Regulation FCAS Contribution Factor Procedure
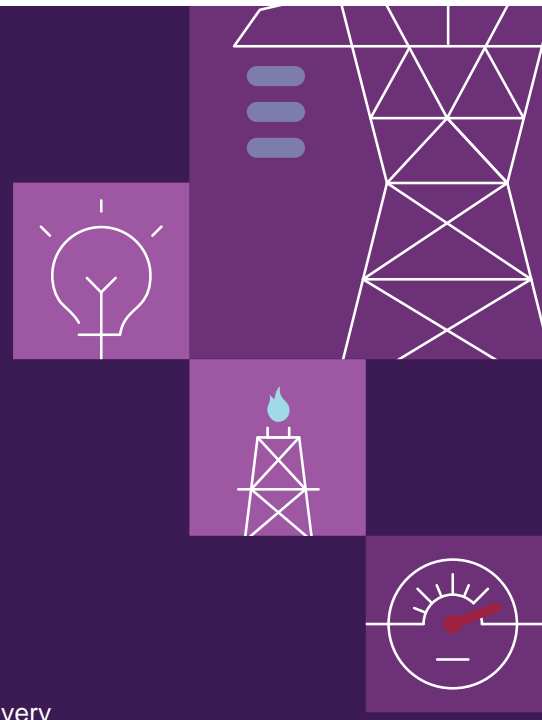
Determination of Contribution Factors for Regulation FCAS Cost Recovery

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Current version release details

Version	Effective date	Summary of changes
1.0	14 August 2001	First Issue following National Electricity Code Determination Report on 'Impementation of Causer Pays for Small Deviation FCAS'
2.0	1 December 2006	Amended procedure
3.0	1 January 2009	Amended for *Cost Recovery of Localised Regulation Services* and *Central Dispatch and Integration of Wind and Other Intermittent Generation* Rule Changes
4.0	15 December 2013	Amended for *Market Small Generation Aggregator* (SGA) Rule Change.
5.0	3 March 2017	Amended for determination of NEM Dispute Resolution Panel dated 3 October 2016 to specify a procedure for determining relevant contribution factors when a *region* operates asynchronously.
6.0	2 December 2018	Amended to provide for: • Adjustment of performance measure calculations where frequency indicator (FI) value does not correlate with system frequency. • Expansion of general principles to remove unnecessary detail but cover all material parts of the process and recent market and system changes, including dealing with physical facilities represented as multiple dispatchable units. Overall restructure and revision to improve clarity, readability, accuracy and consistency with rules and process.
7.0		Amended to enable aggregated dispatch conformance under the National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021.

1. Introduction

1.1. Purpose and scope

This is the procedure for the determination of contribution factors made under clause 3.15.6A(k) of the National Electricity Rules (**NER**) (**Procedure**).

The Contribution Factors determined under this Procedure represent the values of 'MPF' applied in the calculations set out in clause 3.15.6A(i) of the NER, to determine trading amounts for the recovery of amounts determined under clause 3.15.6A(a) for *regulating raise services* and *regulating lower services* (**Regulation FCAS**).

This Procedure has effect only for the purposes set out in the NER. The NER and the National Electricity Law prevail over this Procedure to the extent of any inconsistency.

1.2. Definitions and interpretation

1.2.1. Glossary

Terms defined in the National Electricity Law and the NER have the same meanings in these Procedures unless otherwise specified in this clause.

Terms defined in the NER are intended to be identified in these Procedures by italicising them, but failure to italicise a defined term does not affect its meaning.

In addition, the words, phrases and abbreviations in the table below have the meanings set out opposite them when used in these Procedures.

Term	Definition
4-second performance measure	A factor determined for a 4-second interval
5-minute factor	Intermediate aggregation of 4-second performance measures into different categories, as outlined in clause 6.1
ACE	Area control error
ADC Facility	A portfolio of *generating units* and *loads* that was selected at the time of registration to have Portfolio ADC.
ADE	Aggregate dispatch error
ADF	Area deviation factor
ADRF	Area deviation residual factor
AEMO	Australian Energy Market Operator Limited
AFF	Area forecast error factor
AFMNS	The component of AFF allocated to appropriately metered *market non-scheduled generation* and *load*.
AFRF	Area forecast error residual factor. This is associated with the deviation of the least squares line of best fit of non-scheduled *power system* demand for a DI with the forecast demand for that DI.
AGC	*Automatic generation control system*
AMNSF	Aggregate performance factor for appropriately metered *market non-scheduled generating units* and *loads* in a given area, including its contribution to AFF.
AMNSTOT	Total of the performance factors for appropriately metered *market non-scheduled generating units* and *loads* in a given area (before adjustment for AFF and ADF).

Term	Definition
AMSF	Metered and *scheduled generating unit* and *scheduled load* factor.
Appropriate metering	*Metering* with the capability to record the *active power* output or consumption of *plant* at intervals of not more than 4 seconds in the Mainland area, and not more than 8 seconds in Tasmania.
Area	An area of AGC continuously modelled as a separate system, being Mainland and Tasmania.
AreaMPF$_{MNS}$	Area MPF for a *Market Participant's* non-scheduled portfolio
AreaMPF$_{RES}$	Area MPF for residual demand
AreaMPF$_{SSS}$	Area MPF for a *Market Participant's* scheduled and semi-scheduled portfolio
APF$_{SSS}$	Portfolio performance factor assigned for the scheduled and semischduled part of the portfolioa for the 28 day period.
APF$_{NS}$	Portfolio performance factor assigned for the scheduled and semischduled part of the portfolioa for the 28 day period.
ARLF	Area residual load factor
ATF	Total area factor, used to produce normalised Contribution Factors.
CMPF	Constraint MPF (see clause 8.3)
Contingency FCAS	*Fast raise services*, *slow raise services*, *delayed raise services*, *fast lower services*, *slow lower services* and *delayed lower services*.
Contribution Factor	The factor that represents the percentage of Regulation FCAS costs for which a particular *Market Participant* is liable.
CRMPF	Constraint residual MPF (see clause 8.3)
Deviation	The difference (in MW) of a measurement of *active power* and the reference trajectory for a facility.
DF	Demand forecast offset
DG	Demand measured at *generating unit* terminals
DGB	Base demand at *generating unit* terminals
DGEN	5-minute dispatchable *generation*
DGX	Ex-post least squares line of best fit for demand measured at *generating unit* terminals
DI	A 5-minute *dispatch interval*
DM	Measured demand
DMX	Measured demand at the beginning of a DI
EMS	AEMO's Energy Management System
FCAS	*Frequency control ancillary service*
FL	5-minute *interconnector* flow
Frequency Indicator (FI)	The parameter from AEMO's AGC[1] indicating the extent to which more or less *generation* is required to adjust the *frequency* towards 50 Hz. The sign of FI indicates the direction of *regulating capability* required at a given time (positive for a *regulating raise service*, negative for a *regulating lower service*). This value is capped and has positive and negative limits of +/- 1560. It can be calculated by summing the published GenRegComp_MW values in the area.
G	Measured *generating unit* output
GB	*Generation* at *generating unit* terminals

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[1] This parameter is labelled in AEMO's AGC as 'Regulation requirement'

Term	Definition
GenRegComp_MW	The raw amount of Regulation FCAS allocated to a *generating unit* by the AGC. This is later modified by the unit control model.
GSSL	An equation/data source relating to *semi-scheduled generating units*
IL	5-minute *interconnector* loss
IRE	*Inter-regional* export, measured at *region* boundary
IREB	Base *inter-regional* flow measured at RRN
IRL	*Inter-regional* losses
IRLB	Base *inter-regional* losses
LEF	Lower-enabled factor. Assigned to *market scheduled generating units* or *scheduled loads* that are *enabled* for *regulating lower service* (lower-enabled).
LNEF	Lower non-enabled factor. Assigned to appropriately metered system components that either not lower-enabled or that cannot be lower-enabled.
Mainland	All *regions* of the *NEM* except Tasmania.
MLF	Marginal loss factor
EMMS	AEMO's Energy Market Management System producing 5-minute *market dispatch* data.
MPF	Market Participant factor. A term used with an approporiate descriptor to describe, for a *Market Participant* or category of *Market Participants*: a) a Contribution Factor in respect of a specified portfolio (for appropriately metered *generation* and *load*), or residual demand, being the final values of MPF applied in clause 3.15.6A(i) of the NER; or b) an interim factor calculated as a step in determining those Contribution Factors.
MPF$_{MNS}$	Normalised NEM Contribution Factor calculated for each *Market Participant* in respect of its appropriately metered *market non scheduled generation* and *load* portfolio.
MPF$_{RES}$	Normalised NEM Contribution Factor calculated for *Market Customers* in respect of residual demand.
MPF$_{SSS}$	Normalised NEM Contribution Factor calculated for each *Market Participant* in respect of its portfolio of *scheduled* and *semi-scheduled generation* and *scheduled load.*
MW	Megawatt
MWh	Megawatt hours
N	DI index
NEMDE	*NEM* dispatch engine
NER	National Electricity Rules
NI	5-minute *regional* net interchange (includes losses)
Non-scheduled generation forecast	A forecast of *non-scheduled generation* over a 5-minute period
Portfolio ADC	*Aggregated dispatch conformance as selected at the time of registration by generating units and loads within the same portfolio for a Market Participant.*
Residual	The percentage of costs assigned to *Market Customers* that do not have an MPFi Contribution Factor calculated for them.
Residual demand	Net demand from *generation* and load without appropriate metering.
REF	Raise-enabled factor. Assigned for system components *enabled* for *regulating raise service* (raise-enabled).
RNEF	Raise non-enabled factor. Assigned to appropriately metered system components that either are not raise-enabled or that cannot be raise-enabled.
Reference Trajectory	A pre-determined trajectory for a *scheduled generating unit*, or a forecast for a *semi-scheduled generating unit* or a *non-scheduled generating unit*.

Term	Definition
Region demand forecast error	Base demand at *generating unit* terminals minus the ex-post demand calculated as a 5-minute least-squares best-fit straight line through the measured values of the *regional* demand measured at *generating unit* terminals.
Regulation FCAS	*Regulating lower service* and *regulating raise service* (the same meaning as *regulation services* in the NER).
RAMPF	Regional Aggregate Market Particpation Factor (see clause 8.3)
RR	Regulating requirement
RRN	*Regional* reference node
RSPD	The *power system* demand for a *region* averaged over the sample period as determined by the EMS.
settlement factor	Factor calculated over the settlement period
system component	Any part of the *power system* that is not a *generating unit*, for instance an *interconnector* or *region*.
SCADA	Supervisory control and data acquisition system.
T	4-second time
TPSD	The total *power system* demand averaged over the sample period as determined by EMS
TI	*trading interval*

1.2.2. Interpretation

The following principles of interpretation apply to these Procedures unless otherwise expressly indicated:

a)   These Procedures are subject to the principles of interpretation set out in Schedule 2 of the National Electricity Law.

b)   References to time are references to Australian Eastern Standard Time.

1.3. Related documents

Reference	Title	Location
160-0392	Efficient Dispatch and Localised Recovery of Regulation Services Business Specification	https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/0160-0049-pdf.pdf

2.   General Principles

a)   AEMO *enables* Regulation FCAS to either raise or lower system frequency to counteract small changes in *power system frequency*, and any accumulation of these changes over time.

b)   Once *enabled*, Regulation FCAS are deployed as needed by AGC based on the detected system *frequency* and accumulated time error of the system.

c)   Contribution Factors are determined for the purpose of apportioning the costs of Regulation FCAS to *Market Generators, Market Customers* and *Market Small Generation Aggregators*, based on the assessed contribution of *plant* at their *connection points* to recent variations in system *frequency* causing the need for Regulation FCAS.

d)   The calculations for Contribution Factors assess deviations from a reference trajectory for each area, which is derived from expected *dispatch* or expected MW consumption. The *deviations* are calculated every four seconds and averaged over a DI.

e)   *Generating units* and *loads* that are under the same portfolio level for a given *Market Participant* have the option to select Portfolio ADC at the time of registration. If the Portfolio ADC option is selected, then a single AGC setpoint will be allocated across all *generating units* and *loads* within the resulting ADC Facility. The Causer Pays process will then aggregate them as one in the ADC Facility.

f)   The ADC Facility in its entirety will be considered as:

   (i)   enabled if any of its *generating units* or *loads* is enabled for Regulation FCAS (Raise or Lower Services) for a given interval; or

   (i)(ii)   not enabled if none of its *generating units* or *loads* is enabled for Regulation FCAS (Raise or Lower Services) for a given interval.

d)g)   For these purposes AEMO may, where it considers appropriate, elect to assess the deviation of appropriately metered plant with more than one NER classification as a single component, provided it is treated by the AGC as a single unit.[2]

e)h)   Interim factors are determined on an area basis and then normalised to produce NEM Contribution Factors for *Market Participants*.

f)i)   Individual Contribution Factors (MPF_{SSS} and MPF_{MNS}) are determined for *Market Participants* based on the net performance of their appropriately metered *market generation* and *market load* in each category (*scheduled/semi-scheduled* and *market non-scheduled*) over a 28 day historical sample period.

g)j)   A residual demand Contribution Factor (MPF_{RES}) is also calculated and attributed to *Market Customers* in proportion to their energy consumption. This residual demand factor represents the contribution of all *generating units*, *loads* and *market network services* that are not accounted for in the individual *Market Participant* Contribution Factors.

h)k)   Once calculated, the Contribution Factors are published and applied in *AEMO's* settlement systems across a 28 day application period.

i)l)   In the event of temporary asynchronous operation between Mainland regions, or for any other reason there is a *local ancillary service requirement* for Regulation FCAS, the Contribution Factors are applied only to those *Market Participants* relevant to the *region* in which the *local ancillary service requirement* arose.

3.   Overview of Calculation Process

a)   *Central dispatch* assumes that *load* consumption and *generating unit* output moves in a straight line trajectory from one 5-minute MW level to the next. Regulation FCAS provides the means to manage any variations from straight-line trajectories or any error in the straight-line trajectories themselves.

b)   Table 1Table 1 presents some of the potential sources of *frequency* deviation on the *power system*, and how they are allocated to components of *plant* and the associated *Market Participants* through the calculations described in this Procedure.

Table 1 Power system deviation sources

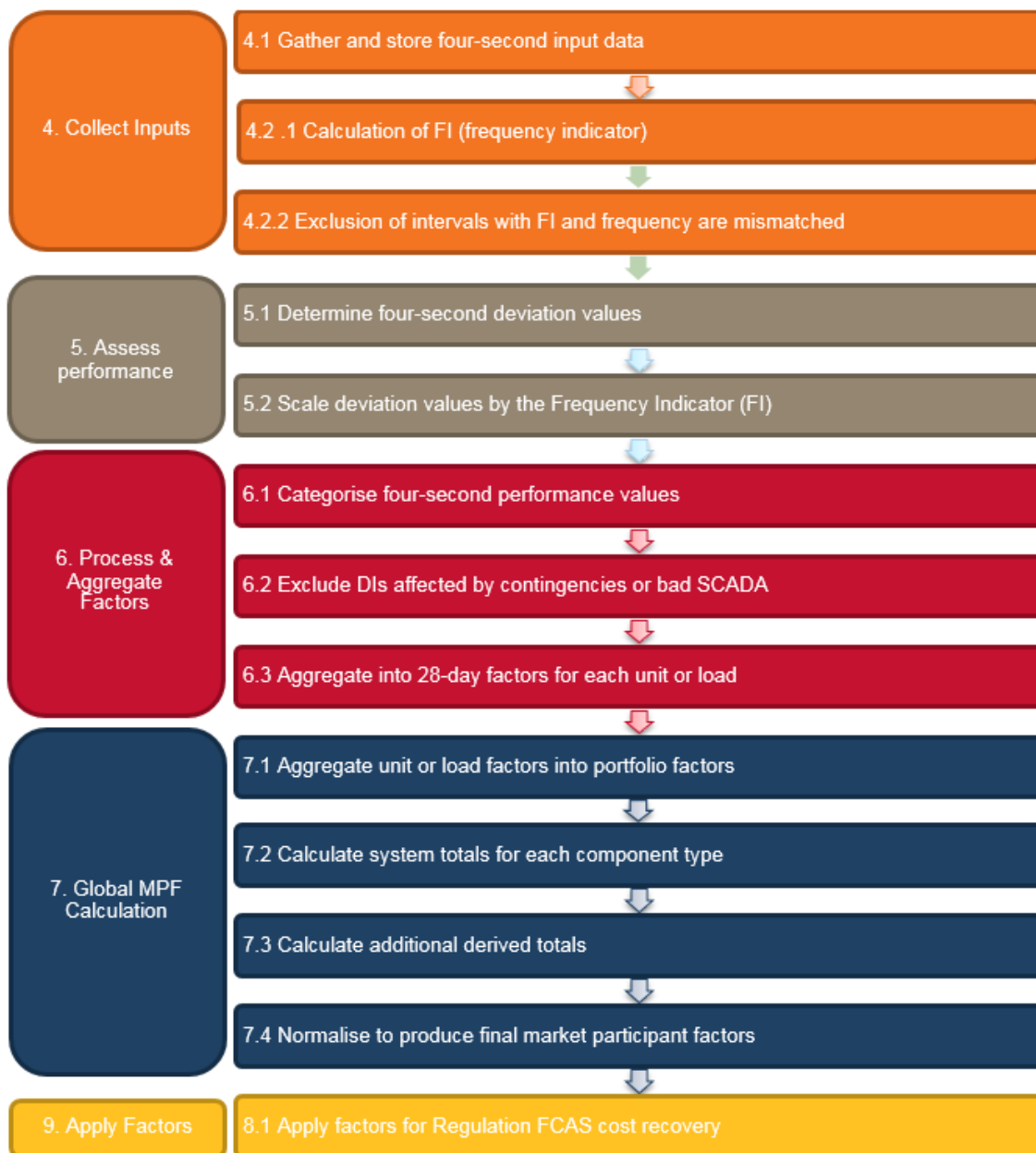| Component	Allocation
Deviation of *scheduled generating units and scheduled loads* from *dispatch schedule*.	To the specific *generating unit* or *load, or ADC Facility Portfolio* if the deviation exacerbated the overall *power system frequency* deviation.

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[2] An example is a battery that is classified as both a *scheduled generating unit* and a *scheduled load* depending on its mode of operation.

Component	Allocation
Deviation of *semi-scheduled generating units* from their forecast levels.	
Deviation of *non-scheduled generating units and loads* (with appropriate metering) from their initial conditions.	
Deviation of residual demand from its expected trajectory due to forecasting error.	To all *Market Customers* and Non-scheduled generating units and loads with appropriate metering
Deviation of residual demand from its expected trajectory due to non-linearity within a five-minute period.	
Region component of Area Demand Error Aggregate Dispatch Error (ADE)	Ignored.[3]

c) As individual Contribution Factors are only determined for *Market Generators*, *Market Customers* and *Market Small Generation Aggregators* in respect of their *connection points* with appropriate metering, the impact of non-linearity in:

    (i) *non-market generating units*;

    (ii) *market non-scheduled generating units* without appropriate metering;

    (iii) *market network services*; and

    (iv) residual demand from *loads* without appropriate metering,

is captured indirectly through the *regional* (residual) Contribution Factor.

d) An overview of the calculation process is provided in Figure 1Figure 1, where the numbering in the figure corresponds to the relevant clause numbers in this Procedure.

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[3] The ADE is an allowance made for expected *generating unit* non-conformance based on the current *generating unit* non-conformance. For assessment purposes, it is sufficient to assess *generating unit*s against their *scheduled dispatch* alone, without the ADE adjustment. It is also not appropriate to include the ADE adjustment with the demand forecast error.

Figure 1 Overview of calculation process

4. Collect Inputs	4.1 Gather and store four-second input data
	4.2 .1 Calculation of FI (frequency indicator)
	4.2.2 Exclusion of intervals with FI and frequency are mismatched
5. Assess performance	5.1 Determine four-second deviation values
	5.2 Scale deviation values by the Frequency Indicator (FI)
6. Process & Aggregate Factors	6.1 Categorise four-second performance values
	6.2 Exclude DIs affected by contingencies or bad SCADA
	6.3 Aggregate into 28-day factors for each unit or load
7. Global MPF Calculation	7.1 Aggregate unit or load factors into portfolio factors
	7.2 Calculate system totals for each component type
	7.3 Calculate additional derived totals
	7.4 Normalise to produce final market participant factors
9. Apply Factors	8.1 Apply factors for Regulation FCAS cost recovery

4. Collect Inputs

4.1. Gather 4-Second Data

4.1.1. Types of input data

There are four primary types of input data used to calculate Contribution Factors, described in clauses **Error! Reference source not found.** to **Error! Reference source not found.**:

a)   4-second *active power* measurement data;

b)   4-second Frequency Indicator value;

c)   5-minute demand forecasts and *generating unit* targets; and

d)   Contingency and data quality information;

e)   Frequency measurements.

4.1.2. 4-second active power measurement data

a)   SCADA measurements of *active power* for appropriately metered *generating units* and *loads* are captured from the EMS. This represents the most recent data available at each 4-second sample.

b)   AEMO's database application provides linear data interpolation in cases where the resolution of the *SCADA data* is larger than four-seconds, and in cases where interpolation is required across DI boundaries.

4.1.3. 4-second Frequency Indicator value

a)   The Frequency Indicator (FI) represents the total Regulation FCAS requirement identified by AEMO's AGC in a given 4-second period, and is sourced directly from AEMO's AGC SCADA dataset.

b)   Contribution Factor calculations include an FI weighting component based on the significance of a given deviation, and its direction (whether it increases or decreases the need for Regulation FCAS).

c)   More information on the FI value calculation is provided in clause 5.2.4.

4.1.4. 5-minute demand forecasts and generator targets

Demand forecasts and *dispatch instructions* are both used to calculate reference trajectories, against which the 4 second performance can be measured. *Dispatch* data is sourced directly from AEMO's MMS.

4.1.5. Frequency and data quality information

a)   Frequency measurements captured from the EMS are used to identify the observed *frequency*.

b)   Any reported issues on data quality are considered in the identification of SCADA data requiring additional verification checks.

c)   If any of the required four-second SCADA data for a DI is determined on verification to be of corrupt or questionable quality, the data is corrected where possible by reloading from an alternative source, such as a duplicate server.

d)   More information on the exclusion of data is provided in clause 6.2.

4.2. Estimated FIs and Preprocessing

4.2.1. Publication of estimated FI values

AEMO publishes indicative FI values close to real time as it understands this may be useful for *Market Participants*. These values are to be treated as subject to change because:

a)   they are produced by an automated system and not all of the data inputs may be available at the time of publication;

b) FI values are subject to manual verification and checks before applying them in Contribution Factor calculations.

4.2.2. Verification and exclusion of FI values

a) An FI value may not correlate to the net frequency error in any 4 second period for a number of reasons, including:

    (i) low pass filtering, which smooths any changes to the Regulation FCAS requirement in response to a sharp deviation in *frequency*;

    (ii) time error correction, which requires the AGC to target the *frequency* to get to a value other than the nominal *frequency*.

    (iii) the integral control part of the AGC logic, which adds a component to the Regulation FCAS requirement to correct the long term average of the *frequency* error; and

    (iv) deadbands applied for stability, which does not respond to small changes in frequency.

b) FI values in any 4 second period are excluded where either:

    (i) *frequency* > 50 Hz and FI > 0; or

    (ii) *frequency* <50Hz and FI <0.

c) If a significant proportion[4] of the 4-second FI values in the same DI are excluded under paragraph b), all performance data for the relevant DI and area will be excluded from Contribution Factor calculations.

d) If an abnormal frequency island (as defined in the *frequency operating standards*) forms within an area, separate FI values for each island are not determined and all performance data for the area for the duration of the islanding will be excluded from Contribution Factor calculations.

5. Assess Performance

5.1. Determine 4-Second Deviation Values
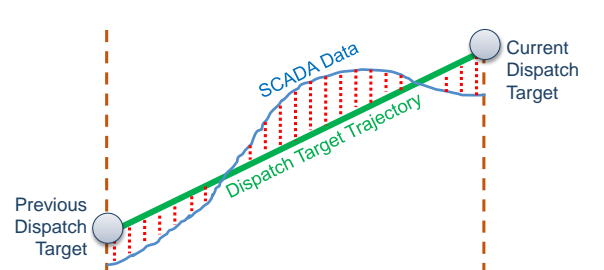
Four-second *deviation*s (in MW) are calculated by comparing SCADA measurements against a reference trajectory which differs depending on the deviation source. These calculations are described in the following clauses.

5.1.1. Scheduled and semi-scheduled plant

The reference trajectory for *scheduled generating units, semi-scheduled generating units* and *scheduled loads* is illustrated in Table 2.

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[4] To be determined by AEMO from time to time based on operational experience. As at ~~1 July 2018~~June 2021, AEMO considers the exclusion of ~~50~~66% or more of the FI values in a DI to be a significant proportion.

Table 2 Scheduled generating units, semi-scheduled generating units, and scheduled loads

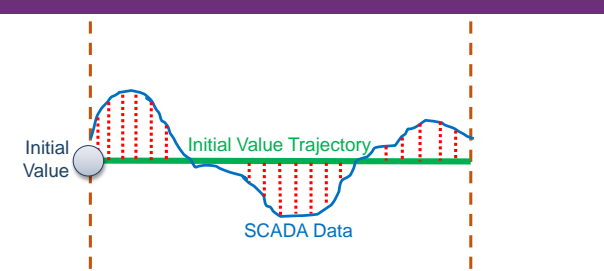| Reference Trajectory	Actual Measurement	Example
Straight line between previous *dispatch target* and current *dispatch target*.	SCADA metering data for the unit or load.	
GS(t) Source: straight line between total cleared values	*G(t)* Source: SCADA metered value at each four-second sample.	$Scheduled\ Deviation\ Gen$ $= ActualGeneration$ $- TargetTrajectory$ **EQ. 1** $E_{SM}(t) = G(t) - GS(t)$

5.1.2. Other market connection points with appropriate metering

The reference trajectory for *non-scheduled market generating units* and *non-scheduled market loads* with appropriate metering is illustrated in Table 3.

Table 3 Non-scheduled generating units and non-scheduled loads with appropriate metering

Reference Trajectory	Actual Measurement	Example
Continuation of the initial metered MW level at the start of the current DI.	SCADA metering data for the unit or load.	
DMX(t) Source: SCADA metered value at the start of the *dispatch inteval* held constant for the full five-minute period.	*DM(t)* Source: SCADA metered value at each four-second sample.	$NSM\ Gen\ Deviation = ActualGeneration - InitialMetered$ **EQ. 2** $E_{NSM}(t) = DM(t) - DMX(t)$

5.1.3. Residual demand components

a)   There are two *region*-specific trajectories used in calculating and allocating a residual component to *generating units* and *loads* without appropriate metering.

b)   These components require the calculation of:

   (i)   four-second *regional* demand from SCADA measurements of *generation*; and

   (ii)   *interconnector* flow corrected for *inter-regional losses*.

c)   The two reference trajectories represent the non-linearity of demand and the forecast error. They are determined in accordance with clauses 5.1.4 to 5.1.7 and illustrated in Table 4~~Table 4~~ and Table 5~~Table 5~~ respectively.

5.1.4. Step 1 - Estimate actual 4-second interconnector loss

Although *generation* and *interconnector* flows at the *regional* boundary are available from SCADA data, there are no measured losses. Therefore, 4-second *interconnector* loss is estimated as follows:

$$ActualLoss = ExpectedLoss + MLF \times (ActualFlow - ExpectedFlow)$$

EQ. 3 $$IRL(t) = IRLB(t) + MLF(t) \times (IRE(t) - IREB(t))$$

Where:

a) **IRL** is the four-second estimated *interconnector* loss, used in subsequent demand calculations.

b) **IRLB** is the expected (base) loss, based on a straight line trajectory between the five-minute MWLOSS values recorded in the *market* dispatch data. This represents the loss NEMDE expected to occur had the *interconnector* flow moved linearly between its energy targets for consecutive DIs.

c) **MLF** is the *marginal loss factor* for the *interconnector*. MLF is estimated every 4 seconds as the linear interpolation between MLFs calculated at the start and end of the relevant DI (by substituting scheduled flow and demand values in the *interconnector* loss equations.)

d) **IRE** is the actual SCADA metered value of interconnector flow.

e) **IREB** is the expected (base) flow, based on a straight line trajectory between the five-minute MWFLOW values recorded in the *market* dispatch data of AEMO's MMS. This represents the flow NEMDE expected to occur had the *interconnector* moved linearly between its targets – and is the basis for NEMDE's IRLB (expected loss) calculations.

5.1.5. Step 2 - Calculate 4-second regional demand

Once IRL has been determined, four-second regional demand is calculated as follows:

$$Demand = \sum LocalGeneration(t) - \sum RegionExports(t) - \sum ICLoss(t)$$

EQ. 4 $$DG(t) = \sum G(t) - \sum IRE(t) - \sum IRL(t)$$

Where:

a) **DG** represents the generator terminal demand within a particular region.

b) **G** represents the SCADA metered generator terminal demand for each scheduled and semi-scheduled generating unit within the region.

c) **IRE** is the actual SCADA metered value MW flow on each *interconnector* connected to the region (with sign chosen such that positive values are exports from the region).

d) **IRL** is the four-second estimated actual loss on each interconnector connected to the region (calculated in EQ. 33).

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5.1.6. Step 3 - Least squares error (LSE) line of best fit calculation

a) After calculating the actual 4-second regional demand trajectory, a straight line approximation for that trajectory is calculated by using least square error estimation. This LSE approximation uses all data samples for the DI including the ones where FI and the frequency error is not correlated.

b) The least square error line is continuous when data from the previous DI is available. That is, the line starts from the end point of the previous DI's LSE line when available.

5.1.7. Step 4 - Reference trajectory calculation

The reference trajectory is calculated as the linear trajectory between the *regional* demand at the start and end of the DI. Demand at a dispatch interval boundary is calculated by using NEMDE data representing:

a)   *generation* targets for *scheduled generating units* and *semi-scheduled generating units*;

b)   *interconnector* flow targets; and

c)   scheduled losses for *interconnectors.*

Table 4 Non-linearity of demand (DG) per region

Reference Trajectory	Actual Measurement	Example
Least squares line of best fit of four-second regional demand during the curent dispatch interval.*	Four-second regional demand.*	
DGX(t) Source: function which converts 5-minutes of **DG(t)** values into a line of best fit.	**DG(t)** Source: EQ. 4~~EQ. 4~~ based on SCADA generation, region exports, and losses.	$Demand\ Deviation = ActualDemand - ReferenceDemand$ **EQ. 5** $E_{DG}(t) = DG(t) - DGX(t)$

Table 5 Forecasting error (FE) per region

Reference Trajectory	Actual Measurement	Example
Straight line between previous and current dispatch interval demand forecast.	Least squares line of best fit of four-second regional demand during the current dispatch interval.	
DGB(t) Source: straight line between MMS total demand values after subtracting ADE[5].	**DGX(t)** Source: function which converts 5-minutes of **DG(t)** values into a line of best fit.	$Forecast\ Deviation$ $\qquad = ReferenceDemand - ForecastDemand$ **EQ. 6** $E_{FE}(t) = DGX(t) - DGB(t)$

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[5] In order to obtain a true estimate of the base *region* demand the ADE is removed. This is because ADE is an offset added to the total demand to account for non-conformance of *generating units*.

5.2. Scale Deviations by the FI

5.2.1. General

a) The 4-second deviation values determined under clause **Error! Reference source not found.** are multiplied by the value of FI, with the objectives of:

(i) weighting the deviation by its significance so that, for example, in periods where the system is under *frequency* stress, deviations have a higher weighting; and

(ii) identifying 'helpful' deviations, i.e. a deviation which reduces frequency in a period where frequency is too high, or vice versa.

b) The FI value represents the total Regulation FCAS requirement identified by AEMO's AGC in a given 4 second period, where:

(i) a positive FI value indicates a *regulation raise service* requirement; and

(ii) a negative FI value indicates a *regulation lower service* requirement.

c) The AGC calculates the total Regulation FCAS requirement and resulting FI value using the logic set out in clauses 5.2.2 to 5.2.4 (noting that the applicable gains and thresholds are derived by AEMO from time to time during tuning of the AGC).

5.2.2. Area control error

a) AEMO first calculates an area control error (ACE), representing the MW equivalent size of the current frequency deviation and accumulated frequency deviation (time error) of the system.

EQ. 7 $$ACE = 10 \cdot Bias \cdot (F - FS - FO)$$

Where:

(i) **Bias** is the area frequency bias and is a tuned value that represents the conversion ratio between MW and 0.1Hz of frequency deviation;

(ii) **F** is the current measured system frequency;

(iii) **FS** is the scheduled frequency (50.0Hz); and

(iv) **FO** is a frequency offset representing accumulated frequency deviation, i.e. time error.

b) The AGC works on a proportional-integral controller feedback logic, and so AGC also calculates an integral of the ACE value (ACEI) using repeated addition, as follows:

EQ. 8 $$ACEI(t) = ACEI(t-1) + ACE(t) \cdot (4s/3600s)$$

5.2.3. Regulation FCAS requirement

The AGC uses both the ACE and ACEI value to calculate required Regulation FCAS (RR):

EQ. 9 $$RR = (ACE \cdot Gain_{ACE}) + (ACEI \cdot Gain_{ACEI})$$

Where:

a) **Gain_{ACE}** and **Gain_{ACEI}** are values taken from a look-up tables tuned by AEMO from time to time based on system performance and response to deployed Regulation FCAS. The AGC also applies both static and dynamic deadbands which makes gains to zero under specific conditions to ensure stability of the system.

b) **ACE** is the area control error, as defined in EQ. 7~~EQ. 7~~.

c) **ACEI** is the integral of ACE, as defined in EQ. 8~~EQ. 8~~.

5.2.4. FI value

a) The RR value from EQ. 9~~EQ. 9~~ is subsequently split amongst all *enabled* providers of Regulation FCAS for that particular requirement, and processed by a low pass filter to avoid large swings in AGC output for individual *Market Participants.*

b) These filtered values are recombined to yield the final value of FI. representing the actual quantity of Regulation FCAS that AGC has identified in the 4 second period. Note that the quantity actually *enabled* will be a different value, due to the application of unit control models in later steps of the AGC calculation algorithm.

c) Separate values of FI are calculated for each area, and applied to the performance factors of units and loads within that area.

5.2.5. 4-second performance measures

Each 4-second deviation value multiplied by the resulting FI value for the corresponding interval yields a a 4-second performance measure as described in Table 6.

Table 6 Calculation of 4-second performance measures

Deviation Category	Equation	
For each *scheduled generating unit* and *semi-scheduled generating unit*.	EQ. 10	$F_{SM}(t) = E_{SM}(t) \cdot FI(t)$
For each *scheduled load*	EQ. 11(a)	$F_{SM}(t) = -E_{SM}(t) \cdot FI(t)$
For each *non-scheduled generating unit* with appropriate metering.	EQ. 12	$F_{NSM}(t) = E_{NSM}(t) \cdot FI(t)$
For each *non-scheduled load* with appropriate metering.	EQ. 13(a)	$F_{NSM}(t) = -E_{NSM}(t) \cdot FI(t)$
For each *region*, representing the non-linearity of demand.	EQ. 14	$F_{DG}(t) = -E_{DG}(t) \cdot FI(t)$
For each *region*, representing the demand forecasting error.	EQ. 15	$F_{FE}(t) = -E_{FE}(t) \cdot FI(t)$

6. Process and aggregate factors by unit or load

6.1. Categorise and Aggregate 4 Second Performance Measures

a) Each 4-second performance measure is further categorised to reflect whether the deviation occurred when the *regulating raise service* or *regulating lower service* was required, and whether the relevant *plant* was *enabled* to provide Regulation FCAS at the time.

b) In subsequent steps, these categories allow the calculation to identify when deviations helped or hindered *power system frequency*, and whether or not units have already been compensated for providing *frequency* support.

c) The categorised 4-second performance measures are aggregated to *dispatch interval* resolution, to determine the average performance for each DI after excluding periods where frequency error and the FI value are not correlated. This process results in categorised and aggregated 5-minute factors, presented in Table 7~~Table 7~~.

d) At this point, a positive 5-minute factor identifies a *generating unit* or *load* that responded in a manner that generally assisted *power system frequency* during the DI. A negative

factor identifies a *generating unit* or *load* that has generally contributed to the need for Regulation FCAS during the DI.

Table 7 Aggregation to 5-minute performance factors

Component type	Sum of 4s factors With Raise Required & Enabled	Sum of 4s factors With Lower Required & Enabled	Sum of 4s factors With Raise Required & Not Enabled	Sum of 4s factors With Lower Required & Not Enabled
For each *scheduled* and *semi-scheduled generating unit* or *scheduled load*.	REF_5M_{SM}	LEF_5M_{SM}	$RNEF\_5M_{SM}$	$LNEF\_5M_{SM}$
For each *non-scheduled generating unit* or *load* with appropriate metering.	REF_5M_{NSM}	LEF_5M_{NSM}	$RNEF\_5M_{NSM}$	$LNEF\_5M_{NSM}$
For each *region*, representing the non-linearity of demand.	-	-	$RNEF\_5M_{DG}$	$LNEF\_5M_{DG}$
For each *region*, representing the demand forecasting error.	-	-	$RNEF\_5M_{FE}$	$LNEF\_5M_{FE}$

6.2. Exclude Periods Affected by Contingencies or Bad SCADA

a) For a given DI and area, all factors (REF_5M, LEF_5M, RNEF_5M, LNEF_5M) are excluded from further calculation for all *generating units*, *loads*, and *regions*, if:

   (i) the *power system frequency* is outside the *normal operating frequency band* (typically due to a *contingency event*) in any 4-second sample within the DI;

   (ii) one or more 4-second SCADA samples are deemed corrupt, unless that data can be substituted by reliable data from an alternative source, such as a duplicate server;

   (iii) there is an abnormal frequency island (as defined in the *frequency operating standards*) within an area; or

   (iv) the relevant data is excluded in accordance with clause **Error! Reference source not found.**12c).

b) The exclusions apply to all data for the DI in question, regardless of the location or impact of the *contingency event* or corrupt data. For example, if a relevant *contingency event* occurs in Queensland, the Contribution Factors for all *regions* in the Mainland area will exclude data for that period. This is done to reduce complexity in the calculation, and on the basis that the sample period is sufficiently large that this will not significantly affect the normalised Contribution Factors.

6.3. Aggregate to 28-day Factors for a Unit or Load

a) At the end of the 28-day sample period, the remaining (non-excluded) 5-minute factors for each appropriately metered *generating unit* and *load*, *region* and for each category are aggregated to produce a single 28-day factor. The aggregation calculations are shown in Table 8Table 8.

Table 8 Aggregate to 28-day factors

Component type	Raise Required & Enabled Factor	Lower Required & Enabled Factor	Raise required & not enabled Factor	Lower required & not enabled Factor
For each *scheduled* and *semi-scheduled generating unit* or *scheduled load*.	REF_{SM} $= \sum\limits_{28\,day} REF\_5M_{SM}$	LEF_{SM} $= \sum\limits_{28\,day} LEF\_5M_{SM}$	$RNEF_{SM}$ $= \sum\limits_{28\,day} RNEF\_5M_{SM}$	$LNEF_{SM}$ $= \sum\limits_{28\,day} LNEF\_5M_{SM}$
For each *non-scheduled generating unit* or *load* with appropriate metering.	REF_{NSM} $= \sum\limits_{28\,day} REF\_5M_{NSM}$	LEF_{NSM} $= \sum\limits_{28\,day} LEF\_5M_{NSM}$	$RNEF_{NSM}$ $= \sum\limits_{28\,day} RNEF\_5M_{NSM}$	$LNEF_{NSM}$ $= \sum\limits_{28\,day} LNEF\_5M_{NSM}$
For each *region*, representing the non-linearity of demand.	-	-	$RNEF_{DG}$ $= \sum\limits_{28\,day} RNEF\_5M_{DG}$	$LNEF_{DG}$ $= \sum\limits_{28\,day} LNEF\_5M_{DG}$
For each *region*, representing the demand forecasting error.	-	-	$RNEF_{FE}$ $= \sum\limits_{28\,day} RNEF\_5M_{FE}$	LEF_{FE} $= \sum\limits_{28\,day} LNEF\_5M_{FE}$

7. Global Requirement Contribution Factors

7.1. General

This clause describes the process for determining *Market Participant* Contribution Factors for the purposes of NER clause 3.15.6A(j)(1), to be applied in the recovery of costs for *global market ancillary service requirements* for Regulation FCAS*.*

7.2. Aggregate Unit or Load Factors into Area Portfolio Factors

a)   The 28-day factors calculated in clause 7~~7~~ for appropriately metered *market generating units* and *loads* are aggregated at a portfolio level for a given *Market Participant* to produce 'portfolio factors', using the equations described in Table 9.

Note: This allows positive performance from one unit or load within a portfolio to offset negative performance from other units or loads within the same portfolio.

Note: The 28-day factors for *regional* demand are not further aggregated.

b)   At this step, *Market Participant* portfolio factors are calculated separately for appropriately metered:

(i)   *scheduled* and *semi-scheduled generating units* and *scheduled loads* in each area; and

(ii)   *non-scheduled generating units* and *loads* in each area.

c)   At this point, any positive REF or LEF factors are set to zero. Although they represent helpful *frequency* support, the relevant *ancillary service generating unit* or *load* was *enabled* (and therefore compensated) for providing support during those periods.

d) A positive area portfolio factor for a *Market Participant* indicates the relevant portfolio had a net positive impact on *frequency* control during the 28-day period, and is set to zero so that the relevant *Market Participant* makes no contribution to the costs for *global market ancillary service requirements*.

e) Accordingly, final area portfolio factors will be:

(i) negative for *Market Participants* whose appropriately metered *generating units* and *loads* within the relevant category and area (on a net aggregate basis) contributed to the need for Regulation FCAS in the 28-day period; and

(ii) zero for *Market Participants* whose appropriately metered *generating units* and *loads* within the relevant category and area (on a net aggregate basis) alleviated the need for Regulation FCAS in the 28-day period.

Table 9 Aggregate to Portfolio factors

Component type	Area Portfolio Factor
For each portfolio containing scheduled or semi-scheduled generating units or scheduled loads.	**EQ. 16** $$APF_{SSS} = \min(0, (\min(0, \sum_{unit} REF_{SM}) + \min(0, \sum_{unit} LEF_{SM}) + \sum_{unit} RNEF_{SM} + \sum_{unit} LNEF_{SM}))$$
For each portfolio containing non-scheduled generating units or loads with appropriate metering.	**EQ. 17** $$APF_{NS} = \min(0, (\min(0, \sum_{unit} REF_{NSM}) + \min(0, \sum_{unit} LEF_{NSM}) + \sum_{unit} RNEF_{NSM} + \sum_{unit} LNEF_{NSM}))$$
For each region, representing the non-linearity of demand.	**EQ. 18** $$APF_{DG} = RNEF_{DG} + LNEF_{DG}$$
For each region, representing the demand forecasting error.	**EQ. 19** $$APF_{FE} = RNEF_{FE} + LNEF_{FE}$$

7.3. Calculate Area Totals for Component Types

a) To facilitate the allocation of demand deviations between *non-scheduled generating units and loads* with and without appropriate metering, a set of area totals is calculated as described in Table 10~~Table 10~~.

b) This process is performed separately for each area, namely Mainland and Tasmania, as shown in Table 10~~Table 10~~.

Table 10 Derived Area Totals

Component Type	Total Name	Calculation	
All scheduled and semi-scheduled generating units and scheduled loads	Area Market Scheduled Factor (AMSF)	**EQ. 20**	$AMSF = \sum APF_{SSS}$
All non-scheduled units and loads with appropriate metering	Area Metered non-scheduled unit total (AMNSTOT)	**EQ. 21**	$AMNSTOT = \sum APF_{NS}$
Demand (representing the non-linearity component)	Area deviation factor (ADF)	**EQ. 22**	$ADF = \min(0, \sum APF_{DG})$

Component Type	Total Name	Calculation	
Demand (representing forecasting error component)	Area forecast error factor (AFF)	**EQ. 23**	$AFF = \min(0, \sum APF_{FE})$

7.4. Calculate Additional Derived Totals

a) The area totals calculated in clause 7.3 are processed into a collection of derived values to allow the area forecasting error factor (AFF) and the area deviation factor (ADF) to be allocated appropriately between appropriately metered and non-appropriately metered *non-scheduled generating units* and *loads*.

b) The contribution of appropriately metered *non-scheduled generating units and loads* towards the area deviation factor is already known from EQ. 21EQ. 21 (AMNSTOT). The residual component attributable to non-appropriately metered *generating units and loads* can be calculated by:

EQ. 24 $\qquad ADRF = ADF - AMNSTOT$

c) The same ratio can be used to divide the area forecast error factor (AFF) between appropriately metered and non-appropriately metered generating units and loads as follows:

EQ. 25 $\qquad AFMNS = AFF \cdot \left(\frac{MNSTOT}{ADF}\right)$

EQ. 26 $\qquad AFRF = AFF \cdot \left(1 - \frac{MNSTOT}{ADF}\right)$

Where AFMNS represents the appropriately metered *non-scheduled* component of AFF, and AFRF represents the residual (not appropriately metered) component of AFF.

d) The appropriately metered *non-scheduled* components of AFF and ADF can now be combined into a total factor for appropriately metered *non-scheduled generating units* and *loads* (AMNSF):

EQ. 27 $\qquad AMNSF = AMNSTOT + AFMNS$

e) The same can be done for the residual (unmetered) components of AFF and ADF to produce a total area residual load factor (ARLF):

EQ. 28 $\qquad ARLF = ADRF + AFRF$

f) To facilitate normalisation of factors in clause 7.5, a total area factor (ATF) can be produced by combining the portfolio factors for all scheduled and semi-scheduled portfolios (AMSF), with the contribution of appropriately metered *non-scheduled generating units* and *loads* (AMNSF), and with the residual load factor (ARLF) for that area:

EQ. 29 $\qquad ATF = AMSF + AMNSF + ARLF$

g) Figure 2Figure 2 summarises the above derivation steps in graphical form.

Figure 2 Calculation of derived values
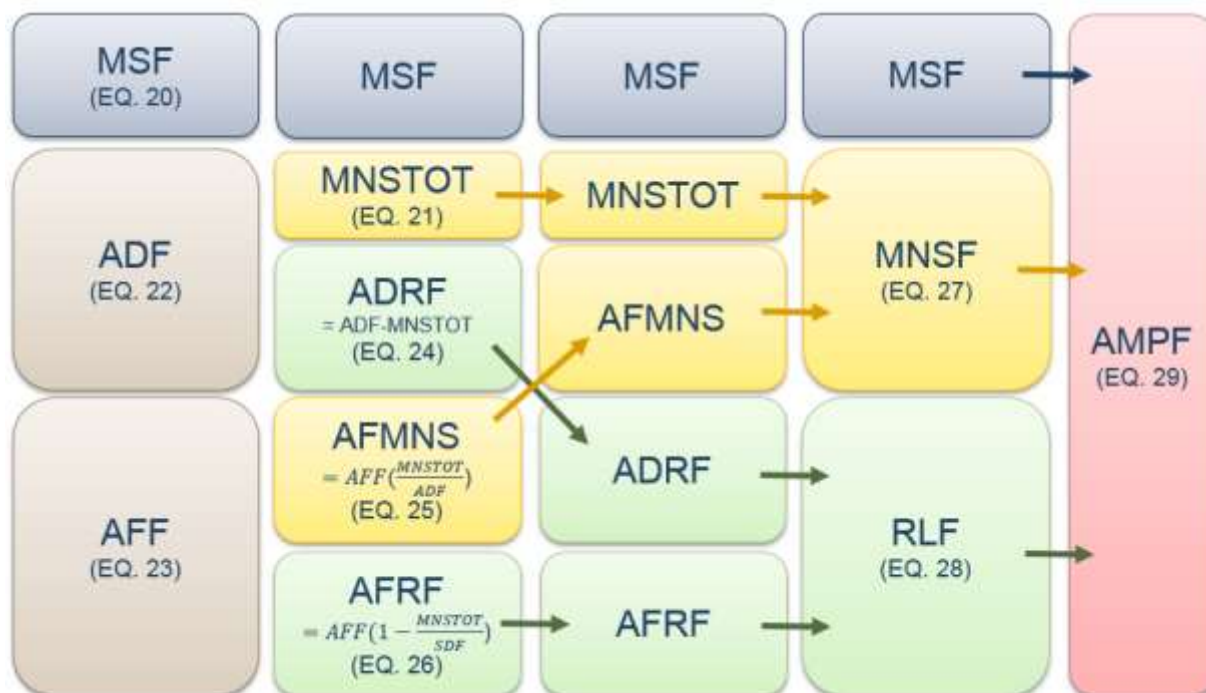
7.5. Normalise to Produce Area Contribution Factors

a) Using the portfolio totals from clause 7.2 and the derived totals from clause 7.3, final area Contribution Factors for each *Market Participant* are calculated for each of Mainland and Tasmania.

b) These factors are calculated as described in Table 11~~Table 11~~, ensuring that the sum of all area contribution factors for each area equals 1 (100%).

Table 11 Area Contribution Factors for Mainland and Tasmania

Component Type	Area Calculation	
For each portfolio containing scheduled and semi-scheduled generating units or scheduled loads	**EQ. 30**	$AreaMPF_{SSS} = \frac{APF_{SSS}}{ATF}$
For each portfolio containing non-scheduled generating units or loads with appropriate metering.	**EQ. 31**	$AreaMPF_{MNS} = \frac{APF_{NS}}{AMNSTOT} \cdot \frac{AMNSF}{ATF}$ $AreaMPF_{MNS} = (1 + \frac{AFF}{ADF}) \cdot \frac{APF_{NS}}{ATF}$
Residual Component	**EQ. 32**	$AreaMPF_{RES} = \frac{ARLF}{ATF}$

7.6. Normalise to Produce Global Requirement Contribution Factors

To produce a single set of Contribution Factors for the Mainland and Tasmania for the purposes of NER clause 3.15.6A(j)(1), each area contribution factor calculated under clause 7.5 must be normalised according to area demand. The following equations are used to normalise the Contribution Factors for each *Market Participant* and for the residual component:

$$MPF_{SSS} = \sum_{Area}(AreaMPF_{SSS} \times \frac{AAD}{TAD})$$

$$MPF_{MNS} = \sum_{Area}(AreaMPF_{MNS} \times \frac{AAD}{TAD})$$

$$MPF_{RES} = \sum_{Area}(AreaMPF_{RES} \times \frac{AAD}{TAD})$$

- o   Where:MPF_{SSS}, MPF_{MNS} and MPF_{RES} are the normalised market participation factors;
- o   AAD is the *power system* demand for the area averaged over the sample period; and
- o   TAD is the total *power system* demand averaged over the sample period.

8.   Local Requirement Contribution Factors

This clause describes the process for determining *Market Participant* Contribution Factors for the purposes of NER clause 3.15.6A(j)(2), to be applied in the recovery of Regulation FCAS costs for *local market ancillary service requirements* (whether those requirements apply as a result of temporary asynchronous operation between *regions* or otherwise)*.

8.1. General

a)   AEMO uses the process described in this clause to determine the Contribution Factors to be applied for the recovery of Regulation FCAS costs:

  (i)   when *regions* are operating asynchronously with each other for the purposes of NER clause 3.15.6A(j)(2); and

  (ii)   when *local market ancillary service requirements* for Regulation FCAS apply in any other circumstances.

b)   Notwithstanding paragraph a), Contribution Factors are not calculated under this clause in relation to the permanent asynchronous operation of Tasmania and the Mainland in circumstances where the Basslink frequency controller is operating normally and there is no *local market ancillary service requirement* for Regulating FCAS in Tasmania.

c)   The key inputs for Contribution Factors determined under this clause 8 are:

  (i)   the currently applicable published MPF_{SSS} and MPF_{MNS} values of those *Market Participants* that are relevant to the *region(s)* identified in a *constraint* for a *local market ancillary service requirement*;

  (ii)   the currently applicable published MPF_{RES} value and

  (iii)   the total *customer energy* for those *regions*, and for all *regions* in the *NEM*.

d)   Estimates of these Contribution Factors are provided in the *pre-dispatch* and *dispatch* timeframes (for the purposes of clause 3.15.6A(nb) of the NER) using total demand figures for each *region*, as *customer energy* is only determined in the *settlement* timeframe.

8.2. Identifying Relevant Market Participants

Each *constraint* for a *local market ancillary service requirement* for Regulation FCAS identifies one or more *regions* to which the requirement applies. Each *Market Participant* that is *financially responsible*[6] for a *connection point* in the *region(s)* (including as a *Local Retailer*) is 'relevant' to the requirement.

8.3. Calculating CMPF, CRMPF and RAMPF Values

For each *local market ancillary service requirement* for Regulation FCAS, AEMO calculates:

a)   the Constraint MPF (CMPF), being the sum of the currently applicable *NEM* values of MPF_{SSS} and MPF_{MNS} for all relevant *Market Participants*; and

b)   the Constraint Residual MPF (CRMPF), as follows:

$$CRMPF = MPF_{RES} \times \frac{\Sigma ATCE\ (Regions\ \text{included in the requirement})}{\Sigma ATCE\ (\text{All}\ regions)}$$

where:

(i) MPF_{RES} = the currently applicable value of MPF for the *NEM*, representing the aggregate Contribution Factor set for *Market Customers* without appropriate *metering* under clause 3.15.6A(i)(2) of the NER; and

(ii)   ATCE = Aggregate Total Customer Energy, the half-hourly sum of total *customer energy* for a *region*. ATCE values would be the same for every *dispatch interval* within a *trading interval*; and

c)   the Regional Aggregate Market Participation Factor (RAMPF), being the sum of CMPF and CRMPF.

8.4. Individual and Residual Contribution Factors

a)   For each *Market Participant* with a published MPF_{SSS} or MPF_{MNS}, and which is relevant to a *local market ancillary service requirement* for Regulation FCAS, the *Market Participant's* individual Contribution Factor is determined as a percentage by dividing MPF_{SSS} or MPF_{MNS} (as applicable) by RAMPF.

b)   For each *Market Customer* which is relevant to the *local market ancillary service requirement* for Regulation FCAS, their share of the allocation of Regulation FCAS costs is based on the aggregate residual demand Contribution Factor, which is determined as a percentage by dividing CRMPF by RAMPF.

8.5. Estimated CMPF and CRMPF Values

a)   For each *dispatch interval* in *dispatch* and (where possible) each *trading interval* in *pre-dispatch* during a period of asynchronous operation, AEMO *publishes* estimates of the CMPF and the CRMPF applicable to each *local market ancillary service requirement* for Regulation FCAS.

b)   The CMPF is estimated by summing the MPF_{SSS} and MPF_{MNS} values for all *Market Participants* relevant to the affected *region(s)*.

c)   The CRMPF is estimated by multiplying MPF_{RES} by the proportion of total demand in the affected *regions* to total demand in the *NEM*. Total demand figures would be different for each *dispatch interval* within a *trading interval*.

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[6] Including as a *Local Retailer* in the *region(s)*

d)   *Market Participants* can use their MPF$_{SSS}$ or MPF$_{MNS}$ or expected total demand (as applicable) to estimate their contribution to the cost of each *local market ancillary service requirement*, but actual contributions may vary materially from estimated values.

9.   Published DATA

AEMO publishes the following datasets relevant to the determination of Contribution Factors:

a)   indicative FI values under clause **Error! Reference source not found.** close to real time;

b)   following the analysis period:

(i)   the values of MPF$_{SSS}$ and MPF$_{MNS}$ for each applicable *Market Participant* portfolio, and the value of MPF$_{RES}$, for each 28-day application period;

(ii)   raw data for appropriately metered *market generating units* and *market loads* over the 28-day period; and

(iii)   a list of DIs that have been excluded from the calculation of Contribution Factors due to *contingency events* or a significant proportion of suspect SCADA data.