely to resolve the performance issue and be compliant with the applicable Registered Generator Performance Standards in the future.

Explanatory Note Clause 3A.8.5(a) is intended to be a civil penalty provision.

3A.8.5. Prior to being issued an Approval to Generate Notification, if a Market Participant responsible for a Transmission Connected Generating System is not meeting the applicable Registered Generator Performance Standards or complying with the applicable conditions, the Market Participant responsible for the Transmission Connected Generating System must:

(a) immediately notify AEMO and provide details of the non-compliance; and

(b) either:

i. make any modification required to comply with the conditions and meet the applicable Registered Generator Performance Standards within the timeframe specified by the Network Operator or, if a Rectification Plan is required pursuant to clause 3A.8.7, within the timeframe specified in the approved Rectification Plan; or

ii. as soon as practicable request to renegotiate any applicable Registered Generator Performance Standards it is unable to meet in which case clause 3A.8.8 applies.

3A.8.6. Where AEMO is notified pursuant to clause 3A.8.5(a), AEMO must advise the relevant Network Operator as soon as reasonably practicable.

3A.8.7. Where a Network Operator is notified pursuant to clause 3A.8.6, the Network Operator may, with the approval of AEMO, require a Market Participant responsible for the Transmission Connected Generating System to submit a Rectification Plan for approval in accordance with section 3A.11.

3A.8.8. A Network Operator may, in its discretion and with the approval of AEMO, agree to a request made pursuant to clause 3A.8.5(b)(ii) to renegotiate a Registered Generator Performance Standard for a Transmission Connected Generating System where the Network Operator and AEMO agree the Market Participant responsible for the Transmission Connected Generating System will be able to meet and comply with an alternative Generator Performance Standard that meets the applicable criteria listed in clause 3A.5.2, in which case the process for consideration and approval of Proposed Generator Performance Standards in section 3A.5 applies.

3A.8.9. If a Network Operator refuses a request made pursuant to clause 3A.8.5(b)(ii) to renegotiate a Registered Generator Performance Standard for a Transmission Connected Generating System or an alternative Generator Performance Standard cannot be agreed between the Network Operator, AEMO and the Market Participant responsible for the Transmission Connected Generating System, the Market Participant must comply with the applicable Registered Generator Performance Standards previously approved as recorded in the GPS Register within the timeframe specified by the Network Operator.

3A.8.10. Subject to clause 3A.8.11, a Network Operator may revoke an Interim Approval to Generate Notification issued pursuant to clause 3A.8.2 or clause 3A.8.3 where the Network Operator reasonably considers that:

(a) the performance of the Transmission Connected Generating System differs from the applicable Registered Generator Performance Standards; or

(b) the conditions placed on an Interim Approval to Generate Notification have not been met or complied with,

and the Market Participant responsible for the Transmission Connected Generating System has not complied with requirement in clause 3A.8.5(b).

3A.8.11. A Network Operator may only make a decision under clause 3A.8.10 where the Network Operator has consulted with AEMO, and AEMO agrees with the decision to revoke the Interim Approval to Generate Notification issued to the Market Participant responsible for the Transmission Connected Generating System.

3A.8.12. A Network Operator must issue an Approval to Generate Notification to a Market Participant responsible for a Transmission Connected Generating System where:

(a) a GPS Monitoring Plan for the Transmission Connected Generating System has been approved by AEMO under clause 3A.6.5 and the Network Operator has included it in the GPS Register;

(b) the operational performance of the Transmission Connected Generating System is considered satisfactory to both the Network Operator and AEMO; and

(c) AEMO and the Network Operator consider the Market Participant responsible for the Transmission Connected Generating System has met the requirements of, and indicated compliance with, the applicable Registered Generator Performance Standards in accordance with the WEM Procedure referred to in clause 3A.9.1.

Explanatory Note

Section 3A.9 provides a head of power for AEMO to create a WEM Procedure which sets out testing requirements and compliance verification mechanisms in relation to Registered Generator Performance Standards and GPS Monitoring Plans. The section enables AEMO to request a Market Participant to undertake testing in accordance with the WEM Procedure should AEMO or the relevant Network Operator reasonably consider that a Market Participant may not be compliant with the applicable Registered Generator Performance Standards.

The section also requires that a Market Participant provides any information and data requested to enable compliance monitoring and testing to be undertaken.

3A.9. Testing and Compliance

3A.9.1. AEMO must develop and maintain a WEM Procedure which sets out the testing requirements and how compliance with:

(a) Registered Generator Performance Standards will be verified, including tests required before an Interim Approval to Generate Notification and an Approval to Generate Notification is issued; and

(b) a GPS Monitoring Plan is measured and verified.

3A.9.2. Where AEMO or the relevant Network Operator reasonably considers a Market Participant responsible for a Transmission Connected Generating System may not be compliant with the applicable Registered Generator Performance Standards, AEMO may require the Market Participant to undertake testing in accordance with the WEM Procedure referred to in clause 3A.9.1 to determine whether the Transmission Connected Generating System is compliant with the applicable Registered Generator Performance Standard.

3A.9.3. Where AEMO requires a Market Participant responsible for a Transmission Connected Generating System to undertake testing pursuant to clause 3A.9.2, the Market Participant must use best endeavours to agree an appropriate timeframe with AEMO for the testing to occur in accordance with the WEM Procedure referred to in clause 3A.9.1.

3A.9.4. A Market Participant responsible for a Transmission Connected Generating System must provide any information and data requested by AEMO to enable compliance monitoring and testing to be undertaken in respect of the applicable Registered Generator Performance Standards, the GPS Monitoring Plan approved by AEMO or any approved Rectification Plan for the Transmission Connected Generating System in the format and by the time reasonably required by AEMO.

3A.9.5. Notwithstanding that a Market Participant responsible for a Transmission Connected Generating System may propose a Rectification Plan in accordance with section 3A.11, a Market Participant must seek to rectify any non-compliance with the Registered Generator Performance Standards or the GPS Monitoring Plan approved by AEMO for the Transmission Connected Generating System as soon as possible.

Explanatory Note

Section 3A.10 sets out the self-monitoring and reporting regime, which requires:

- a Market Participant to notify AEMO:
  - in relation to a non-compliance with an applicable Registered Generator Performance Standard, or GPS Monitoring Plan, or whether it intends to propose a Rectification Plan in relation to the same; or
  - where it is aware that the Transmission Connected Generating System will be unable to fully respond in accordance with its Registered Generator Performance Standards;
- a Network Operator to notify AEMO, where a Market Participant responsible for a Transmission Connected Generating System may have been, or may not be, compliant with any applicable Registered Generator Performance Standard; and
- AEMO to notify:
  - a Market Participant and subsequently the relevant Network Operator and Economic Regulation Authority (as applicable), where the Market Participant may not have been, or may not be, compliant with the applicable Registered Generator Performance Standards or GPS Monitoring Plan; or
  - a Market Participant and subsequently the relevant Network Operator and Economic Regulation Authority (as applicable), whether the Market Participant intends to propose a Rectification Plan in relation to the same.

3A.10. Self-Reporting Regime

Explanatory Note

Clause 3A.10.1(a) is intended to be a civil penalty provision.

3A.10.1. A Market Participant responsible for a Transmission Connected Generating System that has been issued an Approval to Generate Notification must, acting in good faith, notify AEMO:

(a) immediately after becoming aware of a non-compliance or suspected non-compliance with:

i. an applicable Registered Generator Performance Standard; or

ii. the GPS Monitoring Plan approved by AEMO for the Transmission Connected Generating System; and

(b) as soon as practicable whether or not it intends to propose a Rectification Plan in accordance with clause 3A.11.1 in respect of a non-compliance or suspected non-compliance with:

i. an applicable Registered Generator Performance Standard; or

ii. the GPS Monitoring Plan approved by AEMO for the Transmission Connected Generating System.

3A.10.2. A Market Participant responsible for a Transmission Connected Generating System must, acting in good faith, notify AEMO:

(a) where it is aware that the Transmission Connected Generating System will be unable to respond or provide the full range of response in accordance with its Registered Generator Performance Standards; or

(b) where it is aware that it is likely to become non-compliant with the GPS Monitoring Plan approved by AEMO for the Transmission Connected Generating System.

3A.10.3. If a Network Operator reasonably considers a Market Participant responsible for a Transmission Connected Generating System may have been, or may not be, compliant with any applicable Registered Generator Performance Standard it must notify AEMO.

3A.10.4. Other than where AEMO is notified in accordance with clause 3A.10.1, where AEMO reasonably considers that a Market Participant responsible for a Transmission Connected Generating System may not have been, or may not be, compliant with the applicable Registered Generator Performance Standards or GPS Monitoring Plan, AEMO must notify the Market Participant before notifying any other party in accordance with clause 3A.10.6.

3A.10.5. Where a Market Participant responsible for a Transmission Connected Generating System is notified by AEMO pursuant to clause 3A.10.4, it must, as soon as practicable, notify AEMO whether it intends to propose a Rectification Plan in respect of the non-compliance or suspected non-compliance.

3A.10.6. AEMO must, as soon as practicable, notify:

(a) the Economic Regulation Authority if AEMO is notified by a Network Operator of a non-compliance or suspected non-compliance in accordance with clause 3A.10.3; and

(b) the Economic Regulation Authority and the relevant Network Operator of:

i. any instances where AEMO reasonably considers that a Market Participant responsible for a Transmission Connected Generating System may not have been, or may not be, compliant with the Registered Generator Performance Standards or GPS Monitoring Plan approved by AEMO for the Transmission Connected Generating System; and

ii. whether the Market Participant responsible for the Transmission Connected Generating System has indicated an intention to propose a Rectification Plan in respect of the non-compliance or suspected non-compliance in accordance with clause 3A.10.5 or clause 3A.11.1,

to avoid doubt, AEMO may notify the Economic Regulation Authority and the relevant Network Operator of each of the matters in clause 3A.10.6(b) separately.

Explanatory Note
Section 3A.11 sets out the right of a Market Participant responsible for a Transmission Connected Generating System who has been issued an Interim Approval to Generate Notification or an Approval to Generate Notification to submit a proposed Rectification Plan (or propose amendments to an existing Rectification Plan) when they are not compliant with either their Registered

Generator Performance Standards or approved GPS Monitoring Plan. It also sets out the minimum requirements for a proposed Rectification Plan.

AEMO may object, approve, seek further information, or propose an alternative Rectification Plan when considering whether to approve a Rectification Plan or amendment to a Rectification Plan.

AEMO is required to consult with the relevant Network Operator where a proposed Rectification Plan relates to a non-compliance with the applicable Registered Generator Performance Standards.

Non-compliance with an approved Rectification Plan can result in cancellation of that plan by AEMO if agreed by the Network Operator.

3A.11. Rectification Plans

3A.11.1. A Market Participant responsible for a Transmission Connected Generating System who has been issued an Interim Approval to Generate Notification or an Approval to Generate Notification may submit a proposed Rectification Plan for consideration by AEMO within 10 Business Days, unless a longer period is otherwise agreed, after becoming aware of a non-compliance or suspected non-compliance with the Registered Generator Performance Standards or the GPS Monitoring Plan approved by AEMO for the Transmission Connected Generating System.

3A.11.2. A proposed Rectification Plan must at a minimum include:

(a) the nature of the non-compliance or suspected non-compliance to be addressed by the proposed Rectification Plan;

(b) the time by which the Market Participant responsible for the Transmission Connected Generating System will become compliant with the applicable Registered Generator Performance Standards or the GPS Monitoring Plan approved by AEMO, as applicable;

(c) the actions that the Market Participant responsible for the Transmission Connected Generating System must take to become compliant with the applicable Registered Generator Performance Standards or the GPS Monitoring Plan approved by AEMO, as applicable; and

(d) what testing will be undertaken to establish compliance with the applicable Registered Generator Performance Standards or alternative means of monitoring that may be undertaken to address the non-compliance or suspected non-compliance with the GPS Monitoring Plan approved by AEMO, as applicable.

3A.11.3. AEMO must use best endeavours to respond to a Market Participant within 10 Business Days in respect of a proposed Rectification Plan submitted under clause 3A.11.1:

(a) approving the proposed Rectification Plan;

(b) rejecting the proposed Rectification Plan and providing the reason for rejection, including, if applicable, any reasons provided by the relevant Network Operator in accordance with clause 3A.11.7;

(c) seeking further information necessary for AEMO to assess the suitability of the proposed Rectification Plan; or

(d) proposing an alternative Rectification Plan if AEMO and the Network Operator consider an alternative Rectification Plan would be acceptable.

3A.11.4. A Rectification Plan will only be binding on a Market Participant responsible for the Transmission Connected Generating System where AEMO has approved the proposed Rectification Plan or, in the case of an alternative Rectification Plan proposed by AEMO, that Rectification Plan has been accepted by the Market Participant.

3A.11.5. Before AEMO may approve a proposed Rectification Plan that relates to a non-compliance or suspected non-compliance with the applicable Registered Generator Performance Standards, AEMO must consult with the relevant Network Operator on the proposed Rectification Plan.

3A.11.6. A Network Operator must use best endeavours to respond to AEMO, when consulted in accordance with clause 3A.11.5, within 5 Business Days recommending the proposed Rectification Plan is either approved or rejected.

3A.11.7. If a Network Operator recommends the proposed Rectification Plan is rejected under clause 3A.11.6, the Network Operator must provide reasons to AEMO for the rejection and AEMO must reject the proposed Rectification Plan in accordance with clause 3A.11.3.

3A.11.8. AEMO must notify and provide the Economic Regulation Authority with a copy of any Rectification Plan approved as soon as practicable after the Rectification Plan is approved.

3A.11.9. If a Market Participant responsible for a Transmission Connected Generating System reasonably considers it is unable to meet or comply with the requirements of an approved Rectification Plan it must notify AEMO as soon as reasonably practicable and may propose an amendment to the approved Rectification Plan.

3A.11.10. Where a Market Participant responsible for a Transmission Connected Generating System considers that compliance with an approved Rectification Plan will pose a credible safety risk or threaten Power System Security or Power System Reliability, it must immediately notify AEMO and provide:

(a) details of the actions required by the Rectification Plan that pose the safety risk or threat to Power System Security or Power System Reliability; and

(b) propose amendments to the Rectification Plan to address the safety risk or threat to Power System Security or Power System Reliability.

3A.11.11. If a Market Participant responsible for a Transmission Connected Generating System proposes an amendment to an approved Rectification Plan, AEMO may:

(a) subject to clause 3A.11.13, approve the proposed amendment to the Rectification Plan; or

(b) reject the proposed amendment to the Rectification Plan and, at AEMO's discretion, propose an alternative amendment to the Rectification Plan if it considers a suitable alternative is available, which must be accepted or rejected by the Market Participant within 5 Business Days or such longer period agreed by AEMO.

3A.11.12. If a proposed amendment to an approved Rectification Plan is rejected by AEMO and an alternative amendment to the Rectification Plan is proposed by AEMO in accordance with clause 3A.11.11(b), it will be deemed to be rejected by the Market Participant if the Market Participant does not notify AEMO that it accepts or rejects the alternative amendment proposed by AEMO within the required timeframe.

3A.11.13. Before AEMO may approve a proposed amendment to an approved Rectification Plan that relates to a non-compliance or suspected non-compliance with the applicable Registered Generator Performance Standards pursuant to clause 3A.11.11(a), AEMO must use best endeavours to consult with, and obtain approval from, the relevant Network Operator regarding the proposed amendment within 10 Business Days.

3A.11.14. Where a Market Participant responsible for a Transmission Connected Generating System proposes an amendment to an approved Rectification Plan pursuant to clause 3A.11.9, the Market Participant must continue to comply with the requirements of the approved Rectification Plan until such time as any amendment is approved by AEMO, the Rectification Plan has been completed or AEMO advises that the Market Participant can suspend compliance while the proposed amendment is considered.

3A.11.15. A Network Operator must use best endeavours to respond to AEMO, when consulted in accordance with clause 3A.11.14, within 5 Business Days recommending the proposed amendment to the Rectification Plan is either approved or rejected.

3A.11.16. Where a Market Participant responsible for a Transmission Connected Generating System proposes an amendment to an approved Rectification Plan pursuant to clause 3A.11.10(b), the Market Participant is only required to comply with the requirements of the approved Rectification Plan that do not pose a safety risk or threat to Power System Security or Power System Reliability unless AEMO advises that the Market Participant can suspend compliance while the proposed amendment is considered.

3A.11.17. AEMO must notify and provide the Economic Regulation Authority with the detail of any approved amendment to a Rectification Plan as soon as practicable after the amendment is approved.

3A.11.18. A Market Participant responsible for a Transmission Connected Generating System must comply with an approved Rectification Plan. For the avoidance of doubt, references to an approved Rectification Plan is taken to include any amendments approved by AEMO to the Rectification Plan.

3A.11.19. Subject to clause 3A.11.20, if AEMO reasonably considers a Market Participant responsible for a Transmission Connected Generating System has not complied, or is not complying, with the requirements of an approved Rectification Plan and any approved amendments, AEMO may cancel the Rectification Plan by written notice to that Market Participant.

3A.11.20. Before AEMO may cancel an approved Rectification Plan that relates to a non-compliance or suspected non-compliance with the applicable Registered Generator Performance Standards in accordance with clause 3A.11.19, AEMO must consult with, and obtain approval from, the relevant Network Operator.

3A.11.21. AEMO must notify the Economic Regulation Authority as soon as practicable if:

(a) a Market Participant responsible for a Transmission Connected Generating System does not propose a Rectification Plan within the timeframe in clause 3A.11.1;

(b) AEMO rejects a proposed Rectification Plan in accordance with clause 3A.11.3(b) and does not consider an alternative Rectification Plan would be acceptable or such alternative Rectification Plan has not been accepted by the Market Participant responsible for the Transmission Connected Generating System;

(c) AEMO cancels a Rectification Plan in accordance with clause 3A.11.19; or

(d) AEMO considers a Market Participant responsible for a Transmission Connected Generating System has complied with, and completed, an approved Rectification Plan and is compliant with:

i. the applicable Registered Generator Performance Standards, where the Rectification Plan relates to the applicable Registered Generator Performance Standards; or

ii. the GPS Monitoring Plan approved by AEMO, where the Rectification Plan relates to a GPS Monitoring Plan.

Explanatory Note

Section 3A.12 creates an immunity for a Market Participant responsible for a Transmission Connected Generating System from non-compliance with its Registered Generator Performance Standards or approved GPS Monitoring Plan in limited circumstances when a Market Participant is complying with an approved Rectification Plan.

The immunity does not apply where the Market Participant has repeatedly failed to comply with the same Registered Generator Performance Standard, or another applicable Registered Generator Performance Standard or its GPS Monitoring Plan, or the alleged non-compliance or suspected non-compliance threatens Power System Security or Power System Reliability.

3A.12. Effect of a Rectification Plan

3A.12.1. Notwithstanding the requirements of this Chapter 3A and Appendix 12, and subject to clause 3A.12.3, a Market Participant responsible for a Transmission

Connected Generating System will not breach these WEM Rules in respect of a non-compliance or suspected non-compliance with the Registered Generator Performance Standards or a GPS Monitoring Plan approved by AEMO for the Transmission Connected Generating System where a Rectification Plan in respect of the non-compliance or suspected non-compliance is submitted and approved by AEMO in accordance with section 3A.11 and the Market Participant:

(a) is complying with the requirements of the approved Rectification Plan; or

(b) has complied with, and completed, the approved Rectification Plan and is compliant with:

i. the applicable Registered Generator Performance Standards, where the Rectification Plan relates to the applicable Registered Generator Performance Standards; or

ii. the GPS Monitoring Plan approved by AEMO, where the Rectification Plan relates to a GPS Monitoring Plan.

3A.12.2. AEMO must notify the Economic Regulation Authority of an alleged non-compliance or suspected non-compliance with a Registered Generator Performance Standard or GPS Monitoring Plan approved by AEMO as soon as practicable if AEMO considers the alleged non-compliance or suspected non-compliance threatens Power System Security or Power System Reliability.

3A.12.3. The immunity in clause 3A.12.1 will not apply and the Economic Regulation Authority must investigate the alleged breach of the Registered Generation Performance Standards or the GPS Monitoring Plan approved by AEMO for the Transmission Connected Generating System in accordance with clause 2.13.10 where:

(a) the Economic Regulation Authority has been notified by AEMO in accordance with clause 3A.12.2;

(b) the Market Participant has repeatedly failed to comply with the same Registered Generator Performance Standard or another applicable Registered Generator Performance Standard; or

(c) the Market Participant has repeatedly failed to comply with the GPS Monitoring Plan approved by AEMO for the Transmission Connected Generating System.

Explanatory Note

Section 3A.13 establishes an obligation on a Market Participant responsible for a Transmission Connected Generating System or an Exempt Transmission Connected Generating System to notify the relevant Network Operator prior to undertaking a Potential Relevant Generator Modification to a generating unit or generating works that are part of a Transmission Connected Generating System or Exempt Transmission Connected Generating System.

A Potential Relevant Generator Modification may be declared by the Network Operator to be a Relevant Generator Modification. If a Relevant Generator Modification is declared, section 3A.14 applies.

A Network Operator, in consultation with AEMO, is required to develop, maintain and publish guidelines to inform Market Participants and provide examples of Potential Relevant Generator

Modifications and circumstances and situations in which a Potential Relevant Generator Modification may be declared a Relevant Generator Modification.

3A.13. Potential Relevant Generator Modifications to be declared by the relevant Network Operator

Explanatory Note

The concept and definition of 'Potential Relevant Generator Modification' will apply for the purposes of Chapter 3A only at this stage. If it affects another workstream this will be reconsidered.

3A.13.1. Potential Relevant Generator Modification means for the purposes of Chapter 3A, a modification to a generating unit or generating works that are part of a Transmission Connected Generating System or Exempt Transmission Connected Generating System that:

(a) has the potential or may be likely to materially impact or change any of the characteristics, performance or capacity of the generating unit or generating works in respect of a Technical Requirement;

(b) has the potential to alter the capacity of the Transmission Connected Generating System or Exempt Transmission Connect Generating System in respect of any Technical Requirement for which the Ideal Generator Performance Standard has been amended since the applicable Registered Generator Performance Standard was approved;

(c) is reasonably considered to require an amendment to the Market Participant's Arrangement for Access for the Transmission Connected Generating System or Exempt Transmission Connected Generating System; or

(d) requires submission of a connection application in accordance with a Network Operator's policy for access to its Network,

but does not include the replacement of equipment where the capacity of the Transmission Connected Generating System to meet the Registered Generator Performance Standard remains unchanged as a result of the replacement of equipment.

3A.13.2. A Network Operator, in consultation with AEMO, must develop, maintain and publish guidelines to inform Market Participants and provide examples of:

(a) Potential Relevant Generator Modifications; and

(b) circumstances and situations in which a Potential Relevant Generator Modification may be declared a Relevant Generator Modification,

for the purposes of Chapter 3A.

Explanatory Note

Clause 3A.13.3 is intended to be a civil penalty provision.

3A.13.3. A Market Participant responsible for a Transmission Connected Generating System or an Exempt Transmission Connected Generating System must notify the relevant Network Operator prior to undertaking a Potential Relevant Generator Modification.

3A.13.4. Subject to clause 3A.13.5 and clause 3A.13.6, a Network Operator may declare a Potential Relevant Generator Modification to be a Relevant Generator Modification.

3A.13.5. Where a Network Operator is notified of a Potential Relevant Generator Modification in accordance with clause 3A.13.3, it must consult with AEMO before making a decision whether or not to declare the Potential Relevant Generator Modification a Relevant Generator Modification pursuant to clause 3A.13.4.

3A.13.6. A Network Operator must declare a Potential Relevant Generator Modification to be a Relevant Generator Modification where AEMO advises the Network Operator pursuant to clause 3A.13.5 that the Potential Relevant Generator Modification should be declared a Relevant Generator Modification.

3A.13.7. If a Network Operator declares a Potential Relevant Generator Modification to be a Relevant Generator Modification in accordance with clause 3A.13.4, the Network Operator must notify the Market Participant responsible for the Transmission Connected Generating System or Exempt Transmission Connected Generating System.

3A.13.8. If, following consultation with AEMO in accordance with clause 3A.13.5, a Network Operator does not intend to declare the Potential Relevant Generator Modification to be a Relevant Generator Modification, the Market Participant may undertake the Potential Relevant Generator Modification as notified to the Network Operator subject to any other requirements or obligations that apply to the Market Participant under its Arrangement for Access, the Access Code, the Technical Rules applicable to the Network or any applicable law.

Explanatory Note

Section 3A.14 establishes a Market Participant's obligation to submit Proposed Generator Performance Standards and a proposed GPS Monitoring Plan (or revised plans) if a Network Operator declares a Potential Relevant Generator Modification to be a Relevant Generator Modification.

The process for the approval of Proposed Generator Performance Standards and a proposed GPS Monitoring Plan (or revised plans) is the same as if it was a new generating system connecting to the transmission system.

The Network Operator also has a right (where a Relevant Generator Modification has been declared) to revoke the Transmission Connected Generating System's Approval to Generate Notification.

Where a Relevant Generator Modification is undertaken, the Network Operator can require the Transmission Connected Generating System to conduct Commissioning Tests, and require the Market Participant to obtain an Interim Approval to Generate Notification or an Approval to Generate Notification in accordance with section 3A.8.

3A.14. Relevant Generator Modifications to Transmission Connected Generating Systems and Exempt Transmission Connected Generating Systems

3A.14.1. If a Network Operator declares a Potential Relevant Generator Modification to be a Relevant Generator Modification in accordance with clause 3A.13.4 the Market Participant responsible for the Transmission Connected Generating System or Exempt Transmission Connected Generating System must submit:

(a) Proposed Generator Performance Standards, or revised Proposed Generator Performance Standards, addressing each Technical Requirement in accordance with clause 3A.5.2 prior to undertaking the Relevant Generator Modification; and

(b) a proposed GPS Monitoring Plan, or revised proposed GPS Monitoring Plan, to AEMO for approval by the timeframe notified by the Network Operator that meets the requirements in clause 3A.6.4,

for the Transmission Connected Generating System or Exempt Transmission Connected Generating System.

3A.14.2. Where a Market Participant submits Proposed Generator Performance Standards or revised Proposed Generator Performance Standards pursuant to clause 3A.14.1(a), the process for consideration and approval of Proposed Generator Performance Standards in section 3A.5 applies.

3A.14.3. Where a Market Participant submits a proposed GPS Monitoring Plan or a revised GPS Monitoring Plan in accordance with clause 3A.14.1(b), the process for consideration and approval of a proposed GPS Monitoring Plan in section 3A.6 applies.

3A.14.4. Where the Network Operator has declared a Relevant Generator Modification, the Network Operator may:

(a) on and from the date that works in respect of the Relevant Generator Modification are scheduled to be undertaken or commence, revoke the Transmission Connected Generating System's Approval to Generate Notification; or

(b) require the Transmission Connected Generating System to conduct Commissioning Tests and, if the Network Operator is not satisfied with the results of the Commissioning Tests, revoke the Transmission Connected Generating System's Approval to Generate Notification,

and require the Market Participant to obtain an Interim Approval to Generate Notification (with or without conditions) or an Approval to Generate Notification, and the process in section 3A.8, as relevant, applies.

Explanatory Note

New Chapter 3B sets out the new Frequency Operating Standards as specified in the Taskforce Paper *Revising Frequency Operating Standards in the SWIS.*

Frequency Operating Standards in the SWIS are currently provided for in section 2.2 of Western Power's Technical Rules. As part of the WEM Reforms, Frequency Operating Standards will be moved to the WEM Rules and revised to:

- be consistent with the adoption of a SCED market model and a revised ESS framework;
- adopt a simplified approach to terminology and wording, where possible;
- maintain consistency with current frequency settings, adapted to fit within the structure of the revised standards;
- be clear in how they must apply to the power system and any islanded systems in the SWIS;
- ensure definitions are technology-neutral, to the extent possible; and
- support a robust and effective governance framework.

Chapter 3B is intended to commence on 1 February 2021.

3B. FREQUENCY OPERATING STANDARDS

Explanatory Note

Clause 3B.1.1 requires AEMO to ensure the SWIS is operated at the Normal Operating Frequency Band of 50Hz and to achieve the Frequency Operating Standards.

The obligation reflects good practice to operate as close as possible to 50Hz under normal operating circumstances to ensure that the levels of Essential System Service are sufficient (and to not continuously over-speed or under-speed mechanical equipment).

3B.1. Frequency Operating Standard responsibility

3B.1.1. Notwithstanding section 3B.3, AEMO must use reasonable endeavours to:

(a) ensure the SWIS is operated with a SWIS Frequency of 50 Hz except under Controlled Circumstances; and

(b) achieve that the Frequency Operating Standards set out in this Chapter 3B.

3B.1.2. The Frequency Operating Standards set out in this Chapter 3B only apply to Embedded Systems and Microgrids when they are connected to the SWIS.

Explanatory Note

The Frequency Operating Standards in section 3B.2 relate to existing settings in the SWIS with the exception of the Normal Operating Frequency Excursion Band, for which there is currently no equivalent. This term provides an absolute target or reporting level for normal operations when the system is not operating within the Normal Operating Frequency Band, which is 99% of the time. This allows for the specification of performance targets around the remaining 1%.

The Frequency Operating Standards are set out in Table 1 and Table 2, Appendix 13.

3B.2. Frequency Bands

3B.2.1. The Normal Operating Frequency Band is the normal frequency operating range set out in Table 1, Appendix 13 for the SWIS and Table 2, Appendix 13 for an Island.

3B.2.2. The Normal Operating Frequency Excursion Band is an allowable frequency operating range where no action or response is required by AEMO for infrequent or momentary excursions outside of the Normal Frequency Operating Band. The frequency operating range and duration are set out in Table 1, Appendix 13 for the SWIS.

3B.2.3. The Credible Contingency Event Frequency Band is the allowable frequency operating range where there has been a Credible Contingency Event on the SWIS. The frequency operating range and duration are set out in Table 1, Appendix 13 for the SWIS and Table 2, Appendix 13 for an Island.

3B.2.4. The Island Separation Frequency Band is the allowable frequency operating range immediately following a Separation Event on the SWIS which creates one or more Islands. The frequency operating range and duration are set out in Table 1, Appendix 13 for the SWIS and Table 2, Appendix 13 for an Island.

3B.2.5. The Multiple Contingency Event Frequency Band is the allowable frequency operating range where there has been a Multiple Contingency Event on the SWIS. The frequency operating range and duration are set out in Table 1, Appendix 13 for the SWIS and Table 2, Appendix 13 for an Island.

Explanatory Note

Section 3B.3 sets out the bounds of the frequency bands and performance parameters for each frequency band. The section refers to the Frequency Operating Standards in Table 1 and Table 2, Appendix 13. The current SWIS settings are adopted for each band except for the Normal Operating Frequency Excursion Band which is a new band as noted above.

3B.3. Required SWIS Frequency outcomes

3B.3.1. Other than for an Island, while in an Emergency Operating State or during a system restart, the Accumulated Time Error must not exceed 10 seconds for 99% of the time over any rolling 30-day period in the SWIS.

3B.3.2. Other than for a Credible Contingency Event or Multiple Contingency Event, the SWIS Frequency must not exceed the Normal Operating Frequency Band in accordance with the relevant requirements set out in Table 1, Appendix 13 for the SWIS and Table 2, Appendix 13 for an Island.

3B.3.3. Other than for a Credible Contingency Event or Multiple Contingency Event, the SWIS Frequency must not exceed the Normal Operating Frequency Excursion Band, and must Stabilise, in accordance with the relevant requirements set out in Table 1, Appendix 13 for the SWIS and Table 2, Appendix 13 for an Island.

3B.3.4. Subject to clause 3B.3.5, for any Credible Contingency Event, the SWIS Frequency must not exceed the relevant rate of change requirements set out in Table 1, Appendix 13 for the SWIS and Table 2, Appendix 13 for an Island.

3B.3.5. Clause 3B.3.4 does not apply to the initial formation of an Island following a Separation Event.

3B.3.6. Other than for a Separation Event, if there is a Credible Contingency Event, the SWIS Frequency must not exceed the Credible Contingency Event Frequency Band, and must Stabilise and Recover, in accordance with the relevant requirements set out in Table 1, Appendix 13 for the SWIS and Table 2, Appendix 13 for an Island.

3B.3.7. Following a Separation Event, an Island is permitted to be temporarily de-energised with frequency subsequently required to be restored to the relevant requirements set out in Table 1, Appendix 13 for the SWIS and Table 2, Appendix 13 for an Island as soon as practicable

3B.3.8. Subject to clause 3B.7, if there is a Separation Event, SWIS Frequency must not exceed the Island Separation Frequency Band, and must Stabilise and Recover, in accordance with the relevant requirements set out in Table 1, Appendix 13 for the SWIS and Table 2, Appendix 13 for an Island.

3B.3.9. If there is a Multiple Contingency Event, SWIS Frequency must not exceed the Multiple Contingency Event Frequency Band, and must Stabilise and Recover, in accordance with the relevant requirements set out in Table 1, Appendix 13 for the SWIS and Table 2, Appendix 13 for an Island.

3B.3.10. Based on the readings recorded in AEMO's SCADA system, a Contingency Event, including a Credible Contingency Event, Separation Event or Multiple Contingency Event, commences at the time SWIS Frequency exceeds the frequencies in the Normal Operating Frequency Excursion Band set out in Table 1, Appendix 13 for the SWIS and Table 2, Appendix 13 for an Island, and ends at the time at which SWIS Frequency Recovers.

…

Explanatory Note

Amendments to section 4.5, including consequential amendments as a result of the new Essential System Services framework, will be made in the PASA workstream. The section will incorporate the Long Term PASA Essential System Services forecasting requirements. The PASA will be used to forecast all Essential System Services requirements, and not only FCESS.

Amendments will also be made to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

4.5. Long Term Projected Assessment of System Adequacy

4.5.1. The Long Term PASA must be performed annually by AEMO and must address each of the years in the Long Term PASA Study Horizon.

4.5.2. The Long Term PASA must take into account:

(a) demand growth scenarios, including peak and annual energy requirements;

(b) expected Demand Side Management capabilities and taking into account clause 4.28.10;

(c) generation capacity expected to be available, including details of any Early Certified Reserve Capacity, seasonal capacities, Ancillary Service capabilities, long duration outages and, for Non-Scheduled Generators, production profiles;

(d) expected transmission network capabilities allowing for expansion plans, losses and constraints; and

(e) the capacity described in clause 4.5.2A.

4.5.3. AEMO must notify Rule Participants of the information that it requires from them in the areas described in clause 4.5.2, in respect of each year of the Long Term PASA Study Horizon, no later than 1 April of Year 1 of the relevant Reserve Capacity Cycle.

4.5.3A. The information requested by AEMO under clause 4.5.3 must include a request for Market Customers to provide the following information pertaining to Intermittent Loads and Loads that are expected to be registered and operating as Intermittent Loads during the second Capacity Year commencing during the Long Term PASA Study Horizon:

(a) the amount of capacity required to serve that Load in the event of a failure of on-site generation where this amount of capacity cannot exceed the greater of:

i. either:

1. for an existing Intermittent Load, the maximum allowed level of Intermittent Load specified in Standing Data for that Intermittent Load at the time of providing the data; or

2. for an Intermittent Load that is yet to be registered with AEMO, zero; and

ii. the Contractual Maximum Demand associated with that Intermittent Load to apply during the Capacity Year to which the nomination relates. The Market Customer must provide evidence to AEMO of this Contractual Maximum Demand level unless AEMO has previously been provided with that evidence; and

(b) for each Intermittent Load that is yet to be registered with AEMO:

i. the location of the Load;

ii. evidence that the Load can be expected to satisfy the requirements to be registered as an Intermittent Load during the second Capacity Year within the Long Term PASA Study Horizon; and

iii. the expected firm MW capacity and location of any generation system to serve that Intermittent Load in accordance with clause 2.30B.2(a) that is to be located at a different connection point to the Intermittent Load.

4.5.4. Rule Participants must provide the data requested by AEMO in accordance with clause 4.5.3 within 15 Business Days from the date of that request.

4.5.5. AEMO may request from persons who are not Rule Participants information in the areas described in clause 4.5.2 in respect of each year of the Long Term PASA Study Horizon.

4.5.6. AEMO must review the information provided to it in accordance with clause 4.5.4 and as a result of a request under clause 4.5.5, and where necessary, seek clarifications.

4.5.7. AEMO must treat all information provided to it in accordance with clauses 4.5.4, 4.5.5 and 4.5.6 as confidential except where the provider has granted permission for its release or as otherwise provided under these Market Rules. However, AEMO may release any such information as part of an unidentifiable component of an aggregate number in a Statement of Opportunities Report.

4.5.8. Where information provided to AEMO in accordance with clauses 4.5.4, 4.5.5 and 4.5.6 is not adequate or is insufficient for the purpose for which it is required, AEMO may make its own estimate and use that estimate in place of information provided in accordance with clauses 4.5.4, 4.5.5 and 4.5.6.

4.5.9. The Planning Criterion to be used by AEMO in undertaking a Long Term PASA study is that there should be sufficient available capacity in each Capacity Year during the Long Term PASA Study Horizon to:

(a) meet the forecast peak demand (including transmission losses and allowing for Intermittent Loads) supplied through the SWIS plus a reserve margin equal to the greater of:

i. 7.6% of the forecast peak demand (including transmission losses and allowing for Intermittent Loads); and

ii. the maximum capacity, measured at 41°C, of the largest generating unit;

while maintaining the Minimum Frequency Keeping Capacity for normal frequency control. The forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of ten; and

(b) limit expected energy shortfalls to 0.002% of annual energy consumption (including transmission losses).

4.5.10. AEMO must use the information assembled to:

(a) assess the extent to which the anticipated installed generation capacity and Demand Side Management capacity is capable of satisfying the Planning Criterion, identifying any capacity shortfalls in each Relevant Year in the Long Term PASA Study Horizon, for each of the following scenarios;

i. median peak demand assuming low demand growth;

ii. one in ten year peak demand assuming low demand growth;

iii. median peak demand assuming expected demand growth;

iv. one in ten year peak demand assuming expected demand growth;

v. median peak demand assuming high demand growth;

vi. one in ten year peak demand assuming high demand growth,

where the low, expected, and high demand growth cases reflect demand changes stemming from different levels of economic growth, with these being temperature adjusted to produce the one in ten year peak demand cases.

(b) forecast the Reserve Capacity Target and corresponding expected peak demand for each Capacity Year during the Long Term PASA Study Horizon, where:

i. the Reserve Capacity Target for a Capacity Year is the capacity required to meet the Planning Criterion in that year under the scenario described in clause 4.5.10(a)(iv); and

ii. the expected peak demand in that year is the peak demand under the scenario described in clause 4.5.10(a)(iv);

(c) identify and assess any potential capacity shortfalls isolated to a sub-region of the SWIS resulting from expected restrictions on transmission capability or other factors;

(d) identify any potential transmission, generation or demand side capacity augmentation options to alleviate capacity shortfalls identified in clause 4.5.10(a) and (c); and

(e) develop a two dimensional duration curve of the forecast minimum capacity requirements over the Capacity Year ("Availability Curve") for each of the second and third Capacity Years of the Long Term PASA Study Horizon. The forecast minimum capacity requirement for each Trading Interval in the Capacity Year must be determined as the sum of:

i. the forecast demand (including transmission losses and allowing for Intermittent Loads) for that Trading Interval under the scenario described in clause 4.5.10(a)(iv); and

ii. the difference between the Reserve Capacity Target for the Capacity Year and the maximum of the quantities determined under clause 4.5.10(e)(i) for the Trading Intervals in the Capacity Year.

4.5.11. AEMO must publish the Statement of Opportunities Report for a Reserve Capacity Cycle by the date specified in clause 4.1.8.

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

(a) [Blank]

(b) the minimum capacity required to be provided by Availability Class 1 capacity if Power System Security and Power System Reliability is to be maintained. This minimum capacity is to be set at a level such that if:

i all Availability Class 2 capacity (excluding Interruptible Load used to provide Spinning Reserve to the extent that it is anticipated to provide Certified Reserve Capacity), were activated during the Capacity Year so as to minimise the peak demand during that Capacity Year; and

ii the Planning Criterion and the criteria for evaluating Outage Plans set out in clause 3.18.11 were to be applied to the load scenario defined by clause 4.5.12(b)(i), then

it would be possible to satisfy the Planning Criterion and the criteria for evaluating Outage Plans set out in clause 3.18.11, as applied in clause 4.5.12(b)(ii), using, to the extent that the capacity is anticipated to provide Certified Reserve Capacity, the anticipated installed Availability Class 1 capacity, the anticipated Interruptible Load capacity available as Spinning Reserve and, to the extent that further Availability Class 1 capacity would be required, an appropriate mix of Availability Class 1 capacity to make up that shortfall; and

(c) the capacity associated with Availability Class 2, where this is equal to the Reserve Capacity Target for the Capacity Year less the minimum capacity required to be provided by Availability Class 1 capacity under clause 4.5.12(b).

…

Explanatory Note

Clause 4.10.1(l) is proposed to be amended to remove the reference to the 'Balancing Facility Requirements', and replace it with a reference to the Market Participant being required to provide evidence of how its Facility will be able to receive, confirm and respond to Dispatch Instructions in accordance with the WEM Procedures: Communications and Control Systems, and Dispatch.

It is expected that section 4.10 will be further amended in the Reserve Capacity Mechanism workstream, and to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

4.10. Information Required for the Certification of Reserve Capacity

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, where applicable, except to the extent that it is already accurately provided in Standing Data, the following information:

…

(j) whether the Facility will be subject to a Network Control Service Contract;

(k) where an applicant nominates to use the methodology described in clause 4.11.2(b) and the Facility is already in full operation under the configuration for which certification is being sought (as outlined in clause 4.10.1(dA)), the date on which the Facility became fully operational under this configuration, unless this date has already been provided to AEMO in a previous application for certification of Reserve Capacity; and

~~(l) for a Balancing Facility, evidence of the extent to which the Facility will meet the applicable criteria of the Balancing Facility Requirements.~~

(l) evidence of the extent to which the Facility will be able to receive, confirm, and implement Dispatch Instructions from AEMO in accordance with the WEM Procedures referred to in clauses 2.35.4 and 7.6.18.

…

Explanatory Note

Clause 4.11.12 is proposed to be amended to remove the reference to the 'Balancing Facility Requirements', and replace it with a reference to the Market Participant being required to provide evidence of how its Facility will be able to receive, confirm and respond to Dispatch Instructions in accordance with the WEM Procedures: Communications and Control Systems, and Dispatch.

It is expected that further amendments will be made to section 4.11, in the Reserve Capacity Mechanism workstream, and to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

4.11. Setting Certified Reserve Capacity

…

~~4.11.12. AEMO must not assign Certified Reserve Capacity to a Balancing Facility with a rated capacity equal to or greater than 10MW unless AEMO is satisfied the Facility is likely to be able to meet the Balancing Facility Requirements.~~

4.11.12 AEMO must not assign Certified Reserve Capacity to a Facility with a rated capacity equal to or greater than 10MW unless AEMO is satisfied the Facility is likely to be able to receive, confirm, and implement Dispatch Instructions from AEMO in accordance with the WEM Procedures referred to in clauses 2.35.4 and 7.6.18.

…

Explanatory Note

Clause 4.12.1(a)(i) is to be amended as the function of Interruptible Loads is changing so that it will not be meaningful for Market Participants to hold Capacity Credits in respect of an Interruptible Load (they can still hold Capacity Credits for that function via a Demand Side Programme).

Clause 4.12.1(a)(iv) is to be deleted as the 'Remaining Available Capacity' referred to in new clause 4.12.1(a)(vi) includes the effects of any Outages affecting, or likely to affect, the Facility in the Trading Interval.

Projected Essential System Services quantities (currently Ancillary Service quantities) will no longer be deducted from Reserve Capacity Obligation Quantities (**RCOQ**). All of a Market Participant's non-Demand Side Programme RCOQ must be offered into STEM, regardless of whether the Registered Facility may be dispatched for Essential System Service. Accordingly, the paragraph after clause 4.12.1(a)(iv) is proposed to be amended accordingly (in new subclauses (v) and (vi)).

Clause 4.12.1(c) is amended to refer to 'Dispatch Interval' instead of 'Trading Interval'.

It is expected that further changes will be made to section 4.12 in the Reserve Capacity Mechanism workstream, and to reflect the Administrative Changes referred to in the cover Note of these draft Amending Rules.

4.12. Setting Reserve Capacity Obligations

4.12.1. The Reserve Capacity Obligations for each Market Participant holding Capacity Credits are as follows:

(a) a Market Participant must ensure that for each Trading Interval:

i. the aggregate MW equivalent of the quantity of Capacity Credits held by the Market Participant applicable in that Trading Interval for ~~Interruptible Loads and~~ Demand Side Programmes registered to the Market Participant; plus

ii. the MW quantity calculated by doubling the Market Participant's Net Contract Position in MWh for the Trading Interval, corrected for Loss Factor adjustments so as to be a sent out quantity; plus

iii. the MW quantity calculated by doubling the total MWh quantity covered by STEM Offers which were not scheduled and the STEM Bids which were scheduled in the relevant STEM Auction determined by AEMO for that Market Participant under section 6.9 for that Trading Interval, corrected for loss factor adjustments so as to be a sent out quantity~~; plus~~,

iv. ~~capacity expected to experience a Forced Outage at the time that STEM submissions were due which becomes available in real time,~~ [Blank] is ~~not less than~~ greater than or equal to, the lesser of:

v. the total Reserve Capacity Obligation Quantity for that Trading Interval for all Registered Facilities registered to that Market Participant~~,~~; and

vi. the total Remaining Available Capacity for energy for that Trading Interval for all Registered Facilities registered to that Market Participant. ~~less double the total MWh quantity to be provided as Ancillary Services as specified by AEMO for that Market Participant in accordance with clause 6.3A.2(e)(i).~~

(b) [Blank]

(c) the Market Participant must make the capacity associated with the Capacity Credits provided by a Registered Facility applicable to a ~~Trading~~ Dispatch Interval, up to the Reserve Capacity Obligation Quantity for the Registered Facility for that ~~Trading~~ Dispatch Interval, available for dispatch by ~~System Management~~ AEMO in accordance with Chapter 7.

Explanatory Note

New clause 4.12.1A clarifies that the RCOQ for each Dispatch Interval is equal to the RCOQ for the Trading Interval in which those Dispatch Intervals fall. The Reserve Capacity Mechanism workstream will decide whether to change the RCOQ from per Trading Interval to per Dispatch Interval.

4.12.1A. Without limiting clause 4.12.1, the Reserve Capacity Obligation Quantity for a Registered Facility in a Dispatch Interval is equal to the Reserve Capacity Obligation Quantity for the Registered Facility for the Trading Interval in which the Dispatch Interval falls.

…

Explanatory Note

Clause 4.25.9(h) is proposed to be amended as a consequential amendment resulting from the removal of Operating Instructions.

It is expected that section 4.25 may be further amended in the Reserve Capacity Mechanism workstream, and to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

4.25. Reserve Capacity Testing

…

4.25.9. In conducting a Reserve Capacity Test, AEMO must:

(a) subject to clauses 4.25.9(b), 4.25.9(c) and 4.25.9(d), endeavour to conduct the Reserve Capacity Test without warning;

(b) allow sufficient time for the Market Participant to schedule fuel that it is not required under these ~~Market~~ WEM Rules to be stored on-site;

(c) allow sufficient time for switching a Facility from one fuel to an alternative fuel if operation using the alternative fuel is being tested;

(d) in the case of an Interruptible Load or a Demand Side Programme, give at least as much notice as is specified under clause 4.10.1(f)(v) to allow for arrangements to be made for the Facility to be triggered;

(e) [Blank]

(f) maintain adequate records of the Reserve Capacity Test to allow independent verification of the test results; and

(g) [Blank]

~~(h) issue an Operating Instruction to increase the Facility's output or decrease its consumption to a level specified by, or referred to in, the Operating Instruction.~~

(h) notify the Market Participant of the level of Injection or Withdrawal required by the Reserve Capacity Test.

…

Explanatory Note

Currently, Market Participants are required to offer adequate capacity into the STEM to cover the amount of Capacity Credits held by them for their Registered Facilities. Market Participants who fail to meet those obligations will pay capacity cost refunds on the shortfall.

In the new market, Market Participants must offer adequate capacity into the STEM and the Real-Time Market to cover the RCOQ for their Registered Facilities.

Therefore, the Net STEM Shortfall is proposed to be changed to Net Offer Shortfall, as it will take into account the shortfall in offers into both the STEM and the Real-Time Market.

Further changes to the Net STEM Shortfall (i.e. proposed Net STEM Offer Shortfall) calculation are required to reflect that:

- Essential System Service quantities (currently Ancillary Service quantities) will no longer be relevant to the calculation;
- new Outage reporting mechanisms are to be based on 'availability' instead of 'unavailability' (i.e. calculations are to be adjusted to use the 'available quantity' instead of the 'unavailable quantity');
- most inputs will be on a Dispatch Interval basis, and therefore must be converted to Trading Interval quantities for the purposes of the calculation; and
- the calculation currently compares sent-out RCOQ with loss-adjusted STEM quantities, and is proposed to be amended to compare sent-out RCOQ with sent-out STEM quantities.

The new Net Offer Shortfall calculation has four components:

- RCOQ: a Market Participant's obligations;
- OUTA: availability after declared outages (refunds are to be separately calculated for outages);
- CAPASTEM: the capacity actually made available in STEM; and
- CAPART: the capacity actually made available for dispatch in the Real-Time Market.

4.26. Financial Implications of Failure to Satisfy Reserve Capacity Obligations

…

~~4.26.2. AEMO must determine the net STEM shortfall ("Net STEM Shortfall") in Reserve Capacity supplied by each Market Participant p holding Capacity Credits associated with a generation system in each Trading Interval t as:~~

~~SF(p,t) = Max(RCDF(p,t), RCOQ(p,t) – A(p,t)) – RCDF(p,t)~~

~~where:~~

$$A(p,t) = \mathrm{Min}\big(RCOQ(p,t), CAPA(p,t)\big);$$

~~RCOQ(p,t) for Market Participant p and Trading Interval t is equal to:~~

~~(a) the total Reserve Capacity Obligation Quantity of Market Participant p's unregistered facilities that have Reserve Capacity Obligations, excluding Loads that can be interrupted on request; plus~~

~~(b) the sum of the product of:~~

~~i. the factor described in clause 4.26.2B as it applies to Market Participant p's Registered Facilities; and~~

~~ii. the Reserve Capacity Obligation Quantity for each Facility,~~

~~for all Market Participant p's Registered Facilities, excluding Demand Side Programmes,~~

~~CAPA(p,t) for Market Participant p and Trading Interval t is:~~

~~(c) equal to RCOQ(p,t) for a Trading Interval where the STEM Auction has been suspended by AEMO in accordance with section 6.10;~~

~~(d) subject to clause 4.26.2(c), the sum of:~~

~~i. the Reserve Capacity Obligation Quantities in Trading Interval t of that Market Participant's Interruptible Loads; plus~~

~~ii. the MW quantity calculated by doubling that Market Participant's Net Contract Position in MWh for Trading Interval t, corrected for Loss Factor adjustments so as to be a sent out quantity in accordance with clause 4.26.2A; plus~~

~~iii. the MW quantity calculated by doubling the total MWh quantity covered by the STEM Offers which were not scheduled and the STEM Bids which were scheduled in the relevant STEM Auction, determined by AEMO for that Market Participant under section 6.9 for Trading Interval t, corrected for Loss Factor adjustments so as to be a sent out quantity in accordance with clause 4.26.2A; plus~~

~~iv. double the total MWh quantity to be provided as Ancillary Services as specified by AEMO in accordance with clause 6.3A.2(e)(i) for that Market Participant corrected for Loss Factor adjustments so as to be a sent out quantity in accordance with clause 4.26.2A; plus~~

~~v. the greater of zero and (BSFO(p,t) – RTFO(p,t));~~

~~$RCDF(p,t) = RTFO(p,t) + RTNREPO(p,t);$~~

~~$RTNREPO(p,t) = \sum_{f \in F} \left(Max\left(0, NREPO(f,t) - BSPO(f,t)\right) \right);$~~

~~NREPO(f,t) is the total MW quantity of Refund Payable Planned Outage associated with Facility f for Trading Interval t;~~

~~BSPO(f,t) is the total MW quantity of Planned Outage associated with Facility f before the STEM Auction for Trading Interval t, as provided to the AEMO by System Management in accordance with clause 7.3.4;~~

~~F is the set of Scheduled Generators registered to Market Participant p, and f is a Facility within that set;~~

~~BSFO(p,t) is the total MW quantity of Forced Outage associated with Market Participant p before the STEM Auction for Trading Interval t, where this is the sum over all the Market Participant's Registered Facilities of the lesser of the Reserve Capacity Obligation Quantity of the Facility for Trading Interval t and the MW Forced Outage of the Facility for Trading Interval t as recorded in accordance with section 7.3; and~~

~~RTFO(p,t) is the total MW quantity of Forced Outage associated with Market Participant p in real-time for Trading Interval t, where this is the sum over all the Market Participant's Registered Facilities of the lesser of the Reserve Capacity Obligation Quantity of the Facility for Trading Interval t and the MW Forced Outage of the Facility for Trading Interval t as recorded in accordance with clause 7.13.1A(b).~~

4.26.2. AEMO must determine the shortfall ("Net Offer Shortfall") in Reserve Capacity supplied by each Market Participant p holding Capacity Credits associated with a generation system in each Trading Interval t as:

$$\begin{aligned} \mathrm{NetOfferShortfall(p,t)} &= \mathrm{Max(0, Min(RCOQ(p,t), OUTA(p,t))} \\ &\quad - \mathrm{Min(CAPASTEM(p,t), CAPART(p,t)))} \end{aligned}$$

Where:

(a) $\mathrm{RCOQ(p,t)}$ for Market Participant p and Trading Interval t is equal to the minimum of RCOQ(p,DI) across the Dispatch Intervals in the Trading Interval:

$\mathrm{RCOQ(p,t) = Min(RCOQ(p,DI)} \forall \mathrm{\ DI\ in\ t)}$

Where:

$\mathrm{RCOQ(p,DI)}$ for Market Participant p and Dispatch Interval DI is equal to the sum of RCOQ(f,DI) for all of Market Participant p's Registered Facilities.

$$\mathrm{RCOQ(p,DI)} = \sum_{\mathrm{f \in Facilities(p,DI)}} \mathrm{RCOQ(f,DI)}$$

Where:

$\mathrm{Facilities(p, DI)}$ is the set of Registered Facilities registered to Market Participant p in Dispatch Interval DI.

$\mathrm{RCOQ(f, DI)}$ is the Reserve Capacity Obligation Quantity for Registered Facility f in Dispatch Interval DI.

(b) $\mathrm{OUTA(p, t)}$ is the minimum of OUTA(p,DI) across the Dispatch Intervals in the Trading Interval.

$$\mathrm{OUTA(p, t) = Min(OUTA(p, DI)\forall\ DI\ in\ t)}$$

Where:

$\mathrm{OUTA(p, DI)}$ is the sum over the Market Participant's Registered Facilities of the lower of:

i. RCOQ(f,DI); and

ii. the lowest Remaining Available Capacity for energy for the Registered Facility in the Dispatch Interval under any Outage.

$$\mathrm{OUTA(p, DI)} = \sum_{\mathrm{f \in Facilities(p,DI)}} \mathrm{OUTA(f, DI)}$$

$$\mathrm{OUTA(f, DI)} \\ = \mathrm{Min(RCOQ(f, DI), Min(OutageAvail(f, DI, o)\forall o\ in\ Outages))}$$

Where:

$\mathrm{Outages}$ is the set of all Outages for Registered Facility f which includes Dispatch Interval DI.

$\mathrm{OutageAvail(f, DI, o)}$ is the Remaining Available Capacity for energy for Registered Facility f in Dispatch Interval DI under Outage o.

(c) CAPART(p,t) is the minimum of CAPART(p,DI) for all Dispatch Intervals in Trading Interval t.

$$\mathrm{CAPART(p, t) = Min(CAPART(p, DI)\forall\ DI\ in\ t)}$$

Where:

$\mathrm{CAPART(p,DI)}$ is the sum over the Market Participant's Registered Facilities of $\mathrm{CAPART(f,DI)}$.

$$\mathrm{CAPART(p, DI)} = \sum_{\mathrm{f \in Facilities(p,DI)}} \mathrm{CAPART(f, DI)}$$

Where:

CAPART(f,DI) is the MW quantity of energy made available from that Registered Facility in the Real-Time Market for that Dispatch Interval.

$$\mathrm{CAPART(f, DI) = OfferAvail(f, DI) + BidAvail(f, DI)}$$

Where:

$\mathrm{OfferAvail(f, DI)}$ is:

i. for a Demand Side Programme, zero; and

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

$\mathrm{BidAvail(f, DI)}$ is:

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

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

(d) CAPASTEM(p,t) for Market Participant p and Trading Interval t is RCOQ(p,t) where the STEM Auction has been suspended by AEMO in accordance with section 6.10 or where $\sum_{f \in \mathrm{STEMFacilities}(p,t)} \mathrm{RCOQ}(f,t) = 0.$ Otherwise:

$$\mathrm{CAPASTEM}(p,t) = \left(\frac{\mathrm{NCP}(p,t) + \mathrm{UnclearedSTEMOffers}(p,t) + \mathrm{ClearedSTEMBids}(p,t)}{\mathrm{LF}(p,t) \times \frac{30}{60} h} \right) + \mathrm{RCOQDSP}(p,t) + \mathrm{Max}\big(0, \mathrm{OUTA}(p,t) - \mathrm{OUTABS}(p,t)\big)$$

Where:

LF(p,t) is the capacity obligation weighted average of the Loss Factors for the Market Participant's Registered Facilities which are not Demand Side Programmes.

$$\mathrm{LF}(p,t) = \frac{\sum_{f \in \mathrm{STEMFacilities}(p,t)} \mathrm{LossFactor}(f,t) * \mathrm{RCOQ}(f,t)}{\sum_{f \in \mathrm{STEMFacilities}(p,t)} \mathrm{RCOQ}(f,t)}$$

Where:

$\mathrm{STEMFacilities}(p,t)$ is the set of Registered Facilities registered to Market Participant p in Trading Interval t other than Demand Side Programmes.

$\mathrm{LossFactor}(f,t)$ is the Loss Factor for Registered Facility f in Trading Interval t.

$\mathrm{RCOQ}(f,t)$ is the Reserve Capacity Obligation Quantity for Registered Facility f in Trading Interval t.

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

$\text{UnclearedSTEMOffers(p,t)}$ is the total MWh quantity covered by the STEM Offers which were not scheduled in the relevant STEM Auction, determined by AEMO for that Market Participant under section 6.9 for Trading Interval t.

$\text{ClearedSTEMBids(p,t)}$ is the total MWh quantity covered by the STEM Bids which were scheduled in the relevant STEM Auction, determined by AEMO for that Market Participant under section 6.9 for Trading Interval t.

RCOQDSP(p,t) is the sum of RCOQ(f,t) over the Demand Side Programmes registered to Market Participant p in Trading Interval t.

OUTABS(p,t) is the minimum of OUTABS(p,DI) for all Dispatch Intervals in Trading Interval t.

$$\text{OUTABS(p,t)} = \text{Min(OUTABS(p,DI)} \forall \text{ DI in t)}$$

Where:

OUTABS(p,DI) is the sum of OUTABS(f,DI) for all the Market Participant's Registered Facilities

$$\text{OUTABS(p,DI)} = \sum_{\text{f} \in \text{Facilities(p,DI)}} \text{OUTABS(f,DI)}$$

$$\text{OUTABS(f,DI)} = \text{Min(RCOQ(f,DI), Min(OutageAvail(f,DI,o)} \forall \text{o in OutagesBS))}$$

OutagesBS is the set of all Outages for Registered Facility f which include Dispatch Interval DI as they existed at the STEM Submission Cutoff.

4.26.2A. ~~All values in clause 4.26.2 which are required to be corrected for Loss Factor adjustments so as to be a sent out quantity are to be adjusted based on an assumed Loss Factor of 1.~~ [Blank]

4.26.2B. ~~AEMO is to set the factor described in the definition of RCOQ(p,t) in clause 4.26.2 to equal one in all situations except for Scheduled Generators and Non-Scheduled Generators with Loss Factors less than one, in which case the factor must equal the Facility's Loss Factor.~~ [Blank]

…

Explanatory Note
The proposed amendments to clause 4.26.3 are consequential amendments to refer to the new terms "Net Offer Shortfall" and "Net Offer Refund". Further changes are expected to be made in the Reserve Capacity Mechanism workstream.

4.26.3. The Generation Capacity Cost Refund for Trading Interval t in Capacity Year y for a Market Participant p holding Capacity Credits associated with a generation system is the lesser ~~of—~~ of:

(a) the Maximum Participant Generation Refund determined for Market Participant p and Capacity Year y less all Generation Capacity Cost Refunds applicable to Market Participant p in previous Trading Interval t falling in Capacity Year y; and

(b) the Generation Reserve Capacity Deficit Refund for Market Participant p and Trading Interval t, plus the Net ~~STEM~~ Offer Refund in Trading Interval t for Market Participant p,

where the Net ~~STEM~~ Offer Refund is calculated as ~~follows—~~ follows:

$$\mathrm{N}\cancel{\mathrm{STEM}}\ \mathrm{Offer\ Refund(p,t)} = \mathrm{TIRR\ weighted(p,t)} \times \mathrm{N}\cancel{\mathrm{STEM}}\ \mathrm{Offer\ Short(p,t)}$$

~~Where—~~Where:

i. N ~~STEM~~ Offer Refund(p, t) is the Net ~~STEM~~ Offer Refund for Market Participant p in Trading Interval t;

ii. TIRR weighted(p, t) is the weighted average of the Trading Interval Refund Rate in Trading Interval t for each Facility that Market Participant p holds Capacity Credits for and is calculated as ~~follows—~~ follows:

$$\mathrm{TIRR\ weighted(p,t)} = \sum_{\mathrm{f\epsilon F}} \frac{\mathrm{TIRR(f,t)} \times \mathrm{CC(f,t)}}{\sum_{\mathrm{f\epsilon F}} \mathrm{CC\ (f,t)}}$$

~~where—~~where:

1. F is the set of Scheduled Generators registered to Market Participant p and f is a Facility within that set;

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

3. CC(f,t) is the number of Capacity Credits associated with Facility f in Trading Interval t; and

iii. N ~~STEM~~ Offer Short(p, t) is the Net ~~STEM~~ Offer Shortfall for Market Participant p in Trading Interval t.

…

Explanatory Note

Chapter 6 is to be renamed 'The Short Term Energy Market' and will be limited to matters relating only to the Short Term Energy Market (**STEM**).

The STEM is a financially binding day-ahead market. STEM provides a centrally coordinated opportunity for Market Participants to trade around their bilateral positions, supplementing and complementing the off-market bilateral contracts regime. It allows for financial trading against contract positions, rather than centralised scheduling and commitment, though it does provide a firm financial basis for commitment of long-start-time Registered Facilities.

The changes focus on four main aspects:

- removing narrow windows and timings for AEMO and Market Participants to submit information, in favour of continuously updated information from AEMO, and flexibility for Market Participants to submit information at their convenience;
- Market Participants will now use data from the Pre-Dispatch Schedules to bound their STEM submissions, replacing the current requirement for AEMO to calculate certain information daily for use in the STEM;
- adjusting the present requirement to offer in at short-run marginal cost where the Market Participant has market power, to explicitly allow incorporation of a risk premium where a Market Participant is uncertain of its ability to generate, including for projected Essential System Service provision; and
- removing the requirement for Market Participants to lock-in energy to meet their Net Bilateral Position in the STEM, allowing Market Participants to leave some of their position open until the Real-Time Market.

As a result of Chapter 6 being limited to matters relating only to the STEM, further amendments are proposed to be made as follows:

- sections 6.1 to 6.11 (STEM) will be retained subject to amendments proposed in these draft Amending Rules to reflect the changes outlined above;
- sections 6.11A and 6.12 (Non-Balancing Dispatch) are proposed to be deleted and replaced by new arrangements in the Central Dispatch process in Chapter 7;
- sections 6.13 and 6.14 (Settlement quantities) will be retained subject to amendments proposed in the Settlement workstream;
- section 6.15 (TES) will be deleted as part of the proposed amendments in the Settlement workstream;
- section 6.16 (Metered Schedule) will be retained subject to proposed amendments in the Settlement workstream;
- sections 6.16A, 6.16B and clauses 6.17.3 to 6.17.5C (Out of Merit and Constrained Payments) will be deleted and replaced by uplift payments and other proposed amendments in the Settlement workstream;
- clauses 6.17.1 and 6.17.2 (Balancing Settlement Quantities) will be retained and renamed, and adjusted for the new Real-Time Market as proposed in the amendments in the Settlement workstream;
- clauses 6.17.6 to 6.17.8 (Non-Balancing Facility dispatch payments) will be deleted pursuant to proposed amendments in the Settlement workstream (and changes relating to the Reserve Capacity Mechanism that are scheduled to commence on 1 October 2021);
- clause 6.17.9 (Settlement Tolerance) will be retained and moved to Chapter 9 pursuant to the proposed amendments in the Settlement workstream;
- clause 6.17.10 and section 6.18 (Portfolio Settlement Tolerance) will be deleted (as the portfolio will no longer exist under the new market arrangements) pursuant to the proposed amendments in the Settlement workstream;
- section 6.19 (Market Advisories) is to be deleted and merged with Dispatch Advisories to create new Market Advisories in section 7.8;

- section 6.20 (Energy Price Limits) will be retained subject to amendments pursuant to the proposed amendments in the Market Power workstream; and
- section 6.21 (Settlement Data) is to be retained subject to amendments pursuant to the proposed amendments in the Settlement workstream.

6. The Short Term Energy Market

Energy Scheduling Timetable and Process

6.1. [Blank]

6.2. Bilateral Submission Timetable and Process

Explanatory Note

Clause 6.2.1 is amended to remove the current window for submitting Bilateral Submissions for a Trading Day. Market Participants will be able to submit Bilateral Submissions up until 8:50am on the Scheduling Day for the Trading Day, or such other time as may be notified by AEMO in accordance with clause 6.4.6B.

6.2.1. A Market ~~Generator~~ Participant may submit Bilateral Submission data for a Trading Day to AEMO ~~between:~~ at any time before the Bilateral Submission Cutoff for the Trading Day.

~~(a) 8:00 AM of the day seven days prior to the start of the Scheduling Day for the Trading Day; and~~

~~(b) 8:50 AM on the Scheduling Day for the Trading Day.~~

Explanatory Note

Clause 6.2.2 is amended to clarify when AEMO will use a Standing Bilateral Submission as the Bilateral Submission for the relevant Trading Day.

6.2.2. Where, at the Bilateral Submission Cutoff for a Trading Day:

(a) AEMO holds a Standing Bilateral Submission applicable to the Trading Day for a Market Participant; and

(b) AEMO does not hold a Bilateral Submission applicable to the Trading Day for the Market Participant,

AEMO must make the Standing Bilateral Submission the Bilateral Submission for the Trading Day for the Market Participant. ~~AEMO holds a Standing Bilateral Submission for a Market Generator as at the time specified in clause 6.2.1(a), where that Standing Bilateral Submission is applicable to the Trading Day to which clause 6.2.1 relates and where that Standing Bilateral Submission conforms to the requirements of clause 6.7 at that time, AEMO must make the Bilateral Submission with respect to the Trading Day as at the time specified in clause 6.2.1(a).~~

Explanatory Note

Clause 6.2.2A requires AEMO to accept or reject Bilateral Submission data and to notify the Market Participant of its decision.

6.2.2A. Where AEMO receives Bilateral Submission data from a Market Participant under clause 6.2.1, AEMO must, as soon as practicable after receiving the Bilateral Submission data:

(a) if the Bilateral Submission data complies with section 6.7 and was provided before the Bilateral Submission Cutoff, make the Bilateral Submission data the Bilateral Submission for the Trading Day; and

(b) notify the Market Participant which submitted the Bilateral Submission data under clause 6.2.1, that:

i. the Bilateral Submission data has been made the Bilateral Submission for the Trading Day to which the Bilateral Submission data submitted under clause 6.2.1 relates; or

ii. AEMO rejects the Bilateral Standing Submission data as it does not comply with section 6.7, or was received after the Bilateral Submission Cutoff for the Trading Day to which the Bilateral Submission data submitted under clause 6.2.1 relates.

~~6.2.2A. When AEMO receives Bilateral Submission data from a Market Generator during the time interval described in clause 6.2.1, it must as soon as practicable communicate to that Market Generator whether or not AEMO accepts the data as conforming to the requirements of clause 6.7. Where AEMO accepts the data then AEMO must revise the Bilateral Submission to reflect that data.~~

Explanatory Note

Clause 6.2.3 requires AEMO to maintain and provide Bilateral Submission quantities to Market Participants for each Trading Interval in the Week Ahead Schedule Horizon.

6.2.3. ~~By 8:30 AM on each Scheduling Day~~ AEMO must ~~communicate~~ maintain and provide to each Market Participant ~~a list of~~ the Bilateral Submission quantities associated with that Market Participant for each Trading Interval ~~on the Trading Day~~ in the Week Ahead Schedule Horizon as they would be used in the STEM Auction, including the party supplying, or being supplied by, the Market Participant.~~, where this~~ AEMO must update this information whenever AEMO accepts Bilateral Submission data under clause 6.2.2(a) or Standing Bilateral Submission data under clause 6.2A.2(a) ~~must be based on Bilateral Submissions held by AEMO at a time not earlier than 8:20 AM on the Scheduling Day~~.

6.2.4. [Blank]

6.2.4A. [Blank]

6.2.4B. A Market Generator may cancel Bilateral Submission data held by AEMO for any Trading Interval before the Bilateral Submission Cutoff for the Trading Day to which the cancelled Bilateral Submission data relates.~~ of the Trading Day during the time interval specified in clause 6.2.1.~~

6.2.5. [Blank]

6.2.6. [Blank]

6.2.7. By making or revising a Bilateral Submission a Market Participant acknowledges that it is acting with the permission of all affected Market Participants.

6.2.8. ~~By 9:00 AM on each Scheduling Day AEMO must communicate to each Market Participant a list of the Bilateral Submission quantities associated with that Market Participant for each Trading Interval on the Trading Day, including the party supplying, or being supplied by, the Market Participant.~~[Blank]

6.2A. Standing Bilateral Submission Timetable and Process

Explanatory Note

Clause 6.2A.1 is proposed to be amended to remove the current window for provision of Standing Bilateral Submission data to AEMO. Market Participants will be able to submit Standing Bilateral Submissions to AEMO at any time.

6.2A.1. A Market~~ Generator~~ Participant may submit Standing Bilateral Submission data to AEMO at any time.~~ on any day between the times of:~~

~~(a) 1:00 PM; and~~

~~(b) 3:50 PM,~~

~~where if accepted by AEMO the data will apply from the commencement of the subsequent Scheduling Day.~~

Explanatory Note

Clause 6.2A.2 is proposed to be amended to improve the drafting to clarify that AEMO is required to accept or reject Standing Bilateral Submission data and notify the Market Participant of its decision.

~~6.2A.2. When AEMO receives Standing Bilateral Submission data from a Market Generator during the time interval described in clause 6.2A.1, it must as soon as practicable communicate to that Market Generator whether or not AEMO accepts the data as conforming to the requirements of clause 6.7. Where AEMO accepts the data then AEMO must revise the Standing Bilateral Submission to reflect that data.~~

6.2A.2. AEMO must, as soon as practicable after receiving Standing Bilateral Submission data under clause 6.2A.1, but before the start of the next Scheduling Day:

(a) accept the Standing Bilateral Submission data provided it complies with section 6.7; and

(b) notify the Market Participant which submitted the Standing Bilateral data under clause 6.2A.1 that:

i. AEMO accepts the Standing Bilateral Submission data and has revised the Standing Bilateral Submission to reflect the Standing Bilateral Submission data; or

ii. AEMO rejects the Standing Bilateral Submission data.

Explanatory Note
Clause 6.2A.2 has been added to clarify when Standing Bilateral Submission data accepted by AEMO under clause 6.2A.2 will apply from.

6.2A.2A. Standing Bilateral Submission data accepted by AEMO under clause 6.2A.2 will apply from the time specified for the Standing Bilateral Submission under clause 6.7.1(b)(ii)(2).

6.2A.3. Standing Bilateral Submission data must be associated with a day of the week and when used as Bilateral Submission data will only apply to Trading Days commencing on that day of the week.

6.2A.4. A Market ~~Generator~~ Participant may cancel Standing Bilateral Submission data held by AEMO for any Trading Interval in any day of the week at any time ~~of the Trading Day during the time interval specified in clause 6.2A.1~~.

~~6.2A.5. AEMO must confirm to the Market Generator any cancellation of Standing Bilateral Submission data made in accordance with clause 6.2A.4. Where such cancellation is made then AEMO must remove the relevant data from the Standing Bilateral Submission.~~

Explanatory Note
Clause 6.2A.5 is proposed to be amended to improve the drafting to clarify AEMO's obligations when a Market Participant cancels Standing Bilateral Submission data.

6.2A.5. Where any Standing Bilateral Submission data is cancelled in accordance with clause 6.2A.4, AEMO must:

(a) remove the cancelled Standing Bilateral Submission data from the Standing Bilateral Submission; and

(b) notify the Market Participant which cancelled the Standing Bilateral Submission data under clause 6.2A.4, that the cancelled Standing Bilateral Submission data has been removed from the Standing Bilateral Submission,

for the Trading Interval of the day of the week to which the cancelled Standing Bilateral Submission data relates.

6.3. [Blank]

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

~~6.3A.1. AEMO must publish the following information:~~

(a) ~~by 8:00 AM of each Scheduling Day to support the Bilateral Submission process the Load Forecast in MWh and MW as measured at the Reference Node for each of the Trading Intervals of the Trading Day determined in accordance with clause 7.2.1;~~

(b) ~~by 9:00 AM of each Scheduling Day to support the STEM Submission process:~~

i. ~~the total energy, in MWh as measured at the Reference Node, scheduled with AEMO under bilateral contracts for each of the Trading Intervals of the Trading Day; and~~

ii. ~~data to allow the estimation of the residual Reserve Capacity available in each of the Trading Intervals of the Trading Day after netting off the quantity in (i).~~

Explanatory Note

Clause 6.3A.1 is amended to clarify that the total energy scheduled with AEMO under bilateral contracts will be published for each Trading Interval in the Week Ahead Schedule Horizon, and to require AEMO to update the information when it accepts updated Bilateral Submission data or Standing Bilateral Submission data.

6.3A.1. AEMO must publish the total energy, in MWh, as measured at the Reference Node, scheduled with AEMO under bilateral contracts for each Trading Interval in the Week Ahead Schedule Horizon. AEMO must update this information whenever AEMO accepts Bilateral Submission data under clause 6.2.2(a) or Standing Bilateral Submission data under clause 6.2A.2(a).

6.3A.2. [Blank]~~By 9:00 AM on the Scheduling Day AEMO must have calculated and released to each Market Participant the following parameters to be applied by that Market Participant in forming its STEM Submissions for each Trading Interval in the Trading Day:~~

(a) ~~the Maximum Supply Capability where this equals the maximum Loss Factor adjusted quantity of energy, in units of MWh, that could be supplied during the Trading Interval based on the Standing Data of that Market Participant's Scheduled Generators and Non-Scheduled Generators and assuming the use of the fuel which maximises the capacity of each Facility:~~

i. ~~less an allowance for Outages in the schedule maintained in accordance with clause 7.3.4; and~~

ii. ~~less, for each Market Participant that is a provider of Ancillary Services, the estimated Loss Factor adjusted quantity of energy, in units of MWh, that could potentially be called upon by System Management from that Market Participant after 1:00 PM on the Scheduling Day to meet Ancillary Service requirements for each Trading Interval of the Trading Day,~~

~~where the Maximum Supply Capability may be higher than the actual capacity available during the Trading Interval;~~

(b) ~~the Maximum Consumption Capability where this equals the maximum Loss Factor adjusted quantity of energy, in units of MWh, that could be consumed during a Trading Interval by that Market Participant's Non-Dispatchable Loads and Interruptible Loads based on the Standing Data maximum consumption quantities for those Facilities and Non-Dispatchable Loads, less an allowance for Outages in the schedule maintained in accordance with clause 7.3.4;~~

(c) ~~for each Scheduled Generator and Non-Scheduled Generator that is registered as being able to run on Liquid Fuel only, the maximum Loss Factor adjusted quantity of energy, in units of MWh, that could be supplied during the Trading Interval based on the Standing Data of that Scheduled Generator or Non-Scheduled Generator less an allowance for Outages in the schedule maintained in accordance with clause 7.3.4;~~

(d) ~~for each Scheduled Generator and Non-Scheduled Generator that is registered as being able to run on both Liquid Fuel and Non-Liquid Fuel, the maximum Loss Factor adjusted quantity of energy, in units of MWh represented in units of MW by multiplying by the number of minutes in an hour divided by the number of minutes in a Trading Interval, that could be supplied during the Trading Interval when run on each of Liquid Fuel and Non-Liquid Fuel based on the Standing Data of that Scheduled Generator or Non-Scheduled Generator less an allowance for Outages in the schedule maintained in accordance with clause 7.3.4; and~~

(e) ~~in the case of each Market Participant that is a provider of Ancillary Services:~~

i. ~~the estimated Loss Factor adjusted quantity of energy, in units of MWh, that could potentially be called upon by System Management after 1:00 PM on the Scheduling Day to meet Ancillary Service requirements for each Trading Interval of the Trading Day; and~~

ii. ~~the list of Facilities that System Management might reasonably expect to call upon to provide the energy described in clause 6.3A.2(e)(i).~~

Explanatory Note Clause 6.3A.3 sets out the information AEMO will calculate and provide to each Market Participant for use in their STEM Submissions.

6.3A.3. ~~By 9:05 AM on the Scheduling Day~~ AEMO must ~~have calculated and released~~ calculate and provide to each Market Participant the following parameters for information in forming its STEM Submissions for each Trading Interval in the ~~Trading Day~~ Week Ahead Schedule Horizon:

(a) the total quantity of Capacity Credits held by that Market Participant for each Trading Interval ~~the Trading Day, in units of MW~~;

(b) ~~the estimated Loss Factor adjusted quantity of energy that could potentially be called upon by System Management after 1:00 PM on the Scheduling~~

~~Day to meet Ancillary Service requirements for each Trading Interval of the Trading Day, multiplied by 2, in units of MW;~~[Blank]

Explanatory Note
The outages information in clause 6.3A.3(c) is expected to be re-considered in the Outages workstream.

(c) for each of the Market Participant's Registered Facilities, the lowest Remaining Available Capacity for energy in any Outage applying to the Registered Facility~~the total quantity of Planned Outages and Consequential Outages for that Market Participant in the schedule maintained in accordance with clause 7.3.4, in units of MW~~;

(d) the total quantity specified in any ~~STEM submission~~ Portfolio Supply Curve from that Market Participant that has been accepted by AEMO for that Trading Interval, ~~multiplied by 2,~~ represented in units of MW by multiplying by the number of minutes in an hour divided by the number of minutes in a Trading Interval; ~~and~~

~~(e) the total quantity specified in any STEM submission Ancillary Service Declaration from that Market Participant that has been accepted by AEMO for that Trading Interval, multiplied by 2, in units of MW.~~

(e) the Maximum Consumption Capability where this equals the maximum Loss Factor adjusted quantity of energy, in units of MWh, that could be consumed during a Trading Interval by that Market Participant's Non-Dispatchable Loads based on the Standing Data maximum consumption quantities for those Facilities and Non-Dispatchable Loads, less an allowance for Outages in the schedule maintained in accordance with [outage information publication];

Explanatory Note
The value in clause 6.3A.3(f) is the relevant sum over all of the Market Participant's Registered Facilities, whereas the value in clause 6.3A.3(g) is the relevant sum of each of the Market Participant's Registered Facilities.

(f) the sum of the Loss Factor adjusted Available Capacity and In-Service Capacity offered into the Real Time Market in accordance with section 7.4 for the Market Participant's Registered Facilities, represented in units of MWh by multiplying by the number of minutes in a Trading Interval divided by the number of minutes in an hour; and

(g) the sum of the Loss Factor adjusted Available Capacity and In-Service Capacity offered into the Real Time Market in accordance with section 7.4 for each of the Market Participant's Registered Facilities, represented in units of MWh by multiplying by the number of minutes in a Trading Interval divided by the number of minutes in an hour.

6.3A.4. AEMO must update the information under clause 6.3A.3 whenever there is a change in the data used to calculate that information.

~~6.3A.4. If AEMO accepts a STEM Submission from a Market Participant after it has calculated and released the parameters required under clause 6.3A.3, then AEMO must as soon as practicable update its calculations of the quantities specified in clauses 6.3A.3(d) and 6.3A.3(e) for that Trading Day and release those updated parameters to the Market Participant.~~

Explanatory Note

Clause 6.3B.1 is proposed to be amended to remove the current window for submitting STEM Submissions for a Trading Day. Market Participants will be able to submit STEM Submissions up until 10:50am on the Scheduling Day for the relevant Trading Day, or such other time as may be notified by AEMO in accordance with clause 6.4.6B.

6.3B. STEM Submissions Timetable and Process

6.3B.1. A Market Participant may submit STEM Submission data for a Trading Day to AEMO ~~between:~~ at any time before the STEM Submission Cutoff.

~~(a) 9:00 AM on the Scheduling Day; and~~

~~(b) 10:50 AM on the Scheduling Day.~~

Explanatory Note

Clause 6.3B.1A is proposed to be amended to clarify when AEMO will use a Standing STEM Submission for a Trading Day.

6.3B.1A. Where, at the STEM Submission Cutoff for a Trading Day:

(a) AEMO holds a Standing STEM Submission applicable to the Trading Day for a Market Participant; and

(b) AEMO does not hold a STEM Submission applicable to the Trading Day for the Market Participant,

AEMO must, subject to clause 6.3B.1B, make the Standing STEM Submission the STEM Submission for the Trading Day for the Market Participant. ~~as at the time specified in clause 6.3B.1(a), where that Standing STEM Submission is applicable to the Trading Day to which clause 6.3B.1 relates and where that Standing STEM Submission conforms to the requirements of clause 6.6 at that time, AEMO must make it the STEM Submission with respect to the Trading Day as at the time specified in clause 6.3B.1(a).~~

Explanatory Note

Clause 6.3B.1B sets out the adjustments AEMO may make to a Standing STEM Submission so that it complies with the requirements for a STEM Submission

6.3B.1B. If AEMO is required to make a Standing STEM Submission the STEM Submission for a Trading Day under clause 6.3B.1A, but the Standing STEM Submission does not comply with section 6.6, AEMO must adjust the Standing STEM Submission data to enable it to make a STEM Submission with respect to the Trading Day that complies with section 6.6. ~~the Market Participant's Standing STEM Submission has not been successfully converted into a daily STEM Submission for the Trading~~

~~Day in accordance with clause 6.3B.1A, then AEMO must adjust the Standing STEM Submission to make it a valid STEM Submission with respect to the Trading Day.~~ The adjustment will be made as follows:

(a) if the cumulative MWh quantity over all Price-Quantity Pairs is greater than the quantity calculated under clause 6.3A.3(f) ~~Maximum Supply Capability as calculated under clause 6.3A.2(a)~~, the Price-Quantity Pairs will be adjusted downward so that the cumulative MWh quantity over all Price-Quantity Pairs equals the quantity calculated under clause 6.3A.3(f)~~Maximum Supply Capability~~. This will be achieved by deleting successively or reducing the highest price Price-Quantity Pairs until the cumulative MWh quantity over all remaining Price-Quantity Pairs equals the quantity calculated under clause 6.3A.3(f)~~Maximum Supply Capability as calculated under clause 6.3A.2(a)~~; and

(b) available dual fuel generators shall be declared to be using the same fuel as in the existing Standing STEM Submission~~;~~.

(c) ~~any Ancillary Services shall be declared as using Non-Liquid Fuel; and~~[Blank]

(d) ~~if the number of Price-Quantity Pairs in the modified Portfolio Supply Curve is greater than that allowed by clause 6.6.4, this will be disregarded and the STEM Submission validated.~~[Blank]

6.3B.2. [Blank]

~~6.3B.3. When AEMO receives STEM Submission data from a Market Participant during the time interval described in clause 6.3B.1, it must as soon as practicable communicate to that Market Participant:~~

~~(a) [Blank]~~

~~(b) whether or not AEMO accepts the received STEM Submission data as conforming to the requirements of clause 6.6;~~

~~(c) [Blank]~~

~~where, if AEMO accepts the data, the STEM Submission held by AEMO must be revised to reflect that data.~~

6.3B.3. Where AEMO receives STEM Submission data from a Market Participant under clause 6.3B.1, AEMO must:

(a) if the STEM Submission data complies with clause 6.6, make the STEM Submission data the STEM Submission for that Trading Day; and

(b) notify the Market Participant which submitted the STEM Submission data under clause 6.3B.1, that:

i. the STEM Submission data has been made the STEM Submission for that Trading Day; or

ii. AEMO has rejected the STEM Submission data as it did not comply with section 6.6.

~~6.3B.4. [Blank]~~

6.3B.4. AEMO must maintain and provide to each Market Participant the STEM Submissions associated with the Market Participant for each Trading Interval in the Week Ahead Schedule Horizon as they would be used in the STEM Auction. AEMO must update this information whenever AEMO accepts STEM Submission data under clauses 6.3B.1A(a) or 6.3B.3(a), or Standing STEM Submission data under clause 6.3C.3(a).

6.3B.5. [Blank]

6.3B.6. [Blank]

6.3B.7. [Blank]

6.3B.7A. A Market Participant may cancel any STEM Submission data held by AEMO for any Trading Interval of the Trading Day at any time before the STEM Submission Cutoff ~~during the time interval specified in clause 6.3B.1~~.

> **Explanatory Note**
>
> Clause 6.3B.7B is proposed to be amended to improve the drafting and to clarify AEMO's obligations when a Market Participant cancels any STEM Submission data.

~~6.3B.7B. AEMO must confirm to the Market Participant any cancellation of STEM Submission data made in accordance with clause 6.3B.7A. Where such cancellation is made then AEMO must remove the relevant data from the STEM Submission.~~

6.3B.7B. Where any STEM Submission data is cancelled in accordance with clause 6.3B.7A, AEMO must:

(a) remove the cancelled STEM Submission data from the STEM Submission; and

(b) notify the Market Participant which cancelled the STEM Submission data under clause 6.3B.7A, that the cancelled STEM Submission data has been removed from the STEM Submission,

for the Trading Interval of the Trading Day to which the cancelled Standing STEM Submission data relates.

6.3B.8. ~~Where AEMO does not receive a STEM Submission from a Market Participant by the time specified in clause 6.3B.1(b) on the Scheduling Day, which is accepted in accordance with clause 6.3B.3(b) then AEMO must record that no STEM Submission has been made.~~[Blank]

> **Explanatory Note**
>
> Clause 6.3C.1 has been amended to remove the time period for submission of Standing STEM Submission. A Standing STEM Submission can be submitted at any time.

6.3C. Standing STEM Submission Timetable and Process

6.3C.1. A Market Participant may submit Standing STEM Submission data to AEMO ~~on any day between the times of~~ at any time.~~:~~

~~(a) 1:00 PM; and~~

~~(b) 3:50 PM,~~

~~where if accepted by AEMO the data will apply from the commencement of the subsequent Scheduling Day.~~

6.3C.2. [Blank]

~~6.3C.3. When AEMO receives Standing STEM Submission data from a Market Participant during the time interval described in clause 6.3C.1 it must as soon as practical communicate to that Market Participant:~~

~~(a) whether or not AEMO accepts received Standing STEM Submission data as conforming to the requirements of clause 6.6;~~

~~(b) [Blank]~~

~~where, if AEMO accepts the data, AEMO must revise the Standing STEM Submission to reflect that data.~~

Explanatory Note

Clause 6.3C.3 is proposed to be amended to improve the drafting and to clarify that AEMO is required to accept or reject Standing STEM Submission data and notify the Market Participant of its decision.

6.3C.3. AEMO must, as soon as practicable after receiving Standing STEM Submission data under clause 6.3C.1, but before the start of the next Scheduling Day:

(a) accept the Standing STEM Submission data provided it complies with section 6.6; and

(b) notify the Market Participant which submitted the Standing STEM Submission data under clause 6.3C.1 that:

i. AEMO accepts the Standing STEM Submission data and has revised the Standing STEM Submission to reflect the Standing STEM Submission data; or

ii. AEMO rejects the Standing STEM Submission data.

Explanatory Note

Clause 6.3C.4 has been added to clarify when Standing STEM Submission data accepted by AEMO under clause 6.3C.3 will apply from.

6.3C.4. ~~[Blank]~~Standing STEM Submission data accepted by AEMO under clause 6.3C.3 will apply from the time specified for the Standing STEM Submission under clause 6.6.1(d).

6.3C.5. [Blank]

6.3C.6. [Blank]

6.3C.6A. Standing STEM Submission data must be associated with a day of the week and when used as STEM Submission data will only apply to Trading Days commencing on that day of the week.

6.3C.6B. A Market Participant may cancel Standing STEM Submission data held by AEMO for any Trading Interval of a day of the week ~~the Trading Day during the time interval specified in clause 6.3C.1~~ at any time.

Explanatory Note Clause 6.3C.6C is proposed to be deleted and replaced to improve the drafting and to clarify AEMO's obligations when a Market Participant cancels any Standing STEM Submission data.

~~6.3C.6C. AEMO must confirm to the Market Participant any cancellation of Standing STEM Submission data made in accordance with clause 6.3C.6B. Where such cancellation is made then AEMO must remove the relevant data from the Standing STEM Submission.~~

6.3C.6C. Where any Standing STEM Submission data is cancelled under clause 6.3C.6B, AEMO must:

(a) remove the cancelled Standing STEM Submission data from the Standing STEM Submission; and

(b) notify the Market Participant which cancelled the Standing STEM Submission data under clause 6.3C.6B, that the cancelled Standing STEM Submission data has been removed from the Standing STEM Submission,

for the Trading Interval of the day of the week to which the cancelled Standing STEM Submission data relates.

6.3C.7. [Blank]

6.3C.8. [Blank]

6.3C.9. If a Market Participant's ability to consume or supply energy in any Trading Interval of a Trading Day is less than the maximum level of its STEM supply or consumption as indicated by its current Standing STEM Submission then that Market Participant must either:

(a) submit to AEMO Standing STEM Submission data so as to revise its Standing STEM Submission to comply with this clause 6.3C.9; or

(b) for each Trading Interval for which the current Standing STEM Submission over-states the Market Participant's supply or consumption capabilities, submit ~~valid~~ STEM Submission data that complies with clause 6.6 to AEMO ~~on the Scheduling Day immediately prior to that Trading Day~~.

6.4. The STEM Auction Timetable and Process

6.4.1. AEMO must undertake the process described in section 6.9 and determine the STEM Auction results for a Trading Day after ~~10:50 AM~~ the STEM Submission Cutoff, and before ~~11:30 AM~~ the STEM Results Deadline~~, on the relevant Scheduling Day~~.

6.4.2. AEMO must determine the total quantity of energy scheduled to be supplied under Bilateral Contracts and in the STEM Auction, by each Market Participant, for each Trading Interval of a Trading Day by ~~11:30 AM on the relevant Scheduling Day~~ the STEM Results Deadline.

6.4.3. AEMO must make available to each Market Participant the following information in relation to a Trading Day by ~~11:30 AM on the relevant Scheduling Day~~ the STEM Results Deadline:

(a) the Trading Intervals, if any, in which the STEM Auction was suspended;

(b) the STEM Clearing Price in all Trading Intervals for which the STEM Auction was not suspended;

(c) the quantities scheduled in respect of that Market Participant in the STEM Auction for each Trading Interval; and

(d) the Net Contract Position of the Market Participant in each Trading Interval, as determined in accordance with clause 6.9.13.

6.4.4. [Blank]

6.4.5. [Blank]

Explanatory Note
Clause 6.4.6 has been amended to refer to the Pre-Dispatch Schedule, and to ensure that any extension of time in accordance with the clause maintains a minimum of 110 minutes between publication of a Pre-Dispatch Schedule covering all Trading Intervals in the Trading Day and the STEM Submission Cutoff.

6.4.6. In the event of a software system failure at AEMO's site or its supporting infrastructure, or any delay in publishing a Pre-Dispatch Schedule which includes all Trading Intervals in the relevant Trading Day, ~~preparing any of the information as described in clauses 7.2.1, 7.2.3A or 7.3.4,~~ which prevents AEMO from completing the relevant processes, AEMO may extend one or more of the ~~timelines prescribed in sections 6.2, 6.3A, 6.3B and this section 6.4~~ Bilateral Submission Cutoff, the STEM Submission Cutoff or the STEM Results Deadline, subject to:

(a) any such extension not resulting in more than a two-hour delay to any of the ~~timelines prescribed in sections 6.2, 6.3A, 6.3B and this section 6.4~~ Bilateral Submission Cutoff, the STEM Submission Cutoff or the STEM Results Deadline; and

(b) any such extension maintaining a 110 minute window between: ~~the timelines prescribed in clauses 6.3B.1(a) and 6.3B.1(b) as extended by AEMO.~~

i. publication of the first Pre-Dispatch Schedule that includes all Trading Intervals in the relevant Trading Day; and

ii. the STEM Submission Cutoff.

Explanatory Note
Clause 6.4.6A has been amended to refer to the Pre-Dispatch Schedule, and to ensure that any extension of time in accordance with the clause maintains a minimum of 110 minutes between publication of the error-free Pre-Dispatch Schedule and the latest time for submission of the relevant STEM Submission.

6.4.6A. If AEMO becomes aware of an error in any of the information ~~described in clauses 7.2.1, 7.2.3A or 7.3.4~~ contained in a Pre-Dispatch Schedule at any time before the publication of the relevant STEM Auction results under clause 6.4.3 or a suspension of the STEM under clause 6.10.1, AEMO may:

((a) publish or release (as applicable) corrected or updated versions of the information it has published or released under clauses 6.3A.1, 6.3A.2, 6.3A.3 or 6.3A.4; and

(b) extend any of the ~~relevant timelines prescribed in sections 6.2, 6.3A, 6.3B and this section 6.4~~ Bilateral Submission Cutoff, the STEM Submission Cutoff or the STEM Results Deadline to address the error, subject to:

i. any such extension not resulting in more than a two-hour delay to any of the ~~timelines prescribed in sections 6.2, 6.3A, 6.3B and this section 6.4~~ Bilateral Submission Cutoff, the STEM Submission Cutoff or the STEM Results Deadline; and

ii. any such extension maintaining a 110 minute window between ~~the timelines prescribed in clauses 6.3B.1(a) and 6.3B.1(b) as extended by AEMO.~~:

1. publication of the first error-free Pre-Dispatch Schedule that includes all Trading Intervals in the relevant Trading Day; and

2. the STEM Submission Cutoff.

6.4.6B. If AEMO extends one or more of the ~~timelines in sections 6.2, 6.3A, 6.3B and this section 6.4~~ Bilateral Submission Cutoff, the STEM Submission Cutoff or the STEM Results Deadline under clauses 6.4.6 or 6.4.6A or publishes or releases corrected information under clause 6.4.6A(a), AEMO must notify Rule Participants of any extension and any amended timelines and any corrected information as soon as possible.

6.4.7. Once published under clause 6.4.3, STEM Clearing Prices cannot be altered, either through disagreement under clause 9.20.6, or through dispute under clause 9.21.

6.5. [Blank]

STEM Submission and Bilateral Submission Formats

6.6. Format of STEM Submission and Standing STEM Submission Data

6.6.1. A Market Participant submitting STEM Submission data or a Standing STEM Submission data must include the following information in the applicable submission:

(a) the identity of the Market Participant making the submission;

(b) [Blank]

(c) for STEM Submission data, for each Trading Interval included in the submission:

i. a Fuel Declaration;

ii. ~~an Availability Declaration;~~[Blank]

iii. ~~if the Market Participant is a provider of Ancillary Services, an Ancillary Service Declaration;~~[Blank]

iv. a Portfolio Supply Curve; ~~and~~

v. a Portfolio Demand Curve; and

vi. at the Market Participant's discretion, a Participant Interval Minimum STEM Price and a Participant Interval Maximum STEM Price;

(d) for Standing STEM Submission data, the day of the week to which the submission relates, where data provided for a day of the week relates to the Trading Day commencing on that day, the date on which the Standing Bilateral Submission data is to take effect, and for each Trading Interval included in the submission:

i. a Fuel Declaration;

ii. ~~an Availability Declaration;~~ [Blank]

iii. ~~if the Market Participant is a provider of Ancillary Services, an Ancillary Service Declaration~~[Blank];

iv. a Portfolio Supply Curve; ~~and~~

v. a Portfolio Demand Curve~~.~~; and

vi. at the Market Participant's discretion, a Participant Interval Minimum STEM Price and a Participant Interval Maximum STEM Price.

6.6.1A. Where:

(a) a Market Participant has not specified a Participant Interval Minimum STEM Price in the STEM Submission data or Standing STEM Submission data under clause 6.6.1(c)(vi), AEMO must use the Minimum STEM Price as the Participant Interval Minimum STEM Price for the STEM Submission or Standing STEM Submission; and

(b) a Market Participant has not specified a Participant Interval Maximum STEM Price in the STEM Submission data or Standing STEM Submission data under clause 6.6.1(d)(vi), AEMO must use the Alternative Maximum STEM Price as the Participant Interval Maximum STEM Price for the STEM Submission or Standing STEM Submission.

6.6.2. [Blank]

6.6.2A. For:

(a) a Fuel Declaration~~:~~

~~i.~~ the Market Participant must declare for each of its dual fuel Facilities whether or not that Facility is assumed to be operating on Liquid Fuel or Non-Liquid Fuel in forming the Portfolio Supply Curve;

(b) [Blank]~~an Availability Declaration:~~

~~i. the Market Participant must declare for each of its Scheduled Generators and Non-Scheduled Generators:~~

~~1. the maximum Loss Factor Adjusted energy available from that Facility based on its Standing Data reduced to account for any energy committed to provide Ancillary Services or which is unavailable due to an outage (where such an outage should only be considered where that outage is reported to the Market Participant by AEMO); less~~

~~2. the quantity of energy assumed to be available from that Facility in forming the Portfolio Supply Curve for the Trading Interval,~~

~~if this quantity is greater than zero. The quantity declared must be in units of MWh;~~

(c) [Blank]~~an Ancillary Service Declaration:~~

~~i. a Market Participant which is a provider of Ancillary Services must declare:~~

~~1. the MWh quantity of energy from Non-Liquid Fuelled Facilities (as defined by the Fuel Declaration) that the Market Participant has not committed for inclusion in the Portfolio Supply Curve because it expects to have to maintain surplus capacity with which to provide Ancillary Services;~~

~~2. the MWh quantity of energy from Liquid Fuelled Facilities (as defined by the Fuel Declaration) that the Market Participant has not committed for inclusion in the Portfolio Supply Curve~~

~~because it expects to have to maintain surplus capacity with which to provide Ancillary Services,~~

~~where the sum of the quantities in 1 and 2 must equal the amount specified in clause 6.3A.2(e)(i) for that Market Participant;~~

(d) a Portfolio Supply Curve:

i. one or more Price-Quantity Pairs may be specified;

ii. the cumulative MWh quantity over all Price-Quantity Pairs must not exceed the greater of zero; and the quantity calculated under clause 6.3A.3(f);

~~1. the Market Participant's Maximum Supply Capability as described in clause 6.3A.2(a); less~~

~~2. the total MWh quantity specified by the Market Participant in its Availability Declaration;~~

~~3. [Blank]~~

iii. the cumulative MWh quantity over all Price-Quantity Pairs with prices exceeding the Alternative Maximum STEM Price must not exceed~~:~~

~~1.~~ the sum over all ~~Facilities~~ Registered Facilities declared in the Fuel Declaration to be operating on Liquid Fuel of the MWh quantity specified in clause ~~6.3A.2(d)~~ 6.3A.3(g)~~; less~~

~~2. the total MWh quantity specified by the Market Participant in its Availability Declaration as being unavailable from Facilities declared in its Fuel Declaration to be operating on Liquid Fuel; less~~

~~3. the MWh quantity declared in its Ancillary Service Declaration as being unavailable from Liquid Fuelled Facilities~~;

(e) a Portfolio Demand Curve:

i. one or more Price-Quantity Pairs may be specified; and

ii. the cumulative quantity included in the Price-Quantity Pairs must not exceed ~~the Market Participant's Maximum Consumption Capability as described in clause 6.3A.2(b)~~ the quantity calculated under clause 6.3A.3(e).

Explanatory Note Clauses 6.6.3 to 6.6.3CD, 6.6.3E and 6.6.3F have been added to provide clarity with respect to the requirement for information in a STEM Submission and a Standing STEM Submission to be made in good faith, and for the purposes of clause 6.6.3G, when a risk premium must not be included in a Market Participant's "reasonable expectation" under that clause, and the circumstances when a risk premium may be included.

6.6.3. A Market Participant must:

(a) make information in a STEM Submission and Standing STEM Submission in good faith;

(b) not act in a manner that:

i. is intended to lead; or

ii. the Market Participant should have reasonably known is likely to lead,

to another Rule Participant being misled or deceived as to the existence or non-existence of a material fact relating to the STEM.

6.6.3A. A STEM Submission and Standing STEM Submission are made in good faith under clause 6.6.3 if, at the time they are submitted, the Market Participant had a genuine intention to honour the terms of the STEM Submission or Standing STEM Submission, as applicable, if the material conditions and circumstances upon which the STEM Submission or STEM Standing Submission was based remained unchanged until the relevant Trading Interval.

6.6.3B. A Market Participant may be taken to have not made a STEM Submission or Standing STEM Submission in good faith notwithstanding that the intention of the Market Participant is ascertainable only by inference from:

(a) the conduct of the Market Participant;

(b) the conduct of any other person; or

(c) the relevant circumstances.

6.6.3C. If a Market Participant does not have reasonable grounds for information in a STEM Submission or a Standing STEM Submission at the time it submits that STEM Submission or Standing STEM Submission, then the Market Participant is, for the purposes of clause 6.6.3(b), taken to have known that the STEM Submission or Standing STEM Submission, as applicable, was likely to lead to another Rule Participant being misled or deceived as to the existence or non-existence of a material fact relating to the Short Term Energy Market.

6.6.3CA. For the purposes of clause 6.6.3C, a Market Participant must adduce evidence that it had reasonable grounds for information in a STEM Submission or Standing STEM Submission.

6.6.3CB. The effect of clause 6.6.3CA is to place an evidentiary burden on a Market Participant, and clause 6.6.3CA does not have the effect that, merely because such evidence is adduced, the Market Participant who submitted the STEM Submission or Standing STEM Submission is taken to have had reasonable grounds for including the information in that STEM Submission or Standing STEM Submission.

6.6.3CD. Clause 6.6.3C does not imply that merely because the Market Participant had reasonable grounds for making the representation or the conduct referred to in this Chapter 6, and in particular putting the information in a STEM Submission or

Standing STEM Submission, as applicable, submitted by a Market Participant, that such representation or conduct is not misleading.

> **Explanatory Note**
>
> It is expected that clause 6.6.3D will be considered in the Market Power workstream.

6.6.3D. A Market Generator must not, for any Trading Interval, offer prices within its Portfolio Supply Curve that do not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity when such behaviour relates to market power.

6.6.3E. For the purposes of clause 6.6.3D, a Market Participant's reasonable expectation:

(a) must not include a risk premium in relation to the quantity of energy forecast to be supplied by its Registered Facilities in each Trading Interval according to the Reference Scenario in the latest Pre-Dispatch Schedule published by AEMO before the Bilateral Submission Cutoff; and

(b) may include a risk premium to reflect the Market Participant's reasonable expectation that Network Constraints or Essential System Service enablement will affect the ability of its Registered Facilities to be dispatched for energy in the Real-Time Market.

6.6.3F. In determining whether a Market Participant has made a STEM Submission or Standing STEM Submission in accordance with its obligations under this Chapter 6, the Economic Regulation Authority or AEMO, as applicable, may take into account:

(a) historical STEM Submissions or Standing STEM Submissions, including changes made to STEM Submissions or Standing STEM Submissions, in which a pattern of behaviour may indicate an intention to create a false impression in the Short Term Energy Market;

(b) any information as to whether a Facility was not able to comply with a Dispatch Instruction from AEMO and the reasons for that non-compliance; and

(c) any other information that is considered by the Economic Regulation Authority or AEMO, as applicable, to be relevant.

> **Explanatory Note**
>
> Civil penalty distribution will be addressed in the draft Amending Rules for Settlement. The intention is that distribution of a civil penalty will be in proportion to a Market Participant's consumption over the last 12 months, but that the party liable to pay the civil penalty will be excluded from the distribution. In the meantime, the amendment below is a placeholder.

6.6.3~~A~~G. For the purpose of Regulation 37(a) of the WEM Regulations, where a civil penalty is imposed for a contravention of clause 6.6.3 or clause 6.6.3D, the civil penalty amount should be distributed amongst all Market ~~Customers~~ Participants, excluding the Market Participant that was liable to pay the civil penalty, in proportion to their Market Fees calculated over the previous full 12 months, or part thereof if Market Commencement was less than 12 months prior to the date the civil penalty is received.

6.6.4. The maximum number of Price-Quantity Pairs which a Market Participant may include in a Portfolio Supply Curve is ~~the greater of:~~ 30.

~~(a) 10; and~~

~~(b) the value of:~~

~~i. the limit on the cumulative MWh quantity over all Price-Quantity Pairs as defined in clause 6.6.2A(d)(ii);~~

~~ii. divided by 30 MW,~~

~~rounded down to the nearest integer.~~

6.6.5. For Price-Quantity Pairs in Portfolio Supply Curves:

(a) each Price-Quantity Pair must comprise one price and one quantity;

(b) each Price-Quantity Pair price must be:

i. in units of $/MWh expressed to a precision of $0.01/MWh;

ii. [Blank]

iiA. set such that:

1. the sum of the Price-Quantity Pair quantities from Price-Quantity Pairs in the Portfolio Supply Curve with prices exceeding the Maximum STEM Price must not exceed the cumulative MWh quantity that the Market Participant can offer at the Alternative Maximum STEM Price, as defined in clause 6.6.2A(d)(iii);

2. the prices for the Price-Quantity Pairs in the Portfolio Supply Curve to which clause 6.6.5(b)(iiA)(1) does not relate must not exceed the Maximum STEM Price;

iii. greater than or equal to the Participant Interval Minimum STEM Price;

iv. [Blank]

v. set such that no two Price-Quantity Pairs in a Portfolio Supply Curve have the same price;

(c) each Price-Quantity Pair quantity must be

i. in units of MWh expressed to a precision of 0.001 MWh;

ii. Loss Factor adjusted; and

(d) a Price-Quantity Pair means that the Market Participant is prepared to sell a quantity of energy into the STEM for that Price-Quantity Pair equal to:

i. 0 MWh if the STEM Clearing Price is less than the Price-Quantity Pair price;

ii. the Price-Quantity Pair quantity if the STEM Clearing Price is greater than the Price-Quantity Pair price; and

iii. an amount between 0 MWh and the Price-Quantity Pair quantity if the STEM Clearing Price equals the Price-Quantity Pair price.

6.6.6. [Blank]

6.6.7. The maximum number of Price-Quantity Pairs to be included in a Portfolio Demand Curve is ~~to be the greater of:~~ 30.

~~(a) 10; and~~

~~(b) the integer value of:~~

~~i. the Market Participant's Maximum Consumption Capability as described in clause 6.3A.2(b);~~

~~ii. divided by 30 MW.~~

6.6.8. For Price-Quantity Pairs in Portfolio Demand Curves:

(a) each Price-Quantity Pair price must be:

i. in units of $/MWh expressed to a precision of $0.01/MWh;

ii. less than or equal to the ~~Alternative~~ Participant Interval Maximum STEM Price;

iii. greater than or equal to the Minimum STEM Price; and

iv. set such that no two Price-Quantity Pairs in a Portfolio Demand Curve have the same price;

(b) each Price-Quantity Pair quantity must be

i. in units of MWh expressed to a precision of 0.001 MWh;

ii. Loss Factor adjusted; and

(c) a Price-Quantity Pair means that the Market Participant is prepared to buy a quantity of energy from the STEM for that Price-Quantity Pair equal to:

i. 0 MWh if the STEM Clearing Price is greater than the Price-Quantity Pair price;

ii. the Price-Quantity Pair quantity if the STEM Clearing Price is less than the Price-Quantity Pair price; and

iii. an amount between 0 MWh and the Price-Quantity Pair quantity if the STEM Clearing Price equals the Price-Quantity Pair price.

6.6.9. A Market Generator may apply to AEMO for all or part of the capacity of one of its Scheduled Generators that is not Liquid Fuel capable to be treated as if it was dual-fuel capable where one fuel is Liquid Fuel for the purposes of the STEM, the ~~Balancing~~ Real-Time Market and settlement. The application must be in a form specified by AEMO, including evidence of the arrangement described in clause 6.6.10(a), and must specify the period to which the application relates.

6.6.10. AEMO must assess an application made under clause 6.6.9 and inform the Market Participant whether or not the application is approved. AEMO must approve the application only where the Market Participant provides evidence satisfactory to AEMO that:

(a) the Market Participant has an arrangement with a user of fuel ("**Fuel User**") to release a quantity of fuel for use in a Scheduled Generator which is not Liquid Fuel capable and is registered by the Market Participant;

(b) the use of fuel released under the arrangement would result in the Fuel User using Liquid Fuel in a Facility or other equipment; and

(c) as a consequence of clause 6.6.10(a) and (b), the short run marginal cost of generating electricity using the Scheduled Generator using fuel released under the arrangement would be above the Maximum STEM Price.

6.6.11. Where AEMO approves an application under clause 6.6.9, AEMO must:

(a) notify the Market Participant that the application has been approved as soon as practicable; and

(b) update the relevant Standing Data in accordance with clause 2.34.

6.6.12. When AEMO does not approve an application under clause 6.6.9, AEMO must notify the Market Participant as soon as practicable.

6.7. Format of Bilateral Submission Data

6.7.1. A Market Generator submitting Bilateral Submission data or Standing Bilateral Submission data must include in the submission:

(a) the identity of the Market Generator making the submission;

(b) in the case of:

i Bilateral Submission data, the Trading Day to which the submission relates; and

ii Standing Bilateral Submission data:~~,~~

1. the day of the week to which the submission relates, where data provided for a day of the week relates to the Trading Day commencing on that day; and

2. the date on which the Standing Bilateral Submission is to take effect; and

(c) for each Trading Interval included in the submission:

i. the net quantity of energy to be sold by the submitting Market Generator;

ii. the identity of each Market Participant purchasing the energy covered by the Bilateral Submission;

iii. the net quantity of energy sold to each Market Participant identified in (ii); and

iv. the sum of the quantities in (i) and (iii) must be zero.

(d) [Blank]

6.7.2. All quantities specified in a Bilateral Submission or a Standing Bilateral Submission:

(a) must be in units of MWh;

(b) must equal or exceed 0 MWh for net supply (that is, sold) by the relevant Market Participant;

(c) must be less than 0 MWh for net consumption (that is, purchased) from the relevant Market Participant;

(d) must be expressed to a precision of 0.001 MWh; and

(e) must be Loss Factor adjusted.

6.7.3. A Market Generator must not specify quantities in a Bilateral Submission or a Standing Bilateral Submission which exceed the quantity of energy that the Market Generator is contracted to supply to the relevant Market Customer.

6.7.4. A Market Customer must not significantly over-state its consumption as indicated by its Net Contract Position with a regularity that cannot be explained by a reasonable allowance for forecast uncertainty or the impact of Loss Factors.

6.8. [Blank]

The STEM Auction Process

6.9. The STEM Auction

6.9.1. AEMO must undertake the process described in this clause 6.9 for each Trading Interval in a Trading Day.

6.9.2. The Net Bilateral Position for Market Participant p in Trading Interval t is:

(a) the sum of the quantities of energy referred to in clauses 6.7.1(c)(i) and 6.7.1(c)(iii) for the Market Participant in all Bilateral Submissions for Trading Interval t; or

(b) zero if no Bilateral Submissions for Trading Interval t refer to the Market Participant.

6.9.3. Subject to clause 6.9.4, AEMO must determine STEM Offers and STEM Bids for each Market Participant for each Trading Interval in accordance with Appendix 6 using the valid STEM Submissions and Bilateral Submissions relating to that Trading Interval.

6.9.4. ~~Where AEMO has recorded in accordance with clause 6.3B.8 that~~Where AEMO does not hold a STEM Submission for a Market Participant~~ has not made a STEM Submission~~ for a Trading Interval, AEMO must not determine STEM Offers or STEM Bids for that Market Participant in that Trading Interval.

6.9.5. AEMO must determine an aggregate STEM bid curve for each Trading Interval from the STEM Bids where this aggregate STEM bid curve:

(a) describes the quantity that Market Participants in aggregate wish to purchase from AEMO through the STEM at every price between, and including, the Minimum STEM Price and the Alternative Maximum STEM Price; and

(b) passes through the point indicating zero consumption at the Alternative Maximum STEM Price.

6.9.6. AEMO must determine an aggregate STEM offer curve for each Trading Interval from the STEM Offers where this aggregate STEM offer curve:

(a) describes the quantity that Market Participants in aggregate wish to sell to AEMO through the STEM at every price between, and including, the Minimum STEM Price and the Alternative Maximum STEM Price; and

(b) passes through the point indicating zero supply at the Minimum STEM Price.

6.9.7. AEMO will determine the STEM Clearing Price for a Trading Interval as the lowest price at which the STEM offer curve for a Trading Interval intersects the STEM bid curve for the Trading Interval.

6.9.8. AEMO will determine the STEM Clearing Quantity for a Trading Interval as the greatest quantity at which the STEM offer curve for the Trading Interval intersects the STEM bid curve for the Trading Interval.

6.9.9. All STEM Bid Price-Quantity Pairs for the Trading Interval with a price greater than the STEM Clearing Price for the Trading Interval must be scheduled by AEMO.

6.9.10. A STEM Bid Price-Quantity Pair with a price equal to the STEM Clearing Price for the Trading Interval must be scheduled by AEMO up to the Price-Quantity Pair quantity multiplied by:

(a) the STEM Clearing Quantity less the total quantity for STEM Bid Price-Quantity Pairs scheduled by AEMO in accordance with clause 6.9.9; divided by

(b) the total quantity for all STEM Bid Price-Quantity Pairs with a price equal to the STEM Clearing Price.

6.9.11. All STEM Offer Price-Quantity Pairs for a Trading Interval with a price less than the STEM Clearing Price for the Trading Interval must be scheduled by AEMO.

6.9.12. A STEM Offer Price-Quantity Pair for a Trading Interval with a price equal to the STEM Clearing Price for the Trading Interval must be scheduled by AEMO up to the Price-Quantity Pair quantity multiplied by:

(a) the STEM Clearing Quantity less the total quantity for STEM Offer Price-Quantity Pairs scheduled by AEMO in accordance with clause 6.9.11; divided by

(b) the total quantity for all STEM Offer Price-Quantity Pairs with a price equal to the STEM Clearing Price.

6.9.13. The Net Contract Position for Market Participant p in Trading Interval t is:

(a) the Net Bilateral Position for Market Participant p in Trading Interval t; minus,

(b) the amount of energy purchased by the Market Participant from AEMO through the STEM at the STEM Clearing Price, which is the total quantity associated with Price-Quantity Pairs for Market Participant p scheduled by AEMO under clause 6.9.9 or 6.9.10 for Trading Interval t where this energy purchased is represented as a positive value; plus

(c) the amount of energy sold by the Market Participant to AEMO through the STEM at the STEM Clearing Price, which is the total quantity associated with Price-Quantity Pairs for Market Participant p scheduled by AEMO under clause 6.9.11 or 6.9.12 for Trading Interval t where this energy sold is represented as a positive value.

6.10. Suspension of the STEM

6.10.1. AEMO must suspend the STEM auction for a Trading Interval if AEMO considers that it will not be in a position to undertake the process described in clause 6.9 and publish a valid STEM auction result under clauses 6.4.3(b), (c) and (d) for that Trading Interval by the time specified in clause 6.4.3.

6.10.2. In the event that the STEM auction for a Trading Interval is suspended under clause 6.10.1, no Market Participant can purchase energy from or sell energy to AEMO through the STEM for that Trading Interval and no STEM Clearing Price is to be declared for that Trading Interval.

6.10.3. No compensation is due or payable to any Market Participant in the event that the STEM auction for a Trading Interval is suspended under clause 6.10.1.

6.11. [Blank]

Explanatory Note Sections 6.11A and 6.12 (Non-Balancing Dispatch) are proposed to be deleted and replaced by new arrangements in the Central Dispatch process in Chapter 7.

~~6.11A. Nominating Consumption Decrease Price and Extra Consumption Decrease Price~~

~~6.11A.1. A Market Customer with a Demand Side Programme:~~

~~(a) must submit to AEMO a Consumption Decrease Price and an Extra Consumption Decrease Price; and~~

~~(b) may from time to time submit to AEMO either or both of a changed Consumption Decrease Price and a changed Extra Consumption Decrease Price.~~

~~6.11A.2. When AEMO receives a submission under clause 6.11A.1 from a Market Customer, it must as soon as practicable:~~

~~(a) if the received data complies with, as applicable, clauses 6.11A.3 or 6.11A.4:~~

~~i. accept the received data and communicate the acceptance to the Market Customer; and~~

~~ii. revise the Standing Data accordingly; or~~

~~(b) if the received data does not comply with, as applicable, clauses 6.11A.3 or 6.11A.4—reject the received data and communicate the rejection to the Market Customer.~~

~~6.11A.3. A Consumption Decrease Price submitted under clause 6.11A.1 must—~~

~~(a) be not less than the Minimum STEM Price or more than the Alternative Maximum STEM Price;~~

~~(b) vary between Peak Trading Intervals and Off-Peak Trading Intervals.~~

~~6.11A.4. An Extra Consumption Decrease Price submitted under clause 6.11A.1 must—~~

~~(a) be not less than the Minimum STEM Price or more than the DSM Activation Price;~~

~~(b) vary between Peak Trading Intervals and Off-Peak Trading Intervals.~~

~~The Non-Balancing Dispatch Merit Order~~

~~6.12. The Non-Balancing Dispatch Merit Order~~

~~6.12.1.~~

~~(a) By 5:00 PM on the Scheduling Day, AEMO must determine the Non-Balancing Dispatch Merit Orders identified in clause 6.12.1(b) for the Trading Day. A Non-Balancing Dispatch Merit Order:~~

~~i. lists the order in which Demand Side Programmes will be issued Dispatch Instructions by System Management under clause 7.6.1C(d) to decrease consumption;~~

~~ii. lists the order in which Demand Side Programmes will be issued Dispatch Instructions by System Management under clause 7.6.1C(e) to decrease consumption, as applicable; and~~

~~iii. provides for each Demand Side Programme in the list in clauses 6.12.1(a)(i) and 6.12.1(a)(ii):~~

~~1. the Reserve Capacity Obligation Quantity determined in accordance with clause 4.12.4(c);~~

~~2. the Unused Expected DSM Dispatch Quantity;~~

~~3. the Relevant Demand; and~~

~~4. the aggregate of Minimum Consumptions across all the Facility's Associated Loads.~~

~~(b) A Non-Balancing Dispatch Merit Order for a decrease in consumption relative to the current operating level of a Facility for a Trading Interval must:~~

~~i. list all Demand Side Programmes registered by Market Participants; and~~

~~ii. be determined by ranking the Demand Side Programmes referred to in clause 6.12.1(b)(i) as follows:~~

~~1. Demand Side Programmes with a Reserve Capacity Obligation Quantity greater than zero in that Trading Interval ranked in increasing order of the Facility's Extra Consumption Decrease Price applicable to that Trading Interval;~~

~~followed by~~

~~2. Registered Facilities with a Reserve Capacity Obligation Quantity of zero in that Trading Interval, ranked in increasing order of the Facility's Consumption Decrease Price applicable to that Trading Interval.~~

~~(c) [Blank]~~

~~(d) [Blank]~~

~~(e) [Blank]~~

~~(f) Where the prices described in Standing Data for two or more Demand Side Programmes are equal, then, for the purposes of determining the ranking in any Non-Balancing Dispatch Merit Order, AEMO must rank those Demand Side Programmes in decreasing order of the time since the Facility's consumption was last reduced in response to a Dispatch Instruction. In the event of a tie, AEMO will randomly assign priority to break the tie.~~

Explanatory Note Section 6.13 is to be retained subject to amendments proposed in the Settlement workstream.

Balancing Prices and Quantities

6.13. Real-Time Dispatch Information

6.13.1. System Management must maintain dispatch data for settlement purposes in accordance with clause 7.13.

6.14. [Blank]

Explanatory Note

Section 6.15 is to be deleted as part of the proposed amendments in the Settlement workstream.

6.15. Maximum and Minimum Theoretical Energy Schedule

6.15.1. The Maximum Theoretical Energy Schedule in a Trading Interval is:

(a) for a Balancing Facility which is a Scheduled Generator:

i. the maximum amount of sent out energy, in MWh, which could have been dispatched in the Trading Interval from Balancing Price-Quantity Pairs in respect of the Balancing Facility with a Loss Factor Adjusted Price less than or equal to the Balancing Price; plus

ii. if the Facility's SOI Quantity is greater than the sum of the quantities in the Facility's Balancing Price-Quantity Pairs which have a Loss Factor Adjusted Price less than or equal to the Balancing Price, the minimum amount of sent out energy, in MWh, if any, which could have been dispatched in the Trading Interval from any of the Facility's Balancing Price-Quantity Pairs which have a Loss Factor Adjusted Price greater than the Balancing Price,

taking into account the Balancing Facility's SOI Quantity and Ramp Rate Limit;

(b) for a Balancing Facility which is a Non-Scheduled Generator:

i. if the Loss Factor Adjusted Price of the Balancing Price Quantity-Pair in respect of the Balancing Facility is less than or equal to the Balancing Price, then the Sent Out Metered Schedule as determined in accordance with clause 6.15.3(a)(i); and

ii. otherwise the minimum amount of sent out energy, in MWh, which the Balancing Facility could have generated in the Trading Interval if the Facility had been dispatched downwards at its Ramp Rate Limit from its SOI Quantity; or

(c) for the Balancing Portfolio:

i. the maximum amount of sent out energy, in MWh, which could have been dispatched in the Trading Interval from Balancing Price-Quantity Pairs in respect of the Balancing Portfolio with an associated price less than or equal to the Balancing Price; plus

ii. if the Balancing Portfolio's SOI Quantity is greater than the sum of the quantities in the Balancing Portfolio's Balancing Price-Quantity Pairs which have an associated price that is less than or equal to the Balancing Price, the minimum amount of sent out energy, in MWh, if any, which could have been dispatched in the Trading Interval from any of the Balancing Portfolio's Balancing Price-

Quantity Pairs which have an associated price greater than the Balancing Price,

taking into account the Portfolio Ramp Rate Limit and the SOI Quantity.

6.15.2. The Minimum Theoretical Energy Schedule in a Trading Interval equals:

(a) for a Balancing Facility which is a Scheduled Generator, the amount which is the lesser of:

i. the sum of:

1. the maximum amount of sent out energy, in MWh, which could have been dispatched in the Trading Interval from Balancing Price-Quantity Pairs in respect of the Balancing Facility with a Loss Factor Adjusted Price less than the Balancing Price; plus

2. if the Facility's SOI Quantity is greater than the sum of the quantities in the Facility's Balancing Price-Quantity Pairs which have a Loss Factor Adjusted Price less than the Balancing Price, the minimum amount of sent out energy, in MWh, if any, which could have been dispatched in the Trading Interval from any of the Facility's Balancing Price-Quantity Pairs which have a Loss Factor Adjusted Price greater than or equal to the Balancing Price,

taking into account the Balancing Facility's SOI Quantity and Ramp Rate Limit; and

ii. where the Balancing Facility is subject to an Outage, the maximum amount of sent out energy, in MWh, which could have been dispatched given the Available Capacity for that Trading Interval;

(b) for a Balancing Facility which is a Non-Scheduled Generator:

i. if a Dispatch Instruction was issued to the Balancing Facility to decrease its output and the Loss Factor Adjusted Price of the Balancing Price-Quantity Pair in respect of the Balancing Facility is less than the Balancing Price, then System Management's estimate of the maximum amount of sent out energy, in MWh, which the Balancing Facility would have generated in the Trading Interval had the Dispatch Instruction not been issued; and

ii. otherwise the Sent Out Metered Schedule for the Facility as determined in accordance with clause 6.15.3(a)(i); or

(c) for the Balancing Portfolio, the amount which is the lesser of:

i. the sum of:

1. the maximum amount of sent out energy, in MWh, which could have been dispatched in the Trading Interval from Balancing Price-Quantity Pairs in respect of the Balancing

Portfolio with an associated price less than the Balancing Price; plus

2. if the Balancing Portfolio's SOI Quantity is greater than the sum of the quantities in the Balancing Portfolio's Balancing Price-Quantity Pairs which have an associated price that is less than the Balancing Price, the minimum amount of sent out energy, in MWh, if any, which could have been dispatched in the Trading Interval from any of the Balancing Portfolio's Balancing Price-Quantity Pairs which have an associated price greater than or equal to the Balancing Price,

taking into account the Portfolio Ramp Rate Limit and SOI Quantity; and

ii. where a Facility in the Balancing Portfolio is subject to an Outage, the maximum amount of sent out energy, in MWh, which could have been dispatched given the sum of the Available Capacity of Facilities in the Balancing Portfolio for that Trading Interval.

6.15.3 AEMO must:

(a) calculate Maximum Theoretical Energy Schedules under clause 6.15.1 and Minimum Theoretical Energy Schedules under clause 6.15.2:

i. using Sent Out Metered Schedules determined using SCADA data and output estimates maintained in accordance with clause 7.13.1(cA), notwithstanding any requirement in clause 9.3.4 to use Meter Data Submissions received by AEMO; and

ii. as soon as practicable using applicable SCADA data maintained under clause 7.13.1(cA); and

(b) update Maximum Theoretical Energy Schedules and Minimum Theoretical Energy Schedules calculated under clause 6.15.3(a) as soon as practicable using the schedule of Outages maintained under clause 7.13.1A(b).

Explanatory Note

Section 6.16 will be retained subject to proposed amendments in the Settlement workstream.

6.16. The Metered Schedule

6.16.1. Subject to clause 9.3.3, AEMO must determine the Metered Schedule for a Trading Interval for a Registered Facility or Non-Dispatchable Load in accordance with clause 9.3.4.

6.16.1A. For the purposes of clauses 6.16A and 6.16B, Sent Out Metered Schedules for a Balancing Facility are to be calculated by AEMO.

6.16.2. 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 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.

Explanatory Note

Sections 6.16A and 6.16B are to be deleted and replaced by uplift payments and other proposed amendments in the Settlement workstream.

6.16A. Facility Out of Merit

6.16A.1. The Upwards Out of Merit Generation in a Trading Interval for a Balancing Facility equals:

(a) subject to clause 6.16A.1(b), the Sent Out Metered Schedule less the Maximum Theoretical Energy Schedule; or

(b) zero where:

i. the Economic Regulation Authority has notified AEMO under clause 7.10.8 that the relevant Market Participant has not adequately or appropriately complied with a Dispatch Instruction in respect of the Facility;

ii. the Facility was undergoing a Test or complying with an Operating Instruction; or

iii. the Sent Out Metered Schedule less the Maximum Theoretical Energy Schedule is less than the sum of:

1. any Upwards LFAS Enablement and, if the Facility is a Stand Alone Facility, any Backup Upwards LFAS Enablement, which the Facility was instructed by System Management to provide, divided by two so that it is expressed in MWh; and

2. the applicable Settlement Tolerance.

6.16A.2. The Downwards Out of Merit Generation in a Trading Interval for a Balancing Facility equals:

(a) subject to clause 6.16A.2(b), the Minimum Theoretical Energy Schedule less the Sent Out Metered Schedule; or

(b) zero if:

i. the Economic Regulation Authority has notified AEMO under clause 7.10.8 that the relevant Market Participant has not adequately or appropriately complied with a Dispatch Instruction in respect of the Facility;

ii. the Facility was undergoing a Test or complying with an Operating Instruction;

iii. the Minimum Theoretical Energy Schedule less the Sent Out Metered Schedule is less than the sum of:

1. any Downwards LFAS Enablement and, if the Facility is a Stand Alone Facility, any Backup Downwards LFAS Enablement, which the Facility was instructed by System Management to provide, divided by two so that it is expressed in MWh; and

2. the applicable Settlement Tolerance; or

iv. the Balancing Facility is a Non-Scheduled Generator and System Management has not determined a MWh quantity for the Facility and the Trading Interval under clause 7.13.1(eF).

6.16B. Balancing Portfolio Out of Merit

6.16B.1. The Portfolio Upwards Out of Merit Generation in a Trading Interval for the Balancing Portfolio equals:

(a) subject to clause 6.16B.1(b), the sum of any Sent Out Metered Schedules for Facilities in the Balancing Portfolio less the Maximum Theoretical Energy Schedule for the Balancing Portfolio; or

(b) zero if:

i. the Economic Regulation Authority has notified AEMO under clause 7.10.8 that Synergy has not adequately or appropriately complied with a Dispatch Order; or

ii. the sum of any Sent Out Metered Schedules for Facilities in the Balancing Portfolio less the Maximum Theoretical Energy Schedule for the Balancing Portfolio is less than the sum of:

1. any increase in sent out energy due to a Network Control Service Contract which System Management instructed a Facility within the Balancing Portfolio to provide;

2. if Facilities within the Balancing Portfolio were instructed by System Management to provide LFAS, the sum of Upwards LFAS Enablement and Backup Upwards LFAS Enablement, both divided by two so that they are expressed in MWh;

3. if a Spinning Reserve Event has occurred, any Spinning Reserve Response Quantity; and

4. the Portfolio Settlement Tolerance.

6.16B.2. The Portfolio Downwards Out of Merit Generation in a Trading Interval for the Balancing Portfolio equals:

(a) subject to clause 6.16B.2(b), the Minimum Theoretical Energy Schedule less the sum of any Sent Out Metered Schedules for Facilities in the Balancing Portfolio; or

(b) zero if:

i. the Economic Regulation Authority has notified AEMO under clause 7.10.8 that Synergy has not adequately or appropriately complied with a Dispatch Order; or

ii. the Minimum Theoretical Energy Schedule of the Balancing Portfolio less the sum of any Sent Out Metered Schedules for Facilities in the Balancing Portfolio is less than the sum of:

1. any reduction in sent out energy due to a Network Control Service Contract which System Management instructed a Facility within the Balancing Portfolio to provide;

2. if Facilities within the Balancing Portfolio were instructed by System Management to provide LFAS, the sum of the Downwards LFAS Enablement plus the Backup Downwards LFAS Enablement, both divided by two so that they are expressed in MWh;

3. if a Load Rejection Reserve Event has occurred, any Load Rejection Reserve Response Quantity; and

4. the Portfolio Settlement Tolerance.

Explanatory Note

Sections 6.17.1 and 6.17.2 are to be retained and renamed, and adjusted for the new Real-Time Market as proposed in the amendments in the Settlement workstream.

6.17. Balancing Settlement Quantities

6.17.1. AEMO must determine for each Market Participant and each Trading Interval of each Trading Day:

(a) the Metered Balancing Quantity;

(b) the Non-Balancing Facility Dispatch Instruction Payment;

(c) Constrained On Quantities and associated Constrained On Compensation Prices;

(d) Constrained Off Quantities and associated Constrained Off Compensation Prices;

(e) Portfolio Constrained On Quantities and associated Portfolio Constrained On Compensation Prices; and

(f) Portfolio Constrained Off Quantities and associated Portfolio Constrained Off Compensation Prices,

in accordance with this section 6.17.

6.17.2. The Metered Balancing Quantity, MBQ(p,d,t), for Market Participant p and Trading Interval t of Trading Day d equals:

(a) the net sum of all Metered Schedules for Trading Interval t for the Registered Facilities registered by Market Participant p and Non-Dispatchable Loads associated with Market Participant p as indicated in Standing Data;

(b) less, the Net Contract Position of Market Participant p in Trading Interval t.

Explanatory Note

Section 6.17.3 to 6.17.5C are to be deleted and replaced by uplift payments and other proposed amendments in the Settlement workstream.

Constrained On Quantities and Compensation Prices

6.17.3. Subject to clauses 6.17.5B and 6.17.5C, AEMO must attribute any Upwards Out of Merit Generation from a Balancing Facility that is a Scheduled Generator, in a Trading Interval, as follows:

(a) Constrained On Quantity1 (ConQ1) equals the lesser of:

i. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the Facility's Balancing Price-Quantity Pair N, with a Loss Factor Adjusted Price (Price N) higher than but closest to the Balancing Price, taking into account the actual SOI Quantity of the Balancing Facility and the applicable Ramp Rate Limit; and

ii. the Upwards Out of Merit Generation for the Balancing Facility;

(b) Constrained On Compensation Price1 (ConP1) equals the Loss Factor Adjusted Price N identified in clause 6.17.3(a) less the Balancing Price;

(c) If the Balancing Facility's Upwards Out of Merit Generation exceeds ConQ1 and a Balancing Price-Quantity Pair exists for the Facility and Trading Interval with a Loss Factor Adjusted Price higher than Price N, then:

i. additional Constrained On Quantity2 (ConQ2) equals the lesser of:

1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the Facility's Balancing Price-Quantity Pair N+1 with a Loss Factor Adjusted Price (Price N+1) higher than but closest to the Price N, taking into account when the Balancing Facility's MW level reached the top, or bottom, as applicable, of the quantity associated with the Balancing Price-Quantity Pair N in the calculation in clause 6.17.3(a)(i) and the applicable Ramp Rate Limit; and

2. the Upwards Out of Merit Generation for the Balancing Facility less ConQ1; and

ii. Constrained On Compensation Price2 (ConP2) equals the Loss Factor Adjusted Price N+1 identified in clause 6.17.3(c)(i) less the Balancing Price;

(d) AEMO must repeat the process set out in clause 6.17.3(c) to identify, from the next highest priced Price N+1, any ConQN+1 and ConPN+1 until all Upwards Out of Merit Generation has been attributed to Balancing Price-Quantity Pairs or, otherwise, until there are no remaining Balancing Price-Quantity Pairs;

(e) The Non-Qualifying Constrained On Generation for the Balancing Facility equals the sum, divided by two so that it is expressed as sent out MWh, of any Upwards LFAS Enablement and, if the Facility is a Stand Alone Facility, any Backup Upwards LFAS Enablement, which the Balancing Facility was instructed to provide by System Management;

(f) If:

i. the Non-Qualifying Constrained On Generation exceeds ConQ1, set ConQ1 to zero; or

ii. otherwise reduce ConQ1 by the amount of Non-Qualifying Constrained On Generation;

(g) AEMO must repeat the process set out in clause 6.17.3(f) for each ConQN in ascending order until all Non-Qualifying Constrained On Generation has been deducted from ConQN or, otherwise, until there are no remaining ConQN; and

(h) For settlement purposes under Chapter 9, AEMO must Loss Factor adjust each ConQN calculated in clauses 6.17.3(a) to 6.17.3(f).

6.17.3A Subject to clause 6.17.5B, for any Balancing Facility that is a Non-Scheduled Generator, in a Trading Interval:

(a) ConQ1 equals the Upwards Out of Merit Generation, in MWh, for the Trading Interval, which for settlement purposes under Chapter 9 AEMO must Loss Factor adjust; and

(b) ConP1 equals the greater of:

i. zero; and

ii. the Loss Factor Adjusted Price in the Balancing Price-Quantity Pair associated with the Balancing Facility for that Trading Interval less the Balancing Price for that Trading Interval.

Constrained Off Quantities and Compensation Prices

6.17.4. Subject to clauses 6.17.5B and 6.17.5C, AEMO must attribute any Downwards Out of Merit Generation from a Balancing Facility that is a Scheduled Generator, in a Trading Interval, as follows:

(a) Constrained Off Quantity1 (CoffQ1) equals the lesser of:

i. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from the Facility's Balancing Price-Quantity Pair N, with a Loss Factor Adjusted Price (Price N), taking into account the Available Capacity and actual SOI Quantity of the Balancing Facility and the applicable Ramp Rate Limit, where N is determined from either of the following Balancing Price-Quantity Pairs or, if different, the one with the lower price:

1. the Balancing Price-Quantity Pair associated with the intersection of Available Capacity and the quantities in all Balancing Price-Quantity Pairs summed in order of lowest to highest price; and

2. the Balancing Price-Quantity Pair with a Loss Factor Adjusted Price lower than but closest to the Balancing Price; and

ii. the Downwards Out of Merit Generation for the Balancing Facility;

(b) Constrained Off Compensation Price1 (CoffP1) equals the Balancing Price less the Loss Factor Adjusted Price, Price N, identified in clause 6.17.4(a);

(c) If the Balancing Facility Downwards Out of Merit Generation exceeds CoffQ1 and a Balancing Price-Quantity Pair exists for the Facility and Trading Interval with a Loss Factor Adjusted Price lower than Price N, then:

i. additional Constrained Off Quantity2 (CoffQ2) equals the lesser of:

1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from the Facility's Balancing Price-Quantity Pair N+1 with a Loss Factor Adjusted Price (Price N+1) lower than but closest to the Price N, taking into account when the Balancing Facility's MW level reached the bottom, or the top, as applicable, of the quantity associated with the Balancing Price-Quantity Pair N in the calculation in clause 6.17.4(a)(i) and the applicable Ramp Rate Limit; and

2. the Downwards Out of Merit Generation for the Balancing Facility less CoffQ1; and

ii. Constrained Off Compensation Price2 (CoffP2) equals the Balancing Price less the Loss Factor Adjusted Price N+1 identified in clause 6.17.4(c)(i);

(d) AEMO must repeat the process set out in clause 6.17.4(c) to identify, from the next lowest priced Price N+1, any CoffQN+1 and CoffPN+1 until all Downwards Out of Merit Generation has been attributed to Balancing Price-Quantity Pairs or, otherwise, until there are no remaining Balancing Price-Quantity Pairs;

(e) The Non-Qualifying Constrained Off Generation for the Balancing Facility equals the sum, divided by two so that it is expressed as sent out MWh, of any Downwards LFAS Enablement and, if the Facility is a Stand Alone

Facility, any Backup Downwards LFAS Enablement, which the Balancing Facility was instructed to provide by System Management;

(f) If:

i. the Non-Qualifying Constrained Off Generation exceeds CoffQ1, set CoffQ1 to zero; or

ii. otherwise reduce CoffQ1 by the amount of Non-Qualifying Constrained Off Generation;

(g) AEMO must repeat the process set out in clause 6.17.4(f) for each CoffQN in ascending order until all Non-Qualifying Constrained Off Generation has been deducted from CoffQN or, otherwise, until there are no remaining CoffQN; and

(h) For settlement purposes under Chapter 9, AEMO must Loss Factor adjust each CoffQN calculated in clauses 6.17.4(a) to clauses 6.17.4(f).

6.17.4A. Subject to clause 6.17.5B, for any Balancing Facility that is a Non-Scheduled Generator, in a Trading Interval:

(a) CoffQ1 equals the Downwards Out of Merit Generation, in MWh, for that Trading Interval, which for settlement purposes under Chapter 9 AEMO must Loss Factor adjust; and

(b) CoffP1 equals the Balancing Price for that Trading Interval less the Loss Factor Adjusted Price in the Balancing Price-Quantity Pair associated with the Balancing Facility for that Trading Interval.

Portfolio Constrained On Quantities and Compensation Prices

6.17.5. Subject to clause 6.17.5C, AEMO must attribute any Upwards Out of Merit Generation from the Balancing Portfolio in a Trading Interval as follows:

(a) Portfolio Constrained On Quantity1 (PConQ1) equals the lesser of:

i. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the Balancing Portfolio's Balancing Price-Quantity Pair N with a price (Price N) higher than but closest to the Balancing Price, taking into account the actual Balancing Portfolio SOI Quantity and the Portfolio Ramp Rate Limit; and

ii. the Upwards Out of Merit Generation for the Balancing Portfolio;

(b) Portfolio Constrained On Compensation Price1 (PConP1) equals the Price N identified in clause 6.17.5(a) less the Balancing Price;

(c) if the Portfolio Upwards Out of Merit Generation exceeds PConQ1 and a Balancing Price-Quantity Pair exists for the Balancing Portfolio with a price higher than Price N, then:

i. additional Portfolio Constrained On Quantity2 (PConQ2) equals the lesser of:

1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched from the Balancing Portfolio's Balancing Price-Quantity Pair N+1 with a price (Price N+1) higher than but closest to the Price N, taking into account when the Balancing Portfolio MW level reached the top, or the bottom, as applicable, of Balancing Price-Quantity Pair N in the calculation in clause 6.17.5(a)(i) and the Portfolio Ramp Rate Limit; and

2. the Portfolio Upwards Out of Merit Generation less PConQ1; and

ii. Portfolio Constrained On Compensation Price2 (PConP2) equals the Price N+1 identified in clause 6.17.5(c)(i) less the Balancing Price;

(d) AEMO must repeat the process set out in clause 6.17.5(c) to identify, from the next highest priced Balancing Price-Quantity Pair N+1, any PConQN+1 and PConPN+1 until all Portfolio Upwards Out of Merit Generation has been attributed to Balancing Price-Quantity Pairs or, otherwise, until there are no remaining Balancing Price-Quantity Pairs;

(e) the Non-Qualifying Constrained On Generation for the Balancing Portfolio equals the sum, expressed in sent out MWh, of any increase in energy due to a Network Control Service Contract and of the following Ancillary Services (if any), which System Management instructed Synergy to provide from Facilities within the Balancing Portfolio:

i. Upwards LFAS Enablement;

ii. Backup Upwards LFAS Enablement; and

iii. the Spinning Reserve Response Quantity;

(f) if:

i. the Non-Qualifying Constrained On Generation exceeds PConQ1, set PConQ1 to zero; or

ii. otherwise reduce PConQ1 by the amount of Non-Qualifying Constrained On Generation;

(g) AEMO must repeat the process set out in clause 6.17.5(f) for each PConQN in ascending order until all Non-Qualifying Constrained On Generation has been deducted from PConQN or otherwise until there are no remaining PConQN; and

(h) for settlement purposes under Chapter 9, each PConQN calculated in this clause 6.17.5 is to be Loss Factor adjusted by the Portfolio Loss Factor.

Portfolio Constrained Off Quantities and Compensation Prices

6.17.5A. Subject to clause 6.17.5C, AEMO must attribute any Downwards Out of Merit Generation from the Balancing Portfolio in a Trading Interval as follows:

(a) Portfolio Constrained Off Quantity1 (PCoffQ1) equals the lesser of:

i. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from the Balancing Portfolio's Balancing Price-Quantity Pair N, with Price N, taking into account the Available Capacity of the Balancing Portfolio, the MW level at the start of the Trading Interval and the Portfolio Ramp Rate Limit, where N is determined from either of the following Balancing Price-Quantity Pairs or, if different, the one with the lower price:

1. the Balancing Price-Quantity Pair associated with the intersection of Available Capacity and the quantities in all Balancing Price-Quantity Pairs summed in order of lowest to highest price; and

2. the Balancing Price-Quantity Pair with a price lower than but closest to the Balancing Price; and

ii. the Portfolio Downwards Out of Merit Generation;

(b) Portfolio Constrained Off Compensation Price1 (PCoffP1) equals the Balancing Price less the Price N identified in clause 6.17.5A(a);

(c) if the Portfolio Downwards Out of Merit Generation (in MWh) exceeds PCoffQ1 and a Balancing Price-Quantity Pair exists for the Balancing Portfolio with a price lower than Price N, then:

i. additional Portfolio Constrained Off Quantity2 (PCoffQ2) equals the lesser of:

1. the maximum energy less the minimum energy, if any, in MWh, which could have been dispatched down from the Balancing Portfolio's Balancing Price-Quantity Pair N+1 with a price (Price N+1) lower than but closest to Price N, taking into account when the Balancing Portfolio MW level reached the bottom, or top, as applicable, of Balancing Price-Quantity Pair N in the calculation in clause 6.17.5A(a)(i) and the Portfolio Ramp Rate Limit; and

2. the Portfolio Downwards Out of Merit Generation less PCoffQ1; and

ii. Portfolio Constrained Off Compensation Price2 (PCoffP2) equals the Balancing Price less the Price N+1 identified in clause 6.17.5A(c)(i);

(d) AEMO must repeat the process set out in clause 6.17.5A(c) to identify, from the next lowest priced Balancing Price-Quantity Pair N+1, any PCoffQN+1 and PCoffPN+1 until all Portfolio Downwards Out of Merit Generation has been attributed to Balancing Price-Quantity Pairs or, otherwise, until there are no remaining Balancing Price-Quantity Pairs;

(e) the Non-Qualifying Constrained Off Generation for the Balancing Portfolio equals the sum, expressed in sent out MWh, of any reduction in sent out energy due to a Network Control Service Contract and of the following Ancillary Services (if any), which System Management instructed Synergy to provide from Facilities in the Balancing Portfolio:

i. Downwards LFAS Enablement;

ii. Backup Downwards LFAS Enablement; and

iii. the Load Rejection Reserve Response Quantity;

(f) if:

i. the Non-Qualifying Constrained Off Generation exceeds PCoffQ1 set PCoffQ1 to zero; or

ii. otherwise reduce PCoffQ1 by the amount of Non-Qualifying Constrained On Generation;

(g) AEMO must repeat the process set out in clause 6.17.5A(f) for each PCoffQN in ascending order until all Non-Qualifying Constrained Off Generation has been deducted from PCoffQN or there are no remaining PCoffQN; and

(h) for settlement purposes under Chapter 9, each PCoffQN calculated in this clause 6.17.5A is to be Loss Factor adjusted by the Portfolio Loss Factor.

Constrained On and Off Quantities and Compensation Prices – Exceptions

6.17.5B. Clauses 6.17.3, 6.17.3A, 6.17.4 and 6.17.4A do not apply to Facilities in the Balancing Portfolio.

6.17.5C. Where AEMO is unable to attribute:

(a) Upwards Out of Merit Generation in accordance with clauses 6.17.3 or 6.17.5, as applicable: or

(b) Downwards Out of Merit Generation in accordance with clauses 6.17.4 or 6.17.5A,

for a Market Participant, the Market Participant is not entitled to be paid for any Upwards Out of Merit Generation or Downwards Out of Merit Generation, as applicable.

Explanatory Note

Clauses 6.17.6 to 6.17.8 are to be deleted pursuant to proposed amendments in the Settlement workstream (and changes relating to the Reserve Capacity Mechanism that are scheduled to commence on 1 October 2021).

Non-Balancing Facility Dispatch

6.17.6. The Non-Balancing Facility Dispatch Instruction Payment, DIP(p,d,t), for Market Participant p and Trading Interval t of Trading Day d equals the sum over all Demand Side Programmes registered to Market Participant p of the amount that is the sum of:

(a) the Tranche 2 DSM Dispatch Payments; and

(b) the Tranche 3 DSM Dispatch Payments.

6.17.6A. [Blank]

6.17.6B. AEMO must develop a Market Procedure that details the methodology to calculate the Tranche 2 DSM Dispatch Payment and the Tranche 3 DSM Dispatch Payment for each Demand Side Programme.

6.17.6C. The methodology described in 6.17.6B must ensure that, subject to clauses 6.17.6D and 6.17.6E, the Non-Balancing Facility Dispatch Instruction Payment is determined as follows:

(a) (**Tranche 1**) while the Demand Side Programme's Cumulative Annual DSM Dispatch for a Capacity Year is less than or equal to the Demand Side Programme's Calculated DSP Quantity, the Non-Balancing Facility Dispatch Instruction Payment for each MWh of Deemed DSM Dispatch is zero;

(b) (**Tranche 2**) once the Demand Side Programme's Cumulative Annual DSM Dispatch for a Capacity Year exceeds the Demand Side Programme's Calculated DSP Quantity, the Non-Balancing Facility Dispatch Instruction Payment for each MWh of Deemed DSM Dispatch is the Extra Consumption Decrease Price until:

i. an amount equal to:

A. the sum, across all 12 months in the Capacity Year, of all the amounts payable (or anticipated to become payable) in respect of the Demand Side Programme as "DSM Capacity Payments (p,m)" under clause 9.7.1A;

plus

B. the aggregate of all Non-Balancing Facility Dispatch Instruction Payments received by the Demand Side Programme up to that time in the Capacity Year,

equals or exceeds

ii. an amount equal to the Reserve Capacity Price multiplied by an amount equal to the number of the Demand Side Programme's DSM Capacity Credits; and

(c) (**Tranche 3**) thereafter until the end of the Capacity Year, the Non-Balancing Facility Dispatch Instruction Payment for each MWh of Deemed DSM Dispatch is the Consumption Decrease Price.

6.17.6D. If in a Trading Interval a Demand Side Programme decreases its consumption:

(a) partly in response to a Dispatch Instruction under clauses 7.6.1C(d) or (e); and

(b) partly in accordance with:

i. a Network Control Service Contract;

ii. an Ancillary Service Contract;

iii. these Market Rules in connection with a Test; or

iv. a Supplementary Capacity Contract,

then—

(c) a Non-Balancing Facility Dispatch Instruction Payment is payable only to the extent that the Demand Side Programme would have decreased its consumption in response to the Dispatch Instruction had there been no reduction of the type described in clause 6.17.6D(b); and

(d) no Non-Balancing Facility Dispatch Instruction Payment is payable in respect of any decrease in consumption in excess of the amount referred to in clause 6.17.6D(c) ("**Further DSM Consumption Decrease**").

6.17.6E. If the number of DSM Capacity Credits assigned to a Demand Side Programme changes during a Capacity Year, then either or both of—

(a) the thresholds in clause 6.17.6C(a) and (b) which determine whether the Non-Balancing Facility Dispatch Instruction Payment is to be calculated under clause 6.17.6C(a), (b) or (c); and

(b) the values of Cumulative Annual DSM Dispatch or Calculated DSP Quantity (or both) for the Demand Side Programme for the Capacity Year,

are to be adjusted on a proportional basis in accordance with the Market Procedure established under clause 6.17.6F.

6.17.6F. AEMO must document in a Market Procedure the procedure it follows when making the adjustment referred to in clause 6.17.6E.

6.17.7. The Consumption Decrease Price and Extra Consumption Decrease Price used in clauses 6.17.6C(b) and 6.17.6C(c) must be at the applicable Peak Trading Interval or Off-Peak Trading Interval price.

6.17.8. [Blank]

Explanatory Note
Clause 6.17.9 is proposed to be moved to Chapter 9 – Settlement. However, to enable the Chapter 11 glossary definition of "Sent-Out Capacity" to be deleted in these draft Amending Rules, clause 6.17.9 is proposed to be amended as set out below.

6.17.9. AEMO must~~, other than for Facilities in the Balancing Portfolio,~~ determine a Settlement Tolerance for each Scheduled Generator and Non-Scheduled Generator, where this Settlement Tolerance is equal to:

(a) for a ~~Scheduled Generator~~ Registered Facility for which an applicable Tolerance Range or Facility Tolerance Range has been determined by ~~System Management~~ AEMO, the applicable value determined by ~~System~~

~~Management~~ AEMO under clause 2.13.6D, divided by two to be expressed as MWh; or

(b) for a Registered Facility ~~Facilities~~ for which no applicable Tolerance Range or Facility Tolerance Range has been determined by System Management, the lesser of:

i. 3 MWh; and

ii. the greater of:

1. 0.5 MWh; and

2. 3% of the ~~Facility's Sent Out Capacity~~ sent-out capacity provided as the Standing Data in Appendix 1(b)(iii), Appendix 1(e)(iiA) or Appendix 1(x)(x) divided by two to be expressed as MWh.

…

Explanatory Note Clauses 6.17.10 and section 6.18 are to be deleted (as the portfolio will no longer exist under the new market arrangements) pursuant to the proposed amendments in the Settlement workstream.

6.17.10. The Portfolio Settlement Tolerance equals the lesser of:

(a) 3 MWh; and

(b) 3% of the Sent Out Capacity of the Balancing Portfolio divided by two to be expressed as MWh.

6.18. [Blank]

Explanatory Note Section 6.19 is to be deleted and merged with Dispatch Advisories to create new Market Advisories in section 7.8.

~~Market Advisories and Energy Price Limits~~

~~6.19. Market Advisories~~

~~6.19.1. A Market Advisory is a notification by AEMO to Market Participants and Network Operators of an event that AEMO reasonably considers may impact on market operations.~~

~~6.19.2. AEMO must issue a Market Advisory for future potential events described in clause 6.19.1 if AEMO considers there to be a high probability that the event will occur within 48 hours of the time of issue.~~

~~6.19.3. Market Advisories must be released as soon as practicable after AEMO becomes aware of a situation requiring the release of a Market Advisory.~~

~~6.19.4. AEMO must inform Market Participants and Network Operators of the withdrawal of a Market Advisory as soon as practicable once the situation that the Market Advisory relates to has finished.~~

~~6.19.5. The types of Market Advisories are:~~

~~(a) Market systems outages – for situations where the scheduling or communication systems required for the normal conduct of the scheduling processes under these Market Rules are, or are expected to be, unavailable; and~~

~~(b) Market suspension – for situations where any component of the Market Rules, or the entire Market Rules, have been, or are about to be, suspended for any reason.~~

~~6.19.6. A Market Advisory must contain the following information:~~

~~(a) the type of Market Advisory;~~

~~(b) the date and time that the Market Advisory is released;~~

~~(c) the time period for which the Market Advisory is expected to apply;~~

~~(d) details of the situation that the Market Advisory relates to, including the extent and seriousness of the situation;~~

~~(e) any actions AEMO plans to take in response to the situation;~~

~~(f) any actions Market Participants or Network Operators are required to take in response to the situation, including whether any Market Procedure specified in clause 6.19.10 is applicable; and~~

~~(g) any actions Market Participants or Network Operators may voluntarily take in response to the situation.~~

~~6.19.7. Subject to clause 6.19.8 Market Participants and Network Operators must comply with directions that AEMO issues in any Market Advisory under clause 6.19.6(f).~~

~~6.19.8. A Market Participant or Network Operator is not required to comply with clause 6.19.7 if such compliance would endanger the safety of any person, damage equipment, or breach any applicable law.~~

~~6.19.9. Market Participants and Network Operators must inform AEMO as soon as practicable if they become aware of any circumstances that might reasonably be expected to result in AEMO issuing a Market Advisory.~~

~~6.19.10. AEMO may create one or more Market Procedures to deal with contingencies, and:~~

~~(a) Market Participants must follow that documented Market Procedure after receiving a relevant Market Advisory; and~~

~~(b) AEMO must follow that documented Market Procedure after AEMO has issued a relevant Market Advisory.~~

Explanatory Note

Section 6.20 is to be retained subject to amendments to be proposed in the Market Power workstream.

6.20. Energy Price Limits

6.20.1. The Energy Price Limits are:

(a) the Maximum STEM Price;

(b) the Alternative Maximum STEM Price; and

(c) the Minimum STEM Price.

6.20.2. The Maximum STEM Price is the value published on the Market Web Site and revised in accordance with clauses 6.20.6 and 6.20.11.

6.20.3. Subject to clause 6.20.11, the Alternative Maximum STEM Price is to equal:

(a) from 8 AM on September 1, 2006, $480/MWh; and

(b) from 8 AM on the first day of each subsequent month the sum of:

i. $440/MWh multiplied by the amount determined as follows:

1. the average of the Singapore Gas Oil (0.5% sulphur) price, expressed in Australian dollars, for the three months ending immediately before the preceding month as published by the International Energy Agency in its monthly Oil Market Report, or the average of another suitable published price as determined by AEMO, divided by;

2. the average of the Singapore Gas Oil (0.5% sulphur) price, expressed in Australian dollars, for May, June and July 2006 or, if a revised Alternative Maximum STEM Price takes effect in accordance with clause 6.20.11, for the three months ending immediately before the month preceding the month in which the revised Alternative Maximum STEM Price takes effect, as published by the International Energy Agency in its monthly Oil Market Report, or the average of another suitable published price as determined by AEMO; and

ii from 8 AM on September 1, 2006, to 8 AM on 1 September, 2007, $40/MWh, and for each subsequent 12-month period $40/MWh multiplied by the CPI for the June quarter of the relevant 12-month period divided by CPI for the 2006 June quarter or, if a revised Alternative Maximum STEM Price takes effect in accordance with clause 6.20.11, the June quarter of the year in which the revised Alternative Maximum STEM Price takes effect, where CPI is the weighted average of the Consumer Price Index All Groups value of the eight Australian State and Territory capital cities as determined by the Australian Bureau of Statistics;

rounded to the nearest whole dollar, where a half dollar is rounded up, with the exception that from the date and time that a revised Alternative Maximum STEM Price takes effect in accordance with clause 6.20.11, the revised values supersede the values in 6.20.3(b)(i) and 6.20.3(b)(ii), and are to be the values used in calculating the Alternative Maximum STEM Price for each month subsequent to the month in which the revised Alternative Maximum STEM Price takes effect.

6.20.4. [Blank]

6.20.5. [Blank]

6.20.6. AEMO must annually review the appropriateness of the value of the Maximum STEM Price and Alternative Maximum STEM Price.

6.20.7. In conducting the review required by clause 6.20.6 AEMO:

(a) may propose revised values for the following:

i. the Maximum STEM Price, where this is to be based on AEMO's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by natural gas and is to be calculated using the formula in paragraph (b); and

ii. the Alternative Maximum STEM Price, where this is to be based on AEMO's estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by distillate and is to be calculated using the formula in paragraph (b);

(b) must calculate the Maximum STEM Price or Alternative Maximum STEM Price using the following formula:

(1 + Risk Margin)× (Variable O&M +(Heat Rate × Fuel Cost))/Loss Factor

Where

i. Risk Margin is a measure of uncertainty in the assessment of the mean short run average cost for a 40 MW open cycle gas turbine generating station, expressed as a fraction;

ii. Variable O&M is the mean variable operating and maintenance cost for a 40 MW open cycle gas turbine generating station, expressed in $/MWh, and includes, but is not limited to, start-up related costs;

iii. Heat Rate is the mean heat rate at minimum capacity for a 40 MW open cycle gas turbine generating station, expressed in GJ/MWh;

iv. Fuel Cost is the mean unit fixed and variable fuel cost for a 40 MW open cycle gas turbine generating station, expressed in $/GJ; and

v. Loss Factor is the marginal loss factor for a 40 MW open cycle gas turbine generating station relative to the Reference Node.

Where AEMO must determine appropriate values for the factors described in paragraphs (i) to (v) as applicable to the Maximum STEM Price and Alternative Maximum STEM Price.

6.20.8. [Blank]

6.20.9. In conducting the review required by clause 6.20.6 AEMO must prepare a draft report describing how it has arrived at a proposed revised value of an Energy Price Limit. The draft report must also include details of how AEMO determined the appropriate values to apply for the factors described in clause 6.20.7 (b)(i) to (v). AEMO must publish the draft report on the Market Web Site and advertise the report in newspapers widely published in Western Australia and request submissions from all sectors of the Western Australia energy industry, including end-users, within six weeks of the date of publication.

6.20.9A. Prior to proposing a final revised value to an Energy Price Limit in accordance with clause 6.20.10, AEMO may publish a request for further submissions on the Market Web Site. Where AEMO publishes a request for further submissions in accordance with this clause, it must request submissions from all sectors of the Western Australia energy industry, including end-users.

6.20.10. After considering the submissions on the draft report described in clause 6.20.9, and any submissions received under clause 6.20.9A, AEMO must propose a final revised value for any proposed change to an Energy Price Limit and submit those values and its final report, including any submissions received, to the Economic Regulation Authority for approval.

6.20.11. A proposed revised value for any Energy Price Limit replaces the previous value after:

(a) the Economic Regulation Authority has approved that value in accordance with clause 2.26; and

(b) AEMO has posted a notice on the Market Web Site of the new value of the applicable Energy Price Limit,

with effect from the time specified in AEMO's notice.

Explanatory Note

Section 6.21 is to be retained subject to amendments to be proposed in the Settlement workstream.

Settlement Data

6.21. Settlement Data

6.21.1. AEMO must provide the following information to the settlement system for each STEM Auction:

(a) a flag for each Trading Interval indicating if the STEM Auction was suspended for that Trading Interval;

(b) the STEM Clearing Price in each Trading Interval in units of $/MWh; and

(c) for each Market Participant participating in the STEM Auction, the STEM quantity scheduled in each Trading Interval, in units of MWh, where this amount must be positive for a sale of energy to AEMO and negative for a purchase of energy from AEMO.

6.21.2. AEMO must provide the following information to the settlement system for each Trading Interval in a Trading Day:

(a) the Balancing Price; and

(b) for each Market Participant:

i. the Metered Balancing Quantity;

ii. the Constrained On Quantities and associated Constrained On Compensation Prices calculated in accordance with clauses 6.17.3 and 6.17.3A;

iii. the Constrained Off Quantities and associated Constrained Off Compensation Prices calculated in accordance with clauses 6.17.4 and 6.17.4A;

iv. the Portfolio Constrained On Quantities and associated Portfolio Constrained On Compensation Prices calculated in accordance with clause 6.17.5;

v. the Portfolio Constrained Off Quantities and associated Portfolio Constrained Off Compensation Prices calculated in accordance with clause 6.17.5A;

vi. the Non-Balancing Facility Dispatch Instruction Payment; and

vii. the Tranche 2 DSM Dispatch Payment.

Explanatory Note

The proposed structure of Chapter 7 reflects the integration of the operation of the Real-Time Market and the Central Dispatch process in accordance with the Security Constrained Economic Dispatch (**SCED**) market model.

More specifically:

- Chapter 7 is proposed to be renamed 'Real-Time Market Operation and Dispatch' and substantially amended; and
- Chapters 7A and 7B are to be deleted.

As the name implies, SCED determines the most economic dispatch of individual resources across the SWIS. In the current market, AEMO schedules energy and Essential System Services separately, and congestion on the network is accounted for by amendments to the market dispatch.

The adoption of the SCED market model, which includes consideration of network constraints in the calculation of dispatch schedules, is essential for the SWIS in order to maintain system security as congestion increases. Adopting the SCED market model will require AEMO to replace the existing market and dispatch systems that it uses to operate the Wholesale Electricity Market.

Adopting a SCED market model is fundamental to realising the benefits of the sustainable and efficient management of network constraints, and is expected to deliver the following benefits.

- transparent determination of the least-cost dispatch outcome for the market, accounting for generation offers and network conditions, and allowing Market Participants to respond, resulting in increased competition in the Real-Time Market and a downward pressure on the energy price over time;
- greater automation in the calculation of network constraints, which improves network efficiency by allowing constraints to be set less conservatively without compromising system reliability; and
- greater automation in the dispatch process, so that system security can be managed efficiently as the level of constraints increases, and the generation mix continues to change.

Some parts of Chapter 7 contain proposed subheadings to assist the user. Please note, however, that as is the case for all headings in the WEM Rules (including those in brackets at the beginning of a paragraph), they are for convenience only and do not affect the interpretation of the WEM Rules (clause 1.4.1(f)).

7 Real-Time Market Operation and Dispatch

~~Data used in the Dispatch Process~~

~~7.1. Data Used in the Non-Balancing and Out of Merit Dispatch Process~~

~~7.1.1. System Management must maintain and, in accordance with section 7.6, use the following data set when issuing Dispatch Instructions to Demand Side Programmes, when issuing Dispatch Instructions to Balancing Facilities dispatched Out of Merit, and when providing Operating Instructions:~~

~~(a) Standing Data for Registered Facilities determined in accordance with section 2.34;~~

~~(b) Loss Factors determined in accordance with section 2.27;~~

~~(c) expected Scheduled Generator and Non-Scheduled Generator capacities by Trading Interval determined in accordance with clauses 3.17.5, 3.17.6 and 3.17.8;~~

~~(d) network configuration and capacity by Trading Interval determined in accordance with clauses 3.17.5, 3.17.6 and 3.17.8;~~

~~(e) forecasts of load and non-scheduled generation by Trading Interval determined in accordance with section 7.2;~~

~~(f) Ancillary Service Requirements for each Trading Interval determined in accordance with clause 7.2.4;~~

~~(g) schedules of approved Planned Outages by Trading Interval determined in accordance with section 3.19;~~

~~(h) Forced Outages and Consequential Outages by Trading Interval received from Network Operators in accordance with section 3.21;~~

~~(i) Scheduled Generator, Non–Scheduled Generator and Interruptible Load Forced Outages and Consequential Outages by Trading Interval received from Market Participants in accordance with section 3.21;~~

~~(j) [Blank]~~

~~(k) the Non-Balancing Dispatch Merit Order;~~

~~(l) Supplementary Capacity Contract data, if any; and~~

~~(m) Network Control Service Contract data, if any, received from a Network Operator in accordance with clauses 5.3A.3 and 5.3A.4.~~

~~7.1.2. System Management must continually modify its records of the data described in clause 7.1.1 as System Management becomes aware of changes in that data.~~

~~7.1.3. System Management may, but is not required to, revise its earlier Dispatch Instructions when advised of Forced Outages during the Trading Day.~~

~~7.2. Load Forecasts and Ancillary Service Requirements~~

~~7.2.1. System Management must prepare a Load Forecast for a Trading Day by 7:30 AM on the Scheduling Day for the Trading Day, where this Load Forecast is for information purposes.~~

~~7.2.2. The Load Forecasts for a Trading Day described in clause 7.2.1 must:~~

~~(a) represent Non-Dispatchable Load and Interruptible Load net of forecast non-scheduled generation;~~

~~(b) predict values for both MWh and MW total demand for each Trading Interval in the Trading Day; and~~

~~(c) be Loss Factor adjusted to the Reference Node.~~

~~7.2.3. [Blank]~~

~~7.2.3A. By 8:30 AM on the Scheduling Day, System Management must determine for each Market Participant that is a provider of Ancillary Services (excluding LFAS):~~

~~(a) an estimate of the Loss Factor adjusted MWh of energy that could potentially be called upon by System Management after 1:00 PM on the Scheduling Day to meet Ancillary Service Requirements (excluding LFAS) for each Trading Interval of the Trading Day where these estimates must reflect the Ancillary Service standards described in clause 3.10; and~~

~~(b) a list of Facilities that it might reasonably expect to call upon to provide the energy described in clause 7.2.3A(a).~~

~~7.2.3B. [Blank]~~

~~7.2.4. System Management must determine the actual quantity of Ancillary Services required by location for each Trading Interval of the Trading Day in accordance with the Ancillary Service standards described in clause 3.10.~~

~~7.2.5. Unless otherwise directed by System Management, each Market Generator must by 10 AM each day provide to System Management for each of its Intermittent Generators with capacity exceeding 10 MW its most current forecast of the MWh energy output of the Intermittent Generator for each Trading Interval between noon of the current Scheduling Day and the end of the corresponding Trading Day in a format and by a method specified in a Power System Operation Procedure.~~

~~7.2.6. System Management may only use forecasts provided to it in accordance with clause 7.2.5 for the purpose of setting and revising requirements for Ancillary Service and to update its dispatch plans during the Trading Day.~~

Explanatory Note

Section 7.1 provides a head of power for the Real-Time Market and for AEMO to document the new Real-Time Market Timetable in a WEM Procedure (which is required to be published on the WEM Website).

The Real-Time Market Timetable is the timetable developed by AEMO for the operation of the Real-Time Market and the provision of certain market information relating to, amongst other things, dispatch and pre-dispatch, and specifies who must do what and by when.

As the Real-Time Market Timetable is required to be documented by AEMO in a WEM Procedure, the Procedure Change Process in section 2.10 will need to be followed in relation to any proposed changes to the timetable.

7.1. Real-Time Market

7.1.1. AEMO must establish and operate a Real-Time Market.

7.1.2. AEMO must:

(a) document the Real-Time Market Timetable in a WEM Procedure; and

(b) operate the Real-Time Market according to the Real-Time Market Timetable.

7.1.3. The Real-Time Market Timetable must include:

(a) timelines for:

i. the submission of Real-Time Market Submissions, including any subsequent or replacement submissions;

ii. the calculation and publication on the WEM Website of the following information in a Dispatch Interval for the next Dispatch Interval:

i. Market Clearing Prices;

ii. Dispatch Targets;

iii. Dispatch Caps; and

iv. Essential System Service Enablement Quantities;

iii. the calculation and publication on the WEM Website of the Dispatch Schedule at least once each Dispatch Interval;

iv. the calculation and publication on the WEM Website of the Pre-Dispatch Schedule at least once each Pre-Dispatch Interval; and

v. the calculation and publication on the WEM Website of the Week-Ahead Schedule at least once each Trading Day; and

(b) any other requirements that AEMO considers relevant to the operation of the Real-Time Market Timetable.

Explanatory Note

Section 7.2 provides the head of power for AEMO to operate a Central Dispatch process in accordance with the SCED market model, the objective of which is to maximise the value (of schedulable load) and minimise the cost of supply while taking into account various constraints. See also the Explanatory Note to Chapter 7.

The mathematical formulation of the Dispatch Algorithm that AEMO uses in the Central Dispatch process is to be published by AEMO on the WEM Website.

7.2. Central Dispatch - Process

7.2.1. AEMO must establish and operate a Central Dispatch process to dispatch Registered Facilities in order to balance electricity supply and demand, using its reasonable endeavours to maintain Power System Security and Power System Reliability in accordance with Chapter 3.

7.2.2. AEMO must use its reasonable endeavours to maximise the value of Real-Time Market trading:

(a) within the parameters for maintaining Power System Security and Power System Reliability in accordance with Chapter 3; and

(b) on the basis of Real-Time Market Offers and Real-Time Market Bids.

7.2.3. AEMO must develop and publish in a WEM Procedure the Dispatch Algorithm used by AEMO for the purpose of Central Dispatch and setting Market Clearing Prices, including the formulation described in clause 7.2.6.

7.2.4. Where AEMO reasonably determines that an urgent change to the Dispatch Algorithm is required to maintain Power System Security and Power System Reliability in accordance with Chapter 3, AEMO may implement the change. Where AEMO makes a change to the Dispatch Algorithm in accordance with this clause 7.2.4, AEMO must:

(a) publish the change on the WEM Website, and the reasons the change was required in order for AEMO to maintain Power System Security and Power System Reliability in accordance with Chapter 3; and

(b) if the Power System Security and Power System Reliability issue that is being addressed by the change is not temporary, AEMO must update the WEM Procedure referred to in clause 7.2.6 and may do so without needing to comply with the Procedure Change Process.

Explanatory Note

Clause 7.2.5 is intended to be an exhaustive list of all of the types of constraints that may be included in the optimisation problem that the Dispatch Algorithm will need to solve. If additional necessary constraint types are identified, they would be added to this clause. To the extent that AEMO needs to depart from the Dispatch Algorithm, AEMO would adjust the inputs (clause 7.2.5(f)) or override the outputs through exercising its emergency powers (clause 3.5.5 of the draft Amending Rules for the new frameworks for Essential System Service, Frequency Operating Standard, Operating States and Credible Contingency Events).

7.2.5. The Dispatch Algorithm must seek to maximise the value of Real-Time Market trading by:

(a) maximising the value of dispatched Load based on Real-Time Market Bids; less

(b) the cost of dispatched energy and Frequency Co-optimised Essential System Services based on Real-Time Market Offers,

subject to:

(c) respecting the quantities, Ramp-Rate Limits and other limits specified in Real-Time Market Submissions;

(d) dispatching sufficient energy to meet the Forecast Operational Demand;

(e) respecting Network Constraints, as reflected in the Constraint Equations developed by AEMO in accordance with section 2.27A;

(f) meeting Power System Security and Power System Reliability requirements as reflected in Constraint Equations developed by AEMO having regard to the WEM Procedures referred to in clauses 3.2.7, 3.3.2 and 3.4.11, including any limits on maximum ramp rates;

(g) Transmission Loss Factors and Distribution Loss Factors;

(h) current levels of Injection and Withdrawal;

(i) meeting the Essential System Service Standards as reflected in the Essential System Service requirements determined by AEMO in accordance with the WEM Procedure referred to in clause 3.11.8 and in Constraint Equations developed by AEMO having regard to that WEM Procedure;

Explanatory Note

Clause 7.2.5(j) refers to 'Electric Storage Resources', which are proposed to be defined in the draft Amending Rules in the Registration, Participation and Storage workstream.

(j) respecting limits on energy storage capability of Electric Storage Resources;

(k) respecting Oscillation Control Constraints;

(l) accounting for all relevant Contingency Lower Factors, Contingency Raise Factors and Facility Performance Factors in determining scheduled and dispatched quantities of Contingency Reserve;

(m) accounting for all Inflexible Facilities;

(n) taking into account the Largest Credible Supply Contingency relative to the scheduled or dispatched quantity of Contingency Reserve Raise; and

(o) arrangements for dispatch of tied Real-Time Market Bids and tied Real-Time Market Offers.

Explanatory Note

Clause 7.2.6 refers to the quantities of RoCoF Control Service and Contingency Reserve Raise, as these will be determined dynamically as part of the Dispatch Algorithm, while the required quantity of other Essential System Service will be determined outside the Dispatch Algorithm and provided as an input.

7.2.6. AEMO must document in a WEM Procedure:

(a) the mathematical formulation of the Dispatch Algorithm, including:

i. the conversion of Facility Speed Factors into Facility Performance Factors;

ii. the calculation of Minimum RoCoF Control Requirement and Additional RoCoF Control Requirement; and

iii. the calculation of the required quantity of Contingency Reserve Raise,

in a form that:

iv. sets out the form, scope and construction of each type of Constraint Equation;

v. describes and quantifies the mechanism by which different Constraints are taken into account and prioritised, including in accordance with clauses 3.12.2 and 7.6.25; and

vi will enable a third party, including the Market Auditor, to replicate the results of the Dispatch Algorithm by using the same inputs;

(b) the methodology it uses to determine:

i. Contingency Raise Factors;

ii. Contingency Lower Factors;

iii. Facility Performance Factors;

iv. the Minimum RoCoF Control Requirement;

v. the RoCoF Control Requirement; and

vi. the RoCoF Upper Limit;

(c) the processes to be followed by AEMO and Market Participants in accounting for Inflexible Facilities; and

(d) any methodology for replacement of erroneous or missing input data.

7.2.7. AEMO must use the Dispatch Algorithm to determine Dispatch Targets and Dispatch Caps for each Registered Facility in each Dispatch Interval.

7.2.8. AEMO must use the Dispatch Algorithm to determine the quantity of each Frequency Co-optimised Essential System Service which will be enabled for each Registered Facility in each Dispatch Interval.

Explanatory Note

Clause 7.2.9 provides a head of power for AEMO to relax Constraints.

The Market Clearing Engine is the software to be developed by AEMO to ensure the Central Dispatch process maximises the value and minimises the cost of supply while taking into account various constraints. It may not be possible to respect all Constraints that need to be considered in a Dispatch Interval. Where this occurs, the solution is infeasible and the Market Clearing Engine would produce prices that do not reflect the cost of supply. As this would not be an acceptable outcome, AEMO will have the power to ensure Dispatch processes continue by relaxing Constraints in accordance with the WEM Procedure referred to in clause 7.2.11.

7.2.9. AEMO may relax the Constraints referred to in clause 7.2.5 in order to resolve infeasible dispatch solutions provided that any relaxation of a Constraint:

(a) achieves a feasible dispatch outcome;

(b) meets AEMO's obligations to maintain Power System Security and Power System Reliability in accordance with the WEM Rules; and

(c) meets the pricing principles listed in clause 7.11A.1.

Explanatory Note

Clause 7.2.10 requires AEMO to publish details of any Constraints that were relaxed under clause 7.2.9 on the WEM Website as soon as practicable after the start of the relevant Dispatch Interval, and to prepare a quarterly report summarising, and providing further details, with respect to those relaxed Constraints. The quarterly report is proposed to form part of the Congestion Information Resource referred to in clause 2.27B.3 (which is published on the WEM Website in accordance with clause 2.27B.2(b)).

7.2.10. AEMO must:

(a) as soon as practicable after the start of the Dispatch Interval, publish on the WEM Website details of any Constraints relaxed under clause 7.2.9 for that Dispatch Interval; and

(b) as soon as practicable after the end of each quarter, release a report summarising the total number, frequency and type of Constraints that were relaxed under clause 7.2.9 during that quarter.

Explanatory Note

Clause 7.2.11 requires AEMO to document the processes it will follow for the relaxation of Constraints under clause 7.2.9 and the preparation of reports in accordance with clause 7.2.10(b) in a WEM Procedure.

7.2.11. AEMO must document in a WEM Procedure the processes to be followed by AEMO:

(a) for the relaxation of Constraints under clause 7.2.9, and

(b) in preparing a report under clause 7.2.10(b).

~~7.3. Outages~~

~~7.3.1. [Blank]~~

~~7.3.2. [Blank]~~

~~7.3.3. [Blank]~~

Explanatory Note

Outages data to be used in the Central Dispatch process is specified in section 7.3.

It is expected that further changes may be made in the Outages workstream.

~~7.3.4. System Management must prepare a schedule of Planned Outages, Forced Outages and Consequential Outages for each Registered Facility of which System Management is aware at that time where Outages are calculated in accordance with clause 3.21.6, for each Trading Interval of a Trading Day, between 8:00 AM and 8:30 AM on the Scheduling Day prior to the Trading Day.~~

~~7.3.5. [Blank]~~

~~7.3.6. [Blank]~~

~~7.3.7. [Blank]~~

Explanatory Note

Section 7.3 (which replaces current section 7.2) provides for continual publication of latest Load Forecasts with Market Schedules. Separate Non-Scheduled Generator forecasts are no longer required, as they will be submitted via Real-Time Market Offers.

7.3. Central Dispatch - Data for Load Forecasts

7.3.1. AEMO must prepare a Forecast Operational Demand for:

(a) each Pre-Dispatch Interval within each Week Ahead Schedule Horizon; and

(b) each Dispatch Interval within each Dispatch Schedule Horizon.

7.3.2. The Forecast Operational Demand must:

(a) not include any Injection or Withdrawal included in Real-Time Market Submissions for Registered Facilities;

(b) forecast the total MWh Injection required for each Pre-Dispatch Interval or Dispatch Interval; and

(c) forecast the MW Injection required at the end of each Pre-Dispatch Interval or Dispatch Interval.

7.3.3. The Forecast Operational Demand may adjust the Withdrawal to be excluded in accordance with clause 7.3.2(b) where AEMO reasonably considers the Real-Time Market Submission for a Registered Facility does not accurately represent the Registered Facility's Withdrawal.

7.3.4. AEMO must publish a Forecast Operational Demand at the times specified in section 7.13.

7.3.5. AEMO must document in a WEM Procedure the methodology and processes it follows for determining and publishing the Forecast Operational Demand under this section 7.3.

~~7.4. [Blank]~~

Explanatory Note

Section 7.4 sets out the obligations with respect to Real-Time Market Submissions, and is structured as follows:

- clauses 7.4.1 to 7.4.14 – Obligations and Meanings;
- clauses 7.4.15 to 7.4.30 – Timing;
- clauses 7.4.31 to 7.4.41 – Format;
- clauses 7.4.42 to 7.4.46 – Construction;
- clauses 7.4.47 to 7.4.49 – Validation;
- clauses 7.4.50 to 7.4.53 – Processing; and
- clauses 7.4.54 to 7.4.62 – Standing Submissions.

7.4. Real-Time Market Submissions

> **Explanatory Note**
>
> Clauses 7.4.1 to 7.4.14 set out the obligations with respect to Real-Time Market Submissions and any restrictions on Real-Time Market Bids and Real-Time Market Offers for Registered Facilities with certain characteristics.

Real-Time Market Submissions: Obligations and meaning

7.4.1. A Market Participant must ensure that it has made a Real-Time Market Submission in accordance with this section 7.4 for each Dispatch Interval in the Week-Ahead Schedule Horizon for each of its Registered Facilities.

> **Explanatory Note**
>
> Clause 7.4.2 is intended to be a civil penalty provision.

7.4.2. A Market Participant must ensure that its most recently submitted Real-Time Market Submission or Standing Real-Time Market Submission for each Registered Facility in respect of each Market Service in each Dispatch Interval in the Week-Ahead Schedule Horizon accurately reflects, in accordance with any WEM Procedure referred to in clause 7.4.30:

(a) all information reasonably available to the Market Participant, including:

i. Market Schedules published by AEMO;

ii. any tests required under these WEM Rules, including availability of capacity under sections 4.25 and 4.25A;

iii. in the case of a Semi-Scheduled Facility or a Non-Scheduled Facility, if the Unadjusted Intermittent Generation Forecast has changed by more than the Tolerance Range or Facility Tolerance Range applicable to the Registered Facility; and

iv. any Outage for the Registered Facility;

(b) the Market Participant's reasonable expectation of the capability of its Registered Facility to be dispatched in the Real-Time Market, including intended commitment or decommitment;

(c) the prices at which the Market Participant intends the Registered Facility will participate in the Real-Time Market for:

i. Injecting energy;

ii. Withdrawing energy; and

iii. providing a Frequency Co-optimised Essential System Service for which the Registered Facility is accredited; and

(d) the Reserve Capacity Obligation Quantity in accordance with clause 4.12.1(c).

7.4.3. A Real-Time Market Submission is deemed to constitute a declaration by an Authorised Officer of the Market Participant.

Explanatory Note The SESSM is set out in proposed section 3.15A of the draft Amending Rules for the frameworks for Essential System Service, Frequency Operating Standards, Operating States and Credible Contingency Events. Clause 7.4.4 describes specific obligations with respect to Real-Time Submissions for a Registered Facility where the relevant Market Participant holds a SESSM Supplementary ESS Award for the Registered Facility. The Remaining Available Capacity is to be defined in draft Amending Rules for the Outages workstream.

7.4.4. Where a Market Participant holds a SESSM Supplementary ESS Award for a Registered Facility, without limiting any other obligation or requirement under this section 7.4, the Market Participant must make Real-Time Market Submissions for the Registered Facility in accordance with the SESSM Supplementary ESS Award.

7.4.5. A Real-Time Market Submission under clause 7.4.4 must:

(a) for all Dispatch Intervals within the Service Timing and the Week Ahead Horizon:

i. offer a quantity of the relevant Frequency Control Essential System Service greater than or equal to the lower of:

1. the sum of the relevant Base ESS Quantity and Availability Quantity; and

2. the lowest Remaining Available Capacity for that Frequency Co-optimised Essential System Service under any Outage applying to the Registered Facility in the Dispatch Interval,

in Price-Quantity Pairs; and

ii. specify an offer price in Price-Quantity Pairs relating to the Availability Quantity not exceeding the Offer Cap for the SESSM Supplementary ESS Award before accounting for Enablement Losses; and

(b) where the Reference Scenario for a Pre-Dispatch Interval projects a shortfall in an awarded Frequency Co-optimised Essential System Service, adjust the Real-Time Market Submission for the Registered Facility for that Pre-Dispatch Interval so that the Registered Facility is:

i. committed and cleared for energy; and

ii. offering its full accredited quantity of the relevant Frequency Co-optimised Essential System Service as In-Service Capacity.

7.4.6. Where the Reference Scenario for a Pre-Dispatch Interval shows that a Registered Facility will be enabled to provide RoCoF Control Service and all or part of the enabled quantity is included in the Real-Time Market Submissions for the Registered Facility as Available Capacity, the Market Participant for the Registered Facility must amend the Real-Time Market Submissions for the Registered Facility for that Pre-Dispatch Interval to show the relevant quantity as In-Service Capacity.

> **Explanatory Note**
>
> Clause 7.4.7 provides that where a participant has any control over the output of a Semi-Scheduled Facility (for example by charging or discharging storage, or choosing to curtail output), its intentions to exercise that control must be reflected in its offers.

7.4.7. A Market Participant must ensure that the total quantity of Injection or Withdrawal in a Real-Time Market Offer in a Real-Time Market Submission for a Semi-Scheduled Facility or Non-Scheduled Facility for a Dispatch Interval reflects the Market Participant's best estimate of the Registered Facility's Injection or Withdrawal at the end of the Dispatch Interval. When determining a best estimate, the Market Participant must:

(a) assume that the Registered Facility will not be subject to a Dispatch Instruction that limits its Injection or Withdrawal in that Dispatch Interval;

(b) for a Registered Facility with an Electric Storage Resource, account for the Market Participant's planned operation of the Electric Storage Resource; and

(c) include the effects of any action the Market Participant expects to take that would result in the Registered Facility's Injection varying from its unconstrained capability.

> **Explanatory Note**
>
> Clauses 7.4.8 and 7.4.9 require that the prices offered or bid by a Market Participant in a Real-Time Market Submission for a Non-Scheduled Facility must be at the Energy Offer Caps i.e. floor and ceiling prices.

7.4.8. A Market Participant must ensure that the prices offered in a Real-Time Market Offer contained in a Real-Time Market Submission for a Non-Scheduled Facility for a Dispatch Interval are:

(a) for the quantity of the Market Participant's forecast of the Injection of the Non-Scheduled Facility for the Dispatch Interval, equal to the Energy Offer Price Floor when converted into a Loss Factor Adjusted Price; and

(b) for any additional quantity, equal to the Energy Offer Price Ceiling when converted into a Loss Factor Adjusted Price.

7.4.9. A Market Participant must ensure that the prices offered in a Real-Time Market Bid contained in a Real-Time Market Submission for a Non-Scheduled Facility for a Dispatch Interval are:

(a) for the quantity of the Market Participant's forecast of the Withdrawal of the Non-Scheduled Facility for the Dispatch Interval, equal to the Energy Offer Price Ceiling when converted into a Loss Factor Adjusted Price; and

(b) for any additional quantity, equal to the Energy Offer Price Floor when converted into a Loss Factor Adjusted Price.

Explanatory Note

Clause 7.4.10 requires that bids made by a Market Participant in a Real-Time Market Submission for a Demand Side Programme must be equal to the Reserve Capacity Obligation Quantity for the Demand Side Programme for the Dispatch Interval, and where the Demand Side Programme comprises Loads at multiple connection points, such quantities are to be bid at the Energy Offer Price Ceiling.

7.4.10. A Market Participant must ensure that a Real-Time Market Submission for a Demand Side Programme for a Dispatch Interval:

(a) includes Real-Time Market Bids to Withdraw a quantity of energy equal to the Reserve Capacity Obligation Quantity for the Registered Facility in the Dispatch Interval; and

(b) where the Demand Side Programme comprises Loads at multiple Electrical Locations, specifies Real-Time Market Bids for the quantities referred to in clause 7.4.10(a) at the Energy Offer Price Ceiling.

Explanatory Note

The term 'Distributed Scheduled Load' is to be defined in the draft Amending Rules for the Registration, Participation and Storage workstream.

7.4.11. A Market Participant must ensure that a Real-Time Market Submission for a Distributed Scheduled Load includes a single Real-Time Market Bid to Withdraw a quantity of energy at the Energy Offer Price Ceiling.

Explanatory Note

In accordance with the new framework for Essential System Services, Interruptible Loads will only be eligible to be accredited to provide Contingency Reserve Raise and not any other type of Essential System Service. This clause reflects the intent for Interruptible Loads to use a load association process similar to DSPs, and may be adjusted with the amending rules for Registration.

7.4.12. A Market Participant must ensure that a Real-Time Market Offer in a Real-Time Market Submission for an Interruptible Load for a Dispatch Interval:

(a) is for Contingency Reserve Raise only; and

(b) includes zero MW in respect of any Associated Load of the Interruptible Load that is also an Associated Load of a Demand Side Programme that has been issued a non-zero Dispatch Instruction for the same Dispatch Interval.

Explanatory Note

Section 2.34A of these proposed Amending Rules sets out the provisions with respect to accreditation of Facilities to provide one or more Frequency Co-optimised Essential System Services.

7.4.13. Where a Registered Facility has been accredited in accordance with section 2.34A to provide Contingency Reserve Raise subject to a Maximum Contingency Reserve Block Size, the quantities in each Price-Quantity Pair in the Real-Time Market Offers for Contingency Reserve Raise in a Real-Time Market Submission for the Registered Facility must not exceed the applicable Maximum Contingency Reserve Block Size.

7.4.14. A Registered Facility that has been accredited in accordance with section 2.34A to provide Contingency Reserve Raise subject to a Maximum Contingency Reserve Block Size may respond to a Contingency Event using the whole quantity of all cleared or partially cleared Contingency Reserve Raise Price-Quantity Pairs.

Explanatory Note

Clauses 7.4.15 to 7.4.30 set out the obligations and requirements regarding the timing for Market Participants to make Real-Time Market Submissions, including giving AEMO the power to specify earliest and latest times for submitting Real-Time Market Submissions.

Clause 7.4.15 allows Market Participants to update Real-Time Market Submissions for any Dispatch Interval as long as the update is made within the relevant horizon and before the Gate Closure for the relevant Dispatch Interval.

Real-Time Market Submissions: Timing

7.4.15. Subject to any applicable Real-Time Market Submission Acceptance Horizon and Gate Closure, a Market Participant may submit initial or revised Real-Time Market Submissions for any Dispatch Interval after the current Dispatch Interval.

7.4.16. AEMO may specify a Real-Time Market Submission Acceptance Horizon in a WEM Procedure.

7.4.17. Where a Real-Time Market Submission Acceptance Horizon is specified in a WEM Procedure, AEMO may reject a Real-Time Market Submission for Dispatch Intervals after the Real-Time Market Submission Acceptance Horizon.

7.4.18. The end of a Real-Time Market Submission Acceptance Horizon must not be less than four weeks from the current Dispatch Interval.

Explanatory Note

Clause 7.4.19 provides that a subsequent Real-Time Market Submission will replace an earlier Real-Time Market Submission in respect of any Dispatch Intervals in the earlier Real-Time Market Submission that are also contained in the subsequent Real-Time Market Submission.

7.4.19. A subsequent Real-Time Market Submission made in respect of the same Registered Facility covering the same Dispatch Interval as an earlier Real-Time

Market Submission in accordance with the Real-Time Market Timetable, replaces the earlier Real-Time Market Submission, for, and has effect in relation to, the Dispatch Interval.

7.4.20. Where a subsequent Real-Time Market Submission is made under this section 7.4, a Market Participant must:

(a) specify the reason for the revision in the subsequent Real-Time Market Submission, and

(b) create and maintain a record of the reasons for submitting the subsequent Real-Time Market Submission, including details of any changed circumstances and the impact of those circumstances that gave rise to the subsequent Real-Time Market Submission.

Explanatory Note

Clause 7.4.21 requires a Market Participant to provide reasons in a Real-Time Market Submission for any differences between the parameters specified in the Real-Time Market Submission for maximum and minimum enablement and maximum upwards and downwards ramp rates, and the corresponding parameters as specified in the Registered Facility's Standing Data.

7.4.21. Where a Real-Time Market Submission specifies an Enablement Minimum, Enablement Maximum, Low Breakpoint, High Breakpoint, Maximum Upwards Ramp Rate or Maximum Downwards Ramp Rate, that is different to the Standing Enablement Minimum, Standing Enablement Maximum, Standing Low Breakpoint, Standing High Breakpoint, Standing Maximum Upwards Ramp Rate or Standing Maximum Downwards Ramp Rate value, as applicable, specified in the Standing Data for the Registered Facility, the Market Participant must:

(a) specify the reason for the difference in the Real-Time Market Submission, and

(b) create and maintain a record of the reasons for the differences between the relevant values specified in the Real-Time Market Submission and the corresponding values specified in the Standing Data.

Explanatory Note

Clause 7.4.22 gives the Economic Regulation Authority the power to ask for explanations where there is a change in the parameters in an earlier and subsequent Real-Time Market Submission for the same Dispatch Interval, or with the relevant parameters as specified in Standing Data for the Registered Facility.

7.4.22. Where a Market Participant makes a subsequent Real-Time Market Submission and, in respect to the parameters for Enablement Minimum, Enablement Maximum, Low Breakpoint, High Breakpoint, Maximum Upwards Ramp Rate or Maximum Downwards Ramp Rate:

(a) the value in the Real-Time Market Submission or a subsequent Real-Time Market Submission for the parameter is not the same as the Standing Enablement Minimum, Standing Enablement Maximum, Standing Low

Breakpoint, Standing High Breakpoint, Standing Maximum Upwards Ramp Rate or Standing Maximum Downwards Ramp Rate value, as applicable, in the Standing Data for the Registered Facility; or

(b) a value in a subsequent Real-Time Market Submission for the parameter is not the same as the corresponding value in an earlier Real-Time Market Submission in respect of the same Dispatch Interval,

the Economic Regulation Authority may request the Market Participant to provide further information about the reasons for the revised value.

7.4.23. A Market Participant must respond to a request by the Economic Regulation Authority under clause 7.4.22 by the time specified in the request, which must not be less than one Business Day.

Explanatory Note Clause 7.4.24 allows AEMO to impose a Gate Closure with respect to Real-Time Market Submissions. The Gate Closure will be published on the WEM Website.

7.4.24. AEMO must determine and publish the Gate Closure on the WEM Website. In determining the Gate Closure, AEMO must take into account the extent to which the Gate Closure is, in its reasonable opinion, required to prevent a significant and quantifiable risk to AEMO maintaining Power System Security and Power System Reliability in accordance with Chapter 3.

7.4.25. The Gate Closure determined by AEMO in accordance with clause 7.4.24:

(a) may be as close to zero as practicable; and

(b) must not be more than 15 minutes.

7.4.26. AEMO may, from time to time, but subject to clauses 7.4.24 and 7.4.25, revise the Gate Closure by publishing the revised Gate Closure on the WEM Website and specifying the date from which the revised Gate Closure will take effect.

7.4.27. Where AEMO revises the Gate Closure under clause 7.4.26, AEMO must publish a report on the WEM Website stating:

(a) its reasons for revising the Gate Closure; and

(b) the significant and quantifiable risks to Power System Security and Power System Reliability that exist, requiring the Gate Closure to be revised.

Explanatory Note Clause 7.4.28 allows Market Participants to update a Real-Time Market Submission within Gate Closure for (only) the reasons specified in the clause.

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

(a) for a Semi-Scheduled Facility or Non-Scheduled Facility, to reflect a revision in the Unadjusted Intermittent Generation Forecast; or

(b) for a Registered Facility that has suffered a Forced Outage, to reflect the Registered Facility's Remaining Available Capacity.

7.4.29. AEMO must use the most recently submitted Real-Time Market Submissions in the scheduling and dispatch of Registered Facilities in accordance with this Chapter 7.

> **Explanatory Note**
>
> Clause 7.4.30 gives AEMO the discretion to develop a WEM Procedure describing the circumstances or events that would trigger the requirement for a Market Participant to update a Real-Time Market Submission.

7.4.30. AEMO may document in a WEM Procedure the circumstances requiring a Market Participant to update a Real-Time Market Submission and the frequency of any required updates. In documenting any such WEM Procedure, AEMO must have regard to:

(a) Semi-Scheduled Facility Injection forecasts are likely to be more certain over shorter timeframes; and

(b) the types of events that result in a requirement to update a Real-Time Market Submission.

> **Explanatory Note**
>
> Clauses 7.4.31 to 7.4.41 describes the information that is required to be specified in Real-Time Market Submissions.

Real-Time Market Submissions – Format

7.4.31. AEMO must document in a WEM Procedure the format and methodology to be followed by Market Participants for making Real-Time Market Submissions, including any relevant minimum tranche size for offers and any specific requirements for Registered Facilities that offer Essential System Services and not energy. Market Participants must comply with that documented WEM Procedure when developing and submitting Real-Time Market Submissions.

7.4.32. A Real-Time Market Submission for a Registered Facility must specify:

(a) the Registered Facility;

(b) each Market Service;

(c) each Dispatch Interval covered by the Real-Time Market Submission;

(d) if the Real-Time Market Submission is replacing an earlier Real-Time Market Submission:

i. the reason for the revisions in accordance with clause 7.4.20(a); and

ii. if an Enablement Minimum, Enablement Maximum, Maximum Upwards Ramp Rate or Maximum Downwards Ramp Rate is different to the Standing Enablement Minimum, Standing Enablement Maximum, Standing Maximum Upwards Ramp Rate or Standing Maximum Downwards Ramp Rate value, as applicable, for the parameter specified in the Standing Data for the Registered Facility, the reason for the difference in accordance with clause 7.4.21(a);

(e) the information specified in clauses 7.4.33 to 7.4.35 as applicable; and

(f) any other information specified in the WEM Procedure to be documented by AEMO under clause 7.4.31.

7.4.33. A Real-Time Market Submission for a Registered Facility to supply or consume energy must, in addition to the matters listed in clause 7.4.32, specify, as applicable:

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

(b) the Available Capacity for Injection in MW;

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

(d) the Available Capacity for Withdrawal in MW;

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

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

(g) up to 10 Price-Quantity Pairs where:

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

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

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

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

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

(h) if the Registered Facility is Inflexible.

7.4.34. A Real-Time Market Submission for a Registered Facility to supply Regulation or Contingency Reserve must, in addition to the matters listed in clause 7.4.32, specify:

(a) the total available quantity of Regulation or Contingency Reserve in MW, where this quantity is less than or equal to the total accredited capacity for Regulation or Contingency Reserve for that Dispatch Interval;

(b) the In-Service Capacity for the relevant Frequency Co-optimised Essential System Service;

(c) the Available Capacity for the relevant Frequency Co-optimised Essential System Service;

(d) the Enablement Minimum in MW of the relevant Frequency Co-optimised Essential System Service;

(e) the Low Breakpoint in MW of the relevant Frequency Co-optimised Essential System Service;

(f) the High Breakpoint in MW of the relevant Frequency Co-optimised Essential System Service;

(g) the Enablement Maximum in MW of the relevant Frequency Co-optimised Essential System Service; and

(h) a ranking of Price-Quantity Pairs with MW quantities summing to the maximum available quantity of the Regulation or Contingency Reserve where the prices are to be stated in dollars and whole cents per MW per hour.

7.4.35. A Real-Time Market Submission for a Registered Facility to supply RoCoF Control Service must, in addition to the matters listed in clause 7.4.32, specify:

(a) the maximum available quantity of the RoCoF Control Service in MWs;

(b) the Enablement Minimum in MW of the RoCoF Control Service;

(c) the Low Breakpoint in MW of the RoCoF Control Service;

(d) the High Breakpoint in MW of the RoCoF Control Service;

(e) the Enablement Maximum in MW of the RoCoF Control Service; and

(f) a ranking of Price-Quantity Pairs with MWs quantities summing to the maximum available quantity of the RoCoF Control Service where the prices are to be stated in dollars and whole cents per MWs per hour.

7.4.36. A Market Participant must ensure that Price Quantity Pair prices for energy in Real-Time Submissions are equal to or between the Energy Offer Caps when converted into Loss Factor Adjusted Prices.

Explanatory Note

A Market Participant may include a Dispatch Inflexibility Profile in a Real-Time Market Submission for a Registered Facility where it wants its Registered Facility to be available to be dispatched in real-time as a Fast Start Facility.

7.4.37. A Market Participant may include a Dispatch Inflexibility Profile in a Real-Time Market Submission for a Fast Start Facility in accordance with clause 7.4.38 or a Demand Side Programme in accordance with clause 7.4.39.

7.4.38. A Dispatch Inflexibility Profile for a Fast Start Facility must contain the following parameters to indicate its MW capacity and time related Inflexibilities at the time it is included in the Real-Time Market Submission:

(a) the time, T1, in minutes, following the receipt of a Dispatch Instruction for the Registered Facility to start varying its level of Injection or Withdrawal from 0 MW in accordance with the Dispatch Instruction;

(b) the time, T2, in minutes, that the Registered Facility requires after T1 (as specified in clause 7.4.38(a)) to reach a specified minimum level of Injection or Withdrawal;

(c) the time, T3, in minutes, that the Registered Facility requires to be operated at or above its minimum level of Injection or Withdrawal before the Registered Facility can be safely and securely reduced below that level; and

(d) the time, T4, in minutes, following the receipt of a Dispatch Instruction to reduce its Injection or Withdrawal from the minimum level specified in clause 7.4.38(b) to zero, that the Registered Facility requires to fully comply with the Dispatch Instruction.

Explanatory Note

The minimum level of reduction of Withdrawal referred to in clause 7.4.39(d) is not the same as the RCOQ for the Demand Side Programme, or the Minimum Demand of Associated Loads. Instead, it is the lowest quantity of movement that the Demand Side Programme can activate.

7.4.39. A Dispatch Inflexibility Profile for a Demand Side Programme must contain the following parameters to indicate its MW capacity and time related Inflexibilities at the time it is included in the Real-Time Market Submission:

(a) the time, T1, in minutes, following the receipt of a Dispatch Instruction for the Demand Side Programme to start reducing its Withdrawal in accordance with the Dispatch Instruction;

(b) the time, T2, in minutes, that the Demand Side Programme requires after T1 (as specified in clause 7.4.39(a)) to reach a specified minimum level of reduction in Withdrawal;

(c) the time, T3, in minutes, that the Demand Side Programme requires to be operated at or above its minimum level of reduction in Withdrawal before the Demand Side Programme can safely and securely increase its Withdrawal; and

(d) the time, T4, in minutes, following the receipt of a Dispatch Instruction to stop reducing its Withdrawal (from the minimum level of reduction of

Withdrawal specified in clause 7.4.39(b)) that the Demand Side Programme requires to fully comply with the Dispatch Instruction.

7.4.40. For a Fast Start Facility:

(a) T1, T2, T3 and T4 must all be equal to or greater than zero;

(b) the sum of (T1 + T2) must be less than or equal to 30 minutes; and

(c) the sum of (T1 + T2 + T3 + T4) must be less than 60 minutes.

7.4.41. For a Demand Side Programme:

(a) T1, T2, T3 and T4 must all be equal to or greater than zero;

(b) the sum of (T1 + T2) must be less than or equal to 120 minutes; and

(c) the sum of (T3 + T4) must be less than or equal to 120 minutes.

Explanatory Note

Clauses 7.4.42 to 7.4.46 deal with the construction of Real-Time Market Submissions. Each Registered Facility will be able to make Real-Time Market Offers for Injection and Real-Time Market Bids for Withdrawal. Unlike under the current WEM Rules, Scheduled Generators will need to make Real-Time Market Bids for Withdrawal (if it is metered by the same meter), and be held to compliance with the relevant Dispatch Instruction for it.

Registered Facilities will still be able to operate within their applicable Tolerance Range or Facility Tolerance Range. For example, a Facility with a Dispatch Instruction of 0 MW could make a Withdrawal up to the Tolerance Range or Facility Tolerance Range applicable to the Facility without being in breach of the relevant WEM Rules.

Real-Time Market Submissions – Construction

7.4.42. A Market Participant must ensure that a Real-Time Market Submission for a Registered Facility for energy represents sent-out quantities, and specifies Price-Quantity Pairs for all Injection and Withdrawal, at the network connection point or Electrical Location, as applicable, for the Registered Facility where:

(a) the negative quantities in Price-Quantity Pairs for energy represent bids to Withdraw electricity at the network connection point for the Registered Facility; and

(b) the positive quantities in Price-Quantity Pairs for energy represent offers to Inject electricity at the network connection point or Electrical Location, as applicable, for the Registered Facility.

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

(a) apply at the network connection 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

The costs referred to in clause 7.4.44(a) are the Registered Facility's start-up costs.

7.4.44. A Market Participant may, in respect of a Real-Time Market Submission for a Registered Facility, account for:

(a) where the Real-Time Market Offer is for energy, the recovery of the costs incurred in changing some or all of a Registered Facility's sent out capacity from Available Capacity to In-Service Capacity; and

(b) where the Real-Time Market Offer is for an Essential System Service, expected Enablement Losses, calculated in accordance with clause 7.4.46, for the Registered Facility.

7.4.45. Where a Real-Time Market Offer in a Real-Time Market Submission for a Registered Facility includes:

(a) costs in accordance with clause 7.4.44(a); or

(b) Enablement Losses in accordance with clause 7.4.44(b),

the Market Participant must create and maintain a record of the calculation of those costs or Enablement Losses (as relevant) and the assumptions the Market Participant made in applying those costs or Enablement Losses over the particular Dispatch Intervals and the offer quantities in the relevant Real-Time Market Submission.

Explanatory Note

The interaction between minimum enablement quantities and Real-Time Market Offers to supply Essential System Services is to be specified in the WEM Rules as commitment decisions are made by market participants.

7.4.46. The Enablement Loss for a Registered Facility in a Dispatch Interval is:

$$EL = Max(0, LF*EM * (LFAOP – MCP))$$

Where:

EM is the Enablement Minimum;

LF is the Loss Factor for the Registered Facility.

LFAOP is the Loss Factor Adjusted Price in the Price-Quantity Pair for energy in the Real-Time Market Submission which corresponds to the Enablement Minimum Quantity; and

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

Explanatory Note

Clauses 7.4.47 to 7.4.49 deal with the validation process of Real-Time Market Submissions. Significantly, AEMO will reject the whole Real-Time Market Submission for one 'non-confirming / non-compliant' record, rather than accept a Real-Time Market Submission in part.

Real-Time Market Submissions - Validation of Dispatch Bids and Offers

7.4.47. On receipt of a Real-Time Market Submission in accordance with this section 7.4, AEMO must immediately:

(a) acknowledge receipt of the Real-Time Market Submission to the submitting Market Participant; and

(b) validate the Real-Time Market Submission by verifying that it complies with the following requirements, as applicable

i. the content requirements in clauses 7.4.32, 7.4.33, 7.4.34, 7.4.35, 7.4.38, 7.4.39, 7.4.40, 7.4.41, 7.4.43(b) and 7.4.43(c);

ii. the pricing requirements in clauses 7.4.8, 7.4.9, 7.4.10(b) and 7.4.11;

iii. the quantity requirements in clause 7.4.13; and

iv. the timing requirements in clauses 7.4.17 and 7.4.24.

7.4.48. Where AEMO:

(a) validates the Real-Time Market Submission in accordance with clause 7.4.47(b), AEMO must:

i. accept the Real-Time Market Submission and notify the submitting Market Participant that it has been accepted, and

ii. make available to the Market Participant the data contained in the Real-Time Market Submission as it will be used by AEMO in the Central Dispatch process, including Loss Factor Adjusted Prices and non-Loss Factor Adjusted Prices; or

(b) determines that the Real-Time Market Submission, or any part of it, does not comply with the requirements referred to in clause 7.4.47(b), as applicable, AEMO must:

i. reject the Real-Time Market Submission and notify the submitting Market Participant that it has been rejected, and

ii. provide details of the reasons the Real-Time Market Submission was rejected.

7.4.49. It is the responsibility of each Market Participant to check that the data contained in its Real-Time Market Submission as it will be used by AEMO in the Central Dispatch process is correct.

Explanatory Note

Clauses 7.4.50 to 7.4.53 deal with processing Real-Time Market Submissions, including the arrangements with respect to Loss Factor adjusted prices in Real-Time Market Submissions and the ability for AEMO to make adjustments to certain inputs for use in the Dispatch Algorithm.

Real-Time Market Submissions: Processing

7.4.50. AEMO must convert the prices in a Real-Time Market Submission for energy into Loss Factor Adjusted Prices, and must use those Loss Factor Adjusted Prices in the Dispatch Algorithm.

7.4.51. Where a Loss Factor Adjusted Price in accordance with clause 7.4.50 is outside the relevant Energy Price Cap, AEMO must use the relevant Energy Price Cap for the Real-Time Market Submission in the Dispatch Algorithm.

7.4.52. Where AEMO determines, based on the information available to it at the relevant time, that the capability of a Registered Facility to provide an Essential System Service differs from the quantities and technical parameters specified in the most recently submitted Real-Time Market Submission for the Registered Facility for the relevant Dispatch Interval, AEMO may adjust the following inputs to reflect the information available to it at that time, for use in the Dispatch Algorithm:

(a) Enablement Minimum;

(b) Enablement Maximum;

(c) Low Breakpoint; and

(d) High Breakpoint.

7.4.53. AEMO must document in a WEM Procedure:

(a) the information and processes, including the application of any formulae, AEMO will use in making a determination under clause 7.4.52; and

(b) the circumstances in which AEMO will adjust the inputs specified in clause 7.4.52.

Explanatory Note Clauses 7.4.54 to 7.4.62 deal with Standing Real-Time Market Submissions, which will give Market Participants the flexibility to make 'set and forget' submissions.

Real-Time Market Submissions: Standing Submissions

7.4.54. Market Participants may, at any time, submit a Standing Real-Time Market Submission for a Registered Facility.

7.4.55. A Standing Real-Time Market Submission must comply with the following requirements for the energy or Market Service, as applicable:

(a) content requirements in clauses 7.4.32, 7.4.33, 7.4.34, 7.4.35, 7.4.38, 7.4.39, 7.4.40, 7.4.41, 7.4.42, 7.4.43, 7.44 and 7.4.45;

(b) pricing requirements in clauses 7.4.8, 7.4.9, 7.4.10(b) and 7.4.11; and

(c) quantity requirements in clauses 7.4.12(a) and 7.4.13,

and must also specify:

(e) the Dispatch Interval from which the Standing Real-Time Market Submission will take effect; and

(f) which day of the week the Standing Real-Time Market Submission applies.

7.4.56. A subsequent Real-Time Market Submission or Standing Real-Time Market Submission will override an earlier Standing Real-Time Market Submission.

7.4.57. Unless a Standing Real-Time Market Submission is replaced by a subsequent Real-Time Market Submission or Standing Real-Time Market Submission, the Standing Real-Time Market Submission will apply for the same Dispatch Interval on all future days of the same type, which must be a type of day specified in the WEM Procedure referred to in clause 7.4.62(b), after the Dispatch Interval from which it takes effect.

7.4.58. On receipt of a Standing Real-Time Market Submission, AEMO must, without delay:

(a) acknowledge receipt of the Standing Real-Time Market Submission to the submitting Market Participant; and

(b) validate the Standing Real-Time Market Submission by verifying that it complies with the following requirements, as applicable:

i. the content requirements in clauses 7.4.32, 7.4.33, 7.4.34, 7.4.35, 7.4.38, 7.4.39, 7.4.40, 7.4.41, 7.4.43(b) and 7.4.43(c);

ii. the pricing requirements in clauses 7.4.8, 7.4.9, 7.4.10(b) and 7.4.11; and

iii. the quantity requirements in clause 7.4.13.

7.4.59. Where AEMO:

(a) validates the Standing Real-Time Market Submission in accordance with clause 7.4.58(b), AEMO must:

i. accept the Standing Real-Time Market Submission and notify the submitting Market Participant that it has been accepted, and

ii. make available to the Market Participant the data contained in the Standing Real-Time Market Submission as it will be used by AEMO in the Central Dispatch process; or

(b) determines that the Standing Real-Time Market Submission, or any part of it, does not comply with the requirements referred to in clause 7.4.58(b), as applicable, AEMO must:

i. reject the Standing Real-Time Market Submission and notify the submitting Market Participant that it has been rejected, and

ii. provide details of the reasons the Standing Real-Time Market Submission was rejected.

7.4.60. When AEMO uses a Standing Real-Time Market Submission in the Dispatch Algorithm, AEMO must first convert the prices in a Standing Real-Time Market Submission for energy into Loss Factor Adjusted Prices, and must use those Loss Factor Adjusted Prices in the Dispatch Algorithm.

7.4.61. It is the responsibility of each Market Participant to check that the data contained in its Standing Real-Time Market Submission as it will be used by AEMO in the Central Dispatch process is correct.

7.4.62. AEMO must document in a WEM Procedure:

(a) the processes it must follow when:

i. acknowledging receipt of a Real-Time Market Submission under clause 7.4.47(a) or a Standing Real-Time Market Submission under clause 7.4.58(a);

ii. validating a Real-Time Market Submission in accordance with clause 7.4.47(b) or a Standing Real-Time Market Submission in accordance with clause 7.4.58(b); and

iii. accepting or rejecting a Real-Time Market Submission in accordance with clause 7.4.48 or a Standing Real-Time Market Submission in accordance with clause 7.4.59; and

(b) the types of day that can be nominated in a Standing Real-Time Market Submission, which must include at least one type for each Business Day and Non-Business Day of each week.

~~7.5. [Blank]~~

> **Explanatory Note**
>
> Clauses 7.5.1 to 7.5.4 deal with the Dispatch Algorithm to be used by AEMO for the scheduling and dispatch of energy and Essential System Services.
>
> This section ties into the Constraints Framework, and deals with AEMO's selection of Constraint Equations and Constraint Sets for inclusion in the Dispatch Algorithm, but not the formulation of constraints, unless there is no appropriate Constraint Equation already in the Constraints Library. AEMO's obligations with respect to formulating Constraint Equations are set out in section 2.27A.

7.5. Dispatch Algorithm

Network Constraints

7.5.1. For each Dispatch Interval:

(a) AEMO must reasonably determine, based on the latest information available to it, whether a Network Constraint will affect, or be likely to affect, Dispatch in the Dispatch Interval; and

(b) for each Network Constraint identified by AEMO under clause 7.5.1(a), AEMO must select one or more Constraint Equations or Constraint Sets to use in the Dispatch Algorithm for the Dispatch Interval to address the Network Constraints identified.

Explanatory Note

Clause 7.5.2 describes the circumstances in which AEMO is not required to use a Fully Co-optimised Network Constraint Equation in the Dispatch Algorithm.

7.5.2. Without limiting AEMO's obligations under clause 7.5.1, AEMO must use a Fully Co-Optimised Network Constraint Equation in the Dispatch Algorithm for each Dispatch Interval unless, in AEMO's reasonable opinion:

(a) a Fully Co-Optimised Network Constraint Equation for the Network Constraint that affects, or is likely to affect, dispatch in the Dispatch Interval is not appropriate;

(b) an Alternative Network Constraint Equation is available to better address the Network Constraint that affects, or is likely to affect, dispatch in the Dispatch Interval; and

(c) if the Alternate Network Constraint Equation is used, AEMO will continue to meet its obligations under section 7.2,

in which case, AEMO may use the Alternative Network Constraint Equation in the Dispatch Algorithm for the expected duration of the relevant Network Constraint.

7.5.3. If the Constraints Library does not contain a Constraint Equation or Constraint Set that accurately reflects the Network Constraint identified under clause 7.5.2, then without limiting AEMO's obligations to formulate Constraint Equations under section 2.27A, AEMO must formulate a new Constraint Equation or Constraint Set for use in the Dispatch Algorithm for the Network Constraint and update the Constraints Library in accordance with clause 2.27A.7.

7.5.4. AEMO must document in a WEM Procedure:

(a) the process to be used by AEMO for selecting, applying, invoking and revoking Constraint Equations or Constraint Sets in response to Network Constraints for use in the Dispatch Algorithm; and

(b) the circumstances in which AEMO will use Fully Co-optimised Network Constraint Equations and Alternative Network Constraint Equations in the Dispatch Algorithm.

Explanatory Note

Clauses 7.5.5 to 7.5.8 relate to the requirements for AEMO to include Constraint Equations that involve Essential System Services in the Dispatch Algorithm.

Essential System Services Constraints

7.5.5. AEMO must include Constraint Equations for the dispatch of Essential System Services in the Dispatch Algorithm.

> **Explanatory Note**
>
> Clause 7.5.6 is intended to apply to Regulation Raise, Regulation Lower and Contingency Reserve Lower. The requirements for these services will be set outside the Dispatch Algorithm, and are necessary inputs to determining whether security standards are being met, and feeding into the RoCoF Control Service requirement.

7.5.6. Where the WEM Procedure referred to in clause 3.10.3 provides that the quantity of a Frequency Co-optimised Essential System Service is to be determined outside the Central Dispatch process, AEMO must include Constraint Equations in the Dispatch Algorithm that, subject to clause 7.4.5(b), ensure the exogenously determined quantity of that Frequency Co-optimised Essential System Service is procured from the Real-Time Market.

> **Explanatory Note**
>
> Clause 7.5.7 is intended to apply to Contingency Reserve Raise and RoCoF Control Service. The requirements for these services will be set based on the lowest cost combination of facilities, including limiting the dispatch of facilities to reduce the requirement.

7.5.7. Where the WEM Procedure referred to in clause 3.10.3 provides that the quantity of a Frequency Co-optimised Essential System Service is dependent on factors within the Central Dispatch process, AEMO must include Constraint Equations in the Dispatch Algorithm that, subject to clauses 3.12.2 and 7.2.5(e), ensure that a sufficient quantity of that Frequency Co-optimised Essential System Service is procured to meet the Essential System Service Standards.

> **Explanatory Note**
>
> Clause 7.5.8 provides a head of power for AEMO to undertake pre-processing so that the Dispatch Algorithm will only include Real-Time Market Offers for the supply of Frequency Co-optimised Essential System Services for Registered Facilities operating between Enablement Limits.

7.5.8. Where a Real-Time Market Submission for a Registered Facility specifies non-zero quantities in its Price-Quantity Pairs for any Frequency Co-optimised Essential System Service, then:

(a) if the Registered Facility is operating between its Enablement Limits at the beginning of a Dispatch Interval or a Pre-Dispatch Interval, AEMO may, in accordance with the WEM Procedure referred to in clause 7.2.6, include Constraint Equations in the Dispatch Algorithm to ensure the Energy Dispatch Target for that Registered Facility will not be less than the Minimum Enablement Limit, and not more than the Maximum Enablement Limit; or

(b) if the Registered Facility is not operating between its Enablement Limits at the beginning of a Dispatch Interval or a Pre-Dispatch Interval, AEMO may, in accordance with the WEM Procedure referred to in clause 7.2.6, exclude the Real-Time Market Offers to provide any Frequency Co-Optimised Essential System Service specified in the Real-Time Market Submission for the Registered Facility from the Dispatch Algorithm.

Explanatory Note

Clause 7.5.9 relates to the requirements for AEMO to include Constraint Equations that involve Electric Storage Resources in the Dispatch Algorithm.

Electric Storage Constraints will allow more efficient use of storage resources by including the relevant constraints in the Dispatch Algorithm, instead of requiring the relevant Market Participants to frequently adjust their Real-Time Market Offers for their storage resources. This 'opt-in' process is aimed at pure storage resources.

Storage Constraints

7.5.9. For a Scheduled Facility that comprises only Electric Storage Resources, AEMO may include Constraint Equations relating to restrictions on the simultaneous dispatch of energy and Frequency Co-optimised Essential System Services, to ensure that Dispatch Targets and Essential System Service Enablement Quantities for the Scheduled Facility are able to be achieved based on the Charge Level, maximum storage capacity, maximum Injection capability and maximum Withdrawal capability for the Scheduled Facility.

Explanatory Note

The registration chapter will include a clause that allows Market Participants to designate whether they want Energy Storage Constraints (to be developed by AEMO) to apply to their facility.

7.5.10. For Registered Facilities which the Market Participant notified AEMO under clause [clause reference in the Registration, Participation and Storage Amending Rules] that operation of the Registered Facility is subject to Energy Storage Constraints, AEMO must include Constraint Equations relating to restrictions on the simultaneous dispatch of energy and Frequency Co-optimised Essential System Service, to ensure that Dispatch Targets and Essential System Service Enablement Quantities for the Registered Facility are able to be achieved based on the Charge Level, maximum storage capacity, maximum Injection capability and maximum Withdrawal capability for the Registered Facility. To avoid doubt, where the Market Participant notified AEMO under clause [clause reference in the Registration, Participation and Storage Amending Rules] that operation of the Registered Facility is no longer subject to Energy Storage Constraints, this clause will not apply.

Explanatory Note

Clauses 7.5.11 to 7.5.14 deal with the determination of dynamic parameters by AEMO for use in dispatch.

Dynamic parameters

7.5.11. AEMO must determine the Contingency Raise Factor and Contingency Lower Factor for each Dispatch Interval and Pre-Dispatch Interval of each Market Schedule and in making a determination AEMO must have regard to:

(a) System Inertia;

(b) Load Relief;

(c) Droop Response expected from synchronised Registered Facilities;

(d) the size of the Largest Credible Supply Contingency;

(e) the size of the Largest Credible Load Contingency; and

(f) any other relevant factors specified in the WEM Procedure referred to in clause 7.2.6.

7.5.12. AEMO must determine the RoCoF Control Requirement and the Minimum RoCoF Control Requirement for each Dispatch Interval and Pre-Dispatch Interval of each Market Schedule and in making a determination AEMO must have regard to:

(a) Facility Performance Factors;

(b) System Inertia;

(c) the size of the Largest Credible Supply Contingency;

(d) Contingency Raise Factors;

(e) Contingency Lower Factors; and

(f) any other relevant factors specified in the WEM Procedure referred to in clause 7.2.6.

7.5.13. AEMO must determine a Facility Performance Factor for each Registered Facility that is accredited, in accordance with section 2.34A, to provide an Essential System Service for each Dispatch Interval and Pre-Dispatch Interval of each Market Schedule and in making a determination AEMO must have regard to:

(a) Speed Factors;

(b) System Inertia;

(c) the size of the Largest Credible Supply Contingency;

(d) the size of the Largest Credible Load Contingency; and

(e) any other relevant factors specified in the WEM Procedure referred to in clause 7.2.6.

7.5.14. AEMO must determine the RoCoF Upper Limit for each Dispatch Interval, and must publish the RoCoF Upper Limit:

(a) where the RoCoF Upper Limit is set in advance of the Dispatch Interval, prior to the start of the Dispatch Interval; or

(b) where the RoCoF Upper Limit is determined by the Dispatch Algorithm, in real-time as part of the Dispatch Algorithm for the Dispatch Interval.

Explanatory Note

The Dispatch Process in the current WEM Rules is to be deleted and replaced with the new Central Dispatch process in sections 7.6 and 7.7 below.

~~Dispatch Process~~

~~7.6. The Dispatch Criteria~~

~~7.6.1. Subject to clause 7.6.1B, when scheduling and issuing Dispatch Instructions or Dispatch Orders to Registered Facilities, System Management must seek to meet the following criteria, in descending order of priority:~~

~~(a) to enable operation of the SWIS within the Technical Envelope parameters appropriate for the applicable SWIS Operating State;~~

~~(b) to minimise involuntary load shedding on the SWIS; and~~

~~(c) to maintain Ancillary Services to meet the Ancillary Service standards appropriate for the applicable SWIS Operating State.~~

~~7.6.1A. System Management must give priority to the dispatch of a Registered Facility under a Network Control Service Contract over the dispatch of a Registered Facility under any other arrangement, if the Network Control Service provided under that contract would assist System Management to meet the Dispatch Criteria.~~

~~7.6.1B. In seeking to meet the Dispatch Criteria, System Management may issue an Operating Instruction in priority to any Dispatch Instruction provided the Operating Instruction is also in accordance with:~~

~~(a) a Network Control Service Contract;~~

~~(b) an Ancillary Service Contract;~~

~~(c) these Market Rules in connection with a Test; or~~

~~(d) a Supplementary Capacity Contract.~~

~~7.6.1C. In seeking to meet the Dispatch Criteria System Management must, subject to clause 7.6.1D, issue Dispatch Instructions in the following descending order of priority:~~

~~(a) Dispatch Instructions to Balancing Facilities in the order and, subject to clause 7.7.6B, for the quantities that appear in the BMO, taking into account Ramp Rate Limits for that Facility;~~

~~(b) a Dispatch Instruction to a Balancing Facility Out of Merit but only to the next Facility or Facilities, and associated quantity in the BMO that System Management reasonably considers best meets the Dispatch Criteria, taking into account the associated Ramp Rate Limit for that Facility;~~

~~(c) a Dispatch Instruction to any Balancing Facility Out of Merit, taking into account the Ramp Rate Limit and non-ramp rate Standing Data limitations relevant to that Facility and any other relevant information available to System Management;~~

(d) ~~subject to clauses 7.6.1E and 7.6.1F, a Dispatch Instruction in accordance with the Non-Balancing Dispatch Merit Order to a Demand Side Programme which holds Capacity Credits, taking into account the DSP Ramp Rate Limit; and~~

(e) ~~subject to clause 7.6.1E, a Dispatch Instruction in accordance with the Non-Balancing Dispatch Merit Order to a Demand Side Programme (whether or not it holds Capacity Credits) taking into account the DSP Ramp Rate Limit and non-ramp rate Standing Data limitations relevant to that Facility and any other relevant information available to System Management.~~

~~7.6.1D. System Management may only issue Dispatch Instructions under:~~

(a) ~~clause 7.6.1C(b) in priority to clause 7.6.1C(a);~~

(b) ~~clause 7.6.1C(c) in priority to clause 7.6.1C(b);~~

(c) ~~clause 7.6.1C(d) in priority to clause 7.6.1C(c); and~~

(cA) ~~clause 7.6.1C(e) in priority to clause 7.6.1C(d),~~

~~where System Management considers, on reasonable grounds, that it needs to do so in order to:~~

(d) ~~ensure a High Risk Operating State or an Emergency Operating State is avoided; or~~

(e) ~~if the SWIS is in a High Risk Operating State or an Emergency Operating State, enable the SWIS to be returned to a Normal Operating State.~~

~~7.6.1E. If System Management issues a Dispatch Instruction to a Demand Side Programme under clause 7.6.1C(d) or (e), it must make best endeavours to do so in a way which, when considered across all Dispatch Instructions to all Demand Side Programmes, maximises the extent to which the resulting Non-Balancing Facility Dispatch Instruction Payments are zero under clause 6.17.6C, in preference to causing any Tranche 2 DSM Dispatch Payments or Tranche 3 DSM Dispatch Payments to become payable.~~

~~7.6.1F. System Management must not issue a Dispatch Instruction to a Demand Side Programme under clause 7.6.1C(d) unless it has issued a Dispatch Advisory under clause 7.11.5(k) more than two hours before the time the Dispatch Instruction will come into effect.~~

~~7.6.1G. A Dispatch Advisory can satisfy the requirement in clause 7.6.1F whether or not the Demand Side Programme in question was named in the Dispatch Advisory.~~

~~7.6.1H. If:~~

(a) ~~System Management has issued a Dispatch Instruction to a Facility under clause 7.6.1C(d) or 7.6.1C(e); and~~

~~(b) System Management considers that dispatch of the Facility is, or will be, no longer required to meet the Dispatch Criteria, having regard to clauses 7.6.1A to 7.6.1E,~~

~~then System Management must issue a Dispatch Instruction to the Facility specifying the time from which the Facility is no longer required to restrict its consumption.~~

~~7.6.2. For the purposes of clauses 7.6.1 and 7.6.1C, the Balancing Portfolio is to be treated as a Balancing Facility but the dispatch of any Facility within the Balancing Portfolio is to be under the Dispatch Plan or a Dispatch Order in accordance with clause 7.6A, which is deemed to meet the requirements to issue a Dispatch Instruction in respect of the Balancing Portfolio.~~

~~7.6.2A. Where the Dispatch Criteria requires System Management to alter the Dispatch Plan of Synergy, subject to the limitations imposed by this clause 7.6, System Management must employ reasonable endeavours to minimise the change in the Dispatch Plan and to have regard for the merit order of Synergy Facilities in the Balancing Portfolio.~~

~~7.6.3. [Blank]~~

~~7.6.4. [Blank]~~

~~7.6.5. [Blank]~~

~~7.6.6. [Blank]~~

~~7.6.7. [Blank]~~

~~7.6.8. [Blank]~~

~~7.6.9. [Blank]~~

~~7.6.10. If a Power System Operation Procedure is published under clause 7.6.10A, then a Market Participant who has been assigned DSM Capacity Credits must, in the time and manner specified in the Power System Operation Procedure, provide System Management with, for each Trading Interval—~~

~~(a) the then current consumption, in MW, of each Associated Load of the Demand Side Programme; and~~

~~(b) the then current consumption, in MW, of the Demand Side Programme, which must equal the sum of the consumption of all Associated Loads of that Demand Side Programme provided in clause 7.6.10(a).~~

~~7.6.10A. System Management must develop a Power System Operation Procedure documenting the manner and time in which the obligation in clause 7.6.10 is to be complied with, including how consumption is to be measured or estimated.~~

~~7.6.11. Where AEMO has entered into Supplementary Capacity Contracts, AEMO (in its capacity as System Management) may, by issuing an Operating Instruction, call upon the relevant resource to provide services under any Supplementary Capacity Contract in accordance with the terms of the contract.~~

~~7.6.12. System Management may give a direction to a Market Participant (other than Synergy) in respect of a Scheduled Generator or Non-Scheduled Generator registered by the Market Participant with regard to the reactive power output of that Facility in accordance with any power factor required under the Technical Rules applying to the relevant Network.~~

~~7.6.13. System Management must document in a Power System Operation Procedure the procedure to be followed when scheduling and issuing Operating Instructions to dispatch Registered Facilities covered by any Ancillary Service Contract in a form sufficient for audits and investigations under these Market Rules.~~

~~7.6A. Scheduling and Dispatch of Stand Alone Facilities (for certain Ancillary Services) and the Balancing Portfolio~~

~~7.6A.1. Subject to System Management's obligations under section 7.6, this section 7.6A describes the rules governing the relationship between System Management and Synergy for the purpose of scheduling and dispatching the Stand Alone Facilities for Ancillary Services and for scheduling and dispatching Facilities in the Balancing Portfolio generally.~~

~~7.6A.2. With respect to the scheduling of Stand Alone Facilities for Ancillary Services and the scheduling of Facilities in the Balancing Portfolio generally:~~

~~(a) at least once every month, Synergy must provide to System Management the following information in regard to the subsequent month:~~

~~i. a plant schedule describing the merit order in which the Facilities in the Balancing Portfolio are to be called upon and any restrictions on the operations of such Facilities;~~

~~ii. a plan for which fuels will be used in each Facility in the Balancing Portfolio and guidance as to how that plan might be varied depending on circumstances;~~

~~iii. a description as to how Ancillary Services are to be provided from Facilities in the Balancing Portfolio; and~~

~~iv. a description as to how Ancillary Services are to be provided from the Stand Alone Facilities,~~

~~where the format and time resolution of this data is to be described in a procedure;~~

~~(b) System Management must provide to Synergy by 8:30 AM on the Scheduling Day associated with a Trading Day a forecast of total system~~

~~demand for the Trading Day where the format and time resolution of this data is to be described in a procedure;~~

~~(c) System Management must provide to Synergy by 4:00 PM on the Scheduling Day associated with a Trading Day:~~

~~i. [Blank]~~

~~ii. the Dispatch Plan for each Facility for the Trading Day; and~~

~~iii. a forecast of the detailed Ancillary Services required from each Facility in the Balancing Portfolio and Ancillary Services from each Stand Alone Facility,~~

~~where the format and time resolution of this data is to be described in a procedure;~~

~~(d) System Management must consult with Synergy in developing the information described in clause 7.6A.2(c), and Synergy must provide System Management with any information required by System Management, in accordance with a procedure to support the preparation of the information in clause 7.6A.2(c). In the event of any failure by Synergy to provide information required by System Management in a timely fashion then System Management may use its reasonable judgement to substitute its own information;~~

~~(e) [Blank]~~

~~(f) if, after 4:00 PM on the Scheduling Day but prior to the start of a Trading Interval on the corresponding Trading Day, System Management becomes aware of a change in conditions which will require a significant change in the Dispatch Plan, then it may make such change but must notify Synergy of such change; and~~

~~(g) Synergy must notify System Management as soon as practicable if it becomes aware that it is unable to comply with a Dispatch Plan, providing reasons as to why it cannot comply.~~

~~7.6A.3. With respect to the dispatch of Stand Alone Facilities for the purposes of Ancillary Services other than LFAS but including Backup LFAS Enablement, and the dispatch of Facilities in the Balancing Portfolio generally, during a Trading Day:~~

~~(a) System Management may issue an Operating Instruction for Stand Alone Facilities, and instruct Facilities in the Balancing Portfolio to deviate from the Dispatch Plan, or to change their commitment or output, in accordance with the Dispatch Criteria or in response to System Management's powers under a High Risk Operating State or an Emergency Operating State;~~

~~(b) System Management must provide adequate notice to Synergy, based on Standing Data, before a Facility in the Balancing Portfolio is required to respond to an instruction given under clause 7.6A.3(a); and~~

~~(c) Synergy must notify System Management as soon as practicable if Synergy becomes aware that it is unable to comply with an instruction given under clause 7.6A.3(a).~~

~~7.6A.4. With respect to the dispatch compliance of Synergy for Facilities in the Balancing Portfolio:~~

~~(a) System Management may deem Synergy to be in non-compliance for a Trading Interval if Synergy fails to comply with the Dispatch Plan, its obligations to provide Ancillary Services, or an instruction given under clause 7.6A.3(a), to an extent that could endanger Power System Security;~~

~~(b) In determining whether or not to deem Synergy to be in non-compliance, System Management must give due regard to any reasonable mitigating circumstances of which Synergy has notified it in accordance with clause 7.6A.3(c);~~

~~(c) In determining whether or not to deem Synergy to be in non-compliance, System Management may only consider a deviation by an individual Synergy Facility from an output level specified in any instruction from System Management to be in non-compliance if the deviation at any time exceeds 10 MW; and~~

~~(d) In the event that System Management deems Synergy to be in non-compliance for a Trading Interval then System Management must determine a single MWh quantity describing the total non-compliance of Synergy for that Trading Interval.~~

~~7.6A.5. The following provisions apply with respect to administration and reporting:~~

~~(a) Representatives of System Management and Synergy must, unless both parties agree otherwise, meet at least once per month to review the procedures operating under this section 7.6A. The minutes of these meetings must be recorded by System Management.~~

~~(b) At the meetings described in clause 7.6A.5(a), System Management and Synergy must use best endeavours to address any issues arising from the application of the procedures operating under this section 7.6A. Where agreement cannot be reached either party may seek arbitration by the Economic Regulation Authority.~~

~~(c) System Management must report to the Economic Regulation Authority any instance where it believes that Synergy has failed to meet its obligations under this section 7.6A.~~

~~(d) Synergy may report to the Economic Regulation Authority any instance where it believes that System Management has failed to meet its obligations under this section 7.6A.~~

~~(e) Upon request by the Economic Regulation Authority, Synergy and System Management must make available to the Economic Regulation Authority,~~

~~records created because of the operation of this section 7.6A and procedures required by this section 7.6A.~~

~~7.6A.6. Synergy and System Management must retain all records, including meeting minutes, created because of the operation of this clause 7.6A and procedures required by this clause 7.6A.~~

~~7.6A.7. Subject to clause 7.6A.8, System Management must document the procedures System Management and Synergy must follow to comply with this section 7.6A, including the process to follow in developing the confidential procedure described in clause 7.6A.8, in a Power System Operation Procedure.~~

~~7.6A.8. Any procedure created or data exchanged in accordance with this section 7.6A which is commercially sensitive information of Synergy must not be included in the Power System Operation Procedure specified in clause 7.6A.7. Instead, such information must be included in a confidential procedure developed by System Management in consultation with Synergy.~~

~~7.6A.9. [Blank]~~

~~7.6A.10. AEMO may only decline to approve the confidential procedure, or an amendment to that procedure, if that document is inconsistent with the Market Rules or the market objectives or if it contains material which, in the reasonable view of AEMO, should be in the Power System Operation Procedure specified in clause 7.6A.7.~~

~~7.7. Dispatch Instructions~~

~~7.7.1. A Dispatch Instruction is an instruction issued by System Management to a Market Participant, other than Synergy in respect of its Balancing Portfolio, directing that the Market Participant vary the output or consumption of one of its Registered Facilities.~~

~~7.7.2. Each Dispatch Instruction under clause 7.6.1C(c) or 7.6.1C(e) must:~~

~~(a) be consistent with the latest data described in clause 7.1.1 available to System Management at the time the Dispatch Instruction is determined;~~

~~(b) be applicable to a specific Registered Facility; and~~

~~(c) be issued at a time that takes into account the Standing Data minimum response time for the Registered Facility.~~

~~7.7.3. Each Dispatch Instruction must contain the following information:~~

~~(a) details of the Registered Facility to which the Dispatch Instruction relates;~~

~~(b) the time the Dispatch Instruction was issued;~~

~~(c) the required level of sent out generation or consumption which may be any one of the following:~~

~~i. a target MW output;~~

~~ii. for a Non-Scheduled Generator, that it no longer needs to restrict its output;~~

~~iii. for a Demand Side Programme, a required decrease in consumption, in MW, measured as a decrease from the Facility's Relevant Demand; or~~

~~iv. for a Demand Side Programme, that it no longer needs to restrict its consumption.~~

~~(d) the ramp rate to maintain until the required level of sent out generation or consumption is reached, which (subject to clause 7.7.3B) must not exceed any applicable Ramp Rate Limit (and for a Demand Side Programme, must not exceed the Applicable DSP Ramp Rate Limit); and~~

~~(e) the time at which the ramp rate specified in clause 7.7.3(d) is required to commence.~~

~~7.7.3A. Each Operating Instruction must contain the following information:~~

~~(a) details of the Registered Facility to which the Operating Instruction relates;~~

~~(b) the time the Operating Instruction was issued;~~

~~(c) the time at which the response to the Operating Instruction is required to commence and an estimate of when the Operating Instruction will cease to apply;~~

~~(d) if applicable, the required level of sent out generation or consumption; and~~

~~(e) whether the Operating Instruction relates to a Network Control Service Contract, an Ancillary Service Contract, a Test, a Supplementary Capacity Contract, or a Dispatch Instruction that meets the criteria specified in clause 7.7.11.~~

~~7.7.3B For a Demand Side Programme, a Dispatch Instruction may—~~

~~(a) request (but not require) the Facility to maintain a ramp rate faster than the Applicable DSP Ramp Rate Limit; and~~

~~(b) describe the requested faster ramp rate in non-specific terms (for example, "the highest rate achievable").~~

~~7.7.3C If a Dispatch Instruction requests a ramp rate faster than the Applicable DSP Ramp Rate Limit, then the Facility—~~

~~(a) must maintain a ramp rate at least equal to the Applicable DSP Ramp Rate Limit; but~~

~~(b) is not required to maintain a ramp rate faster than the Applicable DSP Ramp Rate Limit, and is excused from compliance with the Dispatch Instruction to that extent.~~

~~7.7.4. [Blank]~~

~~7.7.4A. When selecting Demand Side Programmes from the Non-Balancing Dispatch Merit Order, and subject to clauses 7.6.1C and 7.6.1E, System Management must select them in accordance with a Power System Operation Procedure. The selection process specified in the Power System Operation Procedure must:~~

~~(a) only discriminate between Demand Side Programmes based on response time and availability;~~

~~(b) permit System Management to not curtail a Demand Side Programme when, due to limitations on the availability of the Demand Side Programme, such curtailment would prevent that Demand Side Programme from being available to System Management at a later time when it would have greater benefit with respect to maintaining Power System Security and Power System Reliability; and~~

~~(c) not be inconsistent with section 7.6.~~

~~7.7.5. System Management must not issue a Dispatch Instruction for a Balancing Facility Out of Merit or a Demand Side Programme for a Trading Interval:~~

~~(a) before 6:00 PM on the Scheduling Day for the Trading Day on which the Trading Interval falls; or~~

~~(b) after the end of the relevant Trading Interval.~~

~~7.7.5A. System Management must develop a Power System Operation Procedure specifying:~~

~~(a) information that a Market Participant must provide to System Management, for each of the Market Participant's Non-Scheduled Generators, and for each Trading Interval, for the purposes of:~~

~~i. the estimate referred to in clause 7.7.5A(b);~~

~~ii. the revised estimate referred to in clause 7.7.5A(c); or~~

~~iii. step 6 of Appendix 9.~~

~~(b) for the purposes of clause 7.7.5B and the Relevant Level Methodology – one or more methods that may be used to estimate the maximum quantity of sent out energy (in MWh) that a Non-Scheduled Generator would have generated in a Trading Interval had a Dispatch Instruction not been issued for that Facility and for that Trading Interval;~~

~~(c) for the purposes of the Relevant Level Methodology only – the process for revising an estimate that was made strictly in accordance with one of the methods that, under clause 7.7.5A(b), must be specified in the Power System Operation Procedure; and~~

~~(d) for the purposes of clause 7.13.1C(e) – one or more methods that may be used to estimate the decrease in the output (in MWh) of each of Synergy's Non-Scheduled Generators as a result of an instruction from System Management to deviate from the Dispatch Plan or change their commitment or output in accordance with clause 7.6A.3(a).~~

~~7.7.5B. The quantity to be used for the purposes of clauses 6.15.2(b)(i) and 7.13.1(eF) is System Management's estimate, determined in accordance with a Power System Operation Procedure, of the maximum amount of sent out energy, in MWh, which each Non-Scheduled Generator, by Trading Interval, would have generated in the Trading Interval had a Dispatch Instruction not been issued.~~

~~7.7.5C. The information to be provided by a Market Participant in the Power System Operation Procedure developed under clause 7.7.5A may include such modelling for the Market Participant's Non-Scheduled Generators that System Management considers may assist it to determine the estimates under clause 7.7.5A(a) or to meet the Dispatch Criteria.~~

~~7.7.5D. System Management must provide the estimate required under clause 6.15.2(b)(i) as soon as reasonably practicable but in any event in time for settlement under Chapter 9.~~

~~7.7.6. Subject to clauses 7.7.7, 7.7.7A and 7.7.7B:~~

~~(a) System Management must issue a Dispatch Instruction or an Operating Instruction by communicating it to the relevant Market Participant in accordance with a Power System Operation Procedure. System Management must develop a Power System Operation Procedure which prescribes a communication method or methods which allow sufficient time for the Market Participant to confirm and to respond to that Dispatch Instruction; and~~

~~(b) a Market Participant must:~~

~~i. confirm receipt of the Dispatch Instruction or Operating Instruction; and~~

~~ii. advise if it cannot comply or cannot fully comply with the Dispatch Instruction or Operating Instruction.~~

~~The advice and confirmation under this clause 7.7.6(b) must be made in the time and manner set out in the Power System Operation Procedure specified in clause 7.7.6(a).~~

~~7.7.6A. Where a Market Participant has notified System Management in accordance with clause 7.7.6(b) that it cannot comply, or cannot fully comply with a Dispatch Instruction:~~

~~(a) the Market Participant must provide System Management with the reason it cannot comply or cannot fully comply with the Dispatch Instruction; and~~

~~(b) the reason provided by the Market Participant under clause 7.7.6A(a) must fall within clause 7.10.2(a).~~

~~7.7.6B. If a Market Participant notifies System Management under clause 7.7.6(b) or clause 7.10.3 that it cannot fully comply with a Dispatch Instruction, then it must, at the same time, provide notice of:~~

~~(a) where the Market Participant can comply with the quantity required in the Dispatch Instruction but not the required ramp rate, the different ramp rate with which the Market Participant can comply; or~~

~~(b) where the Market Participant cannot comply with the quantity required in the Dispatch Instruction:~~

~~i. the reduced quantity (if any) and associated ramp rate with which the Market Participant can comply; and~~

~~ii whether the Market Participant needs to desynchronise the Facility in order to provide the reduced quantity,~~

~~and System Management must, subject to meeting the Dispatch Criteria, issue a new Dispatch Instruction or Operating Instruction, as applicable, to the Market Participant in accordance with the advice received.~~

~~7.7.6C If a Market Participant receives a Dispatch Instruction under clause 7.6.1(d) or (e), and is or becomes aware that the information specified in clause (h)(xv) of Appendix 1 is no longer a reasonable forecast of the Demand Side Programme's likely consumption profile for a Trading Interval in the Trading Day to which the Dispatch Instruction relates if the Market Participant receives a Dispatch Instruction under clause 7.6.1H, then it must notify System Management as soon as reasonably practicable of a revised good faith forecast of the Demand Side Programme's likely consumption profile for the Trading Interval should it receive a Dispatch Instruction under clause 7.6.1H.~~

~~7.7.7. Clause 7.7.6 does not apply where System Management has operational control of the relevant Registered Facility in accordance with clause 7.8, in which case System Management may communicate the Dispatch Instruction or Operating Instruction at a later time and by a method agreed with the Market Participant.~~

~~7.7.7A. Clause 7.7.6 does not apply where the Operating Instruction is deemed to have been issued in respect of a Registered Facility in accordance with an Ancillary Service Contract or Network Control Service Contract and relates to the automatic activation of the Ancillary Service or Network Control Service in which case System Management may communicate the Operating Instruction to the relevant Market Participant at a later time in accordance with the Ancillary Service Contract or Network Control Service Contract.~~

~~7.7.7B. Clause 7.7.6 does not apply where the Operating Instruction has been issued retrospectively under clause 7.7.11, in which case System Management may communicate the Operating Instruction to the relevant Market Participant at a later time, and the Operating Instruction is deemed to have been confirmed by the relevant Market Participant.~~

~~7.7.8. System Management must record all Dispatch Instructions and Operating Instructions, including confirmations of receipt and notifications received from~~

~~Market Participants under clauses 7.7.6(b) and 7.7.6B, in a form sufficient for independent audit and for settlement purposes.~~

~~7.7.9. System Management must develop, in a Power System Operation Procedure, the procedure System Management and Market Participants must follow in forming, issuing, recording, receiving, confirming and responding to Dispatch Instructions and Operating Instructions and that System Management must follow in determining the quantities described in clause 7.7.5A(a).~~

~~7.7.10. When System Management has issued an Operating Instruction to a Demand Side Programme to decrease its consumption, System Management may issue a further instruction terminating the requirement for the Demand Side Programme to decrease its consumption providing that the further instruction is issued at least two hours before it is to come into effect.~~

~~7.7.11. If:~~

~~(a) System Management has issued a Dispatch Instruction to a Balancing Facility to reduce its output under clauses 7.6.1C(b) or 7.6.1C(c) in response to an outage of an item of equipment that is part of:~~

~~i. a Network; or~~

~~ii. a transmission system or distribution system owned by Western Power; and~~

~~(b) the required level of sent out generation specified in the Dispatch Instruction is lower than it would have been if the outage did not occur,~~

~~then System Management must issue a retrospective Operating Instruction to the Facility for the relevant Trading Intervals no later than the time necessary for the Operating Instruction to be included in the schedule specified in clause 7.13.1, and for the purposes of clause 6.16A.2(b)(ii) the Facility is deemed to have been complying with that Operating Instruction in each of those Trading Intervals.~~

Explanatory Note Clauses 7.6.1 to 7.6.22 deal with the Dispatch of Facilities in the Real-Time Market via Dispatch Instructions determined by the Dispatch Algorithm.

7.6. Central Dispatch

Dispatch

7.6.1. AEMO must centrally dispatch Real-Time Market Bids and Real-Time Market Offers using the Dispatch Algorithm.

7.6.2. AEMO must use the Dispatch Algorithm to set Dispatch Targets, Dispatch Caps and Essential System Service Enablement Quantities for each Registered Facility for each Dispatch Interval.

7.6.3. AEMO must document in a WEM Procedure the processes to be followed by AEMO and Market Participants for the dispatch of Registered Facilities where the Dispatch Algorithm is not able to be successfully run for a Dispatch Interval, including:

(a) when a previous Market Schedule will be used as the basis for issuing Dispatch Instructions; and

(b) where a previous Market Schedule will not be used as the basis for issuing Dispatch Instructions, the basis for Dispatch and issuing Dispatch Instructions in those circumstances.

7.6.4. AEMO is to use the Central Dispatch process to set:

(a) the Market Clearing Prices for each Dispatch Interval; and

(b) the Reference Trading Prices for each Trading Interval in accordance with section 7.11B.

7.6.5. A Dispatch Instruction is an instruction issued by AEMO to a Market Participant directing that the Market Participant:

(a) vary the Injection or Withdrawal of a Registered Facility; or

(b) enable a Registered Facility to provide a quantity of a Frequency Co-optimised Essential System Service.

To avoid doubt, the Dispatch Target and the Dispatch Cap in a Dispatch Instruction apply as at the end of a Dispatch Interval.

7.6.6. AEMO is not required to issue a Dispatch Instruction for Automatic Generator Control movements where:

(a) AEMO is adjusting the provision of Regulation within the quantity of Regulation enabled;

(b) AEMO has direct control of a Registered Facility under clause 7.6.30 and the adjustments relate to implementation of a previously recorded Dispatch Instruction; or

(c) the Facility is providing a System Restart Service.

Explanatory Note
Clause 7.6.7 allows AEMO to issue a direction to a Network Operator to support the operation of Central Dispatch. For example, adjusting an open point on the network or adjusting network voltage.

7.6.7. AEMO may direct a Network Operator to do, or not do, an act, matter or thing, if it reasonably determines the act, matter or thing is required to support or enable AEMO's operation of the Central Dispatch process.

Explanatory Note
Clause 7.6.8 sets out the information AEMO is required to include in a Dispatch Instruction.

As a Demand Side Programme may be dispatched over multiple Dispatch Intervals, an applicable Ramp Rate, to be recorded in a Dispatch Instruction in accordance with clause 7.6.8(g), will be determined taking this into account.

7.6.8. For each Dispatch Instruction, AEMO must record:

(a) details of the Registered Facility to which the Dispatch Instruction relates;

(b) the time the Dispatch Instruction was issued;

(c) the Dispatch Target or Dispatch Cap, as applicable, on a sent-out basis;

(d) where the Registered Facility is a Semi-Scheduled Facility or Non-Scheduled Facility, the Dispatch Forecast on a sent-out basis;

(e) where a Registered Facility has opted to receive Dispatch Instructions on an as-generated basis, the Dispatch Target, Dispatch Forecast or Dispatch Cap, as applicable, on an as-generated basis;

(f) Essential System Service Enablement Quantities;

(g) the ramp rate to be maintained by the Registered Facility until the Dispatch Target is reached, which must not exceed the Maximum Upwards Ramp Rate or the Maximum Downwards Ramp Rate, as applicable; and

(h) the information referred to in clauses 7.6.10 to 7.6.12 (as applicable).

7.6.9. At the same time as, or as soon as practicable after, AEMO issues a Dispatch Instruction for a Registered Facility, AEMO must make the information recorded in accordance with clause 7.6.8 available to the Market Participant for the Registered Facility.

Explanatory Note

Scheduled Facilities will always get a Dispatch Target which must be met within the Facility's relevant dispatch tolerance and subject to other service activation (e.g. Regulation).

Semi-Scheduled Facilities will receive:

- a Dispatch Cap (which must not be exceeded beyond the Facility's relevant dispatch tolerance); or
- if the Facility has been cleared to provide an Essential System Service, a Dispatch Target (which must be met within the Facility's relevant dispatch tolerance).

In normal operations, the Dispatch Cap will be the Facility's nameplate capacity, but will be less where the Facility has been cleared for only part of its capacity due to a tiered offer structure or a Constraint.

It is noted that as currently drafted clause 7.6.11 may restrict how a hybrid facility participates in Essential System Service provision. ETIU and AEMO are exploring the possibility of allowing Market Participants to provide the Essential System Service response from a component of the Registered Facility, rather than the Registered Facility as a whole at the sent-out point. Further amendments to clause 7.6.11 may be required to reflect that due diligence.

7.6.10. Each Dispatch Instruction for a Scheduled Facility must include a Dispatch Target.

7.6.11. Each Dispatch Instruction for a Semi-Scheduled Facility must include:

(a) a Dispatch Cap; or

(b) a Dispatch Target, where the Registered Facility has a non-zero Essential System Service Enablement Quantity for Contingency Reserve or Regulation.

7.6.12. Each Dispatch Instruction for a Non-Scheduled Facility must include a Dispatch Forecast.

7.6.13. Where a Dispatch Instruction for a Demand Side Programme:

(a) specifies a non-zero Dispatch Target, the Dispatch Target represents a required reduction in Withdrawal from the Relevant Demand for the Demand Side Programme; or

(b) specifies a zero Dispatch Target, the Dispatch Target indicates that the Demand Side Programme is no longer required to restrict its Withdrawal.

7.6.14. Subject to clause 7.10.3G, AEMO must determine the ramp rate in a Dispatch Instruction using a linear profile between the Registered Facility's Injection or Withdrawal at the start of the Dispatch Interval and at the end of the Dispatch Interval covered by the Dispatch Instruction.

7.6.15. A Dispatch Instruction for a Demand Side Programme must be issued by AEMO at least before the period (T1+T2), in minutes, before the Dispatch Interval in which the Dispatch Target in the Dispatch Instruction is to be achieved, and may be for quantities identified in the Reference Scenario.

7.6.16. Where AEMO issues a Dispatch Instruction specifying a non-zero Dispatch Target to a Demand Side Programme, AEMO must record the Demand Side Programme as Inflexible in the Market Schedules for each subsequent Dispatch Interval and Pre-Dispatch Interval until AEMO has issued a Dispatch Instruction specifying a zero Dispatch Target for the Demand Side Programme.

7.6.17. Where AEMO issues a Dispatch Instruction to a Demand Side Programme in accordance with clause 7.6.15, AEMO must take into account the Demand Side Programme's Dispatch Inflexibility Profile.

7.6.18. AEMO must document in a WEM Procedure:

(a) the processes AEMO and Market Participants must follow in issuing, recording, receiving, confirming and responding to Dispatch Instructions; and

(b) the methodology and data requirements for conversion of sent-out figures to as-generated figures where AEMO agrees to convert sent-out figures to as-generated figures for the purposes of implementing Dispatch Instructions for a Registered Facility.

7.6.19. AEMO must ensure that the communication methods used by AEMO for issuing Dispatch Instructions allow sufficient time for the Market Participant to confirm and respond to the Dispatch Instruction in accordance with these WEM Rules.

7.6.20. A Market Participant must confirm receipt of a Dispatch Instruction that was not issued by AEMO electronically via the Automatic Generation Control System for the Registered Facility in accordance with the WEM Procedure referred to in clause 7.6.18.

7.6.21. AEMO must not issue a Dispatch Instruction retrospectively.

7.6.22. AEMO must maintain a record of:

(a) each Dispatch Instruction;

(b) each confirmation of receipt of a Dispatch Instruction, where confirmation is required; and

(c) each notification from a Market Participant under clause 7.6.31,

in a consolidated electronic form which enables the Market Auditor to audit the information, and sufficient for use in settlement.

Explanatory Note

Clause 7.6.23 deals with tiebreaking arrangements. As most of the tiebreaking will be undertaken post-processing, AEMO will be given the ability to override Dispatch Algorithm outputs in certain circumstances without negating the entire process.

The intent of the priority order is to resolve tied offers by:

- ensuring Registered Facilities are able to meet Dispatch Targets;
- preferring Registered Facilities that would maintain consistency with dispatch in the previous Dispatch Interval;
- preferring Demand Side Programmes over other types of Registered Facilities to preserve flexible capacity (this is expected to only occur where there is a shortfall);
- preferring Demand Side Programmes that do not share an Associated Load with an Interruptible Load over Demand Side Programmes that do; and
- ensuring dispatch would be shared between tied offers. For example, if 10MW was required and the Generator A tied offer tranche is for 20MW, Generator B tied offer tranche is for 30MW, the pro-rata loading would be 4MW for Generator A and 6MW for Generator B.

Tiebreaking

7.6.23. Where the Dispatch Algorithm determines a Degenerate Solution, AEMO may issue Dispatch Instructions that override the output of the Dispatch Algorithm to the extent required to adjust the Dispatch Target of one or more Registered Facilities with tied Price-Quantity-Pairs, and in doing so must seek to, in the following priority order:

(a) ensure that Dispatch Targets can be met by Registered Facilities;

(b) maintain consistency of Dispatch Targets and Essential System Service Enablement Quantities between Dispatch Intervals;

(c) prefer dispatch of Demand Side Programmes to dispatch of other types of Registered Facilities;

(d) prefer dispatch of Demand Side Programmes which do not have an Associated Load which is also an Associated Load of an Interruptible Load, to dispatch of Demand Side Programmes which share an Associated Load with an Interruptible Load; and

(e) ensure pro-rata loading of tied Price-Quantity Pairs.

Explanatory Note

Clauses 7.6.24 and 7.6.25 allow AEMO to include Constraint Equations in the Dispatch Algorithm that seek to avoid large changes in dispatch (for both energy and ESS) for a small benefit. AEMO will be required to publish the impacts of these as for other binding constraints as part of the Congestion Information Resource. The intention is that the Constraint Violation Penalty for these constraints should be set higher than tiebreaking constraints, lower than all other constraints, and low enough to avoid noticeable impact on market prices.

7.6.24. AEMO may include Oscillation Control Constraint Equations in the Dispatch Algorithm to reduce the occurrence of:

(a) Degenerate Solutions that result in inconsistent Dispatch Targets between Dispatch Intervals; and

(b) significant changes in Essential System Services Enablement between Dispatch Intervals.

7.6.25. Where AEMO includes Oscillation Control Constraint Equations in the Dispatch Algorithm in accordance with clause 7.2.6, AEMO must ensure that:

(a) the Dispatch Algorithm firstly takes into account all Constraint Equations other than Constraint Equations used to avoid Degenerate Solutions;

(b) the Dispatch Algorithm violates an Oscillation Control Constraint Equation only in order to take into account other Constraints (according to the formulation specified under clauses 7.2.5(e) and 7.2.5(f)); and

(c) the Constraint Relaxation process in clause 7.2.9 is applied when the Dispatch Algorithm determines that it is necessary to violate an Oscillation Control Constraint Equation.

7.6.26. When setting the parameters of Oscillation Control Constraints, which determine the extent to which Oscillation Control Constraints will bind, AEMO must consider the historic cost of binding Oscillation Control Constraints as published in the Congestion Information Resource and the benefits to Power System Security and Power System Reliability of those Oscillation Control Constraints.

7.6.27. AEMO must document in a WEM Procedure:

(a) the process to be followed by AEMO when issuing Dispatch Instructions that override the output of the Dispatch Algorithm for Dispatch Intervals where the Dispatch Algorithm determines a Degenerate Solution pursuant to clause 7.6.23; and

(b) situations that are deemed to be significant for the purposes of clause 7.6.24(b).

Explanatory Note Clauses 7.6.28 to 7.6.30 replace section 7.8 of the current WEM Rules, but retain existing arrangements allowing AEMO to control Registered Facilities.

~~7.8. Dispatch Instructions and Operating Instructions implemented by System Management~~

~~7.8.1. System Management may, by agreement with a Market Participant, maintain operational control over aspects of a Registered Facility, including, but not limited to:~~

~~(a) the starting, loading and stopping of one or more of that Market Participant's Scheduled Generators; and~~

~~(b) limiting the output of one or more of that Market Participant's Non-Scheduled Generators.~~

~~7.8.2. The maintenance of operational control of a Registered Facility by System Management does not remove the obligation on System Management to produce Dispatch Instructions or Operating Instructions for those Registered Facilities.~~

~~7.8.3. A Market Participant's rights and obligations under these Market Rules in respect of a Facility are not affected or modified where System Management maintains operational control over the Facility in accordance with this clause 7.8. In particular, the compliance obligations described in clause 7.10 remain with the Market Participant responsible for the Registered Facilities to which clause 7.8.1 relates.~~

AEMO Control of Registered Facilities

7.6.28. AEMO may, where required for a Registered Facility to provide an Essential System Service, or otherwise by agreement with a Market Participant, control specified operations of a Registered Facility, including:

(a) the starting, loading and stopping of one or more of the Market Participant's Scheduled Facilities; and

(b) limiting the Injection of one or more of the Market Participant's Semi-Scheduled Facilities.

7.6.29. The operational control of a Registered Facility by AEMO pursuant to an agreement referred to in clause 7.6.28:

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

(b) does not affect or modify a Market Participant's rights and obligations in respect of a Registered Facility under these WEM Rules. To avoid doubt, notwithstanding AEMO's operational control, a Market Participant must comply with the obligations in section 7.10

7.6.30. Where AEMO maintains operational control over a Registered Facility, AEMO must operate the Registered Facility in compliance with Dispatch Instructions recorded for the Registered Facility.

> **Explanatory Note**
>
> Clauses 7.6.31 and 7.6.32 provide a head of power for respecting Registered Facility dispatch inflexibilities.

Dispatch Inflexibilities

7.6.31. Where a Market Participant reasonably expects that its Registered Facility will be unable to comply with a Dispatch Instruction for the Registered Facility in a future Dispatch Interval, the Market Participant must immediately:

(a) amend its Real-Time Market Submission for the Registered Facility by specifying:

i. the Registered Facility is Inflexible in the relevant Dispatch Interval; and

ii. a single offer tranche which specifies the fixed level of Injection, Withdrawal, or Frequency Control Essential System Service enablement, at which the Registered Facility must be operated in the Dispatch Interval;

(b) provide AEMO with a reason why the Registered Facility is Inflexible which must be able to be independently verified; and

(c) submit any Outages for the Registered Facility in accordance with section 3.21.

7.6.32. AEMO must use reasonable endeavours to issue Dispatch Instructions consistent with:

(a) a Real-Time Market Submission that specifies a Registered Facility as Inflexible; and

(b) a Registered Facility's Dispatch Inflexibility Profile.

> **Explanatory Note**
>
> Clauses 7.7.1 to 7.7.12 are intended to tie Operating-State-based intervention to the dispatch process.

7.7. Scarcity and Intervention

7.7.1. AEMO may direct a Market Participant to vary the reactive power output of a Registered Facility in accordance with Chapter 3A.

7.7.2. Where AEMO has entered into a Supplementary Capacity Contract, AEMO may direct the relevant resource to provide an Eligible Service in accordance with the terms of the Supplementary Capacity Contract.

7.7.3. Where AEMO has issued a [notice of projected ESS shortfall level X], AEMO may direct a Market Participant to make a Real-Time Market Submission for a Registered Facility that has been accredited to provide an Essential System Service in accordance with section 2.34A, that requires the total quantity of Essential System Service to be offered to reflect the maximum accredited quantity, or the lowest Remaining Available Capacity under any Outage, applying to the Registered Facility for that Frequency Co-optimised Essential System Service in the Dispatch Interval.

7.7.4. Where AEMO has issued a [notice of projected energy shortfall level X] and the Short Term PASA, Medium Term PASA or the Reference Scenario for the Pre-Dispatch Schedule projects that a Registered Facility will be needed to provide energy, AEMO may, as applicable:

(a) where the projected energy shortfall will occur within four weeks of the date of the notice:

i. cancel one or more Outages for the Registered Facility; or

ii. recall the Registered Facility from an Outage; or

(b) where the projected energy shortfall will occur within one week of the date of the notice, direct the relevant Market Participant to make a Real-Time Market Submission for a Registered Facility offering its full Reserve Capacity Obligation Quantity as In Service Capacity.

7.7.5. Where AEMO has issued a [notice of projected ESS shortfall level X] and the Short Term PASA or the Reference Scenario for the Pre-Dispatch Schedule projects that a Registered Facility will be needed to provide an Essential System Service, AEMO may direct a Market Participant to synchronise the Registered Facility to provide the Essential System Service. AEMO must issue directions under this clause 7.7.5 to Registered Facilities holding a Supplementary ESS Award in priority to other Registered Facilities.

7.7.6. Following a Contingency Event, AEMO may adjust Essential System Service requirements to allow for an orderly transition back to full Essential System Service Enablement Quantities.

7.7.7. Following a Contingency Event, if AEMO reasonably determines that the Dispatch Algorithm is not appropriately scheduling Registered Facilities for Essential System Services, AEMO may reduce an Essential System Service requirement, including to zero, to reflect the activation of enabled Registered Facilities.

7.7.8. Where AEMO issues a direction to a Market Participant in accordance with this section 7.7 or under clauses 3.4.6, 3.4.7 or 3.5.5, AEMO must, as soon as practicable, input appropriate Constraint Equations in the Dispatch Algorithm to ensure that the Dispatch Algorithm generates Dispatch Targets that will allow the Registered Facility to comply with those directions.

7.7.9. A Dispatch Instruction issued by AEMO as a result of a direction issued by AEMO in accordance with this section 7.7 or under clauses 3.4.6, 3.4.7 or 3.5.5, must be:

(a) consistent with the Registered Facility data held by AEMO, including Standing Data, at the time the Dispatch Instruction is determined; and

(b) issued at a time that takes into account the Standing Data minimum response time for the Registered Facility specified in Appendix 1(b)(xix).

7.7.10. Where AEMO directs a Market Participant to vary the operation of a Registered Facility in a way that is not fully set out in a Dispatch Instruction, AEMO must record:

(a) the date, time, and duration of the direction;

(b) the name of the Registered Facility;

(c) the nature of the direction (for example, commitment, fuel choice, reactive power output); and

(d) the reason for the direction.

7.7.10. Subject to clause 7.7.11, Market Participants must comply with directions given by AEMO in accordance with this section 7.7.

7.7.11. A Market Participant is not required to comply with a direction referred to in clause 7.7.10 if it would endanger the safety of any person, damage equipment, or breach any applicable law.

7.7.12. Where a Market Participant cannot, in accordance with clause 7.7.11, comply with a direction from AEMO under this section 7.7, the Market Participant must notify AEMO as soon as possible and provide the reasons why it cannot comply, which must be one or more of the reasons specified in clause 7.7.11.

Explanatory Note

Section 7.8 sets out the requirements for Market Schedules to be determined and published by AEMO.

7.8. Market Schedules

7.8.1. AEMO must determine and publish on the WEM Website the following Market Schedules in accordance with the Real-Time Market Timetable:

(a) Week-Ahead Schedules;

(b) Pre-Dispatch Schedules; and

(c) Dispatch Schedules.

7.8.2. AEMO must use processes that are consistent with the principles in section 7.11A in determining Market Schedules.

7.8.3. AEMO may publish Market Schedules comprising multiple Scenarios.

7.8.4. Where AEMO publishes a Market Schedule comprising multiple Scenarios, AEMO must designate a Reference Scenario for each Market Schedule.

> **Explanatory Note**
>
> Clause 7.8.5 set sets out what a Reference Scenario represents and what it must include.
>
> Although the Reference Scenario represents the mid-point of the range of expected outcomes, AEMO may consider the rest of the range in operating the power system. Where AEMO needs to take action based on wider projections, AEMO will issue a 'Lack of Reserve Notice or Lack of ESS Notice'. These notices are being dealt with in the PASA workstream.

7.8.5. A Reference Scenario for a Dispatch Schedule must:

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

(b) take into account:

i. Enablement Minimums;

ii. Low Breakpoints;

iii. High Breakpoints;

iv. Enablement Maximums;

v. Dispatch Inflexibility Profiles; and

vi. approved Outages and Forced Outages; and

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

> **Explanatory Note**
>
> Clause 7.8.6 is intended to provide guidance on a minimum required set of Scenarios, and to provide flexibility for AEMO to define the details of the Scenario, and to add other Scenarios.

7.8.6. In determining Week-Ahead Schedules and Pre-Dispatch Schedules, AEMO must include Scenarios that:

(a) do not take account of:

i. Enablement Minimum;

ii. Low Breakpoints;

iii. High Breakpoints;

iv. Enablement Maxima; and

v. Dispatch Inflexibility Profiles;

(b) include In Service Capacity in Real-Time Market Offers, and exclude Available Capacity in Real-Time Market Offers;

(c) include In-Service Capacity and Available Capacity in Real-Time Market Offers;

(d) use a higher load forecast than the Reference Scenario; and

(e) use a lower load forecast than the Reference Scenario.

7.8.7. All of the inputs for each Market Schedule must be recorded by AEMO in a form which will enable a third party, including the Market Auditor, to audit each Market Schedule.

7.8.8. AEMO may determine and publish Market Schedule more frequently than the time specified in clauses 7.1.3(a)(iii), 7.1.3(a)(iv) and 7.1.3(a)(v).

7.8.9. AEMO must document in a WEM Procedure the processes for determining Market Schedules, including:

(a) the number and types of Scenarios;

(b) the principles, methodologies and calculations used to determine:

i. input data for each Market Schedule; and

ii. input data for each Scenario; and

(c) how each Market Schedule will apply to clause 7.5.9, including:

i. for each type of Market Schedule; and

ii. Dispatch Intervals or Pre-Dispatch Intervals within each Market Schedule.

Explanatory Note Replacement section 7.9 combines the current commitment rules with new fully-co-optimised security constrained economic dispatch market design.

7.9. Commitment

~~7.9.1. Subject to clauses 7.9.1A and 7.9.2, if a Market Participant intends to synchronise a Scheduled Generator, then unless it is exempt in accordance with clause 7.9.14, it must confirm with System Management the expected time of synchronisation:~~

~~(a) at least one hour before the expected time of synchronisation; and~~

~~(b) must update this advice immediately if the time confirmed pursuant to clause 7.9.1(a) changes.~~

~~7.9.1A. Clause 7.9.1(a) does not apply where a Market Participant intends to synchronise a Scheduled Generator within an hour of desynchronisation, in which case it must:~~

~~(a) confirm with System Management the expected time of synchronisation immediately as it is known; and~~

~~(b) update this advice immediately if the time advised pursuant to clause 7.9.1A(a) changes.~~

~~7.9.2. Clause 7.9.1(a) does not apply where System Management has issued a Dispatch Instruction or an Operating Instruction, or an instruction given under clause 7.6A.3(a), to the Facility that requires synchronisation within one hour of the Dispatch Instruction, the Operating Instruction or an instruction given under clause 7.6A.3(a), being issued.~~

~~7.9.3. System Management may request that a Market Participant who has given a confirmation under clause 7.9.1 provide further notification to System Management immediately before synchronisation of the Facility, and the relevant Market Participant must comply with the request.~~

~~7.9.4. System Management must grant permission to synchronise unless:~~

~~(a) the synchronisation is not in accordance with the relevant Dispatch Instruction, Operating Instruction or instruction issued under clause 7.6A.3(a); or~~

~~(b) System Management considers that it would not be able to meet the criteria set out in clause 7.6.1 if synchronisation were to occur; or~~

~~(c) in the case of a Facility that is undergoing a Commissioning Test, synchronisation is not in accordance with the Commissioning Test Plan for the Facility approved by System Management pursuant to section 3.21A.~~

~~7.9.5. Subject to clause 7.9.6A, if a Market Participant intends to desynchronise a Scheduled Generator, then unless it is exempt in accordance with clause 7.9.14, it must:~~

~~(a) confirm with System Management the expected time of desynchronisation at least one hour before the expected time of desynchronisation; and~~

~~(b) update this advice immediately if the time confirmed pursuant to clause 7.9.5(a) changes.~~

~~7.9.6. Clauses 7.9.5(a) and 7.9.6A do not apply where System Management has issued a Dispatch Instruction, an Operating Instruction or an instruction given under clause 7.6A.3(a), to the Facility that requires desynchronisation within one hour of the Dispatch Instruction, the Operating Instruction or an instruction given under clause 7.6A.3(a), being issued.~~

~~7.9.6A. A Market Participant may not decommit a Facility to such an extent that it will not be available to be synchronised for four hours or more after the time of desynchronisation, unless the Market Participant has been granted permission by System Management to do this in accordance with clause 3.21B.~~

~~7.9.7. System Management may request that a Market Participant who has given a confirmation under clause 7.9.5 provide further notification to System Management immediately before desynchronisation of the Facility, and the relevant Market Participant must comply with the request.~~

~~7.9.8. System Management must grant permission to desynchronise unless:~~

~~(a) the desynchronisation is not in accordance with the relevant Dispatch Instruction, Operating Instruction or instruction issued under clause 7.6A.3(a); or~~

~~(b) System Management considers that it would not be able to meet the criteria set out in clause 7.6.1 if desynchronisation were to occur.~~

~~7.9.9. A Market Participant must comply with a decision of System Management under clause 7.9.4.~~

~~7.9.10. Subject to clause 7.9.11, a Market Participant must comply with a decision of System Management under clause 7.9.8.~~

~~7.9.11. A Market Participant is not required to comply with clause 7.9.5 or with clause 7.9.10 if such compliance would endanger the safety of any person, damage equipment, or breach any applicable law.~~

~~7.9.12. Where a Market Participant cannot comply with clause 7.9.5, in accordance with clause 7.9.11, or with a decision of System Management under clause 7.9.8:~~

~~(a) the Market Participant must inform System Management as soon as practicable; and~~

~~(b) if System Management did not confirm the expected time of desynchronisation or refused to allow desynchronisation of a Facility but the Market Participant did desynchronise that Facility then System Management must record the desynchronisation as a Forced Outage.~~

~~7.9.13. If a Scheduled Generator connected to a distribution network has operating equipment and processes which enable it to synchronise and desynchronise only when it is safe to do so, then the Market Participant for that Scheduled Generator may apply to System Management for an exemption from the requirements in clauses 7.9.1 and 7.9.5.~~

~~7.9.14. Where System Management receives an application under clause 7.9.13 and is satisfied that the relevant Scheduled Generator has operating equipment and processes which enable it to synchronise and desynchronise only when it is safe to do so, System Management may exempt the Market Participant from the requirements in clauses 7.9.1 and 7.9.5 for that Scheduled Generator.~~

~~7.9.15. System Management must notify a Market Participant, in writing, of its decision under clause 7.9.14 to grant an exemption or not and provide written reasons for its decision.~~

~~7.9.16. A Market Participant that is exempt from the requirements in clauses 7.9.1 and 7.9.5 must notify System Management as soon as it becomes aware of any matter or thing which might prevent the Scheduled Generator that is the subject of the exemption from synchronising and desynchronising safely.~~

~~7.9.17. System Management may, at any time, by notice in writing, revoke an exemption granted by it under clause 7.9.14 if it is no longer satisfied that the Scheduled Generator for which the exemption was granted has operating equipment and processes which enable it to synchronise and desynchronise only when it is safe to do so. The notice must include:~~

~~(a) the decision of System Management to revoke the exemption and written reasons for its decision; and~~

~~(b) the date on which the exemption ceases to apply.~~

~~7.9.18. System Management must maintain, on its website, a list of Scheduled Generators for which the relevant Market Participant is exempt from the requirements in clauses 7.9.1 and 7.9.5.~~

~~7.9.19. System Management must document in a Power System Operation Procedure the processes to be used:~~

~~(a) for applications under clause 7.9.13;~~

~~(b) by System Management in determining whether or not to grant an exemption under clause 7.9.14;~~

~~(c) by System Management in determining whether or not to revoke an exemption under clause 7.9.17;~~

~~(d) for notification of any exemptions granted or revoked by System Management; and~~

~~(e) publishing and maintaining on System Management's website any information and details with respect to any exemptions.~~

7.9.1. Fast Start Facilities are Scheduled Facilities and Semi-Scheduled Facilities that are capable of:

(a) synchronising and changing the Registered Facility's rate of Injection or Withdrawal within 30 minutes of receiving a Dispatch Instruction from AEMO; and

(b) shutting down within 60 minutes from the time the Dispatch Instruction to synchronise was issued for the Registered Facility.

7.9.2. Slow Start Facilities are Scheduled Facilities and Semi-Scheduled Facilities that are not Fast Start Facilities.

7.9.3. Where a Real-Time Market Submission for a Registered Facility does not specify a Dispatch Inflexibility Profile, the Registered Facility must commence the process of starting and synchronising without instruction or direction from AEMO to be eligible for dispatch in a Dispatch Interval covered by the Real-Time Market Submission.

7.9.4. If a Market Participant intends to synchronise a Registered Facility, or any part of it, for which it has not specified a Dispatch Inflexibility Profile, then it must notify AEMO of the expected time of synchronisation by designating the Registered Facility's capacity as In Service Capacity in the Real-Time Market Submission for the Registered Facility.

7.9.5. If a Market Participant intends to desynchronise a Registered Facility, or any part of it, for which it has not specified a Dispatch Inflexibility Profile, the Market Participant must notify AEMO of the expected time of desynchronisation by updating the Real-Time Market Submission for the Registered Facility to reflect the Registered Facility's Available Capacity and In-Service Capacity.

7.9.6. If a Market Participant intends to synchronise or desynchronise an unregistered generating system serving an Intermittent Load, the Market Participant must notify AEMO of the expected time of synchronisation or desynchronisation of the unregistered generating system.

7.9.7. Clauses 7.9.5 and 7.9.6 do not apply where:

(a) AEMO issues a Dispatch Instruction to the Registered Facility that requires synchronisation or desynchronisation within one hour of the time the Dispatch Instruction is issued; or

(b) AEMO has directed the Registered Facility to synchronise or desynchronise under clause 3.5.5 or section 7.7.

7.9.8. AEMO may request a Market Participant provide further notification to AEMO immediately before synchronising or desynchronising a Registered Facility, or any part of it. A Market Participant must comply with a request under this clause 7.9.8.

7.9.9. If:

(a) AEMO reasonably considers that the synchronisation or desynchronisation of a Registered Facility, or any part of it, is required to enable AEMO to maintain Power System Security and Power System Reliability in accordance with Chapter 3;

(b) the synchronisation or desynchronisation of the Registered Facility, or any part of it, is not in accordance with the relevant Dispatch Instruction;

(c) AEMO reasonably considers that it would be unable to operate the Central Dispatch process or utilise the Dispatch Algorithm in accordance with section 7.2 if synchronisation or desynchronisation were to occur; or

(d) in the case of a Registered Facility undergoing a Reserve Capacity Test or a Commissioning Test, the synchronisation or desynchronisation is not in accordance with the Reserve Capacity Test or Commissioning Test Plan, as applicable, for the Registered Facility approved by AEMO under section 3.21A,

AEMO may direct a Market Participant to not synchronise or desynchronise the Registered Facility, or any part of it, as applicable.

7.9.10. A Market Participant must comply with a direction by AEMO in accordance with clause 7.9.9 unless complying with the direction would endanger the safety of any person, damage equipment, or breach any applicable law.

7.9.11. Where a Market Participant cannot comply with a direction from AEMO under clause 7.9.9, in accordance with clause 7.9.10, the Market Participant must notify AEMO as soon as possible and provide the reasons why it cannot comply, which must be one or more of the reasons specified in clause 7.9.10.

Explanatory note

Clause 7.9.12 may be amended in the Reserve Capacity Mechanism workstream.

7.9.12. A Market Participant may not decommit a Registered Facility to such an extent that it will not be available to be synchronised for four hours or more after the time of desynchronisation, unless the Market Participant has been granted permission by AEMO to do so in accordance with section 3.21B.

7.9.13. A Market Participant for an Interruptible Load which was activated in response to a Contingency Event must:

(a) obtain approval from AEMO prior to initiating the Restoration Profile for the Interruptible Load; and

(b) notify AEMO if the Restoration Profile for the Interruptible Load is not the same as the Restoration Profile in the Standing Data for the Interruptible Load.

Explanatory Note

Section 7.10 sets out the obligations regarding Market Participants' compliance with Dispatch Instructions.

The obligations of AEMO and the Economic Regulation Authority in relation to Market Participants' compliance (from clause 7.10.4) will be dealt with in the Monitoring and Compliance workstream.

Dispatch Compliance

7.10. Compliance with Dispatch Instructions ~~and Operating Instructions~~

7.10.1. ~~Subject to clause 7.10.2, a~~A Market Participant must comply with the Dispatch Target or the Dispatch Cap, Essential System Service Enablement Quantities and Ramp Rate in the most recently issued Dispatch Instruction~~, Operating Instruction or Dispatch Order~~ applicable to its Registered Facility for the ~~Trading~~ Dispatch Interval.

7.10.2. A Market Participant is not required to comply with clause 7.10.1 if:

(a) such compliance would endanger the safety of any person, damage equipment or breach any applicable law;

(b) the actual Injection or Withdrawal of the Registered Facility does not, at any time the Dispatch Instruction applies, vary from the ramp rate-adjusted Dispatch Target or Dispatch Cap specified in the Dispatch Instruction by more than the applicable Tolerance Range or Facility Tolerance Range;

~~(b) the Facility was physically unable to maintain the ramp rate specified in the Dispatch Instruction but:~~

~~i. the actual output of the Facility did not, at any time the Dispatch Instruction applied, vary from the output specified in the Dispatch Instruction by more than the applicable Tolerance Range or Facility Tolerance Range; and~~

~~ii. the average output over a Trading Interval of the Facility was equal to the output specified in the Dispatch Instruction;~~

(c) both of the following apply:

i. the Market Participant has notified ~~System Management~~ AEMO, in accordance with clause [3.21.4], that its Registered Facility has been affected by a Forced Outage ~~or Consequential Outage~~; and

ii. the quantity of Remaining Available Capacity for the Forced Outage ~~or Consequential Outage~~ notified is consistent with the extent to which the Market Participant did not comply with the most recently issued Dispatch Instruction~~, Operating Instruction or Dispatch Order~~ applicable to its Registered Facility for the ~~Trading~~ Dispatch Interval;

(d) ~~a Demand Side Programme was issued a Dispatch Instruction by System Management under clause 7.6.1C and its Reserve Capacity Obligation Quantity, as determined under clause 4.12.4(c) is or becomes zero; or~~ the Registered Facility has been exempted from complying with the Ramp Rate under clause 7.10.3G, complies with the Dispatch Target, and ramps at the Ramp Rate specified in the Real-Time Market Submission for the Registered Facility; and

~~(e) clause 7.7.3C excuses compliance.~~

(e) the Dispatch Instruction relates to a Demand Side Programme, and the Registered Facility is responding according to the ramp rate-adjusted Dispatch Target specified in the Dispatch Instruction.

7.10.2A. Notwithstanding clause 7.10.2(b), a Market Participant must not consistently operate its Registered Facility at the extremes of the Tolerance Range or Facility Tolerance Range applicable to the Registered Facility.

7.10.2B. Where a Semi-Scheduled Facility contains an Electric Storage Resource, a Market Participant must not operate the Electric Storage Resource to increase the deviation of the Semi-Scheduled Facility's Injection or Withdrawal from the Semi-Scheduled Facility's Dispatch Forecast or Dispatch Cap, unless the deviation is:

(a) instructed as part of the delivery of one or more Essential System Services; or

(b) to provide a required response as part of the Facility's Registered Generator Performance Standard.

7.10.2C. AEMO must document in a WEM Procedure the method for calculating an Electric Storage Resource's contribution to the relevant Semi-Scheduled Facility's deviation from its Dispatch Forecast or Dispatch Cap for the purposes of clause 7.10.2B.

7.10.2D. Where a Market Participant can control the Injection or Withdrawal of a Semi-Scheduled Facility, it must not exercise that control so as to increase the deviation of the Semi-Scheduled Facility's Injection or Withdrawal from the Semi-Scheduled Facility's Dispatch Forecast or Dispatch Cap, unless this deviation is:

(a) instructed as part of the delivery of one or more Essential System Services; or

(b) to provide a required response as part of the Facility's Registered Generator Performance Standard.

7.10.3. Where a Market Participant becomes aware that it cannot comply or fully comply with a Dispatch Instruction ~~or an Operating Instruction, as applicable,~~ it must ~~inform~~ notify ~~System Management~~ AEMO as soon as practicable.

7.10.3A. Where a Market Participant has ~~advised System Management~~ notified AEMO under clause 7.10.3 that it cannot comply or fully comply with a Dispatch Instruction:

(a) the Market Participant must provide ~~System Management~~ AEMO with the reason it cannot comply or cannot fully comply with the Dispatch Instruction; and

(b) the reason provided by the Market Participant under clause 7.10.3A(a) must fall within clause 7.10.2(a).

7.10.3B. Where a Market Participant notifies AEMO under clause 7.10.3 that it cannot comply or fully comply with a Dispatch Instruction, or AEMO observes repeated non-compliance by the Market Participant in accordance with the WEM Procedure referred to in clause 2.15.6A:

(a) AEMO may adjust inputs to the Dispatch Algorithm to accurately reflect the capability of the relevant Registered Facility; and

(b) the Market Participant must immediately after notifying AEMO under clause 7.10.3 update its Real-Time Market Submissions to accurately reflect the capability of its Registered Facility.

7.10.3C. The Economic Regulation Authority may, at any time, request a Market Participant to provide further information in respect of the reasons that it could not comply or fully comply with a Dispatch Instruction, including further information to clarify any reason provided under clause 7.10.3A(a).

7.10.3D. A Market Participant must respond to any request from the Economic Regulation Authority under clause 7.10.3C by the time specified in the request.

7.10.3E. Where a Registered Facility is only capable of ramping at a fixed rate and not in accordance with a linear ramp profile specified in a Dispatch Instruction, the Market Participant for the Registered Facility may apply to AEMO for an exemption from the requirement for the Registered Facility to comply with the Ramp Rate specified in a Dispatch Instruction.

7.10.3F. The Market Participant must provide evidence in support of an application made under clause 7.10.3E, including any information specified in the WEM Procedure referred to in clause 7.10.3K.

7.10.3G. Where AEMO receives an application under clause 7.10.3E and is satisfied that the relevant Registered Generator is unable to comply with a linear ramp profile specified in a Dispatch Instruction, AEMO must exempt the Registered Facility specified in the application from the requirement to ramp in accordance with the Ramp Rate specified in a Dispatch Instruction.

7.10.3H. AEMO must notify a Market Participant, in writing, of its decision under clause 7.10.3G to grant an exemption or not and provide written reasons for its decision.

7.10.3I. A Market Participant that has been granted an exemption in accordance with clause 7.10.3G must immediately notify AEMO if any works to the Registered Facility that is the subject of the exemption results in the Facility being capable of ramping in accordance with the linear ramp profile specified in a Dispatch Instruction.

7.10.3J. In response to a notification under clause 7.10.3I, AEMO may, by notice in writing, revoke an exemption granted by it under clause 7.10.3G.

7.10.3K. AEMO must document in a WEM Procedure:

(a) the processes to be followed by AEMO when it observes repeated non-compliance by a Market Participant in accordance with the WEM Procedure referred to in clause 2.15.6A;

(b) the processes to be followed by a Market Participant making an application under clause 7.10.3E or notifying AEMO under clause 7.10.3I;

(c) the information to be provided by a Market Participant in support of an application under clause 7.10.3E;

(d) the processes to be followed by AEMO in determining whether or not to grant an exemption under clause 7.10.3G or to revoke an exemption under clause 7.10.3J; and

(e) the timeline for assessing an application under clause 7.10.3E and notifying a Market Participant of its decision in accordance with clause 7.10.3H, which must not exceed 10 business days from the date AEMO receives the application.

7.10.3L. A Registered Facility which is granted an exemption under clause 7.10.3G is not exempt from any contribution to the cost of Regulation resulting from its departure from a linear ramp profile specified in a Dispatch Instruction.

Explanatory Note

Clauses 7.10.4 to 7.10.8 will be dealt with in the Monitoring and Compliance workstream.

Amendments will also be made to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

7.10.4. System Management must monitor the behaviour of Market Participants with Registered Facilities to assess whether they are complying with clause 7.10.1 in accordance with the Market Procedure specified in clause 2.15.6A.

7.10.4A For a Demand Side Programme, System Management's monitoring under clause 7.10.4 may be undertaken after the event.

7.10.5. Where System Management considers that a Market Participant has not complied with clause 7.10.1 in relation to any of its Registered Facilities in a manner that is not within:

(a) the Tolerance Range determined in accordance with clause 2.13.6D; or

(b) a Facility Tolerance Range determined in accordance with clause 2.13.6E or, if applicable, varied in accordance with clause 2.13.6H,

System Management must (unless the Registered Facility is a Demand Side Programme, in which case System Management may) as soon as reasonably practicable:

(c) warn the Market Participant about the deviation and request an explanation for the deviation; and

(d) if necessary to meet the Dispatch Criteria, issue a new Dispatch Instruction, Operating Instruction or Dispatch Order in accordance with clause 7.6.

7.10.6. [Blank]

7.10.6A. If a Market Participant receives a warning and a request for an explanation from System Management under clause 7.10.5(c), the Market Participant must as soon as practicable:

(a) provide to System Management an explanation for the deviation; and

(b) ensure it has complied with the requirements of clause 7A.2 in relation to the Market Participant's Balancing Submission.

7.10.7. Where System Management has issued a warning about a deviation to a Market Participant under clause 7.10.5(c) regarding a failure to comply with clause 7.10.1, System Management:

(a) unless the deviation is within the Tolerance Range or Facility Tolerance Range, must prepare a report of the deviation. System Management must include in the report:

i. the circumstances of the failure to comply with clause 7.10.1;

ii. any explanation offered by the Market Participant as provided in accordance with clause 7.10.6A(a);

iii. whether System Management issued instructions to Synergy in respect of its Registered Facilities or Registered Facilities covered by any Ancillary Service Contract or issued Dispatch Instructions or Operating Instructions to other Registered Facilities as a result of the failure; and

iv. an assessment of whether the failure threatened Power System Security or Power System Reliability; and

(b) if the deviation is within the applicable Tolerance Range or Facility Tolerance Range, may prepare a report containing the same information as specified in clause 7.10.7(a).

7.10.8. Where AEMO (in its capacity as System Management) prepares a report under clause 7.10.7, AEMO must promptly provide that report to the Economic Regulation Authority. Where the Economic Regulation Authority receives such a report, if the Economic Regulation Authority determines that (as applicable):

(a) the relevant Market Participant has not adequately or appropriately complied with a Dispatch Instruction; or

(b) Synergy has not adequately or appropriately complied with a Dispatch Order, then

the Economic Regulation Authority must promptly notify AEMO.

Explanatory Note

This section brings together sections 6.19 (Market Advisories) and 7.11 (Dispatch Advisories) in the current WEM Rules.

The WEM Rules still reflect the arrangements when the IMO and System Management each had a head of power to issue notices to the market. Now that AEMO carries out both functions, the current Dispatch Advisories and Market Advisories frameworks will be merged into a new Market Advisory notice.

The new Market Advisory notice will not contain the same level of information as the current notices as a lot of information will be visible in the Pre-Dispatch Schedule. The intent is for as much information as possible to be provided via the standard market operation processes, with Market Advisories being used for exceptions.

In the final version of these draft Amending Rules, section 7.11 will be deleted and replaced to remove all blank clauses and alpha-numeric clause numbers.

~~Dispatch~~Market Advisories and Status Reports

7.11. ~~Dispatch~~ Market Advisories

~~7.11.1. [Blank]~~

7.11.1. A Market Advisory is a notification published by AEMO that there has been, or is likely to be, an event that AEMO reasonably considers may impact Power System Security, Power System Reliability or the operation of Central Dispatch.

7.11.2. ~~System Management~~ AEMO must issue a ~~Dispatch~~ Market Advisory for future potential events if it considers there to be a high probability that the event will occur unless the event has already been signalled in a Pre-Dispatch Schedule ~~within 48 hours of the time of issue~~.

7.11.3. ~~Dispatch~~Market Advisories must be released as soon as practicable after ~~System Management~~ AEMO becomes aware of a situation requiring the release of a ~~Dispatch~~ Market Advisory and ~~System Management~~ AEMO must update the ~~Dispatch~~ Market Advisory as soon as possible after new, relevant information becomes available to it.

7.11.3A ~~For the avoidance of doubt, where System Management~~Where AEMO must respond to an unexpected and sudden event, ~~System Management~~ AEMO may issue a ~~Dispatch~~ Market Advisory after the event has occurred.

7.11.4. ~~System Management~~AEMO must withdraw a Market Advisory and ~~inform~~ notify Market Participants, Network Operators and the Economic Regulation Authority of the withdrawal of a ~~Dispatch~~ Market Advisory as soon as practicable once the situation that the ~~Dispatch~~ Market Advisory relates to has finished.

Explanatory Note

Clauses 7.11.5 to 7.11.6B describe when AEMO will be required to issue a Market Advisory.

The ‘Lack of Reserve Notice and Lack of ESS Notice’ are being dealt with in the PASA workstream, and the reference to relevant outage information will be finalised in the Outages workstream.

~~7.11.5. System Management must release a Dispatch Advisory in the event of, or in anticipation of situations where:~~

~~(a) involuntary load shedding is occurring or expected to occur;~~

~~(b) committed generation at minimum loading is, or is expected to, exceed forecast load;~~

~~(c) Ancillary Service Requirements will not be fully met;~~

~~(d) significant outages of generation transmission or customer equipment are occurring or expected to occur;~~

~~(e) fuel supply on the Trading Day is significantly more restricted than usual;~~

~~(f) scheduling or communication systems required for the normal conduct of the scheduling and dispatch process are, or are expected to be, unavailable;~~

~~(g) System Management expects to issue a Dispatch Instruction Out of Merit including, for the purpose of this clause, issuing a Dispatch Order to the Balancing Portfolio in accordance with clause 7.6.2, which will result in Out of Merit dispatch of the Balancing Portfolio;~~

~~(h) System Management expects to use LFAS Facilities other than in accordance with the LFAS Enablement Schedules, under clause 7B.3.8; or~~

~~(i) the system is in, or is expected to be in, a High Risk Operating State or an Emergency Operating State;~~

~~(j) System Management expects to issue a Dispatch Instruction to a Demand Side Programme within the next 24 hours; or~~

~~(k) System Management expects to issue a Dispatch Instruction to a Demand Side Programme under clause 7.6.1C(d) within the next 24 hours.~~

7.11.5. AEMO must release a Dispatch Advisory in the event of, or in anticipation of, the following situations:

(a) the SWIS is in, or is expected to be in, an Emergency Operating State;

(b) the SWIS is unable to be, or is expected that it cannot be, operated in accordance with the Power System Security Principles;

(c) System Restart Service is, or is expected to be, enabled;

(d) AEMO is unable to maintain the SWIS in a Reliable Operating State;

(e) the whole or any part of the WEM Rules, including, without limitation, in respect to the operation of the Real-Time Market, have been, or are expected to be, suspended in accordance with clause 2.44.1;

(f) fuel supply on Trading Day is at risk, or is significantly more restricted than usual;

(g) involuntary load shedding that AEMO reasonably considers may impact Power System Security, Power System Reliability or the operation of Central Dispatch;

(h) significant degradation or failure of AEMO market or control systems required for the normal conduct of the operation of the Real-Time Market and the Central Dispatch process;

(i) an AEMO Intervention Event has occurred, or is expected to occur;

(j) a Contingency Event or Credible Contingency Event has occurred, or is expected to occur; and

(k) any other circumstance which would, in AEMO's reasonable opinion, significantly threaten Power System Security or Power System Reliability,

unless the situation has already been signalled through a [Lack of Reserve Notice], [Lack of ESS Notice], Pre-Dispatch Schedule, or in the information published under clause [outage information publication], as applicable.

Explanatory Note Clause 7.11.6 sets out the information AEMO is required to include in a Market Advisory.

7.11.6. Subject to clause 7.11.6~~A~~B, a ~~Dispatch~~ Market Advisory must contain the following information:

(a) [Blank]

(b) the date and time that the ~~Dispatch~~ Market Advisory is released;

(c) the time period for which the ~~Dispatch~~ Market Advisory is expected to apply;

~~(cA) the Operating State to be applicable, or expected to be applicable, at different times during the time period to which the Dispatch Advisory relates;~~

(d) details of the situation that the ~~Dispatch~~ Market Advisory relates to, including the location, extent and seriousness of the situation where AEMO is able to reasonably estimate this information at the time the Market Advisory is issued;

~~(dA) where System Management is to release a Dispatch Advisory under clause 7.11.5(g), details of the estimated Out of Merit quantities, reasons for the deviation from the BMO and all relevant information about the deviation;~~

~~(dB) where System Management is to release a Dispatch Advisory under clause 7.11.5(h), details of the estimated quantities of LFAS that are to be used, reasons for the deviation from the LFAS Merit Order and all relevant information about the deviation;~~

~~(dC) where System Management is to release a Dispatch Advisory under clause 7.11.5(j) or 7.11.5(k), for each Trading Interval, details of the total quantity of load reduction expected due to dispatch of Demand Side Programmes;~~

(e) any actions ~~System Management~~ AEMO plans to take in response to the situation, including whether AEMO's actions constitute an AEMO Intervention Event;

(f) any directions which AEMO has issued to Market Participants and Network Operators in response to the situation; and

(g) where AEMO has developed the WEM Procedure referred to in clause 7.11.10, whether that WEM Procedure applies to the situation.

~~(f) any actions Market Participants and Network Operators are required to take in response to the situation; and~~

~~(g) any actions Market Participants may voluntarily take in response to the situation.~~

7.11.6A. AEMO must issue an updated Market Advisory containing the information in clause 7.11.6(d) as soon as practicable where AEMO revises an estimate of the information or after AEMO is able to reasonably determine the information.

7.11.6~~A~~B. If any information that would otherwise be released under clauses 7.11.6(d), ~~7.11.6(dA), 7.11.6(dC),~~ 7.11.6(e)~~,~~ or 7.11.6(f)~~ or 7.11.6(g)~~ is confidential or has a confidentiality status that would prevent the Economic Regulation Authority from releasing the information,~~ System Management~~ AEMO must:

(a) release that information to the Economic Regulation Authority but, subject to clause 7.11.6~~A~~B(b), ensure that the~~ Dispatch~~ Market Advisory contains information of only a general or aggregate nature so that the information ~~publically~~ publicly released is not confidential; and

(b) include in the~~ Dispatch~~ Market Advisory the details of any circumstance that has given rise to~~ System Management~~ AEMO issuing the~~ Dispatch~~ Market Advisory, including:

i. the name of the Registered Facility or Network element where that Registered Facility or Network element has caused or materially contributed to the circumstances giving rise to the~~ Dispatch~~ Market Advisory;

~~i~~Aii. the name of the Registered Facility, or Registered Facilities, that are likely to be dispatched in response to the~~ Dispatch~~ Market Advisory; and

iii. unless already published, any changes to the inputs to the Dispatch Algorithm that AEMO has made or intends to make in response to the situation identified in the Market Advisory, including changes to Constraint Equations.

~~ii. any likely change in the quantities of energy that, but for the circumstance, would have been dispatched under the Market Rules; and~~

~~iii. the quantities of energy likely to be dispatched Out of Merit.~~

~~7.11.6B. If System Management must issue directions to a Market Participant or a Network Operator under a High Risk Operating State or an Emergency Operating State prior to issuing a Dispatch Advisory then System Management may issue such~~

~~directions as if a Dispatch Advisory had been issued provided that it informs the relevant Market Participant or Network Operator of the applicable SWIS Operating State as soon as practicable.~~

7.11.6C. Where AEMO is required to:

(a) make changes to any inputs to the Dispatch Algorithm; or

(b) issue a direction to a Market Participant or a Network Operator,

prior to issuing a Market Advisory, AEMO may make any such changes and issue any such direction as if a Market Advisory had already been issued. In the case of a direction being issued, AEMO must inform the relevant Market Participant or Network Operator of the applicable SWIS Operating State as soon as practicable.

Explanatory Note Clauses 7.11.7 and 7.11.8 are deleted as the obligations to comply with directions are dealt with in clause 7.7.10 for Market Participants and Chapter 3 for Network Operators.

7.11.7. ~~Subject to clause 7.11.8, Market Participants and Network Operators must comply with directions that System Management issues in any Dispatch Advisory under clause 7.11.6(f), or directly to the Market Participant or Network Operator under clause 7.11.6B.~~[Blank]

7.11.8. ~~A Market Participant or Network Operator is not required to comply with clause 7.11.7 if such compliance would endanger the safety of any person, damage equipment, or breach any applicable law.~~[Blank]

7.11.9. Market Participants, Network Operators and the Economic Regulation Authority must inform ~~System Management~~ AEMO as soon as practicable if they become aware of any circumstances that might reasonably be expected to result in ~~System Management~~ AEMO issuing a ~~Dispatch~~ Market Advisory.

7.11.10. AEMO may document in a WEM Procedure the processes to be followed by AEMO and Market Participants with respect to the events or situations specified in, or contemplated by, this section 7.11, including:

(a) the processes to be followed by Market Participants after receiving a relevant Market Advisory; and

(b) the processes to be followed by AEMO after it has issued a relevant Market Advisory.

Explanatory Note The new price determination provisions are set out in the following new sections: • section 7.11A – Price Determination Principles; • section 7.11B – Determination of Market Clearing Prices; and • section 7.11C – Corrections to Price Determinations and Intervention Pricing.

Section 7.11A sets out the principles for using the Dispatch Algorithm to determine Market Clearing Prices, including handling situations where AEMO applies manual constraints on Registered Facilities, and those constraints mean that the Real-Time Market Submissions of that Facility will not flow through into marginal prices for energy or Essential System Services.

The arrangements with respect to uplift payments are being dealt with in the Settlement workstream. Accordingly, the clause reference in clause 7.11A.1(g) will be specified in due course.

Price Determination

7.11A. Price Determination Principles

7.11A.1. The principles applying to the determination of prices in the Real-Time Market are:

(a) subject to this section 7.11A, a Market Clearing Price at the Reference Node is determined by AEMO using the Central Dispatch process for each Dispatch Interval;

(b) a Reference Trading Price is determined by AEMO as the time-weighted average of the Market Clearing Prices for energy for each Dispatch Interval in a Trading Interval;

(c) Registered Facilities which operate in accordance with a direction in the Central Dispatch process are to be taken into account by AEMO, but AEMO must not use the applicable Real-Time Market Offers or Real-Time Market Bids for those Registered Facilities in the calculation of the Market Clearing Price for the relevant Market Service in the relevant Dispatch Interval;

(d) where a Registered Facility is Inflexible, AEMO must take the Registered Facility into account in the Central Dispatch process, but must not use the price in the Real-Time Market Offer for the applicable Market Service in the calculation of the Market Clearing Price for that Market Service in the relevant Dispatch Interval;

(e) Loss Factors and Network Constraints are to be taken into account by AEMO in the calculation of Market Clearing Prices;

(f) where the Injection or Withdrawal of a Registered Facility is limited above or below the level at which it would otherwise have been dispatched by AEMO on the basis of its Real-Time Market Offer or Real-Time Market Bid for energy due to a Constraint Equation included in the Dispatch Algorithm under clause 7.5.8(a):

i. the Registered Facility's Real-Time Market Offer or Real-Time Market Bid for energy, as applicable, is to be taken into account by AEMO in the determination of dispatch, but the Real-Time Market Offer or Real-Time Market Bid, as applicable, is not to be used by AEMO in the calculation of the Market Clearing Price for energy in the relevant Dispatch Interval; and

ii. the Registered Facility's Real-Time Market Submissions for other Frequency Co-optimised Essential System Services is to be used by AEMO in the determination of dispatch and taken into account in determining the Market Clearing Prices for those Market Services;

(g) subject to [uplift payments clause] , AEMO must apply the Reference Trading Price to both sales and purchases of energy in the relevant Trading Interval;

(h) when a Market Clearing Price is determined for a Frequency Co-optimised Essential System Service, AEMO must apply that price to purchases of that Frequency Co-optimised Essential System Service in the relevant Dispatch Interval; and

(i) where there is a shortfall in a Frequency Co-optimised Essential System Service, AEMO must ensure that the resulting Market Clearing Price for that service is based on the marginal price of providing the last unit of the service that was able to be cleared, whether or not AEMO relaxes those Constraints in accordance with clause 7.2.9.

Explanatory Note

Section 7.11B describes how Market Clearing Prices are to be determined by AEMO.

In abnormal situations, the approach for determining Market Clearing Prices is:

- where the Dispatch Algorithm fails to run, AEMO will use the ‘forecast’ prices (clause 7.11B.1);
- when the Dispatch Algorithm runs but with faulty inputs, AEMO will use the prices from the previous Dispatch Interval (Affected Dispatch Interval – clause 7.11C.1); and
- where AEMO intervenes, AEMO will run a ‘what if’ run without the intervention inputs and use the prices from that run (Intervention Dispatch Interval – clause 7.11C.6).

7.11B. Determination of Market Clearing Prices

7.11B.1. Subject to section 7.11C, where AEMO runs the Dispatch Algorithm, AEMO must determine a Market Clearing Price for each Market Service for a Dispatch Interval in accordance with clause 7.6.1, provided that if AEMO fails to run the Dispatch Algorithm to determine Market Clearing Prices for any Dispatch Interval, then the Market Clearing Prices for that Dispatch Interval are:

(a) if the Dispatch Interval has been included in a previous Dispatch Schedule, the Market Clearing Prices determined for the Dispatch Interval in the most recent Dispatch Schedule that includes the Dispatch Interval; or

(b) if the Dispatch Interval has not been included in a previous Dispatch Schedule, the Market Clearing Prices determined for the Pre-Dispatch Interval containing the Dispatch Interval in the Reference Scenario for the most recent Pre-Dispatch Schedule that includes the Dispatch Interval.

7.11B.2. Subject to clauses 7.11B.3, 7.11B.4 and 7.11B.5, the Market Clearing Price for a Market Service represents the marginal value of that Market Service at the Reference Node at that time, which is calculated as the cost of meeting an incremental change in the requirement for the Market Service at that time in accordance with clause 7.6.5.

7.11B.3. If, for any Dispatch Interval:

(a) the Market Clearing Prices for the Dispatch Interval have not already been determined by the Central Dispatch process;

(b) AEMO reasonably determines that the Central Dispatch Process may determine that there is insufficient capacity to meet all load; and

(c) AEMO has issued Dispatch Instructions that are current for the Dispatch Interval to Market Participants relating to involuntary load shedding, or has issued a non-zero Dispatch Instruction to a Demand Side Programme,

then AEMO must set the Market Clearing Price for Energy for the Dispatch Interval to equal the Alternative Maximum STEM Price.

7.11B.4. If, for any Dispatch Interval, AEMO has declared the Dispatch Interval to be an Affected Dispatch Interval under clause 7.11C.1 or an Intervention Dispatch Interval under clauses 7.11C.5 or 7.11C.10, then AEMO must set the Market Clearing Prices for the Dispatch Interval in accordance with section 7.11C.

7.11B.5. If, for any Dispatch Interval, the Market Clearing Price for a Frequency Co-optimised Essential System Service determined using the Dispatch Algorithm is less than zero, then AEMO must set the Market Clearing Price for the Frequency Co-optimised Essential System Service in that Dispatch Interval to zero.

> **Explanatory Note**
>
> New clauses 7.11C.1 to 7.11C.4 set out a regime that gives AEMO the ability to identify incorrect inputs and adjust prices accordingly. Real-time ex-ante pricing provides limited time for AEMO to identify incorrect input data before it is used in the Central Dispatch process to generate Dispatch Instructions and determine the Market Clearing Prices.

7.11C. Corrections to Price Determinations and Intervention Pricing

7.11C.1. AEMO must develop procedures for the automatic identification of Affected Dispatch Intervals, and must document in a WEM Procedure the conditions or circumstances that would identify a Dispatch Interval as an Affected Dispatch Interval.

7.11C.2. Where AEMO determines that a Dispatch Interval is an Affected Dispatch Interval, and no more than 30 minutes have passed since the publication of the Market Clearing Prices for the Affected Dispatch Interval, AEMO must:

(a) replace all Market Clearing Prices with the corresponding prices for the Last Correct Dispatch Interval; and

(b) recalculate and adjust the Reference Trading Price, in accordance with clause 7.11A.1(b).

7.11C.3. As soon as reasonably practicable after the action referred in clause 7.11C.2, AEMO must publish on the WEM Website a report outlining:

(a) the reasons for determining that a Dispatch Interval was an Affected Dispatch Interval;

(b) whether that determination was correct; and

(c) what action will be taken to minimise the risk of a similar event in future.

7.11C.4. At least once each year, AEMO must review the effectiveness of the automated processes developed by AEMO under clause 7.11C.1 and publish a report on the WEM Website detailing the findings of the review.

7.11C.5. A report under clause 7.11C.4 must:

(a) cover the 12 months' period since the end of the period covered by the last report;

(b) be published within 3 months of the end of the review period covered by the report; and

(c) include the following:

i. details of all Affected Dispatch Intervals which should not have been identified as Affected Dispatch Intervals;

ii. the reasons why the Affected Dispatch Intervals identified under clause 7.11C.5(c)(i) were identified as Affected Dispatch Intervals; and

iii. details of any Dispatch Intervals that AEMO has subsequently determined should have been identified by AEMO as Affected Dispatch Intervals, but were not.

Explanatory Note

New clauses 7.11C.6 to 7.11C.11 set out a regime that is intended to ensure that Market Clearing Prices are not depressed by reason of AEMO's manual intervention. For example, if AEMO directs a Registered Facility on, then it will displace a cheaper Facility, and the marginal price of the next unit of energy will be lower than it otherwise would have been (i.e. because that cheaper generation is now available to provide the marginal unit of energy).

This is a structural effect that is not dealt with by the uplift payment mechanism, because even though the directed Market Participant could be made whole via an uplift payment if negatively mispriced, all other relevant Market Participants would receive a lower Market Clearing Price because of the intervention.

7.11C.6. AEMO must declare a Dispatch Interval to be an Intervention Dispatch Interval where one or more AEMO Intervention Events were in effect in the Dispatch Interval.

7.11C.7. Subject to clauses 7.11C.8(a) and 7.11C.8(b), if, in AEMO's reasonable opinion, the reason for an AEMO Intervention Event is to obtain either:

(a) a Market Service for which a Market Clearing Price is determined by the Dispatch Algorithm; or

(b) a service that is a direct substitute for a Market Service for which a Market Clearing Price is determined by the Dispatch Algorithm,

then AEMO must, in accordance with the methodology or assumptions to be documented in the WEM Procedure referred to in clause 7.11C.11, set the Market Clearing Prices for an Intervention Dispatch Interval at the values which AEMO, in its reasonable opinion, considers would have applied as the Market Clearing Prices for that Dispatch Interval had the AEMO Intervention Event not occurred.

Explanatory Note Where AEMO intervenes to change the dispatch of a Registered Facility that is on the other side of a constraint from the Reference Node, the intervention will not affect the Market Clearing Price at the Reference Node, so no intervention pricing change is required. Where AEMO intervenes to change the dispatch of a Registered Facility that is not behind a constraint, it will affect the market clearing price at the Reference Node. Islanding would be an extreme constraint, in which the Market Clearing Price would be set at the Reference Node, and generators in Islands would qualify for uplift pricing.

7.11C.8. If, in AEMO's reasonable opinion, the reason for an AEMO Intervention Event is to obtain:

(a) energy or a Frequency Co-optimised Essential System Service which, as a result of a Constraint, is only capable of being provided by a Registered Facility in a part of the SWIS which does not include the Reference Node due to the Constraint;

(b) demand response which, as a result of a Constraint, is needed to reduce demand for energy or Frequency Co-optimised Essential System Service in a part of the SWIS which does not include the Reference Node due to the Constraint; or

(c) a service, or any other service for which a Market Clearing Price is not determined by the Dispatch Algorithm, regardless of whether energy or Frequency Co-optimised Essential System Services are also provided incidental to the provision of the service,

then AEMO must continue to set the Market Clearing Prices for the Intervention Dispatch Interval in accordance with section 7.11B.

7.11C.9. If more than one AEMO Intervention Event is in effect in respect of an Intervention Dispatch Interval, AEMO must set the Market Clearing Prices pursuant to clause 7.11C.7 as if:

(a) the services described in clause 7.11C.7 were not provided; and

(b) energy or any Essential System Services provided incidental to the provision of any services described in clause 7.11C.8 were taken into account.

7.11C.10. AEMO must use its reasonable endeavours to set Market Clearing Prices according to clause 7.11C.7 as soon as practicable following an AEMO

Intervention Event, but may continue to set Market Clearing Prices as if no AEMO Intervention Event had occurred until the later of:

(a) if AEMO is able to operate the SWIS in accordance with the Power System Security Principles, the second Dispatch Interval immediately following the first Intervention Dispatch Interval; or

(b) if AEMO is not able to operate the SWIS in accordance with the Power System Security Principles, the second Dispatch Interval after AEMO became able to operate the SWIS in accordance with the Power System Security Principles after the first Intervention Dispatch Interval.

7.11C.11. AEMO must document in a WEM Procedure the methodology it will use, and any assumptions it may be required to make, to determine the Market Clearing Prices under clauses 7.11C.7, 7.11C.8 and 7.11C.10. The methodology must, wherever reasonably practicable:

(a) be consistent with the principles for the determination of Market Clearing Prices set out in section 7.11A; and

(b) enable AEMO to determine and publish such prices in accordance with the applicable timeframes for the publication of the Market Clearing Prices under these WEM Rules.

Explanatory Note

Amendments to section 7.12 will be considered in the Monitoring and Compliance workstream, to account for information that is now provided through the new arrangements for Constraints. For that reason, no changes are proposed to be made at this time.

7.12. Status Reports

7.12.1. System Management must provide a report to the Economic Regulation Authority once every three months on the performance of the market with respect to the dispatch process. This report must include details of:

(a) the incidence and extent of issuance of Operating Instructions and Dispatch Instructions;

(b) the incidence and extent of non-compliance with Operating Instructions and Dispatch Instructions;

(bA) the incidence and reasons for the issuance of Dispatch Instructions to Balancing Facilities Out of Merit, including for the purposes of this clause, issuing Dispatch Orders to the Balancing Portfolio in accordance with clause 7.6.2;

(c) the incidence and extent of transmission constraints;

(d) the incidence and extent of shortfalls in Ancillary Services, involuntary curtailment of load, High Risk Operating States and Emergency Operating States, together with:

i. a summary of the circumstances that caused each such incident; and

ii. a summary of the actions that System Management took in response to the incident in each case; and

(e) the incidence and reasons for the selection and use of LFAS Facilities under clause 7B.3.8.

7.12.2. Economic Regulation Authority must publish the report described in clause 7.12.1 after removing any information that cannot be made public under these Market Rules or which it considers should not be made public.

Explanatory Note

Section 7.13 is proposed to be amended in line with the new Market Information framework.

As some of the clauses in section 7.13 are being dealt with in these draft Amending Rules, and other clauses will be considered in the Outages workstream, we have used placeholders for the new clause numbers. The clause numbers after clause 7.31.1 will be assigned in due course.

The market information in clause [7.13.1x5] is to be treated as confidential. Other information is to be made public on the WEM Website. It is expected this will be reflected in the new framework for Market Information in the Wholesale Electricity Market.

Settlement and Monitoring Data

7.13. Settlement and Monitoring Data

~~7.13.1. System Management must prepare the following data for a Trading Day by noon on the first Business Day following the day on which the Trading Day ends:~~

~~(a) a schedule of all of the Dispatch Orders that System Management issued for each Trading Interval in the Trading Day;~~

~~(b) [Blank]~~

~~(c) a schedule of all of the Dispatch Instructions that System Management issued for each Trading Interval in the Trading Day by Market Participant and Facility, including the information specified in clause 7.7.3;~~

~~(cA) a schedule of the MWh output of each generating system monitored by System Management's SCADA system and an estimate of the output, in MWh, of each generating system not monitored by System Management's SCADA system, for each Trading Interval of the Trading Day;~~

~~(cB) the maximum daily ambient temperature at the site of each generating system monitored by a relevant SCADA system for the Trading Day;~~

~~(cC) a schedule of all of the Operating Instructions that System Management issued for each Trading Interval in the Trading Day by Market Participant and Facility, including the information specified in clause 7.7.3A, together with the reasons for the Operating Instruction;~~

~~(d) a description of the reasons for any failure of a Synergy Facility to follow the scheduling and dispatch procedures relating to clause 7.6A;~~

~~(dA) the MWh quantity by which the Facility was instructed by System Management to increase its output or reduce its consumption under a Network Control Service Contract for each Trading Interval in the Trading Day by Facility;~~

~~(dB) the SOI Quantity and the EOI Quantity of each Facility for each Trading Interval;~~

~~(dC) the Relevant Dispatch Quantity for each Trading Interval;~~

~~(e) for each LFAS Facility, the quantity of any Ex-post Upwards LFAS Enablement that was being provided at the end of each Trading Interval by that LFAS Facility;~~

~~(eA) for each LFAS Facility, the quantity of any Backup Upwards LFAS Enablement that System Management activated by the end of each Trading Interval by that LFAS Facility;~~

~~(eB) for each LFAS Facility, the quantity of any Backup Downwards LFAS Enablement that System Management activated by the end of each Trading Interval by that LFAS Facility;~~

~~(eC) for each LFAS Facility, the quantity of any Ex-post Downwards LFAS Enablement that was being provided at the end of each Trading Interval by that LFAS Facility;~~

~~(eD) by Trading Interval, the Load Rejection Reserve Response Quantity and the Spinning Reserve Response Quantity calculated in accordance with a Power System Operation Procedure;~~

~~(eE) [Blank];~~

~~(eF) the maximum quantity of sent out energy in MWh which each Non-Scheduled Generator, by Trading Interval, would have generated in the Trading Interval had a Dispatch Instruction not been issued, as determined in accordance with clause 7.7.5B;~~

~~(eG) for each Demand Side Programme for each Trading Interval, the requested decrease in consumption calculated under clause 7.13.5(a);~~

~~(eH) the consumption data provided to System Management by each Market Participant with a Demand Side Programme under clause 7.6.10;~~

~~(f) in instances where System Management has not used an LFAS Facility which they would otherwise have been required to use under clause 7B.3.6, the reasons why it has not used the LFAS Facility;~~

~~(g) details of the instructions provided to:~~

~~i. Demand Side Programmes that have Reserve Capacity Obligations; and~~

~~ii. providers of Supplementary Capacity,~~

~~on the Trading Day; and~~

~~(h) the identity of the Facilities that were subject to a Commissioning Test or a Reserve Capacity Test for each Trading Interval of the Trading Day.~~

~~(i) for each Demand Side Programme in each Trading Interval any Further DSM Consumption Decrease.~~

7.13.1. AEMO must publish Market Schedule results in accordance with the Real-Time Market Timetable.

[7.13.1x1]. For each Pre-Dispatch Interval or Dispatch Interval of each Market Schedule, AEMO must publish within 30 minutes of the completion of the Market Schedule (or within 5 minutes of completion for the Dispatch Schedule):

(a) total quantity of Real-Time Market Offers for In-Service Capacity for each Service;

(b) total quantity of Real-Time Market Offers for Available Capacity for each Service;

(c) total quantity of Real-Time Market Bids for In Service Capacity for energy;

(d) total quantity of Real-Time Market Bids for Available Capacity for energy; and

(e) Intervention Constraints.

[7.13.1x2]. For each Pre-Dispatch Interval or Dispatch Interval in each Scenario in each Market Schedule, AEMO must publish within 30 minutes of the completion of the Market Schedule (or within 5 minutes of completion for the Dispatch Schedule):

(a) the Forecast Operational Demand;

(b) projected total quantity required of each Frequency Co-optimised Essential System Service;

(c) projected shortfalls in each Market Service;

(d) projected Dispatch Targets, Dispatch Caps, Dispatch Forecasts as applicable for each Registered Facility;

(e) projected Essential System Service Enablement Quantities for each Registered Facility;

(f) binding Constraint Equations;

(g) Constraint Equations within 10% of binding;

(h) projected Market Clearing Prices for each Market Service;

(i) the Minimum RoCoF Control Requirement;

(j) the Additional RoCoF Control Requirement;

(k) the RoCoF Control Requirement;

(l) the Contingency Raise Factor;

(m) the Contingency Lower Factor;

(n) Facility Performance Factors;

(o) for each Semi-Scheduled Facility the Unadjusted Intermittent Generation Forecast; and

(p) the identity of each Registered Facility that was subject to a Commissioning Test or a Reserve Capacity Test.

[7.13.1x3]. Within 5 minutes of each time AEMO completes a run of the Dispatch Algorithm, AEMO must publish:

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

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

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

(d) binding Constraint Equations;

(e) Constraint Equations within 10% of binding;

(f) the Minimum RoCoF Control Requirement;

(g) the Additional RoCoF Control Requirement;

(h) the RoCoF Control Requirement;

(i) the Contingency Raise Factor;

(j) the Contingency Lower Factor; and

(k) Facility Performance Factors.

[7.13.1x4]. Within 5 minutes of the end of a Trading Interval, AEMO must publish the Reference Trading Price for that Trading Interval.

[7.13.1x5]. For each Pre-Dispatch Interval or Dispatch Interval in each Scenario in each Market Schedule, AEMO must, within 30 minutes of the completion of the Market Schedule (or within 5 minutes of completion for the Dispatch Schedule), make available to each Market Participant:

(a) which of its Registered Facilities clause 7.5.8(a) applies to;

(b) which of its Registered Facilities clause 7.5.8(b) applies to; and

(c) the forecast Enablement Loss for each of its Registered Facilities.

~~7.13.1A. System Management must record the following data for a Trading Day by noon on the fifteenth Business Day following the day on which the Trading Day ends:~~

~~(a) the MWh quantity of non-compliance by Synergy by Trading Interval; and~~

~~(b) the schedule of all Planned Outages, Forced Outages and Consequential Outages relating to each Trading Interval in the Trading Day by Market Participant and Facility.~~

[7.13.1x6]. AEMO must prepare and publish the following data for a Trading Day by noon on the first Business Day following the day on which the Trading Day ends:

(a) for each Dispatch Interval of the Trading Day:

i. the MWh Injection or Withdrawal of each Registered Facility monitored by AEMO's SCADA system;

ii. an estimate of the MWh Injection or Withdrawal of each Registered Facility not monitored by AEMO's SCADA System;

iii. the final Unadjusted Intermittent Generation Forecast;

iv. the Charge Level at the end of the Dispatch Interval of each Electric Storage Resource monitored by AEMO's SCADA system;

v. the MWh output or consumption of each [non-registered behind the meter generating facility or storage facility] monitored by AEMO's SCADA system; and

vi. the EOI Quantity of each Registered Facility.

(b) the maximum daily ambient temperature at the site of each Registered Facility recorded in accordance with clause 4.10.1(e)(iv);

(c) details of each Real-Time Market Submission received for Dispatch Intervals in that Trading Day, including:

i. the Registered Facility IDs;

ii. Price-Quantity Pairs for Market Services;

iii. In-Service Capacity for Injection;

iv. Available Capacity for Injection;

v. In-Service Capacity for Withdrawal;

vi. Available Capacity for Withdrawal;

vii. Maximum Upwards Ramp Rates;

viii. Maximum Downwards Ramp Rates;

ix. Enablement Minimums;

x. Enablement Maximums;

xi. Low Breakpoints;

xii. High Breakpoints;

xiii. Dispatch Inflexibility Profiles; and

xiv. any reasons for revisions in accordance with clauses 7.4.20(a) or 7.4.21(a); and

(d) for each Trading Interval of the Trading Day, the requested decrease in consumption for each Demand Side Programme calculated under clause 7.13.5(a).

[7.13.1x7]. AEMO must record, and publish by noon on the fifteenth Business Day following the day on which the Trading Day ends, an estimate of the Injection or Withdrawal in MWh of each Registered Facility not monitored by AEMO's SCADA system for the Trading Day.

~~7.13.1B. If System Management is prevented from completing the relevant processes that enable the recording of the data described in clause 7.13.1, System Management may delay the recording of the data by up to two business days.~~

[7.13.1x8]. If AEMO is prevented from completing the relevant processes that enable the recording of the data described in clause [7.13.1x1, 7.13.1x2, 7.13.1x3, 7.13.1x4, 7.13.1x5, 7.13.1x6 and 7.13.1x7], AEMO may delay the preparation and publication of the data by up to two Business Days.

7.13.1C. ~~System Management~~AEMO must record:

(a) [Blank]~~for each Facility, all information made available to System Management under the Power System Operation Procedure developed under clause 7.7.5A;~~

(b) an estimate of the total quantity of energy not served (in MWh) due to involuntary load shedding (manual and automatic);

(c) an estimate of the reduction in ~~energy consumption~~ Withdrawal (in MWh) of any Interruptible Loads ~~in accordance with the terms of an Ancillary Service Contract~~ in the provision of Contingency Reserve Raise,~~;~~

(d) [Blank]~~a schedule of all instructions, including Dispatch Orders, provided to Synergy's Non-Scheduled Generators to deviate from the Dispatch Plan or change their commitment or output in accordance with clause 7.6A.3; and~~

(e) [Blank]~~an estimate of the decrease in the output (in MWh) of each of Synergy's Non-Scheduled Generators as a result of an instruction from System Management to deviate from the Dispatch Plan or change their commitment or output in accordance with clause 7.6A.3(a),~~

for each Trading Interval.

7.13.1CA. AEMO may, if it reasonably considers it is required in order to estimate, or support AEMO's estimate of, the quantity referred to in clause 7.13.1C(b), request information from Rule Participants in respect to any involuntary load shedding. A Rule Participant must comply with a request under this clause 7.13.1CA within the time specified in the request.

Explanatory Note

Any required changes to clauses 7.13.1D to 7.13.1G, including to reflect any Administrative Amendments referred to in the cover Note to these draft Amending Rules, will be considered in the Outages workstream.

7.13.1D. System Management must as soon as practicable after:

(a) System Management receives a request via System Management's computer interface system for a Planned Outage of a Scheduled Generator or a Non-Scheduled Generator; or

(b) System Management becomes aware via System Management's computer interface system of a change to the information described in clause 7.13.1E,

record any relevant new or amended information outlined in clause 7.13.1E.

7.13.1E The information required to be recorded by System Management under clause 7.13.1D must include:

(a) whether the request is for a Scheduled Outage or Opportunistic Maintenance;

(b) the information provided under clauses 3.18.6(a) and 3.18.6(c) - (g);

(c) the time and date when:

i. the Outage Plan was received by System Management;

ii. any amendment to the outage status occurred; and

(d) the MW quantity of any de-rating to a Scheduled Generator or Non-Scheduled Generator, as measured on a sent out basis at 15 degrees Celsius.

7.13.1F. System Management must as soon as practicable after:

(a) System Management receives a notification of a Forced Outage via its computer interface system or records in its computer interface system that a Consequential Outage has occurred for a Scheduled Generator or a Non-Scheduled Generator; or

(b) System Management becomes aware via System Management's computer interface system of any change to the information described in clause 7.13.1G,

record any relevant new or amended information outlined in clause 7.13.1G

7.13.1G. The information required to be recorded by System Management under clause 7.13.1F must include:

(a) whether the outage is considered to be a Forced Outage or Consequential Outage;

(b) the information provided under clauses 3.21.4(a) - 3.21.4(d);

(c) the time and date when:

i. the Forced Outage was first notified to System Management;

ii. the outage status was amended by System Management; and

iii. System Management recorded in its computer interface system that a Consequential Outage occurred as determined under clause 3.21.2; and

(d) the MW quantity of any de-rating to a Scheduled Generator or Non-Scheduled Generator, as measured on a sent out basis at 15 degrees Celsius.

Explanatory Note Clause 7.13.2 is to be deleted as the timing requirement is now specified with the data.

7.13.2. [Blank]~~System Management must maintain systems capable of providing the data described in clause 10.5.1(y) to the Market Web Site as soon as practicable following the completion of a Trading Interval.~~

7.13.3. ~~System Management~~AEMO must document in a ~~Power System Operation~~ WEM Procedure the procedure to be followed by Rule Participants in providing settlement and monitoring data to AEMO.

7.13.4. ~~System Management~~AEMO must maintain SCADA data by Registered Facility ~~and the Operational System Load Estimate~~.

7.13.5. ~~System Management must—~~AEMO must:

(a) for the purposes of clause [7.13.1x6](d), calculate, for each Demand Side Programme for each Trading Interval, the amount, in MWh, by which the Facility was requested by the applicable Dispatch Instruction to decrease its consumption for the Trading Interval, which ~~amount—~~ amount:

i. must be measured as a requested decrease from the Facility's Relevant Demand (and so must not include any amount above the Relevant Demand);

ii. must not assume a ramp rate faster than was requested in the Dispatch Instruction; and

iii. [Blank]~~must not include any Further DSM Consumption Decrease; and~~

iv. must not take account of the Facility's actual performance in response to the Dispatch Instruction; and

(b) develop a ~~Power System Operation~~ WEM Procedure that details how it will calculate the amount in clause 7.13.5(a).

Explanatory Note

Chapters 7A and 7B are to be deleted and is replaced with a new framework that implements a fully-co-optimised security-constrained economic dispatch market design.

~~7A. Balancing Market~~

~~7A.1. Balancing Market~~

~~7A.1.1. AEMO must operate the Balancing Market.~~

~~7A.1.2. [Blank]~~

~~7A.1.3. The objectives of the Balancing Market are to:~~

~~(a) enable Balancing Facilities to participate in the Balancing Market;~~

~~(b) dispatch the lowest-cost combination of Facilities made available for dispatch in the Balancing Market;~~

~~(c) establish a Balancing Price which is consistent with dispatch;~~

~~(d) seek to ensure timely and accurate energy pricing and dispatch quantity information, including forecasts, and system security information, is provided to all Market Participants; and~~

~~(e) seek to ensure timely and accurate information relevant to the operation and administration of the Balancing Market is provided to affected Rule Participants.~~

~~7A.1.4. The Balancing Market Objectives support, but are subservient to, the Wholesale Market Objectives. To the extent that an application of the Balancing Market Objectives results in an inconsistency with the Wholesale Market Objectives, the latter prevails to the extent of the inconsistency.~~

~~7A.1.5. All Rule Participants must take into account the Balancing Market Objectives in undertaking their functions and obligations under this Chapter 7A.~~

~~7A.1.6. AEMO must specify the following matters in a Market Procedure:~~

~~(a) the technical and communication criteria that a Balancing Facility (or a type of Balancing Facility) must meet, including:~~

~~i. Facility quantity parameters and limits for participation in the Balancing Market;~~

~~ii. the manner and forms of communication to be used while participating in the Balancing Market, including when receiving Dispatch Instructions; and~~

~~iii. ramp rate limitations; and~~

(b) ~~the type of conditions AEMO may impose under clause 7A.1.11(b) and the manner and circumstances in which they may be imposed and lifted.~~

~~7A.1.7. [Blank]~~

~~7A.1.8. A Market Participant must ensure that its Balancing Facilities with a rated capacity equal to or greater than 10 MW meet the relevant specifications of the Balancing Facility Requirements.~~

~~7A.1.9. A Market Participant may inform AEMO that a Balancing Facility registered to that Market Participant with a rated capacity less than 10 MW meets the relevant specifications of the Balancing Facility Requirements.~~

~~7A.1.10. A Market Participant must, when required to do so by AEMO, provide in writing all information reasonably required by AEMO in order to demonstrate that a Balancing Facility registered to that Market Participant meets the relevant specifications of the Balancing Facility Requirements.~~

~~7A.1.11. If based on the information provided to it under clause 7A.1.10, AEMO determines that a Balancing Facility, including a Balancing Facility with a rated capacity of less than 10 MW, does not meet the relevant specifications of the Balancing Facility Requirements, AEMO may impose conditions on the manner in which that Balancing Facility must participate in the Balancing Market under these Market Rules, including:~~

~~(a) the prices at which the Market Participant may include in a Balancing Submission in Balancing Price-Quantity Pairs for that Facility; and~~

~~(b) the manner and time in which a Balancing Submission for that Balancing Facility must be submitted.~~

~~7A.1.12. Where a condition imposed by AEMO under clause 7A.1.11 is inconsistent with another clause in the Market Rules the condition is to be given effect notwithstanding that inconsistency.~~

~~7A.1.13. AEMO must publish a decision to impose a condition on a Balancing Facility under clause 7A.1.11 together with the details of such condition.~~

~~7A.1.14. For the purposes of this Chapter 7A only, unless otherwise indicated, the Balancing Portfolio is to be treated as a single Balancing Facility and references in this Chapter 7A to a Balancing Facility are to be read as including a reference to the Balancing Portfolio.~~

~~7A.1.15. Where this Chapter 7A imposes a timeframe of "as soon as reasonably practicable", AEMO may prescribe, in a Market Procedure, the latest time by which it must be done.~~

~~7A.1.16. With effect on and from the Trading Interval commencing at 8:00 AM on the Balancing Market Commencement Day, AEMO must determine a point in time~~

~~immediately before the commencement of a Trading Interval for the purpose of setting the Balancing Gate Closure. The point in time must be no shorter than two hours and no longer than six hours before the commencement of a Trading Interval and must be published on the Market Web Site.~~

~~7A.1.17. AEMO may, from time to time, change the point in time determined under clause 7A.1.16 by publishing the new point in time on the Market Web Site and specifying the date from which the new point in time is to take effect, which shall be no earlier than 2 months from the date of publication.~~

~~7A.2. Balancing Submissions~~

~~7A.2.1. A Market Participant must at all times ensure that it has made a Balancing Submission in accordance with clause 7A.2.4 for each Trading Interval in the Balancing Horizon for each of its Balancing Facilities.~~

~~7A.2.2. A Market Participant may submit a subsequent Balancing Submission in accordance with clause 7A.2.4 in respect of any of its Balancing Facilities, excluding Facilities in the Balancing Portfolio, and:~~

~~(a) the Balancing Submission may be for one or more Trading Intervals in the Balancing Horizon; and~~

~~(b) the Balancing Submission must be made before Balancing Gate Closure for any Trading Interval in the submission.~~

~~7A.2.3. A Market Participant with a Balancing Facility that is:~~

~~(a) the subject of an Operating Instruction; or~~

~~(b) undergoing a Test that has an approved Test Plan,~~

~~must ensure that a Balancing Submission submitted under this section 7A.2 is consistent with the proposed operation of the Balancing Facility for each Trading Interval specified in the Operating Instruction or the Test Plan. The provisions of this clause 7A.2.3 do not apply to the Balancing Portfolio.~~

~~7A.2.4. A Balancing Submission must:~~

~~(a) be in the manner and form prescribed and published by AEMO;~~

~~(b) constitute a declaration by an Authorised Officer;~~

~~(c) have Balancing Price-Quantity Pair prices within the Price Caps;~~

~~(d) specify, for each Trading Interval covered in the Balancing Submission, whether the Balancing Facility is to use Liquid Fuel or Non-Liquid Fuel;~~

~~(e) specify the Ramp Rate Limit or the Portfolio Ramp Rate Limit (as applicable) for each Trading Interval covered in the Balancing Submission; and~~

~~(f) specify the available capacity and the unavailable capacity as determined under clause 7A.2.4A, 7A.2.4B or 7A.2.4C (as applicable) for each Trading Interval covered in the Balancing Submission.~~

~~7A.2.4A. A Balancing Submission for a Balancing Facility that is a Scheduled Generator must specify the following details for each Trading Interval covered in the Balancing Submission:~~

~~(a) a ranking of Balancing Price-Quantity Pairs covering available capacity; and~~

~~(b) a declaration of the MW quantity that will be unavailable for dispatch,~~

~~where the sum of:~~

~~(c) the quantities in the Balancing Price-Quantity Pairs; and~~

~~(d) the declared MW quantity of unavailable capacity,~~

~~must be equal to the Scheduled Generator's Sent Out Capacity.~~

~~7A.2.4B. A Balancing Submission for a Balancing Facility that is a Non-Scheduled Generator must specify, for each Trading Interval covered in the Balancing Submission, a single Balancing Price-Quantity Pair with a MW quantity equal to the Market Participant's best estimate of the Facility's output at the end of the Trading Interval (based on an assumption, for the purposes of this clause 7A.2.4B, that the Facility will not be subject to a Dispatch Instruction that limits its output during that Trading Interval).~~

~~7A.2.4C. A Balancing Submission for the Balancing Portfolio must specify the following details for each Trading Interval covered in the Balancing Submission:~~

~~(a) a ranking of Balancing Price-Quantity Pairs covering available capacity in the Balancing Portfolio; and~~

~~(b) a declaration of the MW quantity of capacity of Scheduled Generators in the Balancing Portfolio that will be unavailable for dispatch.~~

~~7A.2.5. For the purposes of clause 7A.2.4(b), where AEMO accepts a Balancing Submission from a Market Participant that complies with clause 7A.2.4(a), the submission will be deemed to constitute a declaration by an Authorised Officer of the Market Participant.~~

~~7A.2.6. A subsequent Balancing Submission made under clauses 7A.2.2, 7A.2.9(d), 7A.2.9(e), 7A.2.9(f), 7A.2.9B, 7A.2.9C, 7A.2.10 or 7A.3.5 in respect of the same Balancing Facility covering the same Trading Interval as an earlier Balancing Submission, overrides the earlier Balancing Submission for, and has effect in relation to, that Trading Interval.~~

~~7A.2.7. Where a subsequent Balancing Submission is made under clause 7A.2.6, a Market Participant must create and maintain internal records of the reasons for submitting the subsequent Balancing Submission, including details of any~~

~~changed circumstances and the impacts of those circumstances that gave rise to the new Balancing Submission.~~

~~7A.2.8. A Market Participant (other than Synergy in relation to the Balancing Portfolio) must ensure that, for each Trading Interval in the Balancing Horizon for which Balancing Gate Closure has not occurred, its most recently submitted Balancing Submission in respect of its Balancing Facility and that Trading Interval accurately reflects:~~

~~(a) all information reasonably available to the Market Participant, including Balancing Forecasts published by AEMO, the information provided by AEMO under clause 7A.3.1(c) and the latest information available to it in relation to any Internal Constraint or External Constraint;~~

~~(b) the Market Participant's reasonable expectation of the capability of its Balancing Facilities to be dispatched in the Balancing Market; and~~

~~(c) the price at which the Market Participant submitting the Balancing Submission intends to have the Balancing Facility participate in the Balancing Market.~~

~~7A.2.8A. A Market Participant (other than Synergy in respect of the Balancing Portfolio) must, for each of its Balancing Facilities, and for each Trading Interval in the Balancing Horizon, use its best endeavours to ensure that, at all times, any of the Facility's capacity that is:~~

~~(a) subject to an approved Planned Outage; or~~

~~(b) subject to an outstanding request for approval of Opportunistic Maintenance,~~

~~is declared as unavailable in the Balancing Submission for the Facility and the Trading Interval, unless the Balancing Facility is expected to generate in accordance with an approved Commissioning Test in that Trading Interval.~~

~~7A.2.9. Synergy, in relation to the Balancing Portfolio:~~

~~(a) must, subject to clauses 7A.2.9(d) to 7A.2.9(f), ensure that for each Trading Interval in the Balancing Horizon the most recently submitted Balancing Submission in respect of that Trading Interval accurately reflects:~~

~~i. all information reasonably available to Synergy, including Balancing Forecasts published by AEMO and the latest information available to Synergy in relation to any Forced Outage for a Facility in the Balancing Portfolio;~~

~~ii. subject to clause 7A.2.9A(b), Synergy's reasonable expectation of the capability of its Balancing Portfolio to be dispatched in the Balancing Market for that Trading Interval; and~~

~~iii. the price at which Synergy intends to have the Balancing Portfolio participate in the Balancing Market;~~

~~(b) must indicate in a manner and form prescribed by AEMO:~~

~~i. which of the Balancing Price-Quantity Pairs that it has priced at the Minimum STEM Price are for Facilities that are to provide LFAS;~~

~~ii. which Facilities are likely to provide LFAS; and~~

~~iii. for each completed Trading Interval, which Facilities actually provided the LFAS in the Trading Interval;~~

~~(c) must:~~

~~i. ensure that quantities in the Balancing Price-Quantity Pairs in its Balancing Submissions that are required for the provision of Ancillary Services, other than LFAS, are priced at the Price Caps;~~

~~ii. advise AEMO in a manner and form prescribed by AEMO, the Facilities which are likely to provide the quantities specified in clause 7A.2.9(c)(i); and~~

~~iii. for each completed Trading Interval, advise AEMO which Facilities actually provided the Ancillary Services referred to in clause 7A.2.9(c)(i) in the Trading Interval;~~

~~(d) may submit a new, updated Balancing Submission in relation to any Trading Interval in the Balancing Horizon for which Balancing Gate Closure is more than two hours in the future:~~

~~i. by submitting its updated Balancing Submission to AEMO immediately before 1:00 PM; or~~

~~ii. otherwise by submitting its updated Balancing Submission to AEMO within one hour after LFAS Gate Closure;~~

~~(e) may submit a new, updated Balancing Submission in relation to any Trading Interval in the Balancing Horizon for which Balancing Gate Closure is more than two hours in the future if a Facility in the Balancing Portfolio has experienced a Forced Outage since the last Balancing Submission;~~

~~(f) may after the time specified in clause 7A.2.9(d), submit a new, updated Balancing Submission to reflect the impact of a Forced Outage which Synergy expects will cause a Facility to run on Liquid Fuel, where the Facility would not have run on Liquid Fuel but for the Forced Outage, in order to meet Synergy's Balancing Market obligations in relation to the Balancing Portfolio under this Chapter 7A; and~~

~~(g) must, as soon as it becomes aware that:~~

~~i. either:~~

~~1. a Facility in the Balancing Portfolio has experienced a Forced Outage; or~~

~~2. System Management has approved a request for Opportunistic Maintenance for a Facility in the Balancing Portfolio; and~~

ii. ~~the outage will reduce the available capacity of the Balancing Portfolio in a Trading Interval in the Balancing Horizon from the quantity reported as available in the current Balancing Submission for that Trading Interval; and~~

iii. ~~there is a credible risk that representation of the relevant capacity as available in the Balancing Submission might, in the circumstances:~~

1. ~~affect any expected EOI Quantity provided to another Market Participant for the Trading Interval under clause 7A.3.1(c); or~~

2. ~~cause System Management to dispatch Balancing Facilities Out of Merit under clauses 7.6.1C(b) or 7.6.1C(c),~~

~~submit a new, updated Balancing Submission for the Trading Interval to:~~

iv. ~~make any relevant Scheduled Generator capacity subject to the outage unavailable; and~~

v. ~~unless otherwise permitted under clauses 7A.2.9(d) to 7A.2.9(f), remove or reduce the quantity of the highest price Balancing Price-Quantity Pair or Balancing Price-Quantity Pairs (excluding any Balancing Price-Quantity Pairs that are required to be offered at the Price Caps under clause 7A.2.9(c)) to remove the capacity subject to the outage from its Balancing Price-Quantity Pairs.~~

~~7A.2.9A. Synergy must, to the extent it is able to update its Balancing Submissions subject to clauses 7A.2.9(d) to 7A.2.9(g) (as applicable), for each Scheduled Generator in the Balancing Portfolio, and for each Trading Interval in the Balancing Horizon, use its best endeavours to ensure that, at all times:~~

~~(a) any of the Scheduled Generator's capacity that is subject to an approved Planned Outage is declared as unavailable in the Balancing Submission for the Balancing Portfolio and that Trading Interval, except where that Scheduled Generator is expected to generate in accordance with an approved Commissioning Test; and~~

~~(b) any of the Scheduled Generator's capacity that is subject to an outstanding request for approval of Opportunistic Maintenance is declared as available in the Balancing Submission for the Balancing Portfolio and that Trading Interval.~~

~~7A.2.9B. If System Management rejects a previously approved Planned Outage of a Balancing Facility (or a Facility in the Balancing Portfolio) under clause 3.19.5, then the relevant Market Participant must, as soon as practicable, update its Balancing Submission for any relevant Trading Intervals in the Balancing Horizon for which:~~

~~(a) the Market Participant can make the relevant capacity available for dispatch, taking into account any relevant Equipment Limits; and~~

~~(b) Balancing Gate Closure has not yet occurred,~~

~~to reflect that the capacity will not be subject to a Planned Outage in those Trading Intervals.~~

~~7A.2.9C. If System Management directs a Market Participant to return a Balancing Facility or a Facility in the Balancing Portfolio from a Planned Outage in accordance with an Outage Contingency Plan under clause 3.20.1, then the Market Participant must, as soon as practicable, update its Balancing Submission for any relevant Trading Intervals in the Balancing Horizon for which Balancing Gate Closure has not yet occurred, to reflect the impact of System Management's direction on the proposed end time of the Planned Outage.~~

~~7A.2.10. A Market Participant (other than Synergy in relation to the Balancing Portfolio) as soon as it becomes aware that a Balancing Submission for a Trading Interval for which Balancing Gate Closure has occurred is inaccurate:~~

~~(a) if the inaccuracy is due to an Internal Constraint, must make a new, accurate Balancing Submission so that the quantity in the Balancing Submission reflects the available Sent Out Capacity of that Facility and the Ramp Rate Limit is accurate but no prices are altered, in respect of that Trading Interval as soon as reasonably practicable;~~

~~(b) if the inaccuracy is due to an External Constraint, may make a new, accurate Balancing Submission so that the quantity in the Balancing Submission reflects the available Sent Out Capacity of that Facility and the Ramp Rate Limit is accurate but no prices are altered, in respect of that Trading Interval, as soon as reasonably practicable;~~

~~(c) if the inaccuracy is due to the Market Participant receiving an Operating Instruction, may make a new, accurate Balancing Submission that reflects the Operating Instruction; or~~

~~(d) if the inaccuracy is due to a variation of the availability of the intermittent energy source used by a Non-Scheduled Generator, may make a new, accurate Balancing Submission so that the quantity in the Balancing Submission reflects the Market Participant's best estimate of the Facility's output at the end of the Trading Interval and the Ramp Rate Limit is accurate but the price is not altered, in respect of that Trading Interval.~~

~~7A.2.10A. A Market Participant (other than Synergy in relation to the Balancing Portfolio) must not submit a new, updated Balancing Submission in respect of a Trading Interval for which Balancing Gate Closure has occurred except in accordance with clause 7A.2.10.~~

~~7A.2.11. Where a Market Participant has submitted a Balancing Submission in accordance with clauses 7A.2.10(a) or 7A.2.10(b) after Balancing Gate Closure, the Market Participant must, as soon as reasonably practicable, provide AEMO with written details of the nature of the Internal Constraint or External Constraint, when it occurred and its duration.~~

~~7A.2.12. Where Synergy has submitted an updated Balancing Submission for the Balancing Portfolio in accordance with clauses 7A.2.9(e) or 7A.2.9(f) because of a Forced Outage of one of the Facilities in the Balancing Portfolio after the time specified in the applicable clause it must, as soon as reasonably practicable, provide AEMO with written details of:~~

~~(a) the nature of the Forced Outage;~~

~~(b) when the Forced Outage occurred;~~

~~(c) the duration of the Forced Outage; and~~

~~(d) information substantiating the commercial impact, if any, of the Forced Outage.~~

~~7A.2.13. A Market Participant must:~~

~~(a) make a Balancing Submission under this section 7A.2 in good faith;~~

~~(b) not act in a manner that:~~

~~i. is intended to lead; or~~

~~ii. the Market Participant should have reasonably known is likely to lead,~~

~~to another Rule Participant being misled or deceived as to the existence or non-existence of a material fact relating to the Balancing Market; and~~

~~(c) not include information in a Balancing Submission relating to prices for a purpose of influencing the determination of the Constrained Off Compensation Price, the Constrained Off Quantity which the Facility may provide, the Constrained On Compensation Price or the Constrained On Quantity which the Facility may provide.~~

~~7A.2.14. A Balancing Submission is made in good faith under clause 7A.2.13 if, at the time it is submitted, the Market Participant had a genuine intention to honour the terms of that Balancing Submission if the material conditions and circumstances upon which the Balancing Submission was based remained unchanged until the relevant Trading Interval.~~

~~7A.2.15. A Market Participant may be taken to have not made a Balancing Submission in good faith notwithstanding that the intention of the Market Participant is ascertainable only by inference from:~~

~~(a) the conduct of the Market Participant;~~

~~(b) the conduct of any other person; or~~

~~(c) the relevant circumstances.~~

~~7A.2.16.~~

~~(a) If a Market Participant does not have reasonable grounds for a price, quantity or Ramp Rate Limit it has included in a Balancing Submission at~~

~~the time it submits that Balancing Submission, then the Market Participant is, for the purposes of clause 7A.2.13(b), taken to have known that the Balancing Submission was likely to lead to another Rule Participant being misled or deceived as to the existence or non-existence of a material fact relating to the Balancing Market.~~

~~(b) For the purposes of clause 7A.2.16(a), a Market Participant must adduce evidence that it had reasonable grounds for including a price, quantity or Ramp Rate Limit in the Balancing Submission.~~

~~(c) To avoid doubt, the effect of clause 7A.2.16(b) is to place an evidentiary burden on a Market Participant, and clause 7A.2.16(b) does not have the effect that, merely because such evidence is adduced, the Market Participant who submitted the Balancing Submission is taken to have had reasonable grounds for including a price, quantity or Ramp Rate Limit, as applicable.~~

~~(d) Clause 7A.2.16(a) does not imply that merely because the Market Participant had reasonable grounds for making the representation or the conduct referred to in this Chapter 7A, and in particular putting the price, quantity or Ramp Rate Limit in a Balancing Submission submitted by a Market Participant, that such representation or conduct is not misleading.~~

~~7A.2.17. Subject to clauses 7A.2.3, 7A.2.9(c) and 7A.3.5, a Market Participant must not, for any Trading Interval, offer prices in its Balancing Submission in excess of the Market Participant's reasonable expectation of the short run marginal cost of generating the relevant electricity by the Balancing Facility, when such behaviour relates to market power.~~

~~7A.2.18. In determining whether a Market Participant has made a Balancing Submission in accordance with its obligations under this Chapter 7A, the Economic Regulation Authority or AEMO, as applicable, may take into account:~~

~~(a) historical Balancing Submissions, including changes made to Balancing Submissions, in which a pattern of behaviour may indicate an intention to create a false impression in the Balancing Market;~~

~~(b) the timeliness and accuracy of notification of Forced Outages, Internal Constraints, External Constraints and any information provided under clauses 7A.2.11 or 7A.2.12;~~

~~(c) any information as to whether a Facility was not able to comply with a Dispatch Instruction from AEMO (in its capacity as System Management) and the reasons for that non-compliance; and~~

~~(d) any other information that is considered by the Economic Regulation Authority or AEMO, as applicable, to be relevant.~~

~~7A.2.19. For the purpose of regulation 37(a) of the WEM Regulations, where a civil penalty is imposed for a contravention of clauses 7A.2.8, 7A.2.9, 7A.2.13 or 7A.2.17 the civil penalty amount should be distributed amongst all Market Participants in~~

~~proportion to their Market Fees calculated over the previous full 12 months, or part thereof if the Balancing Market Commencement Day was less than 12 months, prior to the date the civil penalty is received.~~

~~7A.2A. Accounting for Unavailable Capacity in a Balancing Submission~~

~~7A.2A.1. Subject to clauses 7A.2A.3 and 7A.2A.4, a Market Participant (other than Synergy in respect of the Balancing Portfolio) must, as soon as practicable after each Trading Interval, for each of its Balancing Facilities that is an Outage Facility, ensure that it has notified System Management of a Forced Outage or Consequential Outage that relates to any capacity for which the Market Participant holds Capacity Credits that:~~

~~(a) was declared unavailable in the Facility's Balancing Submission for that Trading Interval; and~~

~~(b) was not subject to an approved Planned Outage, Consequential Outage or Commissioning Test Plan in that Trading Interval,~~

~~unless the relevant capacity was declared unavailable in the Facility's Balancing Submission because the Market Participant reasonably expected that its Reserve Capacity Obligations for the Trading Interval would be reduced because the maximum site temperature for the applicable Trading Day would exceed 41 degrees Celsius.~~

~~7A.2A.2. Subject to clauses 7A.2A.3 and 7A.2A.4, Synergy must, as soon as practicable after each Trading Interval, for each Facility in the Balancing Portfolio that is an Outage Facility, ensure that it has notified System Management of a Forced Outage or Consequential Outage that relates to any capacity for which Synergy holds Capacity Credits that:~~

~~(a) was declared unavailable in the Balancing Portfolio's Balancing Submission for that Trading Interval; and~~

~~(b) was not subject to an approved Planned Outage, Consequential Outage or Commissioning Test Plan in that Trading Interval,~~

~~unless the relevant capacity was declared unavailable in the Balancing Portfolio's Balancing Submission because Synergy reasonably expected that its Reserve Capacity Obligations for the Trading Interval would be reduced because the maximum site temperature for the applicable Trading Day would exceed 41 degrees Celsius.~~

~~7A.2A.3. Clauses 7A.2A.1 and 7A.2A.2 do not apply in respect of a Trading Interval if:~~

~~(a) the relevant capacity was previously subject to an approved Planned Outage for the Trading Interval; and~~

~~(b) System Management notified the Market Participant of the rejection of the Planned Outage under clause 3.19.5:~~

~~i. less than 30 minutes before Balancing Gate Closure for the Trading Interval; or~~

~~ii. at a time when the Facility was not synchronised and could not be synchronised by the start of the Trading Interval given the Facility's relevant Equipment Limits.~~

~~7A.2A.4. Clauses 7A.2A.1 and 7A.2A.2 do not apply in respect of a Trading Interval if:~~

~~(a) the relevant capacity was previously subject to an approved Consequential Outage or Commissioning Test Plan for the Trading Interval; and~~

~~(b) System Management notified the Market Participant that the capacity was no longer subject to the Consequential Outage or Commissioning Test Plan for the Trading Interval:~~

~~i. less than 30 minutes before:~~

~~1. Balancing Gate Closure for the Trading Interval, for a Facility that is not in the Balancing Portfolio; or~~

~~2. the latest time specified in clause 7A.2.9(d) for the Trading Interval, for a Facility in the Balancing Portfolio; or~~

~~ii. at a time when the Facility was not synchronised and could not be synchronised by the start of the Trading Interval given the Facility's relevant Equipment Limits.~~

~~7A.3. Forecast BMO and Pricing BMO~~

~~7A.3.1. AEMO must, to the extent that it is reasonably able, as soon as practicable during the first 15 minutes of each Trading Interval, for each future Trading Interval in the Balancing Horizon:~~

~~(a) determine the Forecast BMO in accordance with clause 7A.3.2 using the most recent, valid Balancing Submissions available to it;~~

~~(b) provide System Management with the Forecast BMO determined under clause 7A.3.1(a);~~

~~(c) provide each Market Participant with the EOI Quantities expected to be provided by each of that Market Participant's Balancing Facilities in the Forecast BMO determined under clause 7A.3.1(a); and~~

~~(d) if AEMO has sufficient information available to it, determine the Balancing Forecast in accordance with the Market Procedure specified in clause 7A.3.3 and publish it on the Market Web Site.~~

~~7A.3.2. AEMO must determine a Forecast BMO for a Trading Interval for the purposes of clause 7A.3.1(a) by:~~

~~(a) converting the prices in Balancing Price-Quantity Pairs contained in Balancing Submissions for that Trading Interval into Loss Factor Adjusted Prices, for all Balancing Facilities except the Balancing Portfolio;~~

~~(b) subject to clause 7A.3.2(c), ranking the Balancing Price-Quantity Pairs and associated Balancing Facilities contained in Balancing Submissions for that Trading Interval in order of lowest to highest price, where these prices have been adjusted where appropriate in accordance with clause 7A.3.2(a);~~

~~(c) where there is a tie in the ranking of Balancing Facilities under clause 7A.3.2(b), breaking the tie in accordance with the Market Procedure specified in clause 7A.3.3; and~~

~~(d) where a forecast of the EOI Quantity for a Non-Scheduled Generator prepared under clause 7A.3.15 is available, adjusting the Non-Scheduled Generator's Balancing Submission to reflect that quantity.~~

~~7A.3.3. AEMO must document in a Market Procedure the processes it must follow when:~~

~~(a) determining Forecast BMOs and providing them to System Management;~~

~~(b) preparing and publishing Balancing Forecasts; and~~

~~(c) assigning priority to Facilities in the case where there is a tie in a Forecast BMO or Forecast LFAS Merit Order.~~

~~7A.3.4. AEMO must develop the Market Procedure specified in clause 7A.3.3 in accordance with the following principles:~~

~~(a) to the extent reasonably practicable, Balancing Forecasts must use the latest information available to AEMO; and~~

~~(b) Balancing Forecasts must provide Market Participants with information upon which to make an assessment regarding their Balancing Submissions and whether to update a Balancing Submission.~~

~~7A.3.5. A Market Participant, other than Synergy in respect of the Balancing Portfolio, must, within 60 minutes after LFAS Gate Closure for an LFAS Horizon, for each Trading Interval in that LFAS Horizon, use its best endeavours to make a new Balancing Submission for each of its LFAS Facilities in the LFAS Enablement Schedules for that Trading Interval, which must fulfil the following conditions:~~

~~(a) the total quantity in Balancing Price-Quantity Pairs priced at the Alternative Maximum STEM Price is at least the Upwards LFAS Enablement for the Facility; and~~

~~(b) the total quantity in Balancing Price-Quantity Pairs priced at the Minimum STEM Price is at least the quantity of capacity for the Facility specified in Appendix 1(b)(xiii) plus the Downwards LFAS Enablement for the Facility.~~

~~7A.3.6. [Blank]~~

~~7A.3.7. System Management must, no later than two hours after the end of the Trading Day, prepare an estimate of:~~

~~(a) the SOI Quantity and the EOI Quantity for each Balancing Facility; and~~

~~(b) the Relevant Dispatch Quantity,~~

~~for each Trading Interval in the Trading Day, determined in accordance with a Power System Operation Procedure.~~

~~7A.3.7A. System Management must make reasonable endeavours to prepare, no later than five minutes after the end of each Trading Interval, an estimate of:~~

~~(a) the SOI Quantity and the EOI Quantity for each Balancing Facility; and~~

~~(b) the Relevant Dispatch Quantity,~~

~~for that Trading Interval, determined in accordance with a Power System Operation Procedure.~~

~~7A.3.8. AEMO must, by the end of a Trading Day where System Management has prepared the information under clause 7A.3.7 for a Trading Interval in the previous Trading Day:~~

~~(a) use that information to determine a Provisional Pricing BMO for that Trading Interval, being the last Forecast BMO generated by AEMO for the Trading Interval, adjusted to take into account:~~

~~i. Balancing Submissions made after AEMO has generated the last Forecast BMO for the Trading Interval;~~

~~ii. for the Balancing Portfolio and Balancing Facilities that are Scheduled Generators, the associated Ramp Rate Limits to reflect the physically achievable capacity of the Balancing Portfolio or Balancing Facility given the SOI Quantity; and~~

~~iii. for Balancing Facilities that are Non-Scheduled Generators, the EOI Quantity,~~

~~where the SOI Quantity and the EOI Quantity are the quantities prepared by System Management under clause 7A.3.7;~~

~~(b) use the Provisional Pricing BMO under clause 7A.3.8(a) to determine the Provisional Balancing Price, being the Loss Factor Adjusted Price corresponding to the point where the estimated Relevant Dispatch Quantity plus 1 MW intersects the Provisional Pricing BMO; and~~

~~(c) publish the Provisional Balancing Price on the Market Web Site.~~

~~7A.3.9. System Management must, as soon as reasonably practicable but in any event no later than 24 hours after the start of the Business Day following the time specified in clause 7A.3.7, make updated adjustments to the information recorded under clause 7A.3.7 and AEMO must use any such updated SOI Quantity and EOI Quantity information to revise the Provisional Pricing BMO accordingly.~~

~~7A.3.9A. AEMO must determine the Pricing BMO, which is the Provisional Pricing BMO, adjusted in accordance with clause 7A.3.9 as appropriate.~~

~~7A.3.10. AEMO must, subject to clause 7A.3.13, calculate the Balancing Price using the Pricing BMO determined under clause 7A.3.9A, being the Loss Factor Adjusted Price corresponding to the point where the Relevant Dispatch Quantity plus 1 MW intersects the Pricing BMO.~~

~~7A.3.11. AEMO must publish the Balancing Price for each Trading Interval in a Trading Day on the next Business Day after the latest time specified in clause 7A.3.9.~~

~~7A.3.12. [Blank]~~

~~7A.3.13. If AEMO is unable to determine the Balancing Price under clause 7A.3.10 in time to publish it in accordance with clause 7A.3.11, then AEMO must determine the Balancing Price:~~

~~(a) where the Relevant Dispatch Quantity and/or Pricing BMO is not available, AEMO must use the most recent estimate of the Relevant Dispatch Quantity and/or the Forecast BMO for the Trading Interval so that the Balancing Price is the point where the Relevant Dispatch Quantity or most recent estimate of the Relevant Dispatch Quantity (as applicable) plus 1 MW intersects the Pricing BMO or Forecast BMO (as applicable); or~~

~~(b) [Blank]~~

~~(c) where there is no Forecast BMO:~~

~~i. if AEMO is determining the Balancing Price for a Trading Interval in a Business Day, the Balancing Price will be the value for the equivalent Trading Interval in the most recent Trading Day in the past which is also a Business Day; or~~

~~ii. if AEMO is determining the Balancing Price for a Trading Interval in a day which is not a Business Day, the Balancing Price will be the value for the equivalent Trading Interval in the most recent Trading Day in the past which is also not a Business Day.~~

~~7A.3.14. Once AEMO has published the Balancing Price under clause 7A.3.11 it cannot be altered by:~~

~~(a) disagreement under clause 9.20.6; or~~

~~(b) disputes under clause 9.21.1.~~

~~7A.3.15. System Management must, for each future Trading Interval in the Balancing Horizon, prepare a forecast of the Relevant Dispatch Quantity, and may prepare a forecast of the EOI Quantity for Non-Scheduled Generators, each determined in accordance with a Power System Operation Procedure. System Management must, each time it has new information on which to determine these quantities, update these forecasts, but is not required to do so more than once per Trading Interval.~~

~~7A.4. Synergy – Stand Alone Facilities~~

~~7A.4.1. Synergy may, at any time, nominate one of its Scheduled Generators or Non-Scheduled Generators to be trialled as a Stand Alone Facility by providing notice to AEMO in the prescribed form.~~

~~7A.4.2. Subject to clause 7A.4.3, AEMO must, as soon as reasonably practicable after receiving the information specified in clause 7A.4.1—~~

~~(a) determine whether the Facility should be rejected as a Stand Alone Facility due to potential impacts on the performance of System Management Functions in relation to the SWIS if the Facility were to become a Stand Alone Facility, and if not, must otherwise accept the nomination; and~~

~~(b) [Blank]~~

~~(c) [Blank]~~

~~(d) [Blank]~~

~~(e) notify Synergy of AEMO's decision.~~

~~7A.4.3. A Facility may undergo a trial as a Stand Alone Facility under this clause 7A.4 once only.~~

~~7A.4.4. If AEMO notifies Synergy that it accepts the nomination of the Stand Alone Facility for a trial, then:~~

~~(a) AEMO must notify Synergy of the Trading Day from which the trial of the nominated Stand Alone Facility will commence;~~

~~(b) subject to clause 7A.4.4(d), Synergy may trial the nominated Stand Alone Facility for a period of one month for the purposes of participating in the Balancing Market in accordance with this Chapter 7A;~~

~~(c) seven Business Days before the end of that month Synergy must notify AEMO whether it wishes the nominated Stand Alone Facility to:~~

~~i. cease being a Stand Alone Facility and to form part of the Balancing Portfolio; or~~

~~ii. permanently become a Stand Alone Facility; and~~

~~(d) the nominated Stand Alone Facility will be treated as a Stand Alone Facility until it becomes a permanent Stand Alone Facility under clause 7A.4.9 or the trial ceases under clause 7A.4.8.~~

~~7A.4.5. If Synergy provides a notice under clause 7A.4.4(c)(i), then AEMO must notify Synergy of the time and date from which the nominated Stand Alone Facility will cease to be treated as a Stand Alone Facility.~~

~~7A.4.6. If Synergy provides a notice under clause 7A.4.4(c)(ii), then AEMO must:~~

~~(a) determine whether it should reject the nomination in light of the trial, having regard to any potential impacts on the performance of its functions in~~

~~relation to the SWIS if the nominated Stand Alone Facility permanently becomes a Stand Alone Facility, and if not, must otherwise accept the nomination; and~~

~~(b) [Blank]~~

~~(c) [Blank]~~

~~(d) notify Synergy of AEMO's decision and the reasons for that decision.~~

~~7A.4.7. AEMO must, as soon as practicable after receiving a notice by Synergy under clause 7A.4.6(a)—~~

~~(a) consider all information reasonably available to it, including—~~

~~i. the potential impacts on the performance of System Management Functions in relation to the SWIS (if the nomination of the Stand Alone Facility is accepted or rejected), including system constraint impacts; and~~

~~ii. impacts on the provision of Ancillary Services; and~~

~~(b) prepare reasons for its decision to reject or accept the nomination.~~

~~7A.4.8. If AEMO notifies Synergy that the nominated Stand Alone Facility is not to permanently become a Stand Alone Facility the nominated Stand Alone Facility will cease to be treated as a Stand Alone Facility from the time and date specified by AEMO in the notice to Synergy.~~

~~7A.4.9. The nominated Stand Alone Facility permanently becomes a Stand Alone Facility if AEMO notifies Synergy that it is to permanently become a Stand Alone Facility.~~

~~7B. Load Following Service Market~~

~~7B.1. LFAS Market~~

~~7B.1.1. AEMO must operate the LFAS Market.~~

~~7B.1.2. System Management must, in a Power System Operation Procedure, specify any technical and communication criteria that an LFAS Facility, or a type of LFAS Facility, must meet, including:~~

~~(a) Facility quantity parameters and limits in providing LFAS, including the Minimum LFAS Quantity;~~

~~(b) the manner and forms of communication to be used in providing LFAS, including how LFAS Facilities which are Non-Scheduled Generators, are to be activated; and~~

~~(c) the nature and type of any enablement and quantity restrictions that will apply.~~

~~7B.1.3. A Market Participant must ensure that its LFAS Facility and any LFAS Submission meets the LFAS Facility Requirements.~~

~~7B.1.4. System Management must, by 12:00 PM on the Scheduling Day, determine the Forecast Upwards LFAS Quantity and the Forecast Downwards LFAS Quantity for each Trading Interval in the next Trading Day in accordance with a Power System Operation Procedure.~~

~~7B.1.5. System Management may update the Forecast LFAS Quantities determined under clause 7B.1.4 for a Trading Interval in the Balancing Horizon at any time until one hour before the LFAS Gate Closure for that Trading Interval. System Management may update the Forecast LFAS Quantities more than once.~~

~~7B.2. LFAS Submissions~~

~~7B.2.1. A Market Participant may submit an LFAS Submission in respect of any of its LFAS Facilities, other than the Balancing Portfolio:~~

~~(a) in accordance with clause 7B.2.7;~~

~~(b) for any or all Trading Intervals in the Balancing Horizon; and~~

~~(c) before LFAS Gate Closure for those Trading Intervals.~~

~~7B.2.2. A Market Participant may submit an updated LFAS Submission in respect of any of its LFAS Facilities other than the Balancing Portfolio:~~

~~(a) in accordance with clause 7B.2.7;~~

~~(b) for one or more Trading Intervals in the Balancing Horizon; and~~

~~(c) before LFAS Gate Closure for those Trading Intervals.~~

~~7B.2.3. Synergy must, immediately before 1:00 PM, submit an LFAS Submission, for all Trading Intervals in the Balancing Horizon for which it has not already made an LFAS Submission, by submitting it to AEMO in accordance with clauses 7B.2.5, 7B.2.6 and 7B.2.7.~~

~~7B.2.4. Subject to clause 7B.2.5, Synergy may submit an updated LFAS Submission in respect of the Balancing Portfolio:~~

~~(a) in accordance with clauses 7B.2.6 and 7B.2.7;~~

~~(aA) for one or more Trading Intervals in the Balancing Horizon for which LFAS Gate Closure has not occurred; and~~

~~(b) at the time it makes an updated Balancing Submission under clause 7A.2.9(d).~~

~~7B.2.5. Synergy must ensure that, for each Trading Interval for which it has made LFAS Submissions:~~

~~(a) the sum of the MW quantities contained in the Upwards LFAS Price-Quantity Pairs in those LFAS Submissions equals at least the latest~~

~~Forecast Upwards LFAS Quantity for that Trading Interval published under clause 7B.3.1(d)(i), if any; and~~

~~(b) the sum of the MW quantities contained in the Downwards LFAS Price-Quantity Pairs in those LFAS Submissions equals at least the latest Forecast Downwards LFAS Quantity for that Trading Interval published under clause 7B.3.1(d)(i), if any.~~

~~7B.2.6. Synergy, in its LFAS Submission for the Balancing Portfolio, must include a cost per MW for providing any Backup Upwards LFAS Enablement and for providing any Backup Downwards LFAS Enablement for each Trading Interval in the Balancing Horizon.~~

~~7B.2.7. An LFAS Submission must:~~

~~(a) be in the manner and form prescribed and published by AEMO;~~

~~(b) constitute a declaration by an Authorised Officer; and~~

~~(c) abide by any enablement or quantity restrictions specified under clause 2.34.7A.~~

~~7B.2.8. For the purposes of clause 7B.2.7(b), where AEMO accepts an LFAS Submission from a Market Participant that complies with clause 7B.2.7(a), the submission will be deemed to constitute a declaration by an Authorised Officer of the Market Participant.~~

~~7B.2.9. A subsequent LFAS Submission made under clauses 7B.2.2 or 7B.2.4 in respect of the same LFAS Facility covering the same Trading Interval as an earlier LFAS Submission, overrides the earlier LFAS Submission for, and has effect in relation to, that Trading Interval.~~

~~7B.2.10. Subject to clause 7B.2.4, a Market Participant with an LFAS Facility must ensure that, for each Trading Interval in an LFAS Horizon for which LFAS Gate Closure has not occurred, its most recent LFAS Submission in respect of that LFAS Facility and Trading Interval (if any) accurately reflects:~~

~~(a) all information reasonably available to it;~~

~~(b) the Market Participant's reasonable expectation of the capability of the LFAS Facility to provide the LFAS to the LFAS Market; and~~

~~(c) the price at which the Market Participant intends to have the LFAS Facility provide LFAS.~~

~~7B.2.11. A Market Participant must:~~

~~(a) make an LFAS Submission under this clause 7B.2 in good faith; and~~

~~(b) not act in a manner that:~~

~~i. is intended to lead; or~~

~~ii. the Market Participant should have reasonably known is likely to lead,~~

~~to another Rule Participant being misled or deceived as to the existence or non-existence of a material fact relating to the LFAS Market.~~

~~7B.2.12. An LFAS Submission is made in good faith under clause 7B.2.11 if, at the time it is submitted, the Market Participant had a genuine intention to honour the terms of that LFAS Submission if the material conditions and circumstances upon which the LFAS Submission was based remained unchanged until the relevant Trading Interval.~~

~~7B.2.13. A Market Participant may be taken to have not made an LFAS Submission in good faith notwithstanding that the intention of the Market Participant is ascertainable only by inference from:~~

~~(a) the conduct of the Market Participant;~~

~~(b) the conduct of any other person; or~~

~~(c) the relevant circumstances.~~

~~7B.2.14.~~

~~(a) If a Market Participant does not have reasonable grounds for the price and quantity it has included in a LFAS Submission at the time it submits the LFAS Submission, then the Market Participant is, for the purposes of clause 7B.2.11(b), taken to have known that the LFAS Submission was likely to lead to another Rule Participant being misled or deceived as to the existence or non-existence of a material fact relating to the LFAS Market.~~

~~(b) For the purposes of clause 7B.2.14(a), a Market Participant must adduce evidence that it had reasonable grounds for including the price or quantity in the LFAS Submission.~~

~~(c) To avoid doubt, the effect of clause 7B.2.14(b) is to place an evidentiary burden on a Market Participant, and clause 7B.2.14(b) does not have the effect that, merely because such evidence is adduced, the Market Participant who submitted the LFAS Submission is taken to have had reasonable grounds for including the price or quantity, as applicable.~~

~~(d) Clause 7B.2.14(a) does not imply that merely because the Market Participant had reasonable grounds for making the representation or the conduct referred to in this Chapter 7B, and in particular putting the price or quantity in a LFAS Submission submitted by a Market Participant, that such representation or conduct is not misleading.~~

~~7B.2.15. A Market Participant must not, for any Trading Interval, offer prices within its LFAS Submission in excess of the Market Participant's reasonable expectation of the incremental change in short run marginal cost incurred by the LFAS Facility providing LFAS when such behaviour relates to market power.~~

~~7B.2.16. In determining whether a Market Participant has made an LFAS Submission in accordance with its obligations under this Chapter 7B, the Economic Regulation Authority or AEMO, as applicable, may take into account:~~

~~(a) historical LFAS Submissions and/or Balancing Submissions, including changes made to LFAS Submissions and/or Balancing Submissions in which a pattern of behaviour may indicate an intention to create a false impression in the LFAS Market;~~

~~(b) any information as to whether a Facility was not able to provide LFAS and the reasons for that failure; and~~

~~(c) any other information that is considered by the Economic Regulation Authority or AEMO, as applicable, to be relevant.~~

~~7B.2.17. For the purpose of regulation 37(a) of the WEM Regulations, where a civil penalty is imposed for a contravention of clauses 7B.2.10, 7B.2.11 or 7B.2.15, the civil penalty amount must be distributed amongst all Market Participants in proportion to their Market Fees calculated over the previous full 12 months, or part thereof if the Balancing Market Commencement Day was less than 12 months, prior to the date the civil penalty is received.~~

~~7B.2.18. A Market Participant must, as soon as it becomes aware that an LFAS Facility registered to the Market Participant in an LFAS Enablement Schedule is physically unable to provide some or all of its LFAS Enablement, advise System Management, in the manner and form prescribed by System Management, whether the LFAS Facility is physically able to provide any LFAS in that Trading Interval and if so, the quantity, in MW.~~

~~7B.2.19. A Market Participant must, unless it has provided advice to System Management under clause 7B.2.18, ensure that LFAS Facilities registered to the Market Participant in the LFAS Enablement Schedule provide the relevant LFAS in the Trading Interval when required to do so by System Management under the Market Rules.~~

~~7B.3. LFAS Merit Orders and LFAS Prices~~

~~7B.3.1. AEMO must, to the extent that it is reasonably able, as soon as practicable during the first 15 minutes of each Trading Interval, for all Trading Intervals for which LFAS Gate Closure occurred at the end of the previous Trading Interval and for each later Trading Interval in the Balancing Horizon:~~

~~(a) determine using the most recent, valid LFAS Submissions available to it:~~

~~i. the Forecast Upwards LFAS Merit Order in accordance with clause 7B.3.2(a);~~

~~ii. the Forecast Downwards LFAS Merit Order in accordance with clause 7B.3.2(b);~~

~~iii. the Forecast Upwards LFAS Enablement Schedule in accordance with clause 7B.3.3(a);~~

~~iv. the Forecast Downwards LFAS Enablement Schedule in accordance with clause 7B.3.3(b);~~

~~v. the Forecast Upwards LFAS Price in accordance with clause 7B.3.4(a); and~~

~~vi. the Forecast Downwards LFAS Price in accordance with clause 7B.3.4(b);~~

~~(b) provide System Management with the Forecast LFAS Enablement Schedules determined under clauses 7B.3.1(a)(iii) and 7B.3.1(a)(iv);~~

~~(c) notify each Market Participant with an LFAS Facility in an LFAS Enablement Schedule determined under clause 7B.3.1(a)(iii) or 7B.3.1(a)(iv) of the details of the Market Participant's LFAS Enablements in respect of the LFAS Facility; and~~

~~(d) publish on the Market Web Site to each Market Participant:~~

~~i. the most recent Forecast LFAS Quantities provided by System Management under clauses 7B.1.4 or 7B.1.5;~~

~~ii. the Forecast LFAS Merit Orders, determined under clauses 7B.3.1(a)(i) and 7B.3.1(a)(ii), in the form of anonymous LFAS Price-Quantity Pairs;~~

~~iii. the Forecast LFAS Prices, provided in clauses 7B.3.1(a)(v) and 7B.3.1(a)(vi); and~~

~~iv. the Forecast Backup LFAS Prices, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6.~~

~~7B.3.2. AEMO must:~~

~~(a) subject to clause 7B.3.2(c), determine a Forecast Upwards LFAS Merit Order for a Trading Interval for the purposes of clause 7B.3.1(a)(i) by ranking Upwards LFAS Price-Quantity Pairs and associated LFAS Facilities contained in LFAS Submissions for that Trading Interval in order of lowest to highest price;~~

~~(b) subject to clause 7B.3.2(c), determine a Forecast Downwards LFAS Merit Order for a Trading Interval for the purposes of clause 7B.3.1(a)(ii) by ranking Downwards LFAS Price-Quantity Pairs and associated LFAS Facilities contained in LFAS Submissions for that Trading Interval in order of lowest to highest price; and~~

~~(c) if there is a tie in the ranking of LFAS Facilities in the LFAS Merit Order under clauses 7B.3.2(a) or 7B.3.2(b), then AEMO must break the tie for the Trading Interval in which the tie occurred in accordance with the Market Procedure specified in clause 7A.3.3.~~

~~7B.3.3. AEMO must:~~

~~(a) determine a Forecast Upwards LFAS Enablement Schedule for a Trading Interval for the purposes of clause 7B.3.1(a)(iii) by selecting the lowest priced Upwards LFAS Price-Quantity Pairs and associated LFAS Facilities from the Forecast Upwards LFAS Merit Order determined under clause 7B.3.1(a)(i), so that:~~

~~i. the sum of the quantities in the selected Upwards LFAS Price-Quantity Pairs equals the Forecast Upwards LFAS Quantity; and~~

~~ii. if only part of the quantity in the highest priced Upwards LFAS Price-Quantity Pair selected is required to make up the Forecast Upwards LFAS Quantity, that Upwards LFAS Price-Quantity Pair is selected for that part of the offered quantity only; and~~

~~(b) determine a Forecast Downwards LFAS Enablement Schedule for a Trading Interval for the purposes of clause 7B.3.1(a)(iv) by selecting the lowest priced Downwards LFAS Price-Quantity Pairs and associated LFAS Facilities from the Forecast Downwards LFAS Merit Order determined under clause 7B.3.1(a)(ii), so that:~~

~~i. the sum of the quantities in the selected Downwards LFAS Price-Quantity Pairs equals the Forecast Downwards LFAS Quantity; and~~

~~ii. if only part of the quantity in the highest priced Downwards LFAS Price-Quantity Pair selected is required to make up the Forecast Downwards LFAS Quantity, that Downwards LFAS Price-Quantity Pair is selected for that part of the offered quantity only.~~

~~7B.3.4. AEMO must:~~

~~(a) determine a Forecast Upwards LFAS Price for a Trading Interval for the purposes of clause 7B.3.1(a)(v) by determining the highest price in those Upwards LFAS Price-Quantity Pairs in the Forecast Upwards Enablement Schedule; and~~

~~(b) determine a Forecast Downwards LFAS Price for a Trading Interval for the purposes of clause 7B.3.1(a)(vi) by determining the highest price in those Downwards LFAS Price-Quantity Pairs in the Forecast Downwards Enablement Schedule.~~

~~7B.3.5. [Blank]~~

~~7B.3.6. Subject to clauses 7B.2.18, 7B.3.7, 7B.3.8 and 7B.4.1, for each Trading Interval, System Management must activate each LFAS Facility in each LFAS Enablement Schedule for its full LFAS Enablement and use those LFAS Facilities to provide the relevant LFAS in reasonable proportion to their relevant LFAS Enablement, and those LFAS Facilities must provide that LFAS.~~

~~7B.3.7. Where an LFAS Enablement Schedule for a Trading Interval does not exist, System Management must use Synergy's LFAS Facilities to provide LFAS for that Trading Interval.~~

~~7B.3.8. System Management may select and use LFAS Facilities other than in accordance with an LFAS Enablement Schedule where System Management considers, on reasonable grounds, that it needs to do so in order to ensure the SWIS is operated in a reliable and safe manner.~~

~~7B.3.9. [Blank]~~

~~7B.3.10. [Blank]~~

~~7B.3.11. AEMO must, by the end of a Trading Day, publish the LFAS Prices for each Trading Interval for that Trading Day.~~

~~7B.3.12. If AEMO is unable to determine an LFAS Price under clauses 7B.3.4(a) or 7B.3.4(b) in time to publish it in accordance with clause 7B.3.11, AEMO must determine that LFAS Price as follows:~~

~~(a) if AEMO is determining an LFAS Price for a Trading Interval in a Business Day, that LFAS Price will be the value of the equivalent LFAS Price for the equivalent Trading Interval in the most recent Trading Day in the past which is also a Business Day; or~~

~~(b) if AEMO is determining an LFAS Price for a Trading Interval in a day which is not a Business Day, that LFAS Price will be the value of the equivalent LFAS Price for the equivalent Trading Interval in the most recent Trading Day in the past which is also not a Business Day.~~

~~7B.3.13. Once AEMO has published an LFAS Price under clause 7B.3.11 it cannot be altered by:~~

~~(a) disagreement under clause 9.20.6; or~~

~~(b) disputes under clause 9.21.1.~~

~~7B.4. Synergy Backup LFAS Provider~~

~~7B.4.1. Where:~~

~~(a) an LFAS Facility in an LFAS Enablement Schedule has failed to provide all or part of its LFAS Enablement when called upon to do so by System Management in accordance with clause 7B.3.6 or 7B.3.8;~~

~~(aA) the LFAS Enablement of an LFAS Facility in an LFAS Enablement Schedule is greater than the LFAS Facility's available capacity, taking into account the BMO, Ramp Rate Limits and the quantities for the Facility specified in Appendix 1(b)(iii), Appendix 1(b)(xiii) and Appendix 1(b)(xv); or~~

~~(b) the quantity of upwards or downwards LFAS in a Trading Interval required by System Management is greater than the Upwards LFAS Quantity or Downwards LFAS Quantity for that Trading Interval,~~

~~System Management may use the Balancing Portfolio or a Stand Alone Facility, to provide the LFAS Quantity Balance and/or the Increased LFAS Quantity, as applicable.~~

~~7B.4.2. Where System Management has used the Balancing Portfolio or a Stand Alone Facility to provide LFAS under clause 7B.3.7 or 7B.4.1 in a Trading Interval, System Management must, as soon as reasonably practicable, make a record of the Facilities which provided the LFAS and the quantity, in MW, of LFAS which was provided by the Facility in the Trading Interval.~~

…

Explanatory Note

The proposed amendment to clause 9.3.1(a) is a consequential amendment resulting from the new framework for Essential System Services. This is a placeholder only, as Chapter 9 is expected to be substantially redrafted in the Settlement workstream.

9.3. Data Collection

9.3.1. The following information is to be used by AEMO in performing its settlement obligations:

(a) [Blank]~~the Ancillary Service, and outage compensation settlement data described in clause 3.22~~;

(b) the Reserve Capacity settlement data described in clause 4.29;

(c) the Network Control Service settlement data described in clause 5.9; and

(d) the Energy Market Settlement data described in clause 6.21.

…

Explanatory Note

The proposed amendment to the section 9.9 heading is a consequential amendment resulting from the new framework for Essential System Services. This is a placeholder only, as Chapter 9 is expected to be substantially redrafted in the Settlement workstream.

9.9. The ~~Ancillary~~ Essential System Service Settlement Calculations for a Trading Month

…

Explanatory Note

The proposed amendments to clause 9.11.1 are consequential amendment resulting from the new framework for Essential System Services. This is a placeholder only, as Chapter 9 is expected to be substantially redrafted in the Settlement workstream.

9.11. The Reconciliation of Settlement Calculations for a Trading Month

9.11.1. The Reconciliation Settlement amount for Market Participant p for Trading Month m is:

RSA(p,m) = (-1) x Consumption_Share(p,m) x
(Sum(q∈P,d∈D,t∈T,BSA(q,d,t))
~~+ Cost_LR_Shortfall(m))~~

Where

Consumption_Share(p,m) is the proportion of consumption associated with Market Participant p for Trading Month m determined by AEMO in accordance with clause 9.3.7;

BSA(q,d,t) is the Balancing Settlement amount for Market Participant q for Trading Day d and Trading Interval t;

~~Cost_LR_Shortfall(m) is determined in accordance with clause 9.9.3B;~~

P is the set of all Market Participants, where "p" and "q" are both used to refer to a member of that set;

D is the set of all Trading Days in Trading Month m, where "d" is used to refer to a member of that set; and

T is the set of all Trading Intervals in Trading Day d, where "t" refers to a member of that set.

…

Explanatory Note The proposed amendment to clause 9.18.3(c)(ix)(3) is a consequential amendment resulting from the new framework for Essential System Services. This is a placeholder only, as Chapter 9 is expected to be substantially redrafted in the Settlement workstream.

9.18. Non-STEM Settlement Statements

…

9.18.3. A Non-STEM Settlement Statement must contain the following information:

(a) details of the Trading Days covered by the Non-STEM Settlement Statement;

(b) the identity of the Market Participant to which the Non-STEM Settlement Statement relates;

(c) for each Trading Interval of each Trading Day:

…

ix. details of amounts calculated for the Market Participant under sections 9.7 to 9.14 with respect to:

1. Reserve Capacity settlement;
2. Balancing Settlement;
3. ~~Ancillary~~ Essential System Services settlement;
4. Outage compensation settlement;
5. Reconciliation settlement;
6. [Blank]
7. Fee settlement; and
8. Net Monthly Non-STEM Settlement Amount;

…

…

…

Explanatory Note

The proposed amendment to clause 9.24.3A(a)(ii) is a consequential amendment resulting from the new framework for Essential System Services. This is a placeholder only, as Chapter 9 is expected to be substantially redrafted in the Settlement workstream.

9.24. Settlement in Default Situations

…

9.24.3. Notwithstanding anything else in these ~~Market~~ WEM Rules, if at any time the total amount received by AEMO from Rule Participants in cleared funds ("**Total Amount**") is not sufficient to make the payments which AEMO is required to make under these ~~Market~~ WEM Rules (for example, as a result of default by one or more Rule Participants), then AEMO's liability to make those payments is limited to the Total Amount.

9.24.3A AEMO must apply the Total Amount as follows.

(a) First, AEMO must apply the Total Amount to satisfy:

i. payment of Service Fee Settlement Amounts to AEMO and the Economic Regulation Authority (including as contemplated by clause 9.22.10);

ii. payments which AEMO is required to make under Supplementary Capacity Contracts ~~or to a provider of Ancillary Services holding an Ancillary Service Contract with AEMO (in its capacity as System Management),~~ up to a maximum for any party of the net amount which, if sufficient funds were available, would be payable to that party; and

iii. [Blank]

iv. funds required to be disgorged or repaid by AEMO as contemplated by clause 9.24.2;

but if the Total Amount is not sufficient to satisfy all of these payments then AEMO must reduce the payments proportionally. Each payment will be based on the proportion that the Total Amount bears to the amount that would have been required to make all payments.

…

…

Explanatory Note

Chapter 10 is proposed to be amended to give effect to a new framework for managing Market Information in the Wholesale Electricity Market. It is expected that the amendments to Chapter 10, which are being progressed in the Market Information workstream, will include amendments to the relevant market information the subject of the changes in these draft Amending Rules.

Amendments will also be made to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

In the meantime, for the purposes of clause 3.15B.4(d), placeholder amendments have been made to clause 10.5.1(y) and clause 10.5.1(z), for completeness.

10 Market Information

…

10.5. Public Information

10.5.1. AEMO must set the class of confidentiality status for the following information under clause 10.2.1 as Public and AEMO must make each item of information available from or via the ~~Market Web Site~~ WEM Website after that item of information becomes available to AEMO:

…

(y) as soon as practicable after a Trading Interval or Dispatch Interval:

i. the total generation in that Trading Interval or Dispatch Interval;

ii. the total dispatched quantity of each Frequency Co-optimised Essential System Services ~~Spinning Reserve~~ in that Trading Interval or Dispatch Interval; and

iii. an initial value of the Operational System Load Estimate,

where these values are to be available from the ~~Market Web Site~~ WEM Website for each Trading Interval or Dispatch Interval in the previous 12 calendar months;

(z) as soon as practicable after real-time:

i. the total generation; and

ii. the total offer quantity of each Frequency Co-optimised Essential System Services ~~Spinning Reserve~~,

where these values are not required to be maintained on the ~~Market Web Site~~ WEM Website after their initial publication;

…

Explanatory Note

The Chapter 11 Glossary is proposed to be amended to amend, delete or add the following definitions in line with these draft Amending Rules.

In particular, the definitions that are marked as proposed to be deleted are redundant in the new frameworks.

11. Glossary

…

Accumulated Time Error: For a measurement of SWIS Frequency, means the difference in time measured by integrating the instantaneous operating frequency of the SWIS.

…

Additional RoCoF Control Requirement: For a Dispatch Interval, the RoCoF Control Requirement less the Minimum RoCoF Control Requirement.

…

AEMO Intervention Event: An event where AEMO intervenes in the Real-Time Market by issuing a direction in accordance with clause 3.4.6, clause 3.4.7, clause 7.7.4(b), or clause 7.7.5.

…

Affected Dispatch Interval: A Dispatch Interval for which the Dispatch Algorithm has been used to determine Dispatch Targets, Dispatch Caps and Market Clearing Prices, but the Dispatch Inputs included manifestly incorrect data that AEMO reasonably considers have caused material differences in Market Clearing Prices.

…

Alternative Network Constraint Equation: A Constraint Equation formulation for a Network Constraint other than a Fully Co-optimised Network Constraint Equation.

…

~~**Ancillary Service**: A service, including those described in clause 3.9, that is required to maintain Power System Security and Power System Reliability, facilitate orderly trading in electricity and ensure that electricity supplies are of acceptable quality.~~

~~**Ancillary Service Contract**: A contract between System Management and a Market Participant for the provision by that Market Participant of an Ancillary Service or Ancillary Services to System Management.~~

~~**Ancillary Service Declaration**: A declaration included with a STEM Submission or Standing STEM Submission made by a Market Participant which is a provider of Ancillary Services and which includes the information described in clause 6.6.2A(c).~~

~~**Ancillary Service Provider**: A Rule Participant registered as an Ancillary Service Provider under clause 2.28.11A.~~

~~**Ancillary Service Requirements**: Are as determined in accordance with clause 3.11.~~

…

Approval to Generate Notification: Means the notification issued by the Network Operator to a Market Participant in accordance with clause 3A.8.12 granting final approval to a Transmission Connected Generating System to generate electricity.

…

Automatic Generation Control System (AGC): The system into which Dispatch Targets are entered for Registered Facilities operating on automatic generation control.

Availability Payment: Means the dollar amount payable to the Market Participant for offering the Availability Quantity of Frequency Co-optimised Essential System Service into the market according to the SESSM Service Specification.

Availability Quantity: Means the MW or MWs quantity of a Frequency Co-optimised Essential System Service to be made available in a Dispatch Interval by a Facility notified by AEMO.

~~**Available Capacity**: Means, for a Trading Interval, the sent out capacity, in MW, of a Scheduled Generator or a Non-Scheduled Generator that was not subject to an Outage notified to AEMO under clause 7.13.1A(b).~~

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

…

~~**Backup Downwards LFAS Enablement**: Means, for a Synergy LFAS Facility, the capacity in MW which System Management has activated under clauses 7B.3.7 or 7B.4.1 in a Trading Interval to compensate for a shortfall in Downwards LFAS Enablement, and which has been recorded under clause 7B.4.2.~~

~~**Backup Downwards LFAS Price**: Means the cost referred to in clause 7B.2.6 for Synergy providing Backup Downwards LFAS Enablement for a Trading Interval, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6.~~

~~**Backup LFAS Enablement**: Means Backup Downwards LFAS Enablement and/or Backup Upwards LFAS Enablement, as applicable.~~

~~**Backup LFAS Price**: Means the Backup Downwards LFAS Price and/or the Backup Upwards LFAS Price, as applicable.~~

~~**Backup Upwards LFAS Enablement**: Means, for a Synergy LFAS Facility, the capacity in MW which System Management has activated under clauses 7B.3.7 or 7B.4.1 in a Trading Interval to compensate for a shortfall in Upwards LFAS Enablement, and which has been recorded under clause 7B.4.2.~~

~~**Backup Upwards LFAS Price**: Means the cost referred to in clause 7B.2.6 for Synergy providing Backup Upwards LFAS Enablement for a Trading Interval, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6.~~

~~**Balancing Facility**: Means:~~

~~(a) for a Market Generator other than Synergy:~~

~~i. each of its Scheduled Generators; and~~

~~ii. each of its Non-Scheduled Generators; and~~

~~(b) each Stand Alone Facility.~~

~~**Balancing Facility Requirements**: Means the technical and communication criteria that a Balancing Facility, or a type of Balancing Facility, must meet, which are set out in the Market Procedure developed under clause 7A.1.6.~~

~~**Balancing Forecast**: Means, with respect to a Trading Interval, AEMO's forecast of each of the following matters (as determined in accordance with the Market Procedure specified in clause 7A.3.3):~~

~~(a) the Relevant Dispatch Quantity for the Trading Interval;~~

~~(b) the aggregate output of all Non-Scheduled Generators which are Balancing Facilities for the Trading Interval;~~

~~(c) the Balancing Price for the Trading Interval; and~~

~~(d) the spare capacity for the Trading Interval.~~

~~**Balancing Gate Closure**: For a Trading Interval means the point in time immediately before the commencement of the Trading Interval determined by AEMO under clause 7A.1.16 or 7A.1.17, as applicable.~~

~~**Balancing Horizon**: Means, from 1:00 PM each Trading Day, the 43-hour period from 1:00 PM to the end of the next Trading Day at 8:00 AM.~~

~~**Balancing Market**: Means the mandatory gross pool market operated under Chapter 7A that determines the dispatch of Scheduled Generators and Non-Scheduled Generators in each Trading Interval based on submitted prices and quantities.~~

~~**Balancing Market Commencement Day**: Means the Trading Day commencing at 8:00 AM on 1 July 2012.~~

~~**Balancing Market Objectives**: Means the objectives listed in clause 7A.1.3.~~

~~**Balancing Merit Order**: Means, for a Trading Interval, the ordered list of Balancing Facilities, and associated quantities, used by System Management for issuing Dispatch Instructions for the Trading Interval, determined as:~~

~~(a) the last Forecast BMO for the Trading Interval received by System Management under clause 7A.3.1(b); or~~

~~(b) if no Forecast BMO is received, the Balancing Merit Order that was used by System Management for issuing Dispatch Instructions for the same Trading Interval on the most recent Business Day if the Trading Interval occurs on a Business Day, or the most recent non-Business Day if the Trading Interval occurs on a non-Business Day.~~

~~**Balancing Portfolio**: Means Synergy's Registered Facilities other than:~~

~~(a) Stand Alone Facilities;~~

~~(b) Demand Side Programmes; and~~

~~(c) [Blank]~~

~~(d) Interruptible Loads.~~

~~**Balancing Price**: For a Trading Interval means the price determined under clause 7A.3.10.~~

~~**Balancing Price-Quantity Pair**: Means~~

~~(a) for a Scheduled Generator, the specified non-Loss Factor adjusted MW quantity at which a Market Participant is prepared to operate a Balancing Facility as at the end of a Trading Interval and the non-Loss Factor Adjusted Price, in $/MWh, at which the Market Participant is prepared to provide that quantity by the end of that Trading Interval;~~

~~(b) for a Non-Scheduled Generator the specified non-Loss Factor adjusted MW quantity at which a Market Participant is prepared to reduce its output as at the end of a Trading Interval and the non-Loss Factor Adjusted Price, in $/MWh, at which the Market Participant is prepared to provide that quantity by the end of that Trading Interval; and~~

~~(c) for the Balancing Portfolio, the specified MW quantity at which Synergy is prepared to have the Balancing Portfolio dispatched at as at the end of a Trading Interval and the Loss Factor Adjusted Price, in $/MWh, at which Synergy is prepared to provide from the sum of all of its Sent Out Capacity for each Facility in the Balancing Portfolio by the end of the Trading Interval.~~

~~**Balancing Settlement**: Means the process for settling supply and consumption deviations from contracted bilateral and STEM positions in each Trading Interval.~~

~~**Balancing Submission**: Means a submission by a Market Participant to AEMO, for a Balancing Facility or the Balancing Portfolio, for one or more Trading Intervals, that includes~~

~~the information specified in clause 7A.2.4 and complies with clauses 7A.2.4A, 7A.2.4B and 7A.2.4C as applicable.~~

…

Base ESS Quantity: For a Dispatch Interval and a SESSM Supplementary ESS Award where there is a non-zero Availability Payment, the quantity of the relevant Frequency Co-optimised Essential System Service which the Facility would have been capable of providing if not granted the SESSM Supplementary ESS Award, and which must be offered in addition to the Availability Quantity.

…

Bilateral Submission Cutoff: Means 8:50 AM on the Scheduling Day for the Trading Day, or such other time as may be notified by AEMO under clause 6.4.6B.

…

~~**BMO**: See Balancing Merit Order.~~

Central Dispatch: The process managed by AEMO for the dispatch of Registered Facilities for energy and Essential System Services described in clause 7.2.1.

…

Charge Level: The current level of stored energy in MWh in an Electric Storage Resource, as provided to AEMO in a real-time data feed in accordance with clause [reference in Registration Chapter].

…

Common Requirements: In respect of each Technical Requirement, means each requirement as specified in Appendix 12 that is common to both the Ideal Generator Performance Standard and Minimum Generator Performance Standard.

…

~~**Consumption Decrease Price**: A price specified in Appendix 1(h)(vi)(1) or Appendix 1(h)(vi)(2), accepted by AEMO under section 6.11A, to apply in forming the Non-Balancing Dispatch Merit Order for a Trading Interval for a Demand Side Programme and in the calculation of the Non-Balancing Facility Dispatch Instruction Payment for that Demand Side Programme for that Trading Interval.~~

Contingency Event: Has the meaning given in clause 3.8A.1.

Contingency Lower Factor: For each Dispatch Interval or Pre-Dispatch Interval, the ratio between the Largest Credible Load Contingency and the quantity of Contingency Reserve Lower required to maintain the SWIS frequency in accordance with the Frequency Operating Standards, and where:

(a) a ratio that is less than one means the Contingency Reserve Lower requirement is less than the Largest Credible Load Contingency;

(b) a ratio greater than one means the Contingency Reserve Lower requirement is greater than the Largest Credible Load Contingency and

(c) a ratio of one means the Contingency Reserve Lower requirement is equal to the Largest Credible Load Contingency.

Contingency Raise Factor: For each Dispatch Interval or Pre-Dispatch Interval, the ratio between the Largest Credible Supply Contingency and the quantity of Contingency Reserve Raise required to maintain the SWIS frequency in accordance with the Frequency Operating Standards, and where:

(a) a ratio less than one means the Contingency Reserve Raise requirement is less than the Largest Credible Supply Contingency;

(b) a ratio greater than one means the Contingency Reserve Raise requirement is greater than the Largest Credible Supply Contingency; and

(c) a ratio of one means the Contingency Reserve Raise requirement is equal to the Largest Credible Supply Contingency.

Contingency Reclassification Conditions: Means the conditions that AEMO determines give rise to the need to reclassify a Non-Credible Contingency Event as a Credible Contingency Event.

Contingency Reserve: Has the meaning given in clause 3.9.4.

Contingency Reserve Lower: Has the meaning given in clause 3.9.6.

Contingency Reserve Lower Market Clearing Price: The Market Clearing Price for Contingency Reserve Lower.

Contingency Reserve Raise: Has the meaning given in clause 3.9.5.

Contingency Reserve Raise Market Clearing Price: The Market Clearing Price for Contingency Reserve Raise.

…

~~**Contracted Ancillary Service:** An Ancillary Service provided by a Rule Participant under an Ancillary Service Contract.~~

~~**Contracted Dispatch Support Service:** A Dispatch Support Service provided by a Rule Participant under an Ancillary Service Contract.~~

~~**Contracted Load Rejection Reserve Service:** A Load Rejection Reserve Service provided by a Rule Participant under an Ancillary Service Contract.~~

~~**Contracted Spinning Reserve Service:** A Spinning Reserve Service provided by a Rule Participant under an Ancillary Service Contract.~~

~~**Contracted System Restart Service:** A System Restart Service provided by a Rule Participant under an Ancillary Service Contract.~~

…

Controlled Circumstances: Circumstances where AEMO expects or requires SWIS Frequency to vary as a result of a test or the process of dispatch.

…

Credible Contingency Event: Has the meaning in given in clause 3.8A.2.

Credible Contingency Event Frequency Band: Has the meaning given in clause 3B.2.3.

…

Degenerate Solution: Occurs where, according to the Dispatch Algorithm, more than one combination of Dispatch Targets and ESS Enablement Quantities will maximise the value of Real-Time Market trading while taking into account the various constraints in section 7.2.

…

Dispatch Algorithm: Means, the algorithm used to determine Central Dispatch developed by AEMO in accordance with clause 7.2.3.

Dispatch Cap: The total MW level of Injection or Withdrawal that must not be exceeded by a Semi-Scheduled Facility at the end of the Dispatch Interval.

…

Dispatch Forecast: The total MW level of Injection or Withdrawal expected to be reached by a Semi-Scheduled Facility or Non-Scheduled Facility at the end of the Dispatch Interval which for a Semi-Scheduled Facility, corresponds to the Unadjusted Intermittent Generation Forecast for the Registered Facility.

Dispatch Inflexibility Profile: Means, the parameters that indicate a Registered Facility's MW capacity and time related dispatch inflexibilities in accordance with clause 7.4.38 for a Fast Start Facility and clause 7.4.39 for a Demand Side Programme.

Dispatch Input: Any value, excluding the values made, or required to be made, by Market Participants in a Real-Time Market Submission, that is used by the Dispatch Algorithm, including:

(a) measurements of power system status;

(b) the Forecast Operational Demand;

(c) Constraint Equations; and

(d) software setup for the Dispatch Algorithm.

Dispatch Instruction: Has the meaning given in clause ~~7.7.1~~ 7.6.5.

Dispatch Interval: Means each 5 minute period commencing at 0, 5, 10, 15, 20, 30, 35, 40, 45, 50 and 55 minutes past the hour in which the Dispatch Algorithm is run in accordance with section 7.2.

~~**Dispatch Order**: Means an instruction by System Management under clause 7.6A for a Facility or Facilities in the Balancing Portfolio to vary output or consumption from the Dispatch Plan.~~

~~**Dispatch Plan**: Means System Management's forecast of how it will use each Facility in the Balancing Portfolio to provide energy and Ancillary Services in each Trading Interval of a Trading Day, where this forecast may be revised by System Management during the course of the corresponding Scheduling Day and the Trading Day.~~

…

Dispatch Schedule: A forecast of the Market Clearing Prices, Dispatch Targets, Dispatch Caps, Dispatch Forecasts and Essential System Services Enablement Quantities for each Dispatch Interval in the Dispatch Schedule Horizon.

Dispatch Schedule Horizon: The next 24 Dispatch Intervals after a Dispatch Interval.

…

~~**Dispatch Support Service:** Has the meaning given in clause 3.9.9.~~

…

Dispatch Target: The total MW level of Injection or Withdrawal to be reached by a Registered Facility at the end of the Dispatch Interval.

…

~~**Downwards LFAS Enablement**: Means, for a Trading Interval and an LFAS Facility, the total quantity associated with that LFAS Facility in the Downwards LFAS Enablement Schedule for that Trading Interval.~~

~~**Downwards LFAS Enablement Schedule**: Means, for a Trading Interval, the Forecast Downwards LFAS Enablement Schedule for that Trading Interval most recently provided by AEMO to System Management under clause 7B.3.1(b) between LFAS Gate Closure for that Trading Interval and the point in time 15 minutes after LFAS Gate Closure for that Trading Interval.~~

~~**Downwards LFAS Merit Order**: Means, for a Trading Interval, the Forecast Downwards LFAS Merit Order for that Trading Interval used by AEMO under clause 7B.3.3(b) to determine the Downwards LFAS Enablement Schedule.~~

~~**Downwards LFAS Price**: Means, for a Trading Interval, the Forecast Downwards LFAS Price for that Trading Interval determined by AEMO under clause 7B.3.4(b) from the Downwards LFAS Enablement Schedule, subject to clause 7B.3.12, and published under clause 7B.3.11.~~

~~**Downwards LFAS Price-Quantity Pair**: Means for an LFAS Facility:~~

~~(a) the specified non-Loss Factor adjusted capacity, in MW, by which a Market Participant is prepared to have its LFAS Facility activated downwards within a Trading Interval; and~~

~~(b) the non-Loss Factor Adjusted Price, in $/MW, the Market Participant wants to be paid to have that capacity available within that Trading Interval.~~

~~**Downwards LFAS Quantity**: Means, for a Trading Interval, the Forecast Downwards LFAS Quantity for that Trading Interval used by AEMO under clause 7B.3.3(b) to determine the Downwards LFAS Enablement Schedule.~~

…

Droop Response: A fast, automatic and localised control scheme for generation facilities, wherein power output is proportionally adjusted to counteract frequency deviations.

…

Electrical Location: The zone substation at which the Transmission Loss Factor for a Registered Facility is defined.

…

Embedded System: Means a Network connected at a connection point on the SWIS which is owned, controlled or operated by a person who is not a Network Operator or AEMO.

…

Enablement Maximum: In relation to a Real-Time Market Offer for a Frequency Co-optimised Essential System Service, the level of associated generation or load (in MW) above which no response is specified as being available in the Real-Time Market Submission.

Enablement Minimum: In relation to a Real-Time Market Offer for a Frequency Co-optimised Essential System Service, the level of associated generation or load (in MW) below which no response is specified as being available in the Real-Time Market Submission.

…

Energy Offer Caps: The Energy Offer Price Floor and the Energy Offer Price Ceiling.

Energy Offer Price Ceiling: The price equal to the Alternative Maximum STEM Price.

Energy Offer Price Floor: The price equal to the Minimum STEM Price.

Energy Market Clearing Price: The Market Clearing Price for energy.

…

EOI Quantity: Means the quantity, in MW, at which a ~~Scheduled Generator or a Non-Scheduled Generator~~ Registered Facility was ~~operating~~ Injecting or Withdrawing as at the end of a ~~Trading~~ Dispatch Interval~~, which must equal the SOI Quantity for the next Trading Interval~~.

…

~~**Equipment Limit**: Any limit on the operation of a Facility's equipment that is recorded in the Standing Data for the Facility.~~

Equipment Limit: Has the meaning given in clause 3.2.1.

Explanatory Note The definition for Equipment List will be reviewed in the Outages workstream.

Equipment List: Means the list maintained by AEMO ~~System Management~~ under clause 3.18.2(a).

…

Essential System ~~Services~~ Service: ~~Each~~ A service, including each service described in section 3.9, that is required to maintain Power System Security and Power System Reliability, facilitate orderly trading in electricity and ensure that electricity supplies are of an acceptable quality.

Essential System Service Enablement Quantity: the quantity of a Frequency Co-optimised Essential System Service to be provided by a Registered Facility in a Dispatch Interval.

Explanatory Note Section 3.7 which deals with System Restart Service will be amended separately.

Essential System Service Standards: The standards referred to in these WEM Rules for Essential System Services, including those set out in sections 3.7 and 3.10.

…

Exempt Transmission Connected Generating System: Has the meaning given in clause 3A.3.1.

…

Existing Transmission Connected Generating System: Means a Transmission Connected Generating System for which an Arrangement for Access has been executed prior to the GPS Commencement Date.

…

~~**Ex-post Downwards LFAS Enablement**: Means the capacity, in MW, of an LFAS Facility that was activated to provide downwards LFAS at the end of a Trading Interval.~~

~~**Ex-post Upwards LFAS Enablement**: Means the capacity, in MW, of an LFAS Facility that was activated to provide upwards LFAS at the end of a Trading Interval.~~

…

~~**Extra Consumption Decrease Price**: A price specified in item (h)(vi)(3) and (4) of Appendix 1, accepted by AEMO under section 6.11A, to apply in forming the Non-Balancing Dispatch Merit Order for a Trading Interval for a Demand Side Programme and in the calculation of the Non-Balancing Facility Dispatch Instruction Payment for that Demand Side Programme for that Trading Interval.~~

…

Facility Performance Factor: For a Registered Facility in a Dispatch Interval or Pre-Dispatch Interval, the ratio between the Contingency Reserve enabled at the Registered Facility and the Registered Facility's contribution to meeting the Contingency Reserve requirements, where:

(a) a ratio of one denotes that one MW of Contingency Reserve enabled at the Registered Facility contributes one MW to meeting the Contingency Reserve requirement; and

(b) a ratio of less than one denotes that one MW of Contingency Reserve enabled at the Registered Facility contributes less than one MW to meeting the Contingency Reserve requirement.

Fast Start Facilities: Has the meaning in clause 7.9.1.

…

~~**Forecast Backup Downwards LFAS Price**: Means the cost referred to in clause 7B.2.6 for Synergy providing Backup Downwards LFAS Enablement for a Trading Interval, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6 at the time when that cost is published by AEMO under clause 7B.3.1(d)(iv).~~

~~**Forecast Backup LFAS Price**: Means the Forecast Backup Downwards LFAS Price and/or the Forecast Backup Upwards LFAS Price, as applicable.~~

~~**Forecast Backup Upwards LFAS Price**: Means the cost referred to in clause 7B.2.6 for Synergy providing Backup Upwards LFAS Enablement for a Trading Interval, determined from the most recent, valid LFAS Submissions made in accordance with clause 7B.2.6 at the time when that cost is published by AEMO under clause 7B.3.1(d)(iv).~~

~~**Forecast BMO**: Means the ordered list of Balancing Facilities, and associated quantities, determined by AEMO under clause 7A.3.1(a).~~

…

~~**Forecast Downwards LFAS Enablement Schedule**: Means, for a Trading Interval, a list of LFAS Facilities and associated quantities for that Trading Interval determined by AEMO under clause 7B.3.1(a)(iv).~~

~~**Forecast Downwards LFAS Merit Order**: Means, for a Trading Interval, a ranked list of Downwards LFAS Price-Quantity Pairs for that Trading Interval determined by AEMO under clause 7B.3.1(a)(ii).~~

~~**Forecast Downwards LFAS Price**: Means, for a Trading Interval, the highest price in a Downwards LFAS Price-Quantity Pair selected in a Forecast Downwards LFAS Enablement Schedule for that Trading Interval, determined by AEMO under clause 7B.3.1(a)(vi).~~

~~**Forecast Downwards LFAS Quantity**: Means System Management's estimate of the capacity, in MW, of downwards LFAS required by System Management for a Trading Interval, prepared by System Management under clauses 7B.1.4 or 7B.1.5.~~

~~**Forecast LFAS Enablement Schedule**: Means the Forecast Downwards LFAS Enablement Schedule and/or the Forecast Upwards LFAS Enablement Schedule, as applicable.~~

~~**Forecast LFAS Merit Order**: Means the Forecast Downwards LFAS Merit Order and/or the Forecast Upwards LFAS Merit Order, as applicable.~~

~~**Forecast LFAS Price**: Means the Forecast Downwards LFAS Price and/or the Forecast Upwards LFAS Price, as applicable.~~

~~**Forecast LFAS Quantity**: Means the Forecast Downwards LFAS Quantity and/or the Forecast Upwards LFAS Quantity, as applicable.~~

Forecast Operational Demand: For a Dispatch Interval or Pre-Dispatch Interval, AEMO's estimate of the Injection required to be dispatched by the Dispatch Algorithm, determined according to clauses 7.3.2 and 7.3.3.

~~**Forecast Upwards LFAS Enablement Schedule**: Means, for a Trading Interval, a list of LFAS Facilities and associated quantities for that Trading Interval determined by AEMO under clause 7B.3.1(a)(iii).~~

~~**Forecast Upwards LFAS Merit Order**: Means, for a Trading Interval, a ranked list of Upwards LFAS Price-Quantity Pairs for that Trading Interval determined by AEMO under clause 7B.3.1(a)(i).~~

~~**Forecast Upwards LFAS Price**: Means, for a Trading Interval, the highest price in an Upwards LFAS Price-Quantity Pair selected in a Forecast Upwards LFAS Enablement Schedule for that Trading Interval, determined by AEMO under clause 7B.3.1(a)(v).~~

~~**Forecast Upwards LFAS Quantity**: Means System Management's estimate of the capacity, in MW, of upwards LFAS required by System Management for a Trading Interval, prepared by System Management under clauses 7B.1.4 or 7B.1.5.~~

Frequency Band: Means the Credible Contingency Event Frequency Band, Multiple Contingency Event Frequency Band, Island Separation Frequency Band, Normal Operating Frequency Band or Normal Operating Frequency Excursion Band.

Frequency Co-optimised Essential System Service: Means an Essential System Service as defined in clause 3.9.1 to clause 3.9.7.

Frequency Co-optimised Essential System Service Accreditation Parameters: Means the information in respect of a Facility accredited to provide Frequency Co-optimised Essential System Services that is required to be included in the Standing Data for the Facility as set out in clause 2.34A.6.

Frequency Co-optimised Essential System Service Accreditation Shortfall: Means, for a Frequency Co-optimised Essential System Service in a Dispatch Interval, a difference between the actual or forecast required quantity and the total accredited capability accounting for where Facility response capability is accredited to provide more than one Frequency Co-optimised Essential System Service, as identified under clause 3.11.1.

Frequency Co-optimised Essential System Service Participation Shortfall: Means, for a Frequency Co-optimised Essential System Service in a Dispatch Interval, a difference between the actual or forecast required quantity and the total capability offered as In-Service, as identified under clause 3.11.2(b).

Frequency Operating Standards: Means the SWIS Frequency outcomes set out in Table 1 and Table 2, Appendix 13.

…

Fully Co-Optimised Network Constraint Equation: A Constraint Equation formulation to address a Network Constraint that allows AEMO, through direct physical representation, to control all the variables within the Constraint Equation that can be determined through the Central Dispatch process excluding variables for which control would not materially enhance the security of the power system due to the small size of their coefficients.

…

Gate Closure: Means the point in time before the start of a Dispatch Interval by which a Market Participant must submit a Real-Time Market Submission for that Dispatch Interval, as determined by AEMO under clauses 7.4.22 or 7.4.23 and published on the WEM Website.

…

Generation Centre: A geographically concentrated area containing a generating system or generating systems with significant combined generating capability.

Generator Performance Standard: Means either the Ideal Generator Performance Standard or Negotiated Generator Performance Standard in respect of a Technical Requirement.

GPS Commencement Date: Means the Trading Day commencing at 8.00am on [1 February 2021].

GPS Monitoring Plan: Means a monitoring plan for a Transmission Connected Generating System in respect of the Registered Generator Performance Standards that apply to the Transmission Connected Generating System.

GPS Register: Means a register required to be established and maintained by a Network Operator in accordance with clause 3A.7.1.

…

High Breakpoint: Means, for a Facility providing a Frequency Co-optimised Essential System Service, the MW energy dispatch level above which the Facility cannot provide the maximum quantity of that Frequency Co-optimised Essential System Service which it is capable of providing.

~~**High Risk Operating State**: The state of the SWIS described in clause 3.4.~~

…

Ideal Generator Performance Standard: Means the ideal generator performance standard in respect of a Technical Requirement as specified in Appendix 12.

…

In-Service Capacity: Means, for a Registered Facility in a Dispatch Interval, the sent out capacity in MW that is synchronised or is expected to be synchronised in the Dispatch Interval.

~~**Increased LFAS Quantity**: Means the capacity, in MW, of LFAS which is the difference between the actual capacity of LFAS that was activated in a Trading Interval referred to in clause 7B.4.1(b) and the LFAS Quantity for that Trading Interval.~~

…

Explanatory Note The definition of 'Inertia' will include some wind farms, but not batteries. As battery technology develops further to be able to reliably provide an inertial-equivalent service, this definition will be considered to be expanded.

Inertia: The kinetic energy (at nominal frequency) that is extracted from the rotating mass of a machine coupled to the power system to compensate an imbalance in the system frequency.

Inertia Requirements: Means, the required levels of Inertia to maintain Power System Security and Power System Reliability in an Island determined by the processes specified in the WEM Procedure referred to in clause 3.2.7.

…

Inflexible: Means that a Registered Facility is only able to be dispatched in a Dispatch Interval:

(a) in accordance with its Dispatch Inflexibility Profile, or

(b) for the fixed level of Injection or Withdrawal specified in clause 7.6.31(a)(ii).

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

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

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

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

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

…

Interim Approval to Generate Notification: Means the notification issued by the Network Operator to a Market Participant in accordance with clause 3A.8.1, which may or may not be subject to and contain conditions, granting interim approval to a Transmission Connected Generating System to generate electricity.

…

Intervention Constraint: A Constraint Equation used to implement a direction in the Dispatch Algorithm pursuant to an AEMO Intervention Event.

Intervention Dispatch Interval: A Dispatch Interval declared by AEMO to be an Intervention Dispatch Interval in accordance with clauses 7.11A.1 or 7.11C.10.

…

Island: Means a part of the SWIS that includes energy producing systems (or other energy sources), Networks and Load, for which all of the connection points with the SWIS have been disconnected, provided that the part:

(a) is smaller than the remainder of the SWIS that it has disconnected from; and

(b) contains energy producing systems (or other energy sources) capable of supplying the Load within the part of the SWIS that has been disconnected,

but does not include an Embedded System or Microgrid:

(c) for which all of the connection points with the SWIS have been disconnected; and

(d) which is not operated by AEMO.

Island Separation Frequency Band: has the meaning given in clause 3B.2.4.

Key Project Dates: Means the dates most recently provided to AEMO under clause 4.10.1(c)(iii) or in reports provided under clause 4.27.10, clause 3.15A.42 or clause 3.15A.44.

Explanatory Note

Definitions of Largest Credible Load Contingency and Largest Credible Supply Contingency may be adjusted in amending rules for operational planning.

Largest Credible Load Contingency: Means the maximum possible total MW Withdrawal that could be lost in a Dispatch Interval or Pre-Dispatch Interval due to a single Credible Contingency Event based on the output of the Dispatch Algorithm.

Largest Credible Supply Contingency: Means the maximum possible total MW Injection that could be lost in a Dispatch Interval or Pre-Dispatch Interval due to a single Credible Contingency Event based on the output of the Dispatch Algorithm.

Last Correct Dispatch Interval: Means the most recent Dispatch Interval preceding the Affected Dispatch Interval that is not itself an Affected Dispatch Interval.

…

~~**LFAS**: See Load Following Service.~~

~~**LFAS Enablement**: Means the Downwards LFAS Enablement and/or the Upwards LFAS Enablement, as applicable.~~

~~**LFAS Enablement Schedule**: Means the Downwards LFAS Enablement Schedule and/or the Upwards LFAS Enablement Schedule, as applicable.~~

~~**LFAS Facility**: Means:~~

~~(a) a Stand Alone Facility, or Scheduled Generator or Non-Scheduled Generator registered to a Market Participant other than Synergy:~~

~~i. which the relevant Market Participant has indicated in Appendix 1(j)(i) is intended to participate in the LFAS Market; and~~

~~ii. for which LFAS Standing Data has been accepted by AEMO; or~~

~~(b) the Balancing Portfolio.~~

~~**LFAS Facility Requirements**: Means the technical and communication criteria that an LFAS Facility, or a type of LFAS Facility, must meet, which are set out in the Market Procedure in accordance with clause 7B.1.2.~~

~~**LFAS Gate Closure**: Means, for the 12 Trading Intervals in an LFAS Horizon, the point in time which is 3 hours immediately before the Balancing Gate Closure for the first of those Trading Intervals.~~

~~**LFAS Horizon**: Means a 6 hour period commencing at 8:00 AM, 2:00 PM, 8:00 PM or 2:00 AM, as applicable.~~

~~**LFAS Market**: Means the market operated under Chapter 7B in which LFAS Facilities can provide Load Following Services.~~

~~**LFAS Merit Order**: Means the Downwards LFAS Merit Order and/or the Upwards LFAS Merit Order, as applicable.~~

~~**LFAS Price**: Means the Downwards LFAS Price and/or the Upwards LFAS Price, as applicable.~~

~~**LFAS Price-Quantity Pair**: Means an Upwards LFAS Price-Quantity Pair and/or a Downwards LFAS Price-Quantity Pair, as applicable.~~

~~**LFAS Quantity**: Means the Upwards LFAS Quantity and/or the Downwards LFAS Quantity, as applicable.~~

~~**LFAS Quantity Balance**: Means the capacity, in MW, of LFAS Enablement referred to in clause 7B.4.1(a), which an LFAS Facility has failed to provide, or in clause 7B.4.1(aA), which an LFAS Facility is not available to provide.~~

~~**LFAS Standing Data**: Means the Standing Data in Appendix 1(j)(ii).~~

~~**LFAS Submission**: Means:~~

~~(a) for an LFAS Facility that is:~~

~~i. a Scheduled Generator, for a Trading Interval or Trading Intervals, a ranking of LFAS Price-Quantity Pairs for each MW of capacity which the Market Participant wants to offer for LFAS for each Trading Interval; and~~

~~ii. a Non-Scheduled Generator, for a Trading Interval or Trading Intervals, the Market Generator's best estimate of the capacity for the LFAS Price-Quantity Pair, in MW, the Facility is able to be activated downwards for each Trading Interval; and~~

~~(b) for the Balancing Portfolio for a Trading Interval or Trading Intervals, a ranking of LFAS Price-Quantity Pairs for each MW of capacity which the Market Participant wants to offer for LFAS for each Trading Interval.~~

…

~~**Load Rejection Reserve Event**: Means an event which causes a Facility in the Balancing Portfolio, which System Management has instructed to provide Load Rejection Reserve Service, to provide a Load Rejection Reserve Response.~~

~~**Load Rejection Reserve Response**: Means a load rejection reserve response by a Facility in accordance with clause 3.9.7.~~

~~**Load Rejection Reserve Response Quantity**: Means, for a Trading Interval, the quantity of energy reduction, in MWh, provided by a Facility as a Load Rejection Reserve Response due to a Load Rejection Reserve Event, but excluding any such contribution that occurred because System Management had instructed the Facility to provide Downwards LFAS Enablement or Backup Downwards LFAS Enablement.~~

~~**Load Rejection Reserve Service**: Has the meaning given in clause 3.9.6.~~

Load Relief: The expected change in load in response to a change in power system frequency.

…

Loss Factor: Means~~:~~

~~(a)~~ a factor representing network losses between any given node and the Reference Node where the Loss Factor at the Reference Node is 1, expressed as the product of a Transmission Loss Factor and a Distribution Loss Factor and determined in accordance with clause 2.27.5.~~; and~~

~~(b) in relation to the Balancing Portfolio, the Portfolio Loss Factor.~~

…

Loss Factor Adjusted Price: Means, in respect of any price, that price divided by any applicable Loss Factor for the relevant Facility ~~but any resulting price exceeding the Price Caps, must be adjusted to the relevant Price Cap~~.

…

Low Breakpoint: Means, for a Facility providing a Frequency Co-optimised Essential System Service, the MW energy dispatch level below which the Facility cannot provide the maximum quantity of that Frequency Co-optimised Essential System Service which it is capable of providing.

…

Market Clearing Price: The price for a Market Service in a Dispatch Interval as determined in accordance with section 7.11B.

…

Market Schedule: A Dispatch Schedule, Pre-Dispatch Schedule or Week Ahead Schedule.

Market Service: Energy or any of the Frequency Co-optimised Essential System Services.

…

Maximum Capability: Means, the Facility's MW energy dispatch capability between the Low Breakpoint and the High Breakpoint.

…

Maximum Contingency Reserve Block Size: The largest quantity of Contingency Reserve Raise that may be offered by a relevant Registered Facility at one price, as set by AEMO in a WEM Procedure.

Maximum Downwards Ramp Rate: The Market Participant's best estimate, in MW per minute, on a linear basis, of a Facility's physical ability to decrease its Injection or increase its Withdrawal on the receipt of a Dispatch Instruction.

…

Maximum Upwards Ramp Rate: The Market Participant's best estimate, in MW per minute, on a linear basis, of a Facility's physical ability to increase its Injection or decrease its Withdrawal on the receipt of a Dispatch Instruction.

…

Medium Term PASA: A PASA study conducted in accordance with clause 3.16 in order to assist ~~System Management~~ AEMO in ~~determining~~ forecasting ~~Ancillary Service~~ Essential System Service ~~Requirements~~, outage planning for Registered Facilities and also assessing the availability of Facilities in respect of which Capacity Credits are held.

…

Microgrid: Means a part of the SWIS that is not an Embedded System, that is designed to be separated from the SWIS at a particular connection point (or connection points) on a Network, and that has disconnected from the SWIS and is being operated independently from the SWIS by a Network Operator.

…

Minimum Generator Performance Standard: Means the minimum generator performance standard in respect of a Technical Requirement as specified in Appendix 12.

~~**Minimum LFAS Quantity**: Means the minimum quantity of LFAS that may be specified in an LFAS Price-Quantity Pair, as determined by System Management in accordance with clause 7B.1.2(a), and which is published by AEMO on the Market Web Site.~~

Minimum RoCoF Control Requirement: Is:

(a) the smallest quantity of scheduled or dispatched RoCoF Control Service in a Dispatch Interval or a Pre-Dispatch Interval that is necessary to maintain the SWIS frequency in accordance with the Frequency Operating Standards; and

(b) zero, where the SWIS frequency can be maintained in accordance with the Frequency Operating Standards without explicit enablement of RoCoF Control Service.

…

MWs: Means megawatt-second.

…

Multiple Contingency Event: Has the meaning given in clause 3.8A.4.

Multiple Contingency Event Frequency Band: Has the meaning given in clause 3B.2.5.

…

Negotiated Generator Performance Standard: Means a Registered Generator Performance Standard that represents a variation from the Ideal Generator Performance Standard but is no less than the Minimum Generator Performance Standard that has been approved and registered in accordance with the process in Chapter 3A.

Negotiation Criteria: Means the criteria that must be met in respect of each Technical Requirement as specified in Appendix 12 if a Market Participant submits a Proposed Negotiated Generator Performance Standard.

…

Net ~~STEM~~ Offer Refund: Has the meaning given in clause 4.26.3.

Net ~~STEM~~ Offer Shortfall: Has the meaning given in clause 4.26.2.

~~**Net STEM Refund:** Has the meaning given in clause 4.26.3.~~

…

New WEM Commencement Month: Means the Trading Month in which the New WEM Commencement Day falls.

~~**Non-Balancing Dispatch Merit Order**: Means, for a Trading Interval, an ordered list of Demand Side Programmes registered by Market Participants, determined by AEMO in accordance with clause 6.12.1.~~

~~**Non-Balancing Facility Dispatch Instruction Payment or DIP**: Has the meaning given in clause 6.17.6.~~

…

Non-Co-optimised Essential System Services: Has the meaning given in clause 3.9.9.

Non-Credible Contingency Event: Has the meaning given in clause 3.8A.3.

…

Normal Operating Frequency Band: Has the meaning given in in clause 3B.2.1.

Normal Operating Frequency Excursion Band: Has the meaning given in clause 3B.2.2.

~~**Normal Operating State**: The state of the SWIS defined in clause 3.3.1.~~

…

Offer Cap: Means the price referred to in clause 3.15A.22(c).

…

~~**Operating Instruction**: Means an instruction issued by System Management:~~

~~(a) requiring a Facility to increase or decrease its output or decrease its consumption to meet the requirements of:~~

~~i. a Network Control Service Contract;~~

~~ii. an Ancillary Service Contract;~~

~~iii. a Test under these Market Rules;~~

~~iv. a Supplementary Capacity Contract; or~~

~~v. Ancillary Services, other than LFAS but including Backup LFAS Enablement, to be provided by Facilities other than Facilities in the Balancing Portfolio; or~~

~~(b) retrospectively under clause 7.7.11.~~

…

Oscillation Control Constraints: Constraints that provide for stability in the Dispatch Algorithm outputs where a significant change to the Dispatch Target or ESS Enablement Quantities of a Registered Facility would result in only a small change in the value of Real-Time Market trading described in clause 7.2.2.

…

~~**Out of Merit**: Means dispatch of a Balancing Facility for a quantity different to that specified for the Facility in the BMO taking into account the Ramp Rate Limit and the Relevant Dispatch Quantity in the applicable Trading Interval for the Balancing Facility.~~

Participant Interval Maximum STEM Price: For a Market Participant in a Trading Interval, a price in $/MWh which:

(a) is less than or equal to the Alternative Maximum STEM Price;

(b) has been provided by that Market Participant as part of a STEM Submission or Standing STEM submission; and

(c) is the maximum price that may be associated with its Portfolio Demand Curve.

Participant Interval Minimum STEM Price: For a Market Participant in a Trading Interval, a price in $/MWh which:

(a) is greater than or equal to the Minimum STEM Price;

(b) has been provided by that Market Participant as part of a STEM Submission or Standing STEM submission; and

(c) is the minimum price that may be associated with its Portfolio Supply Curve.

…

Per-Dispatch Interval Availability Payment: For a SESSM Supplementary ESS Award, the Availability Payment divided by the number of Dispatch Intervals in the SESSM Award Duration for which the Availability Quantity is greater than zero.

…

~~**Portfolio Loss Factor**: For each Trading Interval = sum(Facility(i) Sent Out Metered Schedule x Loss Factor (i))/sum (Facility (i) Sent Out Metered Schedule) for all Facilities in the Balancing Portfolio.~~

~~**Portfolio Ramp Rate Limit**: Means Synergy's best estimate, in MW per minute, on a linear basis, of the Balancing Portfolio's physical ability to increase or decrease its output from the commencement of a Trading Interval.~~

Potential Relevant Generator Modification: Has the meaning given in clause 3A.13.1.

…

Explanatory Note The definition of 'Power System Adequacy' is to be further reviewed in the PASA and Outages workstreams.

Power System Adequacy: Means the ability of the SWIS to supply all demand at the time, allowing for Scheduled Outages and unscheduled outages, taking into account the assessment methodologies and criteria in the WEM Procedure referred to in clause 3.3.2. ~~The ability of the SWIS to supply all demand for electricity in the SWIS at the time, allowing for scheduled and unscheduled outages of generation, transmission and distribution equipment and secondary equipment.~~

…

Power System Reliability: Means the ability of the SWIS to operate in accordance with the Power System Reliability Principles. ~~The ability of the SWIS to deliver energy within reliability standards while maintaining Power System Adequacy and Power System Security.~~

Power System Reliability Principles: Has the meaning given to that term in clause 3.3.3.

Power System Security: Means the safe scheduling, operation and control of the SWIS in accordance with the Power System Security Principles. ~~The ability of the SWIS to withstand sudden disturbances, including the failure of generation, transmission and distribution equipment and secondary equipment.~~

Power System Security Principles: Has the meaning given to that term in clause 3.4.3.

Power Transfer Capability: Means the maximum permitted power transfer through a transmission system or distribution system or part thereof.

…

Pre-Dispatch Interval: A period of 30 minutes commencing on the hour or half hour during a Trading Day, and where identified by a time, the 30 minute period starting at that time.

Pre-Dispatch Schedule: Means a forecast of Market Clearing Prices, Dispatch Targets, Dispatch Caps, Dispatch Forecasts and Essential System Services Enablement Quantities for each Pre-Dispatch Interval in the Pre-Dispatch Schedule Horizon.

Pre-Dispatch Schedule Horizon: The next 96 Pre-Dispatch Intervals after a Pre-Dispatch Interval.

…

Price-Quantity Pair: In the context of:

(a) Reserve Capacity Offers, Supply Portfolio Curves and STEM Offers, a quantity that will be provided to AEMO by a Market Participant for a price equalling or exceeding the specified price. In the context of Demand Portfolio Curves and STEM Bids, a quantity that will be purchased from AEMO by a Market Participant for a price equalling or less than the specified price~~.~~;

(b) Real-Time Market Submissions the specified non-Loss Factor adjusted MW quantity at which a Market Participant is prepared to provide a Market Service from a Registered Facility as at the end of a Dispatch Interval and the non-Loss Factor Adjusted Price at which the Market Participant is prepared to provide that quantity by the end of the Dispatch Interval, where the price is:

i. in $ per MWh for energy;

ii. in $ per MW per hour for Contingency Reserve Raise, Contingency Reserve Lower, Regulation Raise and Regulation Lower; and

iii. in $ per MWs per hour for RoCoF Control Service.

~~**Pricing BMO**: Means the Pricing BMO determined by AEMO in accordance with clause 7A.3.9.~~

…

Proposed Generator Performance Standard: Means a Generator Performance Standard in respect of a Technical Requirement proposed to apply to a Transmission Connected Generating System that has not been approved and registered in accordance with the process in Chapter 3A.

Proposed Negotiated Generator Performance Standard: Means a Proposed Generator Performance Standard that is not an Ideal Generator Performance Standard but is no less than the Minimum Generator Performance Standard.

…

~~**Provisional Balancing Price**: Means the price determined under clause 7A.3.8(b).~~

~~**Provisional Pricing BMO**: Means, for a Trading Interval, the last Forecast BMO as adjusted by AEMO for the Trading Interval under clause 7A.3.8(a).~~

…

Real-Time Market: Means the mandatory gross pool market operated under Chapter 7 that determines the dispatch and Essential System Service Enablement Quantity of Registered Facilities in each Dispatch Interval based on submitted prices and quantities.

Real-Time Market Bid: A bid in a Real-Time Market Submission or Standing Real-Time Market Submission submitted by a Market Participant to AEMO for a Registered Facility to Withdraw energy via the Central Dispatch process.

Real-Time Market Offer: An offer in a Real-Time Market Submission or Standing Real-Time Market Submission submitted by a Market Participant to AEMO for a Registered Facility to supply a Market Service via the Central Dispatch process.

Real-Time Market Submission: A notice submitted by a Market Participant to AEMO setting out the parameters under which it intends to have a Registered Facility participate in the Real-Time Market, in accordance with clauses 7.4.32, 7.4.33, 7.4.34, 7.4.35, 7.4.38 and 7.4.39.

Real-Time Market Submission Acceptance Horizon: The point in time before a Dispatch Interval after which a Market Participant may submit Real-Time Market Submissions for a Registered Facility for that Dispatch Interval.

Real-Time Market Timetable: The timetable documented by AEMO under clause 7.1.2(a) for the operation of the Real-Time Market, which must include the timelines referred to in clause 7.1.3.

…

Recover: Means, in relation to SWIS Frequency Operating Standards, the time at which the SWIS Frequency returns to the applicable Normal Operating Frequency Band, provided it does not go outside that range at any time over the following 1 minute.

Rectification Plan: Means a plan submitted by a Market Participant responsible for a Transmission Connected Generating System in respect of a Transmission Connected Generating System pursuant to clause 3A.11.1.

…

Reference Scenario: The Scenario that represents AEMO's best estimate of future dispatch and market outcomes.

Reference Trading Price: Means, for a Trading Interval, the price determined in accordance with clause 7.11A.1(b).

Registered Generator Performance Standard: Means:

(a) each Generator Performance Standard in respect of a Technical Requirement applying to a Transmission Connected Generating System that has been approved and registered in accordance with the process in Chapter 3A; and

(b) in respect of an Existing Transmission Connected Generating System, the generator performance standard agreed and registered pursuant to section [GPS transitional workstream clause].

…

Regulation: Has the meaning defined in clause 3.9.1.

…

Regulation Lower: Has the meaning defined in clause 3.9.3.

Regulation Lower Market Clearing Price: The Market Clearing Price for Regulation Lower.

Regulation Raise: Has the meaning defined in clause 3.9.2.

Regulation Raise Market Clearing Price: The Market Clearing Price for Regulation Raise.

…

~~**Relevant Dispatch Quantity**: Means, for a Trading Interval, the sum of the EOI Quantities for each Balancing Facility, in MW, at the end of that Trading Interval.~~

Explanatory Note The definition of 'Relevant Generator Modification' will apply for the purposes of Chapter 3A only at this stage. If it affects another workstream this will be reconsidered.

Relevant Generator Modification: Means for the purposes of Chapter 3A, a Potential Relevant Generator Modification that the Network Operator declares to be a Relevant Generator Modification pursuant to clause 3A.13.4.

Reliable Operating State: The state of the SWIS defined in clause 3.3.1.

…

Remaining Available Capacity: For each Dispatch Interval included in an Outage, the remaining capacity of the Facility or item of equipment to provide the Outage Capability at temperatures up to, and including, 41 degrees, and measured in MW for Market Services other than RoCoF Control Service, in MWs for RoCoF Control Service, and in units as specified in the WEM Procedure for other Outage Capabilities.

…

Restoration Profile: The profile over time of the expected change in Withdrawal by the Loads associated with an Interruptible Load after activation in response to a Contingency Event, from the time the Interruptible Load begins to restore Load until the Facility has returned to normal operations.

…

RoCoF Control Requirement: Means the quantity of RoCoF Control Service scheduled or dispatched in a Dispatch Interval or Pre-Dispatch Interval.

RoCoF Control Service or Rate of Change of Frequency Control Service: Has the meaning defined in clause 3.9.7.

RoCoF Control Service Market Clearing Price: The Market Clearing Price for RoCoF Control Service.

RoCoF Limit: Means a limit on the average frequency rate of change over a particular time period.

RoCoF Ride Through Capability: Is the highest RoCoF Limit at which the Facility can operate safely and reliably, expressed over the same timeframe specified in the RoCoF Safe Limit.

RoCoF Safe Limit: Means the RoCoF Limit referred to in Appendix 13.

RoCoF Upper Limit: Means, for a Dispatch Interval, the maximum RoCoF expected on the SWIS if Contingency Reserve was solely used to maintain SWIS frequency after a Contingency Event.

…

Satisfactory Operating State: The state of the SWIS defined in clause 3.4.1.

Scenario: Means a set of inputs used to generate forecast Dispatch Targets and Market Clearing Prices and the set of resulting outputs.

…

Secure Operating State: The state of the SWIS defined in clause 3.4.2.

…

Security Limit: Any technical limit on the operation of the SWIS as a whole, or a region of the SWIS, necessary to maintain the Power System Security, including both static and dynamic limits, and limits to allow for and to manage contingencies.

…

~~**Sent Out Capacity:** Means:~~

~~(a) for a Balancing Facility, other than the Balancing Portfolio, that is:~~

~~i. a Scheduled Generator, the capacity provided as the Standing Data in Appendix 1(b)(iii); and~~

~~ii. a Non-Scheduled Generator, the capacity provided as the Standing Data in Appendix 1(e)(iiiA); and~~

~~(b) for the Balancing Portfolio, the sum of all of the Standing Data in Appendix 1(b)(iii) and Appendix 1(e)(iiiA) for each Facility in the Balancing Portfolio.~~

…

Separation Event: Means a Credible Contingency Event that results in the formation of an Island.

…

SESSM Award Duration: Means the period over which obligations and payments under a Supplementary Essential System Service Submission apply.

SESSM Minimum Availability Requirement: For a SESSM Supplementary ESS Award, the percentage of Dispatch Intervals in the SESSM Service Timing in which the Facility must include the sum of the Availability Quantity and the Base ESS Quantity in its Real-Time Market Submissions for the relevant Frequency Co-optimised Essential System Service from an Available or In-Service Facility or be required to pay Supplementary Essential System Service Mechanism refunds under clause [settlement].

SESSM Service Commencement Date: Means the date a Frequency Co-optimised Essential System Service procured through the Supplementary Essential System Service Mechanism is required to commence.

SESSM Service Quantity Profile: Means the MW or MWs quantity of Frequency Co-optimised Essential System Service sought through the Supplementary Essential System Service Mechanism for each Dispatch Interval in the SESSM Service Timing (which may be zero at some times of the year or in some hours of the day).

Explanatory Note Section 3.7 which deals with System Restart Service will be amended separately.

SESSM Service Specification: Means the specification for any Essential System Service including:

(a) for a Frequency Co-optimised Essential System Service being procured under the Supplementary Essential System Service Mechanism, as set out in clause 3.15A.6; and

(b) for System Restart Service, as set out in clause 3.7.

SESSM Service Timing: Means the time period and Dispatch Intervals during which a Frequency Co-optimised Essential System Service procured through the Supplementary Essential System Service Mechanism is required to be provided.

SESSM Supplementary ESS Award: Means the acceptance of an offer by AEMO to provide additional Frequency Co-optimised Essential System Services by a Market Participant in accordance with a Supplementary Essential System Service Submission through the Supplementary Essential System Service Mechanism.

…

Slow Start Facilities: Has the meaning in clause 7.9.2.

…

~~**SOI Quantity**: Means the quantity, in MW, at which a Balancing Facility was operating as at the start of a Trading Interval.~~

…

Speed Factor: A parameter τ that defines the approximation of the response curve of a Facility to a Contingency Event, in the form:

$$response(t) = reserve * (1 - e^{\frac{-t}{\tau}})$$

…

~~**Spinning Reserve**: Supply capacity held in reserve from synchronised Scheduled Generators or Interruptible Loads, so as to be available to support the system frequency in the event of an outage of a generating works or transmission equipment or to be dispatched to provide energy as allowed under these Market Rules.~~

~~**Spinning Reserve Event**: Means an event which causes a Facility in the Balancing Portfolio, which System Management has instructed to provide Spinning Reserve Service, to provide a Spinning Reserve Response.~~

~~**Spinning Reserve Response**: Means a Spinning Reserve response by a Facility in accordance with clause 3.9.3.~~

~~**Spinning Reserve Response Quantity**: Means, for a Trading Interval, the quantity of additional energy, in MWh, provided by a Facility as a Spinning Reserve Response due to a Spinning Reserve Event, but excluding any such contribution that occurred because System Management had instructed the Facility to provide Upwards LFAS Enablement or Backup Upwards LFAS Enablement.~~

~~**Spinning Reserve Service:** Has the meaning given in clause 3.9.2.~~

…

Stable: Means when the SWIS will return to an acceptable steady-state operating condition following a disturbance.

Stabilise: Means, in relation to SWIS Frequency Operating Standards, when the SWIS Frequency has remained above or below the required level for at least 20 seconds.

…

~~**Stand Alone Facility**: Means a Scheduled Generator or Non-Scheduled Generator that is accepted by AEMO under clause 7A.4 as a stand alone facility.~~

…

Standing Enablement Maximum: The maximum level of associated generation or load (in MW) above which no response will be available for a Frequency Co-optimised Essential System Service.

Standing Enablement Minimum: The maximum level of associated generation or load (in MW) below which no response will be available for a Frequency Co-optimised Essential System Service.

…

Standing High Breakpoint: For a Facility and a Frequency Co-optimised Essential System Service, the maximum level of generation (in MW) above which the Facility cannot provide its maximum quantity of that Frequency Co-optimised Essential System Service.

Standing Low Breakpoint: For a Facility and a Frequency Co-optimised Essential System Service, the minimum level of generation (in MW) below which the Facility cannot provide its maximum quantity of that Frequency Co-optimised Essential System Service.

Standing Maximum Downwards Ramp Rate: The Facility's maximum physical ability, in MW per minute, on a linear basis, to decrease its Injection or increase its Withdrawal on the receipt of a Dispatch Instruction.

Standing Maximum Upwards Ramp Rate: The Facility's maximum physical ability, in MW per minute, on a linear basis, to increase Injection or decrease Withdrawal on the receipt of a Dispatch Instruction.

Standing Real-Time Market Submission: A Real-Time Market Submission made by a Market Participant in accordance with clause 7.4.55 until it is replaced in accordance with clause 7.4.56.

STEM Results Deadline: Means 11:30 AM on the Scheduling Day for the Trading Day, or such other time as may be notified by AEMO under clause 6.4.6B.

…

STEM Submission Cutoff: Means 10:50 AM on the Scheduling Day for the Trading Day, or such other time as may be notified by AEMO under clause 6.4.6B.

…

Supplementary Essential System Service Mechanism: Means the mechanism to procure Frequency Co-optimised Essential System Services under section 3.15A.

Supplementary Essential System Service Submission: Means a submission made by a Market Participant in respect of a Facility to provide Frequency Co-optimised Essential System Services in accordance with clause 3.15A.23 through the Supplementary Essential System Service Mechanism.

…

SWIS Frequency: Means the frequency of the SWIS, or an Island (as applicable).

…

SWIS Frequency Operating Standards: Means the standards set out in Table 1, Appendix 13.

…

SWIS Operating State: One or any of the Reliable Operating State, Satisfactory Operating State, Secure Operating State ~~Operating State, High Risk Operating State~~ or Emergency Operating State.

…

System Inertia: The total Inertia provided by Registered Facilities, Network equipment and other equipment connected to the SWIS.

…

System Restart Contract: A contract between AEMO and a person for the provision by that Market Participant's Facility of a System Restart Service to AEMO.

System Restart Service: The ability of a Registered Facility which an energy producing system to start without requiring energy to be supplied from a Network to assist in the re-energisation of the SWIS in the event of system shut down, or a major supply shutdown. ~~Has the meaning given in clause 3.9.8.~~

System Restart Service Provider: A person who agrees to provide System Restart Service to AEMO under a System Restart Service Contract.

…

System Strength: Is a measure of how resilient the voltage waveform is to disturbances such as those caused by a sudden change in Load or an energy producing system, the switching of a Network element, tapping of transformers and other types of faults.

…

System Strength Requirements: Means, the requirements identified to maintain sufficient System Strength on the SWIS, as determined by the processes specified in the WEM Procedure referred to in clause 3.2.7.

…

Technical Envelope: The limits for the operation of the SWIS in each SWIS Operating State as established and modified by AEMO in accordance with clause 3.2.6.

Technical Requirement: Means each Technical Requirement for a Transmission Connected Generating System specified in Appendix 12.

…

Template GPS Monitoring Plan: Means the template GPS Monitoring Plan set out in the WEM Procedure referred to in clause 3A.6.2 as amended from time to time.

…

Transmission Connected Generating System: Means generating works connected to a transmission system in the SWIS.

…

Trigger Event: Means one or more circumstances specified in a Negotiated Generator Performance Standard, the occurrence of which requires a Market Participant responsible for a Transmission Connected Generating System to undertake required actions to achieve an agreed outcome and or achieve an agreed higher level of performance than the existing Registered Generator Performance Standard applicable in respect of one or more Technical Requirements.

…

Unadjusted Intermittent Generation Forecast (UIGF): The expected maximum available Injection of a Semi-Scheduled Facility in a Dispatch Interval, as provided to AEMO in a Real-Time Market Submission.

…

~~**Upwards LFAS Enablement**: Means, for a Trading Interval and an LFAS Facility, the total quantity associated with that LFAS Facility in the Upwards LFAS Enablement Schedule for that Trading Interval.~~

~~**Upwards LFAS Enablement Schedule**: Means, for a Trading Interval, the Forecast Upwards LFAS Enablement Schedule for that Trading Interval most recently provided by AEMO to System Management under clause 7B.3.1(b) between LFAS Gate Closure for that Trading Interval and the point in time 15 minutes after LFAS Gate Closure for that Trading Interval.~~

~~**Upwards LFAS Merit Order**: Means, for a Trading Interval, the Forecast Upwards LFAS Merit Order for that Trading Interval used by AEMO under clause 7B.3.3(a) to determine the Upwards LFAS Enablement Schedule.~~

~~**Upwards LFAS Price**: Means, for a Trading Interval, the Forecast Upwards LFAS Price for that Trading Interval determined by AEMO under clause 7B.3.4(a) from the Upwards LFAS Enablement Schedule, subject to clause 7B.3.12, and published under clause 7B.3.11.~~

~~**Upwards LFAS Price-Quantity Pair**: Means for an LFAS Facility:~~

~~(a) the specified non-Loss Factor adjusted capacity, in MW, by which a Market Participant is prepared to have its LFAS Facility activated upwards within a Trading Interval; and~~

~~(b) the non-Loss Factor Adjusted Price, in $/MW, the Market Participant wants to be paid to have that capacity available within that Trading Interval.~~

~~**Upwards LFAS Quantity**: Means, for a Trading Interval, the Forecast Upwards LFAS Quantity for that Trading Interval used by AEMO under clause 7B.3.3(a) to determine the Upwards LFAS Enablement Schedule.~~

…

Week-Ahead Schedule: A forecast of Market Clearing Prices, Dispatch Targets Dispatch Caps, Dispatch Forecasts and Essential System Services Enablement Quantities for each Pre-Dispatch Interval in the Week Ahead Schedule Horizon.

Week Ahead Schedule Horizon: The next 336 Pre-Dispatch Intervals after a Pre-Dispatch Interval.

…

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

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

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

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

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

Explanatory Note

The proposed amendments to Appendix 1 are, in most cases, consequential changes resulting from the new framework for Essential System Services. These amendments are placeholders only, as the proposed amendments to Appendix 1 will be made in the Registration and Participation and Settlement workstreams.

Amendments will also be made to Appendix 1 to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

Appendix 1: Standing Data

This Appendix describes the Standing Data to be maintained by AEMO for use by AEMO in market processes and by System Management in dispatch processes.

Standing Data required to be provided as a pre-condition of Facility Registration and which Rule Participants are to update as necessary, is described in clauses (a) to (h).

Standing Data not required to be provided as a pre-condition of Facility Registration but which AEMO is required to maintain, and which Rule Participants are to update as necessary, includes the data described in clauses (j) to (~~m~~n).

(a) [Blank]

(b) for a Scheduled Generator:

…

x. the capability to provide each of the ~~following~~ Frequency Co-optimised Essential System Services, including information on trade-off functions when more than one other type of Essential System Service and/or energy is provided simultaneously.~~:~~

~~1. Load Following;~~

~~2. Spinning Reserve; and~~

~~3. [Blank]~~

~~4. Load Rejection Reserve;~~

…

Explanatory Note

Consequential amendment to the removal of Operating Instructions.

xix. the facility's minimum physical response time before the facility can begin to respond to a Dispatch Instruction ~~or Operating Instruction~~;

…

…

(e) for a Non-Scheduled Generator:

i. evidence that the communication and control systems required by section 2.35 are in place and operational;

ii. the nameplate capacity of the generator, expressed in MW;

iiA. the minimum load at the connection point of the generator that will automatically trip off if the generator fails, expressed in MW;

iii. the ramp down rates;

iiiA. the sent out capacity of the generator, expressed in MW;

iv. [Blank]~~the capability to provide Load Rejection Reserve, including information on trade-off functions when energy is provided simultaneously;~~

v. [Blank]

vi. the minimum response time before the facility can begin to respond to an instruction from System Management to change its output;

vii. the Metering Data Agent for the facility;

viii. the single line diagram for the facility, including the locations of transformers, switches, operational and settlement meters;

ix. the point on the network at which the facility can connect;

x. the short circuit capability of facility equipment; and

xi. sub-transient, transient and steady state impedances (positive, negative and zero sequence) for the facility;

…

(g) for an Interruptible Load:

…

vi. the capability to provide Continency Reserve Raise ~~each of the following Services~~ as a function of consumption~~:~~;

~~1. Spinning Reserve.~~

~~2. [Blank]~~

…

…

(j) [Blank]~~for a Scheduled Generator and a Non-Scheduled Generator:~~

~~i. whether the Market Participant intends the facility to participate in the LFAS Market; and~~

~~ii. for each facility that a Market Participant intends to participate in the LFAS Market, evidence that the Facility meets the LFAS Facility Requirements including any limitations on enablement and quantities.~~

…

(l) For each Market Customer:

i. the Individual Reserve Capacity Requirement for the Market Customer;

ii. a list of Non-Temperature Dependent interval meters; and

iii. a Standing STEM Submission (if provided by the Market Participant) comprising for each Trading Interval for a Trading Week:

1. a Fuel Declaration;

2. an Availability Declaration;

3. if the Market Participant is a provider of Essential System Services, an Essential System Service Declaration;

4. a Portfolio Supply Curve; and

5. a Portfolio Demand Curve; and

(m) [Blank]~~For each Intermittent Facility, whether it is exempted from funding Spinning Reserve costs.~~

(n) For each Facility:

i. RoCoF Ride-Through Capability which if greater that the RoCoF Safe Limit must be supported by test results or engineering studies acceptable to AEMO;

ii. start-up costs;

iii. minimum generation costs;

iv. if the Facility is accredited to provide a Frequency Co-optimised Essential System Service, the Frequency Co-optimised Essential System Service Accreditation Parameters; and

v. if the Facility is not accredited to provide a Frequency Co-optimised Essential System Service the Facility's indicative, as applicable:

1. Maximum Capability;

2. Standing Enablement Minimum and Standing Enablement Maximum;

3. Speed Factor; and

4. MWs inertia of the Facility when running, or if the Facility can operate in multiple configurations with differing levels of inertia, the MWs of inertia in each of those configurations.

…

Explanatory Note

Any changes to Appendix 3 resulting from the new framework for Essential System Services will be made in a subsequent version of these Amending Rules, or the Reserve Capacity Mechanism workstream.

Amendments will also be made to Appendix 3 to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

Appendix 3: Reserve Capacity Auction and Trade Methodology

…

Explanatory Note

Appendix 6, clauses (b) and (c) are to be amended to refer to the new Participant Interval Minimum STEM Price and Participant Interval Maximum STEM Price, respectively.

Appendix 6: STEM Price Curve Determination

The first part of this appendix describes a process for converting a Market Participant's Portfolio Supply Curve and Portfolio Demand Curve into a single STEM Price Curve and to then convert a Market Participant's STEM Price Curve into STEM Bids and STEM Offers relative to its Net Bilateral Position.

For each Market Participant and for each Trading Interval in the Trading Day except those for which AEMO has recorded that the Market Participant has not made a STEM Submission:

(a) Determine for every price between the Minimum STEM Price and the Alternative Maximum STEM Price:

i. the maximum cumulative quantity the Market Participant is prepared to sell into the STEM from all of its Price-Quantity Pairs in its Portfolio Supply Curve;

ii. the minimum cumulative quantity the Market Participant is prepared to sell into the STEM from all of its Price-Quantity Pairs in its Portfolio Supply Curve;

iii. the maximum cumulative quantity the Market Participant is prepared to buy from the STEM from all of its Price-Quantity Pairs in its Portfolio Demand Curve;

iv. the minimum cumulative quantity the Market Participant is prepared to buy from the STEM from all of its Price-Quantity Pairs in its Portfolio Demand Curve;

v. the STEM Price Curve quantity for that price where

1. the minimum STEM Price Curve quantity for that price equals the value in (ii) less the value in (iii);

2. the maximum STEM Price Curve quantity for that price equals the value in (i) less the value in (iv); and

3. the STEM Price Curve for that price includes all quantities between those in (1) and (2).

(b) If the minimum quantity in a STEM Price Curve is greater than the Net Bilateral Position of the Market Participant then extend the STEM Price Curve to include the range between the Net Bilateral Position and the minimum quantity in the STEM Price Curve where this range is priced at the Participant Interval Minimum STEM Price.

(c) If the maximum quantity in a STEM Price Curve is less than the Net Bilateral Position of the Market Participant then extend the STEM Price Curve to include the range between the maximum quantity in the STEM Price Curve and the Net Bilateral Position where this range is priced at the ~~Alternative~~ Participant Interval Maximum STEM Price.

(d) If the Net Bilateral Position equals the minimum STEM Price Curve quantity then there are no STEM Bids, otherwise:

i. for the STEM Price Curve between the minimum STEM Price Curve quantity and the Net Bilateral Position of that Market Participant identify each price for which more than one STEM Price Curve quantity is defined;

ii. for each price identified in (i) identify the minimum STEM Price Curve quantity for which that price applies, such that the STEM Price Curve quantity lies between the minimum STEM Price Curve quantity and the Net Bilateral Position;

iii. for each price identified in (i) identify the maximum STEM Price Curve quantity for which that price applies, such that the STEM Price Curve quantity lies between the minimum STEM Price Curve quantity and the Net Bilateral Position;

iv. for each price identified in (i) set a Price-Quantity Pair price equal to that price;

v. for each price identified in (i) set a Price-Quantity Pair quantity equal to the quantity defined in (iii) less the quantity defined in (ii);

vi. set the Market Participant's STEM Bids to be the set of Price-Quantity Pairs defined in (iv) and (v) where each Price-Quantity Pair means that the Market Participant is prepared to buy a quantity of energy from the STEM for that Price-Quantity Pair equal to:

1. 0 MWh if the STEM Clearing Price is greater than the Price-Quantity Pair price;

2. the Price-Quantity Pair quantity if the STEM Clearing Price is less than the Price-Quantity Pair price;

3. an amount between 0 MWh and the Price-Quantity Pair quantity if the STEM Clearing Price equals the Price-Quantity Pair price;

(e) If the Net Bilateral Position equals the maximum STEM Price Curve quantity then there are no STEM Offers, otherwise:

i. for the STEM Price Curve between the Net Bilateral Position of that Market Participant and the maximum STEM Price Curve quantity identify each price for which more than one STEM Price Curve quantity is defined;

ii. for each price identified in (i) identify the minimum STEM Price Curve quantity for which that price applies, such that the STEM Price Curve quantity lies between the Net Bilateral Position and the maximum STEM Price Curve quantity;

iii. for each price identified in (i) identify the maximum STEM Price Curve quantity for which that price applies, such that the STEM Price Curve quantity lies between the minimum STEM Price Curve quantity and the Net Bilateral Position;

iv. for each price identified in (i) set a Price-Quantity Pair price equal to that price;

v. for each price identified in (i) set a Price-Quantity Pair quantity equal to the quantity defined in (iii) less the quantity defined in (ii);

vi. set the Market Participant's STEM Offers to be the set of Price-Quantity Pairs defined in (iv) and (v) where each Price-Quantity Pair means that the Market Participant is prepared to sell a quantity of energy into the STEM for that Price-Quantity Pair equal to:

1. 0 MWh if the STEM Clearing Price is less than the Price-Quantity Pair price;

2. the Price-Quantity Pair quantity if the STEM Clearing Price is greater than the Price-Quantity Pair price;

3. an amount between 0 MWh and the Price-Quantity Pair quantity if the STEM Clearing Price equals the Price-Quantity Pair price;

Appendix 9: Relevant Level Determination

This Appendix presents the methodology for determining the Relevant Levels for Facilities that have applied for certification of Reserve Capacity under clause 4.11.2(b) for a given Reserve Capacity Cycle ("Candidate Facility").

…

Explanatory Note
The Unadjusted Intermittent Generation Forecast SCADA feed negates the need for different treatment for adjustment. The counterfactual quantity is determined in real-time rather than afterwards.

Step 3: For each Candidate Facility, identify any Trading Intervals in the period identified in step 1(b) where the Facility was directed to restrict its Injection under a Dispatch Instruction with a Dispatch Cap or Dispatch Target as provided in a schedule under clause [7.13.1].~~:~~

~~(a) the Facility, other than a Facility in the Balancing Portfolio, was directed to restrict its output under a Dispatch Instruction as provided in a schedule under clause 7.13.1(c); or~~

~~(b) the Facility, if in the Balancing Portfolio, was instructed by System Management to deviate from its Dispatch Plan or change its commitment or output as provided in a schedule under clause 7.13.1C(d); or~~

~~(c) was affected by a Consequential Outage as notified by System Management to AEMO under clause 7.13.1A.~~

Step 4: For each Candidate Facility and Trading Interval identified in step 3 use the time-weighted average of the Unadjusted Intermittent Generation Forecast in each Dispatch Interval for the Candidate Facility in each of those Trading Intervals~~ (a):~~.

~~(a) identify the actual quantity as determined in step 2 if:~~

~~i. System Management has made a revised estimate of the maximum quantity in accordance with clause 7.7.5A(c) and the Power System Operation Procedure specified in clause 7.7.5A; and~~

~~ii. the revised estimate of the maximum quantity is lower than the actual quantity as determined in step 2;~~

~~(b) identify the actual quantity as determined in step 2 if:~~

~~i. step 4(a) does not apply; and~~

~~ii. the estimated maximum quantity determined by System Management under clause 7.13.1(eF) is lower than the actual quantity (as specified in a Meter Data Submission covering the Facility and the Trading Interval); and~~

~~(c) if steps 4(a) and (b) do not apply:~~

~~i. identify the revised estimate of the maximum quantity determined by System Management in accordance with the Power System Operation Procedure specified in clause 7.7.5A; or~~

~~ii. if there is no revised estimate, identify the estimate determined by System Management under clause 7.13.1(eF).~~

Step 5: ~~For each Candidate Facility and Trading Interval identified in step 3(b) use:~~

~~(a) the estimate recorded by System Management under clause 7.13.1C(e); and~~

~~(b) the quantity determined for the Facility and Trading Interval in step 2,~~

~~to estimate the quantity of energy (in MWh) that would have been sent out by the Facility had it not complied with System Management's instruction to change its commitment or output during the Trading Interval.~~[Blank]

Step 6: ~~For each Candidate Facility and Trading Interval identified in step 3(c) use:~~

~~(a) the schedule of Consequential Outages determined by System Management under clause 7.13.1A;~~

~~(b) the quantity determined for the Facility and Trading Interval in step 2; and~~

~~(c) the information recorded by System Management under clause 7.13.1C(a),~~

~~to estimate the quantity of energy (in MWh) that would have been sent out by the Facility had it not been affected by the notified Consequential Outage during the Trading Interval.~~ [Blank]

Step 7: Determine for each Trading Interval in each 12 month period identified in step 1(b) the Existing Facility Load for Scheduled Generation (in MWh) as:

(Total_Generation + DSP_Reduction + Interruptible_Reduction + Involuntary_Reduction) – CF_Generation

where

Total_Generation is the total sent out generation of all Facilities, as determined from Meter Data Submissions;

DSP_Reduction is the total quantity of Deemed DSM Dispatch for all Demand Side Programmes for that Trading Interval;

Explanatory Note

Interruptible Loads will use the standard dispatch process, and not special contracts.

Interruptible_Reduction is the total quantity by which all Interruptible Loads reduced their ~~consumption~~ Withdrawal in accordance with ~~the terms of an Ancillary Service Contract~~ Essential System Service provision, as recorded by ~~System Management~~ AEMO under clause 7.13.1C(c);

Involuntary_Reduction is the total quantity of energy not served due to involuntary load shedding (manual and automatic), as recorded by System Management under clause 7.13.1C(b); and

CF_Generation is the total sent out generation of all Candidate Facilities, as determined in step 2~~ or estimated in steps 4, 5 or 6 as applicable~~.

Explanatory Note

The proposed amendment to Appendix 11, clause 2.4 is a consequential change resulting from the new Operating States framework and for consistency with the drafting style of the WEM Rules. Any further changes that may be required to Appendix 11 will be made in other workstreams.

Further changes will also be made to Appendix 11 to reflect the Administrative Amendments referred to in the opening Note to these draft Amending Rules.

APPENDIX 11: DETERMINATION OF CONSTRAINED ACCESS ENTITLEMENT

This Appendix presents the method for determining the Constrained Access Entitlement for a Constrained Access Facility in accordance with clause 4.10A.

Terms defined in this Appendix are defined for the purposes of this Appendix alone and must not be used to infer the meaning of those words, or other words, in these ~~Market~~ WEM Rules.

Item 1. The Network Operator must, for each relevant Constrained Access Facility, determine the Constrained Access Entitlement as the MW level of network access expected to be available to the Facility for at least 95% of the generation dispatch scenarios that could, applying the matters in items 2.3.1 and 2.6.1 of this Appendix (as applicable), occur to meet the Peak Demand on the SWIS for the relevant Capacity Year.

Item 2. In making its determination under item 1, the Network Operator must apply the following—

2.1. Assume that all major transmission network elements are in service, except those which are normally configured to be out of service under peak demand conditions.

2.2. Assume peak demand is equal to the value calculated under clause 4.5.10(a)(iv) and used in the calculation of the Reserve Capacity Requirement for the relevant Capacity Year (**Peak Demand**).

2.3. Develop in its sole discretion and in accordance with item 2.3.1, a range of generation dispatch scenarios that describe how Facilities could be dispatched at the time of the Peak Demand in order to identify possible network limitations (**Constraint Identification Dispatch Scenarios**).

2.3.1. The Constraint Identification Dispatch Scenarios must—

(a) include, as determined by the Network Operator in its sole discretion, variations in the combination of Facilities dispatched to meet the Peak Demand;

(b) only include Facilities that have made a valid application for certification of Reserve Capacity for the relevant Capacity Year and Registered Facilities that have historically generated at peak times and, as determined by the Network Operator in its sole discretion, are likely to generate in the relevant Capacity Year at the Peak Demand;

(c) include, as determined by the Network Operator in its sole discretion, variations in the output of all generation systems in the Constraint Identification Dispatch Scenarios, limited, where applicable, to the maximum sent out capacity available from each Facility at 41 degrees Celsius (as indicated in Standing Data or the relevant application for certification of Reserve Capacity); and

(d) in accordance with the dispatch priorities in clause 7.6.1D, assume Demand Side Management is not dispatched until all generation systems are dispatched.

2.4. Applying only the Constraint Identification Dispatch Scenarios, identify network limitations that the Network Operator, in its sole discretion, considers could limit the output of a Constrained Access Facility, in order to maintain a Satisfactory ~~Normal~~ Operating State, ~~assuming—~~ assuming:

(a) all transmission network augmentations which the Network Operator is committed to commissioning prior to the relevant Capacity Year are accounted for as at the time it makes the determination in this Appendix 11;

(b) as determined by the Network Operator in its sole discretion, the distribution of the location of Peak Demand; and

(c) transmission equipment thermal ratings are at the normal operational rating at 41 degrees Celsius.

2.5. Using the network limitations identified in item 2.4, prepare a consolidated list of network limitations (**Network Constraint List**).

2.6. Develop, in accordance with item 2.6.1, a range of generation dispatch scenarios that describe how Facilities could be dispatched at Peak Demand (**Entitlement Identification Dispatch Scenarios**).

2.6.1. The Entitlement Identification Dispatch Scenarios—

(a) are not required to include the dispatch of Constrained Access Facilities if the methodology employed by the Network Operator in item 2.7 does not require those Facilities to be included;

(b) must include, as determined by the Network Operator in its sole discretion, variations in the output of Scheduled Generators that are not Constrained Access Facilities, limited to—

i. where the Facility has previously been assigned Capacity Credits, the MW equivalent of the most recently assigned Capacity Credits; or

ii. where the Facility has not previously been assigned Capacity Credits, the maximum sent out capacity available from the Facility at 41 degrees Celsius (as indicated in Standing Data or the relevant application for certification of Reserve Capacity);

(c) must assume the output of Non-Scheduled Generators that are not Constrained Access Facilities is equal to—

i. where the Facility has previously been assigned Capacity Credits, the MW equivalent of the most recently assigned Capacity Credits;

ii. where the Facility has not previously been assigned Capacity Credits—

1. where the applicant for Certified Reserve Capacity in respect of the Facility has nominated under clause 4.10.1(i) for the Facility to be assessed under clause 4.11.2(b) (and AEMO has not rejected such nomination under clause 4.11.2(a)), the value determined in accordance with Appendix 9; or

2. otherwise, the level of Certified Reserve Capacity the applicant has applied for in respect of the Facility under clause 4.10; or

(d) otherwise, the Network Operator must determine in its sole discretion, the likely output of the generation system at the time of Peak Demand in the same manner as set out in items 2.3.1(a), (b) and (d).

2.7. Subject to item 2.8, only consider the MW level of network access available, as determined in the Network Operator's sole discretion, to each Constrained Access Facility in each relevant Entitlement Identification Dispatch Scenario applying the constraints in the Network Constraint List.

2.8. In determining the network access available under item 2.7, the Network Operator must assume each Constrained Access Facility—

(a) is constrained in a manner consistent with any relevant Arrangement for Access (including any Network Control Service Contract); and

(b) would, unless a Constrained Access Facility is required to operate at a lower level due to the application of limitations in the Network Constraint List or in accordance with item 2.8(a), operate at—

i. where the Facility has previously been assigned

Capacity Credits, the MW equivalent of the most recently assigned Capacity Credits; or

ii. where the Facility has not previously been assigned Capacity Credits—

1. where the applicant for Certified Reserve Capacity in respect of the Facility has nominated under clause 4.10.1(i) for the Facility to be assessed under clause 4.11.2(b) (and AEMO has not rejected such nomination under clause 4.11.2(a)), the value determined in accordance with Appendix 9; or

2. otherwise, the level of Certified Reserve Capacity the applicant has applied for in respect of the Facility under clause 4.10.

Explanatory Note

Appendix 12 sets out the Generator Performance Standards the subject of Chapter 3A. These standards will apply to new Transmission Connected Generating Systems which connect to the Network. Existing Transmission Connected Generating Systems will be subject to a transitional regime which will be detailed in a separate workstream.

APPENDIX 12: TRANSMISSION CONNECTED GENERATING SYSTEM GENERATOR PERFORMANCE STANDARDS

This Appendix lists each of the Technical Requirements for Transmission Connected Generating Systems and sets out the Ideal Generator Performance Standard, Minimum Generator Performance Standard and any applicable Common Requirements for each Technical Requirement.

Each Technical Requirement may specify Negotiation Criteria which must be met if a Market Participant responsible for a Transmission Connected Generating System submits a Proposed Negotiated Generator Performance Standard.

If a Technical Requirement specifies Common Requirements, these apply regardless of the Generator Performance Standard for a Transmission Connected Generating System.

Use of defined terms in this Appendix 12

Terms defined in Part 1 of this Appendix 12 are defined for the purposes of this Appendix alone and must not be used to infer the meaning of those words, or other words, in these WEM Rules. Terms which are defined in the WEM Rules will apply to this Appendix unless defined in this Appendix or the context otherwise requires.

Where the terms Scheduled Generator and Non-Scheduled Generator are used in this Appendix, in relation to generating works that are proposed to be connected to a transmission system and is yet to be registered under these WEM Rules as a Facility or a Facility that is undergoing an upgrade that may impact its Facility Class, these terms are to be used as they will ultimately apply to the relevant Facility.

When producing electric power, Electricity Storage which is part of a Generating System will be considered as Generation and must meet the Technical Requirements of Appendix 12.

Where terms defined in Technical Rules are used in this Appendix, then any references to the power system in those definitions should be read as the SWIS.

For ease of reference, a list of the Technical Requirements that apply to Transmission Connected Generating Systems contained in this Appendix is set out below.

Appendix 12 Part	Technical Requirement

2	Active Power Capability
3	Reactive Power Capability
4	Voltage and Reactive Power Control
5	Active Power Control
6	Inertia and Frequency Control
7	Disturbance Ride Through for a Frequency Disturbance
8	Disturbance Ride Through for a Voltage Disturbance
9	Disturbance Ride Through for Multiple Disturbances
10	Disturbance Ride Through for Partial Load Rejection
11	Disturbance Ride Through for Quality of Supply
12	Quality of Electricity Generated
13	Generation Protection Systems
14	Remote Monitoring Requirements
15	Remote Control Requirements
16	Communications Equipment Requirements
17	Generation System Model

1. DEFINITIONS

In this Appendix 12, the following terms are defined:

Active Power: As described in the Technical Rules of the applicable Network Operator.

Adequately Damped: As described in the Technical Rules of the applicable Network Operator.

Apparent Power: As described in the Technical Rules of the applicable Network Operator.

Asynchronous Generating System: Means a Generating System comprised of Asynchronous Generating Units.

Asynchronous Generating Unit: Means a Generating Unit that is not a Synchronous Generating Unit.

Connection Point: Means the point on the Network Operator's Network where the Network Operator's Primary Equipment (excluding metering assets) is connected to the Primary Equipment of the Transmission Connected Generating System.

Continuous Uninterrupted Operation: In respect of a Generating System or operating Generating Unit within a Transmission Connected Generating System that is operating immediately prior to a power system disturbance, means:

(a) not disconnecting from the SWIS except in accordance with its Registered Generator Performance Standard;

(b) during the disturbance, contributing active and reactive current as required by its Registered Generator Performance Standard;

(c) after clearance of any electrical fault that caused the disturbance, only substantially varying its Active Power and Reactive Power as required or permitted by its Registered Generator Performance Standard; and

(d) not exacerbating or prolonging the disturbance or causing a subsequent disturbance for other connected Equipment, except as required or permitted by its Registered Generator Performance Standard,

with all essential auxiliary and reactive Equipment remaining in service.

Control Centre: Means the facilities used to direct and control the operation of a Generating System.

Control System: As described in the Technical Rules of the applicable Network Operator.

Communication Standard: Means the requirements for the provision of information to be provided between Network Operators and AEMO as described in the WEM Procedure referred to in clause 2.36A.1 and as contemplated under section 2.36A.

Credible Contingency Event: As described in the Technical Rules of the applicable Network Operator.

Critical Fault Clearance Time: As described in the Technical Rules of the applicable Network Operator.

Dispatch: Means the process of dispatch as described in these WEM Rules.

Dispatch Systems Requirements: Means the requirements described in section 2.35.

Electricity Storage: Means equipment consisting of Storage Works but does not include non-controllable energy storage equipment compensator or flywheel.

Equipment: As described in the Technical Rules of the applicable Network Operator.

Excitation Control System: As described in the Technical Rules of the applicable Network Operator.

Generation: As described in the Technical Rules of the applicable Network Operator.

Generating System: As described in the Technical Rules of the applicable Network Operator.

Generating Unit: As described in the Technical Rules of the applicable Network Operator.

Generator Capability Chart: Means a chart defining the capability of a Generating System or Generating Unit to produce Active Power while producing or consuming Reactive Power. The capability is provided for specified ambient conditions and voltage levels at the Connection Point based on a template provided by the Network Operator. The chart shows the Reactive Power capability achievable for any level of Active Power output while not exceeding limits necessary to prevent damage to Equipment or ensure stable operation.

Maximum Continuous Current: Means the maximum current injected at the Connection Point when the Generating System is delivering Rated Maximum Apparent Power and the Connection Point voltage is within the normal range.

Nameplate Rating: As described in the Technical Rules of the applicable Network Operator.

Nomenclature Standards: As described in the Technical Rules of the applicable Network Operator.

Power Factor: As described in the Technical Rules of the applicable Network Operator.

Power Station: As described in the Technical Rules of the applicable Network Operator.

Primary Equipment: As described in the Technical Rules of the applicable Network Operator.

Protection Scheme: As described in the Technical Rules of the applicable Network Operator.

Protection System: As described in the Technical Rules of the applicable Network Operator.

Rated Capacity: Means the name plate capacity of a Generating Unit as identified by the manufacturer.

Rated Maximum Active Power: Means:

(a) in relation to a Generating Unit, the maximum amount of Active Power that the Generating Unit can continuously deliver at the Connection Point when operating at its Nameplate Rating; and

(b) in relation to a Generating System, the combined maximum amount of Active Power that its Generating Units can deliver at the Connection Point, when its Generating Units are operating at their respective Nameplate Ratings.

Rated Maximum Apparent Power: Means:

(a) in relation to a Generating Unit, the maximum amount of Apparent Power that the Generating Unit can continuously deliver at the Connection Point when operating at its Nameplate Rating; and

(b) in relation to a Generating System, the combined maximum amount of Apparent Power that its Generating Units can deliver at the Connection Point, when its Generating Units are operating at their respective Nameplate Ratings.

Reactive Power: As described in the Technical Rules of the applicable Network Operator.

Reactive Power Capability: Means the required level of Reactive Power performance as specified in Part 3 of this Appendix 12.

Rated Minimum Active Power: Means

(a) in relation to a Generating Unit, the minimum amount of Active Power that the Generating Unit can continuously deliver while maintaining stable operation at the Connection Point or another specified location in the SWIS (including within the Generating System); and

(b) in relation to a Generating System, the combined minimum amount of Active Power that its in-service Generating Units can deliver at the Connection Point while maintaining stable operation.

Remote Control Equipment or **RCE:** As described in the Technical Rules of the applicable Network Operator.

Remote Monitoring Equipment or **RME:** As described in the Technical Rules of the applicable Network Operator.

Rise Time: In relation to a control system, means the time taken for an output quantity to rise from 10% to 90% of the maximum change induced in that quantity by a step change of an input quantity.

RoCoF: Means the rate of change of frequency, expressed in Hertz per second.

Secondary Equipment: As described in the Technical Rules of the applicable Network Operator.

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

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

(b) the sustained changed induced in that output quantity.

Static Excitation System: As described in the Technical Rules of the applicable Network Operator.

Synchronism: As described in the Technical Rules of the applicable Network Operator.

Synchronous Generating Unit: As described in the Technical Rules of the applicable Network Operator.

Synchronous Generating System: Means a Generating System comprised of Synchronous Generating Units.

Tap-Changing Transformer: As described in the Technical Rules of the applicable Network Operator.

Temperature Dependency Data: Means a set of data defining the maximum achievable Active Power of a Generating System or Generating Unit at a particular temperature. The data will be provided based on a template provided by the Network Operator. The data shows the Active Power capability achievable for any temperature while not exceeding limits necessary to prevent damage to plant or ensure stable operation.

Total Fault Clearance Time: As described in the Technical Rules of the applicable Network Operator.

Transformer: As described in the Technical Rules of the applicable Network Operator.

Transmission System: As described in the Technical Rules of the applicable Network Operator.

Turbine Control System: As described in the Technical Rules of the applicable Network Operator.

2. TECHNICAL REQUIREMENT: ACTIVE POWER CAPABILITY

2.1. Common Requirements

As the Ideal Generator Performance Standard is the same as the Minimum Generator Performance Standard for Active Power capability, there are no additional Common Requirements for this Technical Requirement.

2.2. Ideal Generator Performance Standard

The Ideal Generator Performance Standard is the same as the Minimum Generator Performance Standard for Active Power capability.

2.3. Minimum Generator Performance Standard

(a) In relation to the application of this Technical Requirement, the requirements apply at the Connection Point unless otherwise specified.

(b) The Generator Performance Standard for Active Power capability must include Temperature Dependency Data up to and including the maximum ambient temperature specified by the Network Operator:

   i. for the Generating System measured at the Connection Point; and

   ii. for each Synchronous Generating Unit measured at the Generating Unit terminal.

(c) The maximum ambient temperature specified by the Network Operator will be based on an assessment of where the Generating Units are physically located.

(d) Subject to clause A12.2.3(e), the Generating System must be capable of achieving Rated Maximum Active Power output level for all operating conditions, unless otherwise directed by AEMO or the Network Operator, and capable of maintaining its Rated Maximum Active Power output level, subject to energy source availability, at temperatures up to and including the maximum ambient temperature as specified by the Network Operator.

(e) Clause A12.2.3(d) does not apply to the extent that a temporary reduction in Active Power has been agreed to by the Network Operator in order to achieve the required Reactive Power Capability under maximum ambient temperature conditions as set out in Part 3 of this Appendix 12.

2.4. Negotiation Criteria

There are no Negotiation Criteria for this Technical Requirement.

3. TECHNICAL REQUIREMENT: REACTIVE POWER CAPABILITY

3.1. Common Requirements

(a) In relation to the application of this Technical Requirement, the requirements apply at the Connection Point unless otherwise specified.

(b) The Generator Performance Standard must include a Generator Capability Chart, including data for the maximum ambient temperature specified by the Network Operator.

(c) There must be no control system limitation, protection system or other limiting device in operation that would prevent the Generating System from providing the Reactive Power output within the area defined in the Generator Capability Chart.

(d) The maximum ambient temperature specified by the Network Operator will be based on an assessment of where the Generating Units are physically located.

(e) Each Generating System's Connection Point must be capable of permitting the Dispatch of the full Active Power and Reactive Power Capability of the Generating System.

3.2. Ideal Generator Performance Standard

(a) For all operating conditions, including at temperatures up to and including the maximum ambient temperature specified by the Network Operator, each Generating Unit within the Generating System must be capable of supplying or absorbing Reactive Power continuously of at least the amount equal to the product of the Rated Maximum Active Power output of the Generating Unit at nominal voltage and 0.484 while operating at any level of Active Power output between its maximum Active Power output level and its minimum Active Power output level as agreed by the Network Operator and AEMO as part of the Generator Performance Standard.

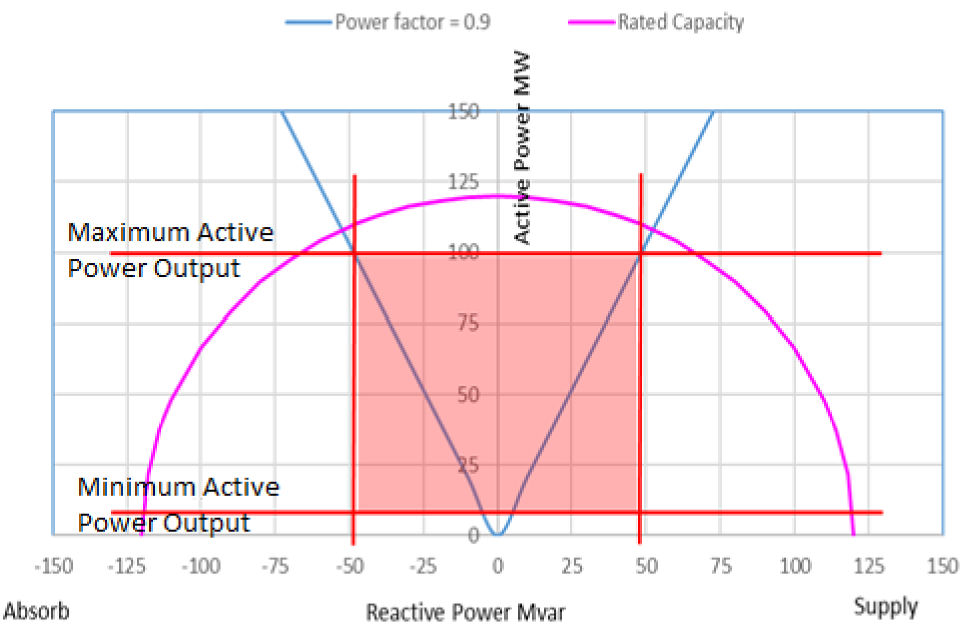

Figure 3.2(a): Example Reactive Power Capability required to meet Ideal Generator Performance Standard[1]

(b) The required levels of Reactive Power Capability must be able to be delivered continuously for voltages at the Connection Point within the allowable steady state voltage ranges as specified in the Technical Rules.

3.3. Minimum Generator Performance Standard

(a) Subject to clause A12.3.3(c), for all operating conditions, including at temperatures up to and including the maximum ambient temperature specified by the Network Operator, the Generating System must be capable of supplying or absorbing Reactive Power continuously of at least the amount equal to the product of the Rated Maximum Active Power output of the Generating System and 0.329 while operating at any level of Active Power output level between its maximum Active Power output level and minimum Active Power output level as agreed by the Network Operator and AEMO as part of the Generator Performance Standard.

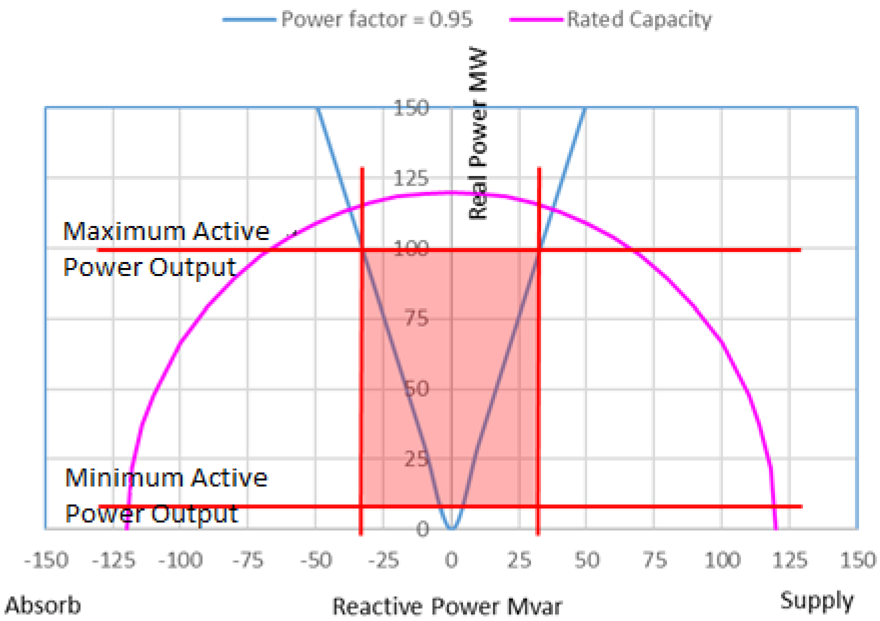

Figure 3.3(a): Example Reactive Power Capability required to meet the Minimum Generator Performance Standard[2]

(b) The Reactive Power Capability may be varied as shown in Figure 3.3(b) when the voltage at the Connection Point varies between 0.9 per unit and 1.1 per unit, where the Generating System must be capable of absorbing or supplying Reactive Power continuously when operating anywhere inside the curve specified in Figure 3.3(b).

[1] Example only. Relevant to clause 3.2(a)
[2] Example only. Relevant to clause 3.3(a)

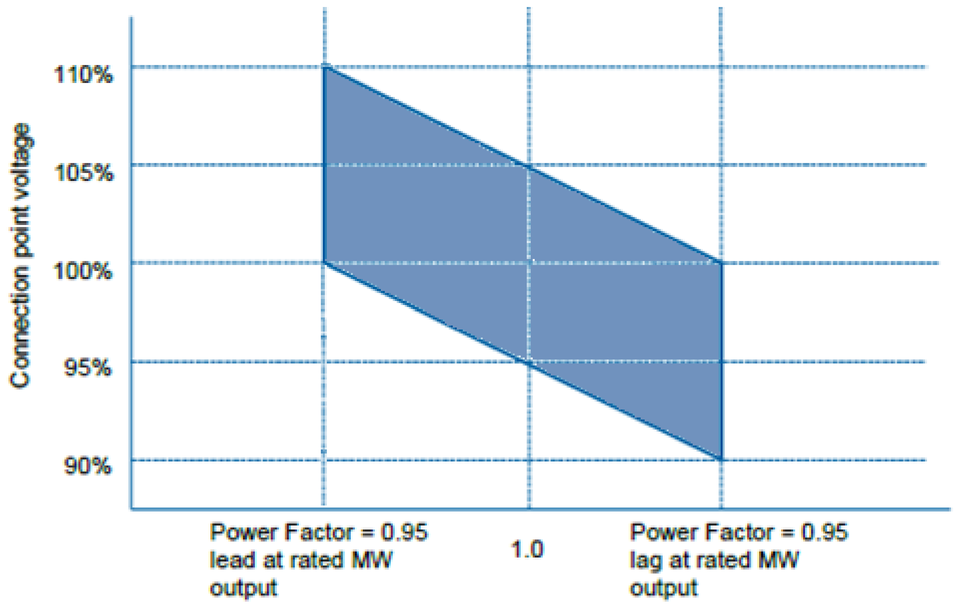

Figure 3.3.(b): Relaxation of Reactive Power requirement with Connection Point voltage

(c) Non-Scheduled Generators may, with the Network Operator's agreement, achieve the Reactive Power Capability specified in clause A12.3.3(a) by reducing Active Power output when the ambient temperature exceeds 25 degrees Celsius in their location, with the conditions forming part of the Generator Performance Standard.

3.4. Negotiation Criteria

There are no Negotiation Criteria for this Technical Requirement.

4. TECHNICAL REQUIREMENT: VOLTAGE AND REACTIVE POWER CONTROL

4.1. Common Requirements

There are no Common Requirements for this Technical Requirement.

4.2. Ideal Generator Performance Standard

(a) The Ideal Generator Performance Standard, as it applies to different Generating Systems, is specified in Table 4.2.1.

Type of Generating System	Relevant requirement
Generating System comprised solely of Synchronous Generating Units.	Clause A12.4.2(b) to clause A12.4.2(i) and clause A12.4.2(j) to clause A12.4.2(l).
Generating System comprised solely of Asynchronous Generating Units.	Clause A12.4.2(b) to clause A12.4.2(i) and clause A12.4.2(m) to clause A12.4.2(p).
Generating System comprised of Synchronous Generating Units and Asynchronous Generating Units.	Clause A12.4.2(b) to clause A12.4.2(i) and: (a) for that part of the Generating System comprised of Synchronous Generating Units, clause A12.4.2(j) to clause A12.4.2(l); (b) for that part of the Generating System comprised of Asynchronous Generating Units, clause A12.4.2(m) to clause A12.4.2(p).

Table 4.2.(a): Voltage and Reactive Power Control Ideal Generator Performance Standard

All Generating Systems

(b) The Generating System must have Equipment capabilities and Control Systems, including, if necessary, a power system stabiliser, sufficient to ensure that:

i. power system oscillations, for the frequencies of oscillation of the Generating System against any other Generating System or device, are Adequately Damped;

ii. operation of the Generating System does not degrade the damping of any critical mode of oscillation of the power system; and

iii. operation of the Generating System does not cause instability (including hunting of Tap-Changing Transformer Control Systems) that would adversely impact other Equipment connected to the SWIS.

(c) Control Systems on Generating Systems that control voltage and Reactive Power must include permanently installed and operational, monitoring and recording equipment for key variables including each input and output, and equipment for testing the Control Systems sufficient to establish their dynamic operational characteristics.

(d) A Generating System must have Control Systems capable of regulating voltage, Reactive Power and Power Factor, with the ability to:

i. operate in all control modes; and

ii. switch between control modes, as demonstrated to the reasonable satisfaction of the Network Operator and AEMO. Where a Generating System has been commissioned with more than one control mode, a procedure for switching between control modes must be agreed with AEMO and the Network Operator as part of the Generator Performance Standard.

(e) A Generating System must have a voltage Control System that:

i. regulates voltage at the Connection Point or another agreed location in the SWIS (including within the Generating System) to within 0.5% of the setpoint, where that setpoint may be adjusted to incorporate any voltage droop or reactive current compensation agreed with AEMO and the Network Operator;

ii. regulates voltage in a manner that helps to support network voltages during faults and does not prevent the requirements for voltage performance and stability in the Technical Rules from being achieved;

iii. allows the voltage to be continuously controllable in the range of at least 95% to 105% of the target voltage (as determined by the Network Operator) at the Connection Point or another location on the SWIS, as specified by the Network Operator, without reliance on a Tap-Changing Transformer and subject to the Generator Performance Standards for Reactive Power Capability with the voltage control location agreed with AEMO and the Network Operator; and

iv. has limiting devices to ensure that a voltage disturbance does not cause a Generating Unit to trip at the limits of its operating capability. The Generating System must be capable of stable operation for indefinite periods while under the control of any limiter. Limiters must not detract from the performance of any stabilising circuits and must have settings applied which are coordinated with all Protection Systems.

(f) Where installed, a power system stabiliser must have:

i. two washout filters for each input, with ability to bypass one of them if necessary;

ii. sufficient (and not less than two) lead-lag transfer function blocks (or equivalent number of complex poles and zeros) with adjustable gain and time-constants, to compensate fully for the phase lags due to the Generating Unit;

iii. monitoring and recording equipment for key variables including inputs, output and the inputs to the lead-lag transfer function blocks; and

iv. equipment to permit testing of the power system stabiliser in isolation from the power system by injection of test signals, sufficient to establish the transfer function of the power system stabiliser.

(g) A Reactive Power, including a Power Factor, Control System must:

i. regulate Reactive Power or Power Factor (as applicable) at the Connection Point or another location in the SWIS (including within the Generating System), as specified by the Network Operator, to within:

1. for a Generating System operating in Reactive Power mode, 2% of the Nameplate Rating (in MVA) of the Generating System (expressed in MVAr); or

2. for a Generating System operating in Power Factor mode, a Power Factor equivalent to 2% of the Nameplate Rating (in MVA) of the Generating System (expressed in MVAr); and

ii. allow the Reactive Power or Power Factor setpoint to be continuously controllable across the Reactive Power Capability range specified in the relevant Generator Performance Standard.

(h) The structure and parameter settings of all components of the Control System, including the voltage regulator, Reactive Power regulator, power system stabiliser, power amplifiers and all associated limiters, must be approved by the Network Operator and AEMO as part of the Generator Performance Standard.

(i) Each Control System must be Adequately Damped.

Synchronous Generating Systems

(j) Each Synchronous Generating Unit must have an Excitation Control System that:

i. is capable of operating the stator continuously at 105% of nominal voltage with Rated Maximum Active Power output;

ii. has an excitation ceiling voltage of at least:

1. for a Static Excitation System, 2.3 times; or

2. for other Excitation Control Systems, 1.5 times,

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

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

iv. achieves a minimum equivalent gain of 200.[3]

(k) The performance characteristics required for AC exciter, rotating rectifier and Static Excitation Systems are specified in Table 4.2.(k).

Performance Item	**Units**	**Static Excitation**	**AC exciter or rotating rectifier**
Generating Unit Field voltage *Rise Time:* Time for field voltage to rise from rated voltage to excitation ceiling voltage following the application of a short duration impulse to the voltage reference.	Second.	0.05 maximum.	0.5 maximum.
Settling Time with the Generating Unit unsynchronised following a disturbance equivalent to a 5% step change in the sensed Generating Unit terminal voltage.	Second.	1.5 maximum.	2.5 maximum.
Settling Time with the Generating Unit synchronised following a disturbance equivalent to a 5% step change in the sensed Generating Unit terminal voltage. It must be met at all operating points within the Generating Unit capability.	Second.	2.5 maximum.	5 maximum.
Settling Time following any disturbance which causes an excitation limiter to operate.	Second.	5 maximum.	5 maximum.

Table 4.2.(k): Synchronous Generating Unit Excitation Control System performance requirements

(l) Where provided, a power system stabiliser must have:

[3] Refer IEEE Standard 115-1983 - Test Procedures for Synchronous Machines.

i. measurements of rotor speed and Active Power output of the Generating Unit as inputs; and

ii. an output limiter, which is continually adjustable over the range of –10% to +10% of stator voltage.

Asynchronous Generating Systems

(m) A Generating System, comprised of Asynchronous Generating Units, must have a voltage and Reactive Power Control System that has a power oscillation damping capability with sufficient flexibility to enable damping performance to be maximised, with the stabilising circuit responsive and adjustable over a frequency range from 0.1 Hz to 2.5 Hz. Any power system stabiliser must have measurements of power system frequency and Active Power output of the Generating Unit as inputs.

(n) A Generating System, comprised of Asynchronous Generating Units, must have a control system capable of achieving a minimum equivalent gain of 200.

(o) The performance characteristics required for the voltage and Reactive Power Control Systems of all Asynchronous Generating Systems are specified in Table 1.3.

Performance Item	Units	Limiting Value	Notes
Rise Time: Time for the controlled parameter (voltage or Reactive Power output) to rise from the initial value to 90% of the change between the initial value and the final value following the application of a 5% step change to the Control System reference.	second.	1.5 maximum.	1 and 3.
Settling time of the controlled parameter with the Generating System connected to the Transmission System following a step change in the Control System reference such that it is not large enough to cause saturation of the controlled output parameter. It must be met at all operating points within the Generating Unit's capability.	second	2.5 maximum.	1, 2 and 3.

Performance Item	Units	Limiting Value	Notes
Settling Time of the controlled parameter with the Generating System connected to the Transmission System following any disturbance that is large enough to cause the maximum value of the controlled output parameter to be just exceeded.	second	5 maximum.	2 and 3.
Notes: 1. The step change is 5%, or a lesser value specified by the Network Operator such that it is the largest step change that results in the required Settling Time at the Connection Point. 2. The step change is specified by the Network Operator such that it is the largest step change that results in the required Settling Time at the Connection Point. 3. The step change is to be recorded for future assessment.			

Table 4.2(o): Asynchronous Generating System Control System performance requirements

(p) The controlled parameters used to meet the requirements specified in Table 4.2(o) and measurement of the parameters must be agreed with the Network Operator and AEMO as part of the Generator Performance Standard.

4.3. Minimum Generator Performance Standard

(a) The Minimum Generator Performance Standard for Voltage and Reactive Power Control as it applies to different Generating Systems, is specified in Table 4.3(a):

Type of Generating System	**Relevant requirement**
Generating System comprised solely of Synchronous Generating Units.	Clause A12.4.3(b) to clause A12.4.3(f).
Generating System comprised solely of Asynchronous Generating Units.	Clause A12.4.3(b) to clause A12.4.3(e) and clause A12.4.3(g).
Generating System comprised of Synchronous Generating Units and Asynchronous Generating Units.	Clause A12.4.3(b) to clause A12.4.3(e) and: (a) for that part of the Generating System comprised of Synchronous Generating Units, clause A12.4.3(f); (b) for that part of the Generating System comprised of Asynchronous

	Generating Units, clause A12.4.3(g).

Table 4.3(a): Voltage and Reactive Power Control Minimum Generator Performance Standard

All Generating Systems

(b) A Generating System must have Equipment capabilities and Control Systems, including, if necessary, a power system stabiliser, sufficient to ensure that:

i. power system oscillations, for the frequencies of oscillation of the Generating System against any other Generating System or device, are Adequately Damped;

ii. operation of the Generating System is Adequately Damped; and

iii. Control Systems can be sufficiently tested to establish their dynamic operational characteristics.

(c) A Generating System must have a Control System to regulate:

i. voltage; or

ii. either of Reactive Power or Power Factor, with the agreement of AEMO and the Network Operator.

(d) A voltage Control System for a Generating System must:

i. regulate voltage at the Connection Point or another location in the SWIS (including within the Generating System), as specified by the Network Operator, to within 2% of the setpoint, where that setpoint may be adjusted to incorporate any voltage droop or reactive current compensation agreed with AEMO and the Network Operator; and

ii. allow the voltage setpoint to be controllable in the range of at least 98% to 102% of the target voltage (as determined by the Network Operator) at the Connection Point or an alternative location, as specified by the Network Operator, subject to the Reactive Power Capability agreed with AEMO and the Network Operator under Part 3 of this Appendix 12.

(e) A Generating System's Reactive Power or Power Factor Control System must:

i. regulate Reactive Power or Power Factor (as applicable) at the Connection Point or another location in the SWIS (including within the Generating System), as specified by the Network Operator, to within:

1. for a Generating System operating in Reactive Power mode, 5% of the Nameplate Rating (in MVA) of the Generating System (expressed in MVAr); or

2. for a Generating System operating in Power Factor mode, a Power Factor equivalent to 5% of the Nameplate Rating (in MVA) of the Generating System (expressed in MVAr);

ii. allow the Reactive Power or Power Factor setpoint to be continuously controllable across the Reactive Power Capability defined in the relevant Generator Performance Standard; and

iii. have limiting devices to ensure that a voltage disturbance does not cause a Generating Unit to trip at the limits of its operating capability. The Generating System must be capable of stable operation for indefinite periods while under the control of any limiter. Limiters must not detract from the performance of any stabilising circuits and must have settings applied, which are coordinated with all Protection Systems, and must be included as part of the Generator Performance Standard.

Synchronous Generating Systems

(f) Each Synchronous Generating Unit within the Generating System, with an Excitation Control System required to regulate voltage must:

i. have excitation ceiling voltage of at least 1.5 times the excitation required to achieve generation at the Nameplate Rating for rated Power Factor, rated speed and nominal voltage; and

ii. subject to the ceiling voltage requirement, have a Settling Time of less than 7.5 seconds for a 5% voltage disturbance with the Generating Unit synchronised, subject to the Generating Unit being electrically connected to the SWIS and operating at a point where such a voltage disturbance would not cause any limiting device to operate.

Asynchronous Generating Systems

(g) A Generating System, comprised of Asynchronous Generating Units, with a voltage Control System must have a Settling Time of less than 7.5 seconds for a 5% voltage disturbance subject to the Generating Unit being electrically connected to the SWIS and operating at a point where such a voltage disturbance would not cause any limiting device to operate.

4.4. Negotiation Criteria

A Proposed Negotiated Generator Performance Standard must be the highest level that the Generating System can reasonably achieve, including by installation of additional dynamic Reactive Power Equipment, and through optimising its Control Systems.

5. TECHNICAL REQUIREMENT: ACTIVE POWER CONTROL

5.1. Common Requirements

(a) All Generating Systems must be capable of meeting the Dispatch Systems Requirements.

(b) Any arrangements put in place as part of the Arrangement for Access to limit Active Power output in order to manage constraints on the Network must be included as part of the Generator Performance Standard.

(c) Each Control System must be Adequately Damped.

(d) Any relevant disconnection settings must be included as part of the Generator Performance Standard.

5.2. Ideal Generator Performance Standard

(a) For a Scheduled Generator, a Generating System must have an Active Power Control System capable of:

i. maintaining and changing its Active Power output in accordance with its Dispatch Instructions;

ii. ramping its Active Power output linearly from one level of Dispatch to another; and

iii. in a thermally stable state, of changing Active Power generation in response to a Dispatch Instruction at a rate not less than 5% of the Generating Unit's or Generating System's Rated Active Power per minute.

(b) For a Non-Scheduled Generator, subject to energy source availability, a Generating System must not change its Active Power generation at a rate greater than 10 MW per minute or 15% of the Power Station's aggregate Nameplate Rating per minute, whichever is the lower or as agreed with the Network Operator and AEMO.

5.3. Minimum Generator Performance Standard

(a) For a Scheduled Generator, a Generating System must have an Active Power Control System capable of maintaining and changing its Active Power output in accordance with its Dispatch Instructions.

(b) For a Non-Scheduled Generator, subject to energy source availability, a Generating System must ensure that the change of Active Power output in a 5 minute period does not exceed a value agreed with AEMO and the Network Operator.

5.4. Negotiation Criteria

There are no Negotiation Criteria for this Technical Requirement.

6. TECHNICAL REQUIREMENT: INERTIA AND FREQUENCY CONTROL

6.1. Common Requirements

(a) All Control Systems must be Adequately Damped.

(b) The recorded maximum ramp rate for the Generating System must be expressed as the change in Active Power (measured in MW) achievable across 6 seconds.

(c) Any relevant disconnection settings must be provided as part of the Generator Performance Standard.

(d) Control Systems on Generating Systems that control Active Power must include permanently installed and operational monitoring and recording equipment for key variables including each input and output, and equipment for testing the Control System sufficient to establish its dynamic operational characteristics.

6.2. Ideal Generator Performance Standard

(a) The Ideal Generator Performance Standard requires that:

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

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

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

iv. control ranges and response times, subject to energy source availability, for Generating Units, or the Generating System as applicable, such that:

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

2. the overall response of each Generating Unit, or the Generating System as applicable, must also be capable of achieving a reduction in the Generating Unit's Active Power output of not less than 5% for a 0.1 Hz increase in power

system frequency provided this does not require operation below its Rated Minimum Active Power;

3. the Generating System must be able to sustain Active Power output changes of at least 10% for a frequency decrease and 30% for a frequency increase, and for not less than 10 seconds, if changes occur within the above limits of output;

4. for Scheduled Generators, the Generating System achieves a rate of response for any frequency disturbance, taking into account the specified maximum ramp rate, of at least 90% of the maximum response expected according to the droop characteristic within 6 seconds and the new output must be sustained for not less than a further 10 seconds; and

5. for Non-Scheduled Generators, the Generating System achieves a rate of response for any frequency disturbance, of at least 90% of the maximum response expected within 2 seconds taking into account the specified maximum ramp rate, and the new output must be sustained for not less than a further 10 seconds.

6.3. Minimum Generator Performance Standard

(a) Subject to energy source availability, a Generating System must have:

i. an automatic variable Active Power control characteristic, where Generating Units, or Generating Systems as applicable, with Turbine Control Systems must also include equipment for both speed and Active Power control;

ii. all Generating Units, or Generating Systems as applicable, capable of operation in a mode in which they will automatically alter their Active Power output to arrest and correct to changes in power system frequency, with all Generating Units operating in this mode unless instructed otherwise by AEMO; and

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

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

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

ii. each Generating Unit, or Generating Systems as applicable, must be capable of achieving a reduction in the Generating Unit's, or

Generating System’s as applicable, Active Power output of not less than 5% for a 0.1 Hz increase in power system frequency provided this does not require operation below its Rated Minimum Active Power;

iii. for initial outputs above 85% of Rated Maximum Active Power output, each Generating Unit's or Generating System’s, as applicable, response capability must be included as part of the relevant Generator Performance Standard;

iv. the Generating System must be able to sustain Active Power output changes of at least 10% for a frequency decrease and 30% for a frequency increase, and for not less than 10 seconds, if changes occur within the above limits of output;

v. for Scheduled Generators, the Generating System achieves a rate of response for any frequency disturbance, taking into account the specified maximum ramp rate, of at least 90% of the maximum response expected according to the droop characteristic within 6 seconds and the new output must be sustained for not less than a further 10 seconds; and

vi. for Non-Scheduled Generators, the Generating System achieves a rate of response for any frequency disturbance, of at least 90% of the maximum response expected within 2 seconds taking into account the specified maximum ramp rate, and the new output must be sustained for not less than a further 10 seconds.

6.4. Negotiation Criteria

(a) A Negotiated Generator Performance Standard must require that there is no requirement for a Generating System to operate with an Active Power output:

i. below its Rated Minimum Active Power in response to a rise in the frequency of the SWIS as measured at the Connection Point;

ii. above its Rated Maximum Active Power output in response to a fall in the frequency of the SWIS as measured at the Connection Point; or

iii. to deliver a rate of change in output exceeding the specified maximum ramp rate.

(b) An additional source of inertia or frequency control may be included within the Generating System. The Control System for the additional source of inertia or frequency control must be coordinated with the remainder of the Generating System and, together, must meet the performance requirements of the relevant Technical Requirements.

7. TECHNICAL REQUIREMENT: DISTURBANCE RIDE THROUGH FOR A FREQUENCY DISTURBANCE

7.1. Common Requirements

(a) In relation to the application of this Technical Requirement, the requirements apply at the Connection Point unless otherwise specified.

(b) Any relevant disconnection settings must be provided as part of the Generator Performance Standard.

7.2. Ideal Generator Performance Standard

(a) A Generating System must maintain Continuous Uninterrupted Operation where a power system disturbance causes the frequency to:

i. reach 52.5 Hz for a period of up to 6 seconds;

ii. reach 52 Hz for a period of up to 2 minutes;

iii. reach 51.5 Hz for a period of up to 5 minutes;

iv. operate between 49.0 Hz to 51.0 Hz continuously;

v. reach 47.5 Hz for a period of up to 15 minutes; or

vi. reach 47.0 Hz for a period of up to 2 minutes,

as shown in Figure 7.2(a).

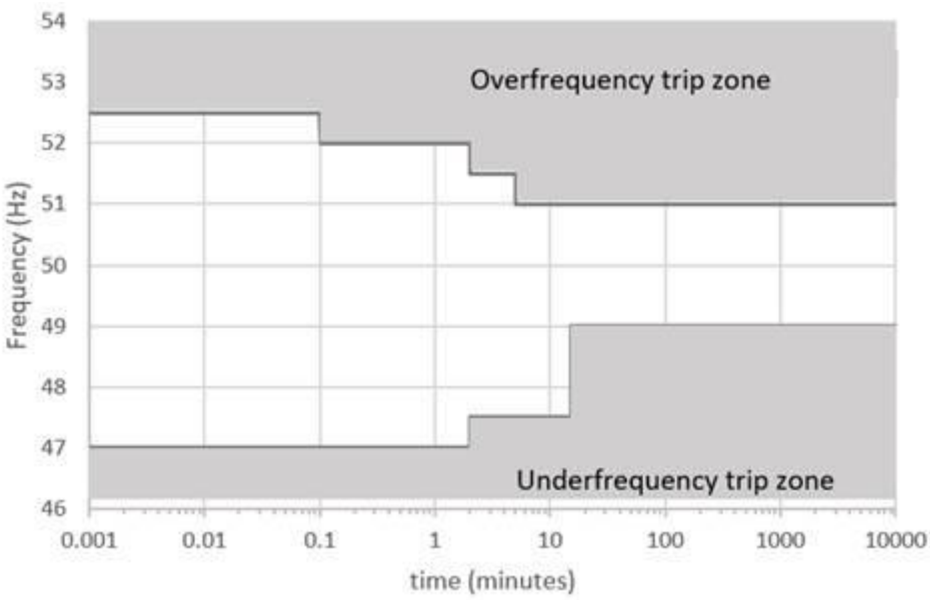

Figure 7.2(a) Frequency variations that a Generating System must ride through to meet the Ideal Generator Performance Standard

(b) A Generating System must maintain Continuous Uninterrupted Operation where a power system disturbance causes the RoCoF to:

i. reach 4 Hz/s over 250 milliseconds during the disturbance; or

ii. reach 3 Hz/s over one second during the disturbance,

as shown in Figure 7.2(b)

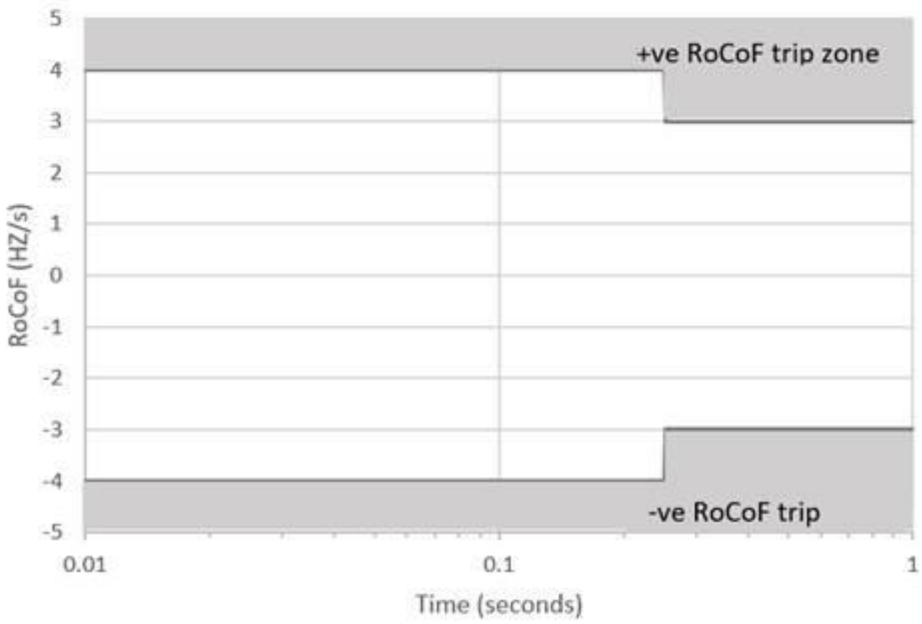

Figure 7.2.2 RoCoF that a Generating System must ride through to meet the Ideal Generator Performance Standard

7.3. Minimum Generator Performance Standard

(a) A Generating System must maintain Continuous Uninterrupted Operation where a power system disturbance causes the frequency to:

i. reach 52.0 Hz for a period of up to 2 minutes;

ii. operate between 49.0 Hz to 51.0 Hz continuously;

iii. reach 48.0 Hz for a period of at least 15 minutes;

iv. reach 47.5 Hz for a period of at least 5 minutes; or

v. reach 47.0 Hz for a period of at least 10 seconds,

as shown in Figure 7.3(a).

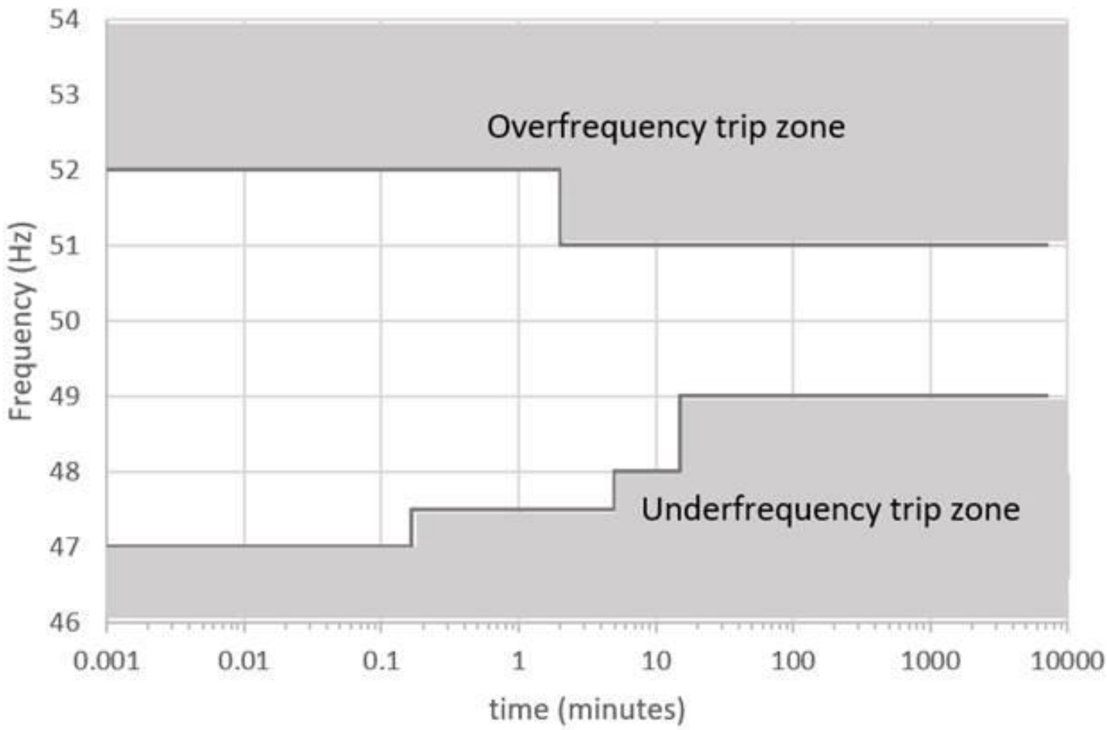

Figure 7.3(a) Frequency variations that a Generating System must ride through to meet the Minimum Generator Performance Standard

(b) A Generating System must maintain Continuous Uninterrupted Operation where a power system disturbance causes the RoCoF to:

i. reach 2 Hz/s over 250 milliseconds during the disturbance; or

ii. reach 1 Hz/s over one second during the disturbance,

as shown in Figure 7.3(b).

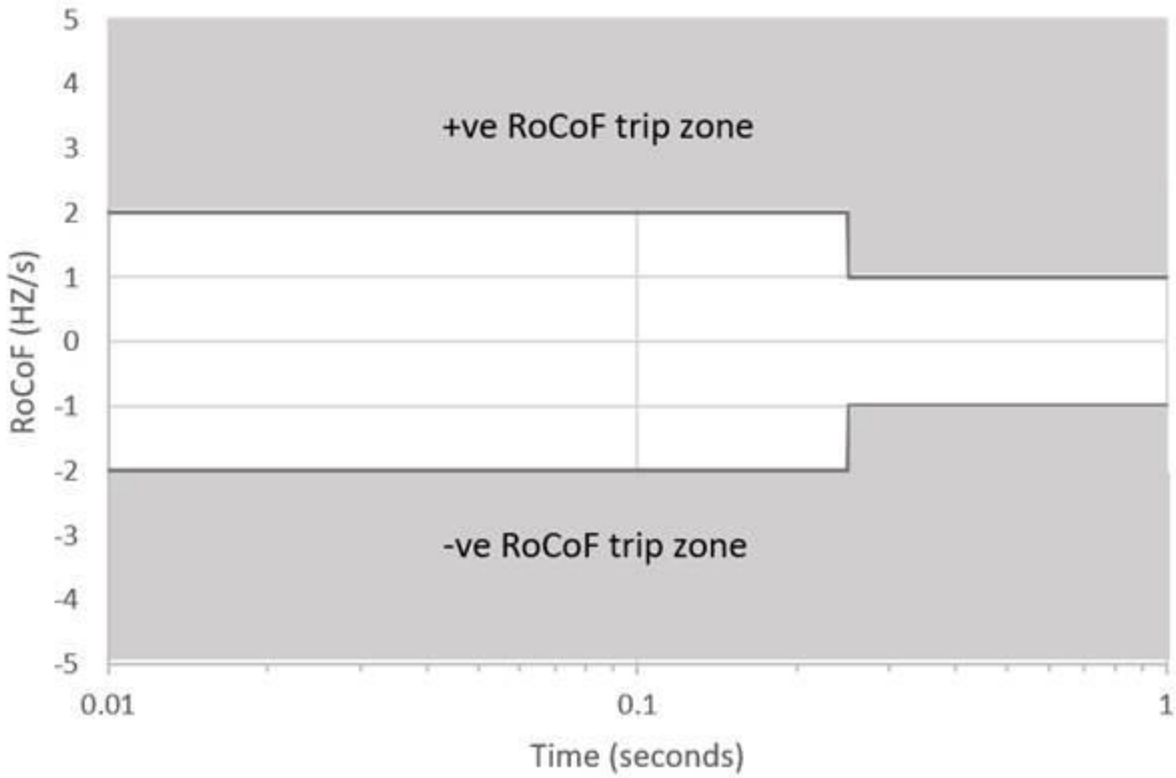

Figure 7.3(b) RoCoF that a Generating System must ride through to meet the Minimum Generator Performance Standard

7.4. Negotiation Criteria

A Proposed Negotiated Generator Performance Standard for disturbance ride through for a frequency disturbance may be accepted provided the Network Operator and AEMO agree that the frequency would be unlikely to fall below the lower bound of the single contingency event band specified in the Frequency Operating Standard.

8. TECHNICAL REQUIREMENT: DISTURBANCE RIDE THROUGH FOR A VOLTAGE DISTURBANCE

8.1. Common Requirements

(a) In relation to the application of this Technical Requirement, the requirements apply at the Connection Point unless otherwise specified.

(b) The Generating System and each of its operating Generating Units is required to remain in Continuous Uninterrupted Operation while the Connection Point voltage remains within 90% to 110% of nominal voltage.

(c) Any relevant disconnection settings must be provided as part of the Generator Performance Standard.

8.2. Ideal Generator Performance Standard

(a) A Generating System must maintain Continuous Uninterrupted Operation where a power system disturbance causes the voltage to vary within the following ranges:

i. voltage does not exceed 130% of nominal voltage for more than 0.02 seconds after T(ov);

ii. voltage does not exceed 120% of nominal voltage for more than 2.0 seconds after T(ov);

iii. voltage does not exceed 115% of nominal voltage for more than 20.0 seconds after T(ov);

iv. voltage does not exceed 110% of nominal voltage for more than 20.0 minutes after T(ov);

v. voltage remains at 0% of nominal voltage for no more than 450 milliseconds after T(uv);

vi. voltage does not stay below 70% of nominal voltage for more than 450 milliseconds after T(uv);

vii. voltage does not stay below 80% of nominal voltage for more than 2.0 seconds after T(uv); and

viii. voltage does not stay below 90% of nominal voltage for more than 10.0 seconds after T(uv).

Where:

T(ov) means a point in time when the voltage first varied above 110% of nominal voltage before returning to between 90% and 110% of nominal voltage; and

T(uv) means a point in time when the voltage first varied below 90% of nominal voltage before returning to between 90% and 110% of nominal voltage.

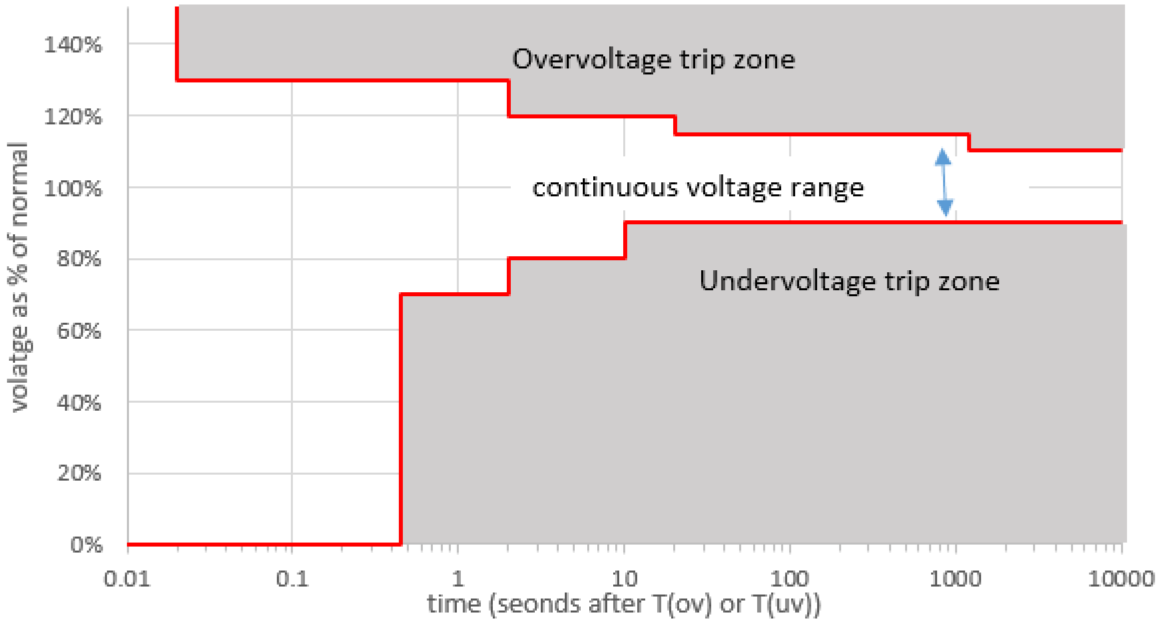

Figure 8.2(a): Voltage variations that a Generating System must ride through to meet the Ideal Generator Performance Standard

8.3. Minimum Generator Performance Standard

(a) A Generating System must maintain Continuous Uninterrupted Operation where a power system disturbance causes the voltage to vary within the following ranges:

i. voltage does not exceed 120% of nominal voltage after T(ov);

ii. voltage does not exceed 115% of nominal voltage for more than 0.1 seconds after T(ov);

iii. voltage does not exceed 110% of nominal voltage for more than 0.9 seconds after T(ov);

iv. voltage remains at 0% of nominal voltage for no more than 450 milliseconds after T(uv) subject to clause A12.8.3(b);

v. voltage does not stay below 70% of nominal voltage for more than 450 milliseconds after T(uv);

vi. voltage does not stay below 80% of nominal voltage for more than 2.0 seconds after T(uv); and

vii. voltage does not stay below 90% of nominal voltage for more than 5.0 seconds after T(uv).

Where:

T(ov) means a point in time when the voltage first varied above 110% of nominal voltage before returning to between 90% and 110% of nominal voltage; and

T(uv) means a point in time when the voltage first varied below 90% of nominal voltage before returning to between 90% and 110% of nominal voltage.

(b) The duration of the zero percent voltage level may be relaxed through agreement with the Network Operator and AEMO, but shall not be lower than the maximum Total Fault Clearance Time with no circuit breaker fail as specified in the Technical Rules.

(c) Any operational arrangements necessary to ensure the Generating System and each of its operating Generating Units will meet its Generator Performance Standard must be provided as part of the Generator Performance Standard.

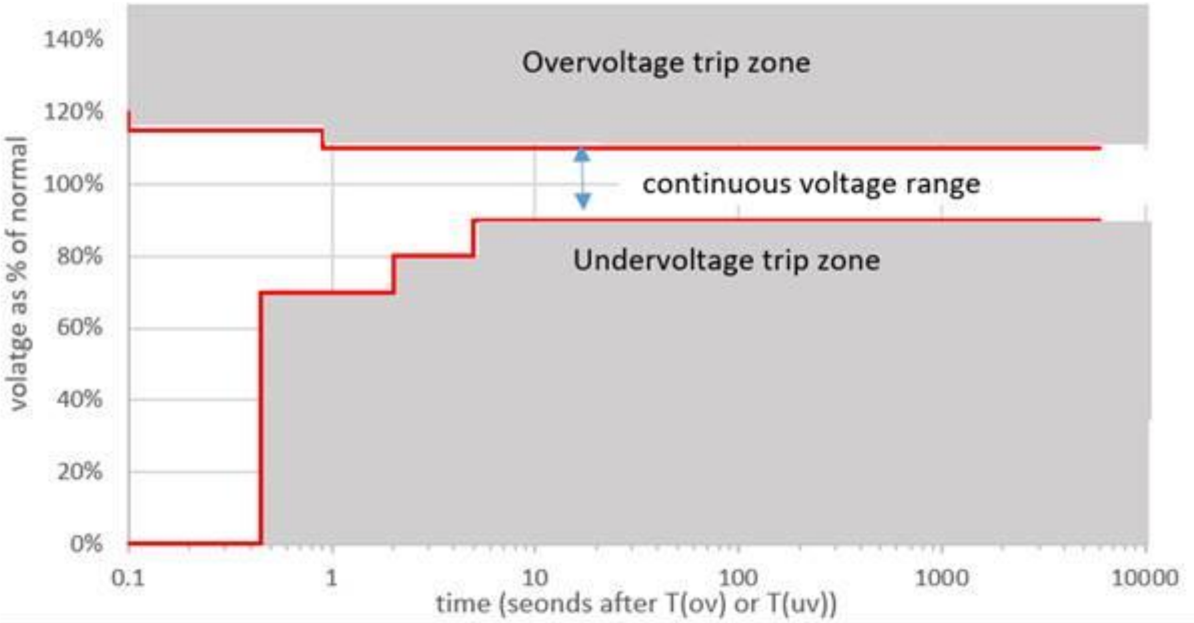

Figure 8.3(c): Voltage variations that a Generating System must ride through to meet the Minimum Generator Performance Standard

8.4. Negotiation Criteria

There are no Negotiation Criteria for this Technical Requirement.

9. TECHNICAL REQUIREMENT: DISTURBANCE RIDE THROUGH FOR MULTIPLE DISTURBANCES

[Note: This Technical Requirement uses the term 'fault' to include a fault of the relevant type having a metallic conducting path.]

9.1. Common Requirements

(a) The Common Requirements for disturbance ride through for multiple disturbances as they apply to different Generating Systems, is specified in Table 9.1(a):

Type of Generating System	Relevant requirement
Generating System comprised solely of Synchronous Generating Units.	Clause A12.9.1(c), clause A12.9.1(d) and clause A12.9.1(e).
Generating System comprised solely of Asynchronous Generating Units.	Clause A12.9.1(c), clause A12.9.1(d) and clause A12.9.1(f).
Generating System comprised of Synchronous Generating Units and Asynchronous Generating Units.	Clause A12.9.1(c) and clause A12.9.1(d) and: (a) for that part of the Generating System comprised of Synchronous Generating Units, clause A12.9.1(e); (b) for that part of the Generating System comprised of Asynchronous Generating Units, clause A12.9.1(f).

Table 9.1(a): Common Requirements for Disturbance Ride through for Multiple Disturbances

(b) Any relevant disconnection settings must be provided as part of the Generator Performance Standard.

All Generating Systems

(c) The Generator Performance Standard must include any operational arrangements to ensure the Generating System, including all operating Generating Units, will meet their agreed performance levels under abnormal Network or Generating System conditions.

(d) When assessing multiple disturbances, a fault that is re-established following operation of automatic reclose Protection Scheme shall be counted as a separate disturbance.

Synchronous Generating Systems and units

(e) For a Generating System comprised solely of Synchronous Generating Units, the reactive current contribution as measured at the Connection Point or another location in the SWIS (including within the Generating System), as specified by the Network Operator, may be limited to 250% of the Maximum Continuous Current of the Generating System. For a Synchronous Generating Unit in any other Generating System, the reactive current contribution may be limited to 250% of the Maximum Continuous Current of that Synchronous Generating Unit.

Asynchronous Generating Systems

(f) For a Generating System comprised of Asynchronous Generating Units:

i. the reactive current contribution as measured at the Connection Point may be limited to the Maximum Continuous Current of the Generating System, including all operating Asynchronous Generating Units;

ii. the reactive current contribution and voltage deviation may be measured at a location other than the Connection Point (including within the relevant Generating System) where agreed with AEMO and the Network Operator, in which case the reactive current contribution and voltage deviation will be assessed at that agreed location;

iii. the reactive current contribution required may be calculated using phase to phase, phase to ground or sequence components of voltages. The ratio of the negative sequence to positive sequence components of the reactive current contribution must be agreed with AEMO and the Network Operator for the types of disturbances specified in this Technical Requirement; and

iv. the Generator Performance Standard must record all conditions (which may include temperature) considered relevant by AEMO and the Network Operator under which the reactive current response is required.

9.2. Ideal Generator Performance Standard

(a) The Ideal Generator Performance Standard as it applies to different Generating Systems, is specified in Table 9.2(a):

Type of Generating System	**Relevant requirement**
Generating System comprised solely of Synchronous Generating Units.	Clause A12.9.2(b), clause A12.9.2(c) and clause A12.9.2(d).
Generating System comprised solely of Asynchronous Generating Units.	Clause A12.9.2(b), clause A12 9.2(c) and clause A12.9.2(e) to clause A12.9.2(h).

Generating System comprised of Synchronous Generating Units and Asynchronous Generating Units.	Clause A12.9.2(b) and clause A12.9.2(c) and: (a) for that part of the Generating System comprised of Synchronous Generating Units, clause A12.9.2(d); (b) for that part of the Generating System comprised of Asynchronous Generating Units, clause A12.9.2(e) to clause A12.9.2(h).

Table 9.2(a): Disturbance Ride through for Multiple Disturbances Ideal Generator Performance Standard

All Generating Systems

(b) A Generating System and each of its operating Generating Units must remain in Continuous Uninterrupted Operation for any disturbances caused by:

i. a Credible Contingency Event;

ii. a three phase fault in a Transmission System cleared by all relevant primary Protection Systems; and

iii. a two phase to ground, phase to phase or phase to ground fault in a transmission or distribution system or a three phase fault in a distribution system cleared in:

1. the longest time expected to be taken for a relevant breaker fail Protection System to clear the fault; or

2. if a Protection System referred to in clause A12.9.2(b)iii.1 is not installed, the greater of 450 milliseconds and the longest time expected to be taken for all relevant primary Protection Systems to clear the fault,

provided that the event is not one that would disconnect the Generating Unit from the SWIS by removing Network elements from service or as a result of the operation of an existing inter-trip, Protection Scheme or runback scheme approved by the Network Operator and AEMO.

(c) A Generating System and each of its operating Generating Units must remain in Continuous Uninterrupted Operation for a series of up to 15 disturbances within any 5 minute period.

Synchronous Generating Systems

(d) Subject to any changed power system conditions or energy source availability beyond the operator of the Generating System's reasonable control, a Generating System comprised of Synchronous Generating Units, in respect of the faults referred to in clause A12.9.2(b), must supply to, or absorb from, the Network:

i. to assist the maintenance of power system voltages during the fault, capacitive reactive current of at least the greater of its pre-disturbance reactive current and 4% of the Maximum Continuous Current of the Generating System including all operating Synchronous Generating Units (in the absence of a disturbance) for each 1% reduction (from the level existing just prior to the fault) of Connection Point voltage or another agreed location in the SWIS (including within the Generating System) during the fault;

ii. after clearance of the fault, Reactive Power sufficient to ensure that the Connection Point voltage or another agreed location in the SWIS (including within the Generating System) is within the range for Continuous Uninterrupted Operation; and

iii. from 100 milliseconds after clearance of the fault, Active Power of at least 95% of the level existing just prior to the fault.

Asynchronous Generating Systems

(e) Subject to any changed power system conditions or energy source availability beyond the operator of the Generation System's reasonable control, a Generating System comprised of Asynchronous Generating Units, for the faults referred to in clause A12.9.2(b), must have equipment capable of supplying to, or absorbing from, the Network:

i. to assist the maintenance of power system voltages during the fault:

1. capacitive reactive current in addition to its pre-disturbance level of at least 4% of the Maximum Continuous Current of the Generating System including all operating Asynchronous Generating Units (in the absence of a disturbance) for each 1% reduction of voltage at the Connection Point below the under-voltage range of 85% to 90% of nominal voltage, except where a Generating System is directly connected to the SWIS with no step-up or connection Transformer and voltage at the Connection Point is 5% or lower of nominal voltage; and

2. inductive reactive current in addition to its pre-disturbance level of at least 6% of the Maximum Continuous Current of the Generating System including all operating Asynchronous Generating Units (in the absence of a disturbance) for each 1% increase of voltage at the Connection Point the over-voltage range of 110% to 115% of nominal voltage,

during the disturbance and maintained until Connection Point voltage recovers to between 90% and 110% of nominal voltage, or such other range agreed with the Network Operator and AEMO; and

ii. from 100 milliseconds after clearance of the fault, Active Power of at least 95% of the level existing just prior to the fault.

(f) The under-voltage and over-voltage range referred to in clause A12.9.2(e)i.1 and clause A12.9.2(e)i.2 may be varied with the agreement of the Network Operator and AEMO (provided the magnitude of the range between the upper and lower bounds remains at 5%).

(g) The reactive current response referred to in clause A12.9.2(e)i.1 and clause A12.9.2(e)i.2 must have a Rise Time of no greater than 40 milliseconds and a Settling Time of no greater than 70 milliseconds and must be Adequately Damped.

(h) Subject to a Generating System's thermal limitations and energy source availability, a Generating System must make available at all times:

i. sufficient current to maintain Rated Maximum Apparent Power of the Generating System including all operating Generating Units (in the absence of a disturbance), for all Connection Point voltages above 115% (or otherwise, above the agreed over-voltage range); and

ii. the Maximum Continuous Current of the Generating System including all operating Generating Units (in the absence of a disturbance) for all Connection Point voltages below 85% (or otherwise, below the agreed under-voltage range),

despite the amount of reactive current injected or absorbed during voltage disturbances, except that AEMO and the Network Operator may agree limits on active current injection where required to maintain Power System Security and/or the Quality of Supply to other Equipment connected to the SWIS.

9.3. Minimum Generator Performance Standard

(a) The Minimum Generator Performance Standard as it applies to different Generating Systems, is specified in Table 9.3(a):

Type of Generating System	Relevant requirement
Generating System comprised solely of Synchronous Generating Units.	Clause A12.9.3(b), clause A12.9.3(c) clause A12.9.3(d).
Generating System comprised solely of Asynchronous Generating Units.	Clause A12.9.3(b), clause A12.9.3(c) and clause A12.9.3(e) to clause A12.9.3(h).
Generating System comprised of Synchronous Generating Units and Asynchronous Generating Units.	Clause A12.9.3(b) and clause A12.9.3(c) and: (a) for that part of the Generating System comprised of Synchronous Generating Units, clause A12.9.3(d); (b) for that part of the Generating System comprised of Asynchronous

	Generating Units, clause A12.9.3(e) to clause A12.9.3(h).

Table 9.3(a): Disturbance Ride through for Multiple Disturbances Minimum Generator Performance Standard

All Generating Systems

(b) A Generating System and each of its operating Generating Units must remain in Continuous Uninterrupted Operation for any disturbance caused by:

i. a Credible Contingency Event; or

ii. a single phase to ground, phase to phase or two phase to ground fault or three phase fault in a transmission or distribution system cleared in the longest time expected to be taken for all relevant primary Protection Systems to clear the fault,

provided that the event is not one that would disconnect the Generating Unit from the SWIS by removing Network elements from service or as a result of the operation of an inter-trip, Protection Scheme or runback scheme approved by the Network Operator and AEMO.

(c) A Generating System and each of its operating Generating Units must remain in Continuous Uninterrupted Operation for a series of up to 6 disturbances within any 5 minute period.

Synchronous Generating Systems

(d) After clearance of a fault, a Generating System comprised of Synchronous Generating Units, in respect of the faults referred to in clause A12.9.3(b) must:

i. deliver Active Power to the Network, and supply or absorb leading or lagging Reactive Power, sufficient to ensure that the Connection Point voltage or another location in the SWIS (including within the Generating System), as specified by the Network Operator, is within the range for Continuous Uninterrupted Operation agreed under the relevant Generator Performance Standard; and

ii. return to at least 95% of the pre-fault Active Power output within a period of time agreed by AEMO and the Network Operator.

Asynchronous Generating Systems

(e) Subject to any changed power system conditions or energy source availability beyond the operator of the Generating System's reasonable control, a Generating System comprised of Asynchronous Generating Units, for the faults referred to in clause A12.9.3(b), must have equipment capable of supplying to, or absorbing from, the Network:

i. to assist the maintenance of power system voltages during the fault:

1. capacitive reactive current in addition to its pre-disturbance level of at least 2% of the Maximum Continuous Current of the Generating System including all operating Asynchronous Generating Units (in the absence of a disturbance) for each 1% reduction of voltage at the Connection Point below the under-voltage range of 80% to 90% of nominal voltage, except where:

    A. voltage at the Connection Point is 15% or lower of nominal voltage; or

    B. where the Generating System is directly connected to the SWIS with no step-up or connection Transformer and voltage at the Connection Point is 20% or lower of nominal voltage; and

2. inductive reactive current in addition to its pre-disturbance level of at least 2% of the Maximum Continuous Current of the Generating System including all operating Asynchronous Generating Units (in the absence of a disturbance) for each 1% increase of voltage at the Connection Point above the over-voltage range of 110% to 120% of nominal voltage,

during the disturbance and maintained until the Connection Point voltage recovers to between 90% and 110% of nominal voltage, or such other range agreed with the Network Operator and AEMO; and

ii. returning to at least 95% of the pre-fault Active Power output, after clearance of the fault, within a period of time agreed by the operator, AEMO and the Network Operator.

(f) The under-voltage and over-voltage range referred to in clause A12.9.3(e)i.1 and clause A12.9.3(e)i.2 may be varied with the agreement of the Network Operator and AEMO (provided the magnitude of the range between the upper and lower bounds remains at 10%).

(g) Where AEMO and the Network Operator require the Generating System to sustain a response duration of 2 seconds or less, the reactive current response referred to in clause A12.9.3(e)i.1 and clause A12.9.3(e)i.2 must have a Rise Time of no greater than 40.0 milliseconds and a Settling Time of no greater than 70.0 milliseconds and must be Adequately Damped.

(h) Where AEMO and the Network Operator require the Generating System to sustain a response duration of greater than 2 seconds, the reactive current Rise Time and Settling Time must be as soon as practicable and must be Adequately Damped. The Rise Time and Settling Time must be provided as part of the Generator Performance Standard.

9.4. Negotiation Criteria

A Proposed Negotiated Generator Performance Standard may be accepted if the connection of the Generating System at the proposed performance level would not cause other Generating Systems or Loads to trip as a result of an event, when they would otherwise not have tripped for the same event.

10. TECHNICAL REQUIREMENT: DISTURBANCE RIDE THROUGH FOR PARTIAL LOAD REJECTION

10.1. Common Requirements

There are no Common Requirements for this Technical Requirement.

10.2. Ideal Generator Performance Standard

A Generating System and each of its operating Generating Units must be capable of Continuous Uninterrupted Operation during and following a sudden reduction in required Active Power generation imposed from the power system, provided that the reduction is less than 30% of the Generating System's Rated Maximum Active Power and the required Active Power generation remains above the Generating System's Rated Minimum Active Power output level.

10.3. Minimum Generator Performance Standard

A Generating System must be capable of Continuous Uninterrupted Operation during and following a sudden reduction in required Active Power generation imposed from the power system, provided that the reduction is less than 5% of the Generating System's Rated Maximum Active Power and the required Active Power generation remains above the Generating System's Rated Minimum Active Power output level.

10.4. Negotiation Criteria

There are no Negotiation Criteria for this Technical Requirement.

11. TECHNICAL REQUIREMENT: DISTURBANCE RIDE THROUGH FOR QUALITY OF SUPPLY

11.1. Common Requirements

There are no Common Requirements for this Technical Requirement.

11.2. Ideal Generator Performance Standard

The Ideal Generator Performance Standard is the same as the Minimum Generator Performance Standard for Disturbance Ride Through for Quality of Supply.

11.3. Minimum Generator Performance Standard

A Generating System including each of its operating Generating Units and reactive Equipment, must not disconnect from the SWIS as a result of voltage fluctuation, harmonic voltage distortion and voltage unbalance conditions at the Connection Point within the levels specified for flicker, harmonics and negative phase sequence voltage in the Technical Rules.

11.4. Negotiation Criteria

There are no Negotiation Criteria for this Technical Requirement.

12. TECHNICAL REQUIREMENT: QUALITY OF ELECTRICITY GENERATED

12.1. Common Requirements

A Generating System, when generating and when not generating, must not produce, at any of its Connection Points for generation, voltage imbalance greater than the limits determined by the Network Operator as necessary to achieve the requirements specified for negative phase sequence voltage at the Connection Point in the Technical Rules.

12.2. Ideal Generator Performance Standard

A Generating System, when generating and when not generating, must not produce at any of its Connection Points for generation:

(a) voltage fluctuation greater than the limits allocated by the Network Operator that are no more onerous than the lesser of the acceptance levels determined in accordance with either of the stage 1 or the stage 2 evaluation procedures defined in AS/NZS 61000.3.7:2001; and

(b) harmonic voltage distortion greater than the emission limits specified in AS 1359.101 and IEC 60034-1 or emission limits allocated by the Network Operator that are no more onerous than the lesser of the acceptance levels determined in accordance with either of the stage 1 or the stage 2 evaluation procedures defined in AS/NZS 61000.3.6:2001.

12.3. Minimum Generator Performance Standard

A Generating System, when generating and when not generating, must not produce at any of its Connection Points for generation:

(a) voltage fluctuations greater than limits determined by the Network Operator through the negotiation using the stage 3 evaluation procedure defined in AS/NZS 61000.3.7:2001, with the Market Participant responsible for the Transmission Connected Generating System agreeing to fund any works necessary to mitigate adverse effects from accepting this emission level; and

(b) Harmonic voltage distortion greater than the emission limits specified in AS 1359.101 and IEC 60034-1 or emission limits determined by the Network Operator through the negotiation using the Stage 3 evaluation procedure defined in AS/NZS 61000.3.6:2001 with the Market Participant responsible for the Transmission Connected Generating System agreeing to fund any works necessary to mitigate adverse effects from accepting this emission level.

12.4. Negotiation Criteria

A Proposed Negotiated Generator Performance Standard must not prevent the Network Operator meeting each SWIS Operating Standard or contractual obligations to existing holders of Arrangements for Access.

13. TECHNICAL REQUIREMENT: GENERATION PROTECTION SYSTEMS

13.1. Common Requirements

There are no Common Requirements for this Technical Requirement.

13.2. Ideal Generator Performance Standard

The Ideal Generator Performance Standard is the same as the Minimum Generator Performance Standard for Generation Protection Systems.

13.3. Minimum Generator Performance Standard

(a) A Generating System must meet the protection requirements specified in the Technical Rules for both Generating Systems and the Transmission System (where relevant), including the requirement for faults to be cleared within maximum Total Fault Clearance Times specified in the Technical Rules or, where specified, a Critical Fault Clearance Time developed by the Network Operator.

(b) All Protection Schemes must have the relevant level of redundancy as specified in the Technical Rules and must operate to clear faults within the prescribed times.

(c) Anti-islanding protection must be installed and made available to ensure the Generating System is prevented from supplying an isolated portion of the SWIS when it is not secure to do so. The details regarding the performance requirements for anti-islanding systems for Transmission Connected Generating Systems are documented in accordance with the guidelines produced by the Network Operator pursuant to clause 3A.4.4.

(d) All Protection Schemes necessary to disconnect the Generating System during abnormal conditions in the power system that would threaten the stability of the Generating System, or risk damage to the Generating System, must be installed and available. The settings of these Protection Schemes must deliver the required performance for disturbance ride through specified in Part 7, Part 8 and Part 9 of this Appendix 12 and form part of the Generator Performance Standard.

(e) All Protection Scheme settings referred to in this Appendix must be made available to the Network Operator and AEMO.

13.4. Negotiation Criteria

There are no Negotiation Criteria for this Technical Requirement.

14. TECHNICAL REQUIREMENT: REMOTE MONITORING REQUIREMENTS

14.1. Common Requirements

There are no Common Requirements for this Technical Requirement.

14.2. Ideal Generator Performance Standard

The Ideal Generator Performance Standard is the same as the Minimum Generator Performance Standard for Remote Monitoring Requirements.

14.3. Minimum Generator Performance Standard

(a) The Network Operator or AEMO may require Remote Monitoring Equipment to be installed in order to enable the Network Operator or AEMO to monitor the performance of a Generating Unit (including its dynamic performance) remotely, where this is necessary in real time for control, planning or Power System Security.

(b) All Remote Monitoring Equipment installed, upgraded, modified or replaced (as applicable) under clause A12.14.3(a), must conform to the Communication Standard as it applies Remote Monitoring Equipment and must be compatible with the Network Operator's and AEMO's SCADA system, including the requirements of the Nomenclature Standards.

(c) The Remote Monitoring Equipment must provide for the signals specified in the WEM Procedure described in clause 2.35.4 and such other information required by the Network Operator or AEMO.

(d) The Remote Monitoring Equipment must be kept available at all times, subject to Outages as agreed by AEMO.

14.4. Negotiation Criteria

There are no Negotiation Criteria for this Technical Requirement.

15. TECHNICAL REQUIREMENT: REMOTE CONTROL REQUIREMENTS

15.1. Common Requirements

There are no Common Requirements for this Technical Requirement.

15.2. Ideal Generator Performance Standard

The Ideal Generator Performance Standard is the same as the Minimum Generator Performance Standard for Remote Control Requirements.

15.3. Minimum Generator Performance Standard

(a) The Network Operator or AEMO may, for any Generating Unit which may be unattended when connected to the Transmission System, require Remote Control Equipment to be installed in order to enable the Network Operator or AEMO to disconnect a Generating Unit from the Transmission System.

(b) All Remote Control Equipment installed, upgraded, modified or replaced (as applicable) under clause A12.15.3(a) must conform to the Communication Standard and must be compatible with the Network Operator's SCADA system, including the requirements of Nomenclature Standards.

(c) The Remote Control Equipment must be kept available at all times, subject to Outages as agreed by AEMO.

15.4. Negotiation Criteria

There are no Negotiation Criteria for this Technical Requirement.

16. TECHNICAL REQUIREMENT: COMMUNICATIONS EQUIPMENT REQUIREMENTS

16.1. Common Requirements

There are no Common Requirements for this Technical Requirement.

16.2. Ideal Generator Performance Standard

The Ideal Generator Performance Standard is the same as the Minimum Generator Performance Standard for Communications Equipment Requirements.

16.3. Minimum Generator Performance Standard

(a) Communications paths must be provided and maintained (with redundancy consistent with the standard developed by AEMO to meet the Communication Standard) between the Remote Monitoring Equipment and Remote Communication Equipment installed at any of its Generating Units to a communications interface at the relevant Power Station and in a location acceptable to the Network Operator. Communications systems between this communications interface and the Network Operator's Control Centre are the responsibility of the Network Operator, unless otherwise agreed.

(b) A Market Participant responsible for the Transmission Connected Generating System must provide and maintain a speech communication channel (Primary Speech Communication Channel) by means of which routine and emergency control telephone calls may be established between the operator of the Generation System and AEMO or the Network Operator, whichever is applicable.

(c) The Primary Speech Communication Channel must meet any requirements specified in the Communication Standard.

(d) Where the public switched telephone network is to be used as the Primary Speech Communication Channel, a sole-purpose connection must be provided, which must be used only for operational communications.

(e) The Network Operator must provide a separate telephone link or other back-up speech communication channel for the primary speech communication channel (Back-up Speech Communication Channel).

(f) The Network Operator must be responsible for planning installing and maintaining the Back-up Speech Communication Channel and for providing access to AEMO to the Back-up Speech Communication Channel, and for obtaining radio licenses if required.

(g) The communications paths to any applicable Remote Monitoring Equipment or Remote Communication Equipment must be kept available at all times, subject to Outages as agreed by AEMO.

(h) The Primary Speech Communication Channel must be maintained in good working order.

16.4. Negotiation Criteria

There are no Negotiation Criteria for this Technical Requirement.

17. TECHNICAL REQUIREMENT: GENERATION SYSTEM MODEL

17.1. Common Requirements

There are no Common Requirements for this Technical Requirement.

17.2. Ideal Generator Performance Standard

The Ideal Generator Performance Standard is the same as the Minimum Generator Performance Standard for Generation System Model.

17.3. Minimum Generator Performance Standard

(a) All modelling data described in the WEM Procedure referred to in clause 3A.4.2 must be provided to the Network Operator within the timeframes specified in the WEM Procedure, as updated from time to time.

(b) The modelling data provided must be sufficient to enable the Network Operator or AEMO to predict the output of the Generation System under all power system conditions.

(c) The observed performance of the Generation System must match the predicted performance of the Generation System using the Generation System Model, as assessed by the Network Operator or AEMO.

(d) The relevant Market Participant must provide updates to the Generation System Model in order to meet the requirements of this Technical Requirement in accordance with the timeframes specified in the WEM Procedure referred to in clause 3A.4.2, as updated from time to time.

17.4. Negotiation Criteria

There are no Negotiation Criteria for this Technical Requirement.

Explanatory Note

This Appendix sets out System Frequency Outcomes for the SWIS and Islands within the SWIS as set out in the Taskforce Paper *Revising Frequency Operating Standards in the SWIS.* It is intended to commence on 1 February 2021.

APPENDIX 13: FREQUENCY OPERATING STANDARDS SYSTEM FREQUENCY OUTCOMES

TABLE 1 – SUMMARY OF SYSTEM FREQUENCY OUTCOMES FOR THE SOUTH WEST INTERCONNECTED SYSTEM

Condition	**Containment Band (Hz)**	**Stabilisation (Hz)**	**Recovery (Hz)**
Normal Operating Frequency Band	49.8 to 50.2 Hz (99% of the time over any rolling 30-day period)	N/A	N/A
Normal Operating Frequency Excursion Band	49.7 to 50.3 Hz	49.8 to 50.2 within 5 minutes	N/A
Credible Contingency Event Frequency Band	48.75 to 51 Hz	For over-frequency events: below 50.5 Hz within 2 minutes	49.8 to 50.2 Hz within 15 minutes
Island Separation Frequency Band	48.75 to 51 Hz	For over-frequency events: below 50.5 Hz within 2 minutes	49.8 to 50.2 Hz within 15 minutes
Multiple Contingency Event	47 to 52 Hz	48.0 to 50.5 Hz within 5 minutes and:	49.8 to 50.2 Hz within 15 minutes

Frequency Band		For under-frequency events: above 47.5 Hz within 10 seconds. For over-frequency events: below 51.5 Hz within 1 minute; and below 51 Hz within 2 minutes	
Rate of Change of Frequency Safe Limit	0.25 Hz over any 500 millisecond period	N/A	N/A

TABLE 2 – SUMMARY OF SYSTEM FREQUENCY OUTCOMES FOR ISLANDS WITHIN THE SOUTH WEST INTERCONNECTED SYSTEM

Condition	**Containment (Hz)**	**Recovery (Hz)**
Normal Operating Frequency Band	49.5 to 50.5 Hz (reasonable endeavours)	N/A
Credible Contingency Event Frequency Band	48.75 to 51 Hz (reasonable endeavours)	49.5 to 50.5 Hz (as soon as practicable)
Island Separation Frequency Band	48.75 to 51 Hz (reasonable endeavours)	49.5 to 50.5 Hz (as soon as practicable)
Multiple Contingency Event	47 to 52 Hz (reasonable endeavours)	49.5 to 50.5 Hz (as soon as practicable)

Frequency Band		
Rate of Change of Frequency Safe Limit	0.25 Hz over any 500 millisecond period	N/A