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Frequency Control Modelling

Investigation of ramp impacts on frequency control in the NEM under high VRE penetration

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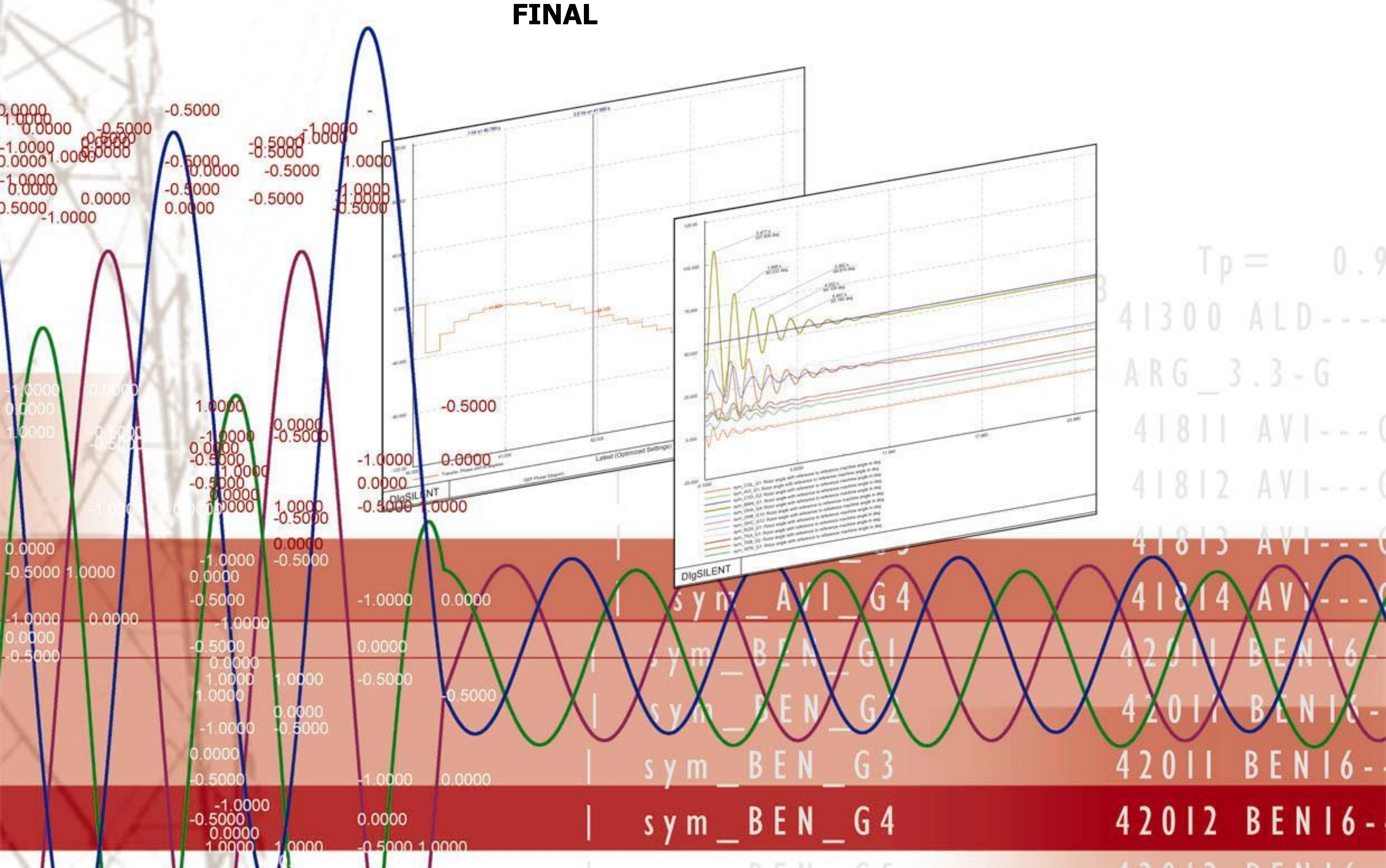
Prepared for:

AEMO

Version 2.0

FINAL



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Version history

Version	Authors	Reviewed by	Date	Comments
0.1	J. Crisp L. Mardira	T. George	19 December 2019	Draft for comment
1.0	J. Crisp L. Mardira	T. George	20 December 2019	Initial version for comment and discussion
1.1	J Crisp L. Mardira	T. George	20 January 2020	Final version incorporating AEMO comments
2.0	J Crisp L. Mardira	T. George	25 March 2020	Additional commentary regarding ramp data and data cleansing impacts. Additional commentary regarding other influences on PFC and AGC quantities and performance

CONTENTS

Glossary of terms

AC	Alternating current, the most common form of electrical energy in power systems. Voltage and current oscillate sinusoidal at 50 or 60 cycles per second.
ACE	Area control error
AGC	Automatic generation control
AEMO	Australian Energy Market Operator.
CCGT	Combined cycle gas turbine
FCAS	Frequency control ancillary services
HV	High voltage, typically referring to voltage of 1kV and above.
Hz	Hertz, a measure of frequency, equivalent to s^{-1}
IEEE	Institute of Electrical and Electronics Engineers
kV	Kilovolts, one thousand volts, a measure of electric potential.
LV	Low voltage
MMS	Market management system
MVA	Megavolt Amperes, a unit for apparent power, the vectorial sum of real and reactive power.
MVAr	Megavolt Amperes Reactive, a unit for reactive power
MW	Megawatts, a unit for real (active) power
NEM	National electricity market; the inter-connected electricity grid of the Australia eastern states.
NER	National Electricity Rules, the rules that govern the planning and operation of the national electricity network of Australia.
NOFB	Normal operating frequency band
OCGT	Open cycle gas turbine
OEM	Original Equipment Manufacturer
P	Signal representing the generator real (active) power output
pf	Power Factor. A unit less parameter representative of the generator load angle, calculated from the tangent of the division of reactive and active power.
PFC	Primary frequency control
PV	Photovoltaic
pu	Per unit, an expression of system quantities as fractions of a defined base unit quantity
Q	Signal representing the generator reactive power output
TNSP	Transmission Network Service Provider
V	Signal representing the terminal voltage
VRE	Variable renewable energy

1 Introduction

DIgSILENT Pacific has been engaged by AEMO to investigate the impact of large ramps on the frequency control in the National Electricity Market (NEM).

Frequency deviations from nominal are caused by mismatches in generation and demand. Both generation and demand change over the day. Generation is dispatched based on the demand forecast, which has a varying amount of error. In addition, generation may not achieve its dispatched output, or, in the case of Variable Renewable Energy generation (VRE) its forecast generation. VRE, because it is subject to a variable source of energy, has a variable output and this contributes to mismatches. For the most part, the changes in VRE output are either:

- Not coincident, and average out to a low net variability across a geographically diverse fleet, or
- Coincident, but forecastable, such as ramping of solar energy after dawn and before dusk.

However, there will always be a small proportion of coincident ramps in the same direction that can lead to mismatches between generation and demand, especially within the five-minute dispatch intervals.

Mismatches are managed by a combination of regulation frequency control through the automatic generation control system (AGC) and primary frequency control (PFC). As the amount of VRE on the power system increases, the average ramps (and hence mismatches in generation and demand) will remain similar, and close to zero, but the size of the largest ramps will increase. This suggests that there may need to be changes to PFC and/or AGC regulation levels to accommodate these occasional, but unforecasted large magnitude ramps.

The nature of the load supplied is also changing. Historically, the high proportion of induction motors in the load resulted in a load relief when frequency dropped and an increase when frequency rose. This damping effect tends to aid frequency control. Increasing utilisation of drives with inverters is reducing this frequency sensitivity of loads because the inverters maintain the output of the load for (small) variations in voltage and frequency. The smaller the load damping effect, the more difficult it becomes to control frequency.

The purpose of this study is to investigate the relationship between primary frequency control and frequency for future NEM conditions in which high levels of VRE can result in very fast ramps in generation output. The added effect of reduced load damping tends to compound the problem.

The investigation involves:

- Modelling the NEM Dispatch by the NEM Dispatch Engine (NEMDE), Automatic Generation Control, the primary frequency control response of generators, the frequency-dependent load response and the response of generation to AGC commands to simulate the frequency response of the power system.
- Tuning the model with historical generation, demand, demand forecast, AGC dispatch of regulation frequency ancillary services
- Investigating the effect of varying levels of primary frequency control (PFC) and regulation FCAS on the frequency response
- Adjusting the generation mix to reflect 2025 generation (from the 2018 ISP) – with a higher representation of VRE and a lower amount of sub-synchronous coal-fired generation this scenario has a lower inertia
- Investigating the projected level of ramps arising from changes in variable renewable generation output.
- Investigating the remedial impact of various levels of PFC

1.1 Modelling and assumptions

1.1.1 The Power System Model

The power system was represented in PowerFactory as a single bus with generation and load connected to the same bus. This is considered a reasonable approach given that the NEM is managed as a single frequency region and the frequency dynamics being investigation are relatively slow. Different types of generation are represented with typical automatic voltage regulators and governors:

- Sub-critical coal
- Super-critical coal

- OCGT
- CCGT
- Hydro
- PV, solar and battery (combined)

VRE plant are represented as having capability for reducing output for high frequencies.

A portion of Hydro generators are assumed to be marginal units for dispatch.

The amount and type of generation providing PFC can be varied in the model.

Regulation FCAS is provided by Hydro.

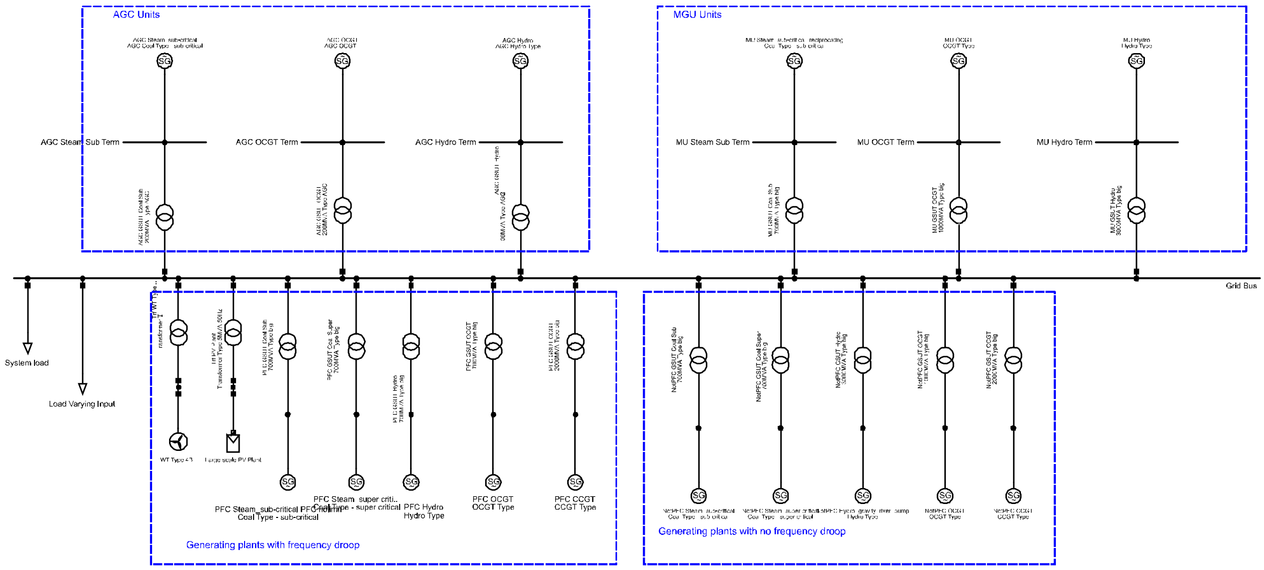

Figure 1 – Power system model in PowerFactory

A detailed description of the power system model is provided in Appendix A.

Note that while the dynamics of generators are included in the model, the model currently does not represent the electrical impedances between the machines, and therefore the dynamics across the power system are not fully represented in the model. The model could be expanded to include such effects, but this level of detail is not within the scope of this study. The generator control systems are generic and tuned to provide typical performance.

1.1.2 AGC model

The AGC model was developed using a range of sources including:

- Information published by AEMO
- Screenshots of the actual AGC controller settings
- Discussions with AEMO experts
- Observation of actual behaviour of outputs from various parts of the control system for which historical data was obtained.

A fixed (configurable) amount of regulation FCAS is enabled in the model (for a half hour period of simulation). For the purpose of tuning the model we used the historical level of FCAS enabled.

Detailed description of the AGC model is provided in Appendix A.

1.1.3 NEM Dispatch Engine model

The NEM Dispatch model is represented as calculating a required change in generation every five minutes and adjusting the marginal generation units by ramping them linearly over five minutes to the new target levels.

The change in generation includes the forecast generation plus an offset to adjust the FCAS regulation units from their output on the dispatch interval back to their neutral generation level (i.e. providing no regulation raise or lower service).

The model assumes the generation commitment is unchanged over a half-hour period of simulation. Only the marginal generation units change their dispatch level through NEMDE.

1.1.4 Load model

In the model load is represented by two elements a fixed component and a variable load. The base k_f for frequency sensitivity ('damping') in the load modelling is 1.0%/%.

Historically kf has been assumed to be in the range 1 to 1.5. A low k_f means that a smaller mismatch in generation and demand will cause a greater deviation in frequency before the load adjustment acts to balance the generation. A low k_f will also make the power system frequency more responsive to changes in generation (for example, to contingency FCAS). Effectively the rate of change of frequency is increased. This can be seen from the swing equation.

$$\frac{2H}{\omega_s}\frac{d^2\delta}{dt^2} = P_m - P_e = P_a \quad p.u.$$

Where

H is inertia constant

ω_s is synchronous speed

The second derivative of rotor angle δ is rate of change of frequency

P_m is mechanical power from the generators

P_e is the electrical load, where $P_e = P_o (1+ k_f f)$, where P_o is the load in pu at 50 Hz and f is frequency in pu.

1.1.5 Simulation method

In preparing for the simulations, the input data were:

- 4s system frequency data
- 4s load variation
- 4s Internal AGC regulation and time error data
- 5-minute operational demand

The main input to the closed-loop simulations is the 4s load variation, while the rest of the data were relevant for the closed-loop simulations and tuning. The system is run as a dynamic simulation with the load forecast adjusted every five minutes, the marginal generation ramping linearly over the five-minute dispatch interval, the AGC scheduling regulation response every 4 seconds, with a 32 second first order delay, as implemented in the EMS.

Generators respond to dispatch commands according to their governor response. PFC enabled generators also respond to frequency deviations within their capability limits and according to governor responses.

Loads respond to frequency according to the k_f value.

The simulation is run for periods of half an hour at a time.

2 Model development and tuning

Model tuning was undertaken in two steps:

- Open loop, feeding the measured frequency as an input to test the AGC response
- Closed loop, feeding back the frequency into the model.

The overall system model is illustrated in Figure 2, it shows the main controllers including the Automatic Generation Control (AGC), Market Management System (MMS), and the generating system AVR, governor and machine models.

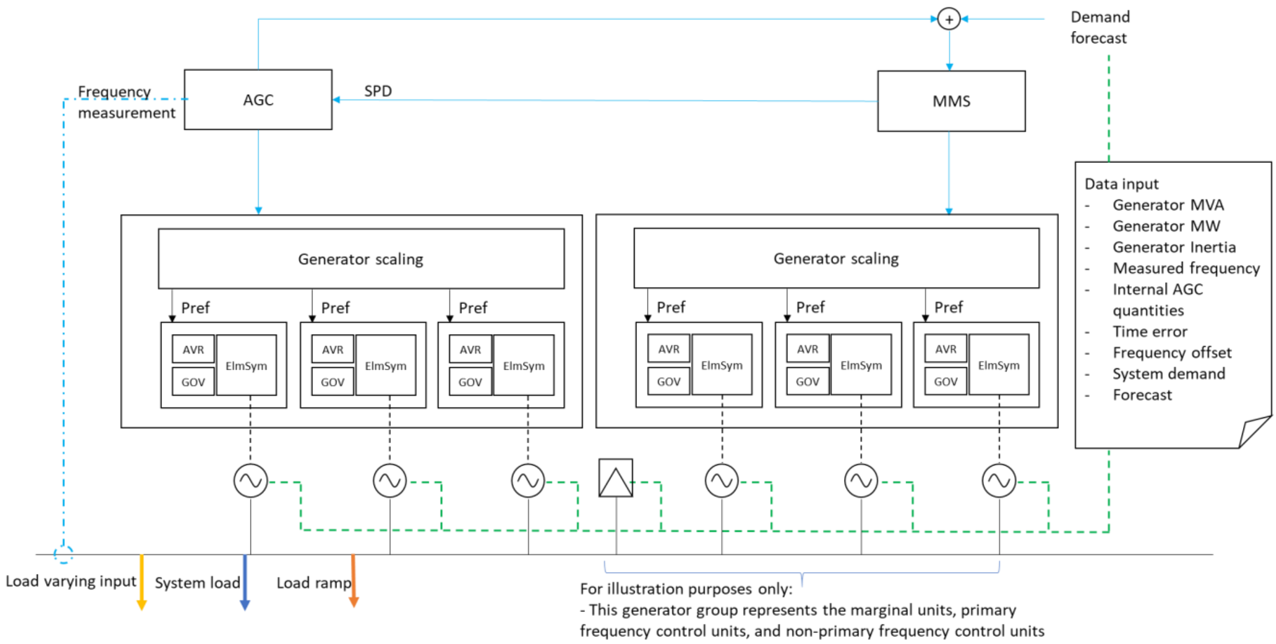

Figure 2 – Closed loop system illustration showing the major controller blocks including AGC and MMS

For the purpose of the model tuning and simulations, the relevant datasets would include the following information:

- Open loop:
  - Measured frequency
  - Initial conditions from the internal AGC signals
- Closed loop:
  - Initial conditions from the internal AGC signals
  - Available generator MVA, MW and inertia during the studied time timeframes
  - System demand
  - Load forecast

The AGC model used for the open loop and closed loop response is shown in Figure 3.

AGC_multigen model:

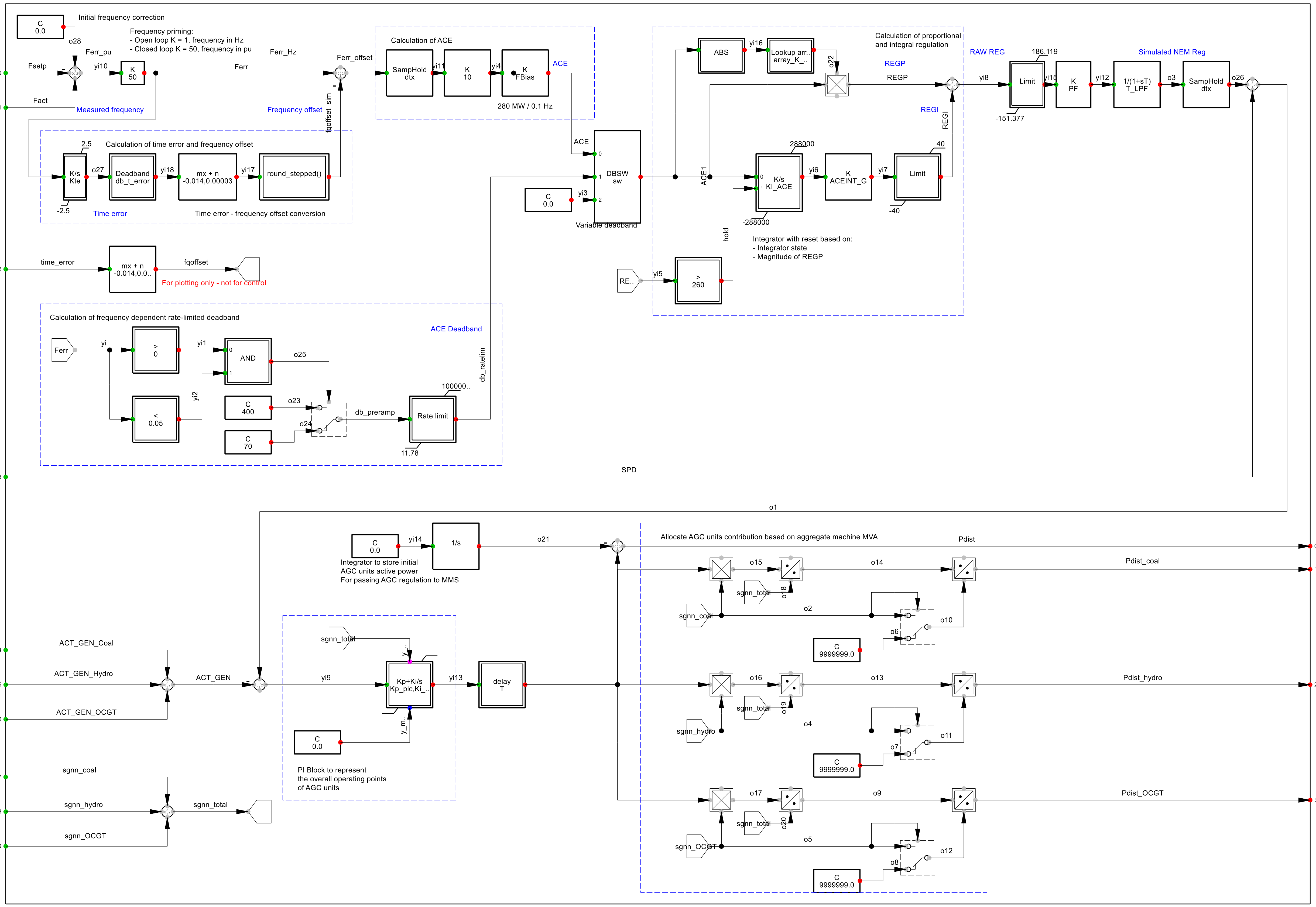

Figure 3 – AGC model, annotated with descriptions on functional blocks (blue boxes) and measurement points (blue texts)

The AGC contains the following main functional blocks:

- **Initial frequency correction**

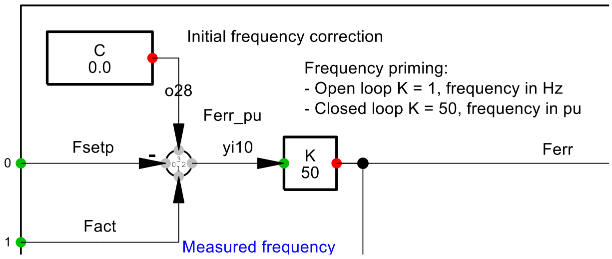

Figure 4 – Initial frequency correction as a constant input to the frequency summing junction

At the beginning of the AGC model, a constant block has been added to provide correction to the frequency level at the beginning of the simulation, as PowerFactory dynamic simulation will initialise the frequency based on a load flow calculation with the assumption the system will converge with system frequency of 50 Hz.

- **Time error and frequency offset calculation block**

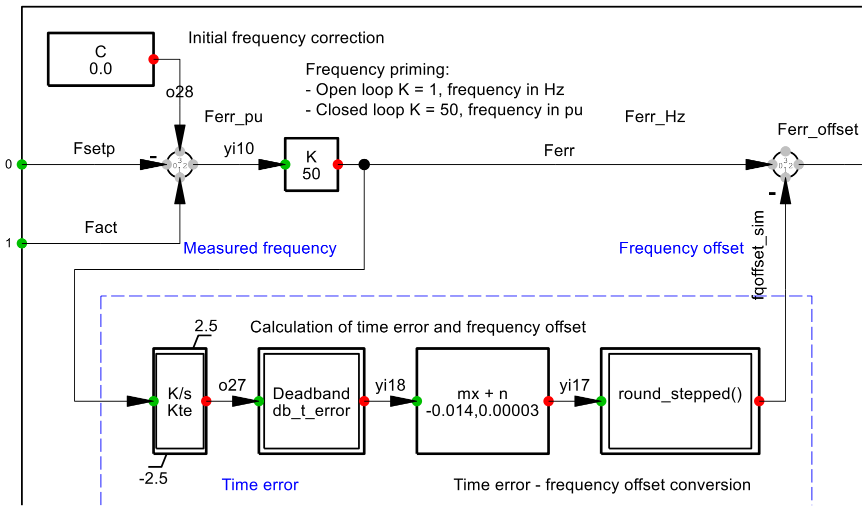

Figure 5 – Time error and frequency offset calculation block

The time error is calculated by integrating the frequency error over time. There is a deadband for blocking time error of less than 0.5 seconds and there is a limit for time error correction of 2.5 seconds. The processed time error is converted into frequency offset and the offset is discretised to the nearest 1 mHz, as shown in Figure 6.

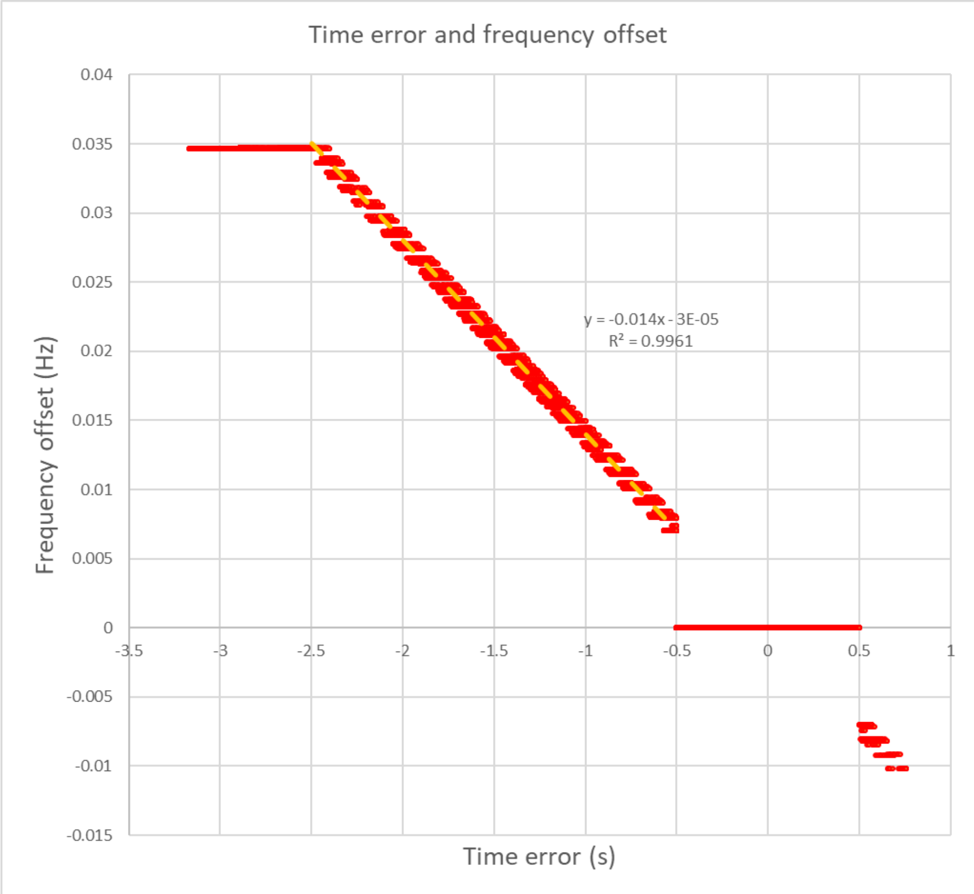

Figure 6 – Time error to frequency conversion characteristic

The slope of the conversion gradient was determined based on the 24-hour period on 1 August 2019.

The frequency offset is subtracted from the frequency error before being passed to the ACE calculation block.

- **ACE calculation block**

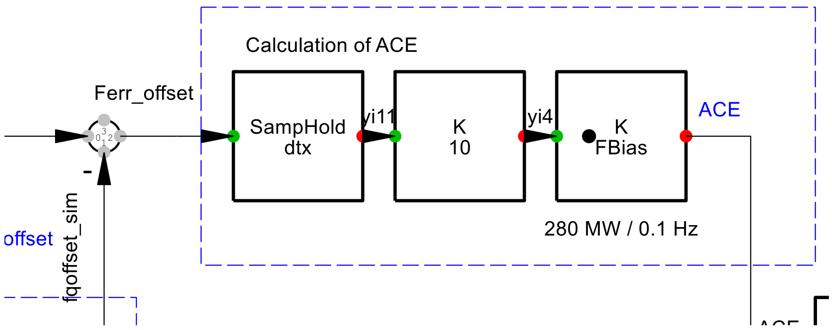

Figure 7 – ACE calculation block

The ACE calculation box has been implemented based on the AEMO document describing the calculation of the ACE from the corrected frequency error [1]. The functional blocks convert the frequency error to an equivalent MW error referred to as Area Control Error (ACE).

- **ACE frequency dependent rate-limited deadband block**

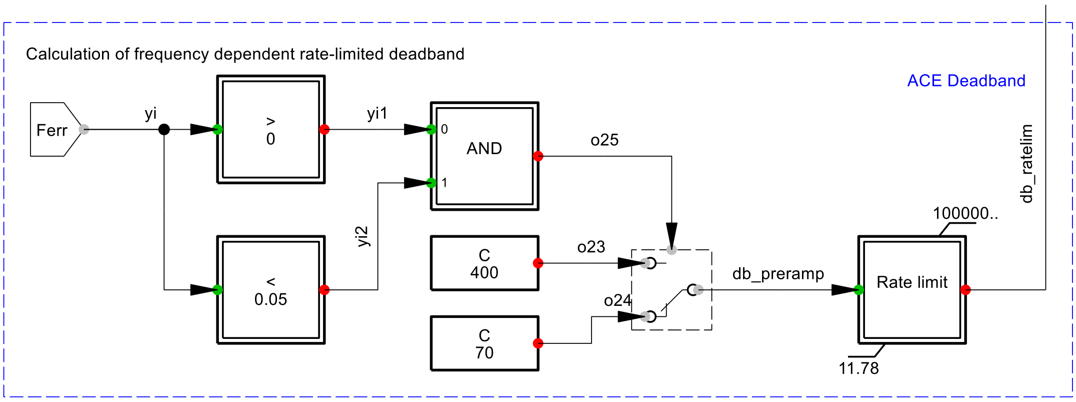

Figure 8 – Frequency dependent rate-limited deadband calculation block

The ACE signal is passed through a variable deadband where the ACE threshold is varied between 400 MW and 70 MW depending on the frequency error magnitude. The deadband variation is instantaneous when transitioning from 70 MW to 400. The transition from 400 MW to 70 MW is ramp limited within 28 seconds (11.78 MW / s).

- **PI regulation block**

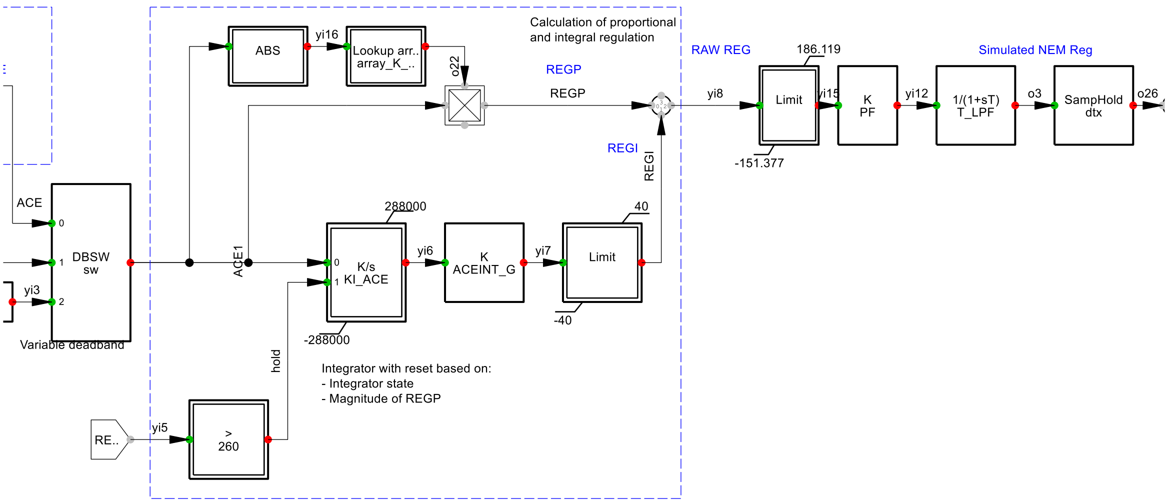

Figure 9 – ACE proportional and integral regulation block

The processed ACE signal is then used by the PI regulation functional block. The main features of this block are as follows:

- Tiered proportional gain for various levels of ACE

  The thresholds and gains are tabulated in Table 1.

Table 1 - ACE operational threshold and proportional gain

ACE Threshold	ACE	ACE Gain
Static deadband	<=70	0
ACE Normal	<210	0.55
ACE Assist	<400	0.65
ACE Emergency	>400	0.8

- Integrator that resets when the processed ACE is 0 and when proportional regulation (REGP) exceeds 260 MW

The sum of the integral and proportional regulation is called raw regulation (RAW REG) and this signal is then filtered with a lag block with a time constant of 32 seconds.

- **Block for representing the overall operating conditions for AGC units block**

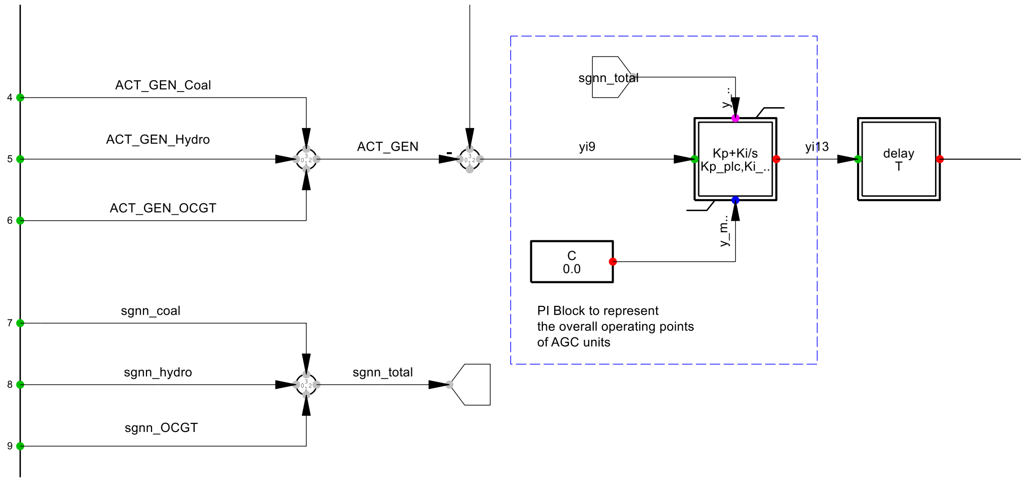

Figure 10 – PI block to represent the state of the overall AGC units

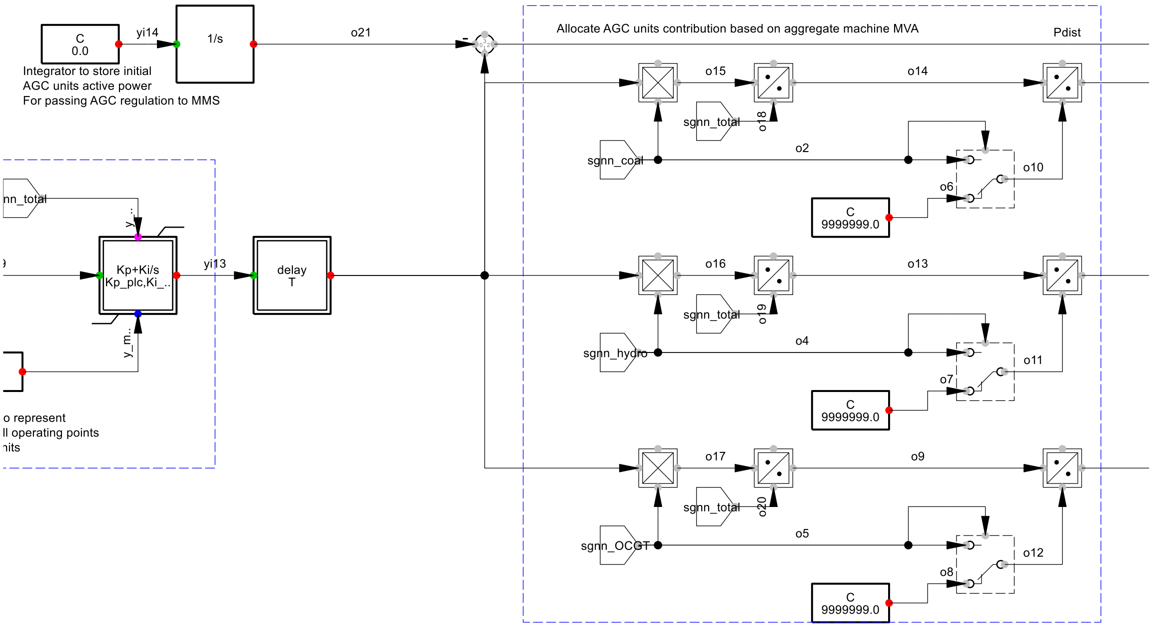

Figure 11 – AGC generator setpoint allocation block

The output of the AGC is the additional active power required to provide a certain degree of frequency regulation every four seconds. This active power will be added on top of the base load or operating points of the aggregated AGC units. Thus, to simulate the base operating level of the AGC units, a PI block has been used to represent the state of the collective AGC units.

The total AGC active power level represented by the PI block is then allocated into the three AGC units based on the rating of each machine.

These blocks do not necessarily mimic the actual operation of the pulse controller applied for the AGC units due to the limitation of market dispatch data and also due to the utilisation of aggregated NEM model.

The output of these blocks is injected into the AGC generators governor active power setpoint.

2.1 Results of open loop response testing

The model tuning based on the open loop response was conducted for three cases:

- 13 August 2019, 06:00 AM – 06:30 AM (Figure 12)

This timeframe was selected as the load was ramped up from roughly 22.8 GW to 25 GW. In this case the frequency excursion briefly went outside the normal operating frequency band (NOFB) and this would likely cause the contingency FCAS to operate. The operation of FCAS will add layers of complexity in the modelling and will add the challenges for the closed loop simulation.

- 14 August 2019, 06:00 AM – 06:30 AM (Figure 13)

  The load was ramped up from roughly 22 GW to 24 GW within this timeframe. Although the frequency did not go outside the NOFB, the fast ramp between 300 s and 600 s indicated unforecasted error that has not been accounted in the model. It was likely that the brief frequency excursion outside the NOFB was not captured due to the 4 second resolution measurement.

- 1 August 2019, 00:00 AM – 00:30 AM (Figure 14)

  This period was selected considering that possibly there would not be significant activities in the NEM. The system frequency was maintained well within the NOFB and this timeframe will be used as the main base case for our closed loop simulations in this report.

The open loop responses presented in the Section 2.1.1 to Section 2.1.3 demonstrate very good alignment between the modelled and the real AGC.

2.1.1 Case 1 open loop response, 13 August 2019, 06:00 AM – 06:30 AM

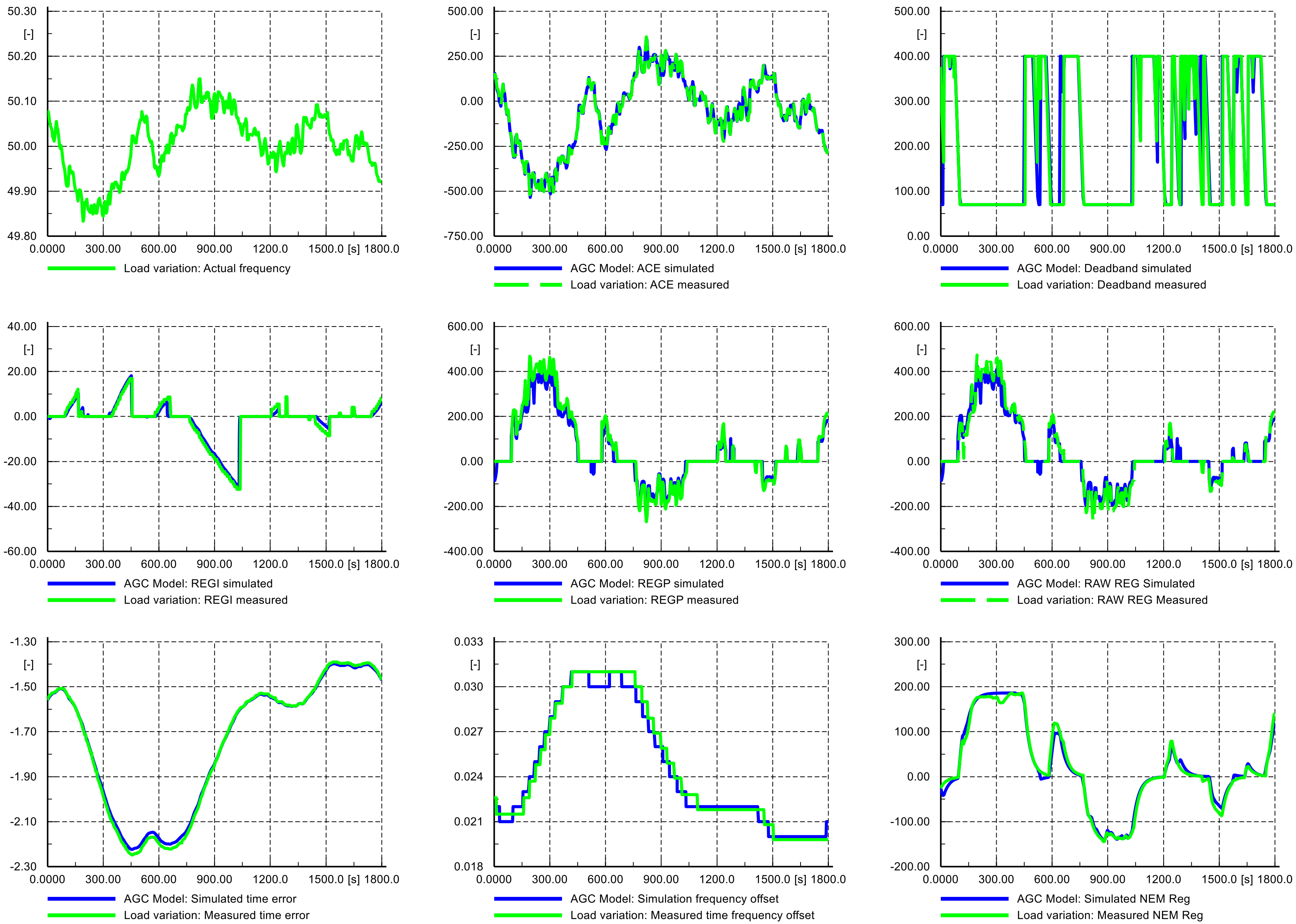

Figure 12 – Open loop ACE tuning - measured vs simulated response (13/08/2019, 06:00 AM – 06:30 AM)

2.1.2 Case 2 open loop response, 14 August 2019, 06:00 AM – 06:30 AM

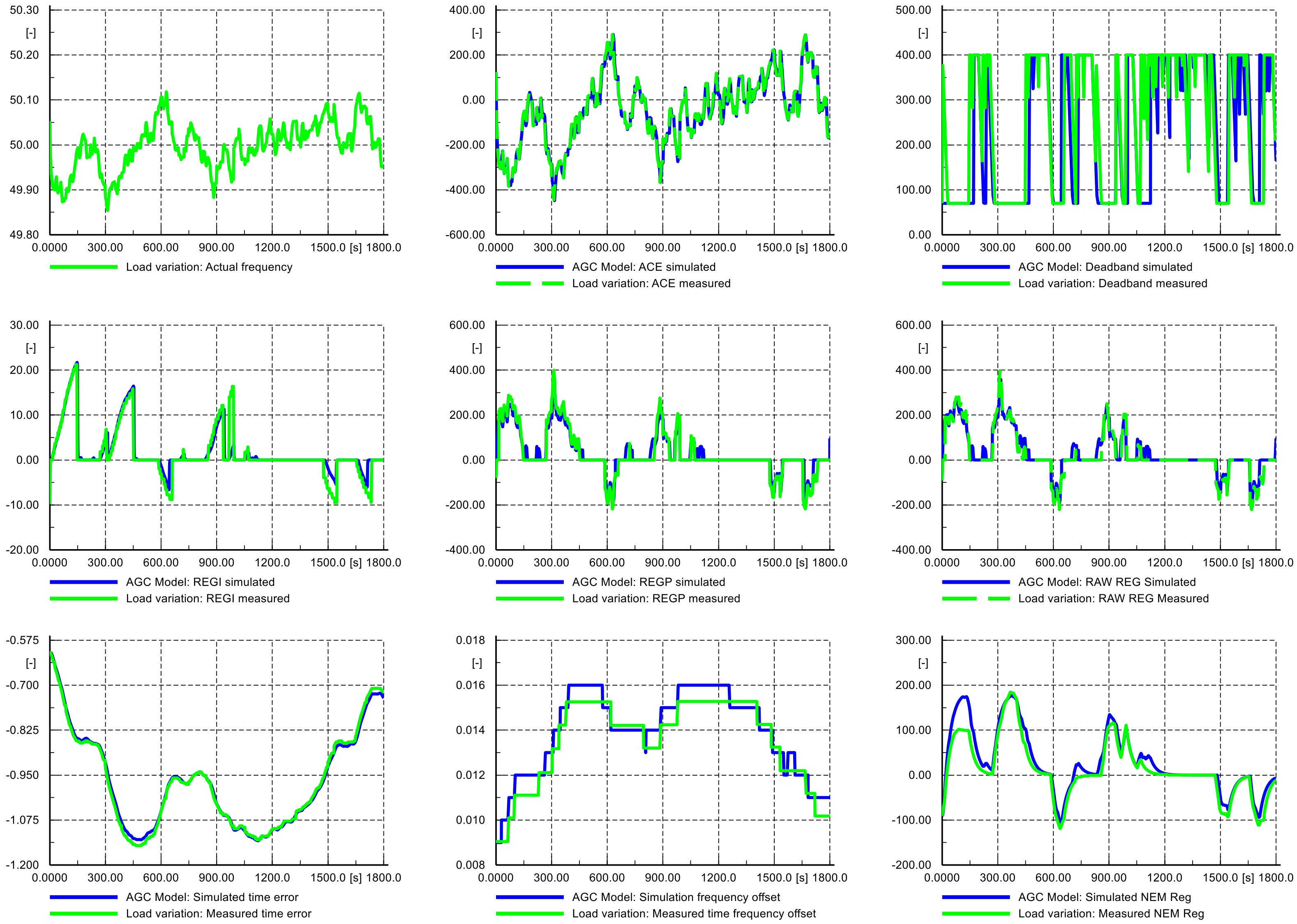

Figure 13 – Open loop ACE tuning - measured vs simulated response (14/08/2019, 06:00 AM – 06:30 AM)

2.1.3 Case 3 open loop response, 01 August 2019, 00:00 AM – 00:30 AM

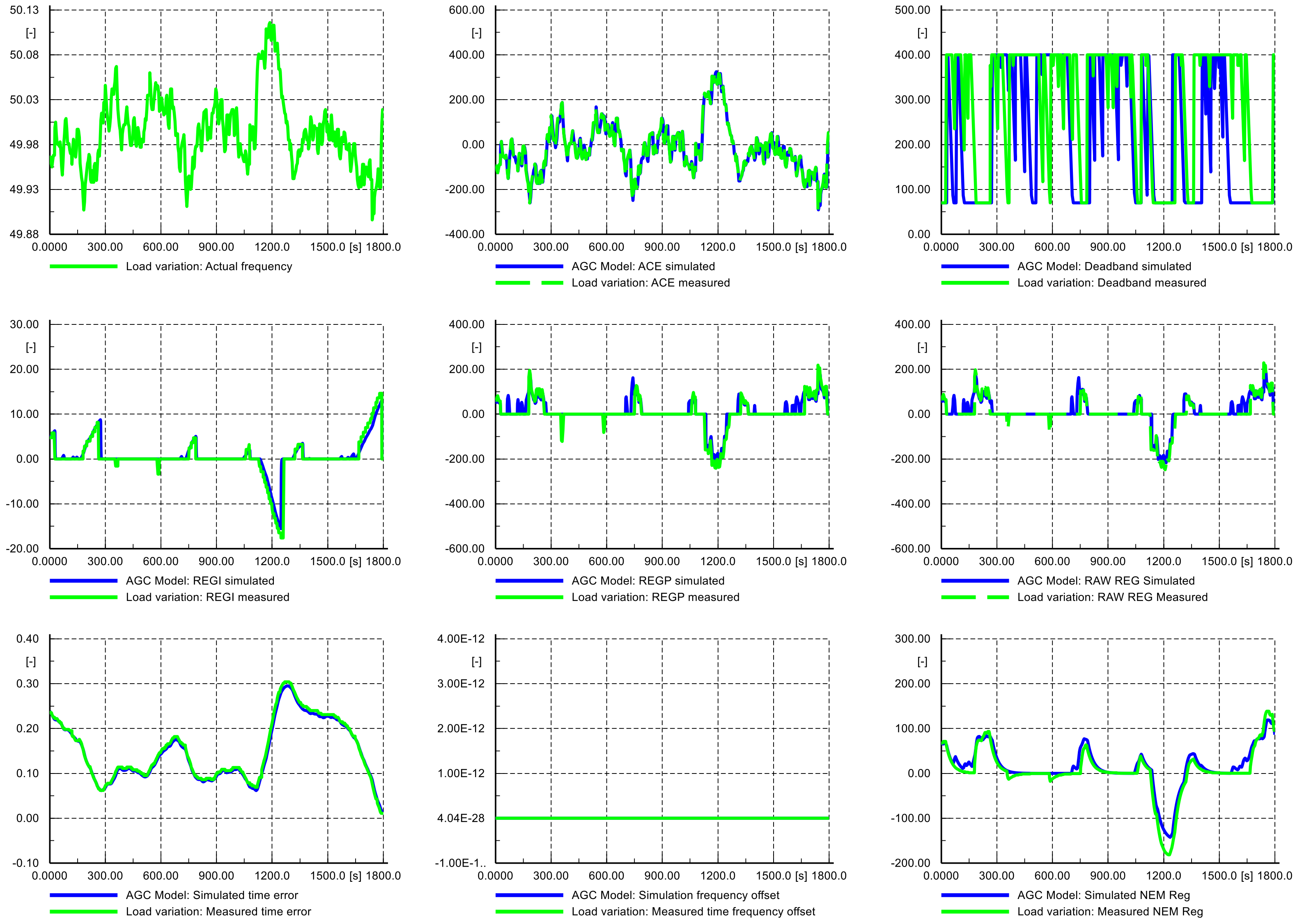

Figure 14 – Open loop ACE tuning - measured vs simulated response (01/08/2019, 00:00 AM – 00:30 AM)

2.2 Discussion of results for open loop tuning

The results show good alignment between the model and measured response. The following key performance items are observed:

- Time error and frequency offset are well aligned. This provides sufficient bias or offset to the frequency error signal, resulting in good alignment for the ACE signal.
- The variable and ramp-limited deadband is also aligned, resulting in good alignment between for the proportional and integral regulation signals.
- Integrator with reset performance was demonstrated.
- Filtered NEM Regulation results are well aligned with the measured performance. It is noted that on the 14th of August 2019, the actual AGC machines produced less response than anticipated from the enabled generation.

2.3 Results for closed loop testing

The closed loop simulations were conducted for the three cases used in the open loop cases. The results from these cases are illustrated in the figures below.

Tuning of parameters found results most closely resembling the actual frequency response, considering the amount of primary frequency control, the load frequency dependence factor kf and the PI controller gain. Impacts of each of these factors are described in Section 2.4, which presents sensitivity studies around these parameters.

For the results reported in this section the settings are:

- PFC in service on 1950 MVA of sub-critical coal generators, droop 5%, no deadbands.
- K_f= 1.0
- Kp_plc = 0; Ki_plc = 0.01

These results give reasonable agreement with measurement. Nevertheless, as discussed in Section 2.4, the results showed intra-five-minute differences between generation and load, which result in frequency deviations not represented in the model.

Case 1 closed loop response, 13 August 2019, 06:00 AM – 06:30 AM

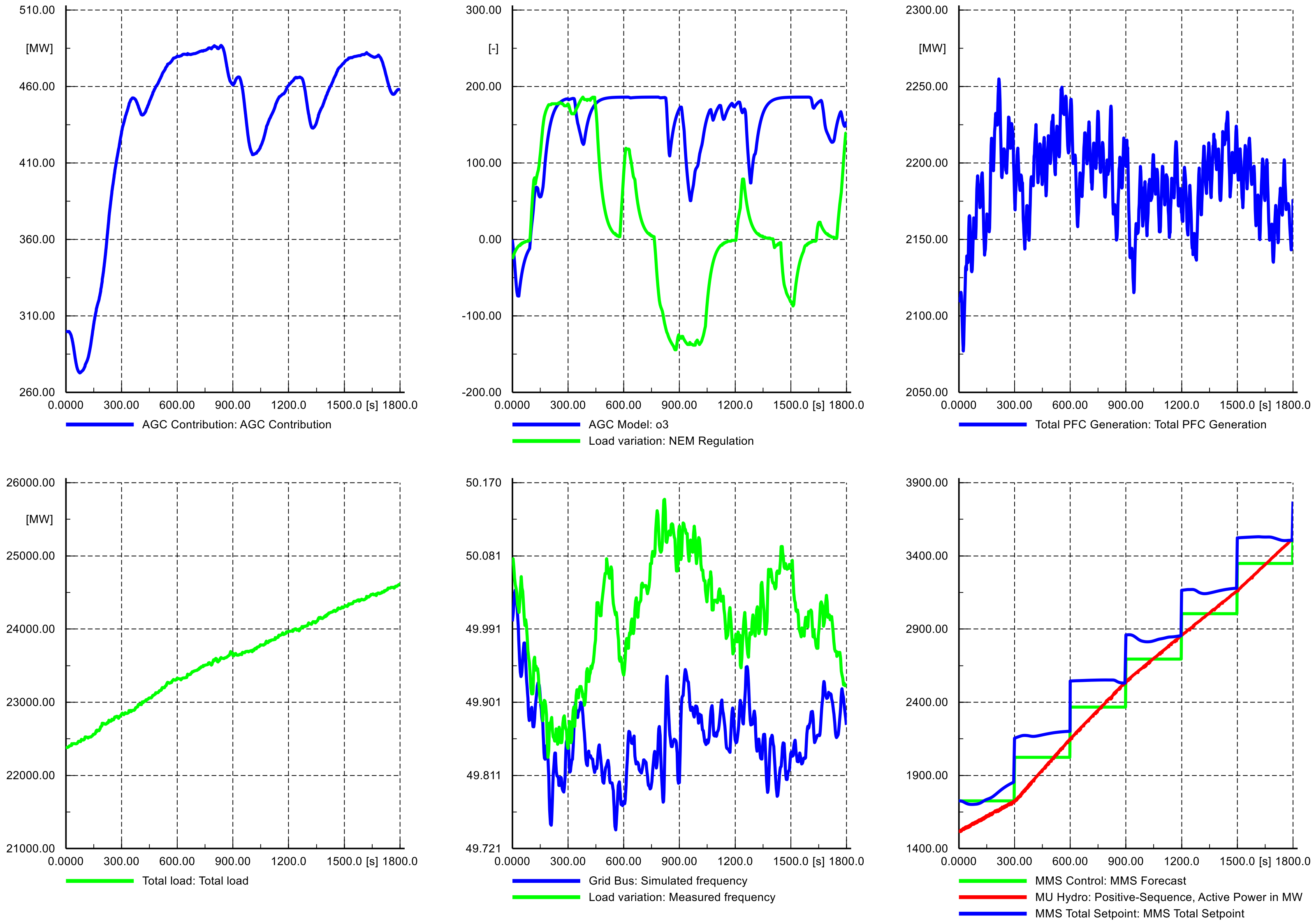

Figure 15 – Closed loop simulation – Overall system response (13/08/2019, 06:00 AM – 06:30 AM)

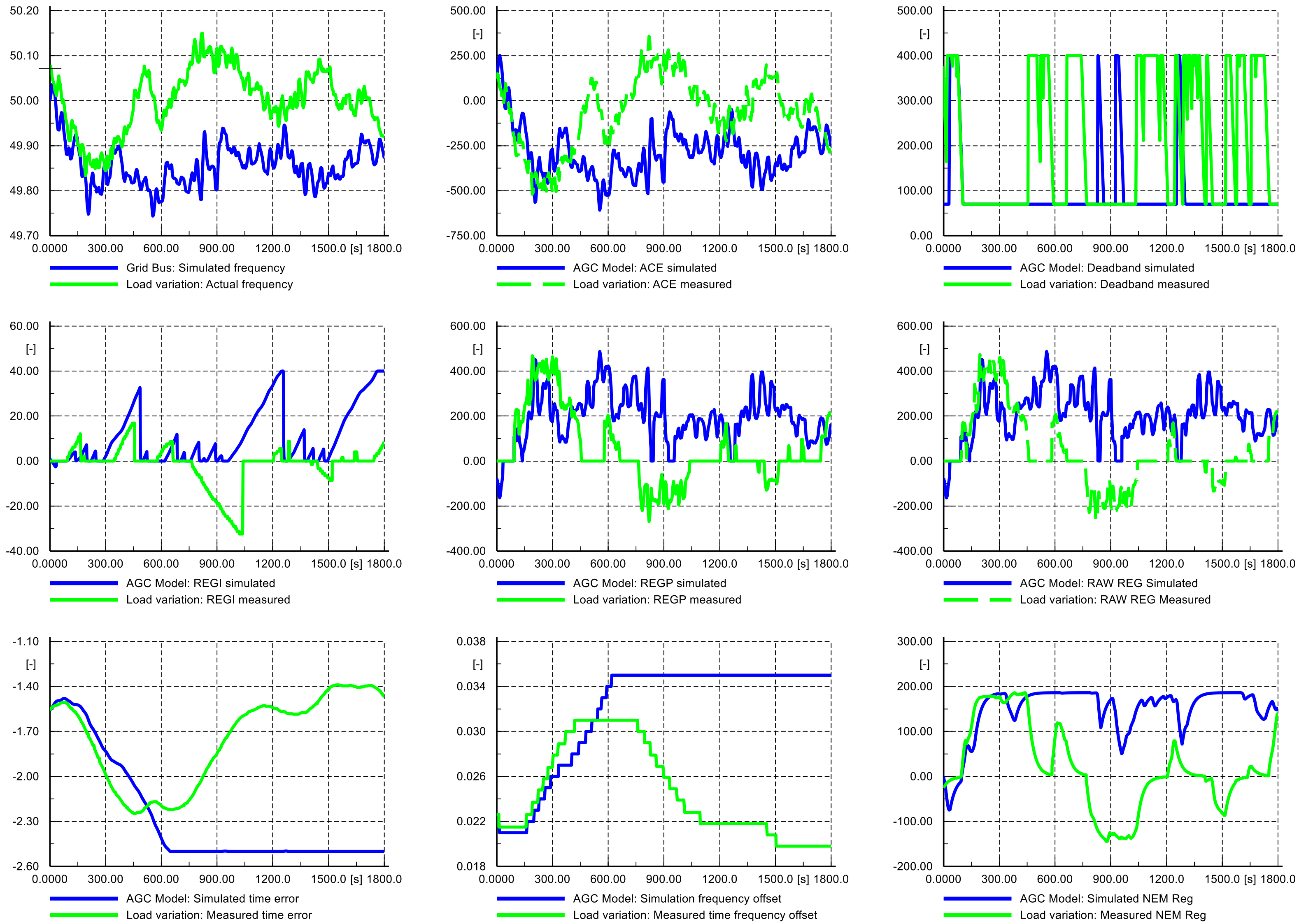

Figure 16 – Closed loop simulation – Internal AGC signals (13/08/2019, 06:00 AM – 06:30 AM)

Case 2 closed loop response, 14 August 2019, 06:00 AM – 06:30 AM

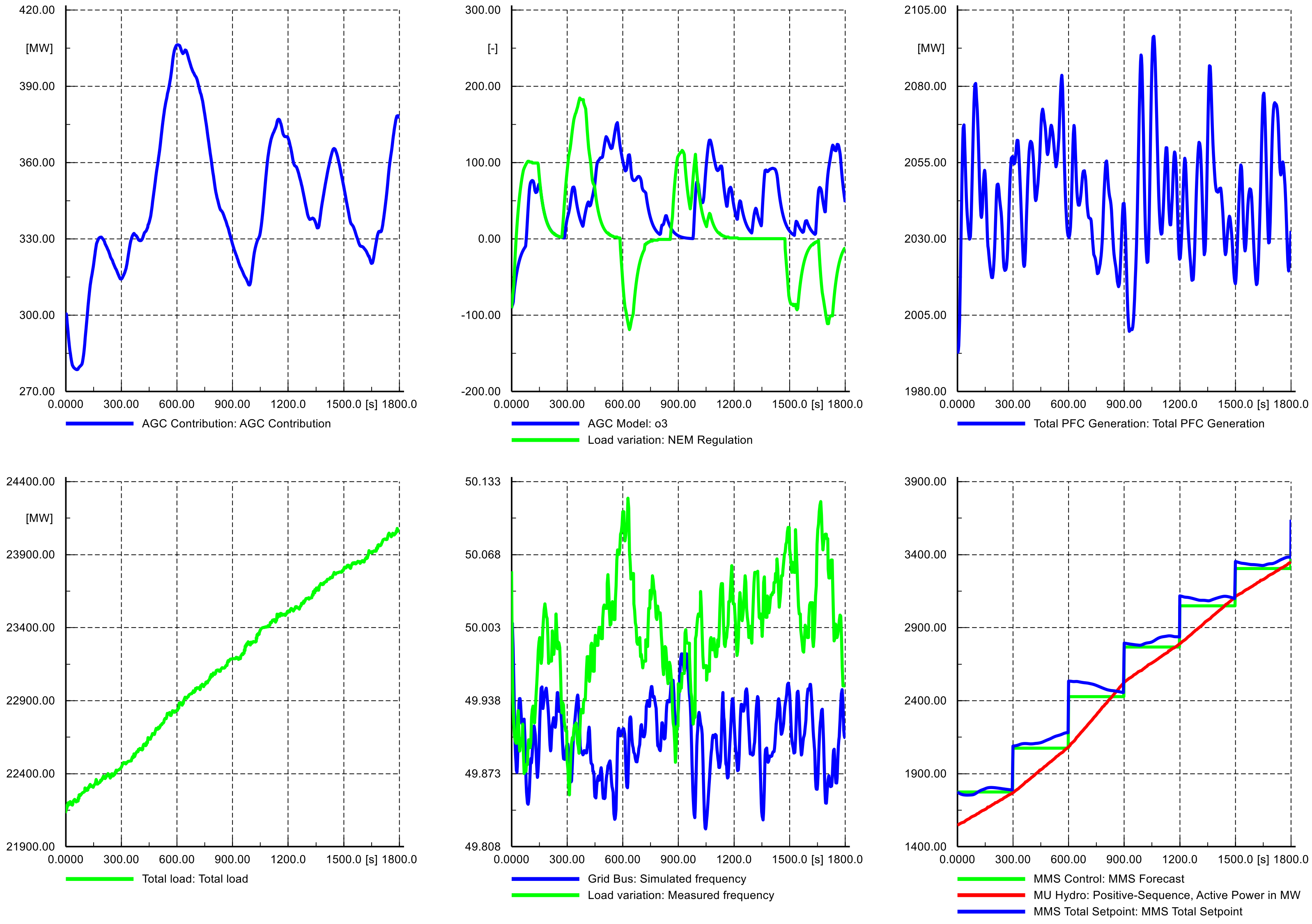

Figure 17 – Closed loop simulation – Overall system response (14/08/2019, 06:00 AM – 06:30 AM)

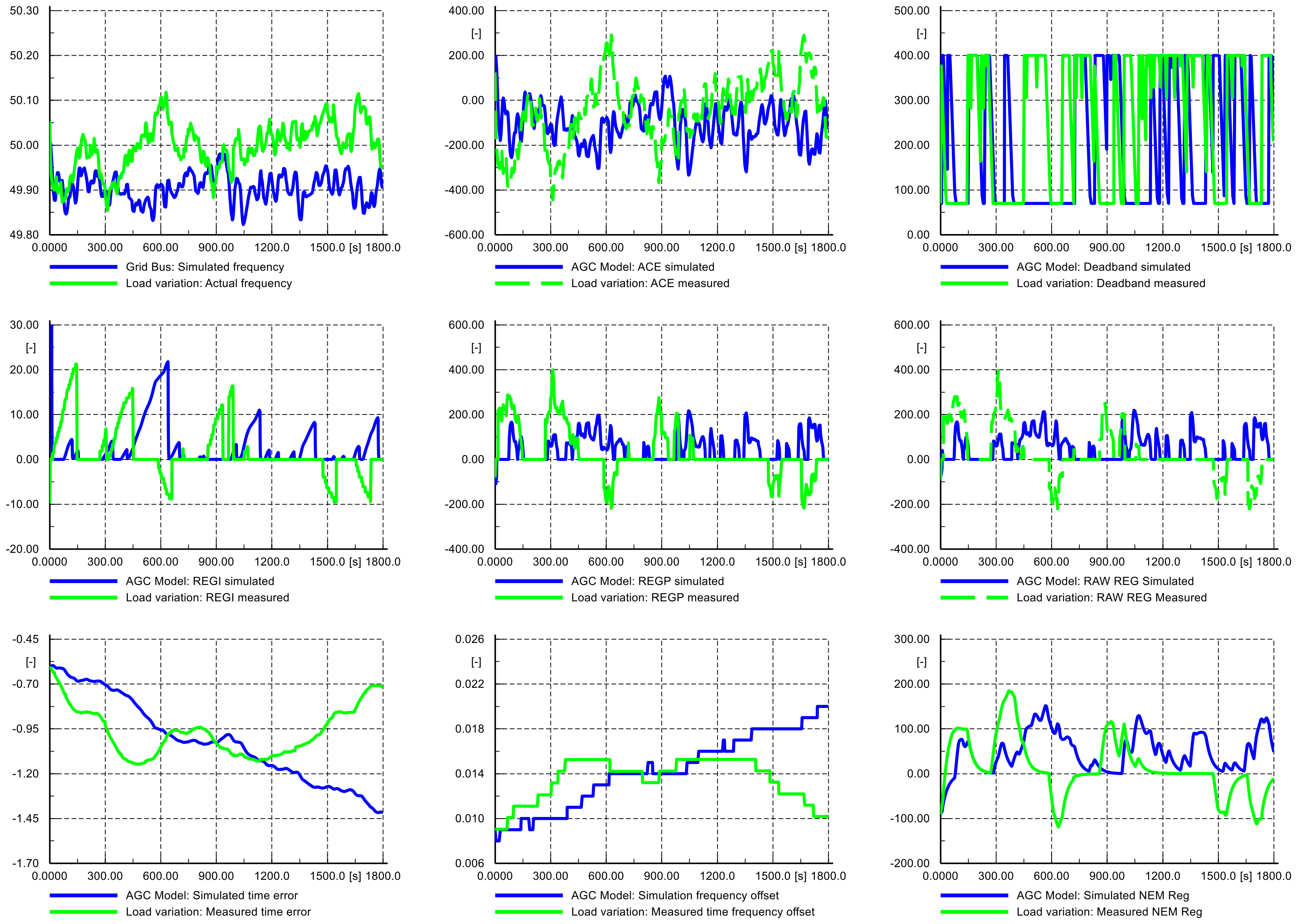

Figure 18 – Closed loop simulation – Internal AGC signals (14/08/2019, 06:00 AM – 06:30 AM)

Case 3A closed loop response, 01 August 2019, 00:00 AM – 00:30 AM

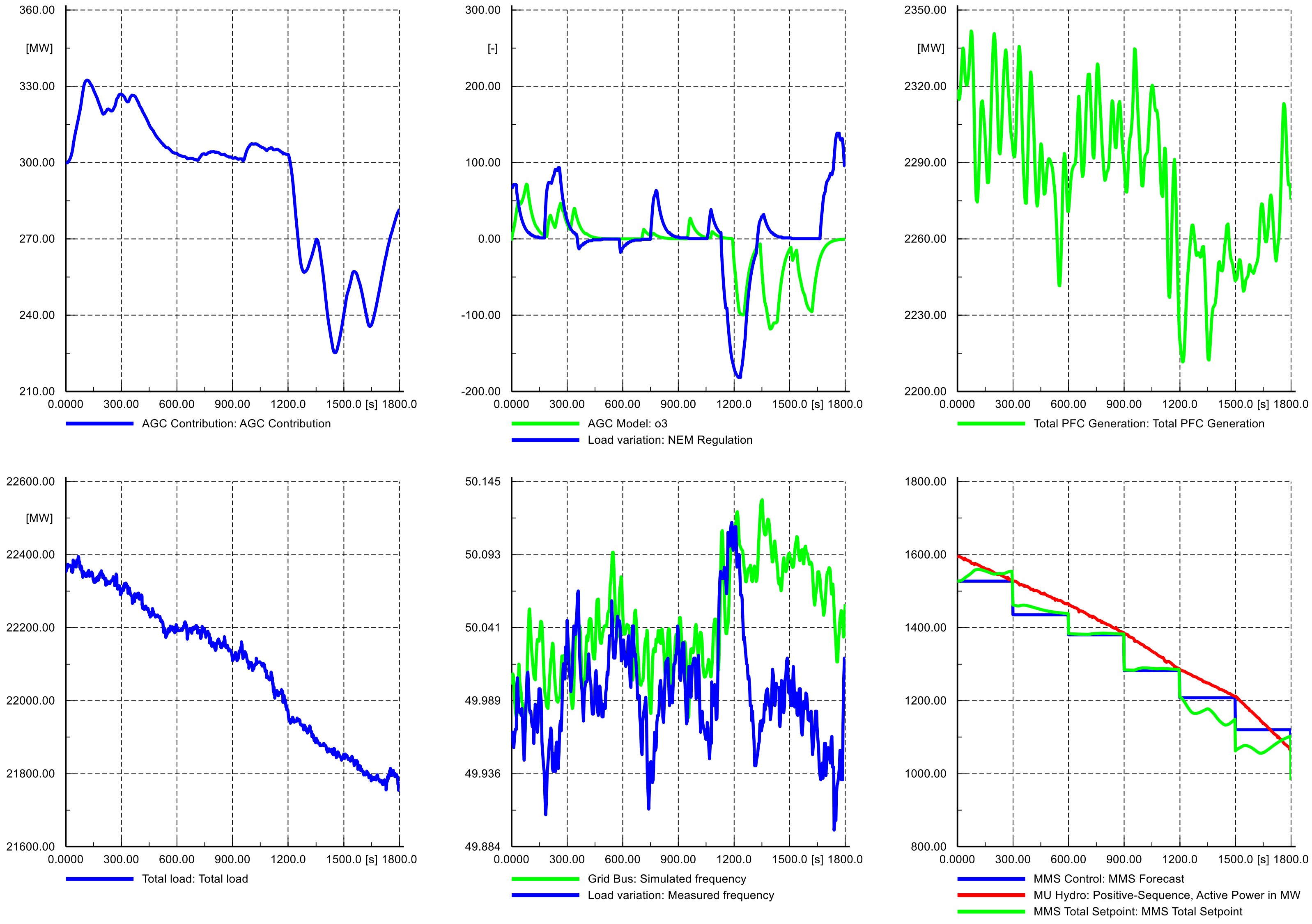

Figure 19 – Closed loop simulation – Overall system response (01/08/2019, 00:00 AM – 00:30 AM)

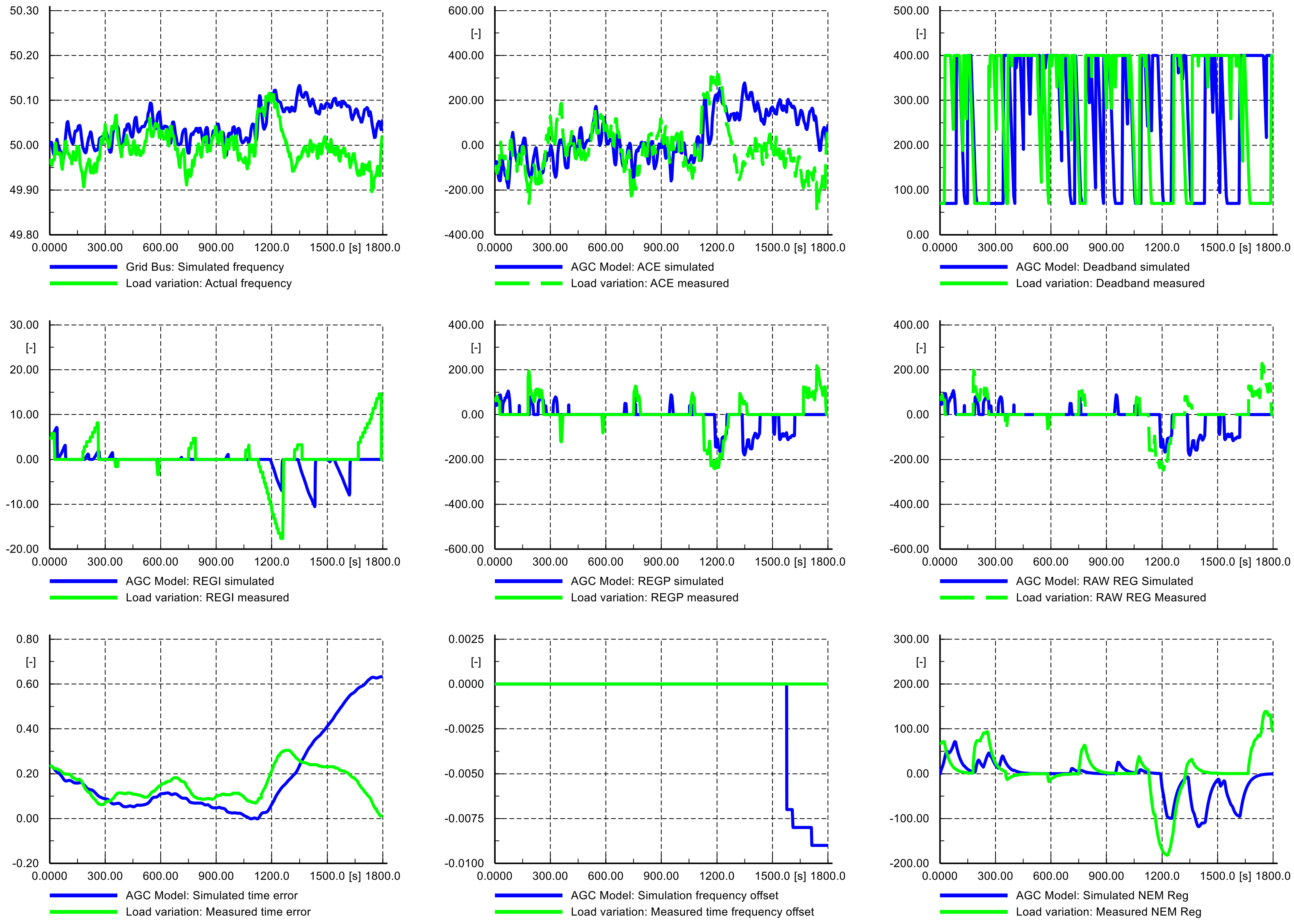

Figure 20 – Closed loop simulation – Internal AGC signals (01/08/2019, 00:00 AM – 00:30 AM)

Case 3B closed loop response with load ramp at 1200 s, 01 August 2019, 00:00 AM – 00:30 AM

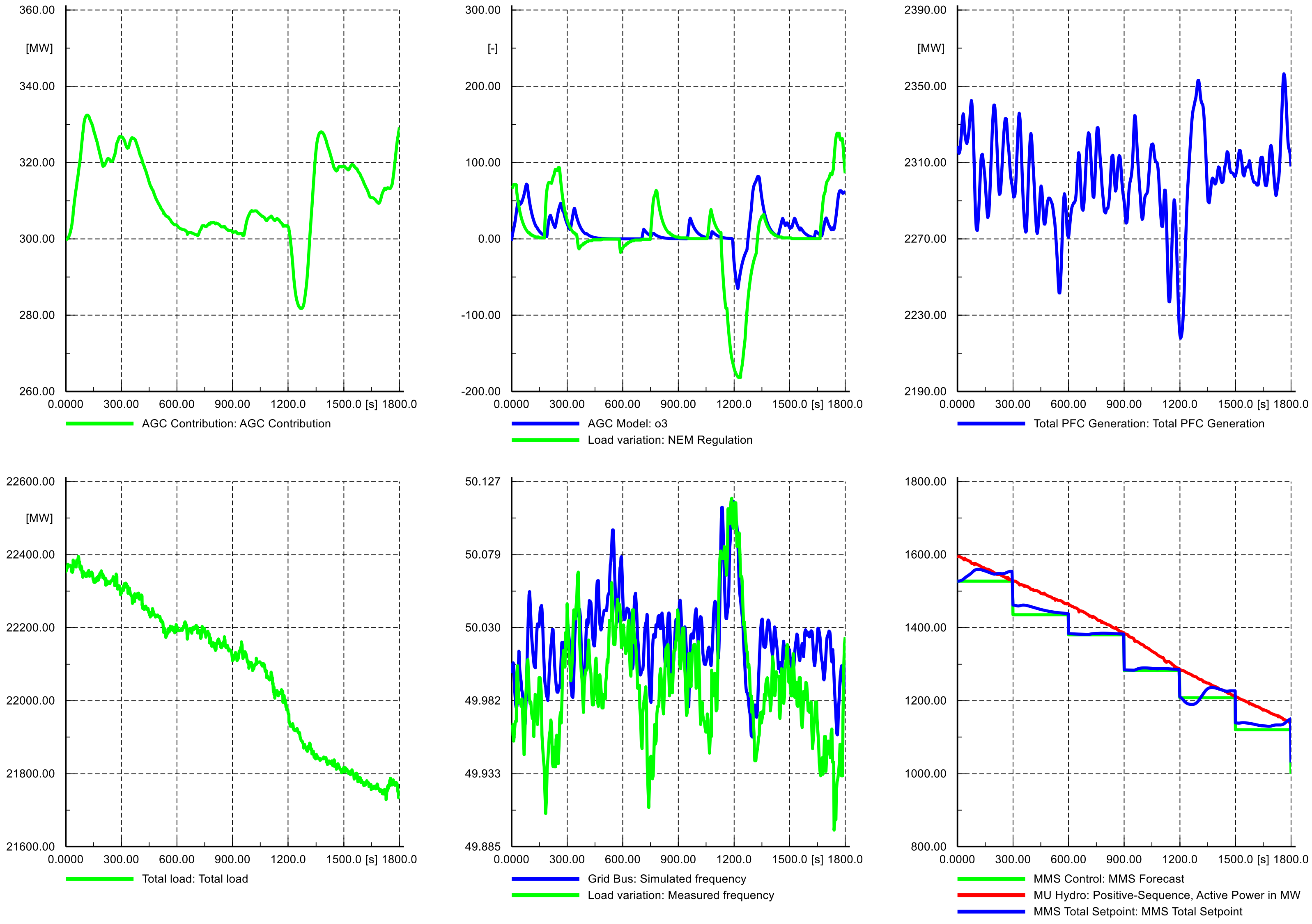

Figure 21 – Closed loop simulation – Overall system response with load ramp event at 1200 s (01/08/2019, 00:00 AM – 00:30 AM)

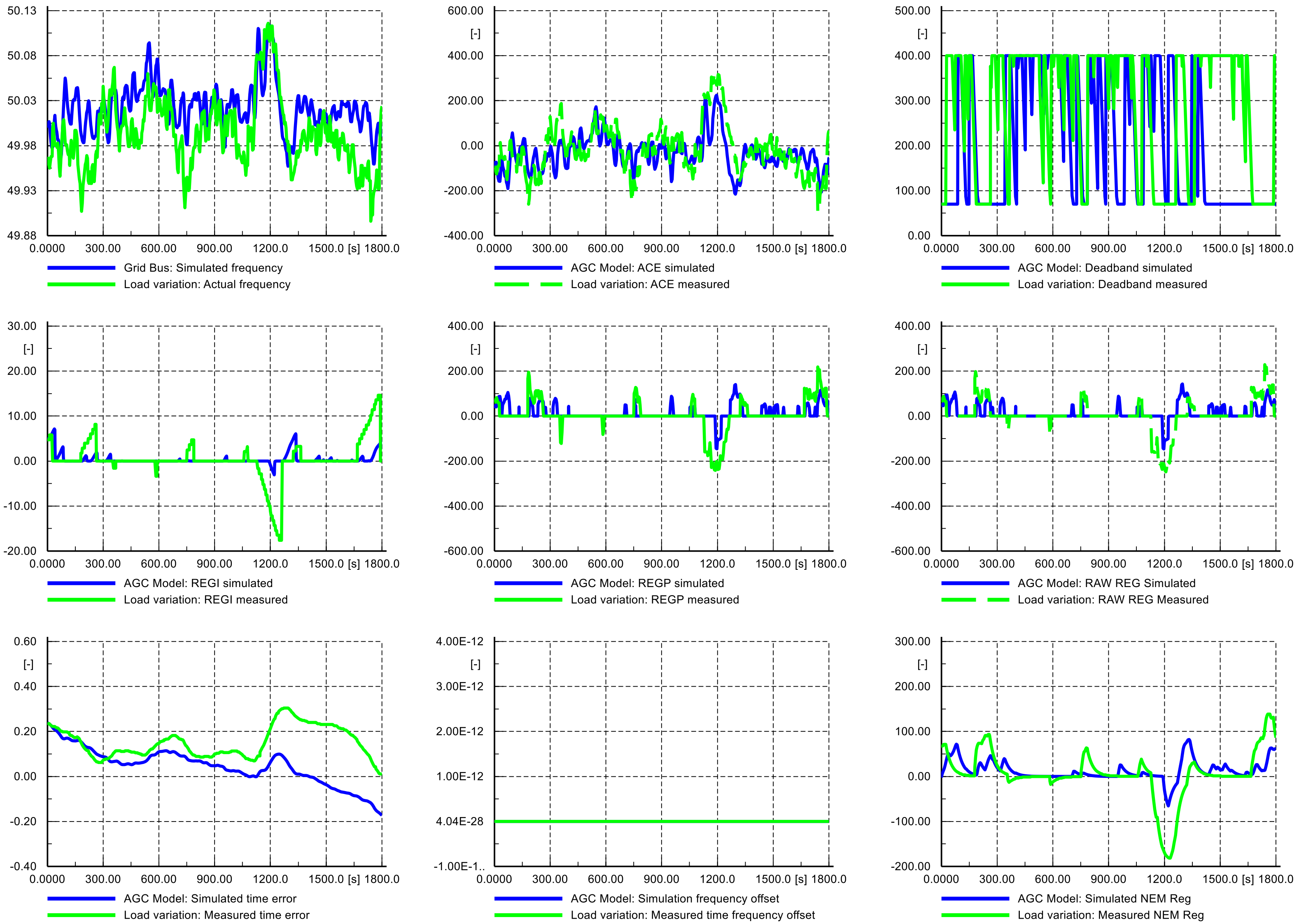

Figure 22 – Closed loop simulation – Internal AGC signals with load ramp event at 1200 s (13/08/2019, 00:00 AM – 00:30 AM)

The overall results for the closed loop simulations show that external / unmodelled factors may affect the degree of alignment between the measured and simulated responses. We observe the following outcomes:

- **Case 1, 13 August 2019, 06:00 AM – 06:30 AM (Figure 15 and Figure 16)**
  In this period, early morning load ramp caused frequency excursion below the lower limit of NOFB. The under-frequency caused the AGC output to increase its output. However, the unforecasted generation increase caused the simulated frequency to remain depressed while the AGC units remained high.
  The initial 300 s of the simulation showed the modelled response to align reasonably well until after the frequency went below 49.85 Hz.
- **Case 2, 14 August 2019, 06:00 AM – 06:30 AM (Figure 17 and Figure 18)**
  This timeframe was selected as the load change was roughly the same as the Case 1 scenario and the frequency was maintained within the NOFB. However, simulation results suggested external factors affected the alignment with measured response. Considering the 4 s frequency measurement resolution, it is likely that the frequency excursion outside the NOFB was not captured.
- **Case 3A, 1 August 2019, 00:00 AM – 00:30 AM (Figure 19 and Figure 20)**
  The closed loop results for this timeframe was expected to be less likely to be affected by the load variation and the frequency was maintained well within the NOFB. The simulated frequency was initially biased by approximately 0.034 Hz, considering the dynamic simulation used loadflow calculation based on a convergence system with system frequency of 50 Hz. However, the overall trend and the magnitude of changes in the simulated frequency was consistent to the measured frequency.
  1200 seconds after the simulation started, a significant frequency reduction was observed in the measured frequency, while the simulated frequency remained high.
- **Case 3B simulation with load ramp, 1 August 2019, 00:00 AM – 00:30 AM (Figure 21 and Figure 22)**
  The simulated frequency deviation could be caused by load increase or generator reduction. A simulated load ramp up event by 175 MW within 90 seconds was configured at 1200 seconds from the start of the simulation and it improved the simulated response alignment.
  In order to improve the simulated frequency, a constant frequency bias of 0.00068 was added to correct the simulated frequency error at the summing junction of the frequency input of the AGC as shown in Figure 23, to correct for the off-nominal initial frequency conditions.
  The comparison between the measured frequency, simulated frequency, and simulated frequency with correction is shown in Figure 24. The same data are shown in histogram form in Figure 25. The figure shows that the frequency distribution range is approximately the same between the measured and corrected values but there is a slight offset in mean frequency, the measured mean values being slightly higher than 50 Hz and the simulated mean values slightly lower than 50 Hz.

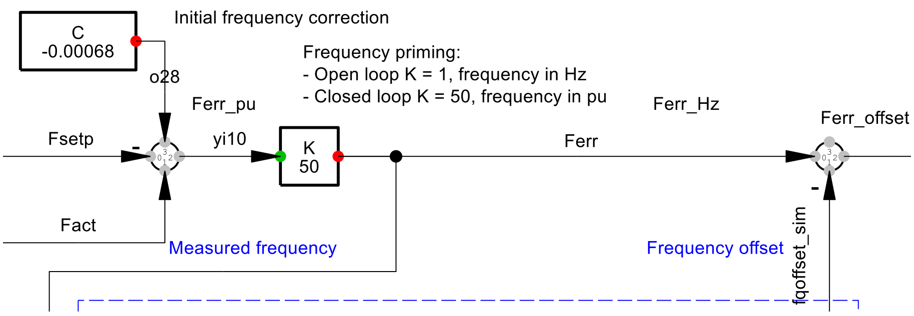

Figure 23 – Frequency correction bias calculated for model initialisation

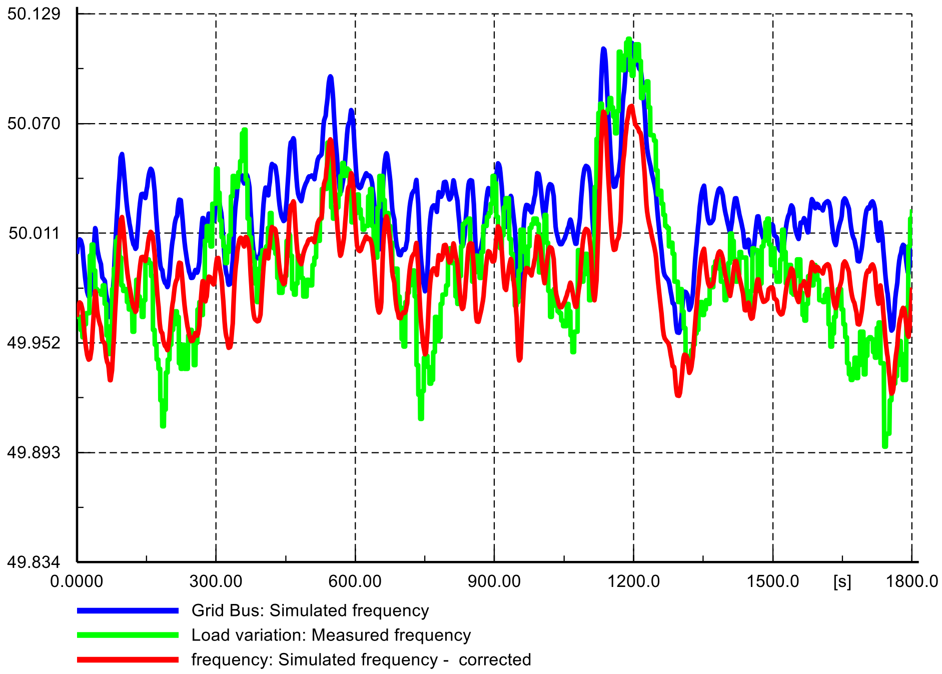

Figure 24 – Measured (green) vs simulated (blue) vs corrected simulated (red) frequency

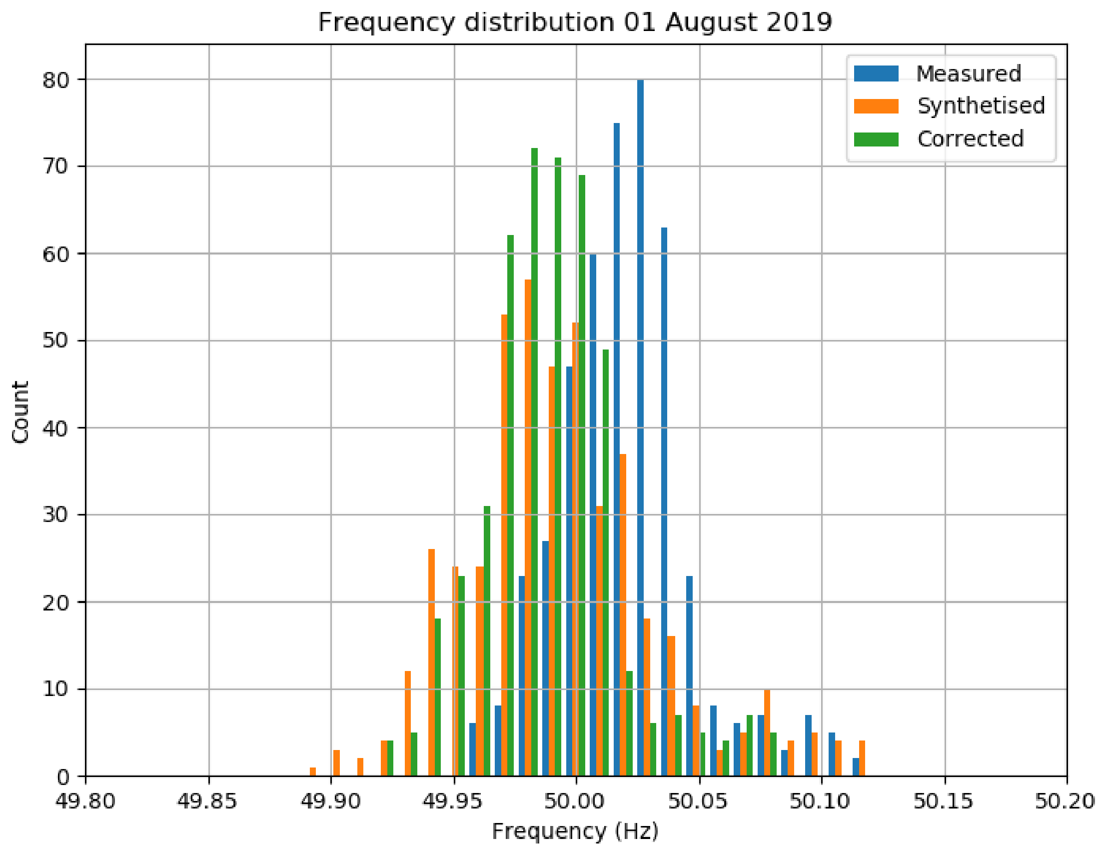

Figure 25 – Frequency distribution for the measured, simulated and corrected simulated frequency (1 August 2019, 00:00 AM – 00:30 AM)

2.4 Discussion of results for closed loop model

The three sets of closed loop responses were for the same time periods as the open loop responses reported in the previous section. The responses indicate that there are more factors at play than included in the model. The influences include the:

- amount of primary frequency control, droop, deadband and the dynamics of the frequency characteristic
- load frequency coefficient (kf) and
- assumptions about the generator active power controller.

Sensitivities to these parameters are reported in the next section.

However, there is another factor that is not modelled in the model, but which is exhibited in the actual closed-loop responses: intra-five-minute variations in load or generation. These variations are unforecasted and come from a combination of load and generation sources, described in the following subsections.

2.4.1 Unforecasted load variations

Unlike generators, loads are not required to adhere to a forecast, unless they are scheduled loads. The only scheduled loads in the NEM[1] are mainly battery or pumped-storage plants. Other loads are permitted to change output at any time. Some of these loads (such as the smelters, and ore processing plants) are significant size.

Some large Customers are exposed to spot market prices and choose to operate their plants in response to market price signals. Prices can change on a five-minute basis. This means that loads can adjust their output over a five-minute basis. Such a change might result in an unforecasted ramp in load.

The AEMC has also been keen to encourage load response to prices from individuals and as aggregated responses through retailers. Some domestic users have smart meters and may be able to respond to price signals by temporarily reducing load. Likewise, some retailers have arrangements to switch loads of customers at high spot prices. These high price periods may cause responses within five-minute periods that are not forecast, and therefore affect the frequency. As the load sensitivity to price is increased this may increase the variability of load and increase forecast deviations, particularly within the five-minute dispatch intervals. We expect that the load forecast will correct itself on the five minutes, at least to the extent that the forecast is adjusted amount of regulation FCAS dispatched in the previous period.

In some cases, loads can trip from protection operation, or be tripped in response to a high-price event, or NSCAS response. Tripping of loads, for whatever reason would result in an unforecasted step change in demand, which then would affect the frequency.

2.4.2 Unforecasted generation variations

Non-scheduled generation is unforecasted and can change its output at any time. These generators are usually small, and therefore the change is unlikely to have a large impact on frequency. Semi-dispatched generators are mostly wind and solar. Semi-dispatched plant has a forecast level, which generally takes into account some level of source variability (for example from a number of anemometers spread across a wind farm). However, there is a potential for unforecasted variation, particularly fast ramps from wind fluctuations affecting a wind farm or fast-moving clouds moving across a solar farm.

Generation ramping from one dispatch level to another with ramp rates different from the expected rate over the full five minutes, non-compliances with dispatch instructions can also result in discrepancies between demand and generation dispatch, as can trips and partial generation trips.

2.4.3 Impact of contingency FCAS on NOFB performance

In recent years there has been a higher incidence of frequency excursions beyond the normal operating frequency band (NOFB) limits, which are +/-0.15 Hz from nominal frequency. When the frequency exceeds these limits contingency FCAS response may be triggered. There are three raise contingency FCAS services

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[1] *From AEMO's NEM Registration and Exemption List (accessed 16 December 2019)*

(fast raise, slow raise and delayed raise and three lower services, also fast lower, slow lower and delayed lower services). The actual implementation of the FCAS response is not fully described. Discussions with AEMO and documentation in the Market Ancillary Service Specification indicates that implementation of contingency responses can occur as either generation or load responses. The generation response includes:

- Generating unit governor response (or equivalent from an asynchronous plant) where the frequency response is proportional to frequency deviation beyond a deadband
- Load reduction, where a load can disconnect quickly
- Rapid generation loading, where a generator can detect a low frequency and start a fast generating unit, or otherwise rapidly ramp up an online generator
- Rapid generation unloading, where a frequency relay detects a high frequency and reduces generator output
- Rapid generation or consumption by a battery.

The response can be from a variable controller (response in proportion to frequency deviation), switching controller (one or more step changes when the frequency rises through a frequency setting) or a combination.

The initiation of the response requirement is defined: fast raise and lower must be generally within 6 seconds, slow raise and lower, within 60 seconds and delayed services are over five minutes.

The sixty second raise or lower service is only triggered if the frequency does not recover to within 49.9 to 50.1 Hz within 6 seconds.

The delayed service is intended to return the frequency to 50 Hz within 5 minutes. The delayed service is not triggered if the frequency recovers to within 49.9 to 50.1 Hz within 60 seconds from the disturbance time.

Delayed services are required to sustain their output until central dispatch can take their generation requirement into account.

The MASS is not very clear about what triggers a plant to discontinue its frequency response, and what the shape of that response might look like. It merely takes into account certain response durations for assessing the quantity of response taken for payment.

Considering Figure 15, at around 300 seconds, the measured frequency drops below the 49.85 Hz threshold for triggering contingency FCAS. The assumed FCAS triggering causes the frequency to increase rapidly. This creates a discrepancy with the model, which does not include contingency FCAS response.

Examination of this trace suggests that fast and slow raise services would have been triggered for this frequency excursion, but probably not delayed service. Interestingly the frequency increases above 50 Hz for this excursion, which might mean that the contingency FCAS is causing an overshoot. We note that the MASS suggests that the delayed service is taken into account when adjusting the generation dispatch but does not mention taking account of fast or slow services. It seems to be assumed that these services are not operating within the NOFB. If the FCAS fast and slow services increase then decrease over a dispatch interval, this will affect the frequency response in the NOFB.

It is beyond the scope of this project to investigate contingency FCAS responses in detail, but we observe that it is possible that the contingency response is contributing to the variability of frequency in the NOFB.

The actual frequency response in both Case 1 and Case 2 show additional variability in frequency beyond the response predicted by the model, most likely a combination of unforecasted load and generation variations.

2.4.4 Sensitivity to load-generation difference

In Case 3, which is for a time of day where fluctuations in load and generation are likely to be smaller, the simulated and actual frequency response are reasonably similar until 1200 seconds, as illustrated in Figure 19, when some change to load or generation occurs. In Figure 20 and described in the previous section, we correct for this by applying a ramp of 175 MW over 90 seconds, which improves the alignment. This indicates that a variation of load or generation of this order can have a significant impact on the frequency response within the NOFB, with the current level of PFC. This modest non-forecast difference between load and generation, results in a change of frequency of approximately 0.159 Hz in the simulation. If the deviation commenced at 50 Hz, this would have resulted in an excursion beyond the NOFB. Such deviations are likely to become even more frequent as the percentage of variable renewable generation increases in the NEM, unless it is also accompanied by storage, which compensates for the loading ramps.

3 Sensitivity studies using historic data

In this section Case 3B is used as a base case for sensitivity studies illustrating the impact of changing key variables in the study.

3.1 Impact of changing the load frequency response

Figure 26 illustrates the impact of the load frequency dependency factor k_f on the response and Figure 27 shows a detail of the frequency response including rate of change of frequency. As k_f becomes smaller the deviations in frequency for the same load changes become larger and the rate of change of frequency is consequently increased. This is particularly apparent for the 175 MW ramp at 1200 seconds.

3.2 Impact of changing the amount of primary frequency response

Figure 28 illustrates the impact of changing the amount of primary frequency response. In this version of the model the sub-synchronous coal governor has no deadband.

As expected, the impact of increasing the amount of primary frequency response is to reduce the extent of frequency excursions. The requirement for AGC regulation raise and lower is generally also reduced with higher amounts of PFC. There is a trade-off between PFC and AGC and this can be explored further with the model.

Likewise, because the frequency excursions are damped, the contingency FCAS is likely to be triggered less often with more PFC.

Figure 30 takes this further by applying a 15 mHz deadband and comparing the current level of PFC (around 1950 MVA, based on the model tuning) with a case with all plant providing PFC (red trace) and an intermediate level with 6600 MVA of plant having PFC. As the level of PFC is increased the frequency range becomes closer to the deadbands. The case with all plant providing PFC and 15 mHz deadband is consistent with settings proposed by AEMO's Rule change request[2] to mandate primary frequency control from all generation.

3.3 Impact of changing PI gain for the AGC unit representation

The PI controller represents the control response of the units to dispatch signals and AGC regulation. In practice every machine has its own characteristic response. As the gain is increased the controller becomes less stable. In our base case we used a value of 0.01 for the integrator gain, as this gave a reasonable frequency response.

The controller gain assumed also affects the AGC units' responses. As shown in Figure 31 the responses become faster for higher gain.

[2] https://www.aemc.gov.au/sites/default/files/2019-08/Rule%20Change%20Proposal%20-%20Mandatory%20Frequency%20Response.pdf

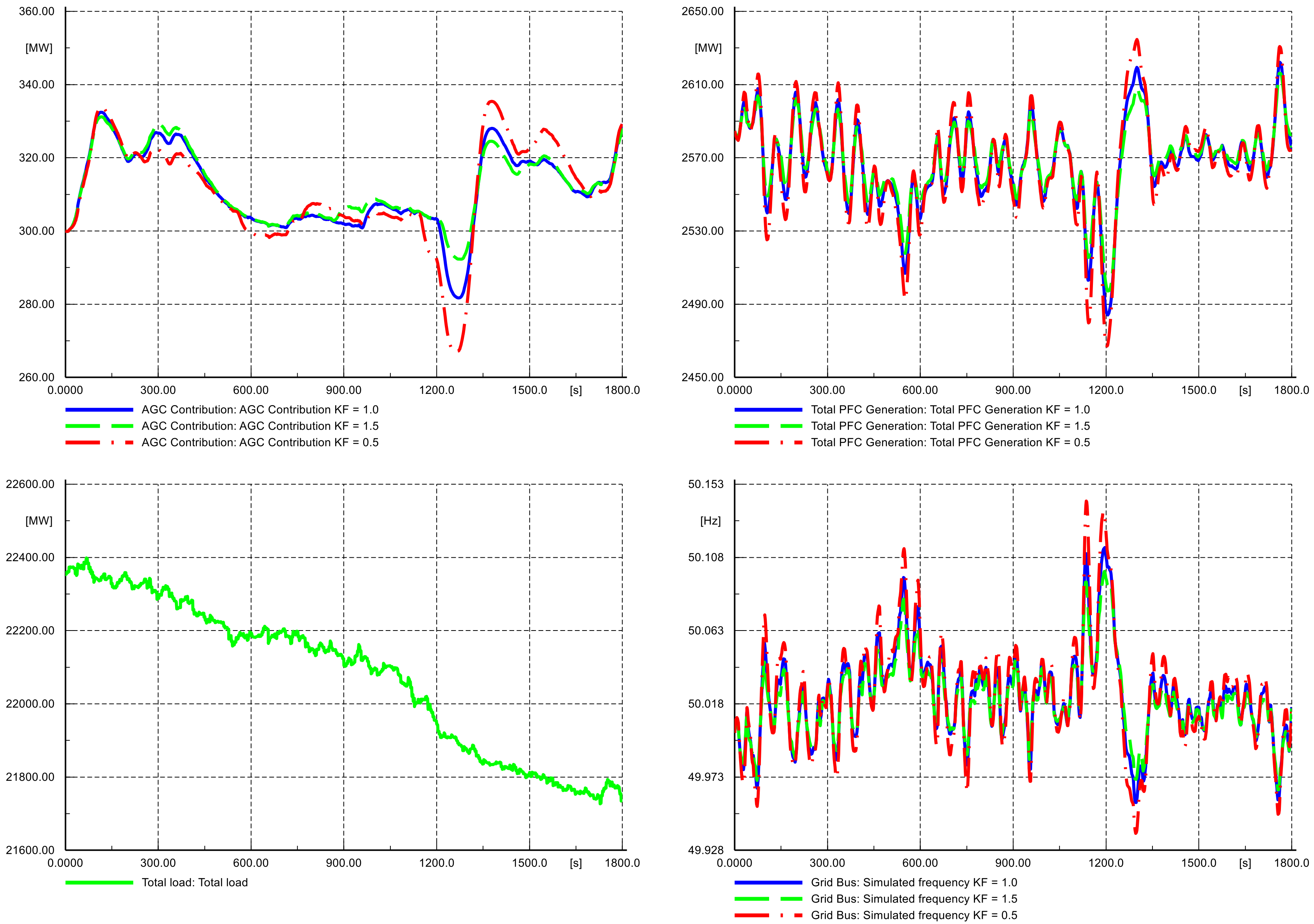

Figure 26 impact of varying load frequency factor Kf: 0.5 (red), 1.0 (blue) and 1.5 (green)

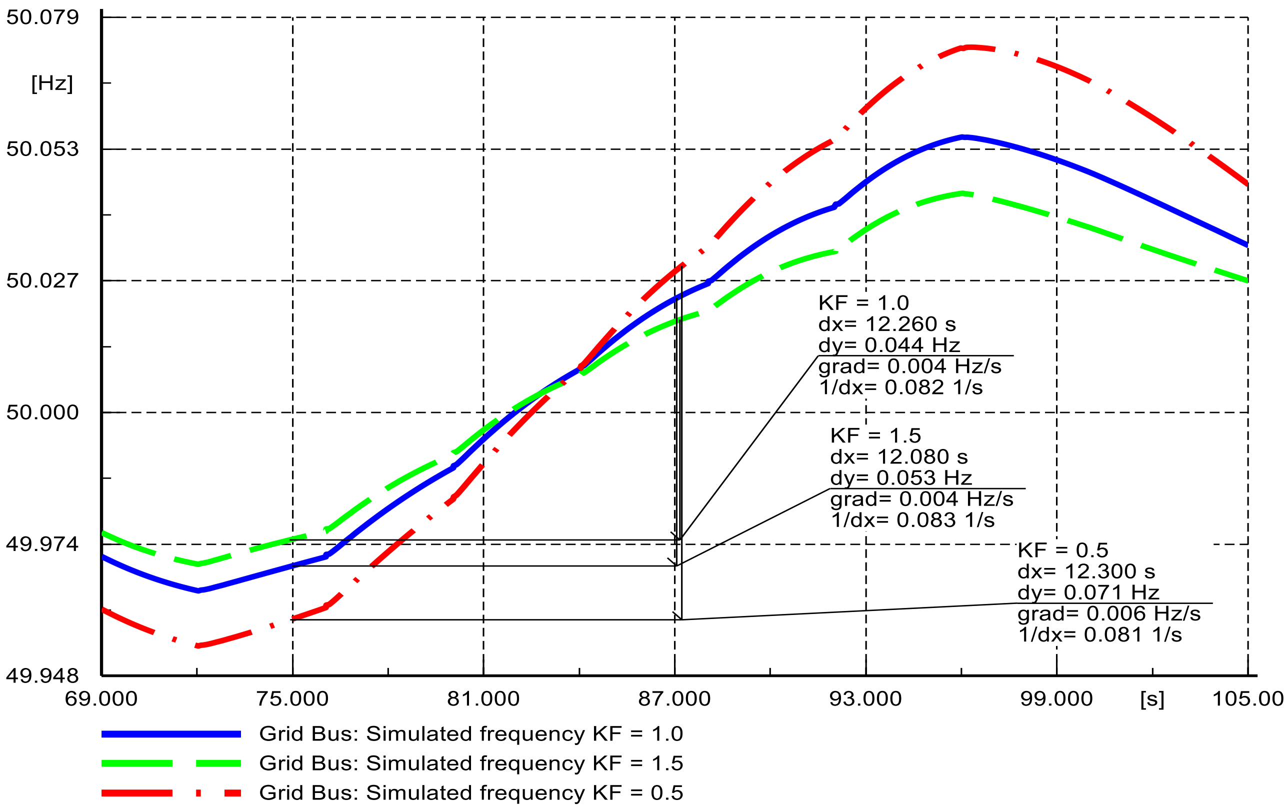

Figure 27 Detail of rate of change of frequency

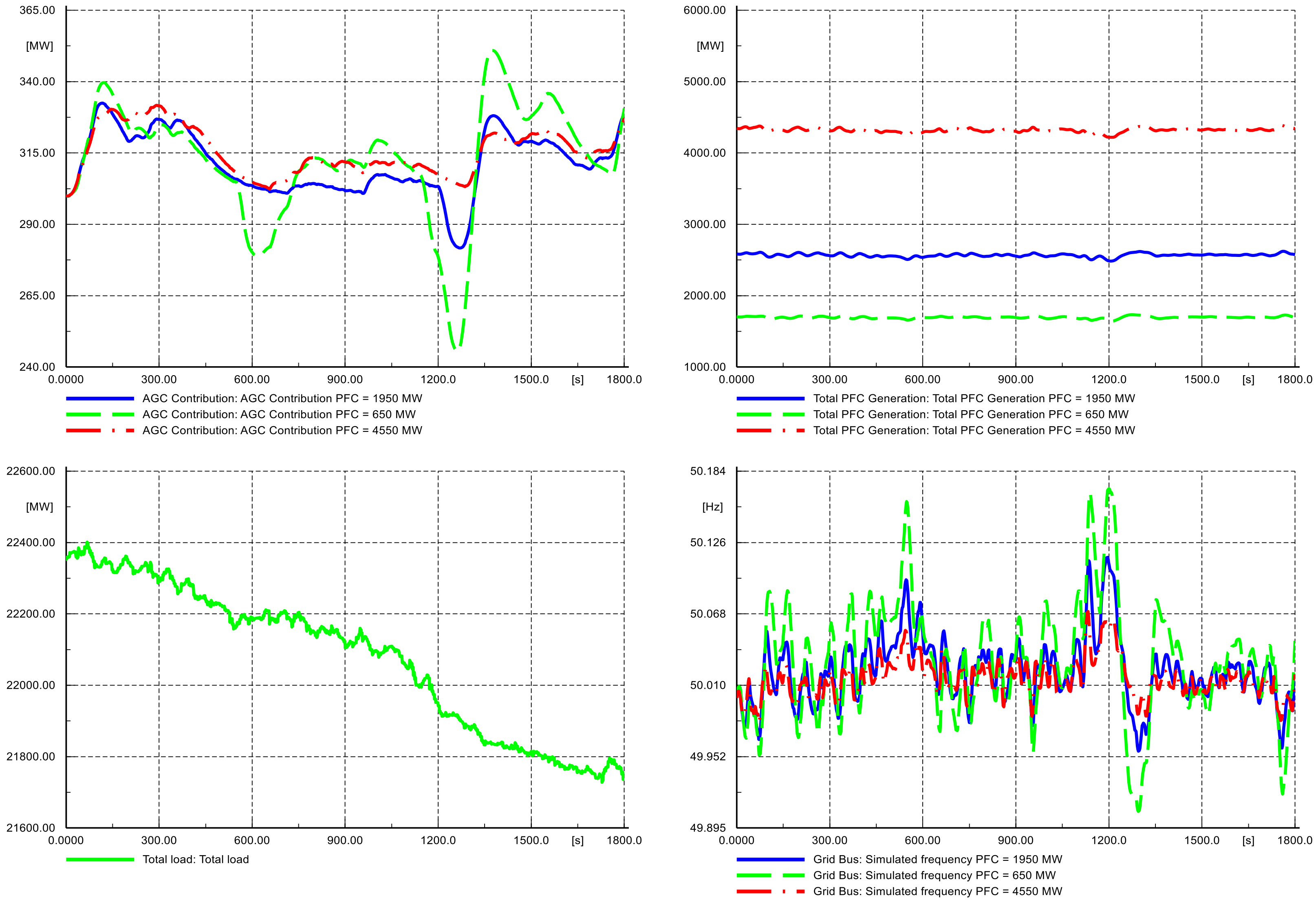

Figure 28 – Impact of changing the amount of primary frequency response: (green PFC = 650 MVA, blue PFC = 1950 MVA, red PFC = 4550 MVA)

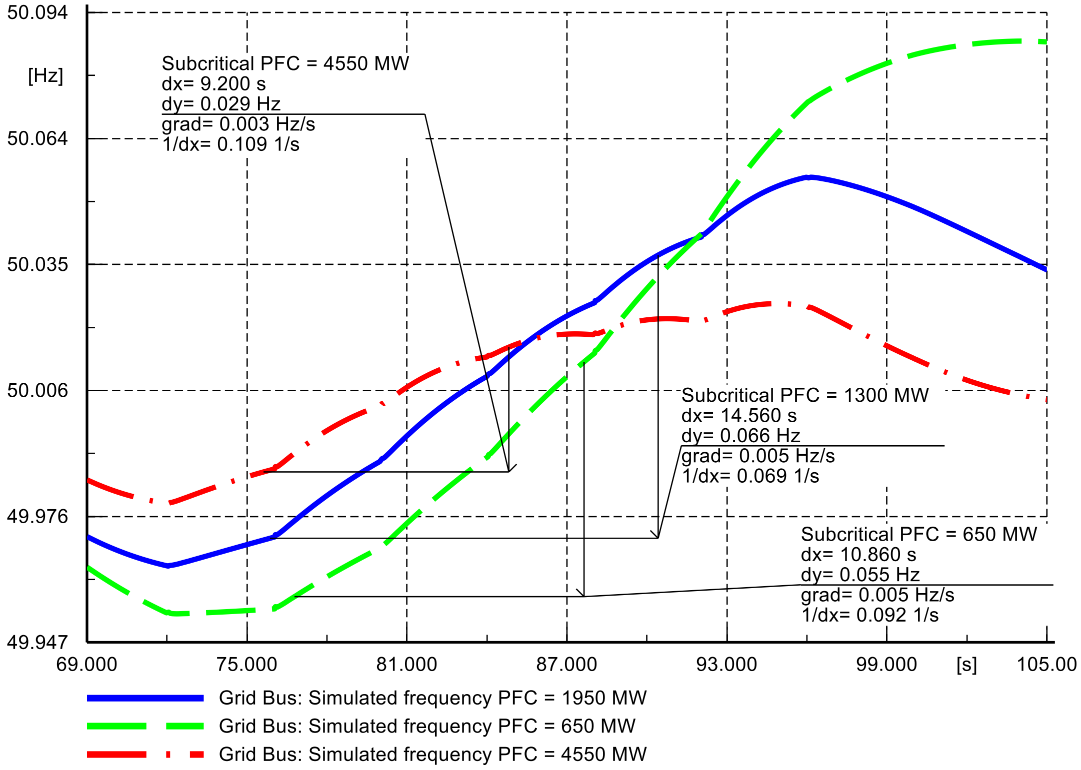

Figure 29 – Detail of impact of primary frequency response

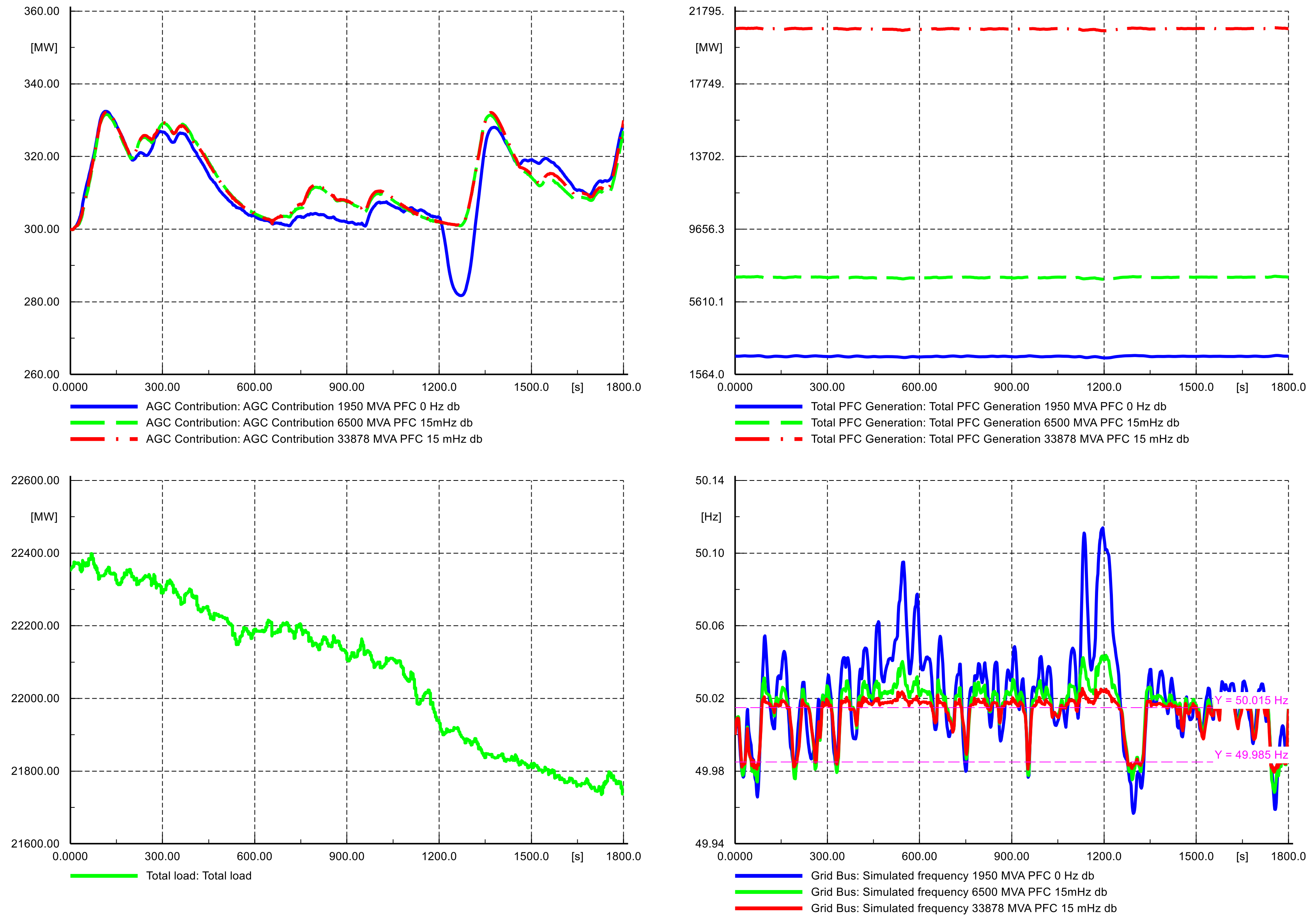

Figure 30 – Impacts of implementing 15 mHz deadband on part of the generating units (green), on all generating units (red), current level of renewables

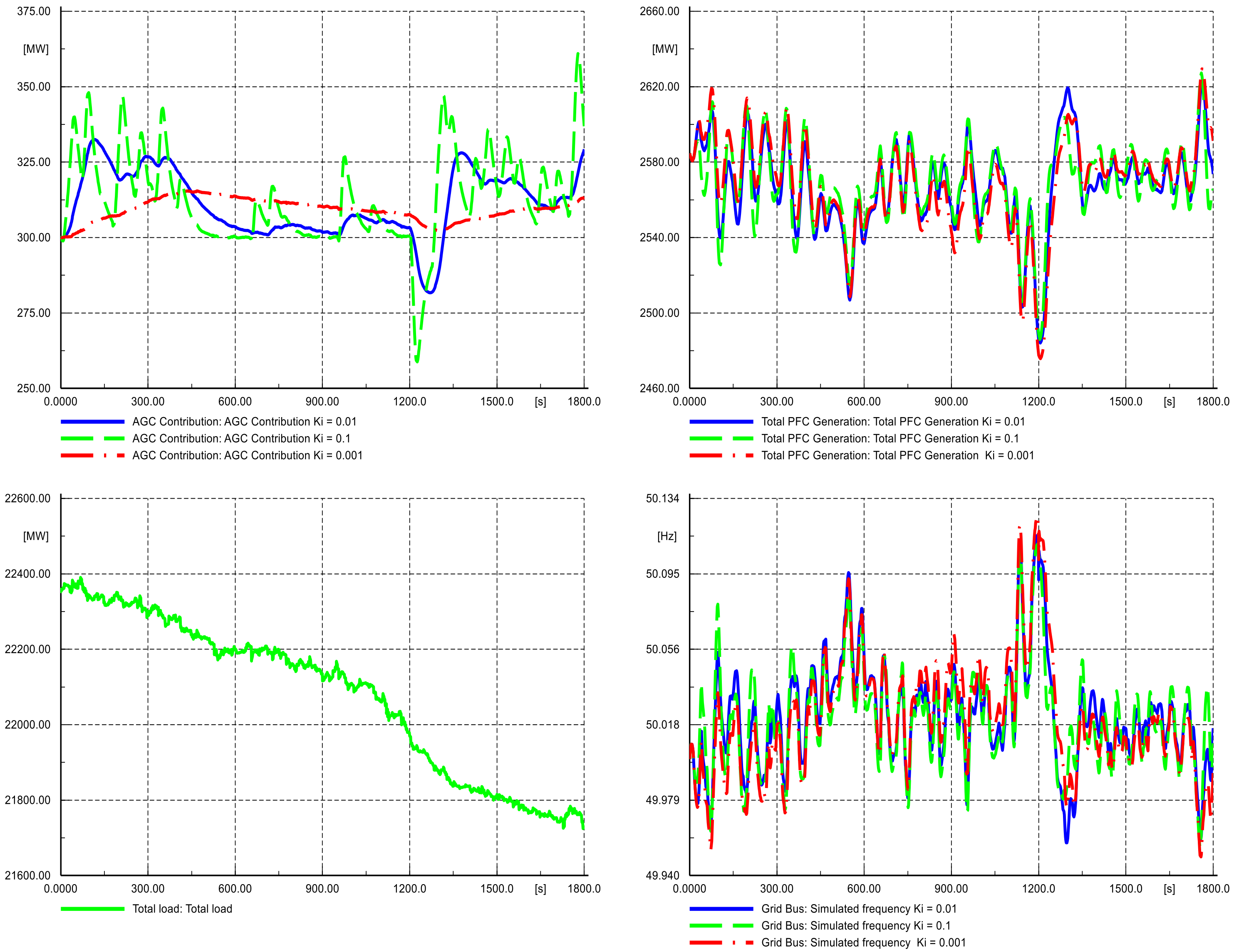

Figure 31 – Impact of changing integrator gain Ki: red = 0.001, blue = 0.01 and green = 0.1

4 Future Scenario - 2025

4.1 VRE ramping in 2025

AEMO has synthesised ramp data for 2025, based on a projected VRE capacity of approximately 13 GW, up from around 4 GW in the historical data. The data were based on meteorological data for locations identified as renewable energy zones in the 2018 Integrated System Plan. Appendix B contains a description of the synthetic data and its derivation.

Subsequent to the studies undertaken for this report, AEMO provided a new data set that eliminated a periodic ramp that was an artefact of concatenation of the daily datasets. In the process of generating the ramp datasets, AEMO joined a number of datasets, each representing a day. The assembly of the data set introduced an incorrect component of the ramp that was related to the joining process. This has now been removed in a new dataset provided by AEMO. See Appendix B.4 for more information on the synthetic ramp data cleansing process.

The data were presented as ramps over various durations. For our studies we have selected five-minute ramp data, and three-minute ramp data, since we would expect that the forecast should, to some extent compensate for longer duration ramps. That is, the forecasting algorithm will correct for errors in the previous five minute forecast when forecasting the next five minutes. Within a five minute period, the change in generation will be a combination of predictable changes (for example, the daily ramp up of solar after dawn), and less predictable changes (for example, the effect of a cloud traversing a solar farm, or a local temporary increase in wind speed). In this report we have not attempted to separate forecastable and less forecastable causes of ramps but have assumed that anything within the five-minute period is not forecast. In any event, semi-scheduled generation only provides output forecasts every five minutes. The impact of using the dataset in its original form will be to use a higher value of ramp (for the three-standard deviation) level than might be considered if a better forecast were considered. This represents a conservative approach.

The frequency distribution of the five-minute ramp data is shown in Figure 32. Because of the geographical diversity of the VRE sources, the majority of ramps over five minutes are around 0 MW. Two standard deviations, (equivalent to around 95th percentile) is around 280 MW and three standard deviations (99th percentile) 420 MW. The highest magnitude 5-minute ramp is 1692 MW.

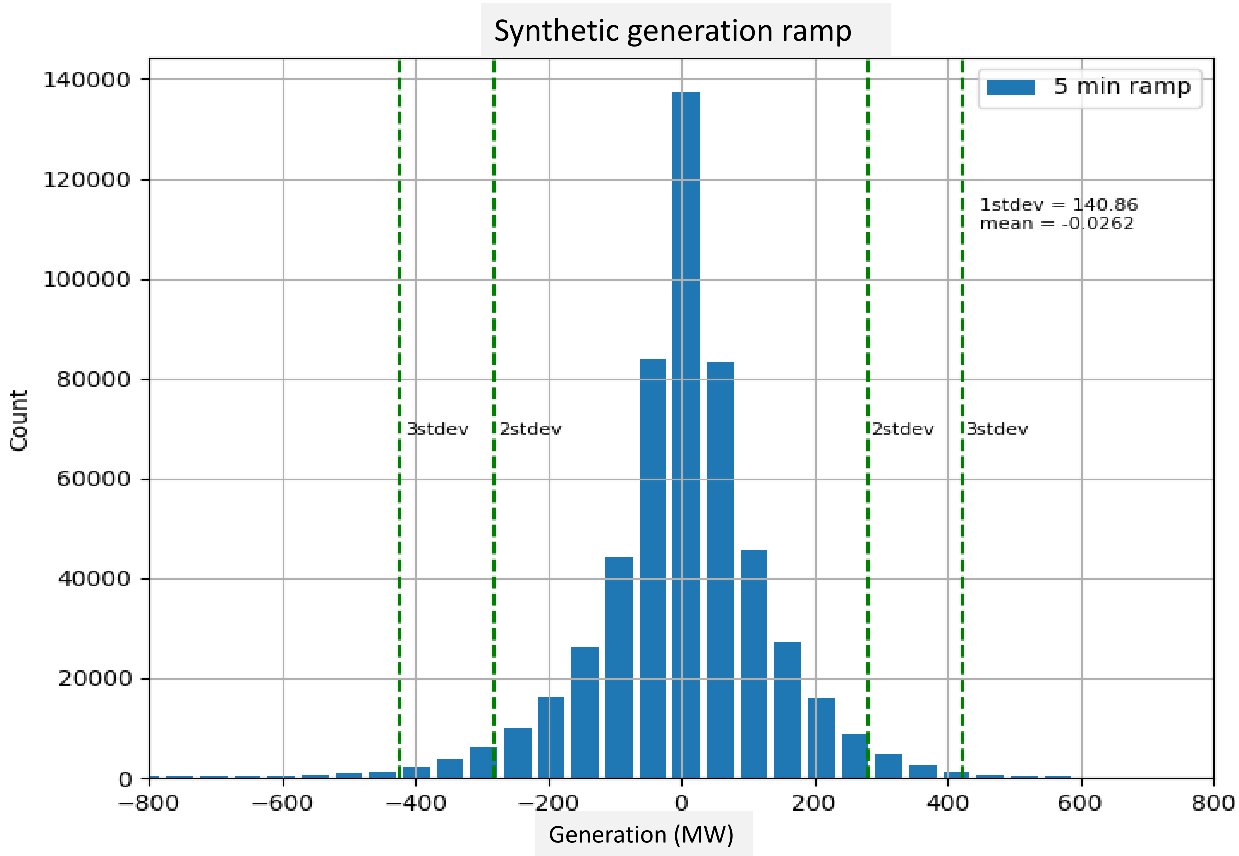

Figure 32 – Histogram of five-minute generation ramps for 2025 synthesised data

The effect of the ramp artefacts is shown in Table 2. The difference in the third standard deviation is approximately 15 MW or 3.5%, which is insignificant considering other uncertainties in the data. All results reported Chapter 4 are based on the original data.

Table 2 Comparison of original synthesised ramp data distribution with cleansed data.

Quantity	**Original data (MW)**	**With data cleansing (MW)**
Mean	-0.026	2.34
1 Std deviation	140.9	135.9
2 Std deviation	281.7	271.9
3 Std deviation	422.6	407.8

The frequency distribution for the three-minute ramps, based on the original data, is illustrated in Figure 33. The mean is close to zero, as for the five-minute ramps. The 3 standard deviation point for three-minute ramps, is around 280 MW and the maximum deviation is 1170 MW.

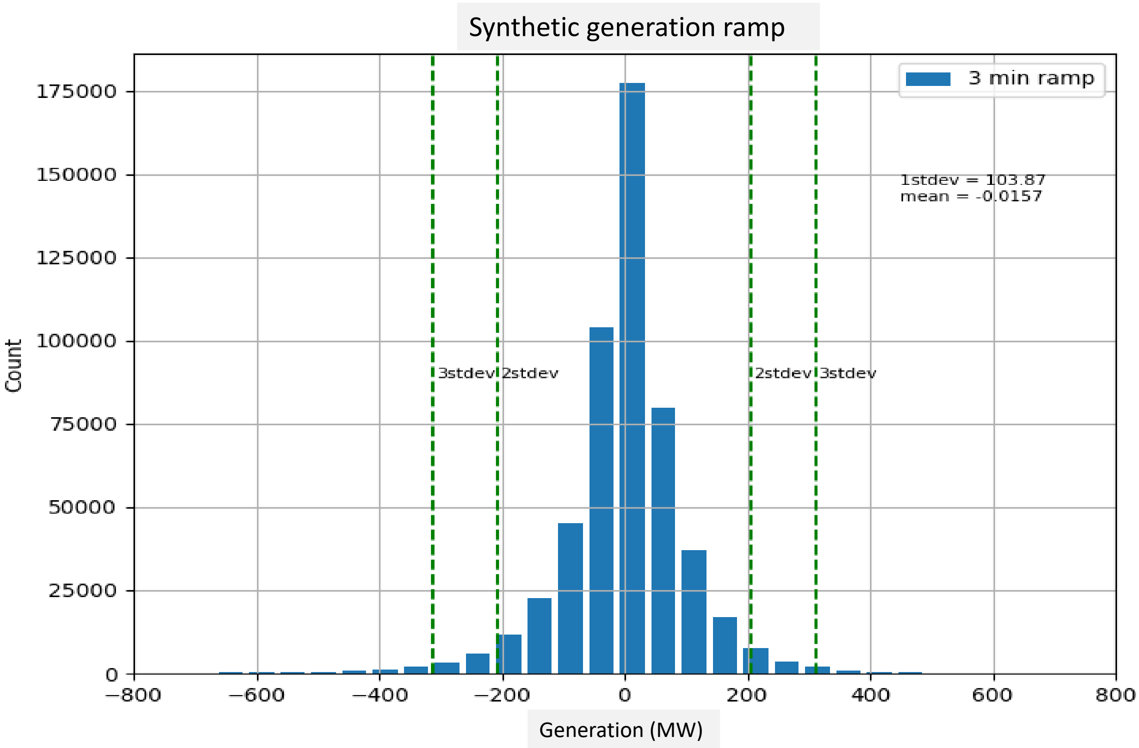

Figure 33 – Histogram of three-minute generation ramps for 2025 synthesised data

There are potentially other power system elements that could change over the period to 2025 which would make effective ramps higher. These factors could include:

- Price-sensitive non-scheduled load and generation. Load and generation that is sensitive to spot market prices has an incentive to adjust is output in line with the five-minute NEM spot prices. There has been focus from the AEMC on driving price response from loads, which, if it is successful, might result in more fluctuation in residential and commercial loads over time.

- Roof-top solar is subject to cloud shading. As the geographical density of roof-top solar is increases over time there is increased potential for cloud fronts to cause higher rates of MW change.

- Our studies have calibrated the frequency response based on the generation that existed at August 2019. It is possible that the amount of primary frequency response is still declining at present in the NEM. It is also possible that, by 2025, the generation plant line may be different, with more VRE during the day and increased gas generation during morning and evening peaks. This may change the PFC response.

Overall considering these factors together with the data limitations, the results could be either pessimistic or optimistic but are probably of the right order of magnitude. The assumptions on forecasting are conservative and forecasting accuracy could improve, stay the same or decline in future years. The studies should therefore be considered as providing relative information rather than absolute accuracy.

4.2 Impact of changing generation mix and primary frequency control

Before applying additional ramps, the generation mix was adjusted. For this study the total generation was kept the same, but the VRE increased to 13000 MVA, while simultaneously reducing the subcritical synchronous coal plant by the same amount.

Figure 34 shows the frequency response with the 2025 generation mix applied to the historical Case 3B, with 15 mHz deadband on all primary frequency response, and the same amount of PFC as in the base case (1950 MW of PFC).

Figure 35 shows the impact of primary frequency response on all plant, applied to the same case, and compared with the historical generation mix, also with primary frequency response on all plant.

Comparing the trace in Figure 34 with the green trace in Figure 35 shows the reduction in frequency excursions resulting from the higher level of PFC.

Comparing the two traces in Figure 35 the impact of changing the generation mix is to reduce the amount of frequency raise, because it was assumed that the wind and solar, which replaced the coal fired generation would not have raise capability. This may be a pessimistic assumption, because some solar and wind generation may choose to provide raise capability (if there is financial benefit from, for example, a market) and some generating systems will include batteries, which have raise capability when not operated at maximum output. Comparing the red and green traces, the case with high VRE has slightly lower minimum frequencies for negative excursions. The traces also show that typically the frequency is close to either the upper or lower end of the primary frequency control deadband for most of the time.

4.3 Impact of VRE ramping – five-minute ramps

In this section we consider the impact on frequency of unforecasted ramps with different levels of PFC.

Figure 36 shows the impact of a 420 MW ramp for five different levels of PFC. The 420 MW represents the 3 standard deviation level (approximately 99.7 percentile level) of five-minute ramps. In each case the 420 MW ramp is applied at 300s. For PFC of 33% more than existing PFC (2.60 GVA of generation providing PFC) to 100% of generators providing PFC (except no raise capability for wind and solar), the frequency remains within the NOFB range following the ramp. However, for PFC approximately equivalent to current levels (1.95 GVA PFC level) the frequency excursion is beyond the lower limit of the NOFB.

Figure 37 shows the impact of a 1692 MW ramp, which was the highest magnitude five-minute ramp event in the synthesised data for 2025 provided by AEMO. This ramp was also applied from 300s in the simulation. The responses are shown for the same four levels of PFC.

As expected, the frequency deviation for this ramp is higher than for the 400 MW ramp. With PFC at approximately current levels, the frequency deviated to approximately 48.5 Hz, which would be at a level to cause load shedding. For the case with 6500 MVA of PFC, the frequency deviation for the 1692 MW ramp takes the frequency below 49.5 Hz, which is similar to a large single contingency event. With 24,000 MVA of PFC, the frequency deviates below lower boundary of the NOFB (49.85 Hz).

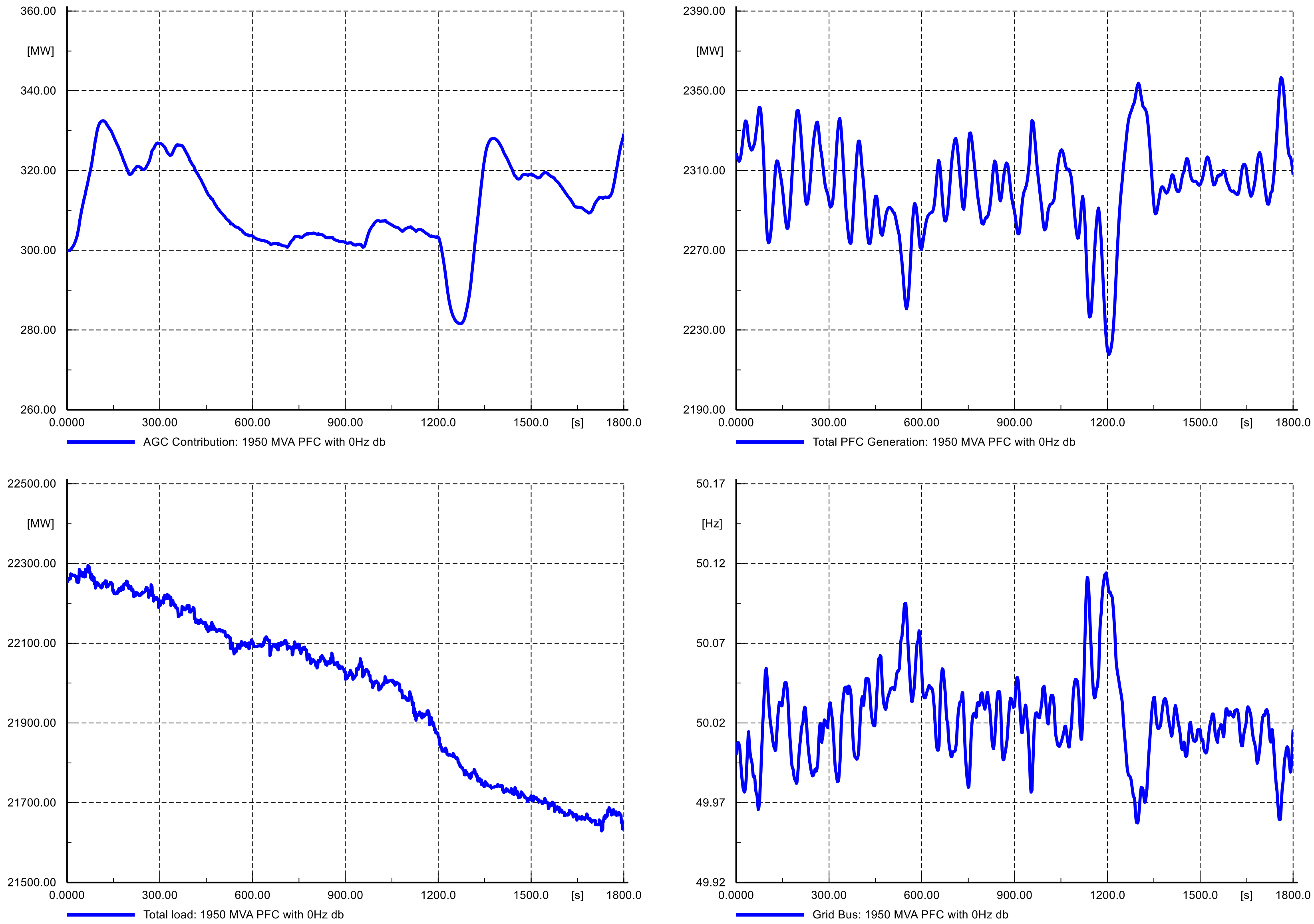

Figure 34 – 2025 generation mix applied to Case 3B, with existing PFC (1950 MVA)

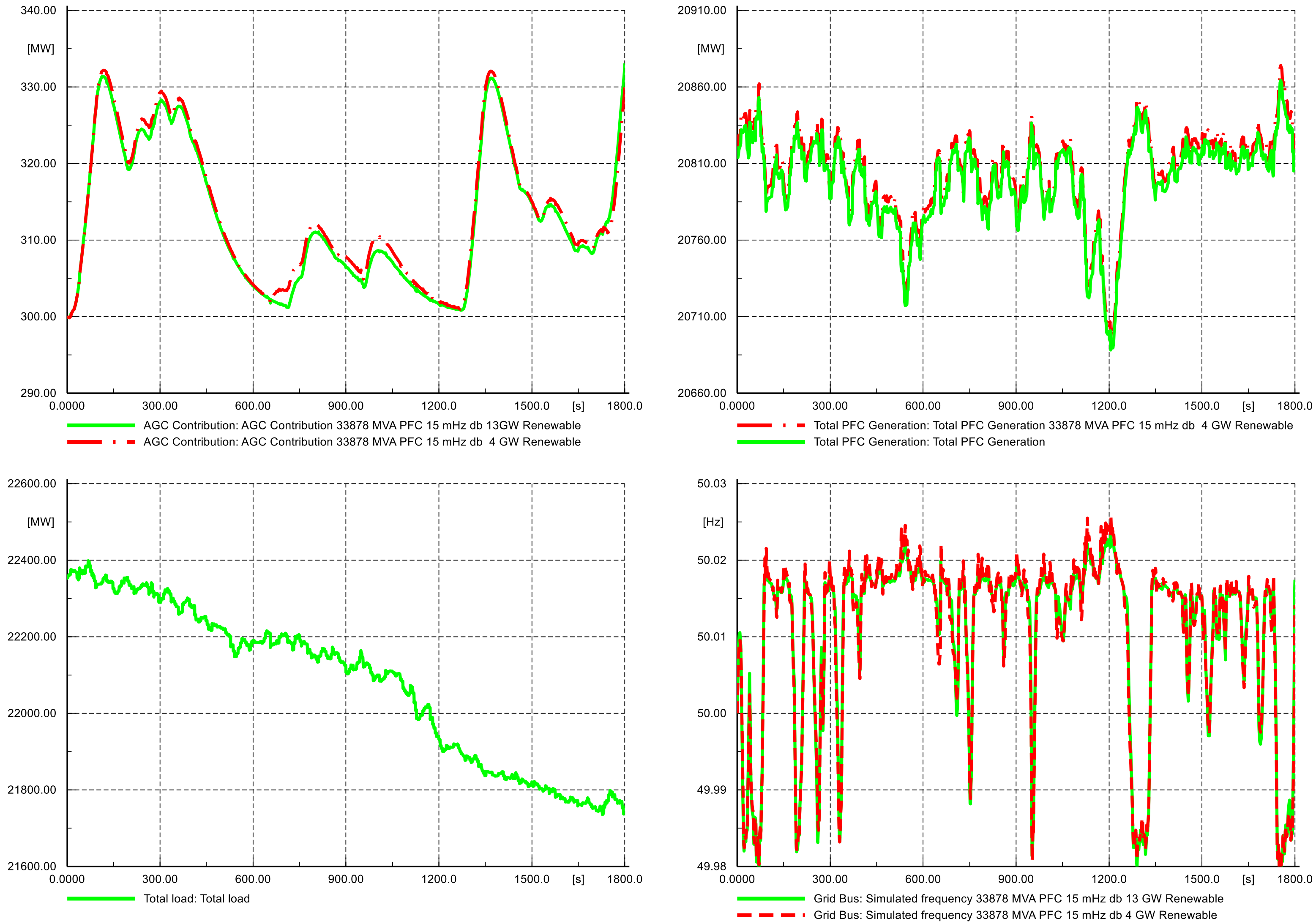

Figure 35 – Case with 15 mHz deadband implemented on all generating units (red) and with future amount of renewable generation (green)

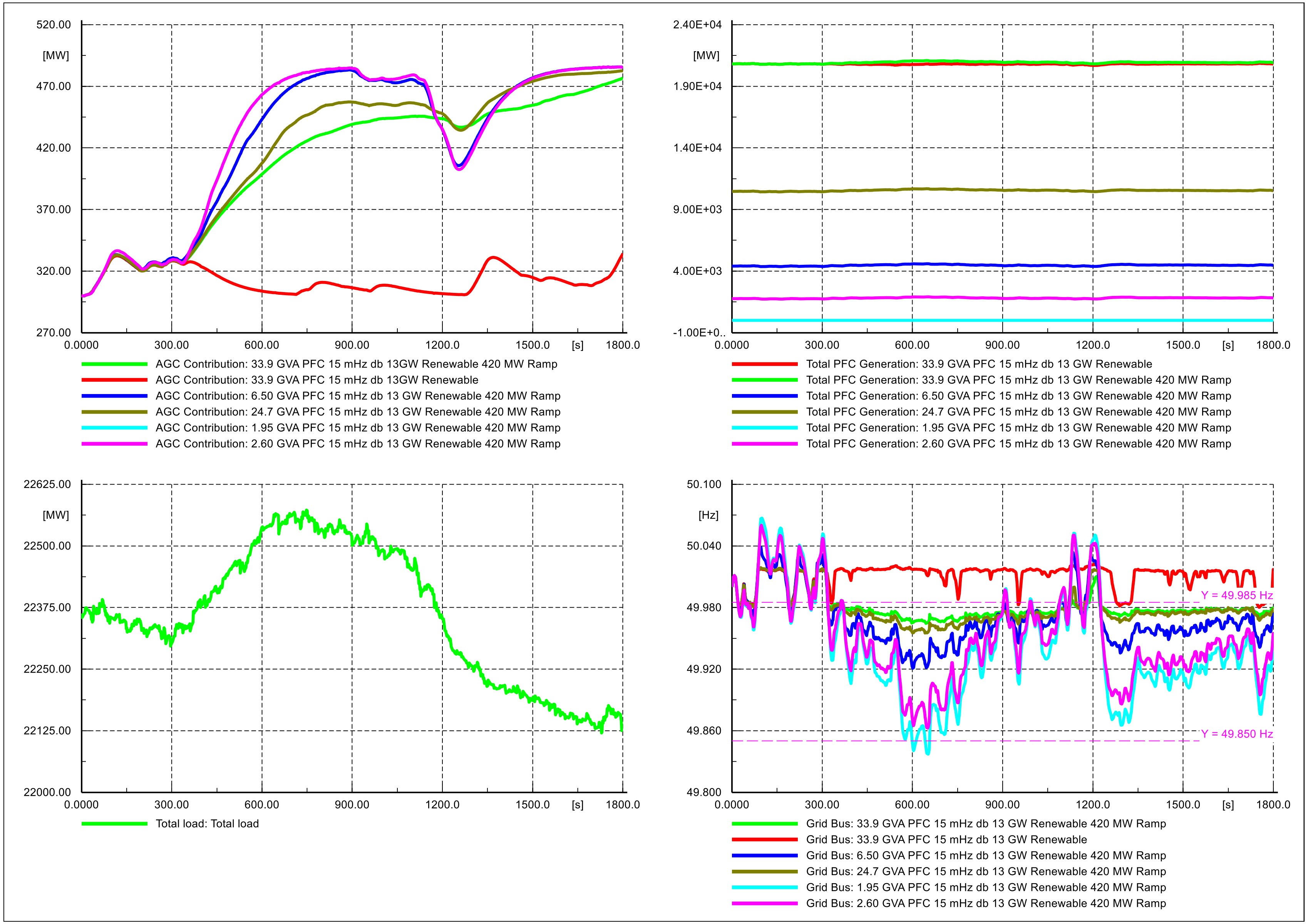

Figure 36 – Sensitivity studies of 5-minute ramp of 420 MW

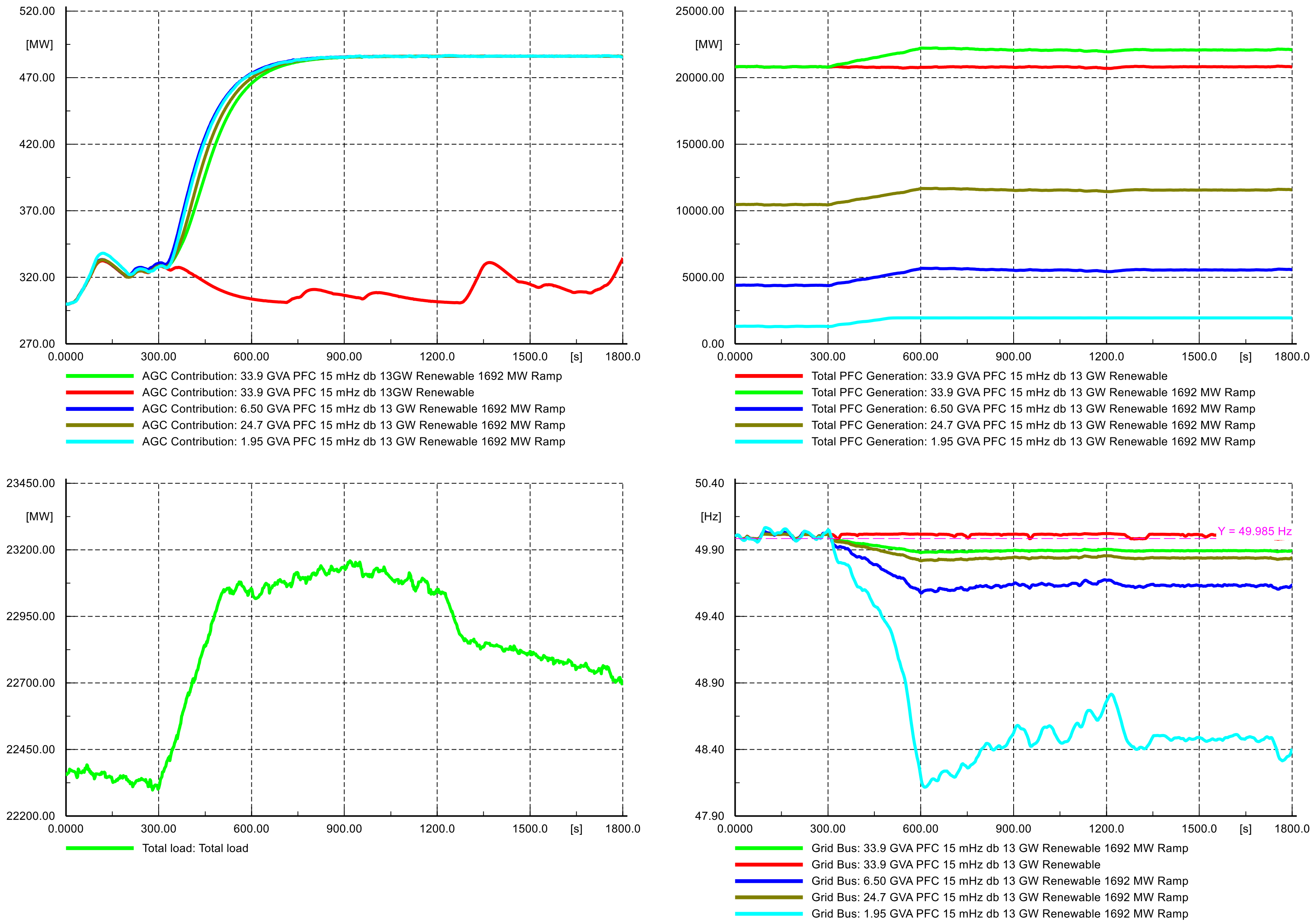

Figure 37 – Sensitivity studies of 5-minute ramp of 1692 MW

4.4 Impact of VRE ramping – three-minute ramps

Figure 38 shows results for the worst-case 3 minute ramp from the synthesised data. This ramp, as for previous studies, superimposed on the tuned Case 3B response. The results suggest a frequency deviation of approximately 0.9 Hz for this ramp with 1.95 GVA PFC, which is greater than the expected deviation for a credible contingency event.

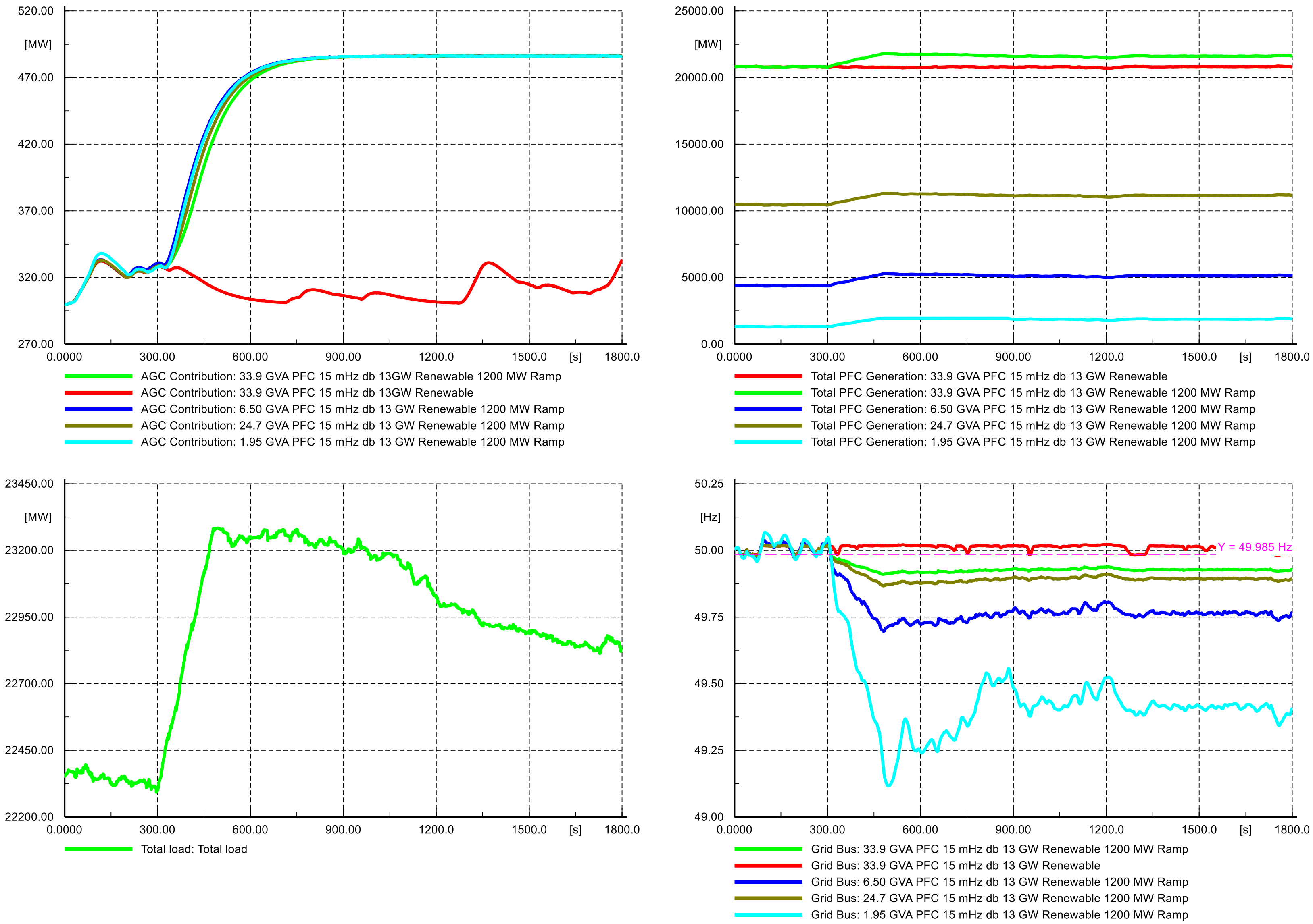

Figure 38 – Sensitivity studies of 3-minute ramp of 1200 MW

4.5 Impact of additional regulation

Figure 39 shows results for a sensitivity study for the 420 MW five-minute ramp case, with 1.95 GVA of generation providing PFC (the base level) and varying the maximum regulation level. Three levels of regulation are plotted: 186 MW, 240 MW and 300 MW. The results suggest that for this level of ramp, the frequency response can be improved by increasing the amount of regulation FCAS, if the primary frequency control remains the same. For this case 240 MW of regulation is sufficient to maintain frequency within the NOFB range.

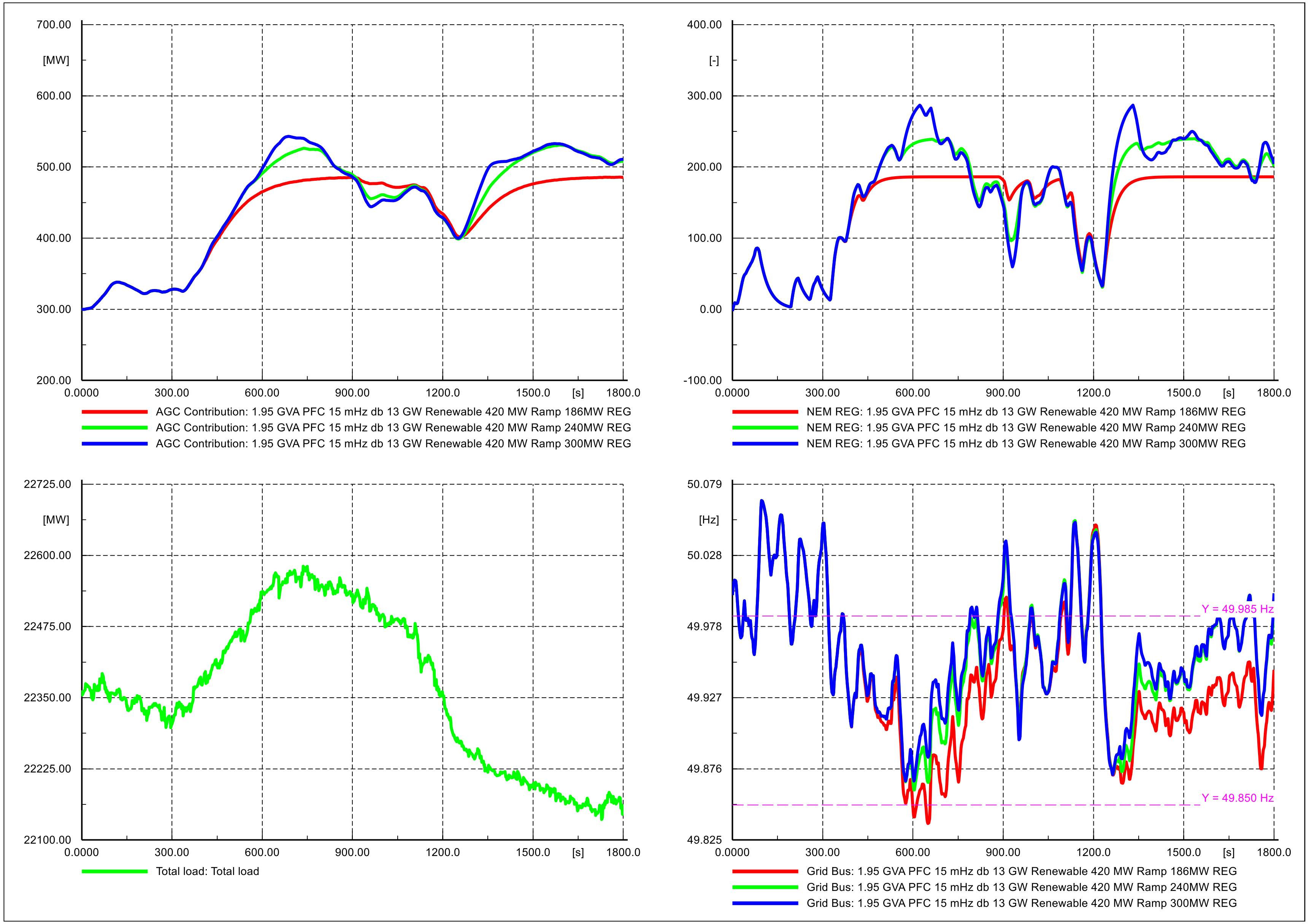

Figure 39 Sensitivity study: increasing the maximum regulation for a 420 MW ramp, 186 MW (red) – the original level, 240 MW (green) and 300 MW (blue)

5 Discussion

The analysis suggests that contingency FCAS is currently being triggered for modest differences between load and generation which result from a number of different sources including VRE ramps, and load changes. The number and size of these frequency disturbances is likely to increase over time because of:

- Growth in the capacity and generation from VRE sources (as reflected in the synthesised data)
- Increased unforecasted price sensitivity from loads, driven by demand-side initiatives
- Increase in non-scheduled generation (may also be price-sensitive)
- Reductions in the load sensitivity factor k_f.

Future ramp sizes could be smaller because:

- Parts of the ramps reflected in the synthesised data are addressed by the forecasting systems, and therefore compensated by dispatch.

There is also a minor impact from an artefact in the synthetic data (explained in Chapter 4), although this effect is not considered significant.

Ramp sizes might be larger because:

- Price sensitivity effects of loads and generation will generally increase with the capacity of non-scheduled generation and the total size of price-sensitive loads, which have not been considered in the input data. Economists generally consider price-responsiveness to be beneficial for the electricity market and have been promoting it through various policies like roll-out of smart meters, but it could result higher demand-supply volatility at the five-minute level. Embedded battery systems and electric vehicle chargers are likely to fall into the category of price-sensitive loads.
- Variability of rooftop solar potentially increases as the geographical density of solar rooftop generation increases (ie the same cloud front could affect a larger number of panels simultaneously).

As mentioned in Chapter 4, it is also possible that the amount of primary frequency response has continued to decrease over the period from August 2019, from which the historical data were derived for purpose of calibration to the present.

AEMO has recently undertaken some measurements of load frequency dependency and found that for some measurements undertaken in Victoria the k_f factor was closer to 0.5 than 1.0 or 1.5 commonly assumed. This may be a result a trend towards use of frequency insensitive loads such as air conditioners and refrigerators with inverter front-ends and variable-speed-drives on large motors, instead of direct-on-line operation. In this report we have illustrated that a lower k_f makes the frequency more sensitive to changes in the difference between load and generation.

In the 2025 scenario VRE penetration is substantially increased, with 13 GW of VRE compared with 4 GW in the historical case. The synthesised ramp information provided by AEMO suggests that while this high generation from VRE would in the vast majority of cases lead to average ramps across five minutes that are close to zero, there are statistically some small proportion of cases for which the combined ramps are much higher. In this study we have focused on the ramps of five-minutes duration and less because if the ramps occur across a dispatch period, we expect that the forecasting system would partially correct for them.

The results show that a 420 MW ramp with current levels of PFC can cause a frequency deviation of more than 0.15 Hz, potentially taking the frequency outside of the NOFB. The synthesised data provided indicates could occur for about 0.3% of the five-minute ramps. With 6.5 GVA of plant providing PFC the deviation in frequency for this size ramp is less than 0.1 Hz. An increase of approximately 33% of generation (from 1.95 GVA to 2.6 GVA) providing PFC with 15 mHz deadband would allow this ramp to be controlled within the NOFB.

For unchanged PFC levels (1.95 GW enabled plant), an increase of around 29% on regulation FCAS magnitude (180 MW to 240 MW, for the case studied) would also be sufficient to keep the frequency within the NOFB range.

Without contingency FCAS response, and with the current level of PFC, the highest forecast magnitude five-minute ramp would cause frequency deviation in excess of 2 Hz, well into the range of load shedding. To keep the response within the NOFB would require more than 20 GVA of primary frequency response.[3]

Results for the worst-case three-minute ramp show deviation of approximately 0.9 Hz, well outside the NOFB range. Again, the simulations suggest around 20 GVA of PFC would keep the frequency deviation within the NOFB range.

The regulation FCAS would not be fast enough to manage these larger generation ramps, which should be considered similar to contingency events. The responses in Figure 39 demonstrate (lower right graph) that the AGC ability to control a rapidly changing frequency is limited. When the frequency stabilises, the AGC control is significantly improved as the regulation quantum is increased.

There would be an economic trade-off between the frequency of these large ramps and the need to maintain frequency with the NOFB. Other results in the simulations show that approximately 6 GVA of PFC delivers good performance for more common ramps. Around 60-100 MW of regulation will improve the probability of staying within the NOFB for common ramps but will have less effect on the larger ramps. Consideration of battery supplied PFC would also assist with frequency control generally.

5.1 Other influences

AEMO made changes to regulation FCAS in March to May 2019 to reduce the time that frequency was outside the NOFB, to below 1%. AEMO increased raise and lower regulation FCAS by [2]:

- 50 MW on 22 March 2019 to 180/170 MW
- 20 MW on 23 April 2019 to 200/190 MW, and
- 20 MW on 23 May 2019 to 220/210 MW.

These changes assisted to bring improve the frequency control in the short term, but as Figure 40 shows there were increased frequency deviations again in September to November 2019, and the frequency distribution continues to be quite flat.

The number of frequency excursions outside the NOFB continues to be high despite a reduction around March to May 2019. The plot also shows considerable volatility in the number of events recorded. There could be several reasons for this:

- There appears to be a slight seasonal correlation (from observation only). Many large generators undertake regular maintenance in spring ahead of the summer demand peak. This can affect the power system in a number of ways:
  - Inertia of the system tends to be lower (affects rate of change of frequency)
  - The amount of PFC could be materially lower (especially since so few plants are providing this service)
  - The proportions of plants of different technologies providing PFC might change seasonally, leading to different response characteristics
- The types of plant providing AGC and contingency FCAS might change over time. For example, if a battery and a hydro plant were asked to provide 50 MW of raise service in 4 seconds, the battery could achieve it accurately, but it is likely the hydro plant could not because of the dynamics of the water column in the penstock.

We conclude that there appear to be other factors at play beyond the ramp effects, level of PFC and level of AGC studied in this report.

It is beyond the scope of this report to study these factors, but they could benefit from further investigation.

[3] *Note that we showed 24 GVA here, but around 4 GVA would have been from VRE, without any raise capability in this scenario.*

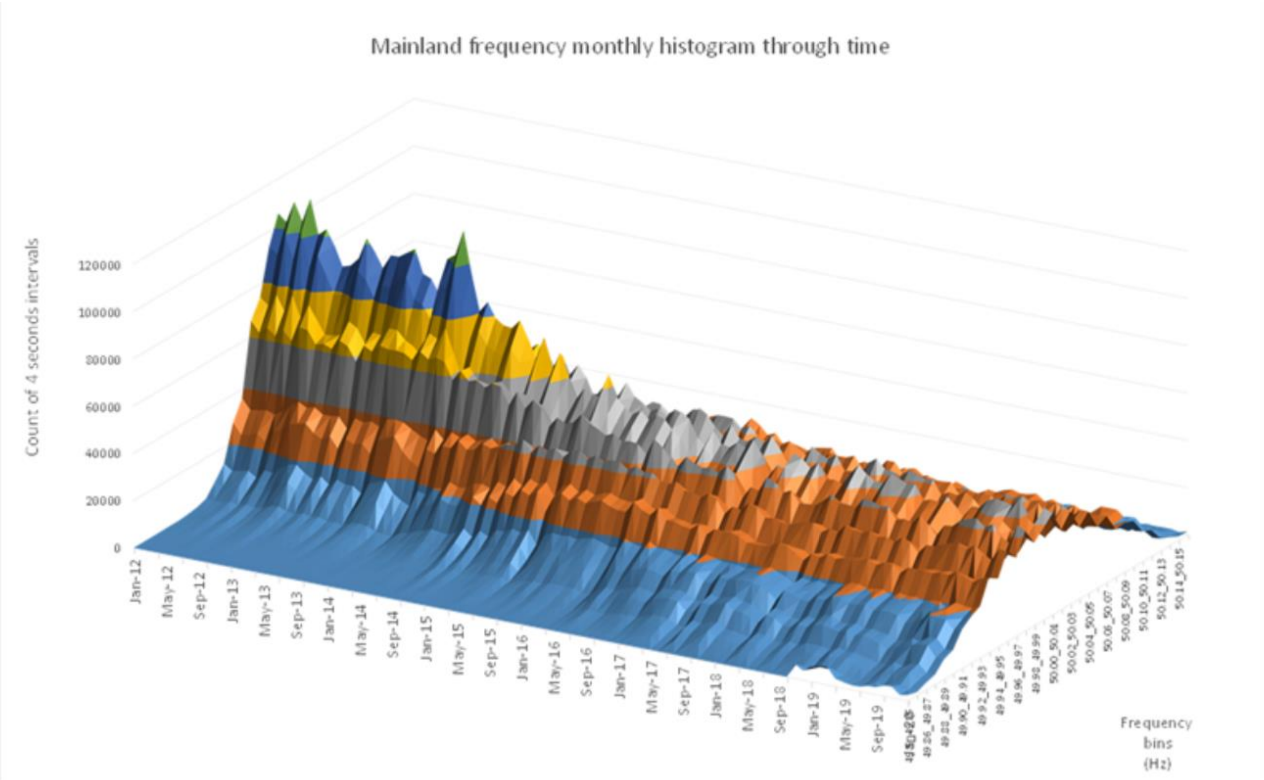

Figure 40 Mainland frequency distribution from January 2012 to December 2019 Source: AEMO

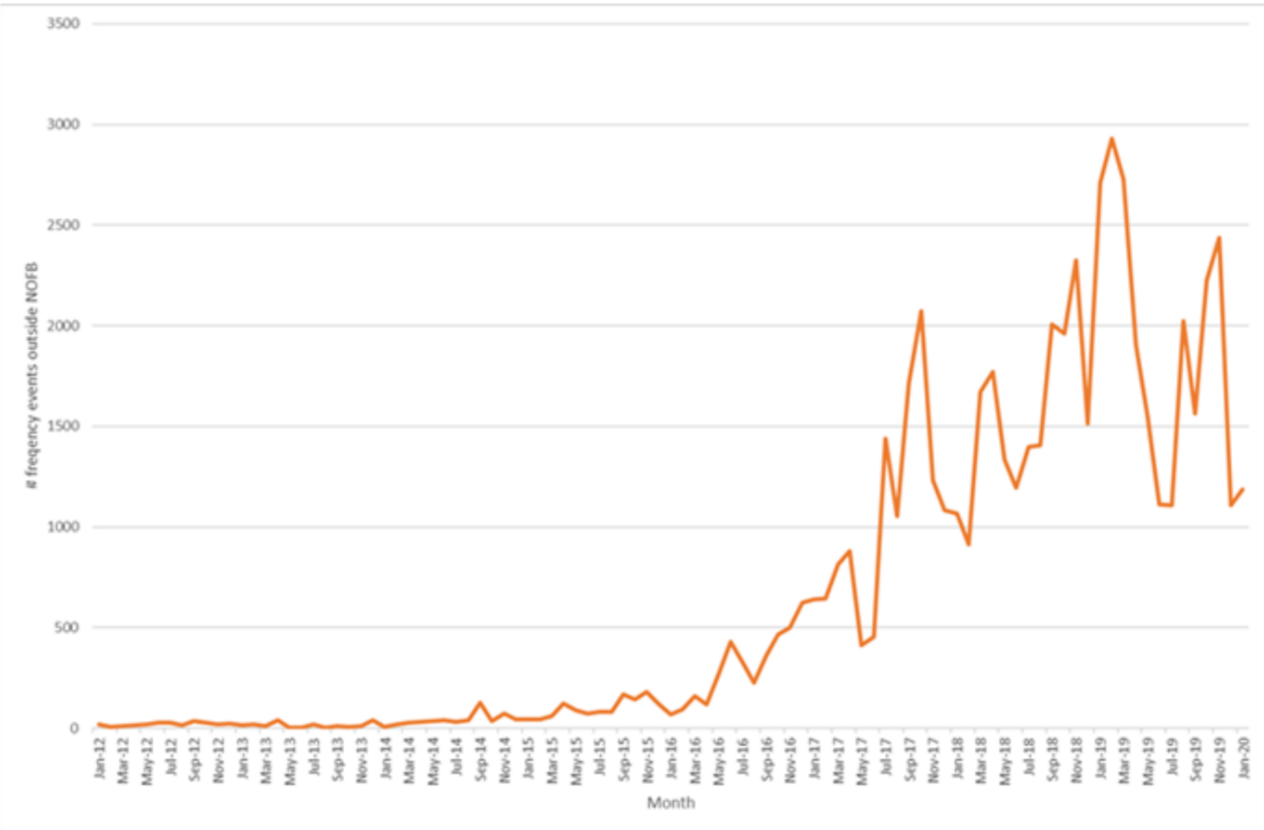

Figure 41 Number of frequency events outside NOFB. Source: AEMO

6 Conclusions

DIgSILENT Pacific has been engaged by AEMO to investigate the impact of large ramps on the frequency control in the National Electricity Market (NEM). For this investigation we have produced a detailed model of the AGC control and the energy dispatch system and an aggregate model of the power system response. We tuned this model with historical records of AGC system controller outputs and power system frequency. We then adjusted the power system model to reflect the 2025 generation mix, and applied ramps based on projections for 2025 data. The key conclusions from the analysis are as follows:

- AGC response both in the model and the measurements shows that the AGC acts to effectively correct frequency deviations, as is expected.

- AGC open loop model shows good correlation with measurement.

- AGC closed loop response shows that there are more intra-dispatch interval changes in generation than modelled in our load. Our model takes a generation profile and varies it only according to five-minute dispatch plus AGC response, whereas the frequency measurement includes impacts of intra-dispatch generation and load.

- In recent times the frequency variations exceed the NOFB boundaries more often. This triggers contingency FCAS response. Inspection of measured frequency suggests that the operation of fast and slow FCAS services can add to the variability of the frequency in the NOFB. This appears to be because, while Contingency FCAS triggers are well-defined, the way that contingency FCAS response is removed following its operation is not managed very effectively in the market. We recommend more work to investigate the impact of contingency FCAS response on the NOFB performance.

- AEMO has provided some synthesised ramp data for 2025, which considers 13GW of VRE. The data shows maximum five-minute ramp of 1690 MW and maximum three-minute ramp of approximately 1200 MW. Mean ramps are close to zero and represent the vast majority of cases. The third-standard deviation of 5-minute ramp data has magnitude of approximately 420 MW.

- More than 99.7% of ramps are within 420 MW[4] over five minutes. For these ramps, it would be reasonable to expect the frequency to operate within the NOFB. With the current levels of PFC, simulations suggest a 420 MW ramp would cause a frequency excursion beyond NOFB. For ramps of 420 MW or less, simulations suggest an increase of PFC of approximately 33% on current levels (1.95 GVA to 2.6 GVA) would allow the frequency excursions to be controlled within the NOFB.

- Likewise, for a 420 MW ramp, for the case studied, increasing regulation FCAS levels from 186 MW to 240 MW (a 29% increase) would allow the ramp to be controlled within the normal operating frequency band. We note that AEMO has been increasing the regulation FCAS levels, and that this generally confirms the reduction in frequency excursions beyond the NOFB.

- There is a trade-off between the level of AGC response and the level of PFC enabled. This is partly an economic trade-off and partly technical, as in the case of the extreme ramps. Optimising the split between AGC and PFC is beyond the scope of this report but could be explored using this model.

- Considering the maximum ramp levels:

    - Both three and five-minute maximum ramp levels exceeded single credible contingencies in their impact on frequency excursion, if levels of PFC similar to current levels are used. A significant increase in PFC is required to improve frequency control.

    - Ramps of these magnitudes should preferably be treated like contingency events and managed through contingency FCAS. While wind and solar variability were largely considered a NOFB issue, as ramp size increases, these large ramps will affect contingency FCAS more.

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[4] *Following corrections of anomaly in synthesised data, 99.7% of ramps were less than 407 MW rather than the 420 MW studied. The difference in results is unlikely to be material.*

Management of these large ramps through contingency FCAS is likely to be more economic than trying to manage these events within NOFB and is justified by the low probability of the maximum ramp levels.

- Additionally, the studies and other information provided by AEMO identified that other factors may also influence the frequency performance of the NEM. These could include:
  - An increase in price-sensitive non-scheduled loads and generation
  - The effect of cloud shading on roof-top solar (for example, as a storm-front approaches an urban area with high density of solar rooftop generation)
  - Seasonal variability in the amount of enabled PFC
  - Variability in the technology types enabled for regulation FCAS, associated with different performance characteristics, as well as
  - Performance of different contingency FCAS providers, especially when the frequency returns to the NOFB.

Because of the complexity of frequency response, and the many factors contributing to it, the results in this report should be considered as indicative rather than definitive – other factors in addition to the ramp sizes will affect the quantities of PFC and AGC required.

References

[1] AEMO, "Automatic Generation Control - A basic description of the AGC Application as it is currently employed in the NEM (Version 3.0)," 2015.

[2] AEMO, "Regulation FCAS changes - June update," 2019.

Appendix A Power System Model

Appendix A.1 Overall power system model

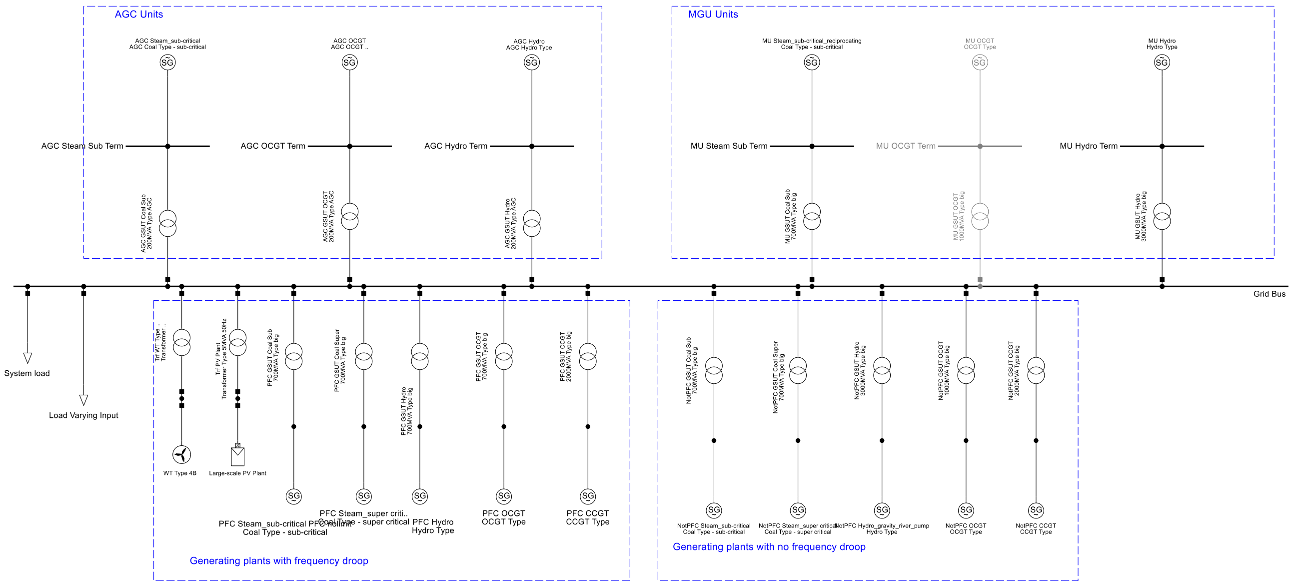

Figure A. 1 – Power system model in PowerFactory

Appendix A.2 Model development and tuning

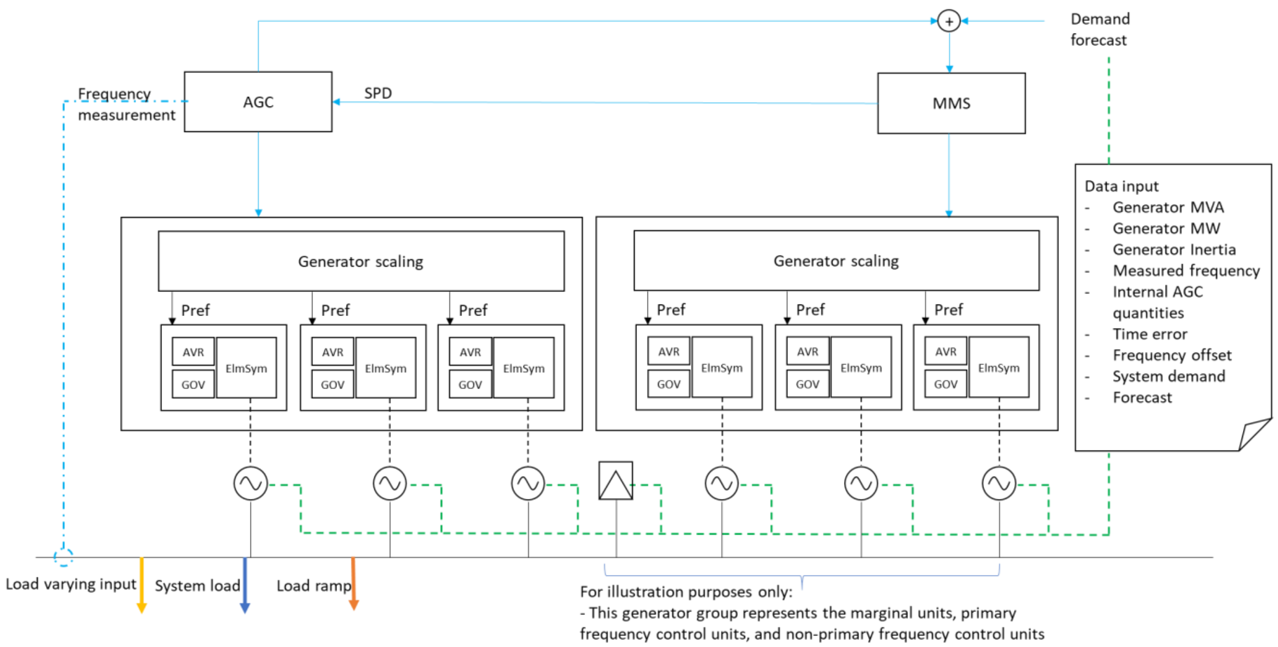

Figure A. 2 – Closed loop system illustration showing the major controller blocks including AGC and MMS

Appendix A.3 Automatic Generation Control (AGC)

AGC_multigen control:

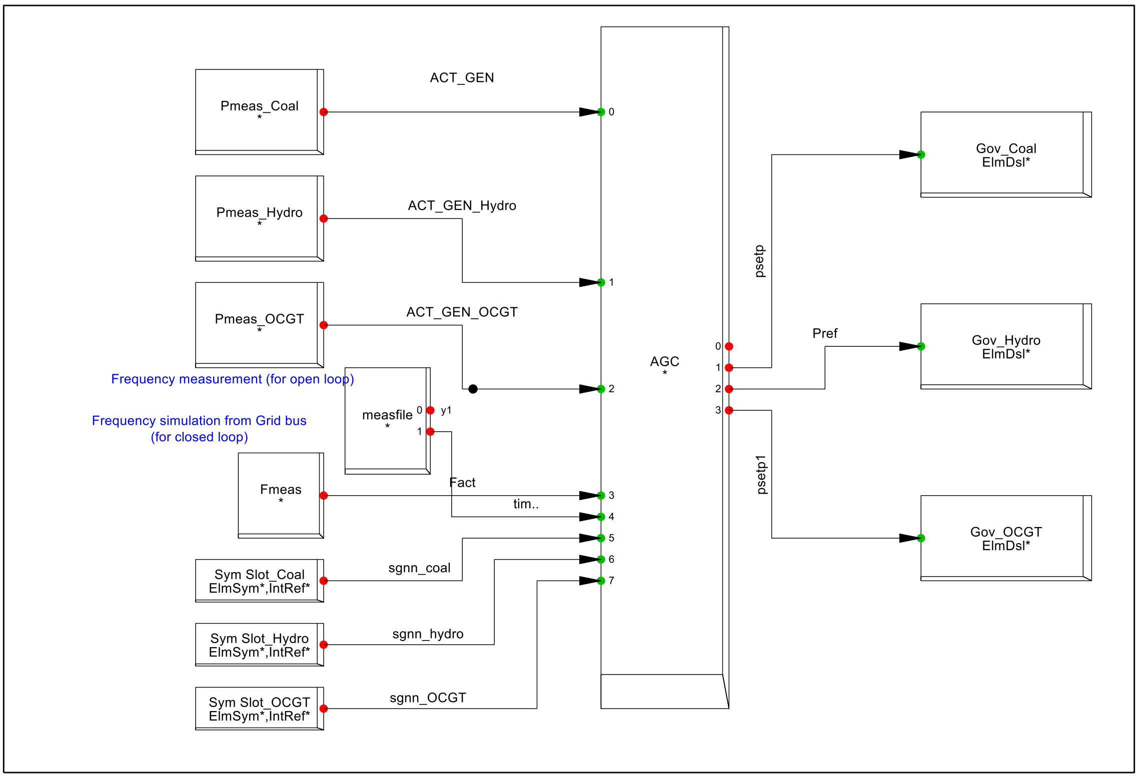

Figure A. 3 – AGC composite model in PowerFactory for connecting load flow objects and the dynamic controllers

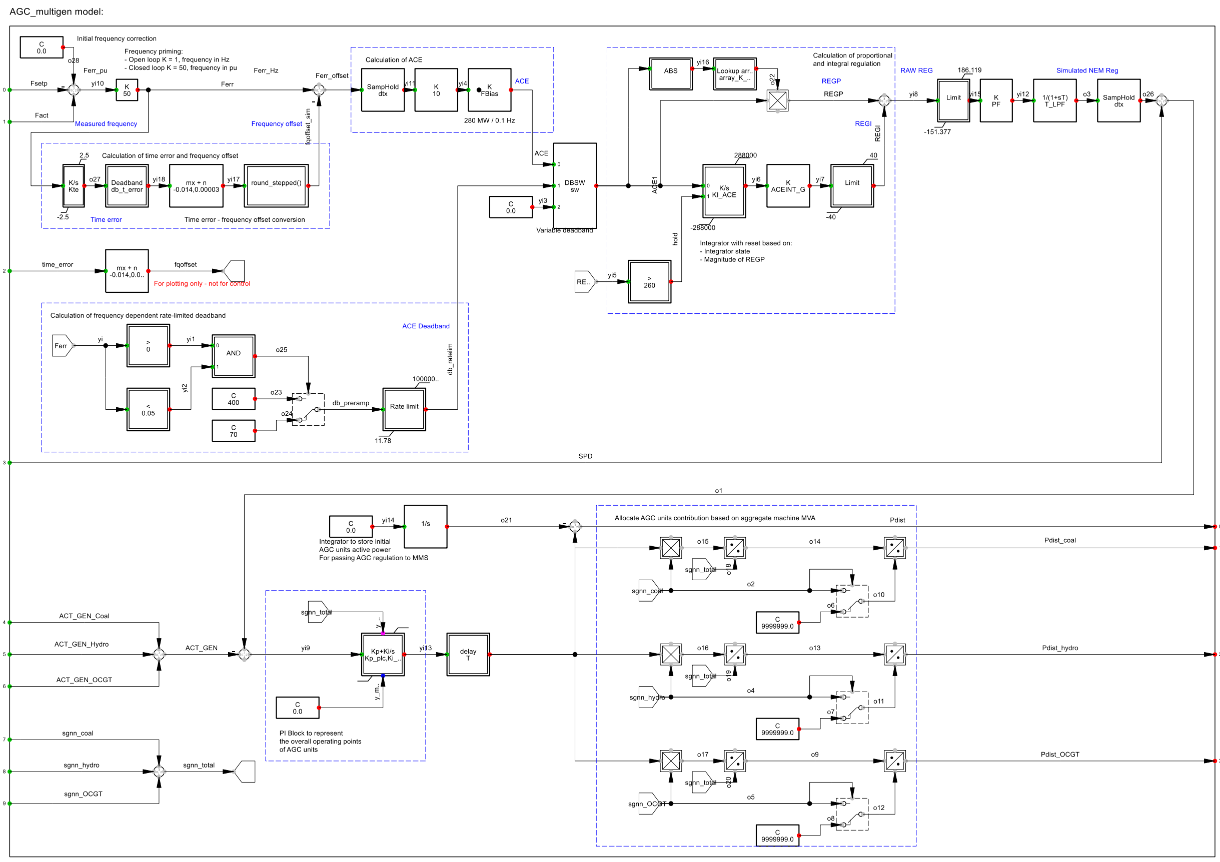

Figure A. 4 – AGC model, annotated with descriptions on functional blocks (blue boxes) and measurement points (blue texts)

The AGC contains the following main functional blocks:

- **Initial frequency correction**

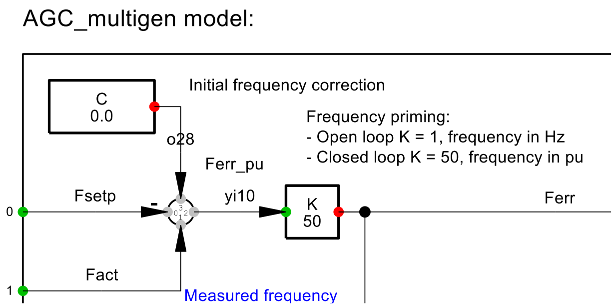

Figure A. 5 – Initial frequency correction as a constant input to the frequency summing junction

At the beginning of the AGC model, a constant block has been added to provide correction to the frequency level at the beginning of the simulation, as PowerFactory dynamic simulation will initialise the frequency based on a load flow calculation with the assumption the system will converge with system frequency of 50 Hz.

- **Time error and frequency offset calculation block**

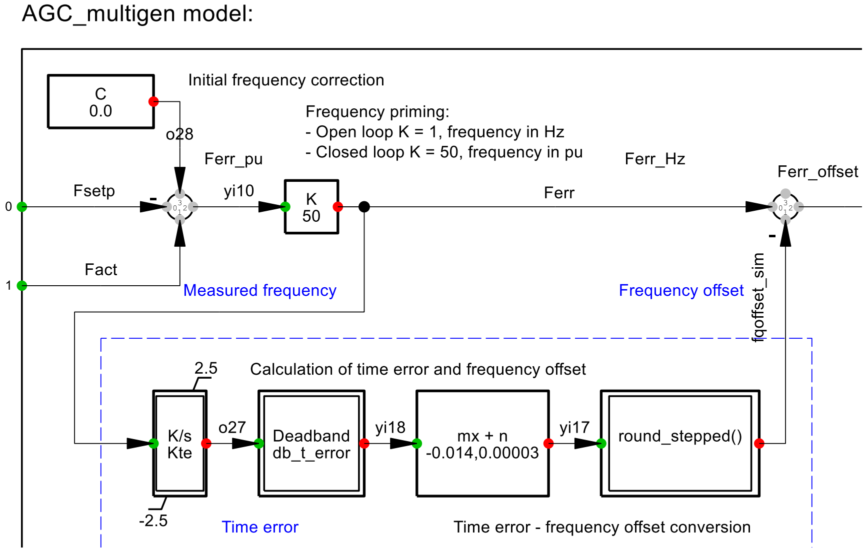

Figure A. 6 – Time error and frequency offset calculation block

The time error is calculated by integrating the frequency error over time. There is a deadband for blocking time error of less than 0.5 seconds and there is a limit for time error correction of 2.5 seconds. The processed time error is converted into frequency offset and the offset is discretised to the nearest 1 mHz, as shown in Figure A. 7.

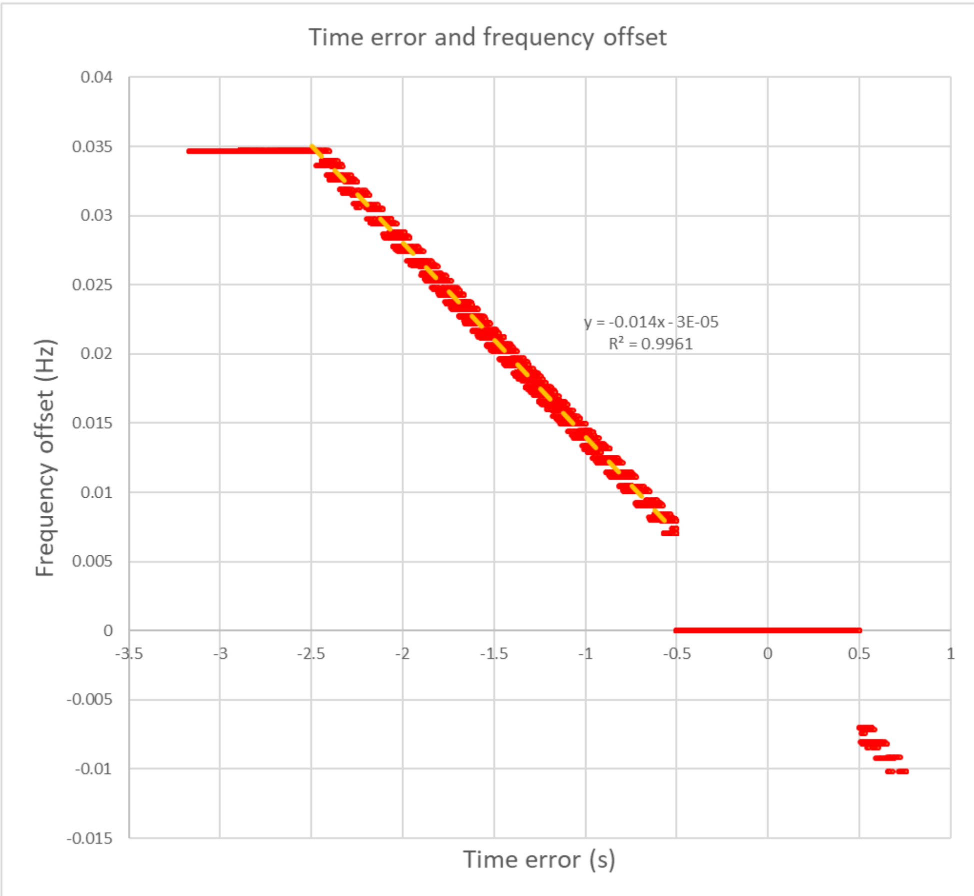

Figure A. 7 – Time error to frequency conversion characteristic

The slope of the conversion gradient was determined based on the 24-hour period on 1 August 2019.

The frequency offset is subtracted from the frequency error before being passed to the ACE calculation block.

- **ACE calculation block**

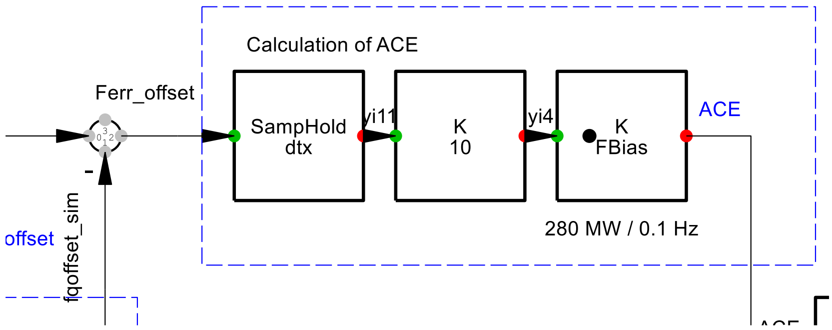

Figure A. 8 – ACE calculation block

The ACE calculation box has been implemented based on the AEMO document describing the calculation of the ACE from the corrected frequency error [1]. The functional blocks convert the frequency error to an equivalent MW error referred to as Area Control Error (ACE).

- **ACE frequency dependent rate-limited deadband block**

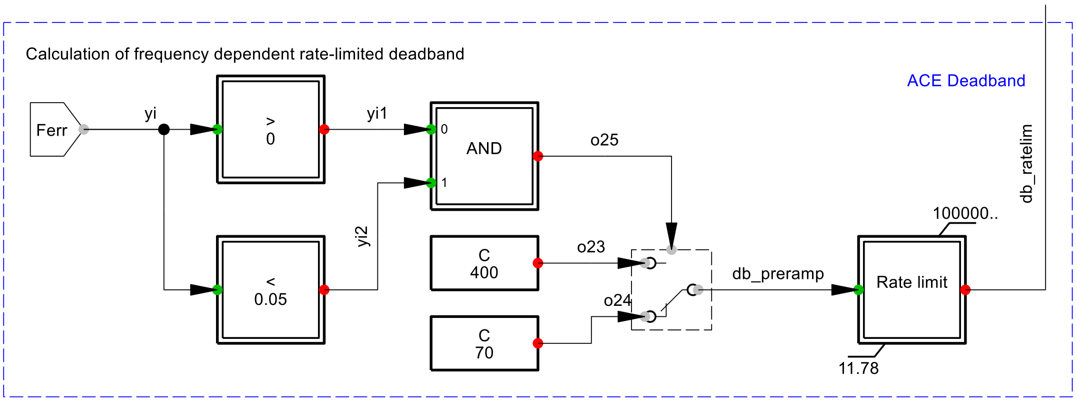

Figure A. 9 – Frequency dependent rate-limited deadband calculation block

The ACE signal is passed through a variable deadband where the ACE threshold is varied between 400 MW and 70 MW depending on the frequency error magnitude. The deadband variation is instantaneous when transitioning from 70 MW to 400. The transition from 400 MW to 70 MW is ramp limited within 28 seconds (11.78 MW / s).

- **PI regulation block**

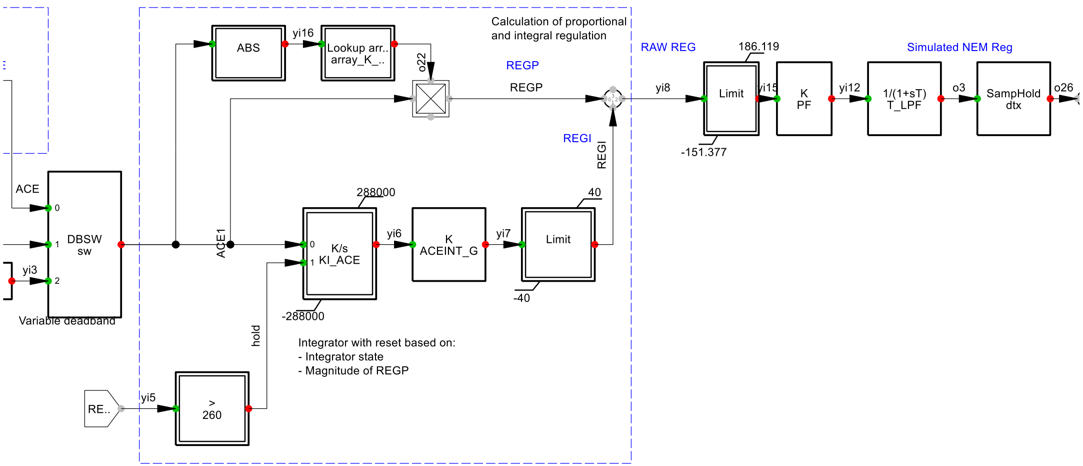

Figure A. 10 – ACE proportional and integral regulation block

The processed ACE signal is then used by the PI regulation functional block. The main features of this block are as follows:

- Tiered proportional gain for various levels of ACE

  The thresholds and gains are tabulated in Table A. 1.

Table A. 1 – ACE operational threshold and proportional gain

ACE Threshold	ACE	ACE Gain
Static deadband	<=70	0
ACE Normal	<210	0.55
ACE Assist	<400	0.65
ACE Emergency	>400	0.8

- Integrator that resets when the processed ACE is 0 and proportional regulation (REGP) exceeds 260 MW

The sum of the integral and proportional regulation is called raw regulation (RAW REG) and this signal is then filtered with a lag block with a time constant of 32 seconds.

- **Block for representing the overall operating conditions for AGC units block**

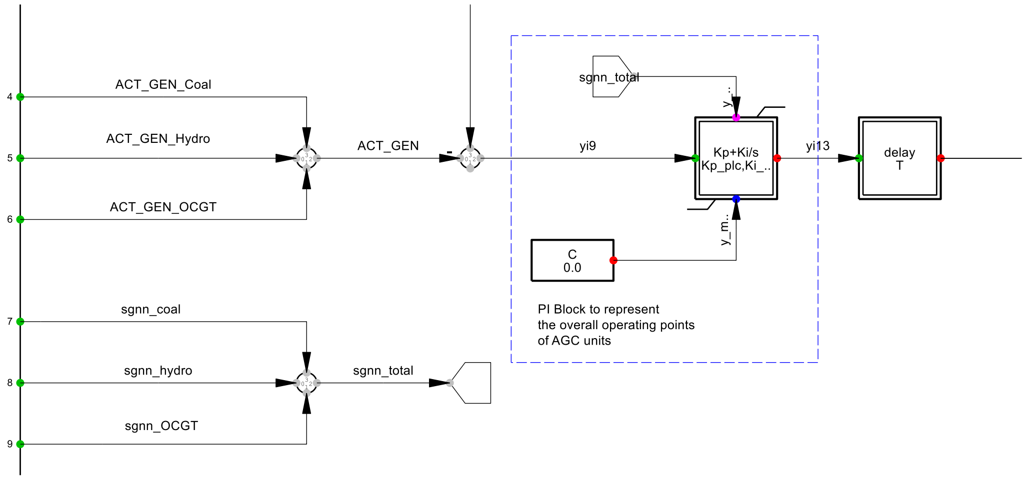

Figure A. 11 – PI block to represent the state of the overall AGC units

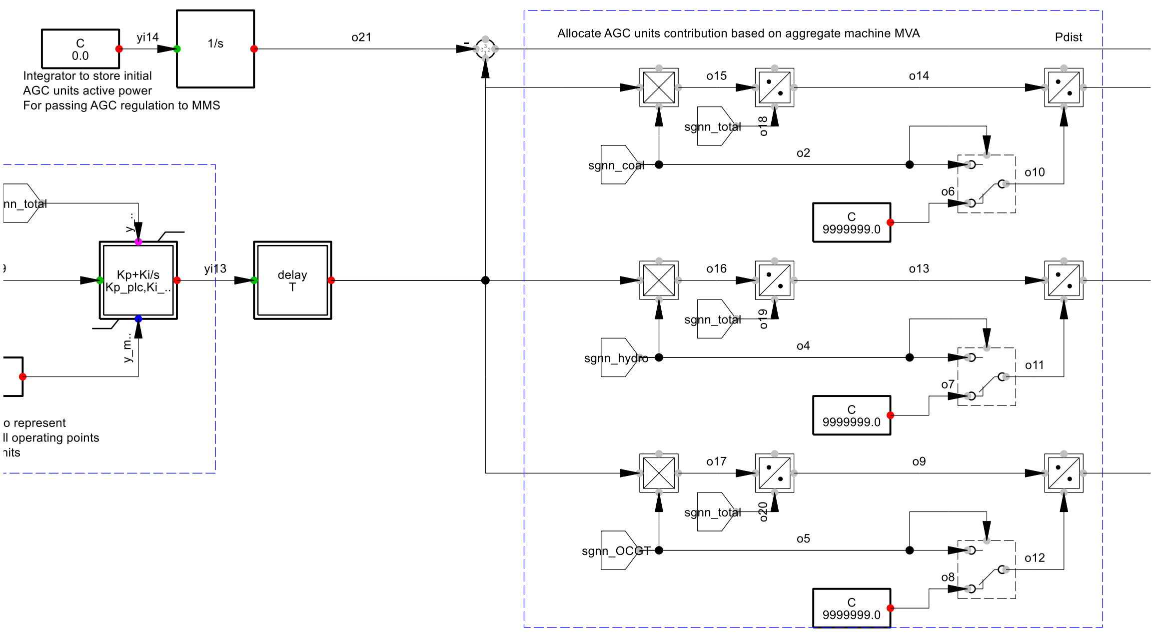

Figure A. 12 – AGC generator setpoint allocation block

The output of the AGC is the additional active power required to provide a certain degree of frequency regulation every four seconds. This active power will be added on top of the base load or operating points of the aggregated AGC units. Thus, to simulate the base operating level of the AGC units, a PI block has been used to represent the state of the collective AGC units.

The total AGC active power level represented by the PI block is then allocated into the three AGC units based on the rating of each machine.

These blocks do not necessarily mimic the actual operation of the pulse controller applied for the AGC units due to the limitation of market dispatch data and also due to the utilisation of aggregated NEM model.

The output of these blocks is injected into the AGC generators governor active power setpoint.

Table A. 2 – AGC Model parameters

Name	Value	Unit	Description
KI_ACE	0.000278	[s]	ACE integrator gain
ACEINT_G	-2	[-]	ACE integral regulation gain
PF	1	[-]	Participation factor
dtx	4	[s]	Sample and hold cycle
Kp_plc	0	[pu]	AGC unit representation proportional gain
Ki_plc	0.01	[pu]	AGC unit representation integral gain
FBias	280	[MW/Hz]	ACE frequency bias
T	0	[s]	Time delay for AGC unit setpoint
T_LPF	32	[s]	Lag block time constant
sw	2	[-]	Variable deadband activation block
Kte	0.019231	[pu]	Time error integral gain
db_t_error	0.5	[Hz]	Time error deadband

Table A. 3 – ACE Model parameter – Proportional ACE gain lookup table

Index	K_AGC_X	K_AGC_Y
0	0	-0.55
1	69.9999	-0.55
2	70	-0.55
3	209.9999	-0.55
4	210	-0.65
5	399.9999	-0.65
6	400	-0.8
7	1000000	-0.8

Appendix A.4 Market Management System (MMS)

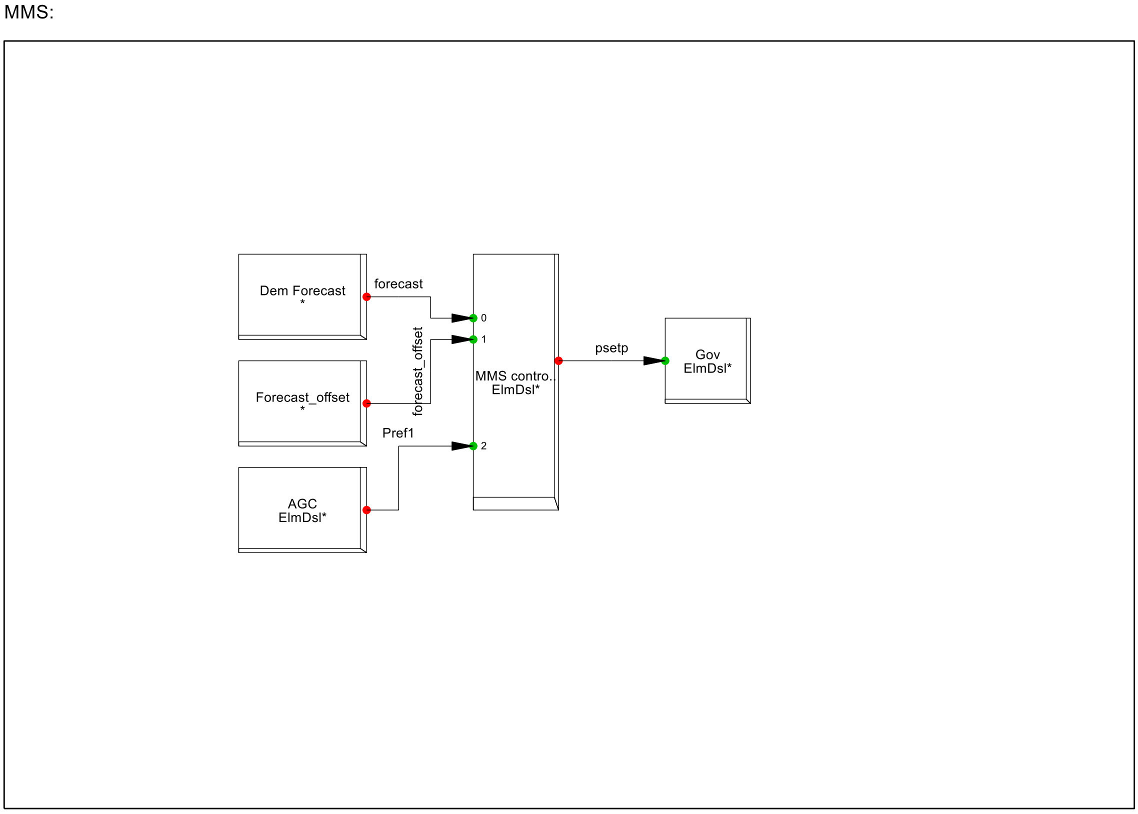

Figure A. 13 – MMS Composite block for connecting AGC and forecast signals to the MMS and marginal unit governor model

MMS common model:

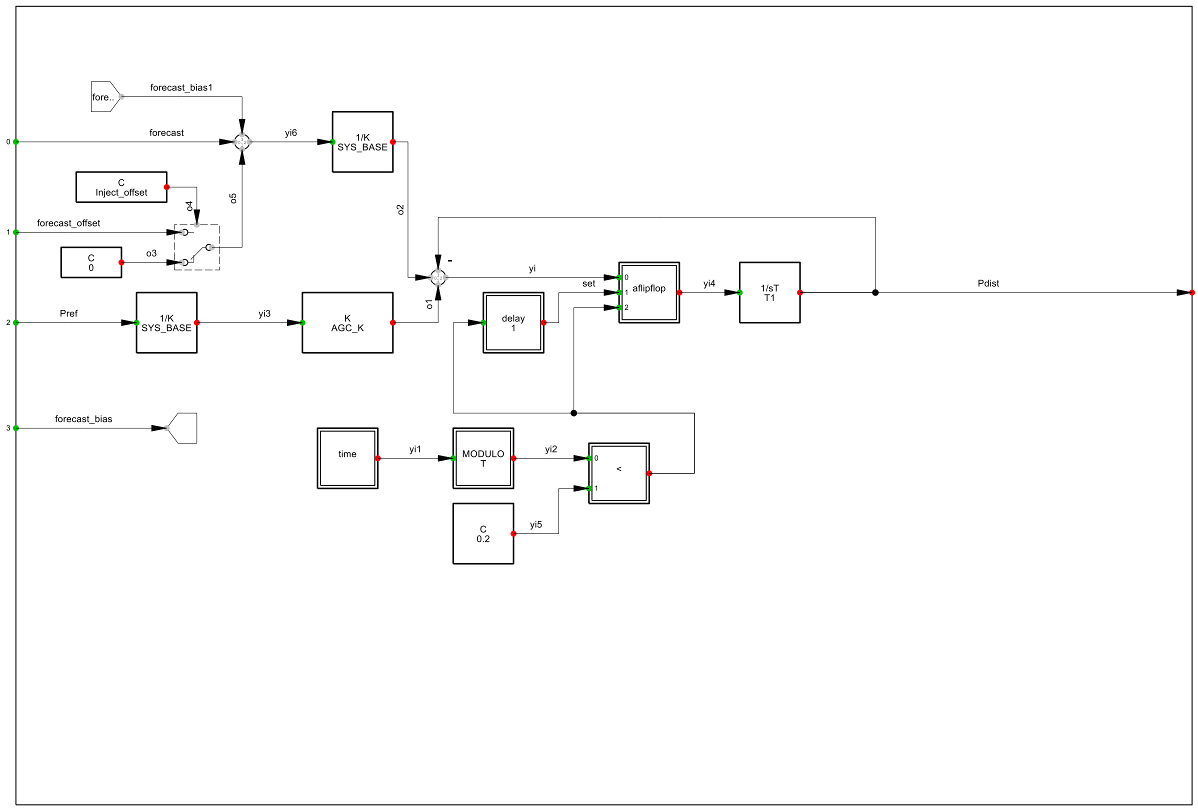

Figure A. 14 – MMS model for ramping marginal generator active power setpoint

Table A. 4 – MMS model parameters

Name	Value	Unit	Description
SYS_BASE	3900	[MVA]	Marginal unit combined rating
T	300	[s]	MMS 5 minute ramp clock
T1	300	[s]	MMS 5 minute ramp clock
AGC_K	1	[pu]	AGC contribution factor to demand forecast
Inject_offset	1	[-]	Enable flag for injecting forecast increase to base level forecast

Appendix A.5 Synchronous Machine Models

SYM Frame_no droop: Synchronous Machine Signal Interconnections

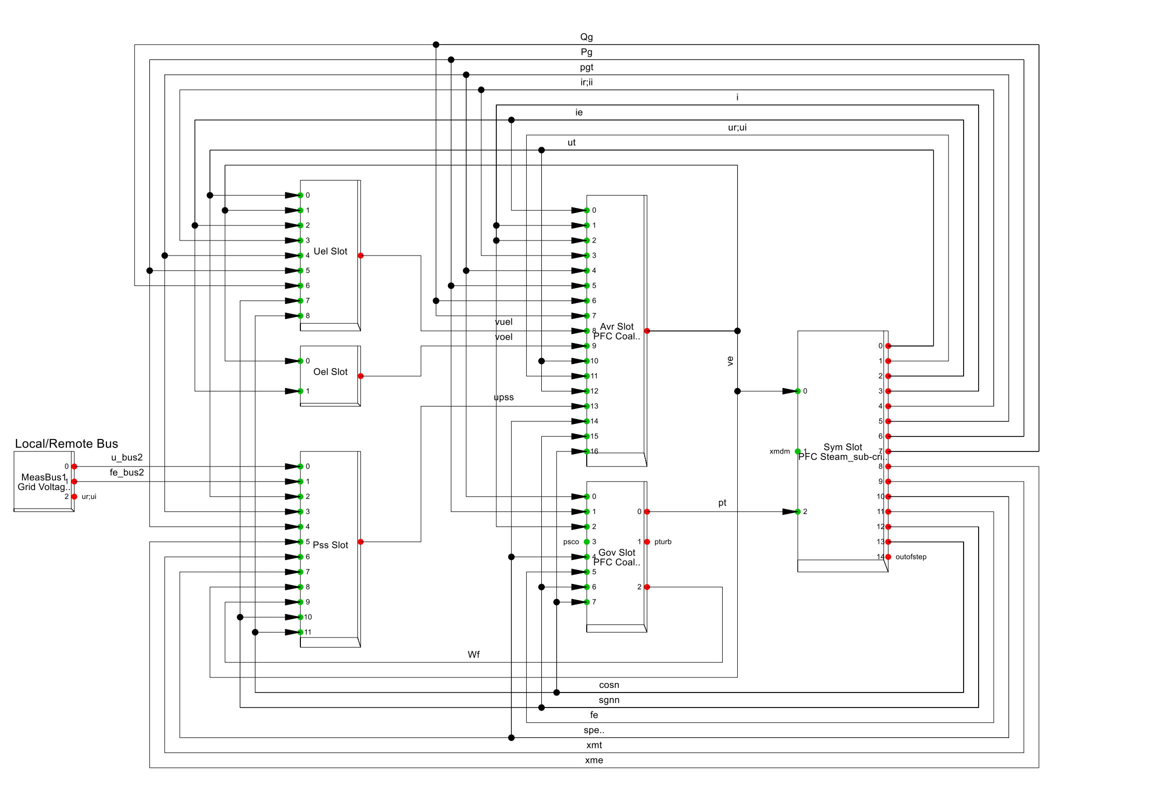

Figure A. 15 – Synchronous machine composite model for connecting inter-controller signals (AVR, governor and machine model) for all synchronous generators

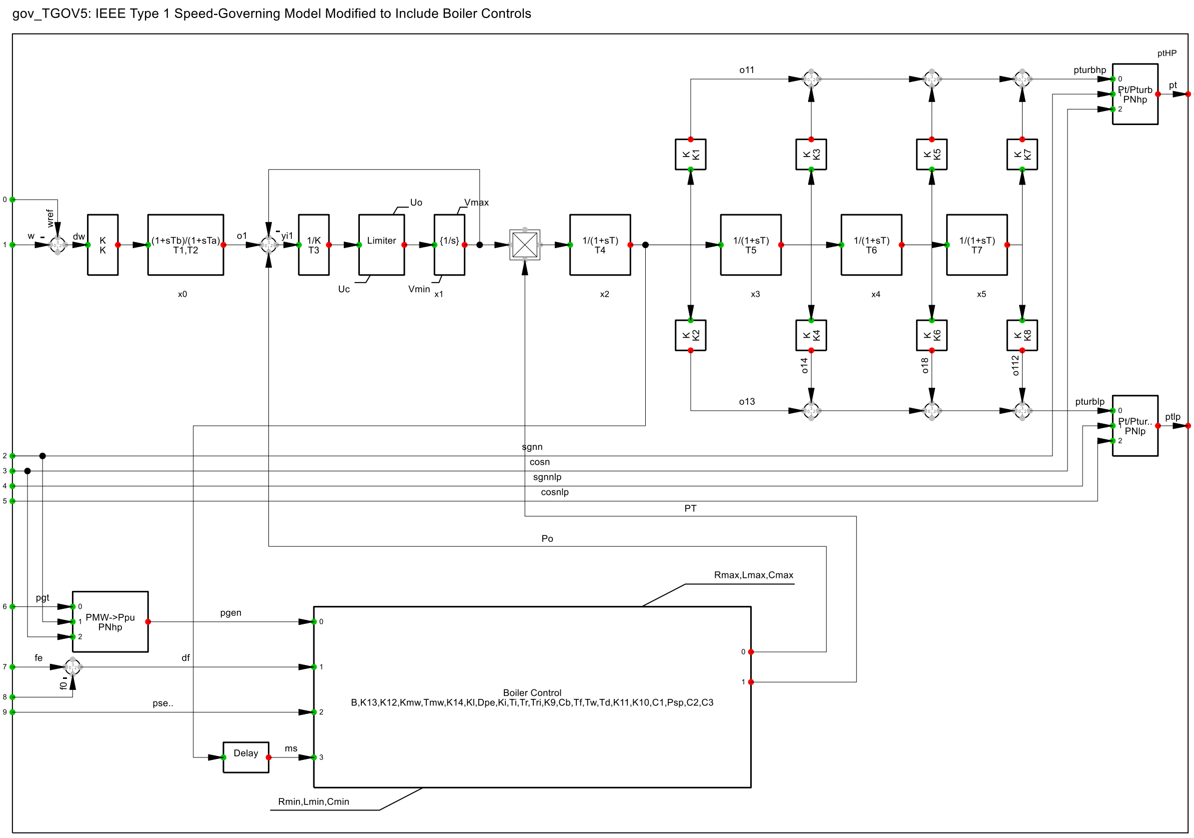

Figure A. 16 – Subcritical and supercritical coal governor model (TGOV5)

Table A. 5 – TGOV5 governor parameters for subcritical generators

TGOV5 - Subcritical units	**Value**					
Name	**PFC**	**Non PFC**	**Marginal Unit (If enabled)**	**AGC unit (if enabled)**	**Unit**	**Description**
K	20	0	0	0	[p.u.]	Controller Gain
T1	0.1	0.1	0.1	0.1	[s]	Governor Time Constant
T2	0	0	0	0	[s]	Governor Derivative Time Constant
T3	0.3	0.3	0.3	0.3	[s]	Servo Time Constant
K1	0.3	0.3	0.3	0.3	[p.u.]	High Pressure Turbine Factor
K2	0	0	0	0	[p.u.]	High Pressure Turbine Factor
T5	15	15	15	15	[s]	Intermediate Pressure Turbine Time Constant
K3	0.3	0.3	0.3	0.3	[p.u.]	Intermediate Pressure Turbine Factor
K4	0	0	0	0	[p.u.]	Intermediate Pressure Turbine Factor
T6	0.3	0.3	0.3	0.3	[s]	Medium Pressure Turbine Time Constant
K5	0.4	0.4	0.4	0.4	[p.u.]	Medium Pressure Turbine Factor
K6	0	0	0	0	[p.u.]	Medium Pressure Turbine Factor
T4	0.2	0.2	0.2	0.2	[s]	High Pressure Turbine Time Constant
T7	0	0	0	0	[s]	Low Pressure Turbine Time Constant
K7	0	0	0	0	[p.u.]	Low Pressure Turbine Factor
K8	0	0	0	0	[p.u.]	Low Pressure Turbine Factor

TGOV5 - Subcritical units	Value					
Name	PFC	Non PFC	Marginal Unit (If enabled)	AGC unit (if enabled)	Unit	Description
PNhp	0	0	0	0	[MW]	HP Turbine Rated Power(=0->PNhp=PgnnHp)
PNlp	0	0	0	0	[MW]	LP Turbine Rated Power(=0->PNlp=Pgnnlp)
B	20	0	0	0	[pu]	The frequency bias for load reference control.
K13	0	0	0	0	[-]	The gain between MW demand and pressure set point.
K12	0.01	0.01	0.01	0.01	[-]	The gain for pressure error bias.
Kmw	1	1	1	1	[-]	The gain of the MW transducer (0 or 1).
Tmw	5	5	5	5	[s]	The MW transducer time constant
K14	0.1	0.1	0.1	0.1	[-]	Inverse of load reference servomotor time constant (= 0.0 if load reference does not change).
Kl	0	0	0	0	[-]	The feedback gain from the load reference (0 or 1).
Dpe	0.1	0.1	0.1	0.1	[pu of Pres]	The deadband in the pressure error signal for load reference control
Ki	0.1	0.1	0.1	0.1	[pu]	The controller integral gain.
Ti	12	12	12	12	[s]	The controller proportional lead time constant
Tr	12	12	12	12	[s]	The controller rate lead time constant
Tri	2	2	2	2	[s]	The inherent lag associated with lead TR
K9	0.01	0.01	0.01	0.01	[-]	The adjustment to the pressure drop coefficient as a function of drum pressure.
Cb	150	150	150	150	[s]	The boiler storage time constant
Tf	5	5	5	5	[s]	The fuel and air system time constant
Tw	5	5	5	5	[s]	Fuel flow time constant
Td	3	3	3	3	[s]	The time delay in the fuel supply system
K11	0	0	0	0	[-]	The gain of anticipation signal from load demand.
K10	0	0	0	0	[-]	The gain of anticipation signal from main stream flow.
C1	0.0001	0.0001	0.0001	0.0001	[-]	The pressure drop coefficient.
Psp	0.95	0.95	0.95	0.95	[pu]	The initial throttle pressure set point.
C2	0.1	0.1	0.1	0.1	[-]	The gain for the pressure error bias.
C3	0	0	0	0	[-]	The adjustment to the pressure set point.
Uc	-0.2	-0.2	-0.2	-0.2	[p.u./s]	Valve Closing Time
Vmin	0	0	0	0	[p.u.]	Minimum Gate Limit
Rmin	-0.004	-0.004	-0.004	-0.004	[pu/s]	The load reference negative rate of change limit
Lmin	-0.4	-0.4	-0.4	-0.4	[pu]	The minimum load reference.
Cmin	0.3	0.3	0.3	0.3	[pu]	The minimum controller output.
Uo	0.2	0.2	0.2	0.2	[p.u./s]	Valve Opening Time
Vmax	1.15	1.15	1.15	1.15	[p.u.]	Maximum Gate Limit

TGOV5 - Subcritical units	Value					
Name	PFC	Non PFC	Marginal Unit (If enabled)	AGC unit (if enabled)	Unit	Description
Rmax	0.004	0.004	0.004	0.004	[pu/s]	The load reference positive rate of change limit
Lmax	1	1	1	1	[pu]	The maximum load reference.
Cmax	1.15	1.15	1.15	1.15	[pu]	The maximum controller output.

Table A. 6 – TGOV5 governor parameters for supercritical generators

TGOV5 - Supercritical units	Value			
Name	PFC	Non PFC	Unit	Description
K	25	0	[p.u.]	Controller Gain
T1	0.04	0.04	[s]	Governor Time Constant
T2	0	0	[s]	Governor Derivative Time Constant
T3	0.1	0.1	[s]	Servo Time Constant
K1	0.3	0.3	[p.u.]	High Pressure Turbine Factor
K2	0	0	[p.u.]	High Pressure Turbine Factor
T5	25	25	[s]	Intermediate Pressure Turbine Time Constant
K3	0.3	0.3	[p.u.]	Intermediate Pressure Turbine Factor
K4	0	0	[p.u.]	Intermediate Pressure Turbine Factor
T6	0.3	0.3	[s]	Medium Pressure Turbine Time Constant
K5	0.4	0.4	[p.u.]	Medium Pressure Turbine Factor
K6	0	0	[p.u.]	Medium Pressure Turbine Factor
T4	0.2	0.2	[s]	High Pressure Turbine Time Constant
T7	0	0	[s]	Low Pressure Turbine Time Constant
K7	0	0	[p.u.]	Low Pressure Turbine Factor
K8	0	0	[p.u.]	Low Pressure Turbine Factor
PNhp	0	0	[MW]	HP Turbine Rated Power(=0->PNhp=PgnnHp)
PNlp	0	0	[MW]	LP Turbine Rated Power(=0->PNlp=Pgnnlp)
B	25	0	[pu]	The frequency bias for load reference control.
K13	0	0	[-]	The gain between MW demand and pressure set point.
K12	0.01	0.01	[-]	The gain for pressure error bias.
Kmw	1	1	[-]	The gain of the MW transducer (0 or 1).
Tmw	5	5	[s]	The MW transducer time constant
K14	1	1	[-]	Inverse of load reference servomotor time constant (= 0.0 if load reference does not change).
Kl	0	0	[-]	The feedback gain from the load reference (0 or 1).
Dpe	0.025	0.025	[pu of Pres]	The deadband in the pressure error signal for load reference control
Ki	0.1	0.1	[pu]	The controller integral gain.
Ti	6.012	6.012	[s]	The controller proportional lead time constant
Tr	12	12	[s]	The controller rate lead time constant
Tri	2	2	[s]	The inherent lag associated with lead TR

TGOV5 - Supercritical units	Value			Description
Name	**PFC**	**Non PFC**	**Unit**	
K9	0.01	0.01	[-]	The adjustment to the pressure drop coefficient as a function of drum pressure.
Cb	50	50	[s]	The boiler storage time constant
Tf	5	5	[s]	The fuel and air system time constant
Tw	5	5	[s]	Fuel flow time constant
Td	3	3	[s]	The time delay in the fuel supply system
K11	0	0	[-]	The gain of anticipation signal from load demand.
K10	0	0	[-]	The gain of anticipation signal from main stream flow.
C1	0.0001	0.0001	[-]	The pressure drop coefficient.
Psp	0.95	0.95	[pu]	The initial throttle pressure set point.
C2	1	1	[-]	The gain for the pressure error bias.
C3	0	0	[-]	The adjustment to the pressure set point.
Uc	-0.1	-0.1	[p.u./s]	Valve Closing Time
Vmin	0	0	[p.u.]	Minimum Gate Limit
Rmin	-0.002	-0.002	[pu/s]	The load reference negative rate of change limit
Lmin	-0.4	-0.4	[pu]	The minimum load reference.
Cmin	0.3	0.3	[pu]	The minimum controller output.
Uo	0.1	0.1	[p.u./s]	Valve Opening Time
Vmax	1.15	1.15	[p.u.]	Maximum Gate Limit
Rmax	0.002	0.002	[pu/s]	The load reference positive rate of change limit
Lmax	1	1	[pu]	The maximum load reference.
Cmax	1.15	1.15	[pu]	The maximum controller output.

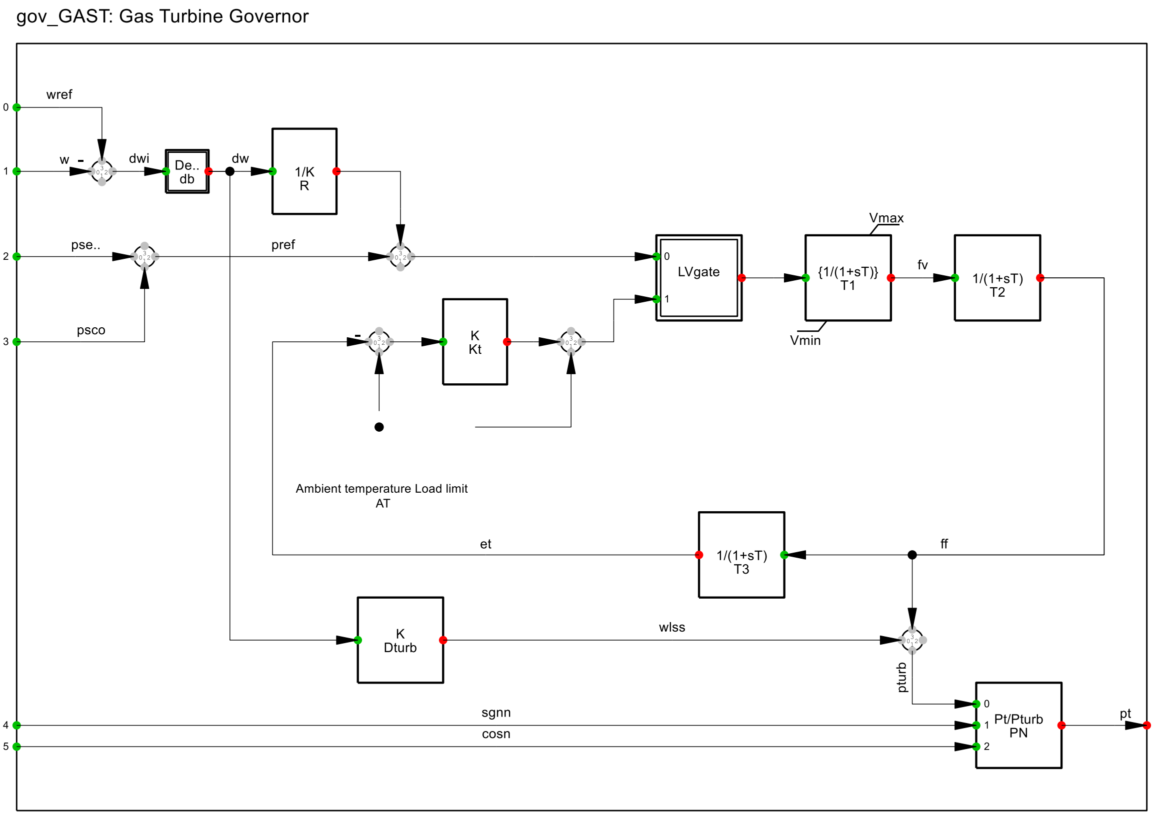

Figure A. 17 – Gas generating unit (CCGT and OCGT) governor model (gov_GAST)

Table A. 7 – gov_GAST governor parameters for OCGT generators

gov_GAST - OCGT	**Value**			
Name	**PFC**	**Non PFC**	**Unit**	**Description**
R	0.05	0.05	[pu]	Speed Droop
db	0.003	1		
T1	0.4	0.4	[s]	Controller Time Constant
T2	0.1	0.1	[s]	Actuator Time Constant
T3	300	3	[s]	Compressor Time Constant
AT	1	1	[pu]	Ambient Temperature Load Limit
Kt	2	2	[pu]	Turbine Factor
Dturb	0	0	[pu]	frictional losses factor pu
PN	0	0	[MW]	Turbine Rated Power(=0->PN=Pgnn)
Vmin	0	0	[pu]	Controller Minimum Output
Vmax	1	1	[pu]	Controller Maximum Output

Table A. 8 – gov_GAST governor parameters for CCGT generators

gov_GAST - CCGT	**Value**			
Name	**PFC**	**Non PFC**	**Unit**	**Description**
R	0.05	0.05	[pu]	Speed Droop
db	0.003	1		

gov_GAST - CCGT	Value			
Name	PFC	Non PFC	Unit	Description
T1	0.4	0.4	[s]	Controller Time Constant
T2	0.1	0.1	[s]	Actuator Time Constant
T3	300	300	[s]	Compressor Time Constant
AT	1	1	[pu]	Ambient Temperature Load Limit
Kt	2	2	[pu]	Turbine Factor
Dturb	0	0	[pu]	frictional losses factor pu
PN	0	0	[MW]	Turbine Rated Power(=0->PN=Pgnn)
Vmin	0	0	[pu]	Controller Minimum Output
Vmax	1	1	[pu]	Controller Maximum Output

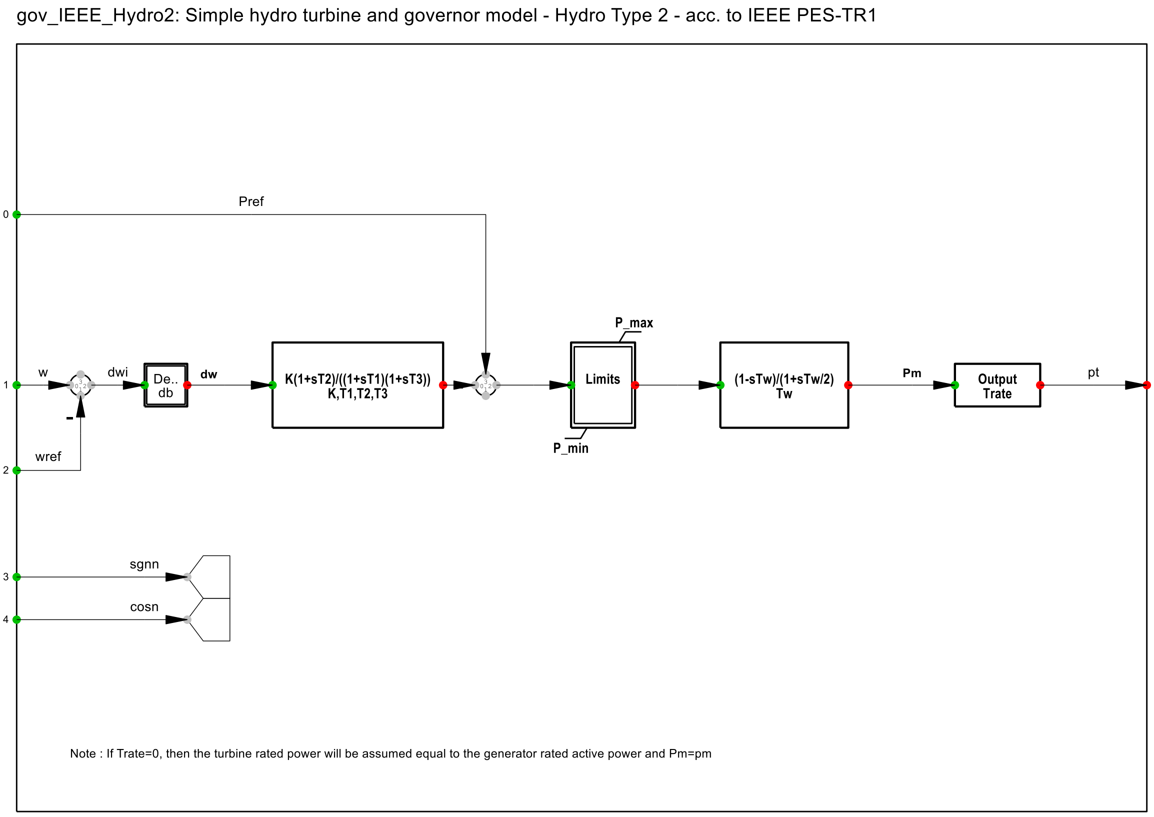

Figure A. 18 – Hydro governor model (gov_IEEE_Hydro2)

Table A. 9 – gov_IEEE_Hydro2 governor parameters for hydro generators

gov_IEEE_Hydro2	Value					
Name	PFC	Non PFC	Marginal Unit (If enabled)	AGC unit (if enabled)	Unit	Description
db	0.003	1	1	1		
Trate	0	0	0	0	[MW]	Turbine rated power (0 => Trate=Prated of SG)

gov_IEEE_Hydro2	Value					
Name	PFC	Non PFC	Marginal Unit (If enabled)	AGC unit (if enabled)	Unit	Description
K	25	0	25	0	[p.u.]	Governor gain
T1	1	1	1	1	[s]	Governor lag time constant
T2	0.5	0.5	0.5	0.5	[s]	Governor lead time constant
T3	1.5	1.5	1.5	1.5	[s]	Gate actuator time constant
Tw	3	3	3	3	[s]	Water starting time
P_min	0	0	0	0	[p.u.]	Gate minimum
P_max	1.1	1.1	1.1	1.1	[p.u.]	Gate maximum

gov_BBGOV1: Braun Boveri Governor Model

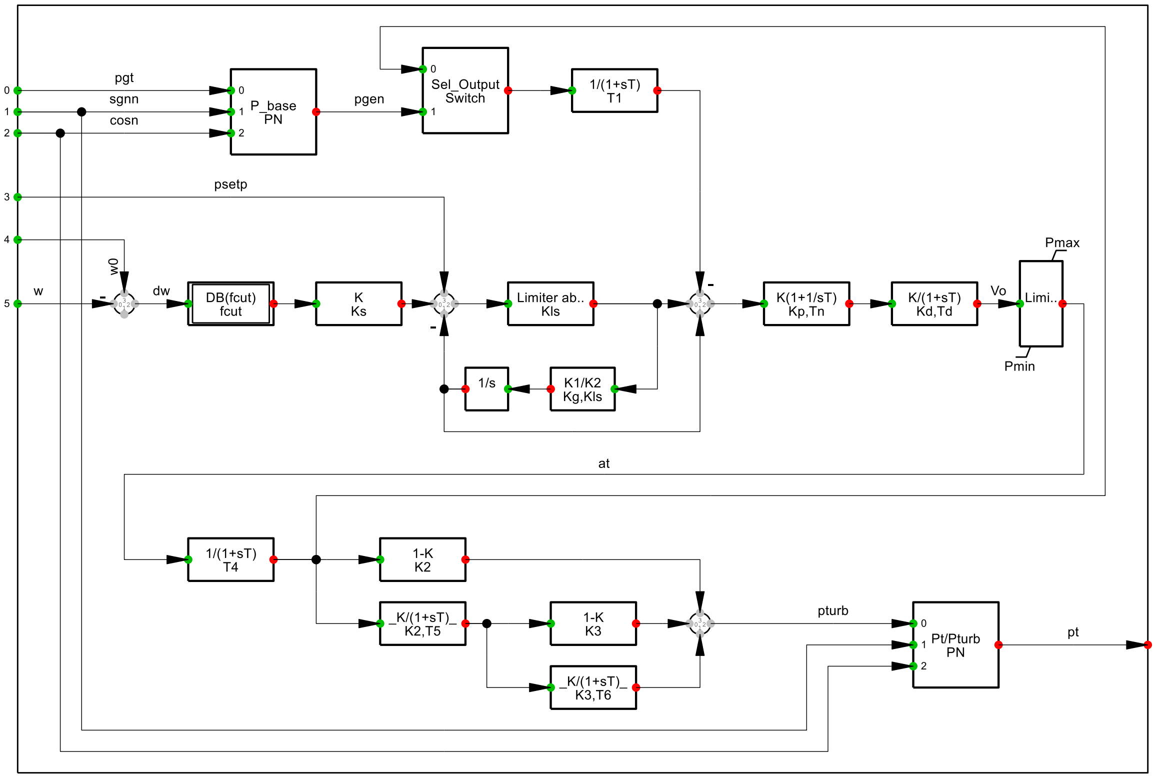

Figure A. 19 – Subcritical and supercritical coal governor model with adjustable frequency deadband (BBGOV1)

Table A. 10 – BBGOV1 governor parameters for subcritical generators with adjustable deadband

BBGOV1 - Subcritical - For simulations with higher deadband			
Name	Value	Unit	Description
fcut	0.0003	[pu]	Dead Band of Speed
Ks	25	[pu]	Speed Gain
Kls	0.1	[pu]	PI Controller Limiter

BBGOV1 - Subcritical - For simulations with higher deadband			
Name	**Value**	**Unit**	**Description**
Kg	0.01	[pu]	PI Gain
Kp	1	[pu]	Controller Gain
Tn	10	[s]	Controller Time Constant
Kd	1	[pu]	Second Controller Gain
Td	0.2	[s]	Second Controller Time Constant
T4	1	[s]	High Presure Time constant
K2	0.6	[pu]	Intermediate Pressure Factor
T5	10	[s]	Intermediate Pressure Time constant.
K3	0.3	[pu]	Low Presure Factor
T6	1	[s]	Low Presure Time constant.
PN	0	[MW]	Turbine Rated Power(=0->PN=Pgnn)
Switch	1	[0/1]	Electric Power Selector
T1	5	[s]	Power Feedback Time constant.
Pmin	0	[p.u.]	Minimum Gate Limit.
Pmax	1	[p.u.]	Maximum Gate Limit.

Appendix A.6 Renewable Generator Models

Frame WECC Large-scale PV Plant: Frame for WECC Large-scale Photovoltaic Plant Model

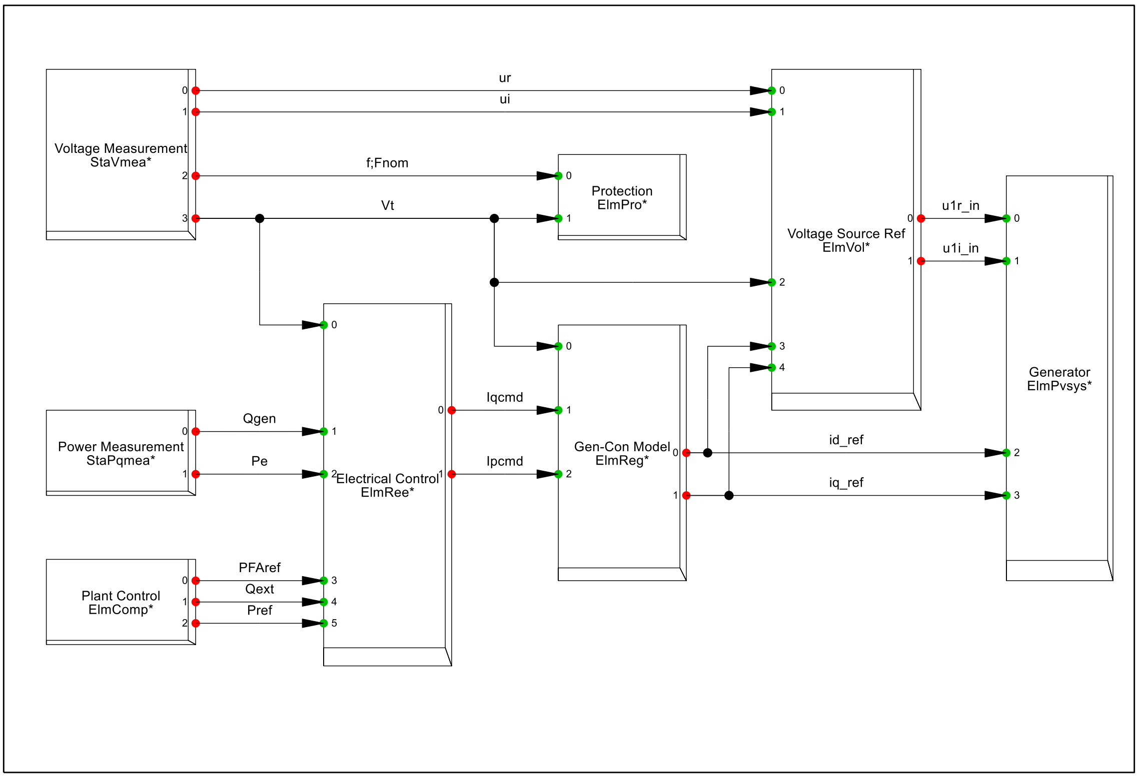

Figure A. 20 – Composite frame of WECC model for large-scale photovoltaic plant model

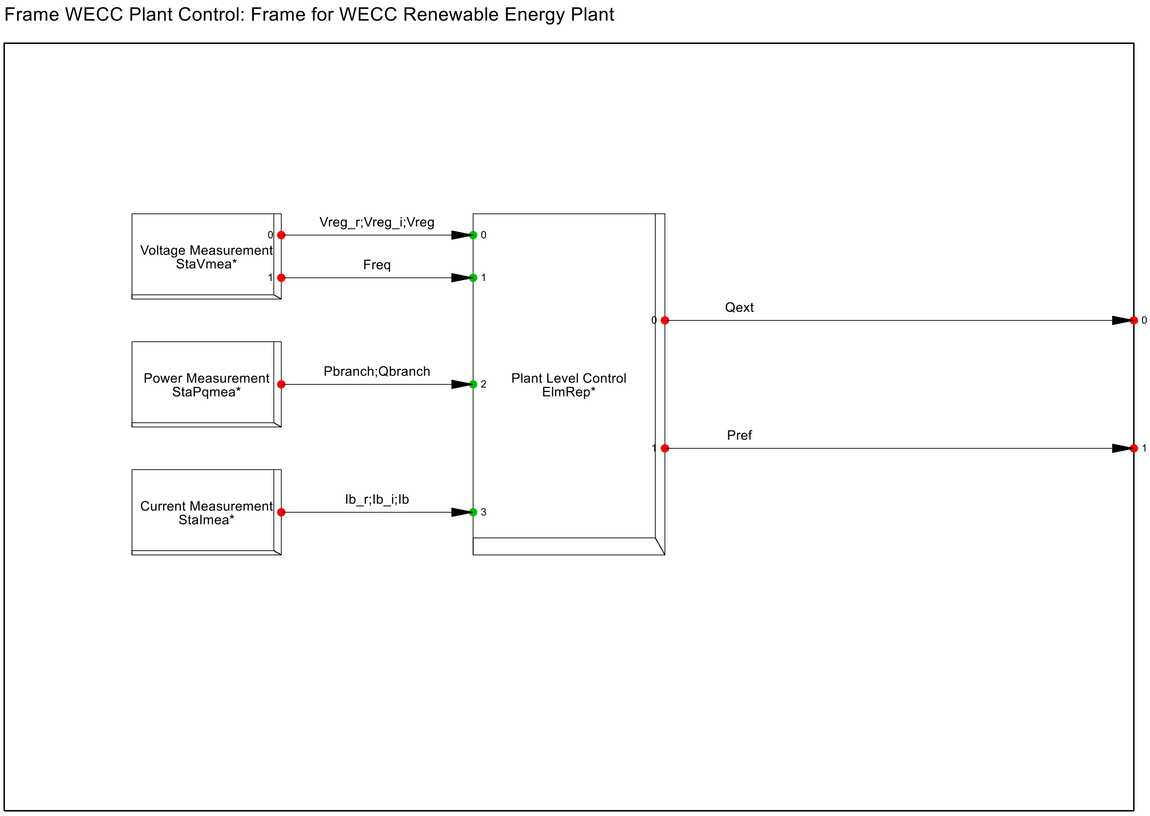

Figure A. 21 – Composite frame of WECC renewable energy plant level control model

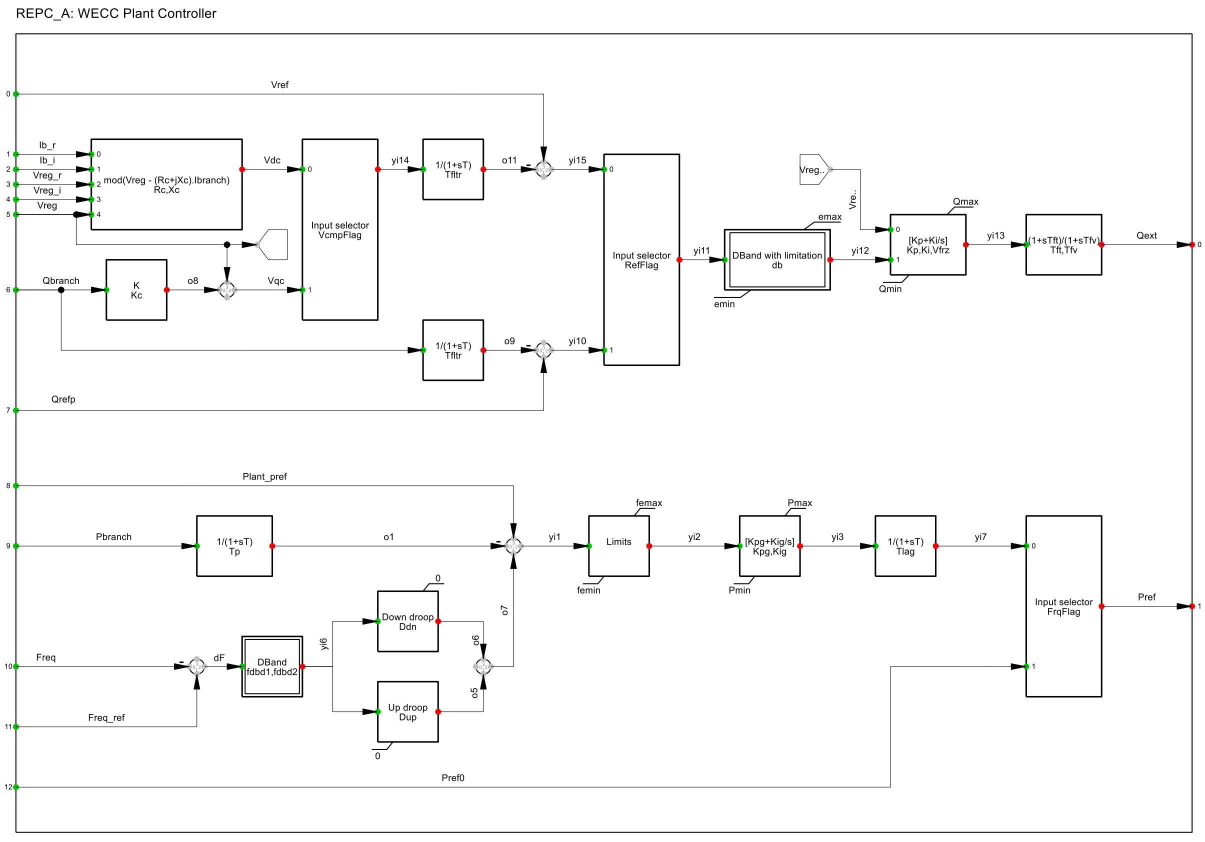

Figure A. 22 – WECC plant controller model (REPCA)

Table A. 11 – Photovoltaic plant control model (REPCA) parameters

Name	Value	Unit	Description
Rc	0	[p.u.]	Line drop compensation resistance
Xc	0	[p.u.]	Line drop compensation reactance
Tfltr	0.02	[s]	Voltage and reactive power filter time constant
Tp	0.25	[s]	Active power filter time constant
db	0.002	[p.u.]	Deadband in reactive power or voltage control
Kp	1	[p.u./p.u.]	Volt/VAR regulator proportional gain
Ki	5	[p.u./p.u.]	Volt/VAR regulator integral gain
Vfrz	0.7	[p.u.]	Voltage for freezing Volt/VAR regulator integrator
Tft	0	[s]	Plant controller Q output lead time constant
Tfv	0.05	[s]	Plant controller Q output lag time constant
Kc	10	[p.u.]	Reactive droop gain
FrqFlag	1		Active power control: 0 = disabled, 1 = enabled
RefFlag	0		: 0 = reactive power control, 1 = voltage control
VcmpFlag	0		0 = reactive droop, 1 = line drop compensation
fdbd1	-0.003	[p.u.]	Frequency deadband downside

Name	Value	Unit	Description
fdbd2	0.003	[p.u.]	Frequency deadband upside
Ddn	25	[p.u./p.u.]	Down regulation droop gain
Dup	0	[p.u./p.u.]	Up regulation droop gain
Kpg	1.1	[p.u./p.u.]	Real power control proportional gain
Kig	3	[p.u./p.u.]	Real power control integral gain
Tlag	0.1	[s]	Plant controller P output lag time constant
emin	-0.5	[p.u.]	Minimum Volt/VAR error
Qmin	-0.313	[p.u.]	Minimum plant reactive power command
femin	-99	[p.u.]	Minimum power error in droop regulator
Pmin	0	[p.u.]	Minimum plant active power command
emax	0.5	[p.u.]	Maximum Volt/VAR error
Qmax	0.313	[p.u.]	Maximum plant reactive power command
femax	99	[p.u.]	Maximum power error in droop regulator
Pmax	1	[p.u.]	Maximum plant active power command

Table A. 12 – Wind turbine WT4B plant control model (REPCA) parameters

Name	Value	Unit	Description
Rc	0	[p.u.]	Line drop compensation resistance
Xc	0	[p.u.]	Line drop compensation reactance
Tfltr	0.02	[s]	Voltage and reactive power filter time constant
Tp	0.25	[s]	Active power filter time constant
db	0.002	[p.u.]	Deadband in reactive power or voltage control
Kp	1	[p.u./p.u.]	Volt/VAR regulator proportional gain
Ki	5	[p.u./p.u.]	Volt/VAR regulator integral gain
Vfrz	0.7	[p.u.]	Voltage for freezing Volt/VAR regulator integrator
Tft	0	[s]	Plant controller Q output lead time constant
Tfv	0.05	[s]	Plant controller Q output lag time constant
Kc	10	[p.u.]	Reactive droop gain
FrqFlag	1		Active power control: 0 = disabled, 1 = enabled
RefFlag	0		: 0 = reactive power control, 1 = voltage control
VcmpFlag	0		0 = reactive droop, 1 = line drop compensation
fdbd1	-0.003	[p.u.]	Frequency deadband downside
fdbd2	0.003	[p.u.]	Frequency deadband upside
Ddn	25	[p.u./p.u.]	Down regulation droop gain
Dup	0	[p.u./p.u.]	Up regulation droop gain
Kpg	1.1	[p.u./p.u.]	Real power control proportional gain
Kig	3	[p.u./p.u.]	Real power control integral gain
Tlag	0.1	[s]	Plant controller P output lag time constant
emin	-0.5	[p.u.]	Minimum Volt/VAR error
Qmin	-0.313	[p.u.]	Minimum plant reactive power command

Name	Value	Unit	Description
femin	-99	[p.u.]	Minimum power error in droop regulator
Pmin	0	[p.u.]	Minimum plant active power command
emax	0.5	[p.u.]	Maximum Volt/VAR error
Qmax	0.313	[p.u.]	Maximum plant reactive power command
femax	99	[p.u.]	Maximum power error in droop regulator
Pmax	1	[p.u.]	Maximum plant active power command

Appendix B Synthetic Ramp Data

This appendix, provided to us by AEMO, contains a description of the synthetic ramp data, its derivation and subsequent data cleansing. The data used in this report contained the artefactual ramps due to periodic discontinuity in the wind generation profile (described in Appendix B.4) The effect of this data discontinuity was to increase slightly the third standard deviation levels compared with cleansed data. However, the impact on results is not material.

Appendix B.1 Description of ramping data provided to DIgSILENT

Synthetic utility scale solar and wind generation trace based on projected generation build in 2025 and historic whether data are contained in the files:

- Synthetic_All_clean_linear.csv (both wind and solar)
- Synthetic_Wind_cleaned_linear.csv (Wind Only)
- Synthetic_Solar.csv (Solar Only)

The data includes:

A. the aggregate generation of all utility wind and solar farms,
B. the calculated changes in aggregate generation (or "ramps") across a selection of time periods.

Variability in load and behind the meter generation, including rooftop-PV, is not included in the data set.

Appendix B.2 How the raw generation data was derived

AEMO engaged a consultant (in 2019, Weatherzone and Solcast) to develop generation forecasts for existing and future registered semi-scheduled and non-scheduled wind and solar farms for the year 2025, based on the Draft ISP 2020 Central scenario projected build. Generation Megawatt forecasts of generation at 1-minute resolutions were provided for wind farm and solar farm locations across the NEM.

Behind the meter solar, or rooftop PV variation is excluded from the data set, along with any other changes in generation or load.

In developing the synthetic traces, the following assumptions were made:

- A single representative point (latitude/longitude) was used for each farm.
- A year was selected that the weather patterns could be considered characteristic of 2025, where 2025 is considered to be an 'average year' under a global warming scenario. This was selected by identifying recent months with major climate drivers (El Nino, Indian Ocean Dipole) in the neutral phase. The months selected were between November 2016 and October 2017.
- Wind farm modelling:
    - High speed cut out events for wind farms are not modelled.
    - A single wind speed to power curve was assumed across all wind farms.
    - A single wind turbine hub height at 100 m was assumed.
- No temperature impact on generation was modelled.
- No network constraints or market interaction with generation is represented in the data set.

Appendix B.3 Calculations of ramps

The forecast generation for each plant was then aggregated for wind and solar resources separately to provide indicative traces on generation based on resource for calculation of ramps. A ramp is defined as the MW difference in generation between the start and the end of a defined rolling time window with a minimum resolution of 1- minute. Rolling windows of 1-, 3-, 5-, 10-, 15-, 30-, 45-, 60- and 90-minutes were then used to calculate the ramp across each of these time windows. A 5minute ramp of 6MW means there was a 6MW net increase between the generation value 5minutes prior and now, not accounting for the variation within that interval.

Appendix B.4 Data cleaning process.

The raw data contains a periodic discontinuity in the wind generation profile caused concatenating daily weather profiles. This causes an artificial 'ramp' each day.

To remove the artificial ramp the following was done:

- Generation data was removed during the period of 6:30pm – 8:30pm in each day and replaced with a linear interpolation to maintain data continuity.
- Any ramps calculated between 6:45pm - 8:15pm each day was removed entirely to avoid any artificial impacts of the linear interpolation on ramp values.

Appendix B.5 Limitations to application of the data for assessment of frequency control

While any duration change in power balance (seconds to minutes) within each 5-minute interval will affect normal band frequency performance, the available data set is limited to 1-minute resolution. Due to this limitation in temporal resolution, assessment of the impact to NOFB performance will be limited to longer duration variation within each 5-minute interval.