

MARKET ANCILLARY SERVICES SPECIFICATION CONSULTATION - COMMENCED SEPTEMBER 2009 - FINAL DETERMINATION AND REPORT

PREPARED BY: Electrical System Operations Planning and Performance

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1. Executive summary

1.1 Matter under Consultation

On 5 May 2009 NEMMCO (predecessor to AEMO) published the final determination of the previous *Rules* consultation to amend the *Market Ancillary Services Specification (MASS)*. The object of the consultation was to amend the *MASS* to reflect the changes to be made to the Tasmanian *frequency operating standards* so that the implementation of the new standard could proceed.

For the purpose of meeting the implementation timetable of the revised Tasmanian *frequency operating standard* it was decided to defer a number of issues raised in the previous consultation to this current consultation. AEMO is now proposing to examine these and other issues in the current *MASS* consultation.

A number of the issues covered in this consultation were part of a submission made by Hydro Tasmania to the earlier consultation completed on 5 May 2009. These issues are:

1. Using *frequency* rate of change to initiate delivery of a *market ancillary service*
2. Using a combined *switching* and *proportional control system* to deliver *market ancillary services*
3. The definition of a *proportional controller*
4. The scaling factor used in verification methods for *proportional controllers*
5. Verification methods for *switching controllers*
6. Verification methods for *slow and delayed raise and lower services*

In addition to the issues raised by Hydro Tasmania there are other issues which AEMO believes are important to address. These are:

1. Improving the performance of *delayed raise service* and *delayed lower service*
2. Use of a smoothing function in *market ancillary service* verification calculations
3. Accounting for changing *dispatch* targets and *dispatch levels* in *market ancillary service* verification calculations
4. The definition of *frequency recovery* in the *MASS*
5. The procedure for allocating *frequency settings* for *switched controllers* in order to take into consideration service availability
6. Adjusting the *trigger range* for data recorders in the Tasmania *region* to take into account changed *frequency operating standards*

In particular, AEMO seeks to recover the *power system frequency* to the *normal operating frequency band* within 5 minutes of a *credible contingency event*, as required by the *frequency operating standards*. This will involve a review of the relevant sections in the *MASS* relating to *delayed raise service* and *delayed lower service*.

1.2 Material Issues Raised

AEMO received four submissions in response to the first stage of consultation and four submissions to the response to the second stage. The submissions to both stages came from AETV Power, CS Energy, Hydro Tasmania and the National Generators Forum (NGF). AEMO identified and addressed 12 material issues from the submissions received.

1.2.1 Material Issue 1: Accounting for changing *dispatch* in FCAS delivery (see also Section 5.1.1)

Major issues were raised in submissions about the way in which the *MASS* interacts with the *dispatch* process. Of particular concern was the proposed method of verifying the amount of FCAS delivered by *scheduled generating units* and *loads* that were responding to changes in dispatch at the time over which they were delivering FCAS. CS Energy and the NGF both submitted that it was not appropriate to expect *scheduled generating units* and *loads* delivering FCAS to increase the amount of service provided when dispatch changes in the direction of frequency recovery. AEMO determined that it was only appropriate to apply compensation when dispatch changes in the direction that is opposed to frequency recovery.

The NGF also submitted that the proposed compensation methodology would disadvantage *scheduled generating units* and *loads* delivering FCAS that were not exactly following their dispatch instructions. AEMO determined to amend the compensation methodology so that *scheduled generating units* and *loads* delivering FCAS that were not exactly following their dispatch instructions would not be disadvantaged.

Another issue of significant concern was the way in which the delivery of contingency FCAS should be assessed when there is a continued need for service across the boundary of two *dispatch intervals*. The NGF submitted that the dispatch process should be able to indicate whether the continued provision of FCAS is required. However AEMO has determined that the current dispatch process is unable to fulfil this function as the current dispatch process does not take into account power system frequency when dispatching the market. AEMO recommends that the possibility of amending the dispatch process so that frequency is considered when dispatching the market be considered by market working groups such as the Dispatch and Pricing Reference Group (DPRG).

1.2.2 Material Issue 2: Improving the performance of delayed services (see also Section 5.1.2)

In order to improve the performance of the power system in meeting the frequency operating standards, a number of proposals were put forward to improve the performance of delayed FCAS. After considering all submissions AEMO determined that:

- the *MASS* require units providing delayed response using only proportional controllers to provide extra response in addition to the purely proportional part of the response be implemented in the amended *MASS*;
- allowing the dispatch process to be amended to take into consideration power system frequency be considered by the DPRG;
- the mainland region frequency levels be adjusted as per Table 3 in of version 3.0 of the *MASS* so that the frequency settings closest to 50 Hz be moved closer to 50 Hz;
- the Tasmania region frequency levels be adjusted as per Table 4 in of version 3.0 of the *MASS* so that the frequency settings most remote from 50 Hz be moved closer to 50 Hz; and
- the Tasmania region trigger range be changed to 49.2 to 50.8 Hz. See Table 2 in of version 3.0 of the *MASS*.

1.2.3 Material Issue 3: Procedure for allocating frequency settings (see also Section 5.1.3)

AETV Power and Hydro Tasmania both submitted that the procedure for allocating frequency settings be amended to allow the frequency settings allocated to particular *ancillary services generating units and loads* to be reviewed if the allocated settings mean that particular *ancillary services generating units and loads* will not be able to deliver FCAS for technical reasons. AEMO determined that a review of allocated settings be allowed if the frequency setting allocated to an *ancillary services generating unit or load* prevents that *ancillary services generating unit or load* from supply FCAS for technical reasons.

1.2.4 Material Issue 4: Definition of frequency recovery (see also Section 5.1.4)

In their submission to the first round of consultation, CS Energy stated that having the *frequency recovery* set point defined at the same level as the *frequency disturbance* set point, as recommended in the Issues Paper, is not ideal. The reason being there is the possibility of multiple 'frequency disturbances' due to the *frequency* fluctuating around the *frequency recovery* boundary. CS Energy recommended that there be 0.05 Hz difference between the *frequency disturbance* and recovery set points.

After considering the submission, AEMO determined that the defined *frequency recovery* set points be moved 0.05 Hz closer to 50 Hz.

1.2.5 Material Issue 5: Switched controller compensation (see also Section 5.1.5)

In their submission to the first round of consultation, CS Energy stated that the proposed compensation methodology for *switch controller* service verification over compensates *switched controller* action in comparison to *proportional controller* action. CS Energy stated that either the proposed compensation methodology for *switch controller* service verification or proposed compensation methodology for *proportional controller* service verification should be amended.

In their submission to the first round of consultation, Hydro Tasmania noted that the compensation methodology for *switch controller* service verification does not account for the time taken to reach *the normal operating band* from 50 Hz in a *standard frequency ramp* or controller activation time.

After considering their submissions, AEMO believes that the proposed *switching controller* compensation methodology should be adjusted to account for the time taken to reach the *normal operating band* from 50 Hz in a *standard frequency ramp*. AEMO does agree with CS Energy that the proposed compensation methodology for *proportional controller* service verification should be amended. In all other respects AEMO believes that the proposed *switching controller* compensation methodology is appropriate.

1.2.6 Material Issue 6: Proportional controller compensation (see also Section 5.1.6)

In their submissions, CS Energy noted two issues with the proposed *proportional controller* compensation methodology: that a *frequency ramp* from 50 Hz is used rather than a ramp from the boundary of the *normal operating frequency band*; and the compensation factor is calculated with respect to the difference between *local frequency* and 50 Hz rather than the difference between *local frequency* and the governor *deadband*.

In their submission, Hydro Tasmania noted that the compensation factor is calculated with respect to the difference between *local frequency* and 50 Hz but should rather be calculated with respect to the difference between *local frequency* and the governor *deadband*.

After considering their submissions, AEMO agrees with CS Energy and Hydro Tasmania that the compensation calculation for *proportional controllers* should take into consideration: *frequency* ramping from the boundary of the *normal operating frequency band*; and the difference between *local frequency* and the *control system's dead-band*.

1.2.7 Material Issue 7: Combined controller compensation (see also Section 5.1.7)

In their submission, Hydro Tasmania described four types of plant that could be used to deliver *market ancillary services* but would not be correctly compensated as per the currently

proposed verification calculations. Two options make use of variable proportional response; another uses a *proportional controller* that is 'switched' on when the *frequency* reaches a certain level; and another would provide rapid but unsustainable response to *frequency disturbances*.

After considering the submission, AEMO determines that each measured proportional response be adjusted to take into account variable proportional responses, and *proportional controllers* that are initiated by *switching controllers* be compensated both as *proportional controllers* and as *switching controllers*.

1.2.8 Material Issue 8: Verification calculations for combined services (see also Section 5.1.8)

In their submission, Hydro Tasmania asked the following question with respect to the proposed new method for verifying the delivery of multiple *market ancillary services*: how can a *Market Participant registered for market ancillary services* determine its bids if it is unsure if it will be *enabled* for multiple services?

After considering the question AEMO determines that it be the responsibility of *participants* to ensure that *FCAS trapeziums* bid for an *ancillary services generating unit* or *ancillary services load* reflect the true service availability of the *generating unit* and *load*. That is the *Market Participant* should assume that *NEMDE* can enable the full amount of all services that are offered as available.

1.2.9 Material Issue 9: Consistent base for verification calculations (see also Section 5.1.9)

In their submissions both the NGF and CS Energy recommended that a consistent base level be used for *market ancillary service* verification calculations if multiple services are being assessed. The NGF suggested that fast service base level (two to four seconds before *frequency disturbance*) be used and CS Energy recommends that the slow and delayed service base level be used (eight to twenty seconds before *frequency disturbance*). CS Energy reasons that the slow and delayed service base level is more appropriate to be used as it is less likely to be influenced by any events associated with the *frequency disturbance*.

After considering the submissions, AEMO determines that if multiple services are being assessed then the slow and delayed service base level be used.

1.2.10 Material Issue 10: Data smoothing algorithms (see also Section 5.1.10)

In their submission, Hydro Tasmania queried the numerical differentiation technique used in the calculation of inertial response. Both CS Energy and Hydro Tasmania also queried the data exponential smoothing technique used in the verification calculations. Both CS Energy and Hydro Tasmania point out that the issue of time lag introduced by the exponential smoothing is not adequately addressed by the current *MASS*.

After considering the submissions AEMO determined that the current numerical differentiation technique is appropriate for the verification calculations. AEMO also concluded that there should be an appropriate offset applied to the exponential smoothing technique used to correct for time lag.

1.2.11 Material Issue 11: Verification calculation tolerance (see also Section 5.1.11)

In their submission Hydro Tasmania suggested that a tolerance be applied to the verification calculations to account for assumptions and approximations made in the *MASS*.

After considering the submission AEMO determined that 5% would be an appropriate tolerance to apply to the results of the verification calculations. For example, if the outcome of the verification calculation showed that an *ancillary services generating unit or load* had delivered 20 MW of service then the *ancillary services generating unit or load* would be assessed as having delivered in the range of 19-21 MW of service (effectively 21 MW).

1.2.12 Material Issue 12: Market ancillary service supplied by switched control alone (see also Section 5.1.12)

Hydro Tasmania questioned whether FCAS requirements can be met by enabling *switching controllers* only?

AEMO notes that it is technically possible to meet frequency operating standards with *switching controllers* alone. However as noted in section 5.1.2 there are issues in supplying delayed service solely by enabling *switching controllers*.

Thus, notwithstanding the outcome of section 5.1.2, AEMO determines no change be made to the *MASS* in relation to ensuring that there is always a combination of *proportional controllers* and *switched controllers* enabled for market ancillary service.

1.2.13 Material Issue 13: Participant understanding of the MASS (see also section 5.1.13)

AETV Power submitted that the specification and verification procedures for market ancillary services are complex and require close examination of the *MASS*. AETV suggest that it would be helpful if an appendix be attached to the *MASS* outlining implication for registration and implementation of various *MASS* settings.

AEMO determined that it will provide information on the application of the *MASS* to participants. However the information will not be supplied via an appendix to the *MASS*.

1.3 Decision

AEMO determines version 3.0 the Market Ancillary Services Specification in the form shown in **Attachment 2**.

2. Background

2.1 Matter under consultation

The *MASS* describes the technical requirements for each of the market ancillary services. For each market ancillary service it includes the following:

- a description of the market ancillary service,
- the method to determine the amount of service for dispatch purposes,
- the required control facilities,
- the required measurement facilities, and
- the method of verification of each service delivered

AEMO is required by clause 3.11.2 of the *Rules* to publish the *MASS*. Clause 3.11.2 permits AEMO to amend the *MASS*, as well as requiring compliance with the *Rules consultation procedures* when making or amending the *MASS*.

The *MASS* was last amended by consultation in 2009 to align with the revised Tasmania frequency operating standards. The objectives of this consultation are to:

- provide *Consulted Persons* with an opportunity to contribute to the development of the *MASS*; and
- ensure that *Consulted Persons* are properly informed about the proposed and final outcome.

2.2 The consultation and decision-making process

The following table provides an outline of the consultation process to date:

PROCESS	DATE
Notice of First Stage of Rules Consultation issued	21 September 2009 completed
Closing date for submissions received in response to the Notice of First Stage of Rules Consultation	26 October 2009 completed
Publication of this Draft Determination and issue of Notice Of Second Stage of Rules Consultation inviting submissions in response to the Draft Determination	21 December 2009 completed
Closing date for submissions received in response to the Notice of Second Stage of Rules Consultation	22 January 2010 completed
Publication of the Final Determination	7 May 2010 completed

AEMO issued a Notice of First Stage of Rules Consultation on 21 September 2009, which invited submissions by 26 October 2009. Four submissions were received and three meetings held at the request of the Interested Persons.

AEMO issued a Notice of Second Stage of Rules Consultation on 21 December 2009. A copy of the Second Stage Notice is contained in **Attachment 1**. The Second Stage Notice invited submissions by 22 January 2010. Four submissions were received and one meeting held at the request of the Interested Person.

The amended *MASS* is now made final and is contained in **Attachment 2**.

3. Interpretation of the Rules

Clause 3.11.2 of the National Electricity Rules (**Rules**) states:

3.11.2 Market ancillary services

- (b) *AEMO* must make and *publish* a *market ancillary service specification* containing:
 - (1) a detailed description of each kind of *market ancillary service*; and
 - (2) the performance parameters and requirements which must be satisfied in order for a service to qualify as the relevant *market ancillary service* and also when a *Market Participant* provides the relevant kind of *market ancillary service*.
- (c) *AEMO* may amend the *market ancillary service specification*, from time to time.
- (d) *AEMO* must comply with the *Rules consultation procedures* when making or amending the *market ancillary service specification*.

4. Consideration of Submissions

4.1 List of submissions received

AEMO received four submissions in response to the First Stage Notice, from the listed respondents:

RESPONDENT	PARTICIPANT TYPE OR OTHER ROLE
Aurora Energy (Tamar Valley) Pty Ltd trading as AETV Power	<i>Generator</i>
CS Energy	<i>Generator, Market Customer</i>
Hydro Tasmania (Hydro-Electric Corporation)	<i>Generator</i>
National Generators Forum (NGF)	Interested Party (representing major <i>Generators</i>)

All submissions were published on AEMO's website prior to the date that this Draft Determination and Report was released.

AEMO received four submissions in response to the Second Stage Notice, from the listed respondents:

RESPONDENT	PARTICIPANT TYPE OR OTHER ROLE
Aurora Energy (Tamar Valley) Pty Ltd trading as AETV Power	<i>Generator</i>
CS Energy	<i>Generator, Market Customer</i>
Hydro Tasmania (Hydro-Electric Corporation)	<i>Generator</i>
National Generators Forum (NGF)	Interested Party (representing major <i>Generators</i>)

All submissions were published on AEMO's website prior to the date that this Final Determination and Report was released.

Section 5 considers all material issues and AEMO's response. **Appendix 3** details for each *Consulted Person*, each issue raised and, for issues AEMO considers to be non-material, AEMO's response.

4.2 Meetings and forums

Three parties requested meetings in the first round of consultations, as follows:

NAME OF PARTY	MEETING DATE
CS Energy	17 November 2009
National Generators Forum	18 November 2009
Hydro Tasmania (Hydro-Electric Corporation)	19 November 2009

One party requested a meeting in the second round of consultations, as follows:

NAME OF PARTY	MEETING DATE
National Generators Forum	18 March 2010

Minutes of meeting(s) have been posted on AEMO's website at:

<http://www.aemo.com.au/electricityops/0168-0001.html>

All issues arising from each meeting are documented in **Appendix 1**.

Material issues arising from these meetings are considered in Section 5.

5. Material issues raised by Consulted Persons

Consulted Persons raised the material issues detailed in the following table:

Issue Number	Issue	Raised by
1	Material Issue 1: Accounting for changing <i>dispatch</i> in FCAS delivery	CS Energy, Hydro Tasmania, NGF
2	Material Issue 2: Improving the performance of delayed services	Hydro Tasmania, NGF
3	Material Issue 3: <i>Procedure</i> for allocating <i>frequency settings</i>	AETV Power, Hydro Tasmania
4	Material Issue 4: Definition of <i>frequency recovery</i>	CS Energy,
5	Material Issue 5: <i>Switched controller</i> compensation	CS Energy, Hydro Tasmania
6	Material Issue 6: <i>Proportional controller</i> compensation	CS Energy, Hydro Tasmania, NGF
7	Material Issue 7: Combined controller compensation	Hydro Tasmania
8	Material Issue 8: Verification calculations for combined services	Hydro Tasmania
9	Material Issue 9: Consistent base for verification calculations	CS Energy, NGF
10	Material Issue 10: Data smoothing algorithms	CS Energy, Hydro Tasmania
11	Material Issue 11: Verification calculation	Hydro Tasmania
12	Material Issue 12: Market ancillary service supplied by switched control	Hydro Tasmania

13	Material Issue 12: Market ancillary service supplied by switched <i>control</i>	AETV Power
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5.1.1 Material Issue 1: Accounting for changing *dispatch* in FCAS delivery

5.1.1.1 Summary of issue from second stage of consultation

In section 1 of their submission to the second stage of consultation, the NGF state:

“The proposal by AEMO to use a trajectory between subsequent dispatch targets as a basis for the measurement of service delivery fails on each of the issues described above:

- it fails to address the question of whether the dispatch process has reached the point of taking the generation requirement into account without the full service delivery;
- it relies on data which is not meaningful in any practical sense;
- it may disadvantage units which are away from their targets at the time of a disturbance, thus conferring a role on AEMO which properly belongs to AER; and
- furthermore it disadvantages such units without regard to the reasons for a departure from a dispatch target, which may in some cases be due to behaviour mandated by the market Rules, or due to force majeure circumstances.

For these reasons, the NGF does not accept that the modified proposal is desirable in principle, and is concerned that it involves AEMO in a role which properly belongs to the AER, namely investigation and potentially seeking a penalty in relation to departures from dispatch targets.

In addition, and for the moment setting aside the questions of principle, we believe that the relevant process described in the draft MASS, version 2.02, is wrongly formulated and would lead to absurd results.”

In section 2 of their submission to the second stage of consultation the NGF state:

“The enablement of FCAS provides a potential change in a component of supply or demand, to be delivered in certain conditions. Once this change is delivered, the resultant level of supply or consumption becomes part of the input to the following dispatch processes, and is not segregated into components of “energy” and “FCAS”, but is simply an energy starting point for the following dispatch.

“If the measured energy level is required in dispatch to be maintained or changed in the direction of service delivery, then it can be said that the need for service delivery may be continuing. But if the dispatch process results in a change from the measured energy level in the direction opposite to service delivery, then it cannot be said that full service delivery is then an ongoing requirement. In this case the measurement of service delivery against the full enabled quantity is clearly not appropriate and the measurement should cease.

“The important point here is that only the comparison between actual energy and energy target can provide the necessary indication of whether full service delivery continues to be required. The comparison of prior and current targets is meaningless in this context.”

“The NGF submits that on the basis of this fuller description now provided, that AEMO should cease to measure FCAS delivery when the dispatch process indicates that full service delivery is no longer required to achieve that supply/demand balance. This indication can validly arise only from a comparison of initial energy and the resultant energy target, and not from comparison of subsequent energy targets.”

In the first point made in the “Minor Discrepancies in Draft MASS VER 2.02” section of their submission to the second stage of consultation, CS Energy state:

“All instances of RT_i are equal to:

“the value of the reference trajectory at time t_i , corresponding to the power measurement P_i , plus RT_0 ”

should be

“ RT_0 minus the value of the reference trajectory at time t_i , corresponding to the power measurement P_i ””

5.1.1.2 AEMO response to second stage submission

AEMO agrees with the NGF that the proposal in the draft determination to take into consideration dispatch targets¹ may “disadvantage units which are away from their targets at the time of a disturbance”². As the NGF points out, it is not the purpose of the MASS to penalise units that are deviating from their *dispatch* targets³. To overcome this issue the MASS will be amended to compensate units which receive a dispatch target contrary to frequency recovery by an amount equal to the difference between the unit’s initial output (at

¹ References to ‘dispatch targets’ relate to energy market dispatch.

² The process proposed in the draft determination would compensate units which receive a dispatch target contrary to frequency recovery by an amount equal to the difference between their metered output and the units’ dispatch target (at DI n) to dispatch target (at DI $n+1$) reference trajectory. If a unit was not following its dispatch target to dispatch target reference then it could possibly be disadvantaged by the proposed compensation methodology.

³ A note on the difference between the dispatch compensation applied in the MASS verification calculations and the Causer Pays Procedure: The Causer Pays Procedure is designed to calculate the contribution made to the need for regulation FCAS. AEMO determined that if a *scheduled generating unit or load* is not following its dispatch target-to-dispatch target trajectory then it is contributing to the need for regulation FCAS. However, the purpose of the dispatch compensation applied in the MASS verification calculations is used to offset the potential negative effects on the delivery of contingency FCAS services thus it is correct to use an “initial-to-dispatch target” reference trajectory. Further as the MASS verification process uses measured generation prior to the frequency disturbance as the basis for assessing quantity of service delivered it is consistent to use an “initial-to-dispatch target” reference trajectory.

DI n) to dispatch target (at DI n) reference trajectory and the value of the reference trajectory at the time of the frequency deviation. Only positive compensation will be applied.

Figure 1 shows the compensation method being applied to an *ancillary services generating unit* supplying *delayed raise service* following a *low frequency event*⁴. Dispatch targets for dispatch intervals 10:50, 10:55 and 11:00 are 240, 192 and 240 MW respectively. The frequency excursion begins in the 10:50 dispatch interval and recovery occurs in the 11:00 dispatch interval. In the 10:55 dispatch interval the unit receives a dispatch target below the value of its reference trajectory at the time of the frequency disturbance. As can be seen the compensation process works to negate the negative impact of dispatch (the decreasing dispatch target in DI 10:55) process whilst not adding additional compensation for the positive impact of the dispatch process (the increasing dispatch targets in DI 10:50 and 10:55).

It should also be noted that the unit is not penalised for deviating from its reference trajectory in the 10:50 dispatch interval, this is shown explicitly in Figure 2.

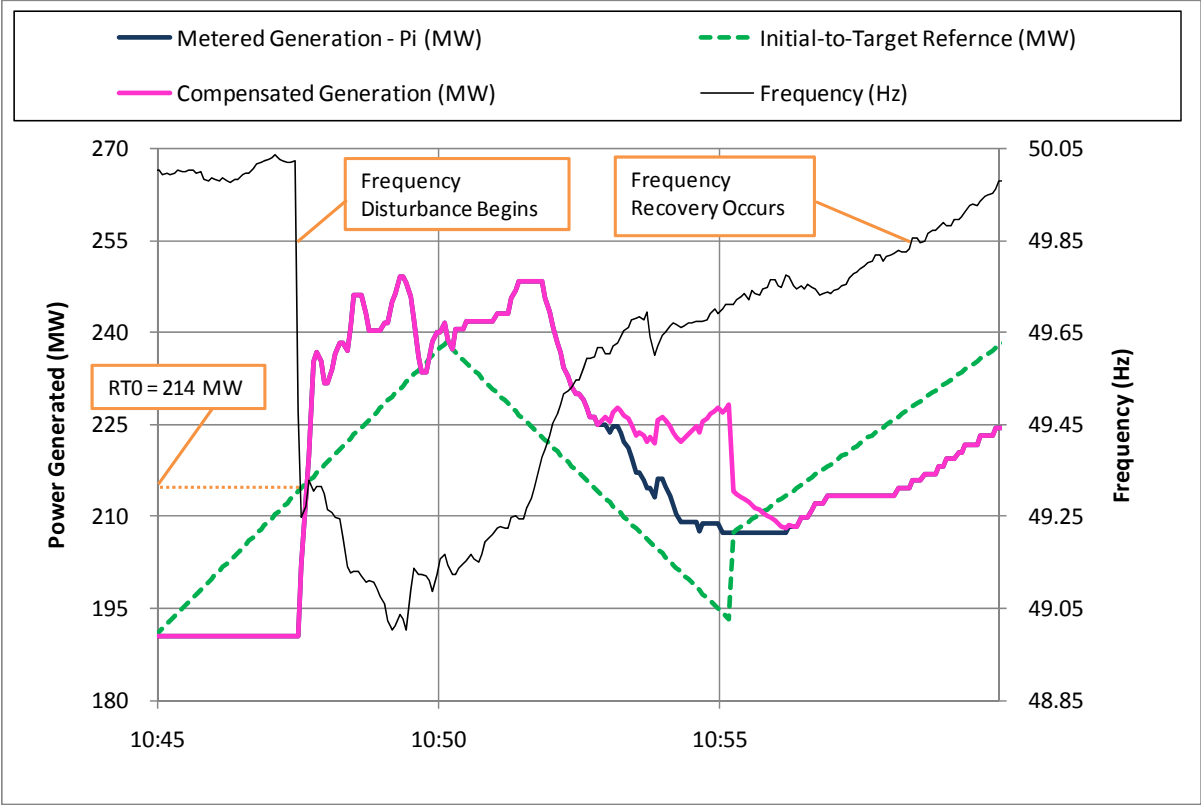


FIGURE 1 – COMPENSATION FOR CHANGE IN DISPATCH

⁴ Data used has been modified for the purpose of this example.

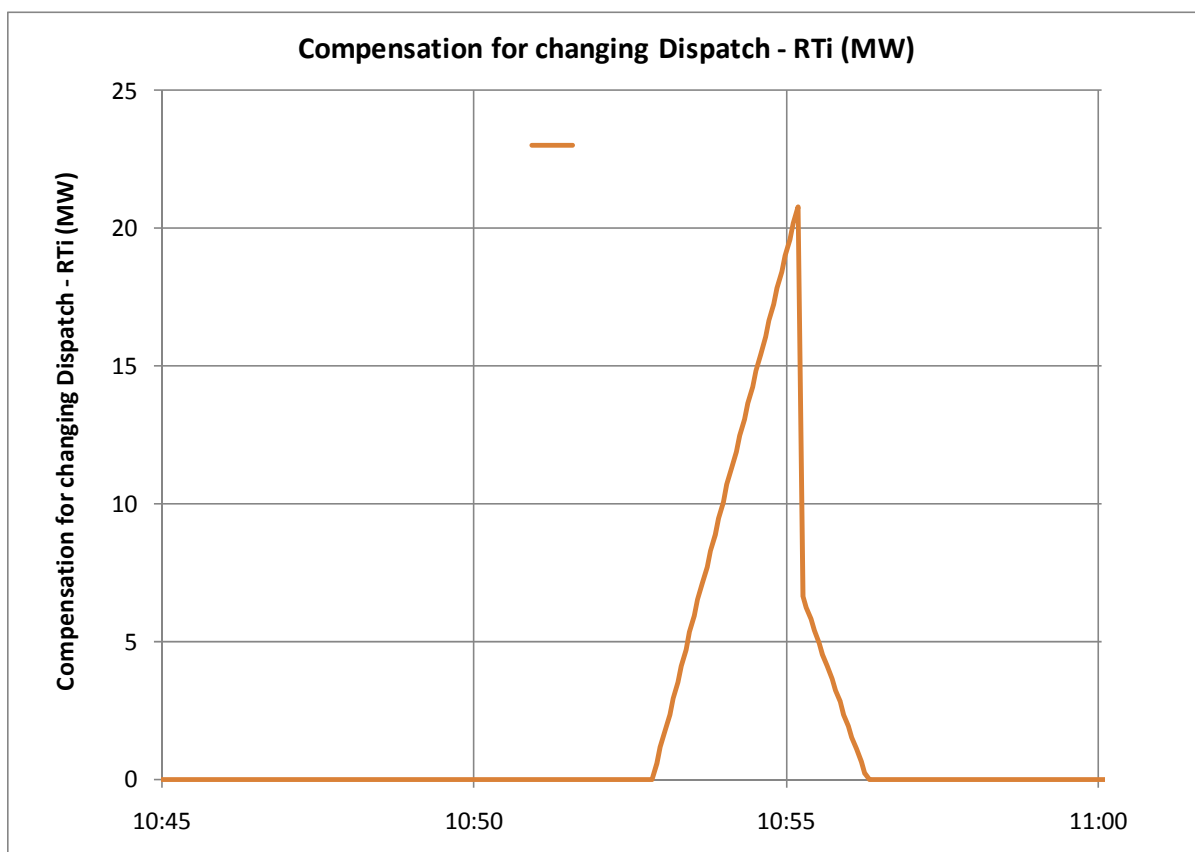


FIGURE 2 – DISPATCH COMPENSATION DERIVED FROM EXAMPLE SHOWN IN FIGURE 1

AEMO acknowledges that any contingency FCAS response of a dispatched unit being delivered across the boundary of two dispatch intervals is incorporated into the metered initial value of that unit at the start of the dispatch interval following a disturbance. However, as the current dispatch process does not consider power system frequency, the dispatch target received by a dispatched unit delivering contingency FCAS at the start of subsequent dispatch intervals following a disturbance will not contain any component regarding any continuing FCAS requirement. That is the dispatch target received by a scheduled unit will be the same whether or not there is continuing requirement for that unit to be delivering FCAS. Thus AEMO cannot accept the NGF proposal that “AEMO should cease to measure FCAS delivery when the dispatch process indicates that full service delivery is no longer required to achieve that supply/demand balance” as the current dispatch process is not able to provide an indication that full service delivery is no longer required.

AEMO however acknowledges that this matter may be considered in a future consultation to amend the MASS if it were possible to amend the dispatch process so that it does take into consideration power system frequency⁵. As amendments to the dispatch process are beyond the scope of this consultation, AEMO suggests that this proposal be addressed through other appropriate forums such as the Dispatch and Pricing Reference Group (DPRG).

AEMO agrees with CS Energy that the formulation of the value “RTi” (elements used to offset detrimental changes in dispatch for scheduled and semi-scheduled generating units and loads) as specified in version 2.02 of the MASS is incorrect. However AEMO does not agree with the specific remedy suggested by CS Energy. Rather, to correct the MASS the following changes will be implemented:

- For *scheduled* and *semi-scheduled* generating units that have been *enabled* for raise services and *scheduled loads* the value of RTi will be defined as the value of RT0 (output at the start of the dispatch interval) minus the value of the reference trajectory at time t_i , corresponding to the power measurement P_i .
- For *scheduled* and *semi-scheduled* generating units that have been *enabled* for lower services and *scheduled loads* the value of RTi will be defined as the value of the reference trajectory at time t_i , corresponding to the power measurement P_i minus RT0.

5.1.1.3 Outcome of second stage of consultation – the final outcome

AEMO determines that:

- Sections 2.6(a), 3.6(a) and 4.6(a) MASS will be amended to compensate units which receive a dispatch target contrary to frequency recovery by an amount equal to the difference between the unit’s initial output (at DI n) to dispatch target (at DI n) reference trajectory and the value of the reference trajectory at the time of the frequency deviation. Only positive compensation will be applied.
- The MASS will not be amended so that the assessment of contingency FCAS ends when the dispatch process indicates that full service delivery is no longer required by providing a dispatch target that is contrary to the direction of frequency recovery. AEMO recommends that possible changes to the dispatch process to take into consideration frequency recovery be considered by the DPRG.

⁵ The *dispatch* process currently does indirectly take into consideration *frequency* by applying Aggregate Dispatch Error (ADE) correction. ADE correction is used to account for total *dispatch* target *non-conformance* of all *dispatched generating units* and *loads* within the *region* that are not *enabled* for *Regulation FCAS*. ADE correction however is of little use assisting *frequency* recovery following a *frequency* excursion from the *normal operating frequency band* as the correction is applied over several dispatch intervals and the *frequency* dependence of *power system* demand is not considered.

- Sections 2.6(a) (i), 3.6 (a) (i) and 4.6 (a) (i) MASS read:

if the *ancillary service generating unit* or *ancillary service load* is *scheduled* or *semi-scheduled* then determine its reference trajectory as the successive straight line interpolations of the initial metered loading to *dispatch target* or *dispatch levels*. The reference trajectory is to start at the with the initial loading at the beginning of the dispatch the dispatch interval in which the frequency deviation occurs and is two continue for the proceeding two dispatch intervals⁶.

- Sections 2.6(a) (iii), 3.6 (a) (iii) and 4.6 (a) (iii) MASS will be amended so that the value of “RT_i” is defined as:

if the *ancillary service generating unit* or *ancillary service load* is a *scheduled generating unit* or *scheduled load* or *semi-scheduled generating unit* respectively, RT_i is equal to:

RT₀ minus the value of the reference trajectory at time t_i, corresponding to the power measurement P_i

where: RT₀ is the value of the reference trajectory at the time of the *frequency disturbance*

- The quantity of contingency *market ancillary services* to be verified be the lesser of (a) the amount of service *enabled* at the time of the *frequency disturbance*, and (b) the amount of service available under the offered trapezium evaluated at the energy level equal to base level for the measurement of response (i.e. FA or SA or DA as applicable). See sections 2.6(d), 3.6(d) and 4.6(d) of version 2.02 of the MASS.
- That the period of verification over which delayed services be verified be the lesser of:
 1. The time from *frequency disturbance* to *frequency recovery*; and
 2. Ten minutes; and
 3. *Service cancellation*.

See section 4.6(a)(x) of version 3.0 of the MASS.

- That the definition of *service cancellation* be re-defined as:

⁶ For example if a frequency event occurs at 01:04 hrs then the associated reference trajectory will be the straight line interpolations of the initial loadings measured at the beginning of the 01:05, 01:10, and 01:15 *dispatch intervals* the dispatch targets corresponding with the 01:05, 01:10, and 01:15 *dispatch intervals*.

“means the time when AEMO has informed the *Market Participant* by telephone, market notice or similar that the relevant service is not required but not including disablement by the *NEM* dispatch engine (*NEMDE*)”

See section 1.1 of version 3.0 of the MASS.

5.1.1.4 Summary of issue from first stage of consultation

In section 1 of their submission to the first stage of consultation, the NGF State:

“... the dispatch process responds to the delivery of FCAS services. This potentially modifies the delivery of FCAS services and therefore should be taken into account in the description and measurement of these services in the MASS. We believe that this interaction has not been properly considered either in the MASS document or in the issues paper.

“The extent of this interaction varies between FCAS services. For example, with the fast services, which are intended to reach their full impact in 6 seconds after a frequency disturbance and may cease after 60 seconds, there is only a small probability that a new dispatch process will occur during the service delivery period. At the other extreme, for the delayed service, where the initial delivery is between one and five minutes from the frequency event and is intended to continue for a period beyond this, it is certain that a new dispatch process will occur during service delivery and may interact significantly with service delivery.

“A number of issues arise from this and will be discussed here in the context of service delivery by a generator, although they have wider relevance:

- the services that were enabled at the time of a *frequency* event may not remain enabled for the whole of the service delivery time;
- to the extent that service delivery has impacted the actual output of a generator at the start of a new *dispatch* interval, that change will be included in the starting point for that unit in the new *dispatch* process, and hence will influence the subsequent dispatch target; and
- depending on the energy resources available for *dispatch* and the economics of dispatch in the new dispatch interval, the *dispatch* target for a unit delivering FCAS may either support or oppose that delivery.

“Both the current MASS and, to a large extent, the issues paper ignore these issues. Where the issues paper does recognise that there is an issue it reaches what we consider to be an incorrect conclusion, because it fails to recognise the second dot point shown above.

...

“A related question, although perhaps beyond the scope of the current consultation, is whether the dispatch process should take into account the fact that the frequency

restoration process (as achieved through FCAS services) may be incomplete at the commencement of a new dispatch interval.

“If the frequency is abnormal at the time that the system “snapshot” is taken, then the dispatch process will target a supply/demand balance effectively at this abnormal frequency, instead of supply/demand balance at a normal frequency. This could be corrected by adjusting the measured demand to allow for the estimated effect of the abnormal frequency. In this way the dispatch process could better assist the restoration of normal frequency.”

In section 4.3 of their submission to the first stage of consultation the NGF State (in relation to section 6 of the Issues Paper):

...

“The unreasonable nature of the proposal that arises from these deficiencies can be seen in the following characteristics –

- Because any response delivered is included in the metered output which forms the basis for the next dispatch, the proposed process calls for multiple and cumulative delivery of a service that was offered and enabled for delivery only once. For example, if a response of R MW was offered and enabled, and then delivered as required, the following dispatch target would be based on a metered output of the prior output plus R. If the following target were equal to this starting value, then to be counted as still delivering the offered service in the new dispatch interval the unit would then need to reach (prior output + R + R), thus needing to deliver twice the offered service in order to be counted as delivering it once. This is clearly unreasonable.
- The proposal ignores the fact that the service availability tails off, as defined by the trapezium, as output approaches a maximum or minimum value. If a unit was enabled for service delivery equal to the full difference between current output and availability, then having delivered the required response the unit would have no further response possible. But under the proposal, if the unit were then dispatched to match its availability the process would not credit the unit with any continuing response, despite the fact that it is delivering the response that was offered.
- The reference trajectories proposed as a basis are unacceptable because they are incompatible with the market dispatch process. As noted above the trajectories implied by dispatch must start from the actual generation, not the previous target.

“Each of these characteristics is unacceptable to the NGF.

“The NGF therefore strongly opposes the proposal to define a changing reference trajectory against which response would be measured.”

In section 4.3.1 of their submission to the first stage of consultation the NGF State:

“The dispatch process is designed to ensure that the enabled FCAS quantities can be delivered by the end of the dispatch interval in which the enablement applies. This does not ensure that a unit can deliver its enabled quantity at any time during the dispatch interval.

...

“The NGF proposes that the quantity of service to be verified be the lesser of (a) the amount of service enabled at the time of the frequency disturbance, and (b) the amount of service available under the offered trapezium evaluated at the energy level equal to base level for the measurement of response (i.e. FA or SA or DA as applicable).”

In section 4.3.2 of their submission to the first stage of consultation the NGF State:

...

“The requirement of the delayed service, as expressed in section 4.1 of the current MASS, is “to sustain their response until central dispatch can take the generation requirement into account”. When we take into account that all FCAS service delivery, whether for units enabled for the service or from others, will be included in the starting point for dispatch, and the time to reach full delivery of delayed service is 5 minutes from the frequency disturbance, it is evident that 15 minutes is unnecessarily long. Even allowing for the uncertainty of when a frequency disturbance will occur within a dispatch interval, a measurement period of 10 minutes will always be sufficient.

“After this time it is clear that the dispatch input will include service delivery in the initial value of generation. This will be retained or augmented in the dispatch target if the response is either still necessary, or is economic in the changed circumstances. If on the other hand the response is not now necessary and is not economic, the dispatch process will “wind it back” in the following target.

“Thus it is clear that at the proposed time of 10 minutes after the frequency disturbance, the dispatch process can “take the generation requirement into account”.

“The NGF proposes that the maximum period of measurement for delayed service verification be reduced from 15 minutes to 10 minutes.”

In section 4.3.3 of their submission to the first stage of consultation the NGF State:

“The current MASS, in section 4.6, requires that measurement be disregarded if made at or after frequency recovery or after service cancellation. We understand that in this context, service cancellation would be by notice from AEMO.

“But as discussed above, the dispatch process itself may indicate that the service delivery is no longer fully required. It will do this by issuing a dispatch target requiring the unit to

change output in the opposite direction to that of the service being delivered (e.g. by requiring a generating unit delivering raise service to reduce output).

“The NGF proposes that the verification process for delayed service provision should disregard measurements made at or after (a) a frequency recovery, or (b) a service cancellation, or (c) the calculation of a dispatch target requiring the unit to change output in the opposite direction to the service delivery.”

In their submission CS Energy supported the issues raised in the NGF’s submission regarding the proposal to account for changing dispatch targets or dispatch levels in verification calculations:

“...CS Energy would like to add that the implementation of this method would further discount unit’s ability to provide FCAS services. Any generator with ramping limitations that provide FCAS would need to discount the quantity of service they offer to allow for a rare situation where they were being ramped by the dispatch process at the same time in which the frequency disturbance occurs. This reduces the supply of MASS service and increases the cost of service at all times to cater for a very low probability event where a unit dispatch is ramping at the same time as the frequency disturbance.

“Combining dispatch and MMS recorder data also increases verification complexity and increases the cost of providing FCAS services.

“Other issues with the proposed methodology include the miss-match in “as generated” data being compared with sent out data and a miss-match in time stamps between the dedicated FCAS recorder information and Unit dispatch data received by AEMO via SCADA. Our experience is that there can be time lags of up to a few seconds due to delays in communications through network services provider systems. This can cause errors in measured performance due to errors in timing of data.

“CS Energy considers that introducing dispatch data into the verification process, introduces errors and additional costs. The benefits are limited and fail to satisfy the NEM Market Objective.”

In section 9 of their submission Hydro Tasmania State:

“Hydro Tasmania generally supports the proposed changes which we believe could be implemented with Hydro Tasmania retaining the existing working arrangements...”

5.1.1.5 AEMO response from the Draft Determination

The submissions received on this topic contain very detailed and thorough critiques of the manner in which the current *MASS* and proposed amended *MASS* deal with the interaction of the *dispatch* process and the delivery of contingency *market ancillary services*. AEMO’s response will be divided into several sections to deal with all the submissions.

Impact of *market ancillary service* delivery on initial and *dispatch* target:

The NGF rightly point out that if an *ancillary services generating unit* or *load* is delivering contingency *market ancillary services* across the boundary of two *dispatch intervals* then the initial metered generation or consumption of that *generating unit* or *load* will be affected by the service delivery. It is also true that, due to *ramp rate* limitations, the initial metered generation or consumption of a *scheduled generating unit* or *load* at the start of a *dispatch interval* might have an impact on the dispatch target for that scheduled *generating unit* or *load*.

Due to the *frequency* dependence of *power system* demand, after a *frequency* event the *power system* demand will change significantly⁷. However no *frequency* adjustment is made to the demand forecast used in the *dispatch* process, which is largely based on the actual metered demand at the start of each *dispatch interval*. Thus if the *frequency* is still abnormal at the start of *dispatch interval* then the *dispatch* process will in effect be dispatching *scheduled generating units* and *loads* to meet a *power system* demand that corresponds to the abnormal *frequency*.

Market ancillary services are used to restore the *frequency* and hence demand to the correct level⁸. To the extent that by *dispatching scheduled generating units* and *loads* to match the amount of demand (service) provided by the *market ancillary services* (in addition to the forecast demand) in previous *dispatch intervals*, the *dispatch* process assists to sustain *frequency recovery*.

Consider an event that occurred three minutes into a *dispatch interval* which caused a significant *frequency* disturbance. The disturbance was such that, in order for *frequency recovery* to occur, delayed *market ancillary services* were required to be delivered in both the *dispatch interval* in which the *frequency* disturbance occurred as well as the following *dispatch interval*. That is the *ancillary services generators* and *loads* that were enabled to provide delayed service in the *dispatch interval* in which the *frequency* disturbance occurred were required to sustain their delivery over the boundary of two *dispatch intervals*. *NEMDE* does not take into consideration the need for *ancillary services generators* and *loads* that were enabled to provide delayed service in the *dispatch interval* in which the *frequency* disturbance occurred to have had their energy (*dispatch*) targets adjusted in the following *dispatch interval* in order to sustain their response.. The *scheduled generating units* and *loads* that would have been *dispatched* to match the amount of service provided by the *market ancillary services* in the *dispatch interval* in which the *frequency* disturbance occurred would have been selected according to economic *dispatch* alone. For this reason and in relation to the cancellation of service delivery AEMO cannot agree with the assertion

⁷ In the mainland *regions* a 1% increase in *frequency* will lead to an approximate 1% increase in *power system demand*, similarly a 1% decrease in *frequency* will lead to an approximate 1% decrease in *power system demand*. In the *Tasmania region* a 1% increase in *frequency* will lead to an approximate 1.5% increase in *power system demand*, similarly a 1% decrease in *frequency* will lead to an approximate 1.5% decrease in *power system demand*.

⁸ Correct demand in this context would mean power system demand when the *frequency* is within the normal operating *frequency band*.

in section 4.3.3 of the NGF's submission that the *dispatch* process will indicate to *ancillary services generating units* and *loads* that service is no longer required by "issuing a *dispatch* target requiring the unit to change output in the opposite direction to that of the service being delivered". A unit's *dispatch* will be decided on economic grounds to meet the *NEMDE* forecast demand while additional *market ancillary services* would still be required to ensure *frequency* recovery within the requirements of the *frequency operating standards*.

As per the first and second dot points in section 4.3 of the NGF's submission, AEMO accepts that it is not reasonable to expect a *scheduled ancillary services generating unit* or *load* to deliver "cumulative" *market ancillary services*. Thus AEMO agrees that it is not appropriate to use a changing reference trajectory based on *dispatch* to assess the delivery of *market ancillary services* when the direction of *dispatch* is such that it supports *frequency* recovery.

Consideration must be given to cases when a *scheduled ancillary service generating unit* or *load* is given a *dispatch* target which is in the opposite direction of *frequency* recovery. In such a case it is not fair to expect a *generating unit* or *load* that receives *dispatch* instructions through the AGC to continue to deliver service with reference to its pre-contingency metered output. AEMO believes that in these cases the measured data should be offset to compensate for changing *dispatch*. Thus AEMO recommends modifying the verification procedure to compensate for a changing *dispatch* trajectories (as described in section 6 of the Issues Paper) but applying them only when there is a change in *dispatch* that is in the opposite direction to *frequency* recovery.

CS Energy note in their submission that if the proposal in section 6 of the issues paper was adopted then there could be issues with *ancillary services generating units* and *loads* not being able to deliver their *enabled* quantity of *market ancillary service* if they were ramping to a new *dispatch* target at the time of a *frequency* disturbance. AEMO believes that this concern is addressed by only applying an offset to when *dispatch* is changing in the opposite direction of *frequency* recovery.

In response to the third dot point in section 4.3 of the NGF's submission it should be noted that the suggested *dispatch* reference used in the *MASS* verification calculations has a different function than the reference trajectory used in the "causer pays calculations". As it is not the purpose of the *MASS* to penalise *generating units* and *loads* that are not conforming to their *dispatch* targets or to account contribution units are making to the need for *regulation FCAS* it is not appropriate to use a *dispatch* target to *dispatch* target reference. It should also be noted that the initial point of the reference is aligned to the initial metered data at the start of the *frequency* deviation.

Quantity of Service to be verified

AEMO agrees with the NGF that a unit ramping to its energy *dispatch* target may not be capable of delivering its enabled quantity at all times during a *dispatch interval* because of the limitation imposed by the offered trapezium and it is not acceptable to assess *ancillary services generating units* and *loads* against their full *enablement* target if, due to the

outcome of the dispatch process, a unit is not in a position to physically deliver an amount of service it is *enabled* for. However it should be noted that joint capacity constraints should ensure that *ancillary services generating units* and *loads* will be able to deliver their full *enablement* amount of FCAS services, assuming that the *FCAS* provider is complying to their dispatch targets.

Maximum period of measurement

As per their *Rules* definitions, *delayed raise service* and *delayed lower service* are designed to recover the “*frequency* to within the *normal operating frequency band*”. The services are designed to be delivered so that the *frequency operating standards* may be met. The *frequency operating standards* require that the *frequency* be returned to the *normal operating frequency band* within five minutes for some types contingency event and ten minutes for other types contingency event. For this reason AEMO agrees with the NGF proposal that the maximum period over which delayed services should be assessed is ten minutes.

Enablement over dispatch intervals

In the first dot point in section 1 of the NGF’s submission it is noted that the *MASS* does take into consideration issue of *market ancillary services* being *enabled* at the start of a *frequency* event and not remaining enabled throughout the duration of the *frequency* event. Though this issue is not directly addressed in the NGF’s submission it should be noted that it is vital for *frequency* recovery that services enabled at the start of *frequency* event be delivered in full regardless of any change to *enablement*. If this was not the case then at the start of every *dispatch interval* where the *frequency* is outside the *normal operating band* a new set of contingency services would have to be delivered. This would clearly be an impractical result.

In the verification of slow and delayed services, all calculations that occur after *service cancellation* are discarded. The NGF in section 4.3.3 of their submission state that, in their understanding, *service cancellation* in the context of *MASS* ‘would be by notice from AEMO’. The definition of *service cancellation* in the *MASS* is:

“means the time when AEMO has notified the *Market Participant* that the relevant service is not *enabled* or not required”

Using this definition *service cancellation* can be taken to mean the point at which the service becomes ‘non-enabled’ by *NEMDE*. As discussed above, in order for the *frequency operating standards* to be met it is necessary that *market ancillary services* are delivered in full from the start of a *frequency* deviation regardless of any change in *enablement*.

AEMO recommends that the definition of service cancellation be changed to:

“means the time when AEMO has informed the *Market Participant* by telephone, *market notice* or similar that the relevant service is not required but not including disablement by the *NEM* dispatch engine (*NEMDE*)”

Data Mismatch Issues

CS Energy expressed concern that there could be issues in aligning ‘as generated’ data supplied by *participants* with data captured independently by AEMO. AEMO agrees that there could be a potential for a mismatch between data sets and that this could lead to significant errors in verification calculations. However AEMO believes that this issue can be sufficiently ameliorated by using the *frequency* measurements supplied by *participants* along with *frequency* measurements captured by AEMO. By aligning the frequency traces it is possible to align other data.

AEMO also accepts that using market systems data in the verification process adds complexity and costs to the provision of market ancillary services. However AEMO believes that this change is warranted in order to ensure that the necessary quantity of service is delivered.

5.1.2 Material Issue 2: Improving the performance of delayed services

5.1.2.1 Summary of issue from second stage of consultation

In their submission to the second stage of consultation AETV Power state:

“AETV agrees with the general principle of establishing market rules that are as technologically neutral as possible and not being more favourable to certain technology types. We also submit that the FCAS rules are already quite complex and that it would be desirable to avoid the introduction of further complexity.

“Based on these observations and without the benefit of detailed analysis of the consequences, it would appear that the best solution to the conundrum between switched and proportional controller issues with providing delayed services is the option to amend the demand forecasting procedure to take into account frequency or time error deviation at the beginning of the dispatch interval.”

In their submission to the second stage of consultation CS Energy state:

“Proportional controllers are inherently incapable of meeting the service description to “restore frequency to 50 Hz within the first 5 minutes...and sustain their response until the central dispatch can take the generation requirement into account”. CS Energy initially accepted the proposed addition of proportional controllers to the delayed service. However, upon reconsideration CS Energy is concerned that a proportional controller’s effect will diminish and its response will be ineffective as the frequency approaches the governor controller’s deadband. The delayed service needs to replace the proportional response which is diminished by the restoration of frequency, so any replacement of switched controllers will degrade the service. CS Energy is also concerned that AEMO are underestimating the amount of FCAS required (as evidenced by the fact that fast and slow proportional response is normally multiple times that dispatched), and that this underestimate then feeds into an under estimate of the larger delayed response.

“In response to AEMO’s request for views on their options, CS Energy would make the following comments:

“Option 1

“CS Energy has already adopted this option to meet the original specification for switched delayed service... CS Energy continues to support this option. CS Energy also supports the NGF concern that there may be insufficient incentive for generators to invest in making the required control system changes for this option. This would be addressed if the requirement for this service is increased to reduce reliance on fast and slow proportional service that has not been enabled.

“Option 2

“Proportional only controllers cannot provide the service required; if they could provide the specified function there would be no need to specify a certain mix of proportional and switched response. This option also conflicts with the principle of being technology neutral.

“Effectively AEMO are specifying an additional service. It is CS Energy’s view that switching controllers effectively provide this service and continue to do so.

“Option 3a (Changes to Demand Forecast)

“Agreed; the dispatch procedures only appear to apply frequency or time error deviation to the regulation service. The sooner the change in supply/demand balance (including an estimate of the change in system load due to the frequency change) is fed into the energy market dispatch the less requirement there will be of regulation and delayed FCAS following a disturbance.

“Option 3b (Extra Regulation Service)

“This option has already been thoroughly considered in the consultation on co-optimisation of regulation and delayed FCAS, so it doubtful there is any benefit in revisiting it.

“Option 4

“The addition of time delays to switched services would greatly alleviate the potential problem of triggering too much response causing over-shoot, while also allowing progressively stronger response if the initial response if the initial response is inadequate to achieve the required standard.”

In section 3 of their submission to the second stage of consultation the NGF state:

“In relation to option 3a (change to demand forecasting) we repeat the point made earlier, namely that the function of FCAS should be to deal with issues that the dispatch process cannot deal with, not with issues that dispatch could deal with, but through error or omission fails to deal with. Hence we say that whether or not this choice is made should have no bearing on the definition or measurement of market ancillary services. These should be

defined on the basis that the dispatch process is assumed to be as effective as it can be within the inherent limitations of a 5-minute cycle.

Both option 1 and option 4 would require changes to some plant offering market ancillary services, thus imposing a cost on these plants, and hence run the risk that some plant will withdraw from the market. These options thus risk a reduction in competition in these markets and we suggest that this potential disadvantage needs to be carefully considered.

Option 3b (extra regulation service) is consistent with current AEMO practice where the amount of regulation service is not fixed, but is increased under conditions where the management of frequency is considered to be temporarily more onerous. While we do not endorse the uncertainty that results from this current practice, we do not believe that extending it to periods following a serious frequency disturbance would make this current uncertainty much worse.

We agree that option 2 would require a Rule change and hence may be seen as outside the scope of the current consultation.”

5.1.2.2 AEMO response to second stage submission

AEMO believes that CS Energy’s concerns that insufficient delayed FCAS is currently enabled are misplaced. The amount of delayed FCAS that is enabled is calculated as the amount of extra generation that is required to bring the power system frequency to within the normal operating band following any credible contingency. Any delivery of fast and slow response that is not enabled but may occur after a frequency deviation is not considered in the calculation to determine the requirement of delayed FCAS. AEMO’s view is that the issue that needs to be addressed is not the under enablement of delayed service but the ‘unsatisfactory performance’⁹ of delayed service.

AEMO acknowledges the concerns that NGF and CS Energy have with implementing option 1 (to require units providing delayed response using proportional controllers to provide extra response in addition to the purely proportional part of the response) – that there may not be sufficient incentive for participants to make the necessary changes to plant control systems to implement this proposal. However, as stated in CS Energy’s submission, in order to be compliant with the existing MASS participants that currently supply delayed FCAS through proportional control systems should already have in place mechanisms to provide more than the purely proportional response (the current MASS requires that switched controllers be used to supply delayed FCAS).

Where option 1 differs from the requirement currently specified in the MASS is that option 1 does not incorporate frequency trigger levels. The response would be required to be delivered for any frequency deviation of significant duration outside the normal operating

⁹ In this context, ‘unsatisfactory performance’ may arise for example because the amplitude of a frequency excursion does not exceed the allocated frequency setting of a delayed service and hence the service delivery is not initiated.

frequency band. With option 1 implemented any participant wishing to supply delayed FCAS would be able to choose whether they provide response via switched controllers (as is currently required by the MASS) or through the proposed, augmented proportional response.

AEMO agrees with both CS Energy and the NGF that option 2 (to amend the FCAS markets to ensure that there is a suitable mix of switched and proportional controllers supplying delayed FCAS) would require extensive changes to the operating environment for limited gain. AEMO does not recommend continuing with this proposal.

As discussed in section 5.1.1.2 AEMO recommends that the option 3a (allowing the dispatch process to be amended to take into consideration power system frequency) be considered by the DPRG.

As indicated by the NGF in their submission option 3b (dispatching extra regulation services following a frequency deviation outside of the *normal operation frequency band*¹⁰) could create extra uncertainty in the market by causing significant price movements in the regulation FCAS price. Thus AEMO does not recommend pursuing this option any further at this stage.

In their submission the NGF noted that the adoption of option 4 (introducing time delays to switched services) would require extra cost for participants to implement and that the extra cost may be enough to force participants to exit the delayed FCAS markets. As time delays would be new concept for the current FCAS markets AEMO believes that further consultation would be needed before option 4 could be implemented. AEMO recommends that if there is no substantial improvement in the performance of delayed FCAS following the introduction of the amended MASS that another consultation be held to consider implementing time delayed frequency settings.

5.1.2.3 Outcome of second stage of consultation – the final outcome

AEMO determines that:

- option 1 (to require units providing delayed response using only proportional controllers to provide extra response in addition to the purely proportional part of the response) be implemented in the amended MASS by not applying proportional compensation to verification calculations for delayed service;
- option 2 (to amend the FCAS markets to ensure that there is a suitable mix of switched and proportional controllers supplying delayed FCAS) not be implemented in the amended MASS at this stage;
- option 3a (allowing the dispatch process to be amended to take into consideration power system frequency) be considered by the DPRG;
- option 3b (dispatching extra regulation services following a frequency deviation) not be implemented in the amended MASS at this stage; and

¹⁰ Extra *regulation service* is currently *enabled* to correct time error. AEMO is not suggesting that this current practice be changed.

- option 4 (introducing time delays to switched services) not be implemented in the amended MASS at this stage but be considered in a future consultation to amend the MASS if there is no significant improvement in the delivery of delayed FCAS.
- that the Mainland *region frequency* levels be amended as per Table 2. See Table 3 in version 3.0 of the MASS.
- that the Tasmania *region frequency* levels be amended as per Table 2. See Table 4 in version 3.0 of the MASS.
- the Tasmania region *trigger range* be changed to 49.2 to 50.8 Hz. See Table 2 in of version 3.0 of the MASS.

5.1.2.4 Summary of issue from first stage of consultation

Hydro Tasmania commented in section 7 of their submission:

...

“

1. Could AEMO comment why the switching controller level 1 provision of delayed service in Tasmania is activated at 49.5/50.5 Hz which does not appear to be tight enough to support the frequency recovery?
2. On use of a proportional controller:
 - a) Delayed service delivered by a proportional controller is dependent on the frequency error and the governor permanent droop settings. Considering these dependencies the frequency may not recover to within the normal operating band. An example in Appendix 3 illustrates delayed FCAS delivery problems when supplied exclusively by proportional controllers.
 - b) Regulation FCAS cannot be relied upon to provide some of the delayed FCAS requirements because some or all of the dispatched regulation may have been used prior to a contingency event occurring.”

In their meeting with AEMO on 19 November 2009, Hydro Tasmania added to their submission the following points:

- There may need to be an additional *frequency* level closer to 50 Hz than the current level 1 setting. The *frequency* level would correspond to a *frequency* band of 49.75 Hz to 50.25 Hz; and
- The Tasmania region *trigger range* be reset to the original settings of 49.2 to 50.8 Hz. This is because having a recorder trigger *frequency* set at ± 0.5 Hz, as proposed in the Issues Paper, would mean that the recorder will trigger on an excessive number of occasions for events such as Basslink transitions.

The NGF commented in section 4.1 of their submission:

“The discussion in this section mentions only obliquely the issue that we believe to be central here. This is that the supply of delayed FCAS has to date been restricted to suppliers using a switching controller.

“The service provided by a switching controller is different in quality from that provided by a proportional controller. This is indirectly acknowledged through the proposal to extend the service definition to include proportional controllers.

“However, there is no clear recognition in the issues paper that the problems of service delivery that are portrayed are consistent with the qualities of service delivery to be expected when supply was restricted to switching controllers only. Since these controllers do not create any service delivery until their individual frequency setting is reached, there is clearly a risk that for less extreme frequency disturbances the response will be insufficient.

“This risk cannot be easily overcome by bringing the frequency settings closer to 50 Hz, since this could create the opposite problem of an over-response to mild frequency disturbances, leading to a frequency disturbance in the other direction.

“This balancing act is reflected in the minimal changes to frequency settings proposed in section 4.1. We do not oppose these minimal changes, but wish that there was more clarity about the problems portrayed being a consequence of the quality of the services recruited, and not necessarily a reflection on the delivery that the offered services have achieved over the period analysed.

“In principle, we support the extension of the service specification to allow proportional controllers, and suggest that if a sufficient part of the service enablement is of this form, then the problems portrayed in Figure 2 should be greatly reduced. However, we are not clear on how two different service qualities can be fairly acquired under a single specification, and would welcome further opportunities to work with AEMO on this subject. This concern is not particular to delayed services, but may also be relevant to fast and slow services.

“As noted above, we believe that the inclusion of proportional controllers requires that a compensation regime based on frequency be also extended to the delayed services.

...

“The NGF believes that the nature of the problem portrayed has been recognised only indirectly by the proposal to extend the definition of delayed services to include those with proportional controllers. We support this proposal, but remain concerned by the difficulties of ensuring equitable treatment of services with different qualities when acquired under a common specification. We would welcome opportunities to work with AEMO on the detail of this proposal.”

5.1.2.5 AEMO response from first stage of consultation

In answer to the question Hydro Tasmania poses regarding why the *frequency setting* level 1 in Tasmania is activated at 49.5/50.5 Hz, AEMO has two responses:

1. The *frequency* in the Tasmania *region* regularly exceeds the 49.5 to 50.5 Hz band without indicating a major *frequency disturbance*. Tightening the Tasmania *region frequency settings* would see delayed service be triggered unnecessarily.
2. When the *frequency* in the Tasmania *region* does not recover to within the *normal operating frequency band* within the time specified by the *frequency operating standards* the *frequency deviation* is generally greater than the level 4 trigger level, see Table 1. Thus the issue with overly long *frequency recovery* is not due to the level 1 *frequency* trigger level being reached, as it is in the mainland *regions*.

TABLE 1 –JULY 2008 TO JUNE 2009 INSTANCES IN THE TASMANIA REGION WHERE FREQUENCY DID NOT RECOVER TO WITHIN THE NORMAL OPERATING FREQUENCY BAND WITHIN THE TIME SPECIFIED BY THE FREQUENCY OPERATING STANDARDS

DATE OF EVENT	TIME TO RECOVERY (SECONDS)	MINIMUM / MAXIMUM FREQUENCY (HZ)	FREQUENCY SETTING LEVEL REACHED
6 September 2008	300	48.6	4
24 September 2008	324	48.9	3
29 January 2009	2776	51.45	4
30 January 2009	532	51.4	4
7 February 2009	332	51.4	4

AEMO does acknowledge the point made by Hydro Tasmania that the *frequency settings* in Tasmania *region* may not be tight enough to support *frequency recovery*. What AEMO proposes is not to move the level 1 frequency closer to 50 Hz but rather to move the level 5 *frequency* closer to 50 Hz thus condensing the *frequency* levels. Considering all *frequency* deviations from July 2008 to June 2009 the minimum *frequency* observed in the Tasmania *region* was found to be 48.6 Hz and the maximum *frequency* observed 51.45 Hz. Thus over this period the level 5 settings were never reached. Proposed new *frequency settings* for the Tasmania *region* can be seen in Table 2.

TABLE 2 – PROPOSED NEW *FREQUENCY SETTINGS* FOR THE TASMANIA REGION

COLUMN 1	COLUMN 2	COLUMN 3	COLUMN 4
Level	Raise service frequency deviation setting (Hz)	Lower service frequency deviation setting (Hz)	Frequency Rate of Change Setting (Hz per second)
1	49.5	50.5	0.875
2	49.3125	50.6875	0.875
3	49.125	50.875	0.875
4	48.9375	51.0625	0.875
5	48.75	51.25	0.875

AEMO agrees with Hydro Tasmania that the *trigger range* for the Tasmania region be reset to the original settings of 49.2 to 50.8 Hz is correct. As can be seen in Table 1 when there is a reportable event the *frequency* will almost certainly exceed the 49.2 to 50.8 Hz *trigger range*.

With regards to point 2 (a) and the example listed in Appendix 3 of the submission from Hydro Tasmania; AEMO understands the point that if all delayed response was supplied by governors operating in droop mode then it is possible for the *frequency* to stabilise at a point outside of the *normal operating frequency band*.

Fast service is designed to arrest *frequency* within the appropriate *containment frequency band*, slow service is designed to stabilise the *frequency* within the appropriate *stabilisation frequency band*, whereas delayed service is designed to aid in the recovery of the *frequency* to within the *normal operating frequency band*. Due to the *power system's frequency* characteristics the quantity of delayed service that is enabled for a particular contingency is significantly higher than the amount of fast service and slow service enabled for the same contingency.

If all *enabled* delayed service was provided by *proportional control* then the *frequency* would stabilise at a level much closer to 50 Hz than the appropriate *stabilisation frequency band*; however there is no guarantee that *frequency* would recover to the *normal operating band*. There are three options ways to ensure that the *power system* recovers to the *normal operating frequency band*:

- there needs to be some response from *switching controllers*; or
- there must be sufficient regulation service dispatched; or

- the units providing delayed response using *proportional controllers* must alter their load set points.

It is likely in a realistic *power system* environment that there will be sufficient response from switching delayed services in addition to proportional delayed services to return the *power system frequency* to the *normal operating frequency band* within the time specified by the *frequency operating standards*.

However the point raised by Hydro Tasmania in their submission needs to be considered along with section 4.1 of the NGF submission. The NGF submission tentatively supports allowing *proportional controllers* to provide delayed service. AEMO agrees with the NGF that that *switched controllers*, as defined by the MASS, are limited in their response to less extreme *power system frequency disturbances* as the *frequency* trigger levels for *switched controllers* may not be reached. In fact, as Figure 2 in the Issues Paper shows, in most instances where the *power system frequency* did not recover within the time required by the *frequency operating standards* in the mainland *regions* the maximum *frequency* deviation was less than the current level 1 *frequency* setting.

Thus in terms of delayed services purely proportional control may not be acceptable except in the initiation of the response. However, as the *frequency* trigger levels for *switched controllers* are seldom reached; *switched controllers* are also limited in their response.

AEMO proposes five options to address this conundrum and seeks comments from Consulted Persons on the best option(s):

1. To require units providing delayed response using *proportional controllers* to provide extra response in addition to the purely proportional part of the response (adjust their load set points or similar). In order to correctly verify that sufficient delayed response has been delivered the verification procedure for delayed services should not include proportional compensation. This is to ensure that the response of the unit is more than the governor droop action.
2. To amend the FCAS markets to ensure that there is a suitable mix of *switched* and *proportional controllers* supplying delayed as suggested in both the NGF and Hydro Tasmania submissions to the consultation. The implementation time for this option would be very long as there would be a requirement to make significant changes the *Rules* as well as AEMO's market systems.
3. To amend the demand forecasting procedure to take into account *frequency* or time error deviation at the beginning of a *dispatch* interval as suggested in the NGF submission. To amend *power system* operating practices to require extra *regulation* service to be provided to supplement *frequency recovery in dispatch* intervals following a *frequency* event.

4. To *change the definition of switched controller frequency level* to incorporate time delays as well as *frequency settings* and *only allow switched controllers to supply delayed services*.

Point 2 b) in section 7 of Hydro Tasmania's submission states that regulation services should not be used to supplement delayed services. The implication of this statement is that it is not correct to co-optimize regulation and delayed service requirements as is currently the case. Though this issue has implications for the MASS it is not within the scope of this consultation as it requires substantial changes to AEMO's market systems.

5.1.3 Material Issue 3: Procedure for allocating *frequency settings*

5.1.3.1 Summary of issue from second stage of consultation

In their submission to the second stage of consultation the NGF state:

"AEMO quite rightly raises the issue of technological neutrality in respect to requests for a frequency setting "more remote from 50Hz". However, it then appears quite contradictory for AEMO to allow Market Participants to have their frequency settings reviewed "on technical grounds" (section 5.1.3.3). Service providers are paid due to enablement of service only and therefore receiving a frequency setting "more remote from 50Hz" means that they will deliver less service whilst still being paid the same as someone with a closer setting.

"We note that participants that are offering market ancillary services can manage any potential overuse of a service by withdrawal of market offers when overuse appears imminent.

"Service providers are registered based on their ability to trigger energy changes, based on excursions from the normal operating frequency band and not on their ability to trigger at "more remote" frequencies. If AEMO wishes to consider providers who can't meet this standard then a Rule change defining a new service to this effect is a more appropriate mechanism than allowing favourable frequency setting reviews on "technical grounds" – a clear breach of the technological neutrality standard under the Rules."

5.1.3.2 AEMO response to second stage submission

The NGF have suggested that the proposal to allow participants to request to have their frequency settings reviewed "on technical grounds" may be seen to be leading to technical discrimination. AEMO disagrees with this submission. It should be noted that any participant in the FCAS markets assigned a *frequency setting* may apply to have their *frequency settings* reviewed. Further some technology types will not be able to participate in the FCAS if they are allocated inappropriate *frequency settings*.

The intention of the proposal is to avoid implementing perverse outcomes resulting from the *frequency setting* process. Such outcomes could occur in:

- a situation where there may not be sufficient fast FCAS available in the market that would be deliverable in the required time frame to be able to meet the frequency

operating standards even though there may actually be the sufficient physical capability to do so provided its delivery were initiated in a prompt manner; or

- a situation where the allocation of a *frequency setting* too close to 50 Hz may result in *frequency* ‘overshoot’. For example consider raise service being supplied by the tripping of a large load block. If the load block is allocated a *frequency setting* too close to 50 Hz it may cause the *frequency* to exceed the upper limit of the *normal operating frequency band* following delivery of the service.

In order to avoid such outcomes and in order not to discriminate on technology type AEMO determines that participants be allowed to request a review of their allocated frequency settings on technical grounds.

5.1.3.3 Outcome of second stage of consultation – the final outcome

AEMO determines that section 6.2(b) of the MASS be:

If there is a technical reason why a particular ancillary service generating unit or ancillary service load will be unable to offer market ancillary services due to its allocated frequency setting then the relevant Market Participant may request AEMO to change the allocated frequency setting. AEMO will have sole discretion in accepting the request for change. If one or more frequency settings have been changed then AEMO may elect to re-allocate the remaining frequency settings as per section 6.2 (a).

5.1.3.4 Summary of issue raised in the first stage of consultation

AETV Power commented in their submission to the first stage of consultation:

...

“Where a switching controller results in supply interruption the FCAS provider would prefer the allocation of the frequency deviation settings that are more “remote” from 50Hz thus avoiding supply interruptions other than for the contingency events that determine the total amount of FCAS scheduled.

...

“A particular issue for Tasmania is the impact of Basslink on the Tasmanian frequency. Every time Basslink reverses flow there is a 50MW step change on the Tasmanian system that gives rise to frequency excursions outside the close to 50Hz trigger frequencies. If the close in trigger frequencies were allocated to interruptible FCAS providers then they could be tripped many times per day.

“The issue raised not only impacts on AETVP but would lessen the potential impact on possible switched FCAS providers. Providers of FCAS that does not result in supply interruption would be presumably re-scheduled within the next dispatch interval or at the latest very soon after. Restoration of supply would take considerably longer.

“Consequently, the suggested allocation of the frequency deviation settings would increase the likelihood of entry of new raise services into the Tasmanian Region, which are in short supply, at lower offer prices than otherwise would be the case and hence assist in meeting the National Electricity Objective.”

Hydro Tasmania commented in section 11 of their submission to the first stage of consultation:

...

“Tasmania may require an additional level of the frequency deviation settings should there be a large increase in the application of switching controller type FCAS services.

“As there are potentially many switching controller solutions, some of them may be better suited to particular range of frequency deviation settings. It is possible that the registering service party have preferences in respect of the trigger level that best matches the device. This consideration may be more important for fast FCAS service and not relevant for slow and delayed services. For example if TWD plant, (as described earlier), is registered as a level 5 switching controller it will not deliver any fast service, however at tighter trigger frequency levels it could be very good provider.

“What will be the basis for determining availability of services? Will AEMO be reviewing availability as determined from market bids?

“What will be a review cycle for allocating switching controller to particular tripping level based on controller availability? The proposal may introduce additional uncertainty to a participant where the commercial value of the service could be impacted due to changed frequency settings.”

5.1.3.5 AEMO response to first stage submissions

The object of the *switched controller frequency* level allocation process proposed in the issues paper is to ensure that there is a suitable spread of services across the *frequency* levels. The process proposed in the Issues Paper is designed to ensure that there is more *market ancillary services* capacity available at levels closest to 50 Hz and is also designed to be impartial to technology type as possible. However AETV Power and Hydro Tasmania point out in their submissions there are significant drawbacks to having a dogmatically impartial allocation mechanism.

AEMO understands AETV Power’s position that participants who supply *market ancillary service* through the interruption of *supply* would be more likely to offer the service if they were guaranteed a *frequency setting* ‘remote from 50 Hz’.

The major problem with this position is one of giving preferential treatment to a specific technology type. *Market ancillary services* providers get paid according to how much service enabled, not how much service is delivered. Services supplied by *switching*

controllers that are assigned to a level 1 setting are more likely to be required to delivered than services assigned to a level 5 setting, however a participant who has 10 MW of service enabled with a level 1 in a dispatch interval setting will be paid the same as a participant who has 10 MW of service enabled with a level 5 setting in the same *dispatch* interval.

Hydro Tasmania position is slightly different; there are some units that will not be able to deliver in full the enabled amount of fast services if they are assigned a *frequency setting* that is too far from 50 Hz. If such a unit is assigned a *frequency setting* too far from 50 Hz then the owner of the unit will be forced to bid 0 MW availability for fast service to reflect the amount that may be delivered in the shorter time period. Again the major problem with endorsing this position is that it seems to give favourable treatment to certain technology types.

In making a determination on this AEMO has to take into account the practicality of process for allocating *frequency settings* as well as the fairness of the process. Under the currently suggested process it is for a scenario to arise where fast services delivered by *supply* interruption are assigned a *frequency* level close to 50 Hz and fast service that require a *frequency setting* close to 50 Hz are allocated a *frequency setting* remote from 50 Hz. In such a scenario there may be a scarcity of fast services offered in a *region* that may actually have sufficient capacity of fast service¹¹.

AEMO proposes that the *switched controller frequency* level allocation process MASS be amended to allow participants to request AEMO review their settings if, due to the *frequency setting* allocated to a particular *ancillary service generating unit* or *load*, that *ancillary service generating unit* or *load* will not be able offer the service it is registered to provide.

The basis for determining availability of services for an *ancillary services generating unit* or *load* described in the issues paper and version 2.01 of the MASS is the amount of time the generating unit or load is connected to the power system. However the method suggested by Hydro Tasmania, to base the service availability on previous bidding history, appears to be more robust. AEMO proposes that the basis for service availability be previous bidding history. New *market ancillary services* entrants will need to supply forecast bid availability.

5.1.4 Material Issue 4: Definition of *frequency recovery*

No further submissions on this issue were received in the second stage of consultation.

5.1.4.1 Summary of Issue raised in the first stage of consultation

CS Energy comments on section 7 of the Issues Paper in their submission to the first stage of consultation:

¹¹ Such a scenario is unlikely to occur in the mainland *regions* but could quite possibly occur in the Tasmania *region* where there is currently a limited availability of fast raise service.

“The proposed definition uses the same setting for the frequency recovery time as the frequency disturbance time, hence depending on the rate that the frequency deteriorates and then recovers, it is possible that multiple “disturbances” will arise from one event, due to multiple short term crossings of the normal band from the small fast fluctuations of approx 2 to 3 rpm on system speed. An analysis of a recent event, shows the proposed definition would have resulted in 3 disturbances within 15 seconds as frequency deteriorated, and several minutes later, a further 11 disturbances within 1 minute before full recovery within the normal band. To avoid this, the Disturbance and Recovery settings need to be off-set by a margin of 3 rpm (0.05 Hz). We would recommend Frequency Disturbance Time be redefined to use the data logging Trigger Range setting of +/- 0.2 Hz, (without the Trigger Rate requirement), which will also remove the variable time in the disturbance log data, between Frequency Disturbance Time and the Trigger time, thus simplifying the verification calculation task. Alternatively, Frequency Recovery should be defined as the frequency crossing inside the normal band by a margin of 0.05 Hz. However, since there is no requirement for data logging or reporting on disturbances that do not reach the Trigger level, it would be more practical to redefine the Frequency Disturbance Time”

Hydro Tasmania comment in section 10 of their submission:

“Hydro Tasmania supports the change of the definition.”

The NGF comment in section 4.4 of their submission:

“This term relates to the verification of contingency FCAS performance. We agree that the role of these contingency services is to arrest, stabilise and recover the frequency during a disturbance, in order to return to the normal operating frequency band. The management of frequency beyond this time should be managed by the combination of the dispatch process and the regulation services, and hence we consider that the role of the contingency services is complete when the normal operating frequency band is regained.”

5.1.4.2 AEMO Response

AEMO believes the original AEMO proposal and the NGF statement that “the role of the contingency services is complete when the *normal operating frequency* band is regained” are philosophically sound. However AEMO also agrees with CS Energy that in having *frequency disturbance time* and *frequency recovery* based on the same *frequency* level can lead to difficulties. As such AEMO welcomes the suggestion that the *frequency* requirement for *frequency disturbance time* and *frequency recovery* be separated and agrees that +/- 0.05 Hz is an adequate separation.

It is AEMO’s preference to change the definition of *frequency recovery* rather than *frequency disturbance time* as it makes sense to align the definition *frequency disturbance* as “an occasion when the *frequency* of the *power system* moves outside the *normal operating frequency band*”.

5.1.4.3 The Final Outcome

AEMO determines that the definition of *frequency recovery* be amended to:

“means the first change in local *frequency* from above 50.15 Hz to below 50.1 Hz, or below 49.85 Hz to above 49.9 Hz, to occur after a *frequency disturbance*”

See section 1.1 of version 3.0 of the MASS.

5.1.5 Material Issue 5: Switched controller compensation

5.1.5.1 Summary of issue raised in second stage of consultation

In their submission to the second stage of consultation AETV stated:

“... the proposed compensation in section 2.6 (a) (ix) does not appear to provide sufficient compensation. In particular, whenever the time to the allocated deviation setting is less than 5 seconds – the compensation is zero.”

5.1.5.2 AEMO Response to second stage of consultation

AEMO agrees with AETV power that the formulation of the switched compensation calculation described in section 2.6 (a) (ix) of version 2.02 of the MASS is not formulated correctly.

This can be remedied by replacing the term frequency reference time with a new term based on the expected time that the power system frequency would have reached the appropriate frequency setting given a standard frequency ramp.

5.1.5.3 Outcome of second stage of consultation – the final outcome

AEMO determines that the definition of *frequency reference time* (refer to equation 11 in the Issues Paper and as proposed in the draft determination) be:

$$\text{frequency reference time, } t_{ref} = 49.85 - f_{ref}/\text{frequency ramp rate}$$

for fast raise service calculations and:

$$\text{frequency reference time, } t_{ref} = 50.15 + f_{ref}/\text{frequency ramp rate}$$

for fast lower calculations.

See section 2.6(a)(vii) of version 3.0 of the MASS.

In addition to the above outcome of the first stage of consultation AEMO determines that the section 2.6 (a) (ix) of the MASS be:

compensate FS by multiplying it by:

$$\text{MAX} (1, (6 - \text{frequency setting time})/(6 - t_{\text{initiate}} + t_{\text{step}}))$$

where

t_{initiate} is time after the event when the local frequency measurement reaches the relevant frequency setting

t_{step} is equal to the time interval between power flow measurements

frequency setting time is the time after the event when the local frequency measurement would have reached the relevant frequency setting had the local frequency changed in a standard frequency ramp at the relevant frequency ramp rate from the frequency disturbance time.

5.1.5.4 Summary of Issue raised in the first stage of consultation

CS Energy comments on section 14 of the Issues Paper in their submission contain:

“The proposed formula 13 divides by “6-t(initiate)” and hence will cause large compensation factors when t(initiate) is close to 6, which is similar to the problem with the existing compensation formula for proportional controllers when frequency is close to 50 Hz. It is unfair to suppliers of fast proportional services to have switched controllers that are only just initiated inside the 6 second window to have their response artificially brought forward from the slow “stabilisation” between 6 & 60 secs into the fast “arresting” time domain between 0 and 6 secs. This is an inherent deficiency of using switched controllers for the fast service, and this compensation compromises the very definition of fast and slow services.

“If such compensation is to be allowed for Switched Controllers, suppliers with proportional controllers with deadbands would be justified in requesting the frequency compensation formula be changed to correctly calculate what the performance would be if the frequency was at the reference frequency. To calculate what the response would be at the reference frequency with use of a governor deadband, the compensation calculation needs to be based on the magnitude of the frequency deviation outside the deadband: Equation 9. $\text{Max}(1, \text{ABS}(50-f(\text{resp-rate})-f(\text{db}))/\text{ABS}((50-f(\text{local})-f(\text{db}))))$, where f(db) is the frequency deadband setting (+/- from 50 Hz).

Hydro Tasmania comment in section 5 of their submission:

“Hydro Tasmania has observed that the calculations shown in Figure 10 and Table 14 do not allow for time within the normal operating frequency band. By allowing for normal operating band the time should extend to 6.375 s for fast FCAS calculations.

“It is noted that not all switching controllers respond instantaneously. It is important that adjustment is made not only for a trigger frequency but also time delays in control actions.”

5.1.5.5 AEMO Response to the first stage of consultation

Both submissions highlight an apparent contradiction in the MASS. The MASS defines the amount of fast service (raise or lower) to be delivered as the amount that the person making the *market ancillary service* offer expects would be delivered at the relevant *connection point*

in addition to the amounts in all cheaper price bands in response to a *standard frequency ramp* from 50 Hz.

However, also as per the MASS the time at which a *frequency* deviation is considered to have started is the time at which the *power system frequency* exits the *normal operating frequency band*. It appears that the correct definitions of the amount of fast service (raise or lower) to be delivered as the amount that the person making the *market ancillary service* offer expects would be delivered at the relevant *connection point* in addition to the amounts in all cheaper price bands in response to a *standard frequency ramp* from the *normal operating frequency band*. This is noted in CS Energy's submission in their comments on section 13 of the Issues Paper. Thus AEMO proposes redefining *frequency reference time* (equation 11 in the Issues Paper) as:

$$\text{frequency reference time, } t_{ref} = 49.85 - f_{ref} / \text{frequency ramp rate}$$

for fast raise service calculations and:

$$\text{frequency reference time, } t_{ref} = 50.15 + f_{ref} / \text{frequency ramp rate}$$

for fast lower calculations.

The compensation calculations used in the verification calculations are designed to compensate the assessed performance of *ancillary services generating units* and *loads* for *frequency* deviations that cause the *frequency* to deviate at less than the *frequency ramp rate* and/or reach a *frequency* that is between the relevant reference *frequency* and 50 Hz.

For this reason AEMO believes that it is appropriate and fair, to compensate *switched controllers* as specified in the Issues Paper, taking into account the amendments referred to above regarding starting the reference *frequency ramp rate* at the boundary of the *normal operating frequency band* rather than from 50 Hz. It should be noted that the process of compensation is analogous to the compensation process used for *proportional controllers*. CS Energy's suggested compensation for *proportional controllers* will be discussed in section 5.1.6.

Hydro Tasmania notes that not all *switching controllers* are instantaneous and suggest that the time delay for switching control actions be taken into account when in the verification calculations for fast services. As the switching time delay for switching control actions is not a function of *frequency* deviation time AEMO does not agree that it is appropriate to compensate for switching time delay time.

5.1.6 Material Issue 6: *Proportional controller compensation*

5.1.6.1 Summary of Issue raised in second stage of consultation

In their submission to the second stage of consultation CS Energy state:

“If the governor deadband is less than the maximum allowable +/- 0.15 Hz, the proportional frequency change compensation formula now over-estimates the response at the reference 0.5 Hz deviation, because AEMO have used fixed values of 49.85 and 50.15 instead of (50-deadband) and (50 +deadband) as we have suggested (49.9 and 50.1 in our case). Correct compensation relies on using the actual governor deadband setting for each generator, which should not be a problem as AEMO have introduced different settings for individual generators in the G factor”.

5.1.6.2 AEMO response to second stage of consultation

AEMO agrees with CS Energy that the method proposed in version 2.02 of the MASS to compensate proportional controllers may lead to errors. AEMO also agrees that in order to correct the compensation calculation actual governor deadband settings should be used. To implement this AEMO recommends changing the proportional response formulae in sections 2.6(a)(viii) and 3.6(a)(viii) be changed form:

$$\text{MIN} \left(\text{MAX} \left(1, \frac{\text{ABS}(49.85 - f_{\text{resp-rate}})}{\text{ABS}(49.85 - f_{\text{local}})} \right), 3 \right) \times G$$

for raise services and

$$\text{MIN} \left(\text{MAX} \left(1, \frac{\text{ABS}(50.15 - f_{\text{resp-rate}})}{\text{ABS}(50.15 - f_{\text{local}})} \right), 3 \right) \times G$$

for lower services, to:

$$\text{MIN} \left(\text{MAX} \left(1, \frac{\text{ABS}(f_{\text{raise DB}} - f_{\text{resp-rate}})}{\text{ABS}(f_{\text{raise DB}} - f_{\text{local}})} \right), 3 \right) \times G$$

for raise services and

$$\text{MIN} \left(\text{MAX} \left(1, \frac{\text{ABS}(f_{\text{lower DB}} - f_{\text{resp-rate}})}{\text{ABS}(f_{\text{lower DB}} - f_{\text{local}})} \right), 3 \right) \times G$$

for lower services.

Where $f_{\text{raise DB}}$ is the relevant governor deadband setting below 50 Hz and $f_{\text{lower DB}}$ is the relevant governor deadband setting above 50 Hz.

5.1.6.3 Final outcome

AEMO determines that:

- changing the definition of $f_{\text{resp-rate}}$ to:

$$f_{\text{resp-rate}} = 49.85 - t \times \text{frequency ramp rate, for } t < t(\text{ref}) \text{ and } f < 49.85$$

$$f_{\text{resp-rate}} = 50.15 + t \times \text{frequency ramp rate, for } t < t(\text{ref}) \text{ and } f > 50.15$$

See section 2.6(a)(viii) of version 3.0 of the MASS.

- changing the definition of *frequency reference time* as per section 5.1.5 of the draft determination
- See section 1.1 of version 3.0 of the MASS the proportional response formulae in sections 2.6(a)(viii) and 3.6(a)(viii) be:

$$\text{MIN} \left(\text{MAX} \left(1, \frac{\text{ABS}(f_{\text{raise DB}} - f_{\text{resp-rate}})}{\text{ABS}(f_{\text{raise DB}} - f_{\text{local}})} \right), 3 \right) \times G$$

for raise services and

$$\text{MIN} \left(\text{MAX} \left(1, \frac{\text{ABS}(f_{\text{lower DB}} - f_{\text{resp-rate}})}{\text{ABS}(f_{\text{lower DB}} - f_{\text{local}})} \right), 3 \right) \times G$$

for lower services.

Where $f_{\text{raise DB}}$ is the relevant governor deadband setting below 50 Hz and $f_{\text{lower DB}}$ is the relevant governor deadband setting above 50 Hz.

5.1.6.4 Summary of Issue raised in the first stage of consultation

CS Energy comments on section 14 of the Issues Paper in their submission to the first stage of consultation contain:

“Formula 10 should reference the frequency ramp at the edge of the normal frequency band not at 50 Hz (the beginning of the reference ramp should match the local frequency Disturbance Time), otherwise the reference frequency ramp will always be inside the actual frequency for a significant portion of the fast response 6 seconds, reducing the frequency compensation unfairly. It is proposed that formula 10 be modified as follows:

$$F(\text{resp} - \text{rate}) = 49.85 - t \times \text{frequency ramp rate, for } t < t(\text{ref}) \text{ and } f < 49.85$$

$$F(\text{resp} - \text{rate}) = 50.15 + t \times \text{frequency ramp rate, for } t < t(\text{ref}) \text{ and } f > 50.15$$

...

This proposal will require the definition of ‘frequency reference time’ $t(\text{ref})$, to be modified to subtract the disturbance setting from the difference between 50 and the reference frequency, before dividing by the ‘frequency ramp rate’.

Hydro Tasmania comment in section 7 of their submission:

“Based on Hydro Tasmania submission AEMO have suggested that Equation 9 (Issue Paper) should be used to calculate the verification method scaling factor for the proportional controllers:

$$\text{MAX} \left(1, \frac{\text{ABS}(50 - f_{\text{resp-rate}})}{\text{ABS}(50 - f_{\text{local}})} \right)$$

“This equation does not recognise the dead band encompassing normal frequency band and therefore Hydro Tasmania recommends that equation 9 should be modified to:

$$\text{MAX} \left(1, \frac{\text{ABS}(50 - f_{\text{resp-rate}}) - f_{\text{nb}}}{\text{ABS}(50 - f_{\text{local}}) - f_{\text{nb}}} \right)$$

Where f_{nb} is 0.15 Hz for the current normal operating band of ± 0.15 Hz.”

This takes into account the fact that no FCAS is required to be delivered within the normal operating band.

5.1.6.5 AEMO Response to submissions in the first stage of consultation

As noted in section 5.1.5 AEMO agrees that the verification calculations should take into consideration a frequency ramp from the edge of the normal operating frequency band to appropriate raise reference frequency. In this respect AEMO agrees with both CS Energy and Hydro Tasmania.

In their meeting with AEMO, Hydro Tasmania noted that it is likely that the methodology proposed by Hydro Tasmania in their submission may result in over compensation when the power system frequency is close to the normal operating frequency band. Also, given the recommendation in section 5.1.4 regarding the definition of frequency recovery, the method suggested by Hydro Tasmania will not work when the frequency is between the defined frequency recovery points and the normal operating frequency band. To correct for these issues AEMO recommends capping the maximum proportional compensation at 3 times metered response¹².

¹² Three times proportional response would correspond to the maximum proportional response that would be allowed using the definition of frequency recovery described in the Issues Paper and the existing proportional controller compensation methodology.

To implement this change AEMO recommends changing the definition of $f_{resp-rate}$ as per CS Energy's submission, changing the definition of *frequency reference time* as per section 5.1.5 of the draft determination and changing the proportional compensation calculation to:

$$MIN \left(MAX \left(1, \frac{ABS(49.85 - f_{resp-rate})}{ABS(49.85 - f_{local})} \right), 3 \right)$$

for raise services and

$$MIN \left(MAX \left(1, \frac{ABS(50.15 - f_{resp-rate})}{ABS(50.15 - f_{local})} \right), 3 \right)$$

for lower services

Making both these changes is equivalent to the changes suggested in the submissions from CS Energy and Hydro Tasmania. Note that the CS Energy submission called for the local *frequency* to be referenced to an individual controller's deadband where as Hydro Tasmania proposed using the *normal operating frequency band* for reference. AEMO proposes to use the *normal operating frequency band* as a reference should encompass the deadbands for most *proportional controllers*.

By making the changes to the proportional compensation calculation AEMO is also addressing the point made by CS energy in their comments on section 14 of the issues paper regarding the comparative fairness of the *switching* and *proportional controller* compensation calculations.

5.1.6.6 Outcome of the first stage of consultation

AEMO proposes

- changing the proportional compensation calculation to:

$$MIN \left(MAX \left(1, \frac{ABS(49.85 - f_{resp-rate})}{ABS(49.85 - f_{local})} \right), 3 \right)$$

for raise services and

$$MIN \left(MAX \left(1, \frac{ABS(50.15 - f_{resp-rate})}{ABS(50.15 - f_{local})} \right), 3 \right)$$

for lower services

See sections 2.6(a)(viii), 3.6(a)(vii) and 4.6(a)(vii) of version 2.02 of the MASS

5.1.7 Material Issue 7: Combined controller compensation

No further submissions on this issue were received in the second stage of consultation.

5.1.7.1 Summary of Issue raised in the first stage of consultation

Hydro Tasmania comment in section 2 of their submission to the first stage of consultation:

...

“In the light of there being a shortage of fast FCAS in Tasmania, Hydro Tasmania has identified several other controller options with potential for substantial increased delivery of fast FCAS. In most cases the controllers do not appear to comply with AEMO’s proposed classification of proportional, switching or combined controller. In some instances, the combined MW output may change in an essentially continuous manner when the local frequency is outside the deadband and in other instances there may be a step change for higher df/dt .”

“The various options will be discussed briefly below:

- “1. Use of a temporary boost of governor PID parameters;
2. Use of feed forward MW set point;
3. Use of hydro plant operating in the tail water depression mode (TWD); and
4. Use of rotating storage devices.”

“The first two options, options 1&2, involve a temporary amplification of the governor output. For example this can be a temporary step change in either auxiliary input signal or a temporary change in the regulator parameter(s). In both cases the MW output of the generator is essentially continuous and it is not feasible to identify the instant the boost has been applied. It should be noted that in any case the output of hydro machines is not strictly proportional.

“The main issue for option 1 and 2 is the difference in FCAS delivery between small and large disturbances (df/dt), where proportionality of machine output to the frequency error may not satisfy MASS requirements due to a possible step increase in output. Although in essence a step change, the overall response of the modified controller still responds to changes in frequency in an essentially continuous and proportional manner.

“Option 3, operation of hydro machines in tail water depression mode (TWD), uses fast transition from machine motoring (operation similar to a synchronous condenser mode) to generation. During the first 1 to 2 seconds the generator response will exhibit a short time delay and a negative MW response, it is essential that fast triggering is used so there are at least 4 seconds available for fast ramping of MW output. Delaying triggering of TWD to frequency levels reserved for switching controller (Table 4) will significantly reduce delivered fast FCAS.

...

“Option 4 covers energy storage options with limited storage capacity. Typically fly wheels can supply 15 to 20 seconds of energy delivered as a rectangular waveform. With the current definition, this option can deliver FCAS equivalent to 30-40% of the device capacity. However, the benefit of this option is an opportunity to deliver energy early when it is the most effective in containing the frequency change. This option, if acceptable, can potentially be developed to support a wind farm supplying dynamic reactive power control, fault level, fast FCAS raise and inertial contribution.

“Hydro Tasmania proposes that the controllers using step changes in secondary control signals where the step change is not reflected as a sudden step change in the MW output be classified as proportional controllers. This is an important issue in light of increasing penetration of wind generation. Hydro Tasmania would welcome an opportunity to discuss it further with AEMO.”

In their meeting with AEMO on 19 November 2009 Hydro Tasmania provided further details of the controller options discussed above. These details can be seen in Attachment 1 and Attachment 2 of the meeting minutes and are available on the AEMO website¹³.

5.1.7.2 AEMO Response to submissions to the first stage of consultation

AEMO agrees with Hydro Tasmania that control systems that use step changes in secondary control signals and where the step change is not reflected as a sudden step change in MW output should be classified as *proportional controllers*. This does introduce further complications for the verification calculations for *proportional controllers* if the *frequency* rate of change is less than the rate of change needed to trigger the secondary control signal. If the *frequency* rate of change is not sufficient to trigger the secondary control signal then the current verification process will not fairly compensate the associated measured response.

AEMO suggests that the measured response of each *proportional controller* be adjusted by a factor G which is given in Equation 1.

EQUATION 1

$$G = \frac{T_{reg}}{T_{act}}$$

where:

T_{reg} is the maximum capacity corresponding to the relevant registered FCAS trapezium

T_{act} is the maximum capacity corresponding to the maximum availability of the trapezium appropriate for the measured maximum rate change that actually

¹³ <http://www.aemo.com.au/electricityops/0168-0001.html>

occurred. Participant supplying market ancillary services would need to provide information to AEMO relevant data to calculate T_{act} .

If the response provided by a *proportional controller* does not vary with respect to *frequency rate of change* then the value of G in Equation 1 will always be 1, hence there will be no added scaling.

The type of controller described in option 3 of Hydro Tasmania's submission can be described as *proportional controllers* that are initiated by *switching controllers*. To correctly compensate this type of controller AEMO recommends that, if this type of controller is used in the delivery of fast services, then it is appropriate to apply proportional compensation to measured response then apply switching compensation. The rationale for this process is that the proportional compensation component will compensate the measured response if the *frequency rate of change* and final frequency is less than the appropriate MASS defined *frequency ramp rate* and *reference frequency*. The switching compensation will then compensate for a switching time which is greater than the switching time that would have occurred had the *frequency* changed at the MASS defined *frequency ramp rate*.

The type of controller described in option 4 of Hydro Tasmania's submission is only able to provide service that is sustained over very short periods of time thus could be used for *fast raise service* delivery. However in order for this type of plant to be suitable for the current *market ancillary service* design it would need to be able to sustain a response long enough to ensure that the average response from 6 to 60 seconds after an event is comparable to the average response in the 0 to 6 second time frame.

5.1.7.3 The Final Outcome

AEMO determines that each measured proportional response be adjusted by a factor G :

$$G = \frac{T_{reg}}{T_{act}}$$

where:

T_{reg} is the maximum service capability corresponding to the relevant registered FCAS trapezium

T_{act} is the maximum service capability corresponding to the maximum availability of the trapezium appropriate for the measured maximum rate change that actually occurred.

See sections 2.6(a)(viii), 3.6(a)(vii) and 4.6(a)(vii) of version 3.0 of the MASS.

AEMO determines that for *proportional controllers* that are initiated by *switching controllers* be compensated first as *proportional controllers* then as *switching controllers*.

5.1.8 Material Issue 8: Verification calculations for combined services

No further submissions on this issue were received in the second stage of consultation.

5.1.8.1 Summary of Issue raised in the first stage of consultation

Hydro Tasmania comments in section 6 of their submission to the first stage of consultation:

“Hydro Tasmania notes with appreciation the improvement in results and agree with the approach. We still have a question on the consistency of proposed verification process with the dispatch process (NEMDE), and in particular when multiple services are enabled from one unit. How can a Generator determine its bids if it is unsure if it will be enabled for multiple services?”

The NGF comment in section 4.6 of their submission:

“The NGF therefore supports the proposed changes aimed at eliminating this unwanted characteristic of the verification calculations.”

5.1.8.2 AEMO Response to submissions in the first stage of consultation

It is AEMO’s position that it is the responsibility of each *Market Participant* to ensure that FCAS trapeziums bid for an *ancillary services generating unit* or *ancillary services loads* reflect the true service availability of the *generating units* and *loads*. That is the *Market Participant* should assume that the NEM dispatch engine (NEMDE) can enable the full amount of all services that are offered as available.

5.1.8.3 The Final Outcome

AEMO determines that no change be made to the MASS in relation to multiple services being bid.

5.1.9 Material Issue 9: Consistent base for verification calculations

No further submissions on this issue were received in the second stage of consultation.

5.1.9.1 Summary of Issue raised in the first stage of consultation

The NGF note in section 3 of their submission to the first stage of consultation:

“The base level for the measurement of responses is derived from measured output (for a generator) averaged over a time interval before the frequency disturbance. This time interval is defined for each of fast, slow and delayed service.

“The different period of measurement for this base level is of little consequence if a unit provides only one service.

“But if a unit provides two or three services, then the measured response in the overlap periods are used in relation to both the overlapping services, and in the process the measured response levels are subtracted. We submit that it is not good practice to subtract measurements made against different bases, and further that there is no logical reason for this practice.

“The way to correct this inconsistency is illustrated in the following amended version of the procedure to determine the value “SA” –

““determine value SA as, if value FA has been determined, equal to FA, or otherwise as the average ...”.

“A similar change should be applied for DA.”

CS Energy comments on section 3 of the Issues paper are:

“The NGF proposal is endorsed, except for one element. The use of FA (4 to 2 seconds before the frequency disturbance time), is less reliable than SA (20 to 8 seconds before the disturbance time). Depending on the governor deadband settings, and the frequency disturbance trajectory, some of the response to the frequency outside the deadband can occur in the FA period, thus producing a false base level. System voltage spikes due to faults or switching close to the connection point, can occur just prior to frequency disturbances, and the voltage disturbance can cause power measurement errors. Hence, it is recommended that in cases where a generator is dispatched for fast and slow services, the base level for response measurement should be SA, not FA.”

5.1.9.2 AEMO Response to submissions to the first stage of consultation

AEMO agrees with CS Energy that if a consistent base level for verification calculations is to be used then SA is better than FA. AEMO’s major concern is that different recording equipment is used to measure fast service delivery than is used for slow and delayed service delivery. Hence AEMO believes there is a possibility there could be an offset error between the metered fast, and slow and delayed data sets.

Market ancillary service metering equipment is the responsibility of the *Market Participants*. Thus if *Market Participants* are confident that using differing data sets will not introduce significant error to the verification process then AEMO will recommend that CS Energy’s position be adopted.

5.1.9.3 The Final Outcome

AEMO determines that a consistent base level be used for verification calculations if multiple services are being assessed. AEMO determines that if fast and slow services are being assessed together then SA be used in place of FA for the verification of fast services.

See section 2.6(a)(v) of version 3.0 of the MASS.

5.1.10 Material Issue 10: Data smoothing algorithms

No further submissions on this issue were received in the second stage of consultation.

5.1.10.1 Summary of Issue raised in the first stage of consultation

CS Energy comments on section 5 of the Issues paper and raised in their submission to the first stage of consultation include:

“The proposed value of ‘a’ of 0.1 does not take into account the data sampling period. Our fast data is recorded at 20 ms compared to the maximum specification of 50 ms. Using ‘a’ = 0.1 with a sample period of 20 ms, results in a smoothing time constant of 0.2 seconds. Using ‘a’ = 0.1 with a sample period of 50 ms, results in a smoothing time constant of 0.5 seconds. To obtain consistent results from service providers with different sampling periods, ‘a’ should be equal to T_s/T_f where T_s = sample period, and the specified first order lag filtering time constant $T_f = 0.5$ s.”

Hydro Tasmania comment in section 8 of their submission to the first stage of consultation:

“The choice of smoothing functions adopted by AEMO raises the following questions:

- Why the particular smoothing function was selected (equation 2 Issue Paper) as it rejects the current value in estimation of the rate of change of frequency?
- Why the smoothing function adopted for Equation 3 considers only past and present values of df/dt and consequently introduces a phase shift and a time error.

“Hydro Tasmania believes that using basic smoothing functions may provide better results.”

5.1.10.2 AEMO Response to submissions in the first stage of consultation

Firstly it should be noted that the smoothing and numerical differentiation methods that are used in verification calculations have been selected and tuned through operational experience. They are simple and robust techniques.

The raw frequency smoothing uses a single exponential smoothing technique of the form:

$$S_n = ax_n + (1 - a)S_{n-1}$$

where:

S_n is the smoothed data corresponding to point n

S_{n-1} is the smoothed data corresponding to point immediately prior to n

x_n is the raw data at point n

a is the smoothing constant.

As pointed out by CS Energy this technique introduces a delay. However the technique proposed by CS Energy to standardise the delay would cause differing smoothing coefficients to be applied to different data sets. Using different smoothing coefficients will result in differing effects on the smoothed data sets.

The average delay introduced by single exponential smoothing is approximately equal to $1/a$. That is if ‘a’ equals 0.1 then the smoothed data will lag the raw data by 10 samples. AEMO proposes to change the exponential smoothing techniques so that the smoothed data is shifted $1/a$ samples forward to correct the lag.

Version 2.02 of the MASS has also been modified to correct some inaccuracies that were introduced in version 2.01 of the MASS:

1. In section 2.6 of the MASS the *frequency* is smoothed then the *frequency* rate of change is smoothed. As the *frequency* rate of change is calculated from the smoothed *frequency* trace the resulting *frequency* rate of change data is smoothed twice. This is an unwanted outcome. To correct this the *frequency* rate of change data is no longer exponential smoothed
2. The exponential smoothing process is not needed to smooth the *frequency* data in sections 3.6 and 4.6 of the MASS and has been removed. This is because the lower resolution sampling and more gradual *frequency* changes that occur during *frequency* recovery mean there is less noise in the data.

5.1.10.3 The Final Outcome

AEMO determines that the single exponential smoothing technique used in the MASS be changed so that the smoothed data is shifted $1/a$ (10) samples forward.

See section 2.6(a)(viii) of version 3.0 of the MASS.

5.1.11 Material Issue 11: Verification calculation tolerance

5.1.11.1 Summary of Issue raised in Second Stage of Determination

In their submission to the second stage of consultation AETV stated:

“We note that there is a set tolerance on the absolute frequency setting but not on the rate of change frequency setting.”

5.1.11.2 AEMO response to second stage of consultation

AEMO believes that there should be a tolerance on frequency rate of change settings and that an appropriate frequency rate of change setting tolerance is 0.05 Hz/s.

5.1.11.3 Outcome of second stage of consultation – final outcome

AEMO determines that a 0.05 Hz/s tolerance be used in sections 2.6(b), 3.6(b) and 4.6(b) of the MASS and that sections 2.4(e), 3.4(e) and 4.4(e) of the MASS should read:

“A switching controller for a fast raise service or fast lower service must be capable of adjustment of its frequency setting to any of the relevant values in Table 3 or Table 4 with error no greater than 0.05 Hz for the absolute frequency settings (values in columns 2 and 3 of tables 3 and 4) and 0.05 Hz/s for frequency rate of change settings (values in column 4 of tables 3 and 4).”

“A switching controller for a slow raise service or slow lower service must be capable of adjustment of its frequency setting to any of the relevant values in Table 3 or Table 4 with error no greater than 0.05 Hz for the absolute frequency settings (values in columns 2 and 3

of tables 3 and 4) and 0.05 Hz/s for frequency rate of change settings (values in column 4 of tables 3 and 4).”

“A switching controller for a delayed raise service or delayed lower service must be capable of adjustment of its frequency setting to any of the relevant values in Table 3 or Table 4 with error no greater than 0.05 Hz for the absolute frequency settings (values in columns 2 and 3 of tables 3 and 4) and 0.05 Hz/s for frequency rate of change settings (values in column 4 of tables 3 and 4).”

5.1.11.4 Summary of Issue raised in the first stage of consultation

In their ‘Additional Comments’ section of their submission Hydro Tasmania raised the following question:

“Actual systems have non-linearity, time delays, respond differently to different shapes of frequency etc which mean that the verification methods, even if technically correct, will show variability in response for real events, even if a unit does exactly what it is supposed to do in response to a real event. Hydro Tasmania suggests an introduction of tolerances in verification of FCAS which could allow real controllers to comply with the definition of *proportional controller*. These tolerances can be defined and specified in MASS document.”

5.1.11.5 AEMO Response to submissions to the first stage of consultation

The MASS specifies that *market ancillary services* metering equipment have an accuracy of at least 2%. As both *frequency* and power measurements are used then it is appropriate to have a tolerance of up to 4% on results of the verification calculations¹⁴ due to metering error.

As noted by Hydro Tasmania the MASS defined calculations introduce some additional error into the verification process. AEMO proposes that a 5% tolerance be used in the verification calculations¹⁵. For example if the outcome of the verification calculation showed that an *ancillary services generating unit or load* had delivered 20 MW of service then the *ancillary services generating unit or load* would be assessed as having delivered in the range of 19-21 MW of service.

5.1.12 Material Issue 12: *Market ancillary service* supplied by switched control alone

No further submissions on this issue were received in the second stage of consultation.

¹⁴ A 2% error compounded is approximately a 4% error.

¹⁵ Twice the average in response to a *standard frequency ramp*

5.1.12.1 Summary of Issue raised in the first stage of consultation

In the 'Additional Comments' section of its submission, Hydro Tasmania raised the question:

“Can FCAS requirements be met by enabling switching controllers only?”

5.1.12.2 AEMO Response to submissions to the first stage of consultation

AEMO notes that it is technically possible to meet *frequency operating standards* with *switching controllers* alone. However as noted in section 5.1.2 there are issues in supplying delayed service by solely enabling *switching controllers*.

5.1.12.3 Final Outcome

Notwithstanding the outcome of section 5.1.2, AEMO determines that no change be made to the MASS to in relation to ensuring that there is always a combination of *proportional* and *switched controller* services enabled for *market ancillary service*. Refer to section 5.1.2 for further discussion on this issue.

5.1.13 Material Issue 13: *Participant* understanding of the MASS

No submissions on this issue were received in the first stage of consultation.

5.1.13.1 Summary of Issue raised in the second stage of consultation

In their submission to the second stage of consultation AETV Power raised the following issue:

“...the delivery of market ancillary services, their specification and performance verification is complex and requires close examination to gain even a reasonable understanding of the issues.

“To assist participants it would be helpful if the MASS contained an appendix outlining implications for registration and implementation of various MASS settings.”

5.1.13.2 AEMO Response to submissions to the second stage of consultation

AEMO agrees with AETV power that the MASS is complex and can be difficult to understand. However AEMO would prefer not to provide this information as an appendix to the MASS as there would need to be a *Rules* consultation undertaken each time the appendix needed to be updated.

AEMO will investigate the best way to provide this information and would welcome feedback from participants on their preferences. Possible methods of providing this include publication on the AEMO website or as part of the information supplied to participants intending to register in the NEM.

5.1.13.3 The Final Outcome

AEMO will make available information regarding implications for registration and implementation of various MASS settings.

6. Determination

AEMO determines to amend the MASS in accordance with *Rules 3.11.2(b), 3.11.2(c) and 3.11.2(d)* and issue as version 3.0 in the form of Attachment 2.

7. Glossary

Italicised terms in this document have their meaning as defined in Chapter 10 of the National Electricity Rules. Capitalised terms bear the meaning given in the table below:

ABBREVIATION OR TERM	DEFINITION
<i>AEMO</i>	has the meaning given to it in the <i>Rules</i>
<i>ancillary service generating unit</i>	has the meaning given to it in the <i>Rules</i>
<i>ancillary service load</i>	has the meaning given to it in the <i>Rules</i>
<i>availability factor</i>	for an <i>ancillary service generating unit</i> means the amount of time in a calendar year as a percentage that the <i>ancillary service generator</i> would expect to be <i>supplying</i> electricity to the <i>power system</i> for an <i>ancillary service load</i> means the amount of time in a calendar year as a percentage that the <i>ancillary service load</i> would expect to be consuming electricity from the <i>power system</i>
<i>central dispatch</i>	has the meaning given to it in the <i>Rules</i>
<i>combined switching controllers</i>	a switching <i>control system</i> that uses a combination of <i>frequency deviation</i> and <i>frequency rate of change</i> to initiate delivery of contingency <i>market ancillary services</i>
<i>connected</i>	has the meaning given to it in the <i>Rules</i>
<i>control system</i>	has the meaning given to it in the <i>Rules</i>
<i>credible contingency event</i>	has the meaning given to it in the <i>Rules</i>
<i>delayed lower service</i>	has the meaning given to it in the <i>Rules</i>
<i>delayed raise service</i>	has the meaning given to it in the <i>Rules</i>
<i>DI</i>	dispatch interval
<i>dispatch interval</i>	has the meaning given to it in the <i>Rules</i>
<i>DPRG</i>	Dispatch and Pricing Reference Group
<i>electrical island</i>	means a part of the <i>power system</i> that includes <i>generation, networks and load</i> , for which all of its network connections with other parts of the <i>power system</i> have been disconnected, provided that the part does not include more than half of the <i>generation</i> of each of two regions (determined by available capacity before disconnection).
<i>enabled</i>	has the meaning given to it in the <i>Rules</i>

<i>fast lower service</i>	has the meaning given to it in the <i>Rules</i>
<i>fast raise service</i>	has the meaning given to it in the <i>Rules</i>
<i>FCAS</i>	Frequency Control Ancillary Services. Defined in the <i>Rules</i> as <i>market ancillary services</i> .
<i>frequency</i>	has the meaning given to it in the <i>Rules</i>
<i>frequency dead-band</i>	means the range of local <i>frequency</i> through which a <i>proportional controller</i> will not operate
<i>frequency deviation setting</i>	the value in column 3 of table 3 (<i>MASS</i>) for <i>regions</i> other than Tasmania and the value in column 3 of Table 4 (<i>MASS</i>) for the Tasmania <i>region</i>
<i>frequency disturbance</i>	means an occasion when the <i>power system frequency</i> moves outside the <i>normal operating frequency band</i>
<i>frequency disturbance time</i>	means the time at which the <i>local frequency</i> falls or rises outside the <i>normal operating frequency band</i> during a <i>frequency disturbance</i> referenced to Australian Eastern Standard Time
<i>frequency operating standards</i>	has the meaning given in the <i>Rules</i> , as applicable to the region in which the relevant <i>ancillary service generating unit</i> or ancillary service <i>load</i> is located
<i>frequency ramp rate</i>	means 0.4 Hz per second in Tasmania and 0.125 Hz per second elsewhere
<i>frequency rate of change setting</i>	means a value in column 4 in table 3 or 4, for a mainland <i>region</i> or Tasmania <i>region</i> respectively, which corresponds to the allocated <i>frequency setting</i> .
<i>frequency recovery</i>	[the following amended definition is proposed in this consultation] means the first change in local frequency from above 50.15 Hz to below 50.1 Hz, or below 49.85 Hz to above 49.9 Hz, to occur after a frequency disturbance
<i>frequency reference time</i>	means the absolute value of 50 minus the appropriate <i>raise reference frequency</i> or <i>lower reference frequency</i> divided by the appropriate <i>frequency ramp rate</i>
<i>frequency setting</i>	means a level of <i>frequency</i> determined by AEMO in accordance with the procedure set out in section 6.2 of the <i>MASS</i> and notified in writing to the <i>Market Participant</i> for use by a <i>switching controller</i> or a <i>combined switching controller</i> for a particular <i>ancillary service generating unit</i> or <i>ancillary service load</i> when providing a particular <i>market ancillary service</i>
<i>generating unit</i>	has the meaning given to it in the <i>Rules</i>
<i>generation</i>	has the meaning given to it in the <i>Rules</i>
<i>generation amount</i>	means the amount of power flow through the <i>connection point</i> of an

	<i>ancillary service generating unit</i> , measured in MW, flow from the <i>ancillary service generating unit</i> being positive
<i>generation event</i>	has the meaning given or implied in the relevant <i>frequency operating standards</i>
<i>high availability</i>	means an <i>ancillary service generating unit</i> or <i>ancillary service load</i> with an <i>availability factor</i> greater than 70%
<i>inertial response</i>	means the change in <i>generation amount</i> or <i>load amount</i> due to the effect of the inertia of the <i>ancillary service generating unit</i> or <i>ancillary service load</i>
<i>initial value</i>	means the <i>generation amount</i> or <i>load amount</i> just prior to the <i>frequency disturbance time</i> of a <i>frequency disturbance</i>
<i>intermediate availability</i>	means an <i>ancillary service generating unit</i> or <i>ancillary service load</i> with an <i>availability factor</i> between 70% and 30%
<i>load</i>	has the meaning given to it in the <i>Rules</i>
<i>load amount</i>	means the amount of power flow through the <i>connection point</i> of an <i>ancillary service load</i> , measured in MW, flow towards the <i>ancillary service load</i> being negative
<i>load event</i>	has the meaning given or implied in the relevant <i>frequency operating standards</i>
<i>local frequency</i>	means the <i>frequency</i> of the electricity delivered by an <i>ancillary service generating unit</i> or consumed by an <i>ancillary service load</i> , measured in Hz
<i>low availability</i>	means an <i>ancillary service generating unit</i> or <i>ancillary service load</i> with an <i>availability factor</i> less than 30%
<i>lower reference frequency</i>	means the containment <i>frequency</i> above 50 Hz for <i>load events</i> , as given in the relevant <i>frequency operating standards</i>
<i>lower response</i>	means the decrease in <i>generation amount</i> or increase in <i>load amount</i> with respect to the corresponding <i>initial value</i>
<i>market ancillary service</i>	has the meaning given to it in the <i>Rules</i>
<i>market ancillary service offer</i>	has the meaning given to it in the <i>Rules</i>
<i>Market Participant</i>	has the meaning given to it in the <i>Rules</i>
<i>MASS</i>	<i>Market Ancillary Services Specification</i> as contemplated by clause 3.11.2(b) of the <i>Rules</i>
<i>multiple contingency event</i>	has the meaning given or implied in the relevant <i>frequency operating standards</i>
<i>network event</i>	has the meaning given or implied in the relevant <i>frequency operating standards</i>
<i>normal operating frequency band</i>	has the meaning given to it in the <i>Rules</i>
<i>power system</i>	has the meaning given to it in the <i>Rules</i>
<i>proportional controller</i>	the following amended definition is proposed in this consultation a

	<i>control system</i> that controls the amount of <i>market ancillary service</i> delivery in relation to the difference between <i>local frequency</i> and 50 Hz in an essentially continuous manner when <i>local frequency</i> is not within the range of the <i>control system's frequency dead-band</i>
<i>raise reference frequency</i>	means the containment <i>frequency</i> below 50 Hz for <i>generation</i> events, as given in the relevant <i>frequency operating standards</i>
<i>raise response</i>	means the increase in <i>generation</i> amount or decrease in <i>load</i> amount with respect to the corresponding <i>initial value</i>
<i>region</i>	has the meaning given to it in the <i>Rules</i>
<i>response capability</i>	has the meaning given to it in the <i>Rules</i>
<i>Rules</i>	National Electricity <i>Rules</i>
<i>scheduled generating unit</i>	has the meaning given to it in the <i>Rules</i>
<i>scheduled load</i>	has the meaning given to it in the <i>Rules</i>
<i>semi-scheduled generating unit</i>	has the meaning given to it in the <i>Rules</i>
<i>separation event</i>	has the meaning given or implied in the relevant <i>frequency operating standards</i>
<i>slow lower service</i>	has the meaning given to it in the <i>Rules</i>
<i>slow raise service</i>	has the meaning given to it in the <i>Rules</i>
<i>standard frequency ramp</i>	means a linear change of <i>local frequency</i> from one level to another at the applicable <i>frequency ramp rate</i> and then sustained
<i>supply</i>	has the meaning given to it in the <i>Rules</i>
<i>switching controller</i>	means a <i>control system</i> that delivers a specific amount of service when one or more specified conditions are met
<i>system frequency</i>	means a <i>frequency</i> measured by or for AEMO that represents the <i>frequency</i> of the <i>power system</i> to which the <i>ancillary service generating unit</i> or <i>ancillary service load</i> is connected
<i>time average</i>	means, in respect of a <i>raise response</i> or <i>lower response</i> and a time interval, the average value of that <i>raise response</i> or <i>lower response</i>
<i>trigger range</i>	For the Tasmania <i>region</i> , means the contiguous range comprising the upper 25% of the range between 50 Hz and the <i>raise reference frequency</i> and the lower 25% of the range between 50 Hz and the <i>lower reference frequency</i> For <i>regions</i> other than Tasmania, means the contiguous range comprising the upper 40% of the range between 50 Hz and the <i>raise reference frequency</i> and the lower 40% of the range between 50 Hz and the <i>lower reference frequency</i>

Appendix 1 – Submissions received

AETV Power

ISSUE	TOPIC	ISSUE	AEMO RESPONSE	OUTCOME
Material Issue - 3	Procedure for allocating delayed services	See section 5.1.3	See section 5.1.3	See section 5.1.3.
Material Issue 13	Participant understanding of the MASS	See section 5.1.13	See section 5.1.13	See section 5.1.13
Minor Issue	Definition of <i>proportional controller</i>	<p><u>From AETV Power's submission to the second stage of consultation:</u></p> <p>Rather than using "the difference between local frequency and 50 Hz" it might be better to use "a smooth function of local frequency variation from 50 Hz" as using "difference" alone would appear to preclude integral and differential controller functions.</p>	AEMO agrees that it would be better to use "a function of variation from 50 Hz" rather than "difference from 50 Hz".	<p>Definition of <i>proportional controller</i> changed to:</p> <p>a <i>control system</i> that controls the amount of service delivery in relation to a function of the variation of <i>local frequency</i> from 50 Hz in an essentially continuous manner when <i>local frequency</i> is not within the range of the <i>control system's frequency dead-band</i></p>
Minor Issue	The wording of section 2.6(a)(iii) of the MASS	<p><u>From AETV Power's submission to the second stage of consultation:</u></p> <p>The wording in section 2.6(a)(iii) as currently drafted suggests that the measurements are adjusted for inertial response by adding the RTi</p>	AEMO agrees that the section 2.6(a)(iii) should not make reference to inertial response.	<p>Section 2.6(a)(iii) changed to:</p> <p>"adjust each power measurement (P_i at time interval i) after the <i>frequency disturbance</i> for changing <i>dispatch</i> targets by first adding to it:</p>

Minor Issue	The wording of section 2.5(b) of the MASS	<p>where in fact section 2.6(a)(iv) makes the inertial response adjustments.</p> <p><u>From AETV Power's submission to the second stage of consultation:</u></p> <p>Suggested wording:</p> <p>...to determine the separate amounts of raise or lower response supplied by the <i>proportional controller</i> and <i>switched controller</i>...</p>	AEMO agrees with the suggested wording	<p>....."</p> <p>Section 2.5(b) changed to:</p> <p>If the <i>control system</i> is a discrete combination of a <i>proportional controller</i> and a <i>switched controller</i> then there must be a process in place to determine the separate amounts of <i>raise response</i> or <i>lower response</i> supplied by the <i>proportional controller</i> and the <i>switching controller</i>. This can be through separate metering or from <i>control system</i> data logged at the time of the <i>frequency disturbance</i> or application of appropriate <i>control system</i> models.</p>
Minor Issue	The wording of section 2.6(a)(v) of the MASS	<p><u>From AETV Power's submission to the second stage of consultation:</u></p> <p>For readability the reference to SA could include "as set out in section 3.6(a)(v)".</p>	AEMO agrees that a reference to section 3.6(a)(v) would be useful.	<p>Section 2.6(a)(v) changed to:</p> <p>determine value FA as the <i>time average</i> of the adjusted power measurements made during the period between four and two seconds before the <i>frequency disturbance time</i> if <i>slow raise service</i> or <i>slow delayed service</i> has not been <i>enabled</i>. If <i>slow raise service</i> or <i>slow delayed service</i> has</p>

Minor Issue	The wording of section 6.2 of the MASS	<p><u>From AETV Power's submission to the second stage of consultation:</u></p> <p>The allocation of frequency settings is based upon Rules defined term "response capability" which relates to the market ancillary services in particular:</p> <p>"the amount of the response in (MW) which is specified in the offer"</p> <p>It would appear that another definition of other than "response capability" is required – possibly "registered capability"</p>	AMEO believes that "maximum response capability" would be a better term to use than "response capability". The only exception is section 6.2(a)(iv) where "response capability" is the correct term.	<p>been <i>enabled</i> then FA is equal to SA as described in section 3.6(a)(v);</p> <p>Change all instance of "response capability" to "maximum response capability" in section 6.2 of the MASS, except for section 6.2(a)(iv).</p>
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CS Energy

ISSUE	TOPIC	ISSUE	AEMO RESPONSE	OUTCOME
Material Issue – 9	Consistent base for verification calculations	See section 5.1.9	See section 5.1.9	See section 5.1.9
Material Issue - 10	Data smoothing algorithms	See section 5.1.10	See section 5.1.10	See section 5.1.10
Material Issue - 1	Accounting for changing	See section 5.1.1	See section 5.1.1	See section 5.1.1

Material Issue - 4	dispatch in FCAS delivery Definition of <i>Frequency recovery</i>	See section 5.1.4	See section 5.1.4	See section 5.1.4
Material Issue - 6	<i>Proportional controller compensation</i>	See section 5.1.6	See section 5.1.6	See section 5.1.6
Material Issue - 5	<i>Switching controller compensation</i>	See section 5.1.5	See section 5.1.5	See section 5.1.5
Minor Issue	Compensation calculations for change in dispatch – sections 2.6(a)(ii), 3.6(a)(ii) and 4.6(a)(ii)	<p><u>From CS Energy's submission to the second stage of consultation:</u></p> <p>2.6(a)(ii), 3.6(a)(ii) and 4.6(a)(ii)</p> <p>All instances of RT_i are equal to:</p> <p>"the value of the reference trajectory at time t_i, corresponding to the power measurement P_i, plus RT₀"</p> <p>should be</p> <p>"RT₀ minus the value of the reference trajectory at time t_i, corresponding to the power measurement P_i"</p>	AEMO accepts the correction made by CS Energy.	Sections 2.6(a)(ii), 3.6(a)(ii) and 4.6(a)(ii) changed to: " RT ₀ minus the value of the reference trajectory at time t _i , corresponding to the power measurement P _i "
Minor Issue	Corrections to sections 2.6(a)(i), 3.6(a)(i), 4.2(b), 4.3(b) and 4.6(a)(i) of the MASS	<p><u>From CS Energy's submission to the second stage of consultation:</u></p> <p>4.2(b) and 4.3(b) both still refer to 5 to 15 minute</p>	AEMO accepts the corrections made to the MASS.	Sections 4.2(b) and 4.3(b) have been changed to refer to a "5 to 10 minute" evaluation period.

		for the DC of the raise/lower delayed service period, while it should be 5 to 10 minutes as per 4.6(a)(x) . The specified range of trajectory “the next four dispatch targets” only needs to be “the next three dispatch intervals”...		Sections 2.6(a)(i), 3.6(a)(i) and 4.6(a)(i) of the MASS now specify the range of the trajectory as: “The reference trajectory is to start at the with the initial loading at the beginning of the dispatch interval in which the frequency deviation occurs and is two continue for the proceeding two dispatch intervals.”
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Hydro Tasmania

ISSUE	TOPIC	ISSUE	AEMO RESPONSE	OUTCOME
Minor Issue	Using <i>frequency</i> rate of change to initiate delivery of a <i>market ancillary service</i>	<p><u>From section 1 of Hydro Tasmania’s submission to the first stage of consultation:</u></p> <p>Our interpretation of Section 10 is that it offers a practical path for implementation of the df/dt trigger to accelerate operation of switching controllers for large disturbances.</p> <p>Hydro Tasmania believes that AEMO’s proposal is workable and provides improved performance. Once implemented, operating experience will allow further improvements, should they be justified.</p>	No Response	No change to proposed MASS

Material Issue - 7	Combined controller compensation	See section 5.1.7.1	See section 5.1.7	See section 5.1.7
Minor Issue	Definition of a <i>proportional controller</i>	<u>From section 3 of Hydro Tasmania's submission to the first stage of consultation:</u> Hydro Tasmania supports the proposed change to the definition however we would like to add to the definition recognition of saturation in machine response...	AEMO believes that the current definition of <i>proportional controller</i> in the MASS is broad enough to incorporate saturation in machine response.	No change to proposed MASS
Material Issue - 6	<i>Proportional controller</i> compensation	See section 5.1.6	See section 5.1.6	See section 5.1.6
Material Issue - 5	<i>Switching controller</i> compensation	See section 5.1.5	See section 5.1.5	See section 5.1.5
Material Issue - 8	Verification calculations for combined services	See section 5.1.8	See section 5.1.8	See section 5.1.8
Material Issue - 2	Improving the performance of delayed services	See section 5.1.2	See section 5.1.2	See section 5.1.2
Material Issue - 10	Data smoothing algorithms	See section 5.1.10	See section 5.1.10	See section 5.1.10
Material Issue - 1	Accounting for changing dispatch in FCAS delivery	See section 5.1.1	See section 5.1.1	See section 5.1.1
Material Issue - 4	Definition of <i>Frequency recovery</i>	See section 5.1.4	See section 5.1.4	See section 5.1.4
Material Issue - 3	Procedure for allocating delayed services	See section 5.1.3	See section 5.1.3	See section 5.1.3

National Generators Forum (NGF)

ISSUE	TOPIC	ISSUE	AEMO RESPONSE	OUTCOME
Material Issue - 1	Accounting for changing dispatch in FCAS delivery	See section 5.1.1	See section 5.1.1	See section 5.1.1
Minor Issue	Compensation for delayed service response	<p><u>From section 2 of the NGF's submission to the first stage of consultation::</u></p> <p>The NGF supports the inclusion of proportional controllers for the delayed services, but only if the compensation arrangement in relation to frequency that apply to fast and slow service are also included for the delayed services.</p>	<p>In the NGF's meeting with AEMO on 18 November 2009 it was noted:</p> <p>The NGF desires that the same proportion controller compensation that is used in the verification calculations for fast and slow services be applied to delayed services.</p> <p>This was the methodology proposed by AEMO in section 4.6(a)(vii) of the then proposed MASS (version 2.01) .</p>	No change to proposed MASS
Material Issue – 9	Consistent base for verification calculations	See section 5.1.9	See section 5.1.9	See section 5.1.9
Material Issue - 2	Improving the performance of delayed services	See section 5.1.2	See section 5.1.2	See section 5.1.2

Material Issue - 10	Data smoothing algorithms	See section 5.1.10	See section 5.1.10	See section 5.1.10
Material Issue - 4	Definition of <i>Frequency recovery</i>	See section 5.1.4	See section 5.1.4	See section 5.1.4
Material Issue - 8	Verification calculations for combined services	See section 5.1.8	See section 5.1.8	See section 5.1.8

Attachment 1 – Copy of the Notice of Second Stage of Rules Consultation

[National Electricity Rules Clause 8.9]

AMENDMENTS TO THE MARKET ANCILLARY SERVICES SPECIFICATION

This Notice of Second State of Rules Consultation informs all Consulted Persons of the second stage of consultation on *Amendments to the Market Ancillary Services Specification*.

This consultation is being conducted under clauses 3.11.2(b), 3.11.2(c) and 3.11.2(d) of the *National Electricity Rules (Rules)* in accordance with the *Rules* consultation requirements detailed in clause 8.9 of the *Rules*.

Date of notice

This Notice of Second Stage of Rules Consultation was issued on 21 December 2009.

First Stage of Consultation

AEMO issued the Notice of First Stage of Rules Consultation on 21 September 2009, together with an issues paper and a proposed updated *Market Ancillary Services Specification (MASS)* version 2.01.

Four submissions were received. All non-confidential submissions have been published on the AEMO website.

Three parties requested meetings, which were subsequently held. The minutes of these meetings are available from the AEMO website.

AEMO has considered the issues raised in the submissions and at the meetings and has now produced a Draft Determination and Report.

The Draft Determination and Report is now available to all Consulted Persons for their consideration.

Objectives of the consultation

The objectives of the consultation are:

- To provide Consulted Persons with the opportunity to be involved in the development of *Market Ancillary Services Specification*.
- To ensure that Consulted Persons are properly informed about the proposed changes and the final outcome.

Background

On 5 May 2009 NEMMCO published the final determination of a Rules consultation to amend the *MASS*. The object of the consultation was to amend the *MASS* to reflect the changes to be made to the Tasmania region *frequency operating standards* so that the implementation of the new standard could proceed.

For the purpose of meeting the implementation timetable of the revised Tasmania region *frequency operating standards* it was decided to defer a number of issues raised in the previous consultation to this current consultation. AEMO is now proposing to examine these and other issues in the current *MASS* consultation.

A number of the issues covered in this consultation were part of a submission made by Hydro Tasmania to the earlier consultation completed on 5 May 2009. These issues are:

1. Using *frequency* rate of change to initiate delivery of a *market ancillary service*;
2. Using a combined *switched* and *proportional control system* to deliver *market ancillary services*;
3. The definition of a *proportional controller*;
4. The scaling factor used in verification methods for *proportional* control;
5. Verification methods for *switching* control; and
6. Verification methods for slow and delayed raise and lower services.

In addition to the issues raised by Hydro Tasmania there are other issues which AEMO believes are important to address. These are:

1. Improving the performance of delayed *FCAS*;
2. Use of a smoothing function in *FCAS* verification calculations;
3. Accounting for changing *dispatch* targets in *FCAS* verification calculations;
4. The definition of *frequency recovery* in the *MASS*;
5. The procedure for allocating *frequency settings* for *switched controllers* in order to take into consideration *service availability*; and
6. Adjusting the *trigger range* for data recorders in the Tasmania *region* to take into account changed *frequency operating standards*

In particular, AEMO seeks to recover the *power system frequency* to the *normal operating frequency band* within 5 minutes of a *credible contingency event*, as required by the *frequency operating standards*. This will involve a review of the relevant sections in the *MASS* relating to delayed raise and lower services.

Matter under consultation

The matter under consultation is identified in clauses 3.11.2(b), 3.11.2(c) and 3.11.2(d) of the Rules. These clauses provide:

3.11.2 Market ancillary services

- (b) *AEMO* must make and *publish* a *market ancillary service specification* containing:
- (1) a detailed description of each kind of *market ancillary service*; and
 - (2) the performance parameters and requirements which must be satisfied in order for a service to qualify as the relevant *market ancillary service* and also when a *Market Participant* provides the relevant kind of *market ancillary service*.
- (c) *AEMO* may amend the *market ancillary service specification*, from time to time.
- (d) *AEMO* must comply with the *Rules consultation procedures* when making or amending the *market ancillary service specification*.

The consultation process

The following table contains an outline of the consultation process, including key dates. Please note that some of these dates are proposed dates and may be subject to change by AEMO.

PROCESS	DATE
Closing date for submissions received in response to this Notice of Second Stage of Rules Consultation	22 January 2010
Publication of the draft determination and invitation to make submissions in response to the Draft Determination and Report	21 December 2009
Closing date for submissions received in response to the Draft Determination and Report	22 January 2010
Publication of the Determination and Report	Currently, proposed date is 5 March 2010


Invitation to make submissions

AEMO invites submissions on the Draft Determination and Report on Amendments to the *Market Ancillary Services Specification*.

Please identify any information in your submission that you consider to be confidential and provide the reasons why you wish that information to be treated as confidential. AEMO reserves the right to publish material that it does not consider to be confidential, despite your submission as to its confidentiality.

You should also note that material identified as confidential may be accorded less weight in the decision-making process than material that is published.

Closing date for submissions



Submissions in response to this Notice of Second Stage of *Rules* Consultation should reach AEMO by 5:00pm EST on 22 January 2010.

AEMO has a discretion to consider late submissions. Any late submission should explain:

- the reason for the lateness; and
- the detriment to you if AEMO fails to consider your submission.

Contact details

AEMO prefers that submissions be forwarded in electronic format (both pdf and Word) as they will be published on the AEMO website.

Please send all e-mail submissions to James Lindley at james.lindley@aemo.com.au.

Alternatively, you may post submissions to:

James Lindley
GPO Box 2516
Mansfield, QLD 4122



Attachment 2 – Copy of Market Ancillary Services Specification, version 3.0