CAUSER PAYS PROCEDURE

DETERMINATION OF CONTRIBUTION FACTORS FOR REGULATION FCAS COST RECOVERY

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VERSION RELEASE HISTORY

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.

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1. INTRODUCTION

1.1. Purpose and Scope

This is the procedure made under clause 3.15.6A(k) of the National Electricity Rules (**NER**) for determining contribution factors for use in clause 3.15.6A(j) of the 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*.

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

The words, phrases and abbreviations set out in the table below have the meanings set out opposite them when used in this Procedure.

Terms defined in the National Electricity Law or the NER have the same meanings in this Procedure unless otherwise specified in this clause. Those terms are intended to be identified in this Procedure by italicising them, but failure to italicise a defined term does not affect its meaning.

Term	Definition
4-second performance measure	A factor determined for a 4-second interval
5-minute factor	See clause 2.
Abnormal frequency island	Has the meaning given to it in the *frequency operating standard*
ADE	Aggregate *dispatch* error
AEMO	Australian Energy *Market* Operator Limited
AGC	*Automatic generation control system*
AMPF	Aggregate *Market Participant* Factor
Base	A pre-determined trajectory for a *scheduled generating unit*, or a forecast for a *semi-scheduled generating unit* or a *non-scheduled generating unit*.
Contribution Factor	The factor that represents the percentage of Regulating FCAS costs for which a particular *Market Participant* is liable.
Causer Types	As defined in Table 2
CMPF	Constraint MPF (see clause 5.2)
CRMPF	Constraint Residual MPF (see clause 5.2)
Deviation	The difference (in MW) of a measurement of *active power* and its Reference Trajectory.
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	*dispatch interval*
D*LOAD*	5-minute *dispatchable load*

Term	Definition
DM	Measured demand
DMF	An equation/data source relating to *non-scheduled generating units*
DMX	Measured demand at the beginning of a DI
DR	Residual demand
DRX	Ex-post line of best fit on residual demand
EMS	Energy Management System
FCAS	*Frequency* control *ancillary service*
FL	5-minute *interconnector* flow
Frequency Indicator (FI)	This parameter indicates the extent to which more *generation* (in which case it is positive) or less *generation* (negative) is required to keep the *frequency* at 50 Hz. The sign of FI indicates which FCAS (raise or lower) is required at any given time. The parameter from AEMO's AGC* indicating the amount of Regulating FCAS required. A positive value indicates that *regulating raise service* is required (that is, *frequency* < 50 Hz). A negative value indicates that *regulating lower service* is required (that is, *frequency* > 50 Hz). This value is capped and has positive and negative limits of +/- 1560. * NOTE: this parameter is labelled in AEMO's AGC system as 'Regulation requirement'.
G	Measured *generating unit generation*
GB	*Generation* at *generating unit* terminals
GS	*Dispatched generation*
GSS	Measured *generating unit generation* or *load* for all metered *market semi-scheduled generating units*
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
IRENB	Base *inter-regional* exports
IRL	*Inter-regional* losses
IRLB	Base *inter-regional* losses
LEF	Lower-enabled factor. Assigned to *market scheduled generating units* or *loads* that are lower-enabled.
LNEF	Lower non-enabled factor. Assigned to metered *market Market Participant* or system components that either not lower-enabled or that cannot be lower-enabled.
MLF	Marginal loss factor
MMS	*Market* Management System producing 5-minute *market dispatch* data.
MNSFFi	Metered *non-scheduled generating unit* and *load* forecast error factor (indexed by i)
MNSFi	Overall metered *non-scheduled generating unit* and *load* factor
MNSTOT	Metered *non-scheduled generating unit* total factor
MPF	Residual *Market Participant* factor for non-metered *loads*
MPFi	*Market Participant* factor for *metered generating units* and *loads* (indexed by i)
MSF	Metered and *scheduled generating unit* and *scheduled load* factor
MW	Megawatt
MWh	Megawatt hours
N	DI index
NI	5-minute *regional* net interchange (includes losses)

Term	Definition
NMPF	Normalised *regional* participation factor for each *Market Generator* or *Market Customer*
Non-scheduled generation forecast	A forecast of *non-scheduled generation* over a 5-minute period
Residual	The percentage of costs assigned to *Market Customers* that do not have an MPFi Contribution Factor calculated for them.
REF	Raise-enabled factor. Assigned to metered *market scheduled generating units* or *loads* that are raise-enabled.
RNEF	Raise non-enabled factor. Assigned to metered *Market Participants* or system components that either are not raise-enabled or that cannot be raise-enabled.
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.
Regulating FCAS	*Regulating lower service* and *regulating raise service*
RAMPF	Regional Aggregate Market Particpation Factor (see clause 5.2)
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.
SDF	System deviation factor
SDRF	System deviation residual factor
settlement factor	Factor calculated over the settlement period
SFF	System forecast error factor
SFRF	The system forecast error residual factor 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.
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
TA	Trading amount from IT specification
TC	5-minute total cleared
TD'	Total demand
TD	Total demand adjusted by ADE and demand forecast
TPSD	The total *power system* demand averaged over the sample period as determined by EMS
TSFCAS	Amount calculated for Regulating FCAS from IT specification
TI	*trading interval*

1.2.2. Interpretation

The following principles of interpretation apply to this Procedure unless otherwise expressly indicated:

(a) This Procedure is 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.

(c) The index 'i' is used to index *generating unit* and *load* variables (eg. GBi).

(d)   The index 'j' is used to index *region* variables (eg. DGBj).

(e)   The index 'k' is used to index *interconnector* variables (eg. IRENBk).

(f)   Several indices could be combined, for example, GBij indicates the base *generation* of *generating unit* (or *load*) i in *region* j. If an index is not specified then an implicit sum is implied, for example, IRENBj means the sum of *interconnector* flows at *region* j.

1.3.   Related Documents

Reference	Title	Location
160-0392	Efficient Dispatch and Localised Recovery of Regulation Services Business Specification	http://aemo.com.au/-/media/Files/PDF/0160-0049-pdf.pdf

2.   GENERAL PRINCIPLES

(a)   Contribution Factors are determined for the purpose of assigning the costs of Regulating FCAS to those *Market Participants* who have caused the need for those services.

(b)   The calculations represent the deviations from a reference trajectory derived from expected *dispatch* or expected MW consumption. The deviations are calculated every four seconds and averaged over a *dispatch interval* (DI). The average results are referred to as 5-minute factors.

(c)   Contribution Factors for individual *Market Participants* are determined based on 28 days of 5-minute factors calculated for the following:

    (i)   all *market scheduled generating units*;

    (ii)   all *market scheduled loads*;

    (iii)   all *market semi-scheduled generating units*;

    (iv)   all *market non-scheduled generating units* with appropriate *metering*;

    (v)   all *market non-scheduled loads* with appropriate *metering*;

    (vi)   all *market small generating units* with appropriate *metering*.

(d)   A residual percentage attributable to *Market Customers* is determined on an energy-weighted basis for those who do not have Contribution Factors calculated for them under paragraph (c). The residual includes the effect of non-*market generating units*, non-*market loads* and *Market Network service providers* on a *region*'s demand deviation although, under Rules 3.15.6A(g) and (i), these are excluded from the *ancillary services* transactions relating to causer pays.

(e)   The Contribution Factors are applied in AEMO's settlement systems for 28 days and, therefore, the cost of Regulating FCAS is recovered on an ex post facto basis.

(f)   The calculation of the Contribution Factors is done using data collected over what is called a "sample period". The sample period is a 28-day period ending at 00:00 hrs (12:00 am) on the Sunday before Contribution Factors are due to be published.

3.   CALCULATION OF CONTRIBUTION FACTORS

3.1.   Process Overview

Central dispatch assumes that *loads* and *generating units* ramp in a straight line from one 5-minute MW level to the next. Regulating FCAS provides the means to manage any MW variations from straight-line trajectories and any error in the straight-line trajectories themselves. The contributions of each *Market Participant* to the need for Regulating FCAS are identified by following the steps summarised below.

3.1.1. Step 1 Gather and store data

(a) There are four sources/types of data used in the causer pays application as follows:

    (i) 4-second data or similar resolution from AEMO's AGC and SCADA systems. The data is captured from AEMO's Energy Management System (EMS) and written to a spreadsheet, in 5-minute samples by an automated database application. This application provides interpolation in cases where the resolution of the SCADA data is greater than 4 seconds;

    (ii) 5-minute and standing data from AEMO's Market Management System (MMS);

    (iii) manually input data mainly relating to the parameters of the causer pays run such as the start and end time of the calculation period;

    (iv) data relating to contingencies that occurred during the sample period provided by an application that logs *contingency events*.

(b) All data is stored on two servers, called the causer pays servers, which are located at separate AEMO sites.

(c) The application that calculates the 5-minute factors from the 4-second SCADA data reads in 4-second data and associated *market* values over successive 5-minute DIs. The data is checked for gaps and errors as it is read into the application. If data within a five minute interval is found to be corrupt, all data for that interval will not be read into the application. These are corrected where possible by re*load*ing data from an alternate source, such as a duplicate server; otherwise the data for the DI is discarded.

3.1.2. Step 2 Determine reference trajectories

Determine reference trajectories from the *market* processes. In all cases these will be straight-line MW trajectories from one DI boundary to the next associated with various Causer Types applied to *generating units* or *loads*, or groups of *generating units* or *loads*.

3.1.3. Step 3 Calculate and store deviations for all Causer Types

Calculate and store the calculated deviations (in MW) from the reference trajectories. The deviations are stored on the causer pays servers. For each category, calculate and store the MW deviations between measurements taken every 4 seconds (or at intervals supported by the telemetering from the point of measurement) and the reference MW level. In some cases, such as *regional* demand forecast error, the deviation is the difference between two straight-line reference levels.

3.1.4. Step 4 Derive Regulating FCAS Performance Measures

(a) For each category, calculate and store a Regulating FCAS performance measure for the 4-second (or more) interval using the following formula:

Performance measure = deviation * FI

(b) FI is a parameter from AEMO's AGC system and is a measure of the *frequency* correction that the *power system* requires.

(c) Separate calculations are performed for when FI is positive (regulating raise service) and negative (regulating lower service).

(d) Note that the measure is positive if the targeted *generating unit* or *load* is momentarily correcting, and negative if momentarily causing the *frequency* deviation. This is so because a *generating unit* or *load* deviation is defined as positive if it is injecting more power, and FI is positive if there is a power deficit.

(e) Different values of FI are calculated in the Tasmania *region* and mainland *regions*.[1]

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[1] If two *regions* are not connected by a synchronous (AC) *interconnector* the *frequency*, hence the Regulating FCAS requirement, will differ between the two *regions*. The Tasmania *region* and mainland *regions* are not connected by a synchronous *interconnector*.

(f)   If an abnormal *frequency* island temporarily forms within the NEM separate values of FI will not be calculated. See clause 5.1 for further details.

(g)   The 4-second performance measures are averaged over each DI to create 5-minute factors. All 5-minute factors that are affected by contingencies are deleted from the causer pays server.

3.1.5.   Step 5 Sum the 5-minute factors

At the end of the sample period, sum the factors for each deviation category for each *generating unit* or *load*.

3.1.6.   Step 6 Aggregate Contribution Factors

For each *Market Participant*, determine the net aggregate of the positive and negative factors for their *generating units* and *loads*. Aggregate the individual *generating unit* and *load* factors for all *generating units* and *loads* within each *Market Participant's* portfolio.

3.1.7.   Step 7 Process the positive Contribution Factors

Having determined a *Market Participant's* aggregate factor, discard the positive factors on the basis that only causers will be paying for the cost of Regulating FCAS enablement.

3.1.8.   Step 8 Determine the residual

Determine the residual percentage attributable to *Market customers* who do not have contribution factors calculated for them.

3.1.9.   Step 9 Calculate the percentage of the residual attributed

Calculate cost shares as the ratio of each *Market Participant's* factor to the total.

3.1.10. Step 10 Allocate costs

Allocate Regulating FCAS costs to *Market Participants* according to the aggregate of Contribution Factors.

This process, steps 1 to 10 is illustrated in Figure 1.
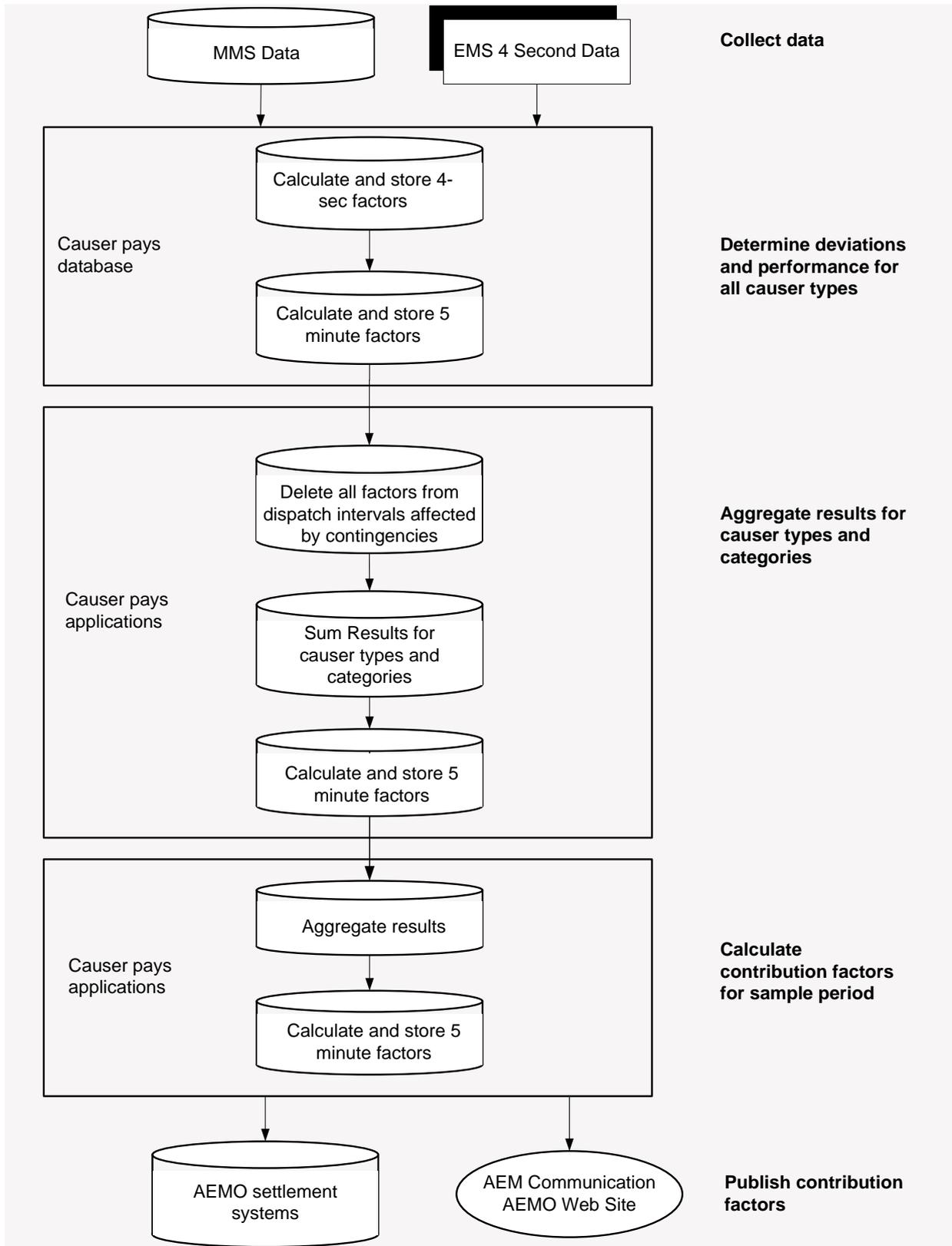
Figure 1   Process Diagram

Figure 2 shows (in yellow) the parts of the FCAS Calculation Module and databases that are required in the calculation of 5-minute factors. The dashed lines indicate the parts that may be alternatively written so, for instance, 5-minute calculation results may be written to the 5-minute database or to the CSV files.

Figure 2   5-minute Factor Calculations
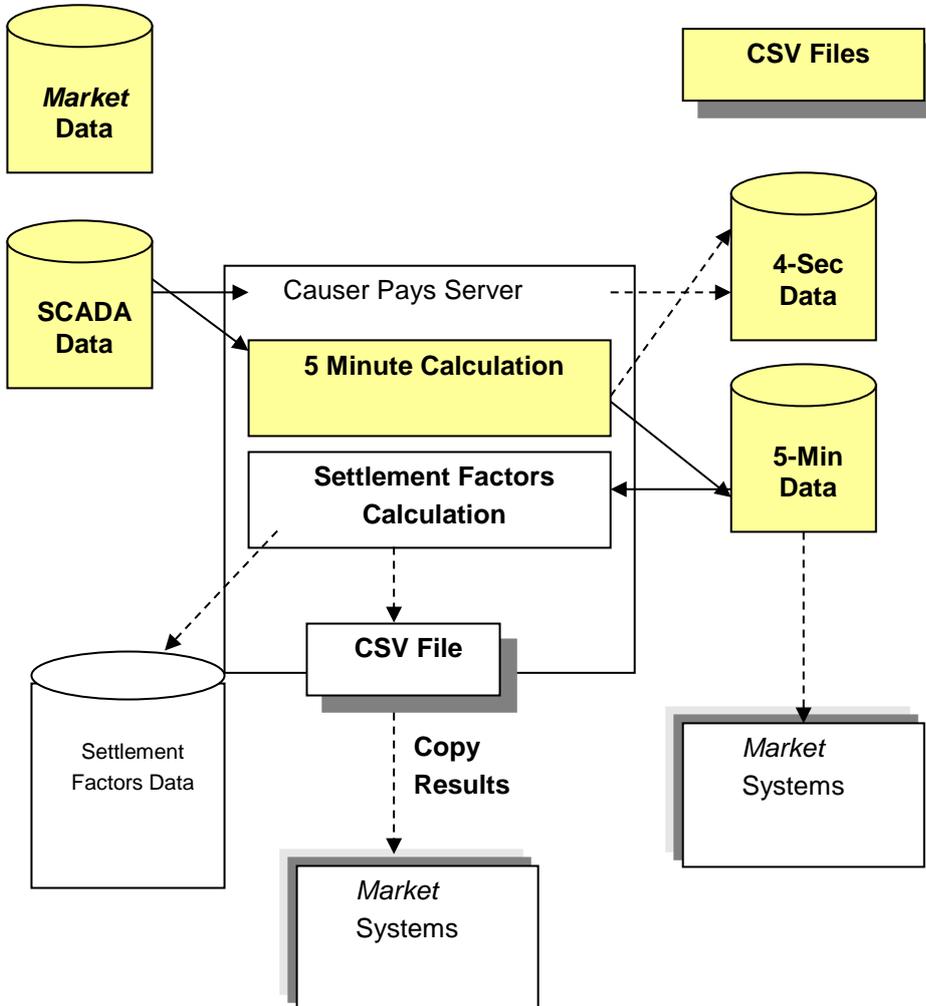
3.2. Gather and Store Data

3.2.1. Data sources and types

There are four sources/types of data used in the causer pays application as follows:

(a) 4-second data or similar resolution from AEMO's AGC and SCADA systems read from AEMO's EMS;

(b) 5-minute and standing data from AEMO's MMS;

(c) manually input data mainly relating to the parameters of the causer pays run;

(d) data relating to contingencies that occurred during the causer pays run from the application that logs *contingency events*.

3.2.2. Process

The process reads in 4-second data and associated *market* values over successive 5-minute DIs. The data is checked for gaps and errors. These are corrected where possible or otherwise discarded.

(a) Establish cache data tables as follows:

    (i) construct database indices[2] to speed up processing of 4-second data and identify mappings between SCADA data and MMS;

    (ii) configure information (for *interconnectors*, for example); and

    (iii) coefficients.

(b) Read MMS and EMS data over the time range that corresponds to the current DI being processed.

(c) Store data needed to interpolate between consecutive DIs.

(d) In order to calculate the 5-minute factor for a DI it is necessary to interpolate data between consecutive DIs. To do this SCADA data either side of each DI is read and processed. SCADA data for a period of 15 seconds plus the maximum measurement time delay before the DI and 15 seconds plus the maximum measurement time delay after the DI is stored in addition to SCADA data from within the DI.

(e) Check for missing and erroneous data

(f) The application that *loads* the data into causer pays servers checks for missing data and errors in each 5-minute (DI) sample it *loads*. The application will not *load* the data if errors are found or data is missing. If data without errors cannot be recovered, all data for the affected DI will not be included in the calculation of the contribution factors.

(g) Using MMS and SCADA data, calculate:

    (i) *inter-regional* marginal loss factors (MLF);

    (ii) *interconnector* losses;

    (iii) measured *regional* demand; and

    (iv) frequency indicator, FI.

(h) Interpolate missing data. The causer pays application provides interpolation in cases where the resolution of the SCADA data is greater than 4 seconds.

(i) Create and archive contribution factor output files - MMS CSV input file and PDF files released for publication.

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[2] The indices are as follows:
    i is a *generating unit/load* index
    j is a *region* index
    k is an *interconnector* index

3.3. Determine Reference Trajectories

(a) Determine reference trajectories for each of the nine Causer Types as described in table 1 – Reference Trajectories. 5-minute factors will later be calculated for each of the nine Causer Types.

Table 1   Reference Trajectories

Causer Type	Description	Reference Trajectory
1	*Market scheduled generating units* (SCADA metering)	Straight-line interpolation between the NEMDE *dispatch* targets of successive DIs.
2	*Scheduled loads* (SCADA metering)	As above for *market scheduled generating units*
3	*Market semi-scheduled generating units* (SCADA metering)	Straight-line interpolation between the NEMDE *dispatch level*s of successive DIs.
4	*Market non-scheduled generating units* (with SCADA metering and without 5-minute forecast)	Straight line at its initial metered MW level (at the start of the relevant DI) over the DI.
5	*Market non-scheduled generating units* (with SCADA metering and 5-minute forecast)	Straight-line interpolation between the *non-scheduled generation* forecasts of successive DIs
6	*Non-scheduled loads* (with SCADA metering)	As above for *market non-scheduled generating units* without 5-minute forecast
7	*Region* demand deviation	The ex-post demand calculated as a 5-minute least squares best-fit straight line through the measured values of *regional* demand measured at the *generating units'* terminals.
8	*Region* demand forecast error	As above for *region* demand deviation.
9	*Market small generating units* (with SCADA metering and without 5-minute forecast)	As above for *market non-scheduled generating units* without 5-minute forecast.

(b) Under Rules 3.15.6A(g) and (i), non-*market generating units*, non-*market loads* and *Market Network Service Providers* are excluded from the ancillary services transactions relating to causer pays but their effect is included in the residual through the *region* demand deviation.

3.4. Calculate and Store Deviations for all Causer Types

3.4.1. Overview

(a) For each Causer Type a measurement of *active power*, where available, is taken every four seconds.

(b) For each 4-second reading, calculate and store the difference between the *active power* and the reference trajectory.

(c) Calculate the average of these results over each DI for each Causer Type to determine a deviation for each DI.

3.4.2. Deviation components

The deviation components are expressed in the following *regional* power balance equation:

> *Generation* deviation from *scheduled dispatch*
>> minus
>
> *Region* component of ADE[3]
>> minus
>
> Export deviation at *region* boundary
>> minus
>
> *Inter-regional* loss deviation
>> plus
>
> Demand forecast error
>> minus
>
> Deviation of SCADA measured demand from its reference trajectory
>> minus
>
> Deviation of residual demand from its reference trajectory
>> =
>
> Zero

(**Equation 1**)

3.4.3. Determine the deviation components

(a)   Components from SCADA

The following components are determined from SCADA, using interpolation where necessary:

(i)   Gij(t), measured *generation* per *generating unit* or *load* for all metered *market scheduled generating units* and *loads*;

(ii)   GSSij(t), measured *generation* per *generating unit* or *load* for all metered *market semi-scheduled generating units*;

(iii)   DMji(t), measured demand including all *scheduled* and *non-scheduled generating units* and *loads* and *small generating units* that can be measured;

(iv)   IREjk(t), *interconnector* flow measurements (corresponding to the 5-minute NEMDE calculations of *interconnector* flows) designated as *inter-regional* export, measured at a *region* boundary.

(b)   Base trajectories from MMS data

MMS data is processed to calculate the base trajectories for the following:

(i)   *market scheduled generating units* and *loads*, GS;

(ii)   *market semi-scheduled generating units*, GSSL;

(iii)   *market non-scheduled generating units* and *market small generating units* without a 5-minute *generation* forecast, DMX;

(iv)   *market non-scheduled generating units* with a 5-minute *generation* forecast, DMF;

(v)   *interconnector* flow, IREB;

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[3] If the calculation of the ADE by *market* systems ceases in the future, the value of ADE will be set to zero for the purposes of determining the Contribution Factors.

(vi)   *interconnector* loss, IRLB;

(vii)   *region* demand, DGB,

where the terms GS, GSSL, DMF, DMX, IREB, IRLB, and DGB have the following meanings:

GSij(t) is the *dispatched generation* is the *market scheduled generating unit* and *load* base trajectory. It is the straight line between successive total cleared (TC) values (TC values are read from the DISPATCHLOAD database table in MMS).

GSSLij(t) is the *dispatch level* is the *market semi-scheduled generating unit* base trajectory. It is the straight line between successive *dispatch level* (to be read from a yet to be specified data source).

DMXij(t) is the metered demand for metered *non-scheduled generating units* and *loads* and *small generating units* (DM) as measured at the start of the DI.

DMFij(t) is the 5-minute *generation* forecast is the base trajectory for *market non-scheduled generating units* with 5-minute *generation* forecast. It is the straight line interpolation between successive 5-minute forecasts.

IREBjk(t) is the *interconnector* base trajectory, for flow (MWFLOW) is given by the straight line between successive flow values (MWFLOW are read from the DISPATCHINTERCONNETORSRES database table in MMS).

IRLBjk(t) is the *interconnector* loss (MWLOSS) base trajectory is given by the straight line between successive loss values (MWLOSS are read from the DISPATCHINTERCONNETORSRES database table in MMS).

DGBj(t) is the base *region* demand is obtained by subtracting ADE[4] from the total (*region*) demand (including demand forecast offset and ADE adjustments). The total *region* demand is determined by subtracting the *dispatchable load* and the net interchange from the *dispatchable generation*.

(c)   Within 5-minute SCADA data and calculations

The following components are calculated using the SCADA data, cached constants and coefficients and, in some cases, the base values described above:

(i)   IRLjk(t), the *interconnector* loss is calculated from an *interconnector*'s base flow, base loss and MLF:

$$IRLj(t) = MLFj(t) * (IREj(t) – IREBj(t)) + IRLBj(t) \qquad \textbf{(Equation 2)}$$

(ii)   DGj(t), the calculated demand, is determined from the summed *market scheduled generating unit* and *load* base trajectories, the *interconnector* flows in and out of the *region* and the associated losses. The signs have been chosen so that the calculated demand is negative for the purpose of this methodology.

$$DGj(t) = Gj(t) – IREj(t) – IRLj(t) \qquad \textbf{(Equation 3)}$$

(iii)   DGXj(t), the ex-post least squares line of best fit for demand, is calculated from the demand measured at *generating unit* terminals (DG) using a function that converts a set of measurements into a set that is a least squares line of best fit.

(iv)   FI(t) is an AGC parameter that indicates whether more (positive) or less (negative) *generation* is required in order to maintain *frequency* at its nominal value as specified by the *frequency operating standard*.

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

Table 2 summarises the 4-second data components and their related equations or data sources.

Table 2   4-second data

Component	Equation / Data Source
Gij(t)	Read directly from SCADA data
GSij(t)	Determined from TC from the DISPATCHLOAD database table in MMS
GSSLij(t)	An equation/data source relating to *semi-scheduled generating units* – these would be established during implementation as required
DMFij(t)	An equation/data source relating to *non-scheduled generating units* – these would be established during implementation as required
IREjk(t)	Read directly from SCADA data
IREBjk(t)	Determined from MWFLOW from the DISPATCHINTERCONNETCORRES database table in MMS
IRLjk(t)	See Equation 2
IRLBjk(t)	Determined from MWLOSS from the DISPATCHINTERCONNECTORRES database table
DMji(t)	Read directly from SCADA data
DMXji(t)	Read directly from SCADA data
DGj(t)	See Equation 3
DGXj(t)	SCADA data and least squares line of best fit function
DGBj(t)	Determined from the TD from the DISPATCHREGIONSUM database table in MMS minus ADE
FI(t)	AGC parameter

3.4.4. Process to calculate the deviation components

(a)   Calculate the following deviation components and instantaneous 4-second performance measures:

(i)   *generation* deviation from *scheduled dispatch* [Gij – GSij (*scheduled generating unit* and *load* deviation component)]

(ii)   deviation of measured *Semi-scheduled generation* from expected *Semi-scheduled dispatch level* [GSSij – GSSLij (*semi-scheduled generating unit* and *load* deviation component)];

(iii)   *generation* deviation from initial metered level [DMij – DMXij (metered *non-scheduled* metered *generating unit* and *load* and *small generating units* deviation without 5-minute forecasts)];

(iv)   *generation* deviation from forecast [DMij – DMFij (*non-scheduled* metered *generating unit* and *load* deviation components with 5-minute forecasts)];

(v)   export deviation at *region* boundary [IREjk – IREBjk (*interconnector* export deviation component, which is not used in the settlement logic)];

(vi)   *inter-regional* loss deviation [IRLjk – IRLBjk (*inter-regional* loss deviation component, which is not used in the settlement logic)];

(vii) deviation from ex-post of SCADA measured demand [DGj – DGXj (demand deviation component)]; and

(viii) demand forecast error [DGXj – DGBj (demand forecast deviation component)].

(b)   Write the deviation components and 4-second performance measures to the database.

3.4.5. Allocate the deviation components

(a)   Allocate the *regional* power deviation components according to Table 3:

Table 3 *Regional* Power Deviation Components

Sign	Component	Allcocation
+	*Generation* deviation from *scheduled* (applies to *semi-scheduled generation*)	To a specific *generating unit* if a causer.
-	*Region* component of ADE	Ignored.[5]
-	Export deviation at *region* boundary	Ignored (cancels at the *power system* level)
-	*Inter-regional* loss deviation	Ignored.[6]
+	Demand forecast error	To individual 4-second metered *non-scheduled generating units* and *loads* and *small generating units* according to a pro-rating formula, and the remainder to all non-4-second metered residual *loads* in proportion to energy
-	Deviation from ex-post of SCADA measured demand	To an individual *load* if a causer.
-	Deviation from ex-post base of residual demand	To all non-4-second metered residual *loads* in proportion to energy

(b) Note that the cost allocation is done by causer category and there may be several categories applicable to a particular *generating unit* or *load*. For example, *non-scheduled generating units* and *loads* and *small generating units* may be assessed and charged for deviations from their straight-line trajectory between one 5-minute boundary and the next. They could also be separately assessed and charged for their share of the cost of the demand forecast errors incurred in their *regions*.

(c) Once the factors have been evaluated for the required deviation components outlined in Table 3, they can be converted into a single contribution factor for each *Market Participant*/component and used as a basis for charging *Market Participants* a portion of FCAS costs. This is described further in clause 3.8.

3.5. Calculate and Assign 5-minute Factors

3.5.1. Calculate 4-second performance measures

(a) The purpose of this clause is to describe how the calculation module processes MMS data and SCADA data to produce raw 5-minute average factors. MMS data contains information for the calculation of base-point (straight line) trajectories and the SCADA data contains 4-second measurements that can be used to either calculate within 5-minute deviations or ex-post.

(b) For each *generating unit* or *load*, calculate a performance measure by multiplying the deviation by the FI and store the result.

Performance measure = deviation * FI   (**Equation 4**)

(c) FI indicates the extent to which more *generation* (in which case it is positive) or less *generation* (negative) is required in order to keep the *frequency* at 50Hz. The sign of FI indicates which Regulating FCAS is required at any given time.[7] By considering the sign

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[5] The ADE is an allowance made for expected *generating unit* non-conformance based on the current *generating unit* non-conformance. For causer pays assessment purposes, it is sufficient to assess *generating units* against their *scheduled dispatch* alone, without the ADE adjustment. On the other hand, it is not appropriate to lump the ADE adjustment with the demand forecast error. Therefore, AEMO identifies and extracts the ADE in the *regional scheduled* demand balance, but excludes it from the causer pays calculations.

[6] The *regional* power balance includes imports and exports from the *region* and their associated losses, which can be separated from *intra-regional* losses using the same logic as used by NEMDE. When assessing the contribution to cause for the *power system* as a whole, the effect of imports and exports at *regional* boundaries cancel out and can, therefore, be ignored. *Inter-regional* losses cannot be associated with particular *Market Participants*. The simplest approach for Regulating FCAS cost allocation purposes is to ignore the performance measure associated with them, regardless of whether they are positive or negative. In any case, the impact of these losses on the power balance is likely to be very small.

[7] Strictly, the assignment is done before the raw measure is assessed through a 40 second low pass filter.

of the cross product terms between the FI and the deviation components (within the DI) it is possible to determine whether each deviation component is assisting or inhibiting the *power system* in minimising *frequency* deviations. The cross-product term, therefore, provides a basis by which to assess whether a *generating unit* or *load* is a causer or helper.

(d) The deviations calculated in clause 3.4.4 allow for the calculation of the 4-second performance measures. The deviations are simply the first term in the following equations for the 4-second performance measures:

    (i) $F4SM_{ij}(t) = (G_{ij}(t) - GS_{ij}(t)) * FI(t)$ (**Equation 5**)

    (ii) $F4SSM_{ij}(t) = (GSS_{ij}(t) - GSSL_{ij}(t)) * FI(t)$ (**Equation 6**)

    (iii) $F4IF_{jk}(t) = - (IRE_{jk}(t) – IREB_{jk}(t)) * FI (t)$ (**Equation 7**)

    (iv) $F4IL_{jk}(t) = - (IRL_{jk}(t) – IRLB_{jk}(t)) * FI (t)$ (**Equation 8**)

    (v) $F4NSM_{ij}(t) = (DM_{ij}(t) – DMX_{ij}(t)) * FI (t)$ (**Equation 9**)

    (vi) $F4NSMF_{ij}(t) = (DM_{ij}(t) – DMF_{ij}(t)) * FI (t)$ (**Equation 10**)

    (vii) $F4DG_{j}(t) = - (DG_{j}(t) – DGX_{j}(t)) * FI (t)$ (**Equation 11**)

    (viii) $F4FE_{j}(t) = - (DGX_{j}(t) – DGB_{j}(t)) * FI (t)$ (**Equation 12**)

Where:

$F4SM_{ij}$ = 4-second performance measure for metered *scheduled generating unit* and *load* ij;

$F4SSM_{ij}$ = 4-second performance measure for metered *semi-scheduled generating unit* ij;

$F4IF_{jk}$ = 4-second performance measure for *interconnector* jk;

$F4IL_{jk}$ = 4-second performance measure for *interconnector* loss jk;

$F4NSM_{ij}$ = 4-second performance measure for metered *non-scheduled generating unit* and *load* and *small generating units* without 5-minute forecast ij;

$F4NSMF_{ij}$ = 4-second performance measure for metered *non-scheduled generating unit* and *load* with 5-minute forecast ij;

$F4DG_{j}$ = 4-second performance measure for *region* j demand deviation; and

$F4FE_{j}$ = 4-second performance measure for *region* j demand forecast error.

(e) All 4-second performance measures have the unit MW squared.

3.5.2. Calculate 5-minute factors

(a) Calculate 5-minute factors for each of the following:

    (i)   metered *scheduled generating units* and *loads*;

    (ii)   metered *semi-scheduled generating units*;

    (iii)   metered *non-scheduled generating units* and *loads*;

    (iv)   *region* demand deviations;

    (v)   *region* demand forecast errors; and

    (vi)   metered *small generating units*,

from Equations 5, 6, 9, 10, 11 and 12.

(b) A 5-minute factor is the time-averaged 4-second performance measure allocated to one of four categories:

    (i)   lower enabled factor (LEF);

        (ii)   lower non-enabled factor (LNEF);

        (iii)   raise-enabled factor (REF); and

        (iv)   raise non-enabled factor (RNEF).

(c)   Only *scheduled generating units* and *loads* can be raise or lower enabled so they are the only components that can accumulate values for LEF and REF. These categories are explained in clause 3.7.

(d)   The calculation module writes out a CSV file that contains the raw settlement factors from the 5-minute factors.

(e)   Write the 5-minute factors to the database.

(f)   Repeat these calculations for each DI that is to be processed.

3.5.3. Remove factors that have been affected by *contingency events*

(a)   Each of LEF, REF, LNEF and RNEF that correspond to DIs where the *power system frequency* was outside the *normal operating frequency band* due to a contingency will be deleted.

(b)   LEF, REF, LNEF and RNEF will be deleted if an event occurs in a mainland *region* that causes the *frequency* to leave the *normal operating frequency band* in both the mainland and Tasmania *regions*, the relevant 5-minute factors will be deleted from the mainland and Tasmania *regions*. If the *frequency* disturbance is only observed in the mainland *regions* or only Tasmania *region*, only the 5-minute factors for the relevant *regions* will be deleted.

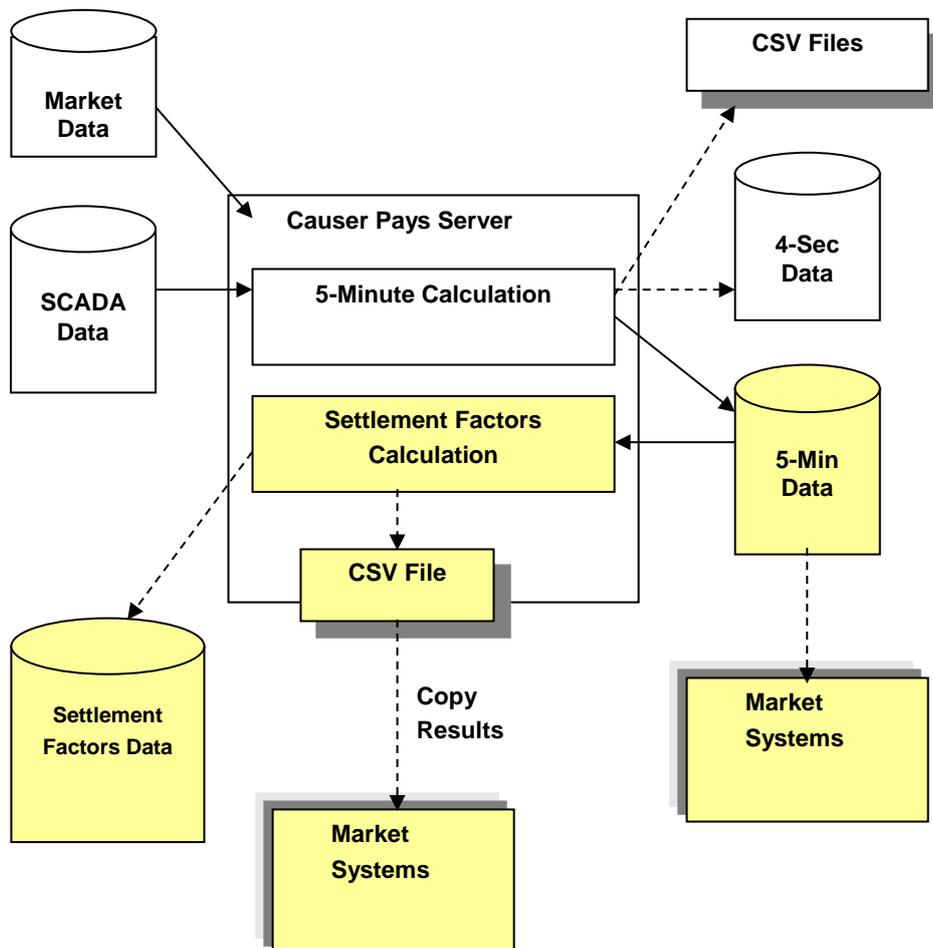## 3.6. Settlement Factors Calculation

This clause describes the logic to convert the 5-minute factor calculations to a form usable in AEMO's settlement systems. The purpose of this logic is to assign each *generating unit* or *load* a fraction of Regulating FCAS costs in accordance with the equations in NER clauses 3.15.6A(h) and (i).

Once the settlement factors have been calculated for each *generating unit* and *load* in the mainland *regions* and for each *generating unit* and *load* in the Tasmania *region* they are normalised to produce a single set of settlement factors. Refer to clause 3.9.

3.6.1. Overview

(a)   The next steps to be performed in determining the causer pays factors are as follows:

        (i)   allocate the 5-minute factors to categories;

        (ii)   aggregate raise and lower calculations for the purpose of determining factors to be used in AEMO's settlement systems;

        (iii)   assess the share of demand forecast error to be assigned to 4-second metered *non-scheduled loads*;

        (iv)   aggregation of *regional* factors to a *power system*-wide level;

        (v)   conversion of the factors to percentage share values; and

        (vi)   aggregation to 28-day values.

(b)   The diagram in Figure 3: Settlement Factors Calculation shows (in yellow) the parts of the FCAS Calculation Module and databases that are required in the settlement factor calculations. The dashed lines indicate the parts of the process where there are alternatives to writing the data. For example, the settlement factors may be written to a database or a CSV file.

Figure 3   Settlement Factors Calculation

3.6.2. Calculating factors for settlement

The Settlement Module calculates the following:

(a)   MPFi (*Market Participant* factor for metered *generating units* and *loads*, indexed by i);

(b)   MPF (the residual *Market Participant* factor for non-metered *generating units*); and

(c)   AMPF (aggregate of all the *Market Participant* factors for a *region*),

Where:

MPFi indicates the fraction of Regulating FCAS costs that are assigned to *Market Participants* with metered *generating units* and *loads*;

MPF indicates the fraction of Regulating FCAS costs that are assigned to *Market Participants* with non-metered *generating units* and *loads*; and

AMPF is simply the sum of all of these.

3.6.3. Procedure

For each DI, n, that falls within the sample period):

(a)   read 5-minute factors for metered *scheduled generating units* and *loads*, *semi-scheduled generating units*, metered *non-scheduled generating units* and *loads* and *small generating units*, *region* demand deviations and *region* demand forecast errors;

(b)   calculate the average of the 5-minute factors for each in the 4 categories of LEF, LNEF, REF, RNEF; and

(c)   create the output files using the logic outlined in this procedure; MMS CSV input file; and PDF files released for publication.

3.7.   Allocate Each 5-minute Factor to a Category

(a)   Allocate each 5-minute factor to one of the following categories: RNEF, REF, LNEF or LEF. The 5-minute factor is determined for these four categories that identify whether the *generating unit* or *load* is enabled for any *regulating raise service* or *regulating lower service*. The four categories are described in Table 4.

Table 4   Categories of Performance Assessment

Condition	Category	Description	Acronym
FI > 0	Raise non-enabled	*Generating unit* or *load* not enabled for *regulating raise service*	RNEF
FI > 0	Raise enabled	*Generating unit* or *load* enabled for *regulating raise service*	REF
FI < 0	Lower non-enabled	*Generating unit* or *load* not enabled for *regulating lower service*	LNEF
FI < 0	Lower enabled	*Generating unit* or *load* enabled for *regulating lower service*	LEF

(b)   If a *generating unit* or *load* is not enabled for *regulating raise service* or *regulating lower service*, the 5-minute factor recorded in the RNEF or LNEF (or both) categories will be zero.

(c)   A positive 5-minute factor identifies a *generating unit* or *load* that responded in a manner that assisted *power system frequency*.

(d)   A negative 5-minute factor identifies a *generating unit* or *load* as a causer of the need for Regulating FCAS.

(e)   In the case of *regional* demands, enablement is not applicable because *regional loads* are not *scheduled* (although the *generating units* to meet them are).

3.8.   Sum the 5-minute Factors

(a)   At At the end of the 28-day sample period, average the 5-minute factors for each category for each Causer Type of *generating unit* or *load*. The averaging of the 5-minute factors is done separately for the Tasmania *region* and mainland *regions*.

(b)   For Causer Type 1, Causer Type 2, *generating units* and *loads*, calculate sub-totals of the 5-minute factors at the *Market Participant* level.

(c)   Positive performance within a category by a *generating unit* or *load* in a *Market Participant's* portfolio can offset poor performance of another *generating unit* or *load* belonging to the same *Market Participant*.

(d)   Define a function, f, and calculate a resultant factor for a *Market Participant* that identifies the *generating units* or *loads* that are causers of the need for Regulating FCAS according to the following equation:

$$f(LEF, LNEF, REF, RNEF) = \min [\, 0, \{ RNEF + LNEF + \min(0, LEF) + \min(0, REF) \} \,]$$
(**Equation 13**)

This equation demonstrates that positive performance in the raise or lower not-enabled categories (RNEF, LNEF) can offset negative performance.

(e)   If the net performance for a *Market Participant* is calculated to be positive, the *Market Participant* is assigned a factor of zero on the basis that only causers will be paying for the costs of Regulating FCAS. Therefore, the resultant factor is negative for causers and

zero for *generating units* or *loads* that have not contributed toward the need for Regulating FCAS.

(f) Letting the sum of factors for metered *scheduled generating units*, metered *scheduled loads* and metered *semi-scheduled generating units* for a *Market Participant* be denoted by SMLEF, SMLNEF, SMREF and SMRNEF, the single factor calculated for a *Market Participant* due to its metered and *scheduled generating unit* or *load* is given by:

$$MSF_i = f(SMLEF_i, SMLNEF_i, SMREF_i, SMRNEF_i) \quad (\textbf{Equation 14})$$

(g) Let *regional* deviation and *regional* demand forecast error factors be denoted by DGLNEFj, DGRNEFj and FELNEFj, FERNEFj, respectively, (noting that j is a *region* index and that the lower-enabled and raise-enabled factors are zero since a *region* cannot participate in these *market*s).

(h) Add the *regional* factors to obtain the system-wide factors and define the system deviation factor (SDF) and the system forecast error factor (SFF) as:

$$SDF = \Sigma f(DGLNEF_j, DGRNEF_j) \quad (\textbf{Equation 15})$$

and

$$SFF = \Sigma f(FELNEF_j, FERNEF_j) \quad (\textbf{Equation 16})$$

(i) Metered *non-scheduled* and *non-scheduled* non-metered *loads* are allocated a proportion of SDF and SFF. The *non-scheduled* non-metered *loads* are allocated the following residual components: SDRF and SFRF (system within-5-minute deviation residual factor[8] and system forecast error residual factor[9]).

(j) Let each metered *non-scheduled generating unit* or *load* or *small generating units* have the factors $NSMLNEF_i$, and $NSMRNEF_i$, (where NSM means metered and *non-scheduled*, i is the *generating unit* (*load*) index, note that *non-scheduled generating units* and *loads* and *small generating units* cannot be raised or lower enabled so these factors are ignored).

(k) Define the sum of the metered *non-scheduled generating unit* or *load* or *small generating units* factors as:

$$MNSTOT = \Sigma f(NSMLNEF_i, NSMRNEF_i) \quad (\textbf{Equation 17})$$

(l) The within-5-minutes system deviation residual factor is then calculated as:

$$SDRF = SDF - MNSTOT \quad (\textbf{Equation 18})$$

Where SDRF = system within-5-minute deviation factor (corresponding to residual (non-4-second metered) *loads*).

(m) Define the fraction MNSTOT / SDF as the proportion of SDF that is assigned to all of the metered *non-scheduled generating unit* or *load* or small *generating units*. Assuming that the same fraction of SFF is assigned to the metered *non-scheduled generating units* and *loads* and *small generating units*, the system residual forecast error factor is given by:

$$SFRF = (1 - MNSTOT/SDF) * SFF \quad (\textbf{Equation 19})$$

Where SFRF = system forecast error residual factor.

(n) The following portion of SFF is divided among the metered *non-scheduled generating units* or *loads* or *small generating units* in the following way:

$$MNSFF_i = (SFF/SDF) * f(NSMLNEF_i, NSMRNEF_i) \quad (\textbf{Equation 20})$$

Where MNSFF = metered and *non-scheduled* forecast error factor.

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[8] The system within-5-minute deviation residual factor is associated with the deviation of *non-scheduled power system* demand during a *dispatch interval* from the least squares line of best fit *of non-scheduled power system* demand for the same *dispatch interval*.

[9] The system forecast error residual factor is associated with the deviation of the least squares line of best fit of *non-scheduled power system* demand for a *dispatch interval* with the forecast demand for that *dispatch interval*.

(o)   The overall factor for each metered *non-scheduled generating unit* or *load* or *small generating unit* is given by the sum of the two (that is, the sum of the factor for within 5-minute system demand deviations and for system demand forecast errors):

$$\text{MNSFi} = \text{f(NSMLNEFi, NSMRNEFi)} + \text{MNSFFi} \qquad (\textbf{Equation 21})$$

Where MNSF = metered and *non-scheduled* factor.

(p)   Combine Equations 14, 18, 19 and 20 to find AMPF, MPFi and MPF as follows:

$$\text{AMPF} = \text{SFRF} + \text{SDRF} + \Sigma\text{MSFi} + \Sigma\text{MNSFi} \qquad (\textbf{Equation 22})$$

for metered *scheduled generating units*, *scheduled* generating *loads* and *semi-scheduled generating units*:

$$\text{MPFi} = \text{MSFi/AMPF} \qquad (\textbf{Equation 23})$$

for metered *non-scheduled generating units* and *loads* and *small generating units*:

$$\text{MPFi} = \text{MNSFi/AMPF} \qquad (\textbf{Equation 24})$$

for non-metered *non-scheduled loads* (the residual):

$$\text{MPF} = \text{(SFRF} + \text{SDRF)/AMPF} \qquad (\textbf{Equation 25}).$$

3.9. Normalise Factors Across All *Regions*

In order to produce a single set of factors for the mainland and Tasmania *regions*[10] the MPF calculated must be normalised according to *regional* demand. The following equation is used to normalise the MPF for each *Market Participant*.

$$NMPF = MPF \times \frac{RPSD_{av}}{TPSD_{av}} \qquad (\textbf{Equation 26})$$

Where:

NMPF is the normalised *regional* participation factor for each *Market* Generator or *Market customer*;

RPSDav is the *power system* demand for the area[11] averaged over the sample period as determined by EMS; and

TPSDav is the total *power system* demand averaged over the sample period as determined by EMS.

3.10. Aggregate Contribution Factors

For each *Market Participant*, determine the net of the positive and negative factors by aggregating the individual *generating unit* and *load* contribution factors for all *generating units* and *loads* within the *Market Participant's* portfolio.

3.11. Process the Positive Contribution Factors

Having determined each *Market Participant's* aggregate contribution factor set all the positive aggregate contribution factors to zero.

3.12. Determine Monthly Contribution Factors (Percentage Attributable)

Determine the percentage share of the total for all *Market Participants* whose *generating units* and *loads* have had their performance assessed in the calculations.

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[10] The values of AMPF and FI will be different in the Tasmania *region* and the mainland *regions.*

[11] In terms of Equation 26 there would be two areas: the mainland *regions* and the Tasmania *region.* The system demand for these two *regions* would be calculated as the total *scheduled* energy in either *region* over the relevant causer pays sample period

3.13. Determine the Residual

The remaining percentage of the total (known as the residual) is attributable to *Market Participants* who have not had their performance assessed.

3.14. Applying Contribution Factors in AEMO's Settlement Systems

(a) For each *Market Participant*, apply a single contribution factor in AEMO's settlement systems. The contribution factor represents the performance of all of the *generating units* and *loads* within each *Market Participant's* portfolio.

(b) The residual factor represents the percentage of Regulating FCAS costs that are to be borne by *Market customers* that do not have a contribution factor calculated for them.

3.15. Allocate Residual Costs

The residual costs are recovered from *Market customers* in proportion to the energy consumed by them over the 28-day sample period.

4. PUBLISHED INFORMATION

The following files are available on the AEMO website:

(a) the Aggregate FCAS Settlement Factors for all *regions*
http://aemo.com.au/Electricity/*Market*-Operations/Ancillary-Services/Process-Documentation/Ancillary-Services-Causer-Pays-Contribution-Factors;

(b) the Elements Index File, the Variables List File and the Dynamic Data File
http://aemo.com.au/Electricity/Data/Ancillary-Services/*Market*-Causer-Pays-Data.

5. DEALING WITH REGIONS WHEN THEY BECOME ELECTRICALLY SEPARATED

5.1. Separation During Sample Period

The current methodology does not calculate factors that reflect separated *regions* during a sample period[12]. There is no automatic logic to deal with *regions* when they become electrically separated. The number of occurrences of *region* islanding is typically very low and the durations when they occur are relatively short and, therefore, the increased complexity of the process and the added expenses of covering these reasonably rare contingencies are not warranted. Although data is collected for the duration of a *regional* separation, this data is discarded and is not applied in determining the contribution factors for the mainland *regions*.

5.2. Contribution Factors for Periods of Asynchronous Operation

5.2.1. Overview

(a) This clause 5.2 explains how Contribution Factors are determined under clause 3 15.6A(j)(2) of the NER during a period in which *regions* are operating asynchronously with each other and a *local ancillary service requirement* for Regulating FCAS applies.[13]

(b) AEMO uses the same procedure to determine the apportionment of the cost of *local market ancillary service requirements* for Regulating FCAS in other circumstances.

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[12] This does not include an outage of Basslink. The calculation of Contribution Factors will not be affected if the Tasmania *region* is separated from the mainland *regions*.

[13] There is no separate process in relation to the permanent asynchronous operation of Tasmania and the mainland *regions* if the Basslink frequency controller is operating normally and there is no local market ancillary service requirement for Regulating FCAS.

(c) To determine the Contribution Factors relevant to the allocation of the cost of Regulating FCAS to a *region* or *regions* that have operated asynchronously during a *trading interval*, the key inputs are:

    (i) the currently applicable published MPFi values of those *Market Participants* that are relevant to the *region(s)* identified in a *constraint* for a *local market ancillary service requirement*: and

    (ii) 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.

5.2.2. Identifying relevant Market Participants

Each *constraint* for a <u>*local market ancillary service requirement*</u> for Regulating FCAS identifies one or more *regions* to which the requirement applies. Each *Market Participant* that is *financially responsible*[14] for a *connection point* in the *region(s)* is 'relevant' to the requirement.

5.2.3. Calculating CMPF, CRMPF and RAMPF values

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

(a) the Constraint MPF (CMPF), being the sum of the currently applicable *NEM* values of MPFi for all relevant *Market Participants*; and

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

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

where:

    (i) MPF = 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*.

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

5.2.4. Calculating individual Market Participant Contribution Factors for asynchronous operation

For each *Market Participant* having a published MPFi, and which is relevant to the *local market ancillary service requirement* for Regulating FCAS, the *Market Participant's* individual Contribution Factor for asynchronous operation is determined as a percentage by dividing MPFi by RAMPF.

5.2.5. Calculating aggregate Residual Contribution Factor for asynchronous operation

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

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

5.2.6. 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 Regulating FCAS, as described in this clause 0.

(b) The CMPF is estimated by summing the MPFi values for all *Market Participants* relevant to the affected *region(s)*.

(c) The CRMPF is estimated by multiplying MPF 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*.

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