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Preliminary Report:

Are Regulation Frequency Control Ancillary Services effectively administered and delivered in the National Electricity Market?

Prepared for:	By:	Date:
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1 Introduction

Frequency Control market arrangements are alleged to be failing to control frequency between the operating bands of 49.85 – 50.15Hz and it has been postulated that changes to generator behaviour and/or changes to generator governor controls are contributing factors.[i] CS Energy would like to assess how effective is regulation FCAS being administered by AEMO, and delivered by different participants and stations, under a range of market conditions. Towards this end, pdView was commissioned to analyse a sample of days with the objective to determine an approach that measures the relative performance, of both the delivery and the administration, of regulation FCAS. This preliminary report aims to achieve this objective by demonstrating an approach that successfully identifies and quantifies the performance of Tasmanian units relative to Mainland units over a short time period.

For further work, pdView proposes to apply this approach with more rigour, over a longer time frame and across a wide range of variables.

2 Possible contributing factors

There are a number of possible contributing factors that can be conjectured and assessed. These include, but are not necessarily limited to, the following:

1. The relative performance between;
    a. stations
    b. fuel types
2. Performance as a function of;
    a. unit load/technical envelop
    b. the magnitude of a change in energy target
    c. the magnitude of utilisation of a regulation service
3. Overall performance as a function of;
    a. the change in demand
    b. the level of wind generation
    c. different operational states such as Basslink deadzone, low and high time error, etc.

If a difference in the efficacy of service delivery is identified then a second question is whether it is caused by AEMO's administration or unit delivery.

3 Sample period – afternoon of the 1st of April

CS Energy highlighted a few days when anomalies and variations in performance were observed. This section reviews one of these days – namely the afternoon of the 1st of April 2017. Appendix 1 provides observations of the other days provided by CS Energy.

During the afternoon of the 1st of April 2017, high prices for raise regulation services oscillated between $20 and $100 per MWhr throughout the afternoon, as is shown in Chart1.

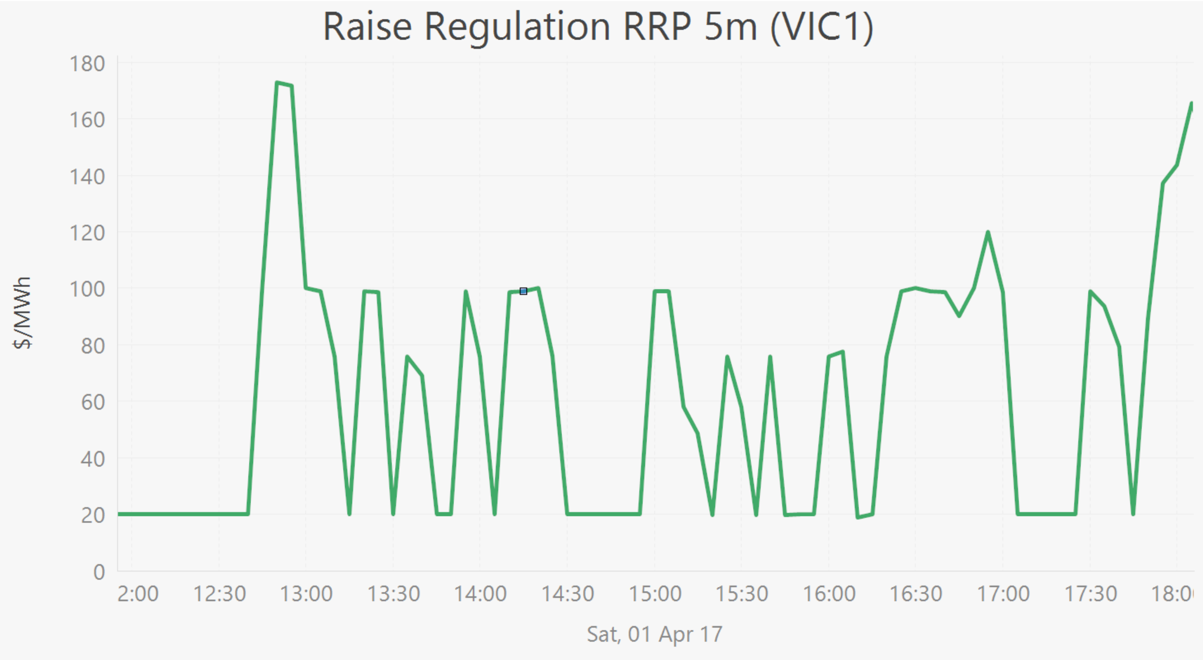


Chart 1

The oscillating high prices coincided with changes to invoked FCAS constraints (Chart2).

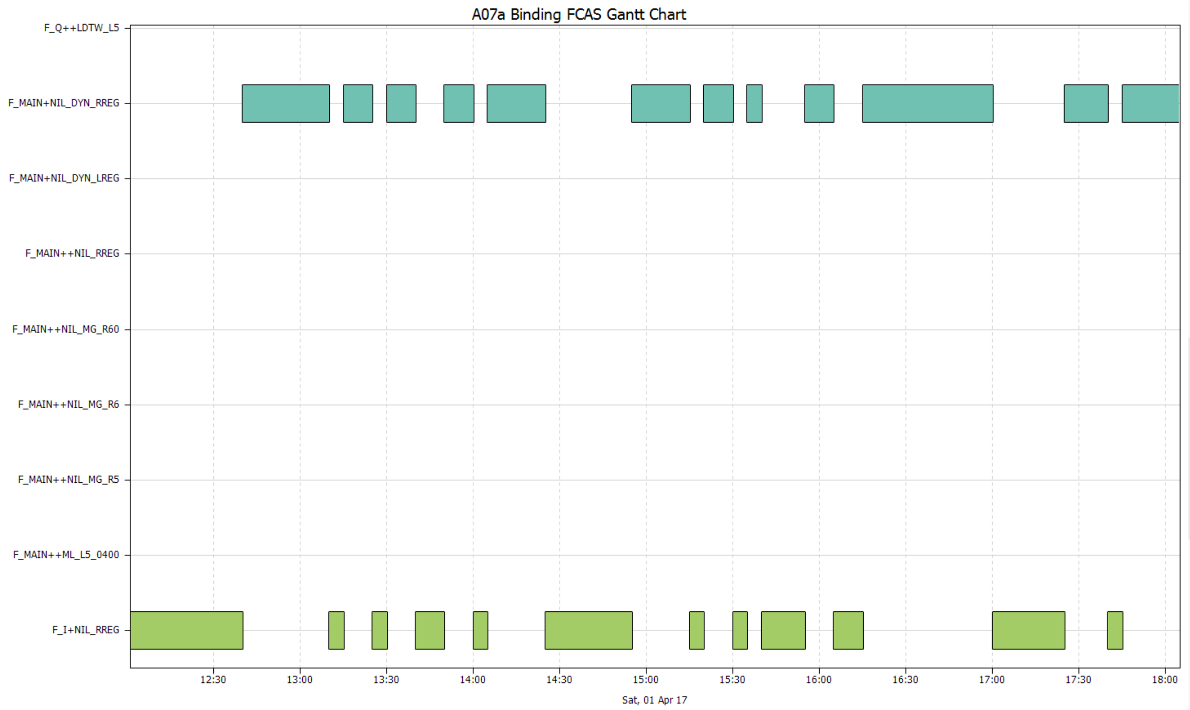


Chart 2

The two invoked FCAS constraints are described by AEMO as follows:

1. Mainland Raise Regulation Requirement, 130MW plus 60MW for each 1s of time error below -1.5s.
2. System Raise Regulation Requirement 130MW.

The change in constraint implies that the time error was moving above and below -1.5s throughout the afternoon – a total of 12 times. This observation suggests that the system was struggling to control time error (and by inference frequency) when the system raise regulation requirement of 130MW was invoked because under this constraint, time error quickly exceeded -1.5s and the mainland constraint was reinvoked.

Next we will investigate the enablement mix during the afternoon. Chart 3 shows the enabled units during one hour from 14:00 to 15:00 (note I've zoomed into one hour for simplicity).

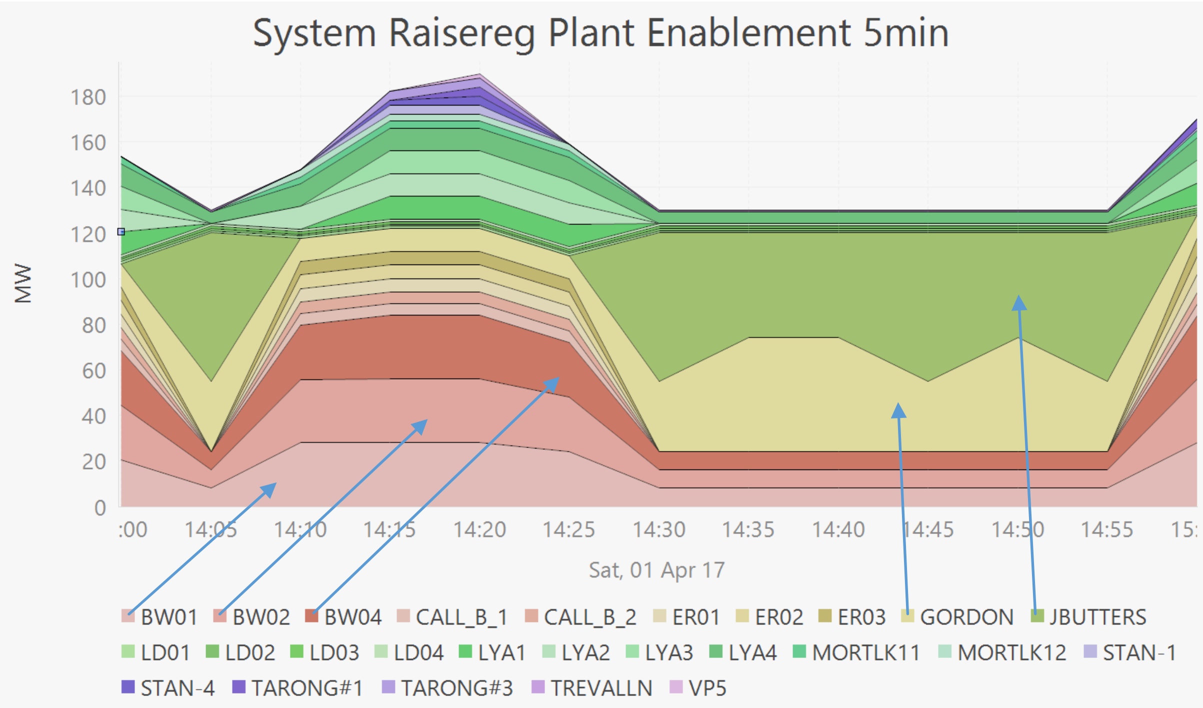


Chart 4*

*Note the graph linearly extrapolates enablement which is not correct since it is a step change from one dispatch interval to the next.

From 14:00 – 14:05 and 14:25 – 14:55 system requirement was 130MW and Hydro Tas was enabled 96MW of this amount (over 70%) via Gordon and John Butters (see arrows on Chart 4). The other times the majority of enablement was provided from the mainland (the arrows highlight Bayswater units which provided nearly half of the enablement volume during the Mainland constraint). This hour is a good candidate to compare the performance of two very different sets of enabled plant.

The frequency and frequency target for both the Mainland and Tasmania is shown in Chart 5. (Frequency target step changes by +/-0.01Hz when the time error reaches +/- 0.5s and increases linearly by the same rate for time error greater than +/- 0.5s.)

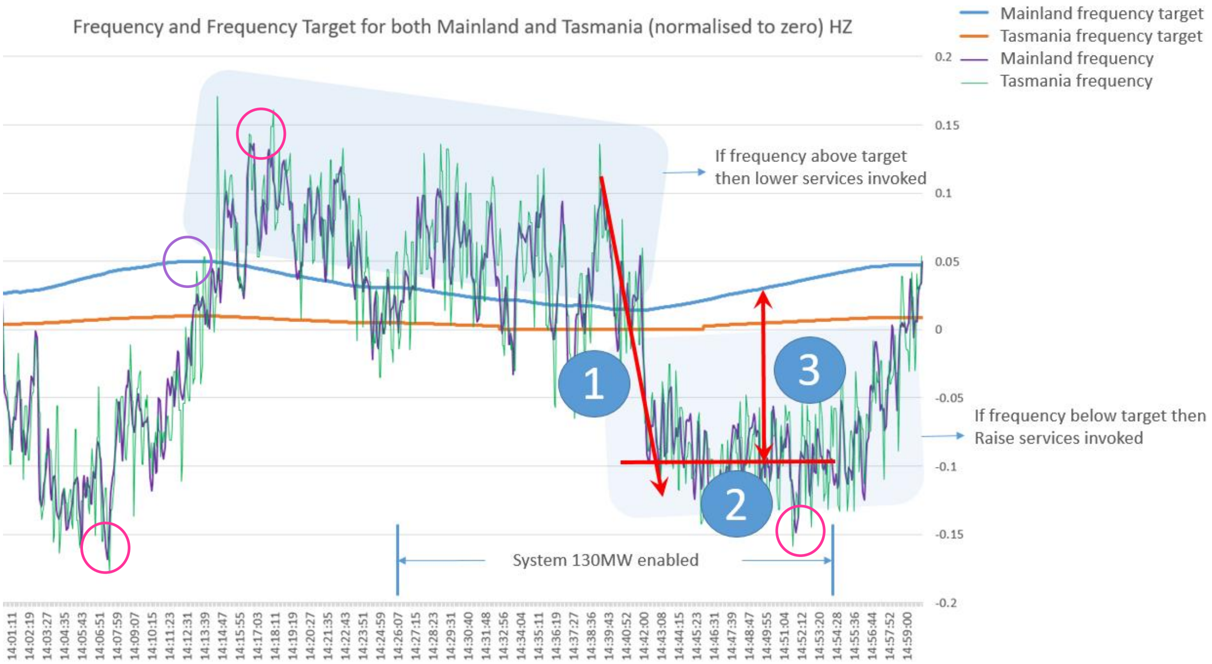


Chart 5

The frequency exceeded (or nearly exceeded) either end of the operating bands (+/- 0.15Hz) on three occasions in just one hour (circled in pink in Chart 5). The frequency target reached 0.05Hz which translates to a time error of -2.5 seconds. (circled in purple.)

The first red line marked 1 shows a quick drop in frequency. The second red line marked 2 shows when the frequency did not return to target for nearly 15 minutes despite the frequency offset being large as shown by the third red line marked 3. Note that during this time, the system requirement was 130MW of which 96MW was sourced from Tasmania. The frequency also did not return to target until the specific Mainland constraint was invoked at 14:55.

The next step in this analysis is to inspect the AGC Signal and Generator Response of both a Mainland and Tasmanian unit. Chart 6 and 7 shows the response of Bayswater 1 and Gordon respectively. Note I've kept the one hour time frame but the time of interest is 14:40 to 14:55.

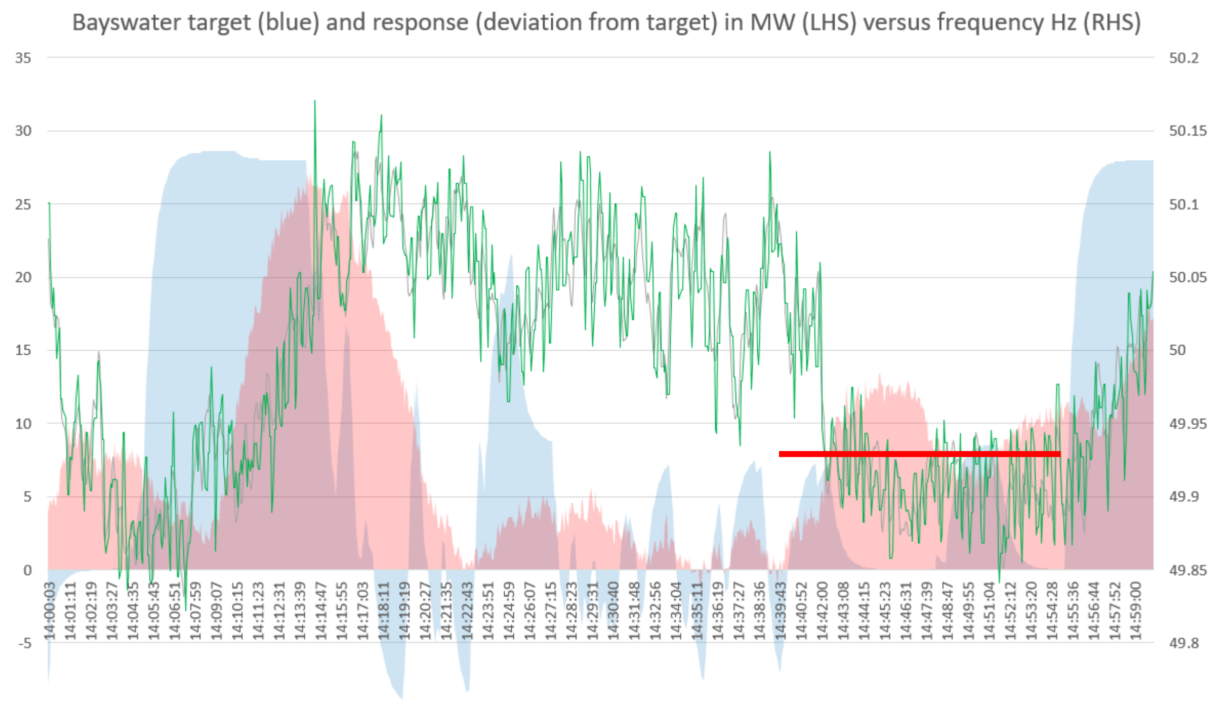


Chart 6

The red line shows the period when frequency was low. As a result, raise regulation AGC signals were sent to the full level of Bayswater's enablement (8MW). Bayswater responded and exceeded the enablement level hence AGC signal was removed but the signal was resent again when response dropped below 8MW. In summary full utilisation was requested and Bayswater responded as instructed.

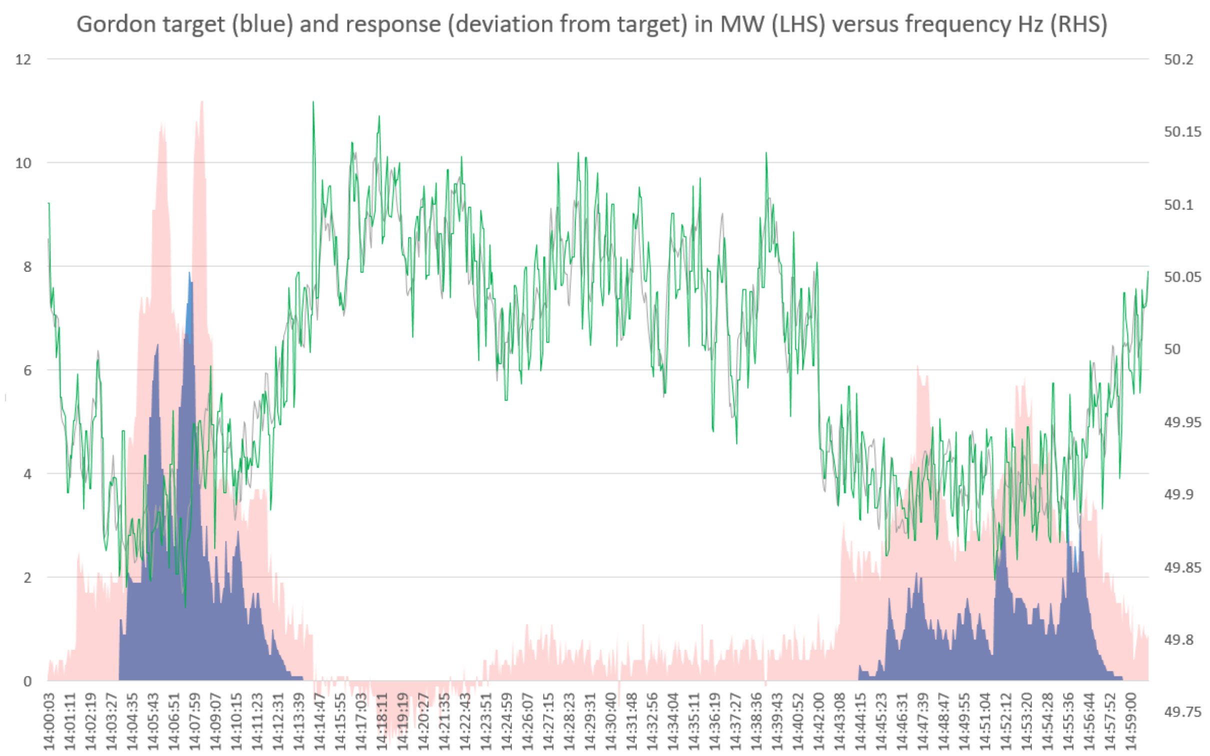


Chart 7

Comparing the same time period, Gordon overshot AGC signal by more than Bayswater however Gordon was enabled between 31 and 50MW for the same time period yet the maximum AGC instruction was only 3MW. It is likely that the AGC signal would have been more if it weren't for the overshoot however even if it is assumed that the AGC signal intent was 5MW and enablement 30MW then this represents an utilisation of only 17% compared to Bayswater (assumed to be 100%).

This observation proposes that the AGC raise regulation instructions to Tasmanian units are proportionally only a fraction of the instructions provided to Mainland units. If this proves to be true then there is a significant bias in the administration of regulation FCAS resulting in ineffective deliver from Tasmanian units to correct Mainland frequency and time error.

To explore this proposition further we undertook a statistical analysis of all enabled units in the NEM on the 1st April 2017 when 130MW of regulation services were sourced system wide.

It is worth noting that Tasmania was enabled just over 50% of the total requirement for the 1st of April 2017.

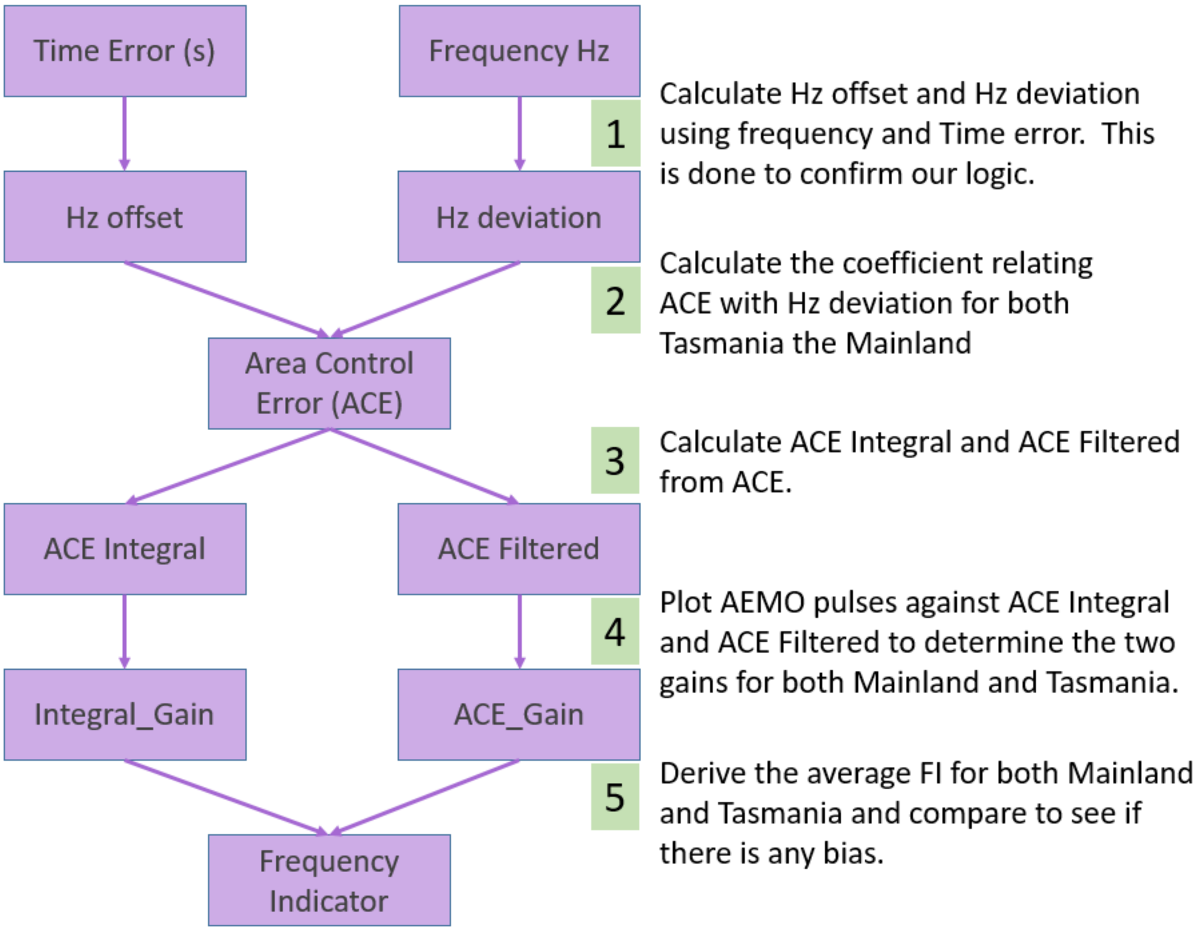
4 Statistical analysis of Tasmanian versus Mainland AGC instructions

This section outlines the method and the results of applying a statistical analysis of the 4 second causer pays data.

We understand, although have not confirmed, that AGC instructions are closely related to the Frequency Indicator (FI) which is known to be defined as follows[ii]:

FI = (ACE_Filtered * ACE_Gain) + (ACE_Integral * Integral_Gain)

The aim of this section is to derive an average value of ACE_Gain and Integral_Gain and ACE and ACE_Integral thereby estimate an average FI for both the Mainland and Tasmanian units and compare these values to see if there is any bias between signals sent to the Mainland compared to signals sent to Tasmania. The following flow diagramme summarises the process to achieve this aim.



Moving through the steps.

1. Let's just say that step 1 worked since the values are otherwise available. We did this to check the data and our logic.
2. The following two plots (Chart 8 and Chart 9) show that a plot of *ACE* (with units of MW) vs. *Hz_Deviation* – *Hz_Offset* has a gradient of 2800 MW/Hz and 140 MW/Hz for the Mainland and Tasmania respectively. Note also that the fit is perfect and so we are 100% confident that this is how AEMO calculate *ACE*. Hence, for the purposes of comparing FI between the Mainland and

Tasmania ***ACE* can be set to 2800MW per Hz for the Mainland and 140MW/HZ for Tasmania.**

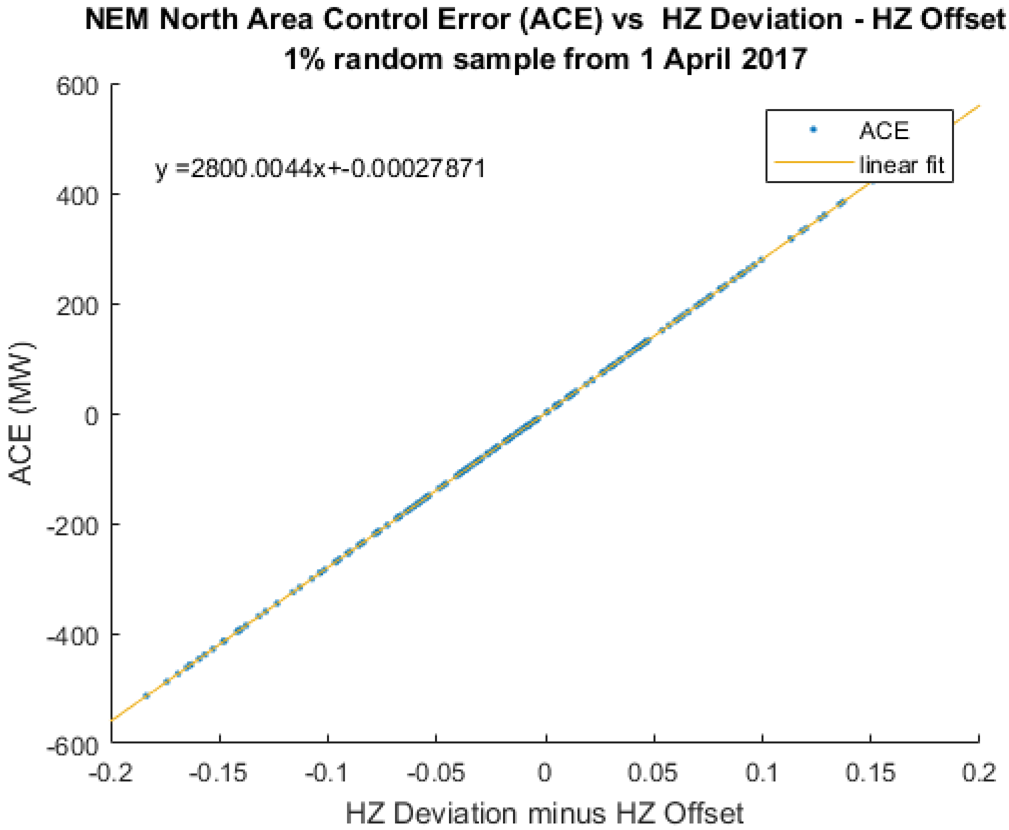


Chart 8

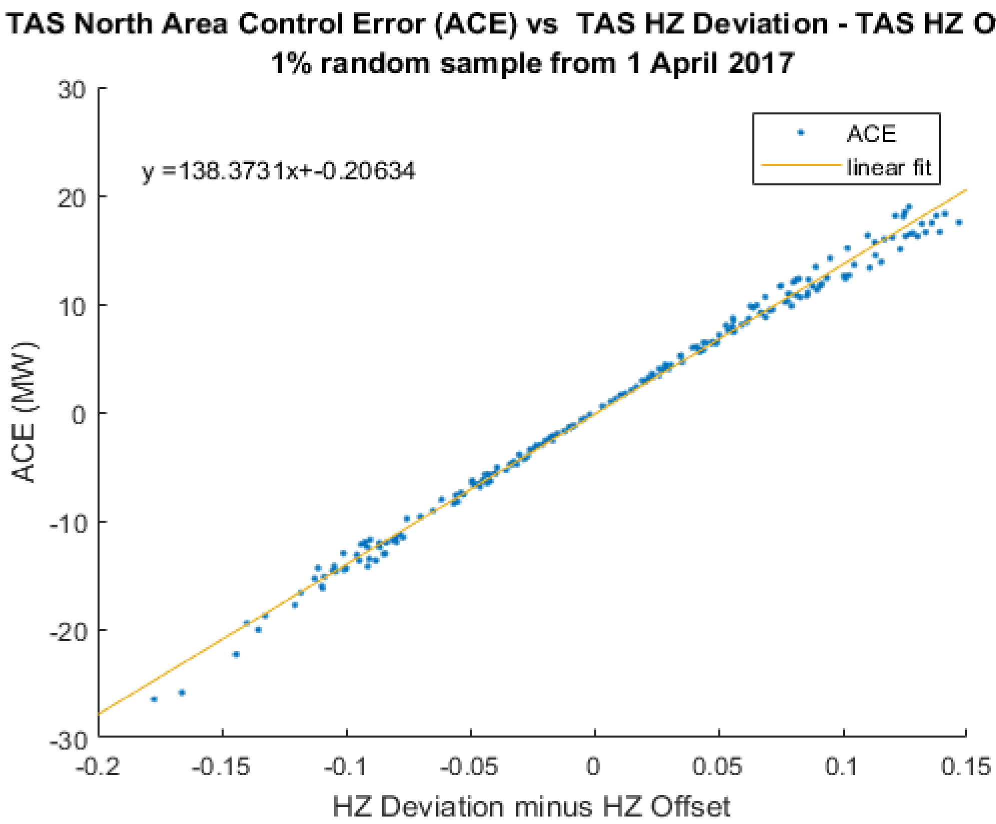


Chart 9

3. *ACE Filtered* was found to simply be *ACE* that had been exponential smoothed (not shown). *ACE Integral* was found to be equal to the previous *ACE Integral* + (*current ACE*/(60*60/4)). Working not shown.
4. The following two plots (Chart 10 and Chart 11) are used to derive estimates of *ACE_Gain* for both the Mainland and Tasmania. (The same can be done for *Integral_Gain* however there is little correlation, see Chart 12 – this raises further questions regarding the purpose of the Integral_Gain however such questions are beyond the scope of this analysis.)

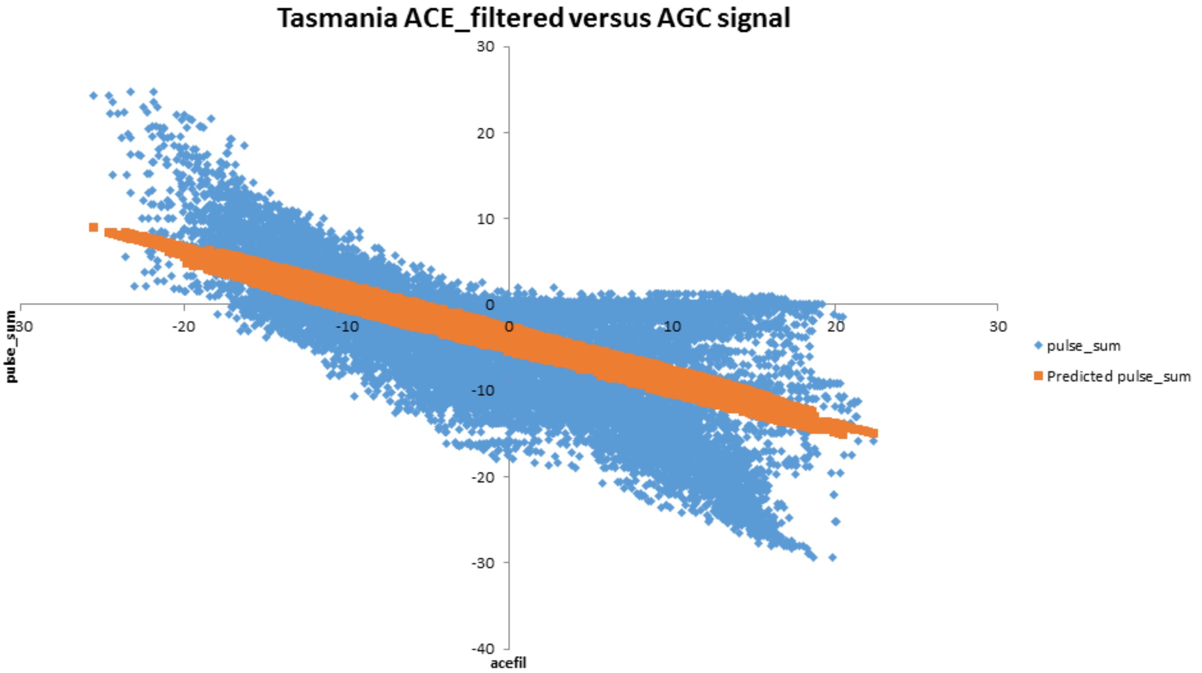


Chart 10

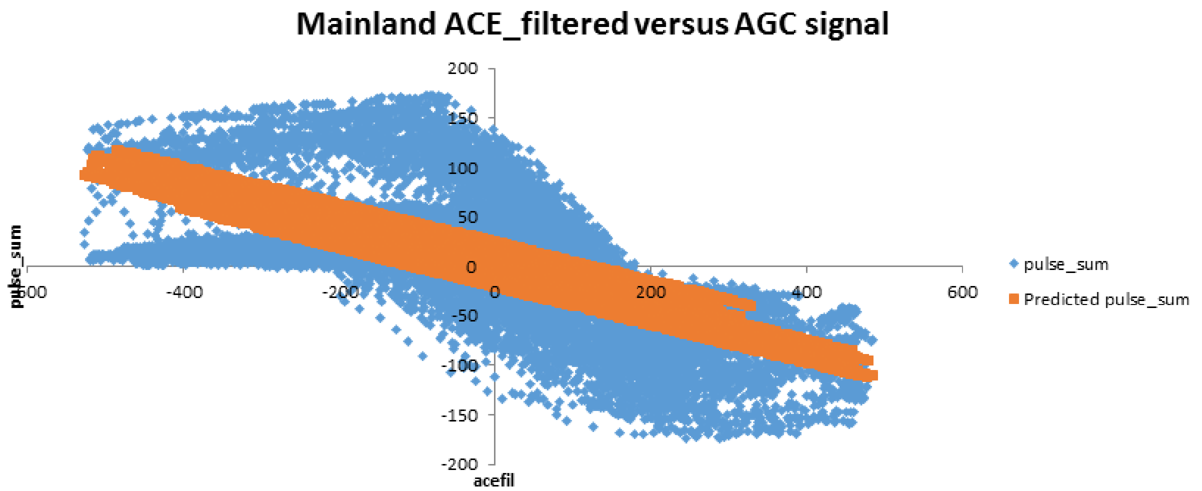


Chart 11

The slope of two graphs which represents the *ACE_Gain* is 0.19 and 0.5 for the Mainland and Tasmania respectively.

5. Derive the FI (or AGC signal) for both the Mainland and Tasmania and compare results.

FI (or AGC signal) = ACE_Filtered * ACE_Gain

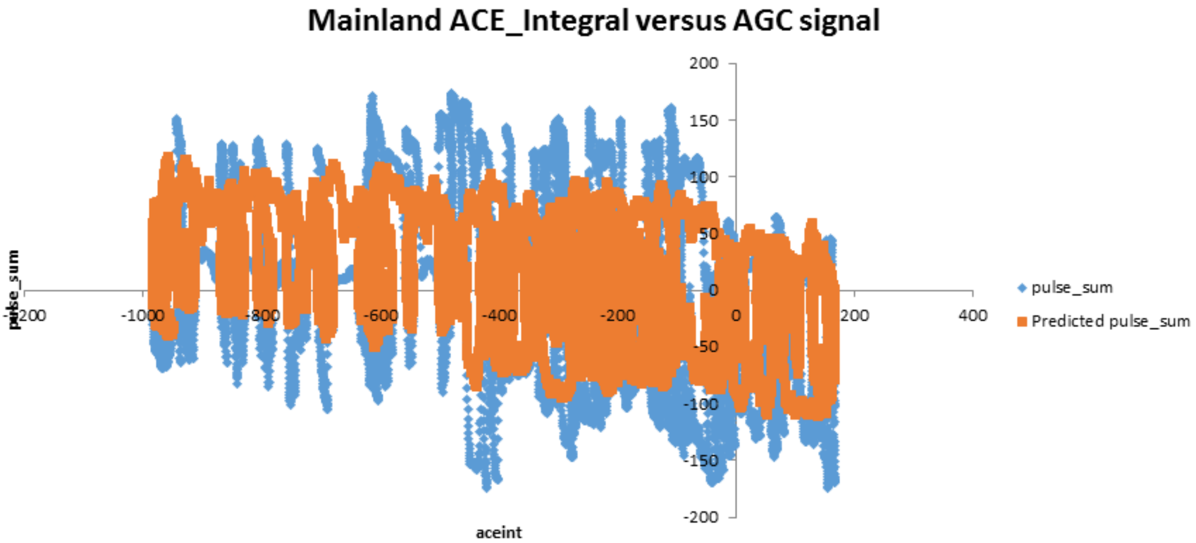
FI for Tasmania = 140 * 0.5 = 70

FI for Mainland = 2800 * 0.19 = 532

Note that FI is not published by AEMO and so the above is only an estimated average over the entire day.

From the above, the ratio of the two signals is: 532/70 = 7.6 or conversely 13%. This translates to a Mainland AGC signal being 7.6 times greater on average than a Tasmanian AGC signal. Or alternatively the Tasmanian signal is 13% of the Mainland signal on average. Note that this value is consistent with the estimated value of 17% derived using Chart 6 and Chart 7.

For completeness the following chart shows AGC_Integral versus AGC signal which shows no obvious correlation hence it was no included in the calculation.



5 The approach

The above approach begins by deriving the relative AGC signal or unit response followed by a statistical analysis to identify any bias between different generator groupings.

6 Some findings

These findings from the statistical analysis shows a possible administration issue of the delivery of regulation FCAS. We suspect that the AGC regulation FCAS system for the Mainland is independent from the one for Tasmania. Basslink flow is controlled by the difference in frequency between the Mainland and Tasmania with a deadband of 0.01Hz therefore all systems are working together to correct frequency and time error. However for whatever reason it appears that on the 1st of April 2017 the gain settings for Tasmania do not translate to the needs of the Mainland.

We stress that although this analysis is rigorous it only applies to the 1st of April 2017. To understand if this bias was temporary or enduring requires analysis over a greater time frame.

7 Proposal for the next step

pdView proposes to undertake a more thorough statistical analysis over a greater time frame with the following objectives:

1. Review and confirm our logic with more rigour. The above work was performed in only 6 days and is a preliminary study only.
2. Derive the effective difference in AGC signals using a longer time frame and identify variations including,
   a. FCAS constraint (such as Basslink deadzone or Mainland specific requirement)
   b. During times of different control status for example
      i. When gain settings were reduced from 15 to 8
      ii. When 34MW and then 50MW maximum enablement was invoked for Tasmania.
   c. Any slow change over the years (say three years)

Appendix 1

The above analysis was only one period of concern raised by CS Energy. For completeness we have appended some extra charts that shows other periods which could form the basis for further studies. The discussion around these charts are brief and are not intended to be comprehensive.

17th of January 2017

Chart A.1 shows Gladstone 5 AGC signal and generator response for one hour on the 17th of January 2017 when system raise regulation requirement reached the maximum of 400MW.

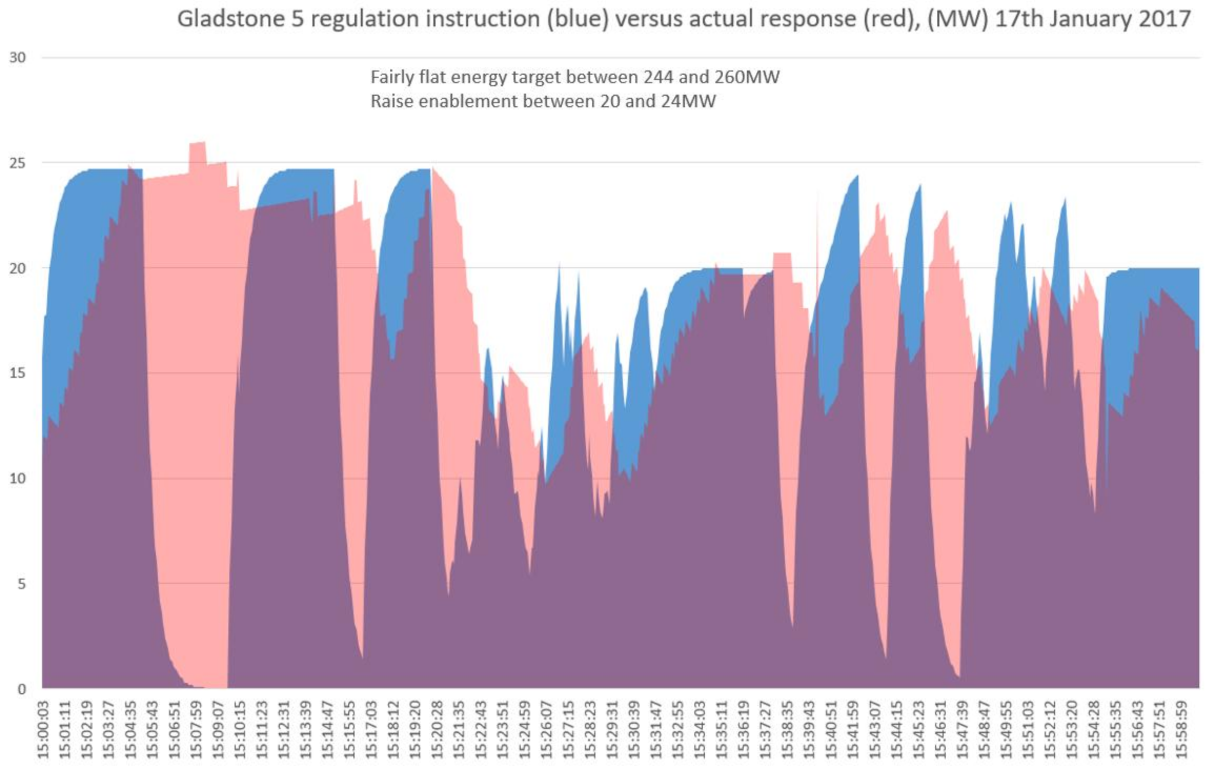


Chart A.1

Gladstone 5 is receiving AGC raise signals in the order of their enablement. Note the periods where the signals drop quickly, we suspect this occurs when the generator response exceeds the enablement level even though a sustained response might is required.

Chart A.2 shows the equivalent graph for Mount Piper 2.

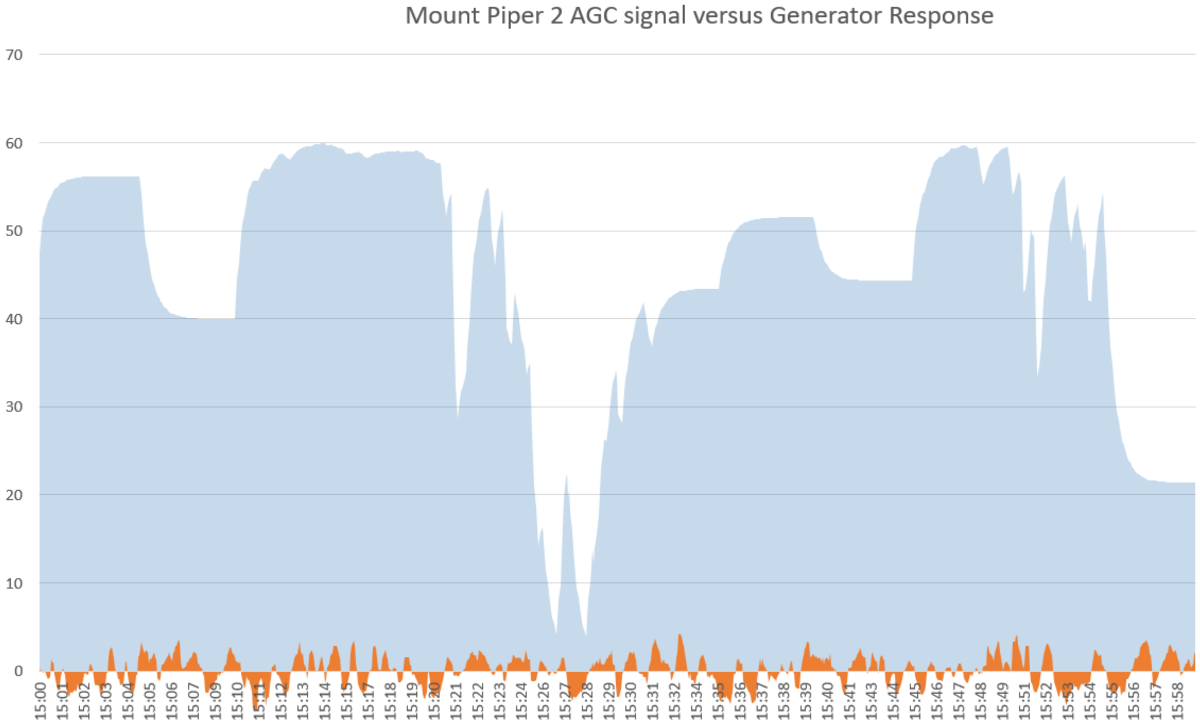


Chart A.2

Raise enablement was up to 60MW and energy target was flat at 600MW. Similar to Gladstone 5 the AGC signal for Mount Piper 2 called for most of the enablement. However the generator response from Mount Piper 2 was virtually non-existent. Indeed the response shown is likely to be random variation in generator output. Whether or not this example of a lack of generator response is typical for Mount Piper or a one off was not explored further.

Tasmanian units were also explored for the hour from 15:00 to 16:00 on the 17th of January 2017. Chart A.3 shows the AGC signal and generator response for Reece 1.

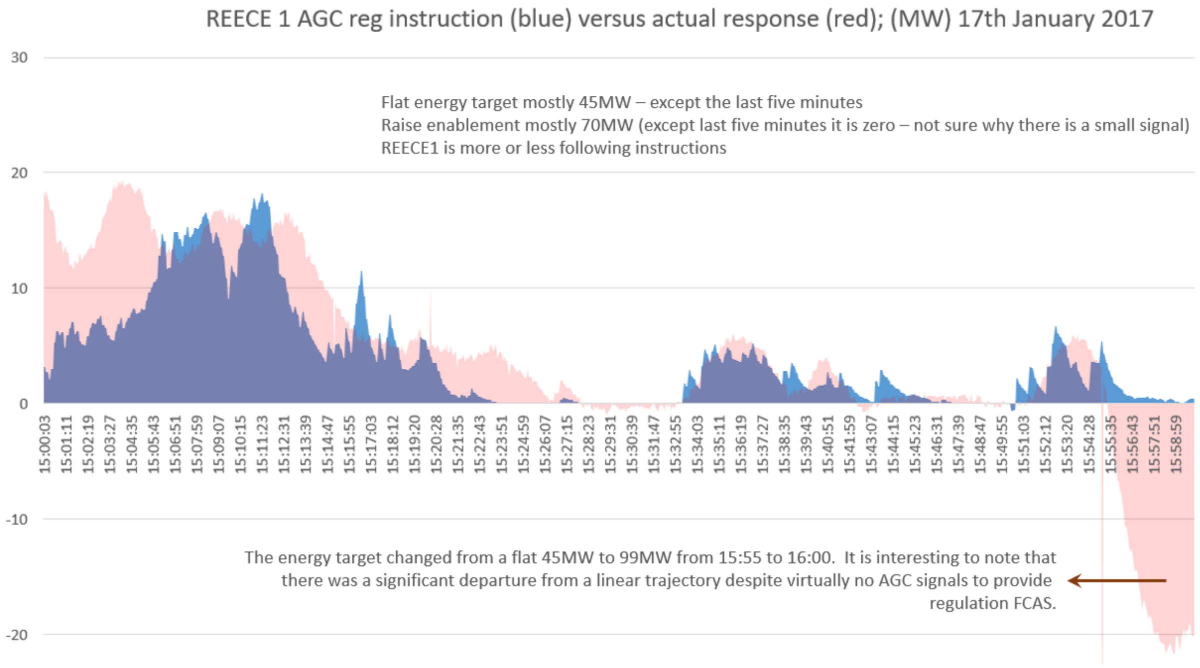


Chart A.3

Although Reece 1 generator response more or less follows AGC signals the signals are only a fraction of the enablement level for Reece 1 (which was 70MW for all but the last 5 minutes). Visually it is safe to conclude that the AGC signals amounted to less than 10% of the units raise regulation enablement. Contrast this to Mainland units which had AGC signals requiring nearly full utilisation of the their respective raise regulation enablement.

One other interesting feature of Chart A.3 is that there was a deviation from target of over 20MW in the final 5 minutes despite no AGC signal to provide regulation services. From 15:55 to 16:00 Reece1 energy target changed from a previously flat 45MW to 99MW. Although this is only one data point it does question whether regulation services can be effectively provided during significant changes in energy target. We suggest that this question is worthy of further study since high ramp rates are anecdotally increasing in the NEM due to the reduction in the number of baseload plants and the increase in wind farm output. Failing to account for changing energy targets in the enablement of regulation services could be a contributing factor to the alleged failure of market arrangements to control frequency.

[i] AEMC, System Security Market Frameworks Review – Final Report. 27th June 2017, pp. 39
[ii] Kate Summers, "Fast Frequency Service – Treating the symptom not the cause?" Submission Paper to Licensing Inverter Connected Generators. 8th February 2017