WHO SHOULD PAY FOR ANCILLARY SERVICES?

A Project Commissioned by the NEMMCO Ancillary Services Reference Group

APPENDICES

July 1999

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A.1 Background

A.1.1 Introduction

The Frequency Control Ancillary Services (FCAS) includes the management of both small and large frequency deviations. Their provision incurs more than half of the cost of ancillary services in the NEM. The draft ancillary services evaluation report recommended the establishment of a two-way energy deviations market to manage small frequency deviations and time error in the NEM, and to contribute to the management of large deviations. It would be supplemented by markets for FCAS enablement that would ensure that a capability to manage frequency deviations is always available.

The energy deviations market would require no external injection of funds. However, during the transition the provision of FCAS would need to be funded and to this end it is proposed to apply the "causer pays" principle. This would require cause and provision of FCAS to be measured at close to real time. For testing purposes and for an initial implementation, this could be done using SCADA measurements of loads that are available to NEMMCO at close to real time. More accurate local measurement techniques could be developed later.

The purpose of this appendix is to consider in more detail how such arrangements could be implemented. The work has been done in consultation with NEMMCO staff, using sample data supplied by NEMMCO. Further testing and analysis will be required prior to implementation.

Any errors of fact or interpretation in this Appendix are the responsibility of IES.

A.1.2 Analysis Required

Section 3.5.4 of the draft evaluation report outlines in very broad terms how energy deviations could be measured, priced and settled. The broad approach will be re-stated here, and refined to take into account the specific features of NEMMCO's AGC in the following sub-section. A more convenient sign convention will also be used. For a particular short term interval (to be determined, but of the order of seconds), we propose the following payment logic:

Energy Deviations Payment (to a generator or by a load)

= Real Time Pricing Increment * Incremental Energy

= Constant * Filtered ACE * Incremental Energy

Where:

Constant	is a (positive) constant tuned on the basis of experience to achieve the amount of regulation required to meet NEM standards.
Filtered ACE	is the filtered Area Control Error as determined by NEMMCO's AGC (this to be extended to allow for time error in the following sub-section). Under

the AGC convention, the ACE is positive if there is a requirement for more power (i.e. energy within a small time interval) to balance the system, and negative if there is a requirement for less power.

Incremental Energy is the difference between actual energy produced or consumed in the interval and a base energy level determined with reference to the energy market.

Similar logic to allocate costs in accordance with the causer pays principle as described later in this Appendix. In both cases, payment would be in proportion to a weighting factor where:

Weighting Factor = Filtered ACE * Incremental Energy

Note that the above Weighting Factor averaged over a number of time periods is similar to the statistical measure of *covariance* between the system deviation (Filtered ACE) and a unit's energy deviation (Incremental Energy)[1]. In essence, though, the concept is to:

- reward a participant in proportion to the extent to which their equipment is helping to correct a frequency/time error deviation; and to
- charge in proportion to the extent which their equipment is causing that deviation.

This is illustrated in the hypothetical and somewhat artificial example in the following table. Note that the relativities in the totals rather than the absolute values are significant.

Table A.1: Example of Provider/Causer Calculation

Int'l	**Filtered ACE (System Deviat'n)**	**Incremental Energy ("Unit" Deviation)**				**Weighting Factor (for each "Unit")**			
		Load	**U1**	**U2**	**U3**	**Load**	**U1**	**U2**	**U3**
1	-10	-10	0	-20	10	100	0	200	-100
2	-20	-20	0	-40	20	400	0	800	-400
3	-120	-120	0	-240	120	14400	0	28800	-14400
4	40	40	0	80	-40	1600	0	3200	-1600
5	0	0	0	0	0	0	0	0	0
6	110	110	0	220	-110	12100	0	24200	-12100
Total	**0**	**0**	**0**	**0**	**0**	**28600**	**0**	**57200**	**-28600**

Although this example is somewhat artificial it does illustrate some basic points:

[1] The term would be equivalent to a covariance if each of its components had an expected value of zero.

- In this lossless model, the generation unit deviations sum to the load, because the total energy market basepoints for generators must equal that of the load, and the sum of actual generation must equal the actual load.
- The system deviation varies from negative values initially (indicating a power surplus) to positive or zero values in later periods (indicating a power deficiency), averaging zero in this example[2].
- The Load in this example begins with a shortfall (negative deviation) relative to the energy market basepoints, but exceeds the energy market basepoints in later periods. The Load in this case tends to contribute to the system deviation. This is indicated by positive weighting factors implying a net payment *by* the Load.
- Unit 1 with zero energy deviations incurs weighting factors of zero (as would all units with no correlation between their deviations and those of the system).
- Unit 2 is below the energy market baseline when the system is in power surplus (negative system deviation) and above it when the system is in deficit (positive system deviation). It therefore acts to correct the system deviations. This is indicated by the positive weighting factors, which imply a payment *to* the unit.
- Unit 3 is above the energy market baseline when the system is in power surplus (negative system deviation) and below it when the system is in deficit (positive system deviation). It therefore acts to cause the system deviations. This is indicated by the negative weighting factors, which imply a payment *by* the unit.
- Relatively high weighting factors are produced by periods of high system and unit deviations.
- In summary, the weighting factors show that Unit 2 has corrected the deviations while Unit 3 and the Load have caused them . The weighting factors are measures of how this cause and effect could be allocated over the period of interest. Note that the sum of the unit weighting factors is positive, indicating a *net* payment *to* the generation sector, which is funded by payments *by* the Load
- Real systems could show more complex interactions. In particular, a unit or load may be causing deviations on some occasions and correcting them on others.

The following sections in this appendix will describe the calculation of the "deviation" terms in more detail, with an examples based on data provided by NEMMCO.

[2] The average would tend to exactly zero if the filtered ACE consisted of linear frequency and time error terms, as any other outcome would imply a long run bias away from target (zero deviation) averages. However, as discussed later in the appendix, the frequency and time errors are modified with non-linear gains within the AGC logic, so the average may be biased away from zero.

A.1.3 Data

NEMMCO has provided sample data from the SCADA and AGC over a period of about 10 hours at 10-second intervals. This sampling interval is rather longer than the AGC cycle time but sufficient for the purpose at hand. Table A.2 on the following page shows the form of the data provided. In essence, for each sample interval the data included:

For the system as whole:

- the system frequency (FREQ);
- corresponding frequency deviation (DEV), Area Control Error (ACE) and ACE integral values (ACE Int) as used in the AGC;
- adjusted values of these variables as processed by AGC regulation logic (Regp and Regi).

For each unit for which data were provided:

- actual generation in MW (Act Gen);
- the set point or target power level in MW from the previous run of the SPD for this interval (Setpoint);
- the amount enabled in MW for the 5-minute raise service obtained from the SPD, using long term contract offer prices (5ra);
- the amount enabled in MW for the 5-minute lower service obtained from the SPD, using long term contract offer prices (5la);
- the Regulation Participation Factor as determined through the SPD process (RPF);
- the required MW of regulation from the unit prior to being filtered (RawReg);
- The filtered MW of regulation required (RegComp);
- The desired total MW of generation from the unit (DesGen).

Data for a range of NSW and Victorian units were provided including units that were enabled for AGC and many that were not. A large NSW power station provided most of the regulation over the period. At the time of writing, the range of units for which data were provided and for which the data were useable was insufficient to allow a complete analysis of generation and loads over the sampling period. Nevertheless, sufficient were provided to examine *how* the data should be analysed and to give some indicative results.

A.1.4 Outline of Appendix

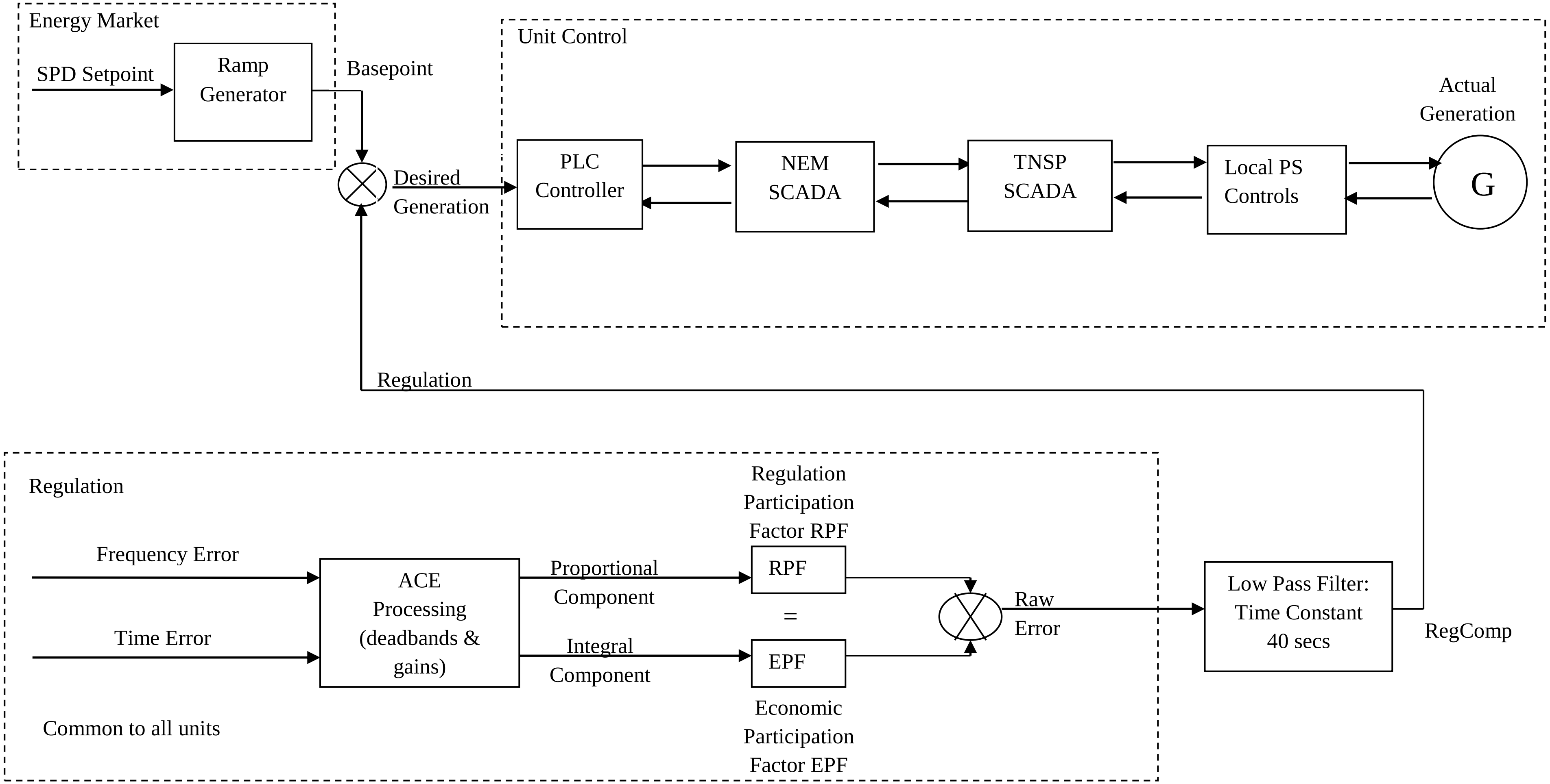
The NEMMCO AGC system is described in some detail in Section A.2 followed by a consideration of how system deviations (Section A.3) and "unit" deviations (Section A.4) can be determined in a manner consistent with this system. In Section A.5 we then analyse the performance of specific units according to this logic. The implications of the analyses are considered in Section A.6. Conclusions are in Section A.7.

Table A.2: Sample of Data Used for Analysis of Deviations

Time	NSW/VIC/SA						Unit 1							
30/03/99	FREQ	DEV	ACE	ACE Int	Regp	Regi	Act Gen	Setpoint	5ra	5la	RPF	Rawreg	RegComp	DesGen
15:11:00	50.007	0.007	14.00	9.25	0.00	-5.55	604	590	50	50	0.2	-1.11023	-0.188	593.3176
15:11:10	50.003	0.003	6.00	9.30	-7.20	-5.58	603	590	50	50	0.2	-2.55557	-0.57395	592.3149
15:11:20	50.005	0.005	10.00	9.32	0.00	-5.59	603	590	50	50	0.2	-1.11796	-0.67475	591.3253
15:11:30	50.008	0.008	16.00	9.37	0.00	-5.62	602	590	50	50	0.2	-1.12463	-0.7934	590.4257
15:11:40	50.018	0.018	36.01	9.45	-90.03	-5.67	602	590	50	50	0.2	-19.1396	-4.19608	585.8039
15:11:50	50.019	0.019	38.01	9.59	-95.02	-5.76	601	590	50	50	0.2	-20.1559	-8.66543	582.1705
15:12:00	50.007	0.007	14.00	9.63	-16.80	-5.78	600	590	50	50	0.2	-4.51556	-8.02229	582.4672
15:12:10	50.016	0.016	32.01	9.75	-80.01	-5.85	600	590	50	50	0.2	-17.1729	-11.019	579.4413
15:12:20	50.014	0.014	28.01	9.83	-70.02	-5.90	601	590	50	50	0.2	-15.1836	-12.4954	577.5046
15:12:30	50.000	0.000	0.00	9.86	0.00	0.00	602	590	50	50	0.2	0	-9.8313	580.1687
15:12:40	50.013	0.013	26.01	9.89	0.00	-5.94	601	590	50	50	0.2	-1.18732	-8.22759	582.3112
15:12:50	50.014	0.014	28.01	9.97	-70.02	-5.98	599	590	50	50	0.2	-15.1996	-7.72938	582.2706
15:13:00	50.010	0.010	20.00	10.01	-24.01	-6.01	598	590	50	50	0.2	-6.00248	-7.45103	583.0296
15:13:10	50.004	0.004	8.00	10.04	-9.60	-6.02	598	590	50	50	0.2	-3.12516	-6.29691	583.7031
15:13:20	50.002	0.002	4.00	10.05	0.00	-6.03	596	590	50	50	0.2	-1.20545	-5.35243	585.0518
15:13:30	49.997	-0.003	-6.00	10.04	0.00	0.00	596	590	50	50	0.2	0	-4.04062	586.6705
15:13:40	49.998	-0.002	-4.00	10.03	0.00	0.00	596	590	50	50	0.2	0	-3.29111	586.7089
15:13:50	50.005	-0.001	-2.00	10.00	0.00	0.00	595	590	50	50	0.2	0	-2.78631	587.2137
15:14:00	50.010	0.010	20.00	10.05	0.00	-6.03	594	590	50	50	0.2	-1.20619	-2.36715	587.2588
15:14:10	50.012	0.002	4.00	10.05	0.00	-6.03	593	590	50	50	0.2	-1.20646	-2.04568	587.7824
15:14:20	50.013	0.013	26.01	10.13	0.00	-6.08	591	590	50	50	0.2	-1.21606	-1.8251	588.1749
15:14:30	50.002	0.002	4.00	10.16	0.00	-6.10	590	590	50	50	0.2	-1.21926	-1.71267	588.3201
15:14:40	50.000	0.000	0.00	10.19	0.00	-6.11	591	590	50	50	0.2	-1.22246	-1.58268	588.4173

Source: NEMMCO

Figure A.1: AGC in the NEM



Notes: Control logic for a particular unit is shown. The EPF is set equal to the RPF in the current AGC implementation.

A.2 Automatic Generation Control (AGC) in the NEM

Figure A.1 on the previous page shows the main elements of the NEM AGC system and its interfaces to the energy market, the key variables in the system (frequency and time error), and the control of generating units through the System Control and Data Acquisition (SCADA) system. The major elements of the system and its parts will be described in turn.

A.2.1 Overall

- The components grouped at the top-left of the system relate to implementing *the energy market logic* that essentially operates on a 5-minute cycle. The energy controlled through these components has been priced though the SPD logic.
- The components at the bottom left relate to the *regulation* of the system i.e. frequency and time error control in real time. Most of this processing is common to all units. It is proposed that the energy controlled through these components be priced and traded using the Real Time Pricing (RTP) logic outlined in Section 5.3 of the Evaluation Report.
- These two components (expressed in terms of MW targets) are then added to produce a desired level of generation (in MW) for each unit. This target is then processed through unit-specific controls to produce actual generation levels, shown at the top and right.
- These actions, when combined with the load, influences system frequency and time error. These are measured and modify the operation of the regulation components of the AGC in a "feedback loop". The energy components operate to a fixed profile until the start of the next 5-minute dispatch interval.

A.2.2 Energy market components

- Each 5-minutes the SPD produces an energy (MW power) target or setpoint for each unit to be achieved by the end of the following 5 minutes.
- The SPD assumption is that the unit will be ramped up at a constant rate *from its actual operating level at the start of the 5 minutes* to its set point value at the end. The SPD solution respects the nominated ramping capability of each unit. Note that setting actual generation as the starting point in the 5-minute dispatch process notionally brings the energy deviations of each unit back into the energy market dispatch process, whether they be due to participation in regulation or simply failure to follow dispatch instructions.
- Ramping is implemented by the ramp generator shown at the top and to the left of the AGC diagram. The output is a real time target for operation in the energy market, called the basepoint.

Figure A.2 illustrates the out-workings of this over a half-hour period of a large black coal-fired generation unit under AGC control. The Figure shows the desired generation of the unit less the regulation component. i.e. it shows the AGC basepoint for the unit[3]. Note that the small-scale variations can be attributed to round-off error in the data.

Figure A.2

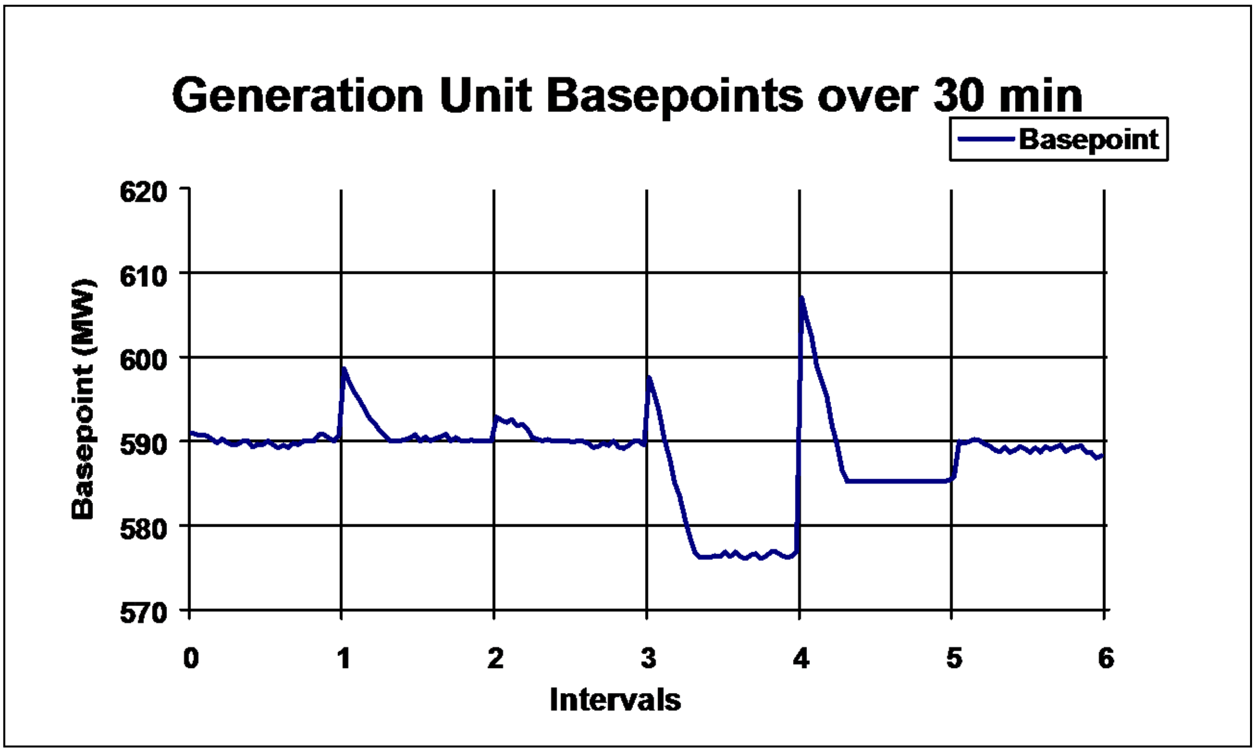


Figure A.2 clearly shows the energy market setpoints as the horizontal parts of the curve. Over the half-hour of interest this setpoint changed three times for the unit. At each 5-minute boundary a step change in basepoint can be seen. This step essentially brings existing generation back into the energy market as previously described.

There is then a clear ramp-down, not over the 5 minutes which the energy market assumes, but over 90 seconds (about one third of the 5 minute interval). NEMMCO advises that this accelerated move to the energy market set point is intended to compensate for the sluggish response usually experienced from some generators. The idea is that an accelerated move to the energy market setpoint as a target will tend to see the target actually being achieved at the end of 5 minutes. NEMMCO also advises that the rate of move to the energy market setpoint will be a parameter that can be set for individual generation unit.

The perceived need to compensate for sluggish performance by some generators using this approach is relevant to the issue of how the reference level for measuring energy should be determined. This will be considered in more detail later.

A.2.3 Regulation components

The regulation control components are shown at the bottom left of Figure A.1.

[3] Direct basepoint values were not provided with the data but can readily be inferred by difference as described.

- Inputs are the measured frequency and time error for the system. These measures are essentially uniform throughout an inter-connected AC system during the timeframe of interest for regulation. The combination of the frequency and time errors are used to make up the Area Control Error (ACE) which the AGC uses to regulate the generation.

- The "ACE Processing" box essentially does the following:

  - Converts the frequency error into an estimate of the MW deficiency in the system – the proportional component of the ACE. The factor used in the data supplied is 2000 MW/Hz.

  - The time error is converted to a value the integral of the ACE (ACE Int), which is a MW equivalent of the time error. The time constant currently used is one hour. In other words, there is a weighting attached to time error which is relatively slow moving relative to the change in frequency error. In essence, time error control is set to provide a second-order trim to the primary function of controlling frequency.

  - ACE processing then multiplies these estimates of MW errors by a variable *gain*. In broad terms, when the error is small, a low gain (as low as zero) is used. This imposes a "dead band" for small deviations, eliminating unnecessary control action at such times. For higher deviations the gain is increased in steps to a value as high as 5. The gain at the higher end is intended to promote a greater and more rapid correction for the more significant deviations [4].

- The proportional (frequency-related) and integral (time-error related) control components are then added to form what is in effect a raw or unfiltered system error.

- The unfiltered system error is then multiplied by the *Regulation Participation Factor (RPF)*, which is obtained through the SPD process based on offers to supply regulation capability (currently under long term contracts). This distributes the desired regulation control to particular units. As currently implemented, the RPF applies to both the frequency and time-error related components of the system error.

- The resulting signal is then put through a low pass digital filter with a time constant currently set to 40 seconds[5]. This essentially smooths out the desired control action to the unit so that it does not respond prematurely to very short-term system fluctuations.

- This signal is then added to the unit's energy base point to set a generation target for the unit.

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[4] In control theory terms, a high gain controller can remove a greater part of the error than a low gain controller, but there is then a greater possibility of instability in the system.

[5] With a 10 second time interval, for example, a digital low pass filter with a 40 second time constant would be implemented as follows:

Current Filtered Error = 0.25 * Current Unfiltered Error + 0.75 * Previous Filtered Error

The combined effect of these filtered error signals from all regulated units (a MW value) represents the total MW response that is being sought at that time from all units under AGC regulation. This will be called the Filtered System Error[6].

A.2.4 Unit control components

These components lie at the top right of Figure A.1. In essence, they convert the desired generation of a unit into signals for actual control, and adjustments are made to reflect the actual performance of the unit in meeting its desired generation. The functions are distributed between NEMMCO's systems, the intermediate NEM and TNSP SCADAs, and local control logic. An important point here is that the "desired generation" input will not always be achieved, especially with slow moving units when the desired generations is changing rapidly to meet a regulation requirement or a change in energy market setpoint.

A.3 Determination of System Deviations

We now turn to a more detailed consideration of how to determine the deviation of the system for the purpose of measuring small deviation FCAS performance. There are two possibilities:

A.3.1 Measure responses of units under regulation

This approach would assume that the units under AGC regulation are being controlled and in fact respond to the requirements of the system to correct frequency and time error deviations. The larger the correction (measured as a deviation from the energy market by units under AGC regulation), the larger the implied frequency deviation. There are two problems with this approach:

- it depends on a particular set of units being nominated as the reference units (i.e. those units under AGC regulation;
- it assumes these units are systematically correcting system deviations according to AGC instructions and never causing them – contrary to the evidence of preliminary analysis.
- it excludes the contribution to correcting frequency deviations of units and loads not under AGC regulation control.

Given that a more objective measure is available as described below, we reject this approach.

A.3.2 Measure deviations of loads

This approach would measure the deviation of loads from the NEMMCO forecasts used in the SPD and presume this is the deviation in the system to be corrected. This approach suffers from the presumption that it is only loads that cause frequency deviations.

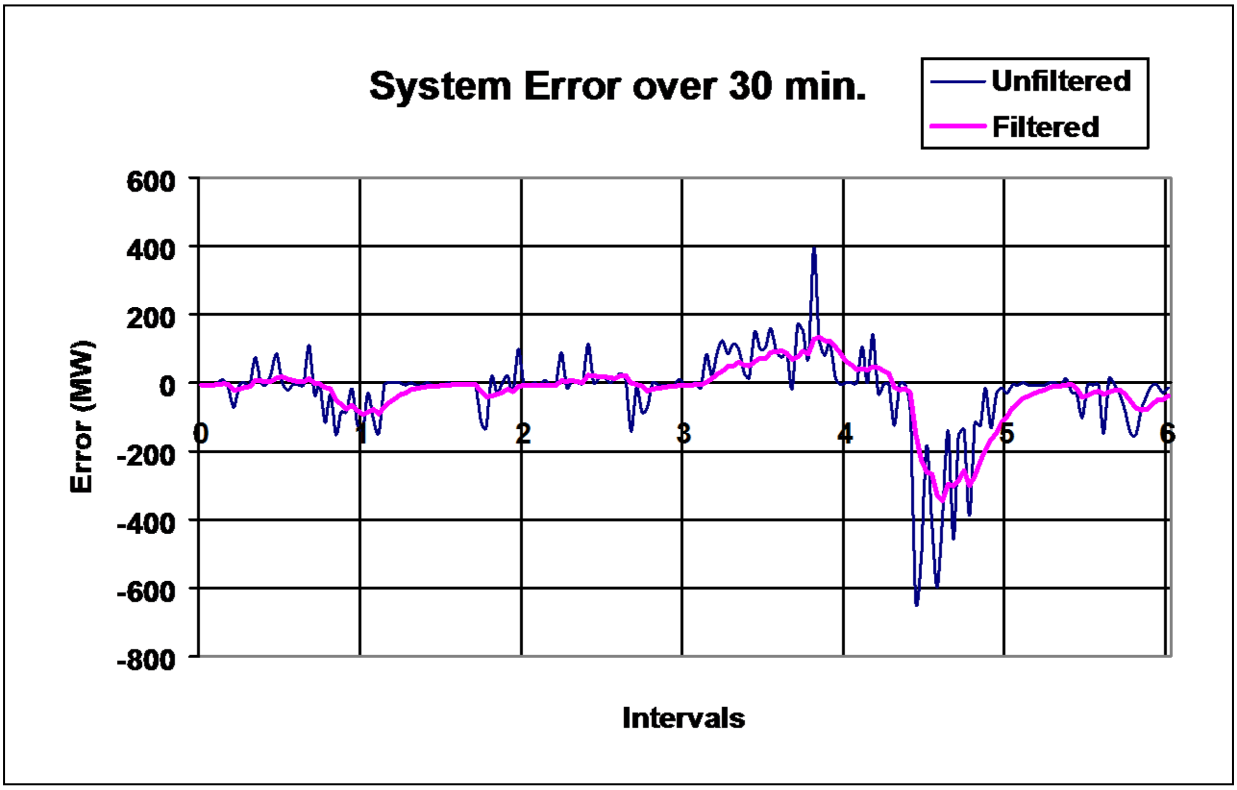
[6] It is straightforward to show that the Filtered System Error can be obtained directly by applying the low-pass filter to the System Error.

A.3.3 Directly reference the system error determined by the AGC

The earlier discussion of the AGC described a "Filtered System Error" calculated by the AGC for control purposes. We argue that this is the appropriate measure of the deviations in the system that FCAS is trying to correct. To see this, suppose that all the units under AGC regulation perform perfectly as the AGC requests, i.e. meet their "desired generation" targets. Then each would be generating an increment (positive or negative) relative to the energy market basepoint that would in total be the MW target defined by the Filtered System Error. This follows directly from the AGC logic. The regulating output of all such units would be fully correlated with the Filtered System Error. In practice, the correlation will not be perfect and could be quite poor if regulating units respond slowly to changes system conditions

It may seem strange that perfect performance of the regulating units does not imply that all the frequency and time deviations in the system are removed. This outcome arises from the control logic of the AGC rather than from the performance of units themselves[7]. While the control algorithm might well be improved in various ways in the future, it is important that the pricing logic of the energy deviations market be fully consistent with the AGC control logic that is actually being used.

Figure A.3



[7] In control theory terms, the filtered system error is a proportional only control signal and an offset (ongoing error) is required to actually produce the control. This offset could be reduced by increasing the gain (the gain is 5 in the system at present) but this may introduce stability problems. Alternatively, an additional "integral" term could be introduced to remove the offset (frequency error and time error) over time. We do not see any immediate need make such changes.

Figure A.3 shows the filtered and unfiltered versions of the System Error over a half-hour. The smoothing effect of the filtering can be seen clearly. The unfiltered error, scaled before filtering by the unit's RPF (which is zero if not participating in regulation) is added to the energy basepoint of each generator to obtain the desired generation for the unit.

Positive deviations imply a MW shortfall (frequency sag). Negative deviations imply the opposite – a rise in frequency caused by excess generation. Figure A.3 shows both moderate and relatively large errors in both directions, corresponding to drifts in frequency within the half-hour. The frequency deviation in this sample and for all the data supplied was well within the small deviation frequency band (within 0.1 Hz of 50 Hz) set by the current NEM frequency standard for normal operation. Note that the MW value of the System Error (either filtered or unfiltered) includes a gain factor set to achieve the desired level of control.

A.3.4 Proposal

The Filtered System Error should be used as the measure of deviation in the system for the purpose of measuring performance. The advantages of using this measure are:

- it is readily obtainable in real time from the AGC;
- its use would be consistent with the idealised performance of units under AGC regulation; and
- its use for pricing or cost allocation purposes would involve no modifications to existing control logic - i.e. the pricing and cost allocation module could be implemented as an independent software module.

A.4 Determination of Unit Deviations

The proposed energy deviations market as well as the cost allocation methodology for small deviation FCAS during the transition both require the deviation of units from the energy market to be measured in close to real time. It is proposed that this be done using SCADA measurement initially, with more robust and accurate measurement being implemented at a later stage if desired. There are at least four possible energy reference levels against which to determine deviations from the energy market. These are:

1. the “desired generation” for each unit as calculated by the AGC which, as noted below, implements an accelerated approach to the 5 minute energy market dispatch setpoints;
2. the desired generation level corresponding to energy market dispatch basepoints implemented without acceleration, taking account of the “reset” process that occurs at the beginning of each 5-minute dispatch period;
3. as in 2 above, but without the reset at the beginning of every 5-minute dispatch period; or
4. a reference level of zero.

Each of these is discussed in turn.

A.4.1 Relative to AGC desired generation

For units under AGC control (with or without regulation) this measure is readily extracted from the AGC. A parallel calculation could be made for dispatchable units not under AGC.

The problem with this approach is that it includes a facility (accelerated approach to the set point, discussed in Section A.2.2) that has been explicitly implemented to compensate for performance shortcomings of particular generation units. It can be argued that such a facility properly belongs in the "Unit Control" section of the AGC and downstream controls, rather than in the energy market dispatch logic. As the AGC is currently configured this measure cannot be used.

A.4.2 Relative to energy market basepoints with 5-minute reset

This reference level would be the energy market base points calculated as if the unit is ramped smoothly from its current level (at the beginning of the 5-minute dispatch period) to the energy dispatch set point for the 5 minutes. The base point would be reset to the actual operating level at the start of each 5-minute dispatch period. This would implement the current interpretation of the boundary between energy market dispatch and ancillary services.

A.4.3 Relative to energy market basepoints without 5-minute reset

An alternative view of the same control logic is that the energy market dispatch is implemented as a continuous trajectory with constant ramping between energy market set points. Any variation between this trajectory and actual operation is a deviation. With this view, it is merely an operational matter that deviations present at the end of 5 minutes are systematically ramped back to zero in the following 5 minutes; a deviation at the end of a 5 minute dispatch interval is still a deviation at the start of the next.

A.4.4 Relative to zero

A more radical view is that the energy market implies no operational trajectory within the half-hour at all – only energy production or consumption in the period of interest. With this view the business of ramping would be managed entirely within an energy deviations market (which would include the current 5-minute dispatch logic with the current settlement anomaly corrected). Application would be simple; the deviation price at any instant would be applied to all the energy at that instant.

A.4.5 Initial assessment

The notion that there is some reference level against which energy deviations of units and loads can be measured arises from a view that the energy market outcome implies a performance contract on dispatchable units. This contract has a reference price and quantity as determined by the 5-minute dispatch outcome[8]. Deviations from this are priced at the reference price with an additional deviation price component set by the state of the system at

[8] Noting that the implementation in settlements is anomalous and needs to be fixed.

the time, designed to maintain the system in a secure condition as described previously. The different cases listed above are different interpretations of what that performance contract is.

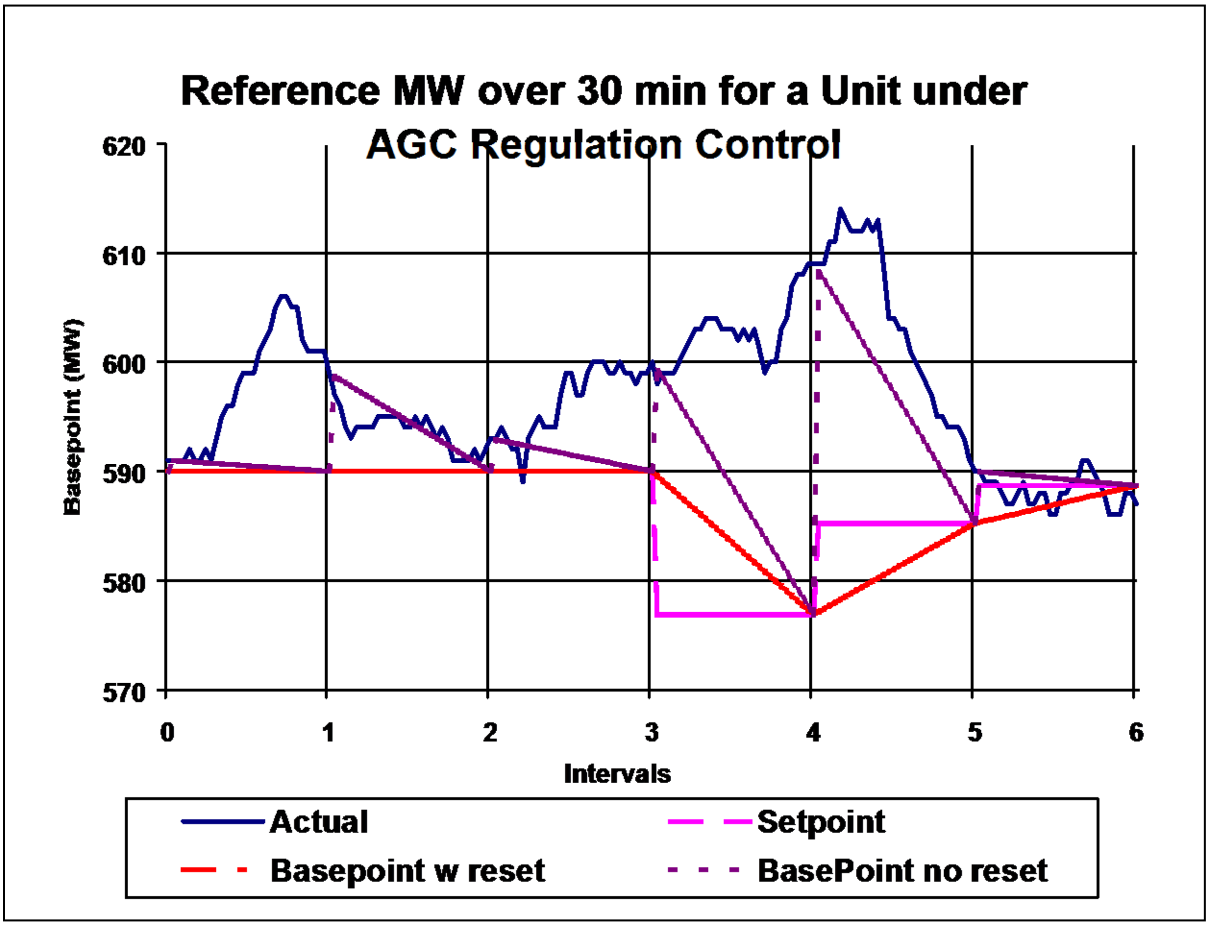
We note at this point that the 5-minute dispatch price takes account of any limitations on the ability to ramp output over 5 minutes. Thus the current 5-minute energy market dispatch logic includes a "load following" service. For this discussion we accept the current boundary between the energy market and FCAS; namely, that load following between 5-minute reset points lies within the energy market whereas the control of frequency within the 5 minutes is FCAS. In broad terms, then, the 5 minute ramping implied by the setpoints from the energy market SPD process provide an appropriate reference level for measuring deviations that are to be corrected by FCAS. We therefore exclude a zero reference level from further consideration and examine only the following two ways for measuring energy deviations:

- relative to energy market base points *with* 5-minute reset;
- relative to energy market base points *without* 5-minute reset.

A.4.6 Example

Figure A.4 shows actual generation for a unit under AGC regulation and these two reference levels, for a half-hour period covered by the sample data. The following should be noted.

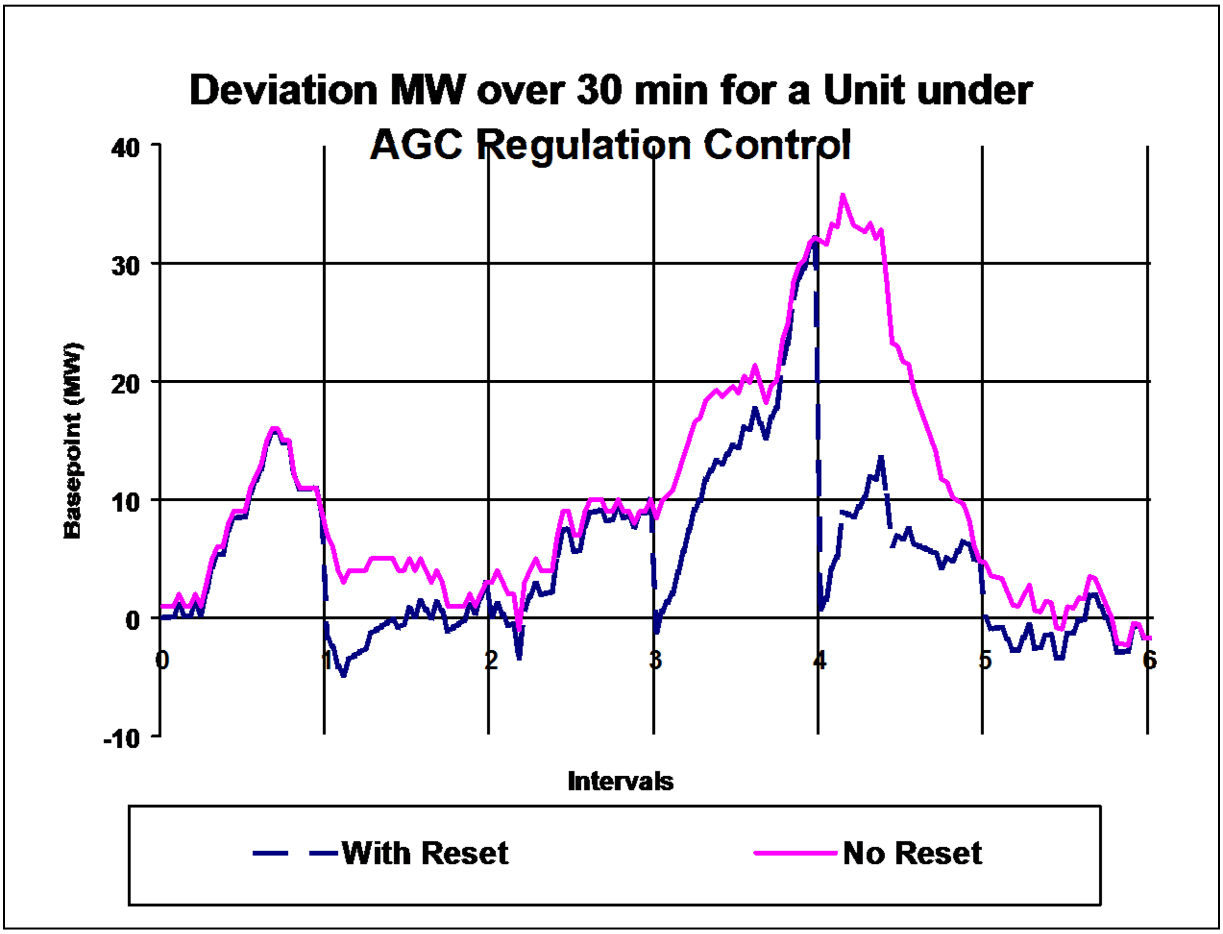
Figure A.4



- Actual generation (the line showing random variation) varies over a range of about 20 MW in the time period. At this time this unit over is under AGC regulation at an RPF of 0.2 i.e. it is scheduled to provide 20% of the small deviation FCAS regulation service
- The setpoint (from the energy market dispatch process) is the horizontal line between intervals that makes a step change at the boundaries. This is provided for information and is not a proposed reference level.
- The Basepoint with Reset is the saw-toothed line. Just prior to the 5-minuter boundary it reaches the energy market setpoint. Just after it is set to the actual generation. In between it ramps at a constant rate.
- The Basepoint with no Reset is the line that linearly ramps between setpoints, the ramp rate changing at the 5-minute boundary.

Clearly, each of these reference energy levels will provide a different measure of energy deviation over the period of interest. Figure A.5 compares the actual deviations for the cases with and without reset.

Figure A.5



There is a clear difference between the reset and no reset cases I Figure A.5. The no reset case is smoother and the deviation is larger, notably at the start of each 5-minute period (when the deviation for the reset case is set to zero, by definition).

A.4.7 Proposal

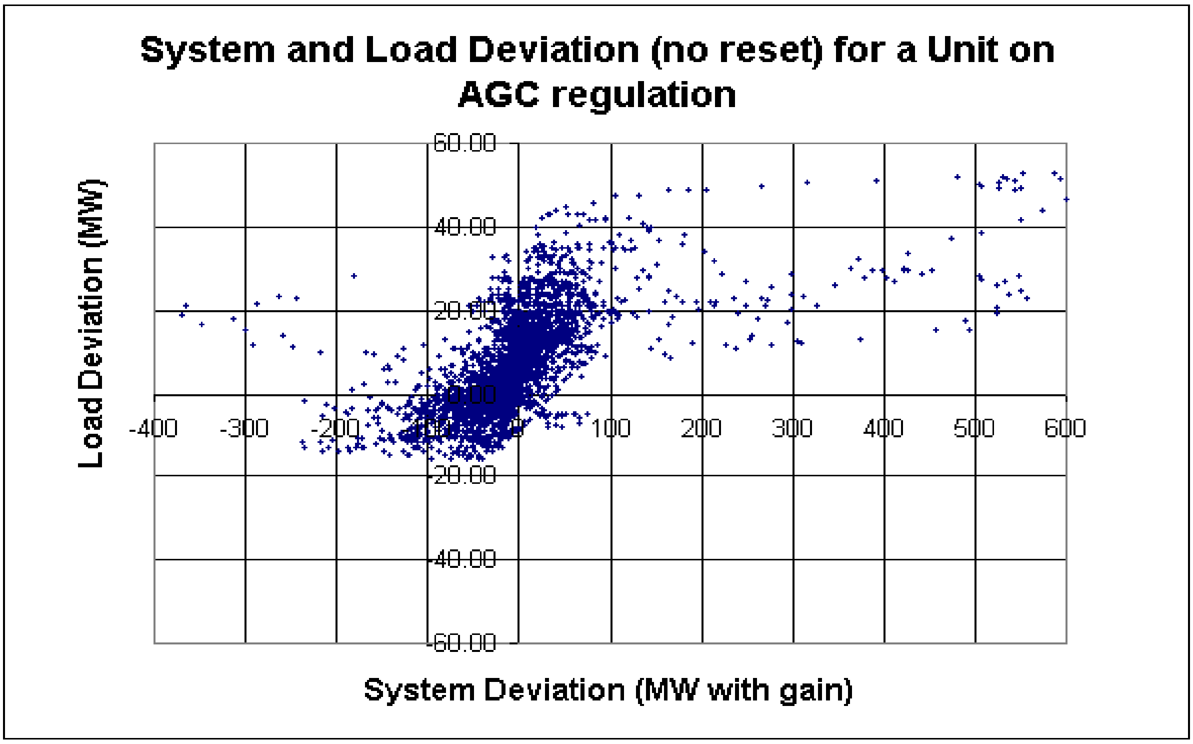
As with energy hedging, the choice of a reference level for measuring energy deviations should not affect the financial outcomes averaged over a long period, although the variability of those outcomes will be affected. We consider that deviations from energy market basepoints (i.e. ramping at a constant rate between 5-minute energy market setpoints) provides a better measure of energy deviation performance than one where the deviation is re-set to zero each 5 minutes. The remainder of the appendix will use the no-reset reference level. This choice could be reviewed during the implementation phase.

A.5 Performance Analysis

A.5.1 Comparison of reference energy options using scattergrams

It is now possible to relate system deviation to individual unit deviation. Before doing so, we will first plot on a scattergram the system deviation (as measured by the Filtered System Error) and unit deviation values (i.e. actual MW less the energy market reference level) over about 10 hours for a large generation unit under AGC regulation control. Such a plot highlights the relationship between the system deviation and the deviation of a generation unit. Figure A.6 is the scattergram for a unit under AGC regulation, where deviations are measured from 5-minute energy market basepoints (constant ramping but with no reset). There is a clear but imperfect correlation.

Figure A.6



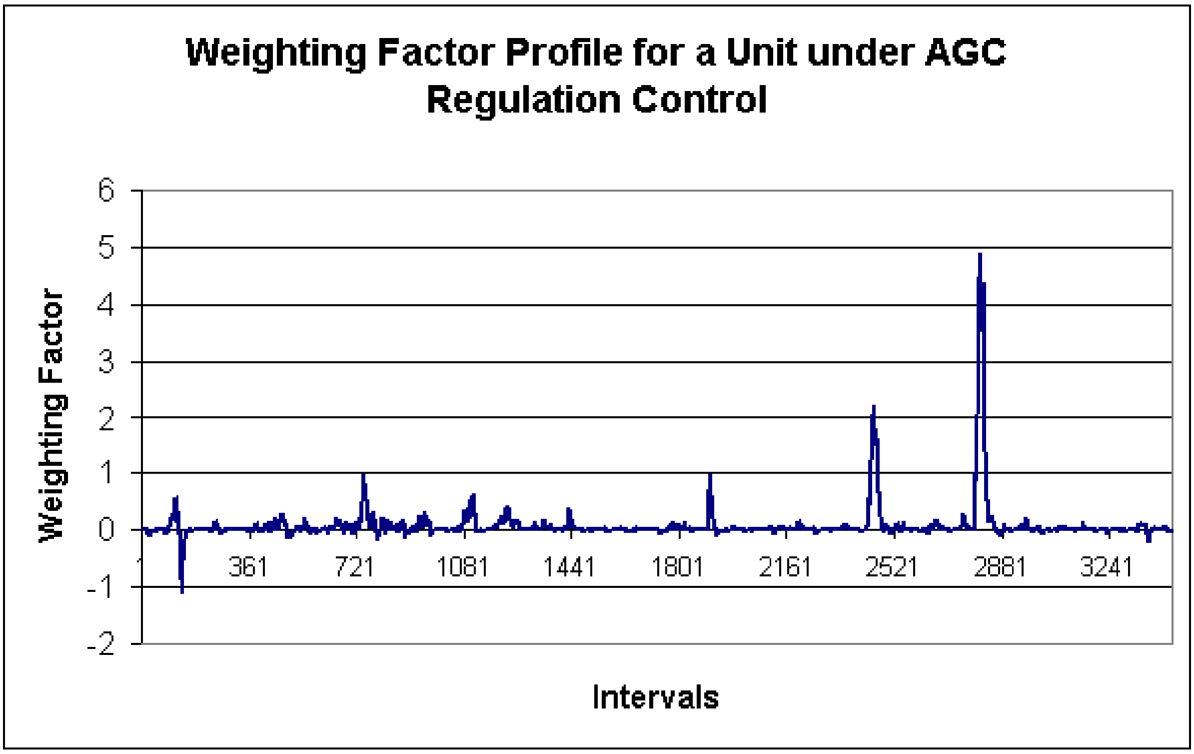
A.5.2 Covariance analysis

In Section A1.2 we define a weighting factor[9], which is a measure of how well a unit is performing in its regulation (provision of small deviation FCAS) at any instant. Repeating the definition but with the more precisely defined measures discussed in previous sub-sections:

Weighting Factor = Filtered System Error (MW) * Unit Deviation (MW)

The factor can be summed over all time periods (10 seconds in this sample data). It gives a measure that would be proportional to the amount paid or received by a unit operating in the proposed energy deviations market. A plot of the factor for a unit under AGC regulation control over about 10 hours of the sample data provided by NEMMCO is shown in Figure A.7. Note that the ordinate has been scaled in a way described later in the Appendix. Apart from an apparent performance problem experienced by the unit towards the start of the period of interest where the factor is significantly negative, the factor is generally positive. This is not surprising as the unit is under being controlled in a way that should deliver such an outcome.

Figure A.7



It is possible to produce an idealised weighting factor profile for comparison purposes. For simplicity, assume a unit has a constant RPF (Regulation Participation Factor) over the period

[9] This weighting factor is closely related to the *covariance* between the unit and system deviations, a statistical measure.

of interest. Assume also that the unit follows its energy market basepoints as well as its regulation target as set by the AGC. Then, in this case:

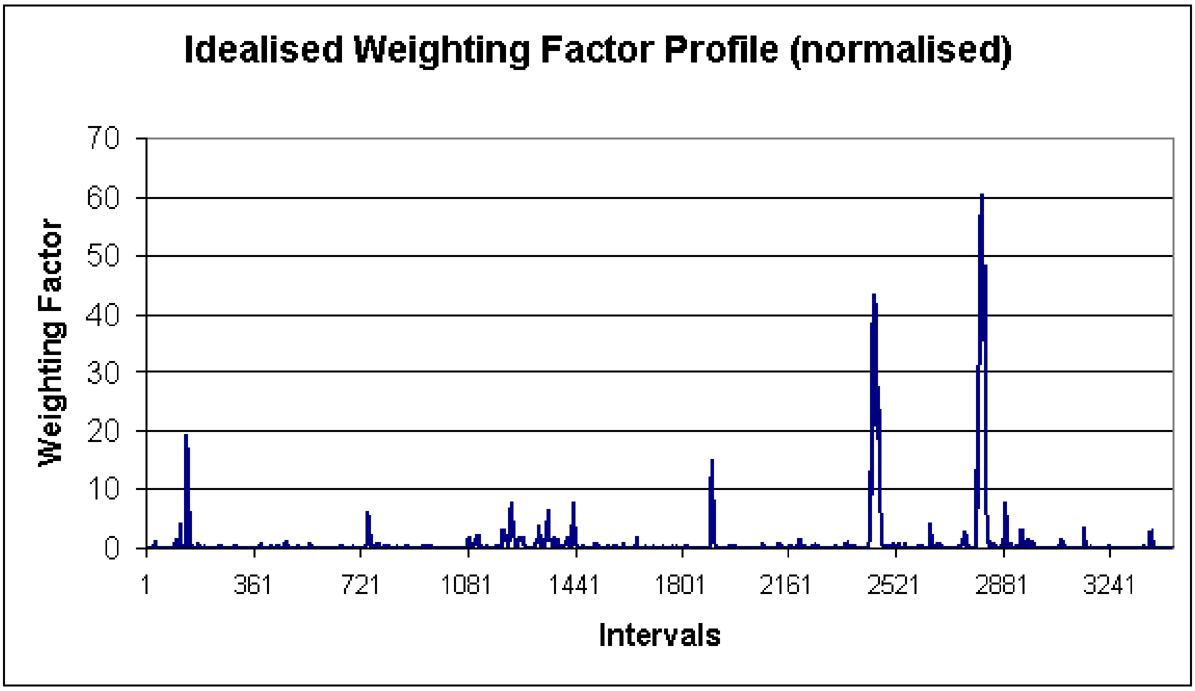
Weighting Factor = Filtered System Error * Unit Deviation

= Filtered System Error * RPF * Filtered System Error

= RPF * Square of Filtered System Error

Thus the square of the filtered system error will produce a weighting factor profile which is proportional to the desired performance of a unit, at least as long as the RPF remains unchanged. Such a profile is plotted in Figure A.8, where the broad similarity to the response in Figure A.7 is evident. Note, however, that the idealised weighting factor is never negative.

Figure A.8



Finally, if payments are in proportion to the weighting factor, a cumulative weighting factor proportional to the accumulated stream of payments made over the period can be plotted. For a unit under AGC regulation this is shown in Figure A.9 as the lower curve, while the upper curve is the cumulative weighting factor if the unit had followed the Regulation MW profile.

While the similarity between the two profiles is clear, the actual performance falls below the desired performance by a factor of about two over the whole period of interest. Figure A.10 below suggests one possible reason for this relatively poor performance. The unit concerned over much of the period of interest is changing its setpoints in the energy market each 5 minutes. To the extent that the unit lags in ramping to meet these setpoints, it could be contributing to the regulation burden. However, there may be other explanations and more analysis would be required to settle the matter.

Figure A.9

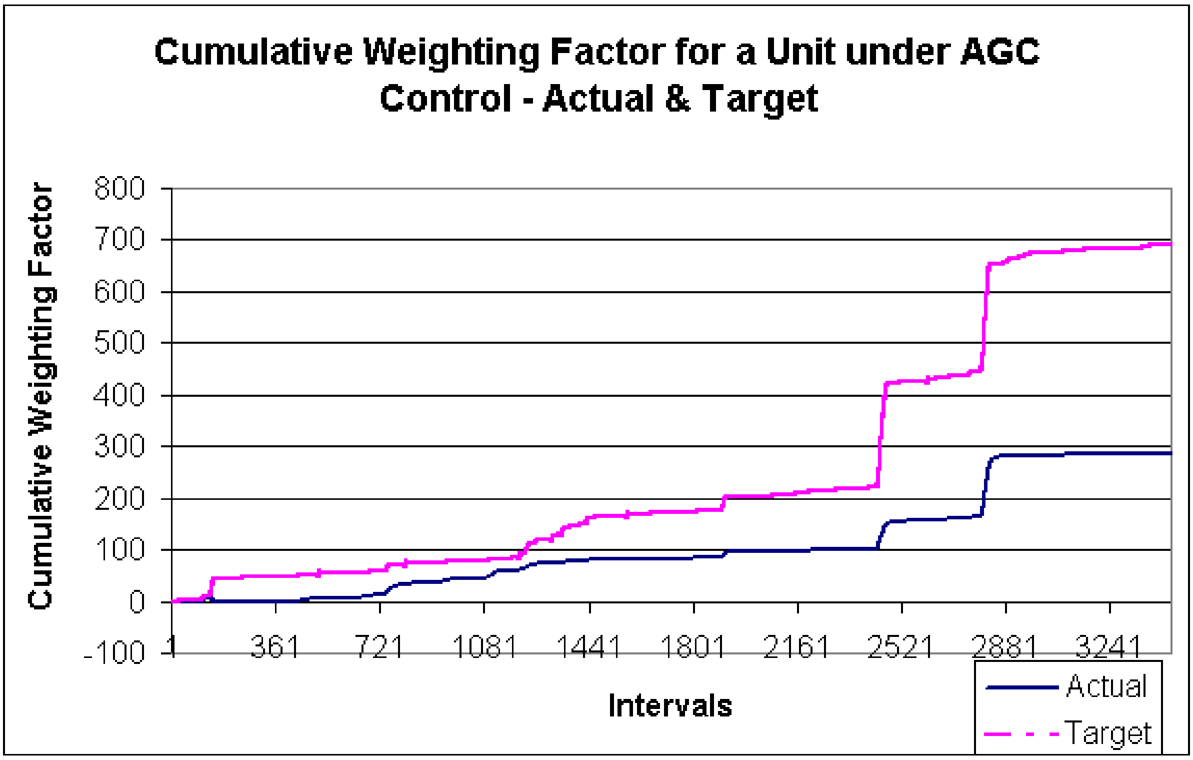
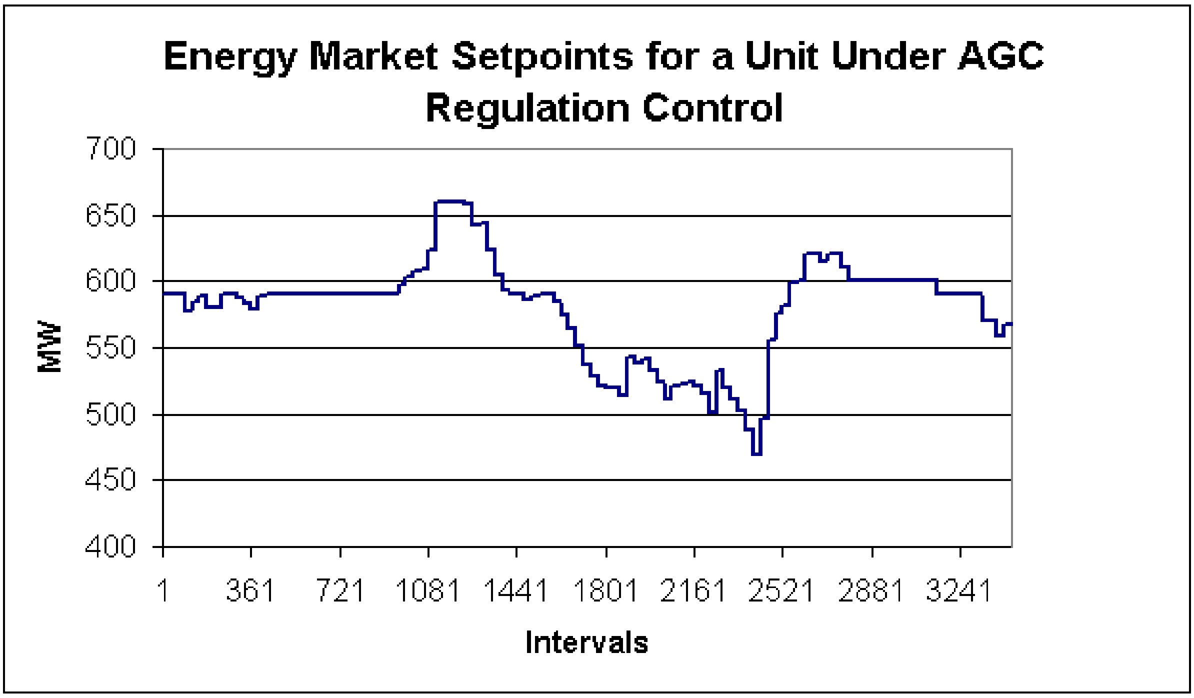


Figure A.10

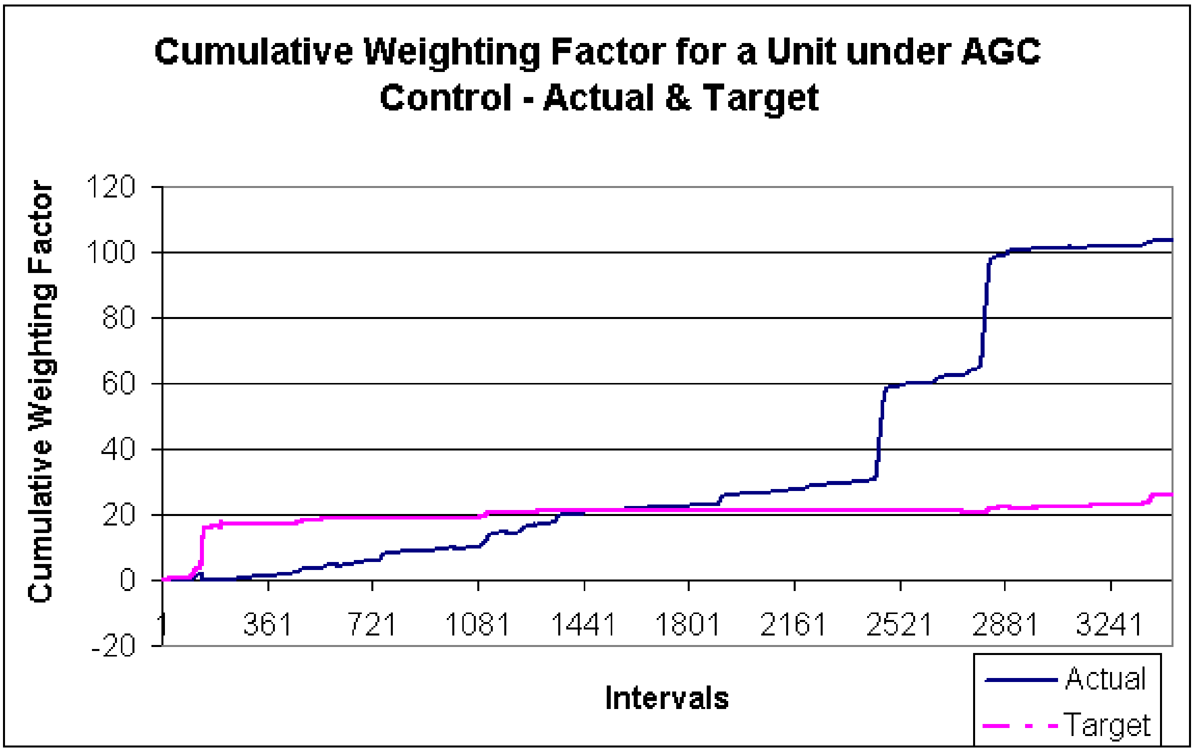


To illustrate the diversity of performance in providing small deviation FCAS, Figure A.11 plots a pair of curves similar to the cumulative weighting factors plotted in Figure A.9, but for a different unit. The idealised performance takes into account the unit's RPF. In the case of

Figure A.11, the unit was enabled for regulation (small deviation FCAS) at the start of the period but very little in the middle and end. This is illustrated by the flat target curve. The unit hardly responds to the initial AGC target but appears to respond to the two large incidents later in the sample period, even though it is not under AGC regulation control at the time (i.e. RPF = 0). As before, further investigation would be required to determine the reason for such behaviour. One such explanation could be that the unit's governor is responding to the larger excursions even though the unit is not enabled for regulation (small deviation FCAS).

The key conclusion for this analysis is that the performance of units enabled for AGC regulation (small deviation FCAS) can be highly variable. This suggests scope for providing incentives to perform that could ultimately lead to a lower small deviation FCAS requirement. Such incentives would be provided by the proposed energy deviations market and, prior to that, by charging for allocating the costs of small deviation FCAS enablement according to cause and provision measured using the methods described in this Appendix.

Figure A.11



A.5.3 Background for the analysis of small deviation FCAS performance

This section contains the analytical background necessary to complete a preliminary analysis of small deviation FCAS performance, and to suggest a general approach to the energy deviations market and the transition to it. In particular, in this sub-sections we will consider:

- an approach to charging for small deviation FCAS enablement; and
- an approach to the energy deviations market (the light on the hill).

In following sub-sections we will:

- present the results of a preliminary analysis using each of these approaches, which are closely related; and
- consider options for implementation, including a transition between the two.

A.5.4 An approach to charging for small deviation FCAS enablement

We assume there is a process for small deviation FCAS enablement where successful units are placed under AGC regulation control. We propose that costs be recovered on the basis of performance, taking account of the implied obligation to perform when a unit receives an enablement payment. The thesis is that a unit that has been successful in the market for small deviation FCAS enablement has been paid to perform the AGC service. If it performs more or less than that, it will be paid or charged accordingly. The same applies to those not under AGC, including non-dispatchable loads and other plant. This line of analysis yields some useful results and an analytical procedure that is described below. The presentation attempts to minimise mathematical symbolism but some knowledge of mathematical and statistical terms is assumed. We propose the following:

1. System deviation should be measured as the AGC's Filtered System Error. This is the sum of the unit "Reg Comp" values from the AGC, which can be shown to be the same as a global "Filtered System Error" value. The unit values and the system value should be readily accessible form the AGC in real time.

2. Unit power deviation should be measured by:

   Actual MW – Energy Market Base Point MW – AGC Regulation MW for Unit

   Note that *energy* deviations are obtained by multiplying by the sampling interval (say 4 seconds).

   Actual MWs are available in real time from the SCADA for most units. Energy market basepoint values for the purpose of establishing reference energy levels should differ from those in the AGC, which attempts to correct for sluggish unit response. Energy market 5-minute basepoints are calculated simply by steadily ramping from one 5-minute setpoint obtained from the SPD to the next. The AGC regulation MW is the value "RegComp" for each unit calculated in the regulation part of the AGC, as discussed earlier in this Appendix. Note again that the sum of all the RegComps for units under AGC regulation control is the Filtered System Error as defined above.

3. Cost allocation to each unit/load should be proportional to:

   Filtered System Error (MW) * Unit Deviation (MW)

   Filtered System Error is positive if more power is required. Thus a positive value of this measure implies a payment to the unit and a negative value implies a payment by the unit.

4. The effect of this assumption is that:

   Cost charged in one interval =

Constant * Filtered System Error (MW) * Unit Deviation (MW) * Interval Duration

5. The total payment is the sum of this over all intervals in the settlement period. The constant is to be determined in a way that balances payments with the cost incurred for enablement over a settlement period of, say, a week.

6. For simplicity in this analysis, assume that the load is measured at generator terminals i.e. loads and gens sum to zero always. In fact, data for some generators in the sample data provided were bad, so that the load includes these and can be regarded as a “residual”. This assumption can be modified on implementation to reflect real metering and losses.

With these assumptions, we can show that:

1. At any given time, the energy market basepoint MW summed over all participants is zero (enforced by SPD and by residual calculation in any case)

2. At any given time, the sum of actual MW is zero (physics and enforced by residual calculation in any case)

3. The sum of all Unit Deviations (including loads) is the Filtered System Error.

   It follows from this that:

   Total Payments over One Interval
   = Constant * Filtered System Error * Sum of (all Unit Deviations) * Interval Duration
   = Constant * (Filtered System Error)^2 * Interval Duration

4. And it can then be shown by summation over the settlement period that:

   Total Payments over Settlement Period
   = Constant * Mean Square of Filtered System Error * Settlement Period Duration

   This follows by re-arrangement from 3 because:

   Settlement Period Duration = Interval Duration * Number of Intervals

5. We now set the total costs charged to equal the amount paid to enabled providers of small deviation FCAS over the settlement period, and from which finally get the Constant:

   $$\text{Constant} = \frac{\text{Total Cost Incurred over Settlement Period}}{\text{Settlement Period Duration * Mean Square of Filtered System Error}}$$

   In essence, we can calculate ex post the constant that would have gone into a real time pricing formula (of the simple form assumed; there might be other viable forms, such a weighting the constant with the current 5 minute price). In the implementation of an energy deviations market, the constant would be set ex ante.

6. It is then fairly straightforward to derive the following from (4) above:

   Payment to be made to (by) a unit over a settlement period, per unit of FCAS enablement cost incurred

$$= \frac{\text{Sum of (Filtered System Error * Unit Deviation * Interval Duration)}}{\text{Settlement Period Duration * Mean Square of Filtered System Error}}$$

It is easy to show in this case (when deviations are measure relative to a reference level equal to the 5-minute energy market basepoint plus regulation target) that the sum over all units of this measure is unity as required i.e. all enablement costs are allocated. This follows from the fact that the sum of the Unit Deviations with reference to any allocation of the Filtered System Error to regulating units must be equal to the Filtered System Error, as noted in 3 above.

7. This cost allocation can be expressed in other useful ways. For example, the payment made to (by) a unit over a settlement period to cover the cost of small deviation FCAS enablement could also be expressed as:

$$= \text{Reference Price* Sum of } \left(\frac{\text{Filtered System Error * Unit Deviation * Interval}}{\text{Root Mean Square of Filtered System Error}} \right)$$

where Reference Price is calculated ex post by:

$$\text{Reference Price} = \frac{\text{Total Cost of Service of Settlement Period}}{\text{Settlement Period Duration * Root Mean Square of Filtered System Error}}$$

Note that the measure in brackets is an energy value that could form the basis for a trade in hedges in the small deviation FCAS service.

For example, if the cost of small deviation FCAS enablement over a week of 168 hours is $300,000 and the Root Mean Square of the filtered system error is 84MW (as measured for sample data - a "magic number"), then:

Reference Price = 300,000 / (168 * 84) = $21/MWh

This happens to be close to the historical pool price average in NSW and Victoria but merely by co-incidence.

8. Another useful measure is the Unit Performance Factor, defined as follows:

Total payment to (from) a unit for small deviation FCAS provision during a settlement period
= Reference Price * Unit Performance Factor * Half-hour Metered Energy

Where Unit Performance Factor

$$= \frac{\text{Sum of (Filtered System Error * Unit Deviation * Interval Duration)}}{\text{Root Mean Square of Filtered System Error * SCADA Metered Energy}}$$

Due account must be taken of sign. The utility of this measure is that it can be calculated using SCADA readings. The Reference Price and Performance Factor together could be expected to comprise a relatively small adjustment to the financial outcomes flowing from the energy market. If this adjustment is less than, say, 1% of the energy market financial turnover, the use of SCADA measurements to calculate the Unit Performance Factor could be considered acceptable. This issue will be examined further later.

Finally, we note again that the analysis outlined above could be modified should examination suggest a modification to the basic cost allocation logic would yield a more robust result. For example, in Proposition 3 above the cost allocation is assumed to be proportional to:

Filtered System Error * Unit Deviation

Given that small deviation FCAS and energy are joint products, an alternative could be a cost allocation in proportion to:

Regional Energy Price * Filtered System Error * Unit Deviation

We consider that an energy price weighting in the cost allocation formula and in the energy deviation real time price (discussed below) is likely to have merit and we commend the concept for consideration during the implementation phase. Such a formula would naturally lead to modified results, but similar in general form to those outlined above.

A.5.5 Real Time Pricing for the Energy Deviations Market

If the Real Time Price (RTP) that would support an energy deviations market has the form:

RTP = Constant * System Deviation = Constant * Filtered System Error

Then this assumption is similar to that proposed for cost allocation and leads to similar results. For example, the payment made to (by) a unit over a settlement period in the energy deviations market could be expressed as:

$$= \text{Reference Price} * \text{Sum of} \left(\frac{\text{Filtered System Error} * \text{Unit Deviation} * \text{Interval}}{\text{Root Mean Square of Filtered System Error}} \right)$$

Expressed in this form we have:

$$\text{RTP} = \text{Reference Price} * \frac{\text{Filtered System Error}}{\text{Root Mean Square of Filtered System Error}}$$

This is identical in form to the proposed small deviation FCAS cost allocation logic but would be implemented as follows:

- Root Mean Square of Filtered System Error is a targeted ex ante value rather than a value calculated ex post;
- Reference Price is an ex ante value rather than a value calculated ex post;
- Unit Deviation is calculated relative to the energy market (5-minute ramp) basepoint rather than the base point plus the regulation MW target set by the AGC.

The consequence of the last point is that unit and load deviations always sum to zero (provided loads are measured at generator terminals), so that the sum of all payments made in this case is zero. Thus the energy deviations market does not, in the simplest case, generate a revenue surplus. Small surpluses and possibly deficits could arise in a real implementation, however, for the same reason as they arise in the energy market. This matter should be dealt with in the implementation phase, but we do not expect it to be a significant issue.

As an aside, for the case where the Filtered System Error and Unit Deviation have a mean of zero, which should tend to be so over a sufficiently long period if Unit Deviations are measured relative to the energy market, we would have:

$$\text{Covariance of Filtered System Error with Unit Deviation} = \frac{\text{Sum of (Filtered System Error * Unit Deviation * Interval Duration)}}{\text{Settlement Period Duration}}$$

Variance of Filtered System Error = Mean Square of Filtered System Error

So that the share of enablement costs paid to (by) a particular unit would be:

$$\frac{\text{Covariance of Filtered System Error with Unit Deviation}}{\text{Variance of Filtered System Error}}$$

A.5.6 Comparative performance analysis for small deviation FCAS

We are now in a position to present a preliminary analysis of the relative performance of units providing a regulation function (small deviation FCAS) over the 10-hour sample period. The analysis includes those under control for regulation as well as those that are not. The results are presented in Table A.3 and key results are plotted on bar charts in Figures A.12 and A.13.

Over the period of interest, Bayswater units were enabled to provide about 75% of the regulation. Vales Point, Wallerawang, Mt Piper and Loy Yang units were enabled at various times for the remainder.

Table A.3 shows the following:

- *Column 1* lists the majority of plant running in the 10-hour period. Roughly the first half have AGC FCAS contracts but not all were enabled over the period and some were enabled more than others.
- *Column 2* shows the average Regulation Participation Factor (RPF) over the period and is an indicator of desired relative contribution, but not necessarily actual contribution.
- *Column 3* shows the average power produced over the period. The residual near the bottom of the table represents the net load and is the negative of the sum of the earlier entries. The average power produced and consumed by all the units and the residual sum to zero, by definition. This implements the assumption in this study that loads are measured at the generator terminals.
- *Column 4* labelled EnNWF the shows a Normalised Weighting Factor indicating the relative amount received or paid had an energy deviations market using the pricing rule described in this Appendix applied over the period. It assumes there are no payments for

being enabled. In this case the reference energy levels are the energy market basepoints (5-minute constant ramping). These results are plotted in Figure A.13. Things to note:

- Bayswater units do most regulation but other enabled units and some disabled ones do a significant amount also. Non-contracted units do very little, as expected (bottom chart). The load is the only significant net payer (negative weighting factor). This does not imply that the load is the only causer of the requirement for the service – the numbers show a net outcome.

- The payments and charges sum to zero, as would be expected in an energy deviations market with the load measured at the generator terminals.

- *Column 5* labelled RegNWF shows the Regulation Normalised Weighting Factor for the enabled units. The value is, in essence, an apportioning of duty (MW regulation target from the AGC) to each unit for each dollar of FCAS payment and therefore sums to 1 over all units. Clearly Bayswater has the largest duty in accordance with its RPFs. Note that Bayswater's Regulation Weighting Factor is significantly more than its actual performance (previous column EnNWF), the reverse being true for most other units.

- *Column 6* labelled TotNWF shows the Total Normalised Weighting Factor for all units. This is the difference between weighting factor measuring performance relative to the energy market (EnNWF) and the weighting factor implied by the stream of RPFs that define enablement for regulation duty (RegNWF). As argued earlier in this Appendix, it represents the proportion of the cost of small deviation FCAS enablement that would be allocated to each unit or load (Residual). Negative represents a charge to and positive represents a payment to the unit or load. The histogram in Figure A.12 plots this column. Things to note:

  - If all enabled units performed perfectly *and* loads were the only cause of the requirement, all entries in the TotNWF column would be zero other than that of the Residual, which would be minus 1 by definition (i.e. it would pay for all of the enablement because it was the only causer. The total of this column is minus 1, which indicates a net payment by the units and Residual (load) from this logic. This net amount pays for the cost of all small deviation FCAS enablement over the period.

  - In fact, the Residual (load) is by no means the only payer, the other being Bayswater and some other enabled units which, at this time, are evidently not performing to the extent that the AGC is requesting.

  - Some units do more than obligated by their enablement, and get compensated (e.g. Loy Yang A and Mt Piper 2 in this example).

  - The Residual (load) would pay about 80% of the small deviation FCAS enablement costs in this sample. This may not be typical, as the data sample spans the afternoon and evening when generator deviations are likely to be smaller than when the load increases rapidly each morning.

- *Column 7* labelled EnPFact is the Performance Factor for the energy deviations market case. Since the reference price is about equal to the pool average price (by co-incidence), these numbers happen represent a rough estimate of the fraction of the unit's dollar turnover relating to energy deviations. The figure is mostly less than 1% except for highly enabled units. For the load it is about 0.5%. The results may not be typical.
- *Column 8* labelled TotPFact is the Performance Factor relating to the cost allocation case. Note the negatives for Bayswater. The measure is unchanged from the previous column if the unit was not under regulation for any time during in the sample.

Figure A.13 shows that, in this sample, Bayswater units are providing most of the regulation capability as would be expected, with smaller but still significant contributions from units enabled for regulation to a lower level. In general, units not enabled show a small weighting factor (either positive or negative) as would be expected. Surprising is the contribution made by some Loy Yang units, as well as some Eraring and Mt Piper units that were not enabled over the period. Further, enabled units do not seem to perform in close accordance with their participation factors as indicated by the cost allocation histogram of Figure A.12.

This analysis does suggests that performance a measure for units providing small deviation FCAS (and large deviation FCAS also, to a degree) is practical to compute. It also suggests that the performance of enabled units shows a wide variation, and some non-enabled units also provide some service. The reason for this is not clear at this stage. It may be that their governors were in action during some of the frequency deviation episodes covered by the sample period although at no time did frequency deviations fall outside the normal frequency band.

Table A.3 Performance Analysis Results:			**FSErms = 84.44 MW**			**Period = 9.58 hrs**	
Plant	**Av RPF**	**AvPwr**	**EnNWF**	**RegNWF**	**TotNWF**	**EnPFact**	**TotPFact**
lypa a1gen	0.0163	481.53	0.0301	0.0075	0.0225	0.0053	0.0040
lypa a2gen	0.0024	472.13	0.0017	0.0041	-0.0024	0.0003	-0.0004
lypa a3gen	0.0044	477.41	0.0285	0.0046	0.0240	0.0050	0.0042
lypa a4gen	0.0028	472.11	0.0255	0.0042	0.0213	0.0046	0.0038
ywps w1gen	0.0000	323.49	0.0007	0.0000	0.0007	0.0002	0.0002
ywps w2gen	0.0000	323.51	0.0011	0.0000	0.0011	0.0003	0.0003
ywps w3gen	0.0000	375.01	0.0028	0.0000	0.0028	0.0006	0.0006
ywps w4gen	0.0016	345.55	0.0060	0.0025	0.0035	0.0015	0.0008
Bayswater 1	0.2087	586.62	0.0831	0.2006	-0.1175	0.0120	-0.0169
Bayswater 2	0.2062	586.02	0.0613	0.2031	-0.1418	0.0088	-0.0204
Bayswater 3	0.2038	586.40	0.0880	0.1973	-0.1093	0.0127	-0.0157
Bayswater 4	0.1178	584.83	0.0726	0.1182	-0.0457	0.0105	-0.0066
Eraring 2	0.0013	583.91	0.0255	0.0007	0.0248	0.0037	0.0036
Eraring 3	0.0001	470.46	0.0456	0.0000	0.0456	0.0082	0.0082
Eraring 4	0.0000	519.55	0.0493	0.0000	0.0493	0.0080	0.0080
Mt. Piper 1	0.0699	631.78	0.0360	0.0944	-0.0584	0.0048	-0.0078
Mt. Piper 2	0.0000	548.01	0.0556	0.0000	0.0556	0.0086	0.0086
Vales Point 5	0.0214	267.99	0.0423	0.0172	0.0251	0.0133	0.0079
Vales Point 6	0.0275	269.60	0.0422	0.0188	0.0233	0.0132	0.0073
Wallerawang 7	0.0614	361.85	0.0237	0.0646	-0.0409	0.0055	-0.0095
Wallerawang 8	0.0546	360.51	0.0157	0.0620	-0.0463	0.0037	-0.0108
Snowy (AGC Unit)	0.0000	620.13	0.0335	0.0000	0.0335	0.0046	0.0046
Northern 1	0.0000	259.49	0.0002	0.0000	0.0002	0.0001	0.0001
Northern 2	0.0000	261.52	0.0002	0.0000	0.0002	0.0001	0.0001
Torrens Island B1	0.0000	126.65	-0.0028	0.0000	-0.0028	-0.0018	-0.0018
Torrens Island B2	0.0000	53.54	0.0013	0.0000	0.0013	0.0021	0.0021
Torrens Island A4	0.0000	80.99	0.0091	0.0000	0.0091	0.0095	0.0095
hwps 1	0.0000	175.55	0.0017	0.0000	0.0017	0.0008	0.0008
hwps 2	0.0000	165.03	-0.0003	0.0000	-0.0003	-0.0001	-0.0001
hwps 4	0.0000	199.12	0.0033	0.0000	0.0033	0.0014	0.0014
hwps 5	0.0000	160.73	0.0066	0.0000	0.0066	0.0035	0.0035
hwps 6	0.0000	184.28	0.0042	0.0000	0.0042	0.0019	0.0019
hwps7	0.0000	190.55	0.0216	0.0000	0.0216	0.0096	0.0096
hwps 8	0.0000	202.35	0.0031	0.0000	0.0031	0.0013	0.0013
lyps b1	0.0000	505.33	0.0023	0.0000	0.0023	0.0004	0.0004
lyps b2	0.0000	506.86	0.0024	0.0000	0.0024	0.0004	0.0004
aps	0.0000	152.49	-0.0007	0.0000	-0.0007	-0.0004	-0.0004
mor1	0.0000	41.15	0.0030	0.0000	0.0030	0.0062	0.0062
mor2	0.0000	25.16	-0.0019	0.0000	-0.0019	-0.0063	-0.0063
mor3	0.0000	22.04	-0.0014	0.0000	-0.0014	-0.0052	-0.0052
dps	0.0000	57.47	-0.0036	0.0000	-0.0036	-0.0053	-0.0053
eps 1	0.0000	10.43	-0.0051	0.0000	-0.0051	-0.0412	-0.0412
eps 2	0.0000	11.27	-0.0075	0.0000	-0.0075	-0.0563	-0.0563
Liddell 1	0.0000	350.79	0.0067	0.0000	0.0067	0.0016	0.0016
Liddell 4	0.0000	462.93	-0.0074	0.0000	-0.0074	-0.0014	-0.0014
ocpl 1	0.0000	121.05	0.0001	0.0000	0.0001	0.0001	0.0001
ocpl 2	0.0000	49.85	-0.0023	0.0000	-0.0023	-0.0039	-0.0039
Residual	0.0000	-14625.01	-0.8040	0.0000	-0.8040	0.0046	0.0046
TOTALS	**1.0000**	**0.00**	**0.0000**	**1.0000**	**-1.0000**		
Key: AvPwr: Avg Power (MW) EnNWF: Norm. Weighting Factor (NWF) wrt Energy Market: RegNWF							
NWF wrt Regulation Tot NWF: NWF wrt Total EnPFact: En Perf. Factor TotPFact: Total Perf. Factor							

Figure A.12: Normalised Weighting Factors for Allocating Cost of Small Deviation FCAS Enablement

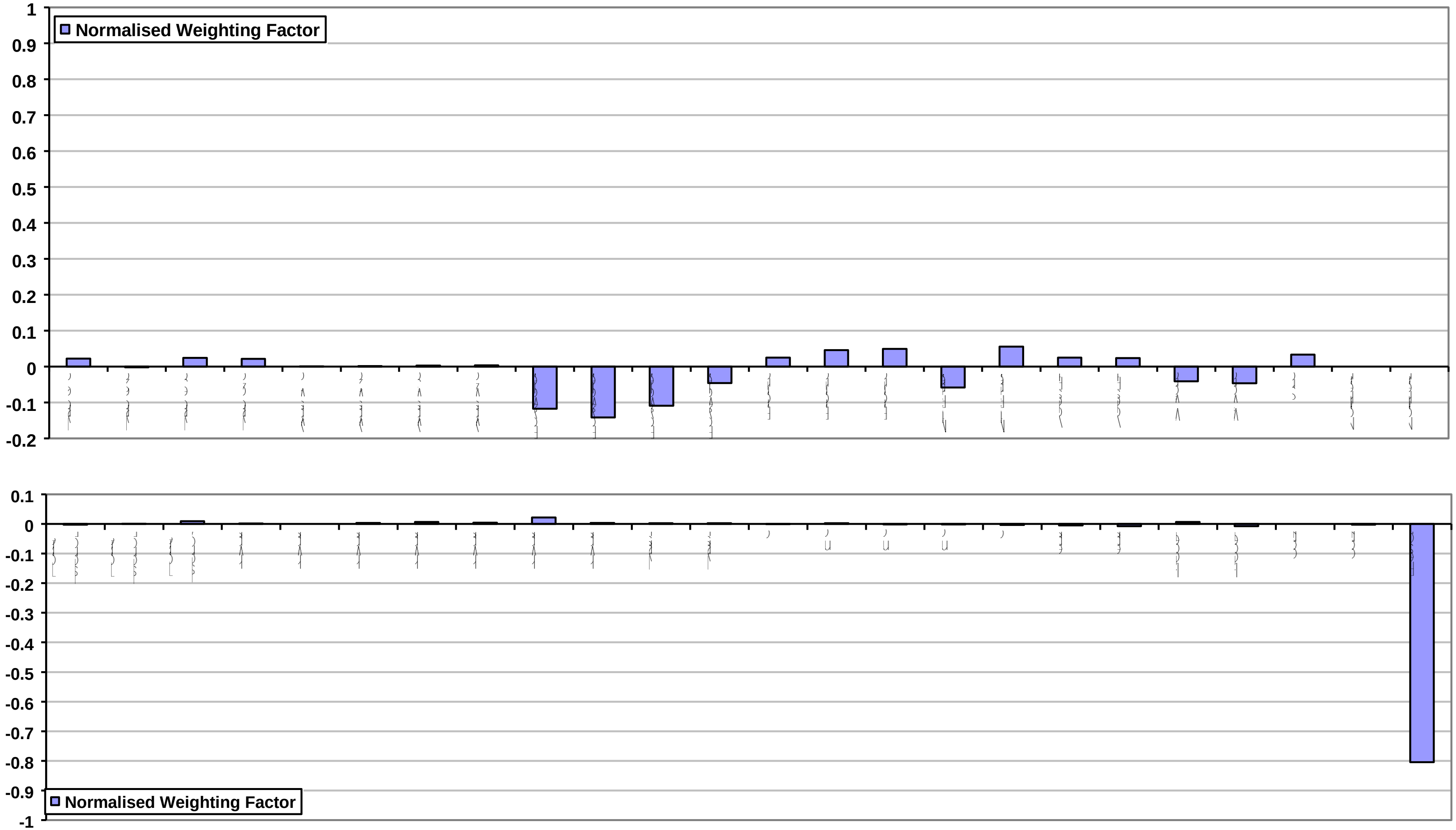
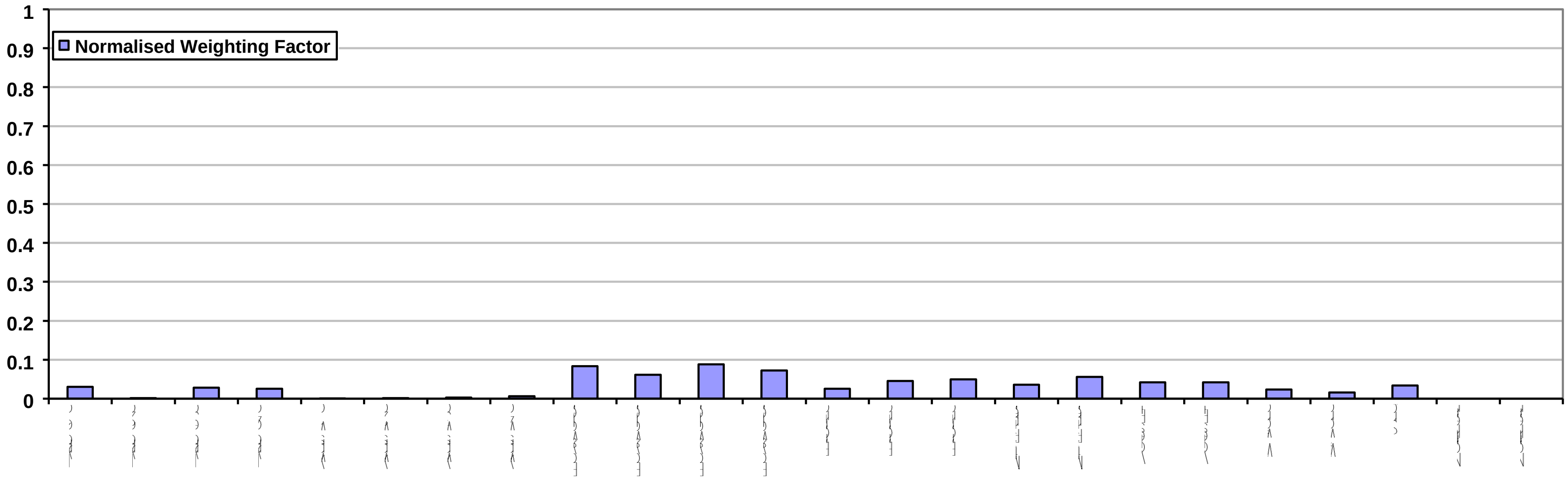
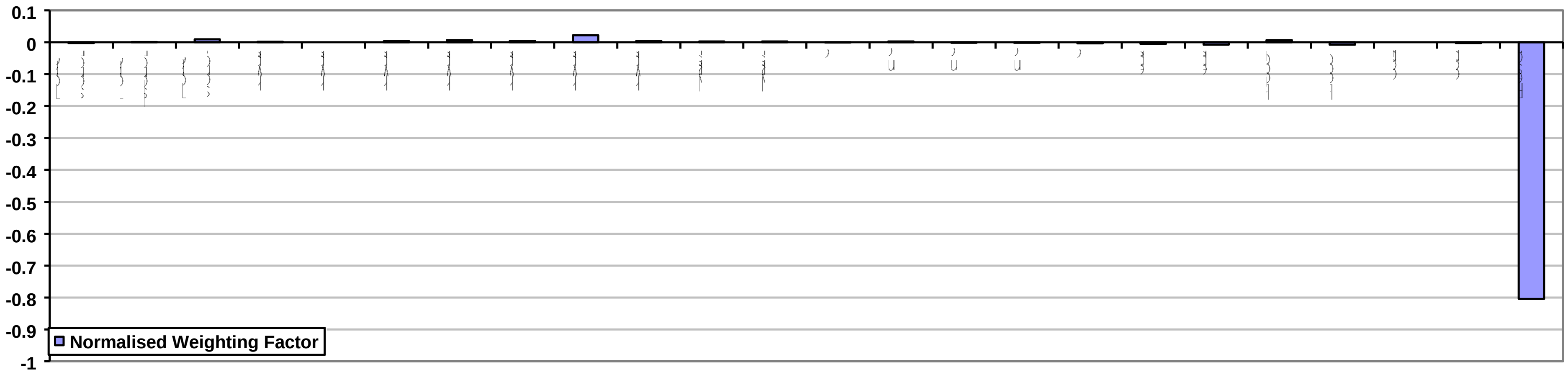


Figure A.13: Normalised Weighting Factors for Energy Deviations Market





A.6 Measurement Issues

For the measurement of small deviation FCAS provision and cause, it is proposed to use SCADA metering data in the first instance. At a later stage such measurements could be brought to a higher standard or a technology for local metering of energy deviations could be developed, if warranted. While SCADA metering is not normally used for billing, we believe that such a grade of metering is useable for small deviation FCAS performance measurement. Some possible forms of error are discussed briefly below.

- Multiplicative and additive errors

  SCADA metering (or any other form) may give errors that differ from the true value by a multiplication factor – say 1.05. There could also be a constant offset error. Such errors can be compensated for by calibration with a meter known to be accurate (e.g. a commercial meter).

- Lag errors

  SCADA readings must travel through a long and sometimes convoluted communication path with inherent delays that may vary over time and be different for different measurements. Delays of the order of several seconds are the norm. Thus it is not practical to use SCADA for very short time frame measurements (of the order of a few seconds. The AGC logic in fact imposes a low-pass filter of 40 seconds on its controls. Small deviation FCAS works on this timeframe. Thus, SCADA measurement lags should not cause major problems for small deviation FCAS performance measurement although this needs to be tested further.

- Random errors

  Random errors are difficult to compensate for and it is clearly highly desirable to work to improve metering and communication reliability. As in the energy market, acceptable rules will need to be determined to deal with cases of measurement failure.

An acceptable approach may be to use SCADA readings to provide *performance factors* as discussed previously. To obtain the desired settlement payment, the performance factor would be multiplied by the energy measured by the commercial-grade metering and the appropriate reference price, as discussed previously. Advantages of this approach are:

- The performance factor is calculated as the ratio of measurements obtained from the SCADA so multiplicative errors will cancel and any additive errors will be bounded.

- The performance factor could be estimated even if there were some interruption to the measurements for some reason.

- The settlement payments for small deviation FCAS will typically be two orders of magnitude less than for the energy market, which should allow for some relaxation in measurement standards.

- In any case, there may be strategies for supporting optional participation in these arrangements. In essence, participation in these arrangements would imply acceptance of the standard of metering and related procedures that would be applied.

At present, there is no measurement of small deviation FCAS performance. Use of SCADA readings to measure and reward performance, coupled with procedures that account errors or interruptions, should be a marked improvement over present practice.

A.7 Implementation

A.7.1 Implementation Options

In this sub-section we consider how the concepts developed in this Appendix for the management of small deviation FCAS, or some further development of them, could be applied. Specifically, we consider the strategy for implementing:

- arrangements for allocating the cost of small deviation FCAS enablement
- the energy deviations market – the light on the hill; and
- the transition to the light on the hill.

The broad approach to each will be summarised before considering implementation options.

A.7.2 Approach to allocating the cost of small deviation FCAS enablement

Enabled units would be paid a common clearing price for the amount enabled, the cost of which must be allocated. Currently, the costs of enablement are allocated to loads under the Code.

We have proposed that this service be paid for in proportion to the measured causers of deviations. Units acting to correct deviations that are not under AGC regulation control would be paid. As enabled units are already being paid to perform, the appropriate basis for measuring deviation is relative to the 5-minute energy basepoint plus regulation target. The apportionment of regulation duty (MW of regulation target) for which the enabled units would be paid is summarised in the column RegNWF of Table A.3. For the sample data provided, this gives the cost allocation TotNWF in Table A.3. Note that if no generation units were causing deviations and enabled units performed as targeted by the AGC, all costs would be allocated to loads. In this sample, the cost allocation was 80% to loads. This may not be typical.

The net outcome should approximate the cost allocation corresponding to the proposed energy deviation market, which is given by the column EnNWF in Appendix A.3. The match is not exact because the allocation of duty by the AGC summarised in TotNWF will not align perfectly with enablement payments. However, there is likely to be a close relationship between the two.

An issue for consideration is what incentives would remain for participation in the enablement market if this cost allocation were applied. The issue arises because, if the cost allocation logic described is fully implemented, there may not be a clear reward for participation in the enablement market, relative to what could be obtained by staying outside it. The obvious advantage, though, is direct control by the AGC to follow the system deviation (i.e. the Filtered System Error).

A.7.3 Approach to the Energy Deviations Market

The energy deviations market would be based on deviations measured relative to the 5-minute energy basepoint only. Further, the reference price (see A.5) would be set ex ante[10] rather than ex post, so that participants would be better guided as to appropriate and rewarding behaviour. The resulting allocation of settlement payments for the sample period studied is given by the EnNWF column in Table A.3. This column excludes any consideration of enablement payments.

A.7.4 Approach to the Transition

Given the close relationship between the cost allocation and energy deviations market logic, there are several variations on how the transition could be managed. Three options are considered here –others should be considered in more detail during the planning for implementation.

Option 1

- Keep cost allocation for enablement as it is (loads pay under current Code) or to an alternative fixed costs allocation based on performance measurements over a suitable sample period.
- Allow optional participation in an arrangement where payments are made based on measured performance factors relative to 5-minute energy market basepoints, with the corresponding "ex ante price" ramped up over time. Costs would be passed on to non-participants in the arrangement on the basis for gross trading interval energy produced or consumed. Most generators would be encouraged to participate in this arrangement as they tend to be net providers.
- Finally, refine the allocation of costs for enablement by assigning them to parties on the basis of continuously measured cause and provision.

Option 2

- Keep cost allocation for enablement as it is (loads pay under current Code) or to an alternative fixed costs allocation based on performance measurements over a suitable sample period.

[10] Although with scope for revision of the reference price, with due notice, at settlement period boundaries in order to better target the desire degree of frequency management.

- Gradually ramp up ex ante prices, applied to deviations from the energy market 5 minute basepoint and regulation target if on AGC regulation (i.e if receiving payment for enablement). Participation by generators on AGC would need to be compulsory.
- This would yield a surplus that would then be credited to those currently paying (loads).
- Finally, refine the allocation of costs for enablement by assigning to parties on the basis of continuously measured cause and provision.

Option 3

- Immediately (i.e. ASAP after first stage of one-way enablement market) allocate costs of enablement in accordance with measured cause and provision (ex post analysis).
- Gradually ramp up ex ante prices, applied to deviations from the energy market whether on AGC regulation or not.

A.7.5 Preliminary analysis of options

Accepting the desirability of the light on the hill – the energy deviations market – some considerations for the transition are:

- Optional participation should be supported to the extent possible and desirable, given the proposed use of SCADA metering. However, parties that have not chosen to participate would still be involved in that they would pay the costs of the facility in proportion to gross trading interval energy produced or consumed.
- There might be a perception that parties are being paid twice, in both the enablement market and in the energy deviations market.
- Uncertainty during the transition should be kept to reasonable levels.
- Interest in the enablement market should be maintained to the extent necessary to allow NEMMCO to meet its system security obligations.
- A smooth rather than sudden transition to the light on the hill would facilitate acceptance by all parties.
- The quantity of small deviation FCAS enabled should be reduced as the performance of the energy deviations market is demonstrated, in order to reduce costs.

Optional participation

Option 1 would begin with the proposed small deviation FCAS enablement market and the status quo for cost allocation (loads pay, or on the basis of sampled measurements). It would then provide additional incentives to correct deviations. Given that most generation units provide do or could contribute to small deviation FCAS, most generators should be willing to participate in such an arrangement. However, non-participants in this arrangement would pay, and to that extent they would probably not be regarded as willing. Enablement costs could be expected to fall as the reference price increases and this could be monitored.

Option 2 would, on the basis of the analysis of this Appendix, result in some payments by enabled units if compulsory (see TotNWF column of Table A.3). Although their net receipts from the enablement market and the first steps of the small deviation market are likely to be positive, they might still be unwilling participants in an arrangement that extracts payments on the basis of SCADA readings. The same comment applies to Option 3.

Perceptions of double-dipping

If the energy deviations market is to be operated in parallel with the enablement market, at least during the transition, there could be a perception that participants would be paid twice for providing the same small deviation FCAS service. This could be the case for Options 1 and 3, but not for Option 2 because the reference level for paying for deviations in this case is the energy market 5-minute basepoint *plus* the assigned regulation duty if enabled. On the other hand, as Option 2 would overtly penalise the non-performance if enabled units, offer prices for enablement in that case could increase. Accepting that the net outcome will depend on the competitiveness of the suppliers (which on the basis of NEMMCO experience is likely to be high), the notion that one option may be better than another on this score is more likely to be a matter of perception than reality.

It is conceivable that it may be more costly to operate an energy deviations market in parallel with an enablement market, rather than the enablement market alone, even though an energy deviations market could, by itself, deliver a more efficient outcome. We consider this to be unlikely but suggest that a carefully phased transition with ongoing review of outcomes is desirable. Actual implementation should be preceded by a demonstration and analysis of likely outcomes using a trial energy deviations pricing and settlement software module.

Managing uncertainty

Options 1 and 2 would support a gradual increase in reference prices and associated deviations payments. Option 3 would be a step change in payment logic, the outcome of which could be uncertain.

Interest in the enablement market

We see no reason why generators would not wish to remain and compete strongly in the enablement market to obtain the benefits and convenience of AGC control for regulation, even if most of the financial rewards ultimately would come from energy deviations payments. Because ex ante energy deviation prices in Options 1 and 2 are ramped up slowly, interest in the enablement market could be monitored. The disadvantage of Option 3 on this score is that it would be hard to assess the likely impact on the enablement market until after the cost allocation logic is implemented.

Smooth transition

Options 1 and 2 would appear to implement a smoother transition than 3. However, the logical end point of Option 2 is an enablement market with units fully motivated to perform. While this would be an improvement over the status quo, it is not in itself the desired end point for the light on the hill, which is an energy deviations market. Thus Option 1 is to be preferred on this ground, although Option 2 may be acceptable.

Flexible quantity of enablement

An issue common to all of these options is the extent to which the quantity of enablement for small deviation FCAS (regulation) might be changed as the energy deviations market takes effect. There are two possible scenarios here, each of which will be discussed in turn.

- Enablement clearing price is zero – enablement market is over-supplied

  It may be that the attraction of being paid for correcting frequency deviations will be great enough to encourage many offers of zero in the enablement market to take advantage of the benefits of direct AGC regulation. It is conceivable, and indeed quite likely, that NEMMCO could be able to accept more than its pre-determined requirement for small deviation FCAS enablement at no direct cost. If this occurs, NEMMCO should accept all the units on offer for AGC regulation.

- Enablement clearing price is positive

  In this case a reduction in enablement quantity should normally reduce the cost of enablement by reducing both quantity and, probably, clearing price. On the other hand, NEMMCO would need adequate assurance that its system security requirements can be met.

  A crude way to implement this approach would be to have an automatic or semi-automatic procedure that would set the small deviation FCAS requirement based on the actual use of enabled facilities over some reasonably extended period, say a month or a year. The enablement requirement would be trimmed where the current requirement was never or rarely fully used according to some cut-off criterion. A more sophisticated approach would be to delineate times of day or week that experience suggests could differ in their requirements. Taking this further, it may be that, with some experience, the energy deviations market could be considered to deal effectively, and to NEMMCO's satisfaction, with all but those few occasions when reserve margins fall below some critical level. This approach would simply be an extension of NEMMCO's current approach. For example, NEMMCO currently enables more regulation capability during the ramp-up to the morning peak period than at other times.

  All options would support such an approach.

Summary

The following table summarises the above discussion. A "Yes" entry means a favourable assessment according to the criterion, "No" unfavourable and "Neutral" is indifferent.

Table A.4: Assessment of Transition Strategies for Small Deviation FCAS

Criterion	Option	1	2	3
Optional Participation		Neutral	No	No
Avoid Perception of Double-Dipping		No	Yes	No
Managing Uncertainty		Yes	Yes	No
Interest in Enablement		Yes	Yes	No
Smooth Transition		Yes	Neutral	No
Flexible Quantity of Enablement		Yes	Yes	Yes

On the basis of this initial assessment, Option 1 would be preferred although Option 2 could warrant closer examination. It is noteworthy that both these options would involve a direct but gradual transition to the energy deviations market, rather than proceeding first with an initial but step change to the cost allocation logic. In this respect we note that our initial assessment on the basis of the sample data provided is that the current allocation of small deviation FCAS costs to loads seems be reasonable first approximation from which the energy deviations market could evolve. This contrasts with the large deviation FCAS case where loads in general play no significant role in driving the requirement.

A.7.6 Concept testing

There are a number of permutations for phasing in the light on the hill arrangements for small deviation FCAS. Further, there are issues that will need to be addressed and confirmed during implementation that cannot sensibly be addressed at this stage. Among these are:

- confirmation of the appropriate of the reference energy level for the purpose of measuring unit deviations.
- whether the small deviation FCAS reference price should exhibit differences over time or between regions, for example by linking it to the 5-minute dispatch price in each region;
- confirmation of the best option for phasing in small deviation FCAS cost allocation and energy deviation market arrangements;
- metering issues.

There is also a need to test the proposed cost allocation and pricing logic over a more extended period spanning a wider range of system conditions, and to demonstrate to affected parties how the proposed new arrangements would work. For this reason we recommend earliest possible implementation of a software module to measure small deviation FCAS performance in real time and to analyse the results. Such a facility would provide a firmer basis for resolving practical implementation issues, including the final pricing formula.

A.8 Conclusions

This study has explored how a cost allocation process and, ultimately, a small deviations market could be implemented in the NEM. Consideration of NEMMCO's regulation control through its AGC suggests that it is possible to determine both a global requirement for FCAS in real time and to assess the performance of individual units in meeting that requirement. The key to this is the calculation in real time of a *small deviation FCAS performance factor* for each unit, initially using SCADA measurements, but later using local metering should that prove desirable or necessary. Such a calculation could be performed in a freestanding software module that references SCADA and AGC values but otherwise does not interfere with them. The use of SCADA measurements should be acceptable if participation can be made voluntary, at least during the transition.

The logic for allocating the cost of small deviation FCAS enablement is very closely related to the pricing and settlement logic proposed for the energy deviations market. This presents a number of options for making the transition to the light on the hill, which is the energy deviations market. Our consideration of these options suggests that it may be much simpler and more effective to phase in the energy deviations market directly than to implement an intermediate change in the allocation of FCAS enablement costs. This of course depends on an early demonstration of the practicality of performing the necessary measurements and calculations and addressing the likely outcomes. Based on the preliminary studies performed ion this appendix, we are confident that this can be done.

Finally, while it is possible to envisage the light on the hill and the likely progress through a transition, it is not possible to anticipate every issue and option that might arise. Thus it is important that associated Code changes describe the broad objectives, but allow for some flexibility in the details of implementation, based on progressive experience and review. The same comment, of course, applies to the development of markets in other ancillary services. We note here again that the small deviation FCAS arrangements considered in this appendix could and should provide strong support for the large deviation FCAS arrangements, as noted in the body of the report.

With all these considerations in mind, the following steps should be taken to develop competitive arrangements for small deviation FCAS, noting their applicability to large deviation FCAS as well.

1. As a high priority, implement a prototype energy deviations pricing and settlement module to demonstrate the feasibility and likely outcomes of the energy deviations market and cost allocation outcomes.

2. Review the pricing and settlement logic for and transition strategy to the energy deviations market. This should include consideration of:

   - whether energy deviations prices should be weighted by the regional energy prices as well as system deviations;

- the issue of possible small settlement surpluses or deficits as occurs in the energy market; and
- any other relevant matter.

3. Implement common clearing price and weekly bidding for enablement. While not strictly necessary to phase in the energy deviations market, a lack of short-term competition in enablement may prevent the achievement of cost reductions as energy deviation prices are ramped up.
4. Continue to charge enablement costs as per the Code during the transition (currently loads, but to be shared between all market participants from July 1999), noting that such costs should decline as the energy deviations market phases in. This approach should be reviewed after consideration of the outcome of the demonstration module.
5. To phase in the energy deviations market do the following, noting that this logic would also apply automatically to large frequency deviations.
   - Beginning with an energy deviations reference price that would result in a dollar turnover in the energy deviations market of around, say, 10% of enablement costs, make payments to providers and causers according to SCADA-measured performance factors, for those who elect to participate.
   - The costs (arising from less than full participation in the energy deviations market) should be allocated those not taking part, including non-participating loads, according to gross trading interval energy produced or consumed.
   - The reference energy level should be the energy market 5-minute basepoints (constant ramping between setpoints). This option should be subject to review at the implementation stage if there is concern about perceived “double dipping”, in which case deviation measurement should be from the energy reference levels that include AGC regulation targets for enabled units.
   - Subject to a satisfactory review of outcomes, progressively ramp up the reference price (energy deviations price scaling factor) for the energy deviations market.
6. NEMMCO should:
   - progressively review enablement requirements according to logical every six months, as a minimum, or more frequently as opportunity permits, with a view to reducing the enablement requirement; and
   - measure, assess and improve its load forecasting accuracy to produce unbiased load forecasts with minimum variance.
7. The spot market in small deviation FCAS enablement (an enhancement of the facility already in place) should be established when convenient.

B CORRECTING THE 5-MINUTE DISPATCH v. HALF-HOUR SETTLEMENT ANOMALY

B.1 Introduction

Section 3.5.1 of the Evaluation Report discussed the anomaly that arises from pricing and dispatching each 5-minutes and setting accounts on the basis of half-hour average prices. Such an arrangement attenuates the rewards to participants who respond rapidly when required to do so in the dispatch process.

This anomaly is currently being considered by NEMMCO's Pricing and Settlement Reference Group and a number of approaches are under consideration. This Appendix considers one such approach. It turns out that the adjustment is relatively simple and structured in a similar way to the pricing rule proposed for small deviation FCAS, although it does depend on accepting SCADA measurements adequate for settlement purposes. For this reason it could be simplest to regard the adjustment as an ancillary service (in essence, a "load following:" ancillary service) and to leave the energy market settlement logic unchanged.

We commend this approach to NEMMCO's Pricing and Settlements Reference Group for consideration.

B.2 An Example

Summarising the current position in the dispatch and settlement process:

- Each half-hourly price is calculated as a simple arithmetic average of the previous 6 five-minute dispatch prices.
- Settlement payments are made on the basis of metered half-hourly energy and the averaged half-hourly price.

Table B.1 below reproduced from the Evaluation Report illustrates the out-workings of this logic for a generator operating over a half-hour period in the NEM when prices and loads are rising rapidly (e.g. mornings before 8 am). The generator is ramping up to help meet the load. The MW readings are averages for the interval concerned and are intended to be indicative.

The example shows a rising sequence of 5-minute dispatch prices and the corresponding dispatch for the unit both in MW and MWh terms. The middle $ columns shows the payment that would apply if this transaction had been settled on a 5 minute basis i.e. reflecting the basis on which the unit had been dispatched ion accordance with its offer price. The amount due if this had been done is $314.

Table B.1 Outworkings of the Dispatch Process for a Ramping Generator

Interval	$/MWh	MW	MWh	$	d$/MWh	dMW	dMWh	d$
1	20	0	0	0	-3	-24	-2	6
2	20	0	0	0	-3	-24	-2	6
3	21	0	0	0	-2	-24	-2	4
4	24	24	2	48	1	0	0	0
5	26	48	4	104	3	24	2	6
6	27	72	6	162	4	48	4	16
Av/Tot	**23**	**24**	**12**	**314**	**0**	**0**	**0**	**38**

		Pmt$	A$/MWh
Pmts$	**Total**	**314**	**26.17**
	Market	**276**	**23.00**
	Diff	**38**	**3.17**

Incremental offer price = $24/MWh
Market payment = 23 * 12 = $276

At present, this half-hour of transactions would have been settled on the basis of the $23/MWh time average price and the 12MWh of energy produced over the half-hour, giving a payment of $276. This leaves the generator $314-$276=$38 short of what it might have expected from the dispatch, as shown at the bottom of the table.

One way of dealing this would be to move to commercial grade metering, perhaps optionally, and to settle on the basis of 5-minute readings as illustrated. The difference could be regarded as an ancillary service and smeared to parties not metered at the 5-minute level.

SCADA metering is of course not acceptable for settling of energy accounts. On the other hands, if such metering could be used to measure a performance factor that could result in a second order ancillary service adjustment, it may be acceptable until more accurate local metering if sub-half-hour performance could be implemented. This would mirror what is proposed for sub-5-minute small deviation FCAS. The way this could be done is outlined in the next sub-section.

B.3 Proposed Approach

The settlement adjustment desired is SA (in $), defined by:

$$SA = \sum_{i=1}^{6} p_i x_i \Delta t - \overline{p}\,\overline{x}T = \sum_{i=1}^{6} (p_i - \overline{p})(x_i - \overline{x})\Delta t = \sum_{i=1}^{6} \Delta p_i \Delta x_i \Delta t$$

where:

p_i = 5-minute dispatch price in interval i

x_i = 5-minute average energy (power) in interval i

$\bar{p}$ = half hour average price

$\bar{x}$ = half hour average energy

$\Delta p_i = p_i - \bar{p}$

$\Delta x_i = x_i - \bar{x}$

Δt = 5 minutes

T = half an hour

The last form of SA above can be regarded as the sum of a price variation and an energy variation, all relative to half-hour averages.

The columns to the right of Table B.1 illustrate how this adjustment works. While the average of the variations of price and energy are zero by definition. The product of these variations summed over the half-hour is not. It is equal to the desired adjustment to the settlement that is to be regarded as an ancillary service. The adjustment of $38 is shown in the right-most column, and is equal to the adjustment calculated earlier.

In most cases this adjustment will be small relative to the energy market settlements and SCADA level metering could be considered adequate to implement it, at least initially and on a voluntary basis. However, some improvement is possible. We write the adjustment as *a 5-minute performance factor* multiplied by the energy market settlement amount.

$$SA = \frac{\sum_{i=1}^{6} \Delta p_i \Delta x_i \Delta t}{\bar{p}\bar{x}T} \, \bar{p}\bar{x}T$$

= 5 Minute Performance Factor* Energy Market Half-hourly Settlement

In the example of Table B.1 the 5 minute performance factor would simply be 38/276 = 0.138. This would be calculated from SCADA metering and 5-minute dispatch prices.

Settlement would then by the normal settlement payment with the performance factor used as an adjustment. In this example:

Payment = 23 * 12 (1 + 0.138) = $314

which gives the desire correction i.e. consistency between 5-minute dispatch and half-hour pricing. Note that the MWh readings would be based on the normal; market metering rather than SCADA.

The performance factor is the *ratio* of SCADA values (weighted by 5-minute prices) that will remove multiplicative meter errors. Additive errors would still be present but the error is in a generally small adjustment term. We commend this approach for consideration.

B.4 Conclusion

The approach proposed to adjust for the settlement error is compatible with that proposed for the energy deviations market for small deviation FCAS. The settlement for a participant in a given half-hour will be of the form:

Total Settlement Payment =

Energy Market Settlement Payment

+ 5-minute Performance Factor * Half Hour Energy Price * Metered Energy

+ Small Deviation FCAS Reference Price
* Small Deviation FCAS Performance Factor Metered Energy

The use of performance factors should allow available metering to be used in the first instance, pending the development of local short-term performance metering.

C PAYMENT FOR LARGE DEVIATION FCAS

C.1 Introduction

The Evaluation Report proposed that the requirement for large deviation FCAS enablement (which may involve several enablement products) be implemented as variable in the dispatch process. Constraints on the solution would then be imposed so that the dispatch of any plant that might be subject to a contingency, including flows over critical network elements, should not exceed the amount of large deviation FCAS that NEMMCO defines as required to deal with it. This approach would support the two-way trade of large deviation FCAS as proposed for the light on the hill in the report. It would also be consistent with the principle in the Ancillary Service Framework that ancillary services dispatch be co-optimised with energy market dispatch where possible.

C.2 Example

Table C.1 below is a simple example of how this could work in the SPD, although it must be recognised that many other permutations are possible. In the example:

- the common clearing price for energy is $40/MWh (assume the contingencies that drive the requirement all reside in one region);
- the common clearing price for the FCAS is $3/MWh
- the quantity of FCAS required has been determined by NEMMCO to be above some threshold value, assumed to be zero in this case.
- The dispatched FCAS quantity is 600 MW
- Assume the critical contingencies are large generators for simplicity.

Table C.1: Example of Dispatch Outcome for Large Deviation FCAS Two-way Market

Generating Unit	Rating (MW)	Offer Price @ 600 MW ($/MWh)	Dispatch (MW)	FCAS Price Allocation ($/MWh)
G1	500	10	500	0
G2	660	41	560	0
G3	660	40	600	0
G4	660	39	600	1
G5	660	38	600	2
			Total	**3**

Considering each generator outcome in turn.

- G1 bids low relative to the energy market price and is dispatched at its rated value. This is below the requirement for FCAS so it pays nothing for this service as it is not driving the requirement.
- G2 is rated above the FCAS requirement determined by the SPD process but its bid at 600 MW is above the market price so it is dispatched below that level. It pays nothing for this service as it is not driving the requirement.
- G3 is rated above the FCAS requirement and happens to be dispatched with its bid equal to the market price at the 600 MW level. It would not be willing to pay anything more to increase its output so it pays nothing for the FCAS.
- G4 is rated above the FCAS requirement and its offer price of $39/MWh is below the energy market offer price of $40/MWh. The SPD assesses that it is willing to contribute $1/MWh for the FCAS at this dispatch level.
- G5 is similar to G4 except that its bid is slightly lower at $38/MWh. It is assessed as willing to pay $2/MWh for FCAS to be dispatched at this level.

The shadow price outcome in the SPD would be to apportion $1/MWh to G4 and $2/MWh of G5 to pay for the $3/MWh common clearing price for the FCAS capability. The payments by generators are just sufficient to pay for the large deviation FCAS enablement. Generators not at the level that drives the requirement, or whose bids indicate indifference at that level, pay nothing for the FCAS.

C.3 Discussion and Conclusion

The SPD process should give an efficient outcome given the offers and all the other data in the SPD model. Specifically, generators that would be dispatched at below the FCAS requirement level would see no FCAS costs from increasing their output, because no additional FCAS costs are incurred.

However there is an apparent anomaly for parties that are setting the FCAS requirement that warrants more consideration. Consider the simple case of a 500 MW unit and 660MW unit that have both been operating at, say, 499 MW with that level setting the large deviation FCAS requirement. The 660 MW generator now wishes to consider moving to, say, 520 MW of output. If it attempts to do this, it will move from paying some fraction of the FCAS requirement (say one half) to all of it. This might seem to give a false signal that would discourage such a unit, or group of units, from “breaking out” to the new generation level.

However, more careful consideration suggests that, as offer price decreases, a unit or group of units will pay a greater and greater proportion of the FCAS until they effectively pay for all of it. At this point they will break through the current FCAS limit. Thus there is not the discontinuity in financial outcomes that might appear at first sight. Of course, it is always open to participants to attempt to minimise their contribution to paying for the FCAS through tactical bidding, as is attempted by some generators on occasions to minimise constraint payments for flow over inter-regional links. Indeed, there is a close parallel between the two phenomena. But this is behaviour that does not materially affect the efficiency of the outcome although it may affect the distribution of costs and benefits, as would nearly all other forms of market behaviour. We see no basis for making any special provision to deal with it.

To summarise, it is possible to include logic in the SPD process that will match the supply of large deviation FCAS provision with the requirement as set by dispatch outcomes in each dispatch interval. The effect of this logic would be that a group of the largest contingencies will set and pay for the requirement in that interval. The energy market price will be effected in two ways:

- on the FCAS supply-side, to the extent that units are backed off from the energy market to provide the large deviation service, thereby affecting the energy market;
- on the demand-side, to the extent that some generation units or network flows may be backed off from the energy market to reduce the cost of the FCAS provision.

The first impact on the energy market is already present; the second would be new.

While the net effect should be an improvement in efficiency by better matching the cost of FCAS supply with willingness to pay, the possible impact on the energy market should be recognised.

D PAYMENT FOR NCAS

D.1 Introduction

For the light on the hill, the Evaluation Report recommended two-way spot markets in the contingency based NCAS where practicable. The mechanism would be dispatch and price such services by co-dispatching them with the energy market dispatch and pricing process. In this way traders in the energy market can effectively buy the NCAS they consider worthwhile to support their energy trade.

Even if such two-way markets should prove impractical to implement at a given time during the evolution of the NEM, there should always be a link between the constraint residues (rents) and the cost of providing the contingency-based NCAS that can affect those residues. In this way the accountability for the balanced provision of the NCAS concerned can be maintained, even where that provision is not competitive. In other words, we seek to follow the basic principle that the beneficiary or causer of the requirement for the service should pay the cost of providing that service.

The provision of continuous voltage control within regions cannot be handled by this logic. However, in this case the beneficiaries of the part of the service provided and paid for initially by NEMMCO can be identified as the TNSP within the region in the first instance, at is the capability of the TNSP's network that is being supported. Of course, that network is being maintained for the benefit of the TNSP's customers, who pay for that capability.

This appendix provides examples of the application of this principle, compares the outcome with the status quo and highlights some issues that arise. The aim is to highlight the issue of who pays than to illustrate a market arrangement

D.2 Examples

D.2.1 Intra-regional NCAS

Within a region a TNSP maintains secure network capability by providing for some redundancy in its network, by ensuring that the supply of continuous reactive power is suitably distributed throughout its network and, in some cases, providing for contingency-based NCAS.

Example 1

Fixed costs of $5m per annum is incurred by a TNSP for voltage control within a region (e.g. reactive plant), plus $1m per annum operating cost incurred by NEMMCO.

- Status quo: $5m p.a. included in TNSP rate base and charged through TUOS. $1m AS operating costs allocated to all loads throughout the NEM.
- Proposed: $5m p.a. of fixed costs would be chargeable by the TNSP thorough TUOS provided they can be justified in competition with other NCAS providers through an open process. To this would be added the $1m operating costs that would be charged

to the TNSP in the first instance, rather than allocated to all loads across the whole NEM.

An energy market settlement residue accrues within a region as a result of the use of marginal loss factors within a region. This residue does not include any component accruing as a result of intra-regional constraints, as the NEM pricing rules within a region prevent such an outcome. For this and other reasons it is possible that the allocation of intra-regional NCAS costs incurred by NEMMCO to regional TNSPs could result in less residue being passed back to customers, or the residue net of the NEMMCO-incurred NCAS costs becoming negative.

Example 2

Consider the situation discussed in Example 1.

- If the current residue is $2m p.a. the net amount passed back to TNSP customers would be this amount less the $1m p.a. incurred by NEMMCO in NCAS costs to support the TNSPs network i.e. $2m - $1m = $1m would be passed back to TNSP customers.

- If the current residue is $0.5m p.a. the net amount passed back to TNSP customers would be this amount less the $1m p.a. incurred by NEMMCO in NCAS costs to support the TNSPs network i.e. $0.5m - $1m = negative $0.5m in the year. This would result an additional charge to TNSP customers of $0.5m in the year

In summary, the proposed transitional charging approach for NCAS incurred by NEMMCO for the purpose of supporting the network within a region would be charged in the first instance to the TNSP responsible for maintaining the capability of the network in that region. This would net off from the intra-regional residue that is currently passed back to TNSP customers, although it is possible that this could result in a net additional charge to TNSP customers. Regulatory arrangements would need to recognise this possibility.

D.2.2 Voltage Contingency NCAS Produced or Consumed by a Distribution Network

Continuous reactive power consumption or production at the point of connection between the transmission and distribution networks enters into voltage contingency constraints on the SPD. The extent of the influence depends on location and general system conditions and will be defined I the form of the constraint that is applied. The proposed approach is to support a base level of reactive provision in a similar way as currently provided by the Code. There would then be a charge or credit for the difference between base (taken as a contract) and actual at the price determined by the clearing price associated with the constraint in the SPD. The difference from the status quo is that these variations will ultimately driven by market prices, although the scope for negotiation and contracting between TNSP and TNSP would remain.

Example

- Base power factor (say) is 0.95

- Real power at time of constraint is 1000MW
- Base reactive consumption is approximately 1000 x 0.05 = 50 MVAR
- Actual consumption is measured 80MVAR
- Purchased on spot is 80-50 = 30MVAR
- Generic constraint clearing price is $40/MWh of inter-regional link capability (say)
- Influence coefficient for the particular point of connection with respect to the constraint is 0.25 MVAR per MW of inter-regional capability (say).
- Reactive price at point of connection is 0.25 x $40 = $10/MVAR
- Amount payable to NEMMCO settlements is 30MVAR * $10/MVAR = $300

This amount is added to any energy spot settlement surplus and provides the funds to pay providers.

- If actual reactive consumption os 50 MVAR, nothing is payable by the DNSP
- If actual reactive consumption is 20MVAR, the DNSP would receive $300.

D.2.3 Inter-regional NCAS for a Regulated Link

This case represents the status quo operationally but NCAS costs are re-assigned.

Consider the following case:

- The flow into a region is restricted by the availability of reactive capability to manage voltage contingencies.
- NEMMCO contracts with a provider to provide that capability at a cost of $1m per annum (say).
- The residue produced by the constraint that the NCAS affects is $3m for a given year.
- The residue stream in the direction of the flow had previously been auctioned for $2m for that year.

Under the current arrangements (assuming the receiving region TNSP receives the net residue from the importing link:

- The TNSP in the affected region receives the net proceeds of the residue sale in the first instance, which in this case is $2m.
- The buyer of the residue stream makes a $1m gross profit from the transaction in this case.
- The $2m received by the TNSP is then passed on to TNSP customers through reduced network charges.

- The $1m of NCAS costs incurred by NEMMCO to support the link is smeared amongst all NEM Customers who are loads; loads in the affected region may only pay, say, one third of this, or $0.33m.

Under the proposed new payment arrangements:

- As before, the TNSP in the affected region receives the net proceeds of the residue sale in the first instance, which in this case is $2m.
- As before, the buyer of the residue stream makes a $1m gross profit from the transaction in this case.
- The $1m of NCAS costs incurred by NEMMCO to support the link is charged to the TNSP who received the net residue (after auctioning).
- The net residue of $2m, less the NCAS costs of $1m, i.e.$1m is passed on to TNSP customers through reduced network charges.

Different permutations are possible, including ones where the NCAS costs might exceed the net revenue. In this case the net costs from these transactions would be passed to TNSP customers.

The net affect of this will be to combine a charge to customers (through the AS levy on loads) and a rebate to customers (through the reduction in TNSP charges due to the settlement residue) into a single net payment or rebate. NCAS costs are paid for by the beneficiaries of the expenditure, rather than allocated across the whole NEM. Further, there is a clear accountability on NEMMCO to balance the cost of NCAS expenditure with the cost to the energy market of constraints.

D.2.4 Entrepreneurial NCAS provider

Where a spot market in a particular NCAS is operating as proposed in the Evaluation Report, it will be open to entrepreneurial providers to offer in their NCAS capability to the market and to receive a settlement payment through the NEM settlement system. The entrepreneur would bear his own NCAS costs and gain the benefit of a component of the energy market residue stream associated with the link whose capability he has enhanced. No further action is required.

D.2.5 Entrepreneurial Link Provider

An entrepreneur may choose to build a link or link expansion that might need to be supported by NCAS. This could be provided through NEMMCO’s processes or by the link owner through direct deals with providers (although the service would still be dispatched by NEMMCO, whether an NCAS market is operating or not).

- Where NEMMCO provides the service through its own processes, all costs would be directly charged to the link owner as the beneficiary.

- Where the owner provides his own NCAS (the preferred approach given that the link is supposed to be entrepreneurial), no issue of centralised payment arrangements for the NCAS arises.

Example (second approach)

- An entrepreneur decides to build an unregulated link between two currently disconnected regions. The capital cost annualises to$20m per year and the nominal capacity is 200MW.

- NEMMCO advises that 10 units of FCAS will be required to maintain that capability for secure operation. This must be provided or the link will be dispatched at the value that NEMMCO considers would maintain security.

- The entrepreneur costs out this amount of NCAS from a number of potential providers and decides he will contract with one for $1m per annum for the required 10 units capability. There is also an amount payable to the NCAS provider of $1k per unit per hour if the NCAS is enabled. The link owner judges, at his own risk, that this additional cost to maintain the link capability at critical times will be justified.

A typical set of operating transactions on a day of high link use that would benefit from the NCAS might then proceed as follows. There is no fundamental difference whether there is an NCAS market operating or not.

- The link owner offers in the NCAS at its marginal cost to the NEMMCO dispatch process, which he can do under his contract with the NCAS provider

- If the NCAS is not dispatched the link owner simply pays the fixed costs of the NCAS to the provider, under his agreement. In this case the link owner might receive no (or very little) settlement residue from the dispatch process

- If the NCAS is fully dispatched for 5 hours in the day when the link also becomes constrained (for example), the link owner:

    - The link owner receives the settlement residue from NEMMCO. This might be, say, $500k on this highly constrained day

    - The link owner pays the NCAS provider his marginal costs, as per his contract with it, This cost is $1k*10*5=$50k. He must also pays the NCAS fixed costs, averaging around $3k/day and his own fixed costs, averaging around $50k/day. All his costs are well covered by the surplus on the day, but may not be every day.

The key point here is that it is the entrepreneur who negotiates the deal for the NCAS and takes the risk in providing it at different levels. The only real difference from the regulated case is that NEMMCO essentially passes on all the risks to the TNSPs in terms of the net settlement residue and NCAS payments, and these risks are then passed on by the TNSPs to its customers.

D.3 Conclusions

The proposed approach to charging NCAS costs can and should be implemented irrespective of whether market arrangements are established are not. They should support a (relatively) smooth transition to entrepreneurial links and would implement the principle that the causers or beneficiaries should pay, irrespective of the arrangements for provision.