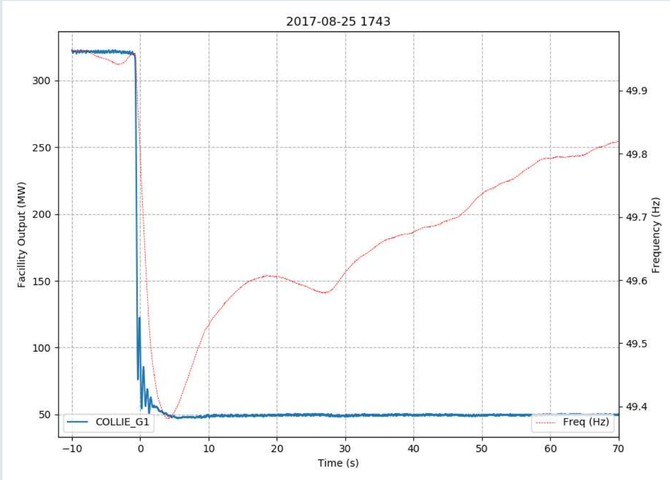
Contingency Frequency Response in the SWIS

Technical Proposal for the PSO-WG
Meeting 3
February 2019

COLLIE G1



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Given the context of the presentation, the plot is predictable: a generation contingency at 17:43:48

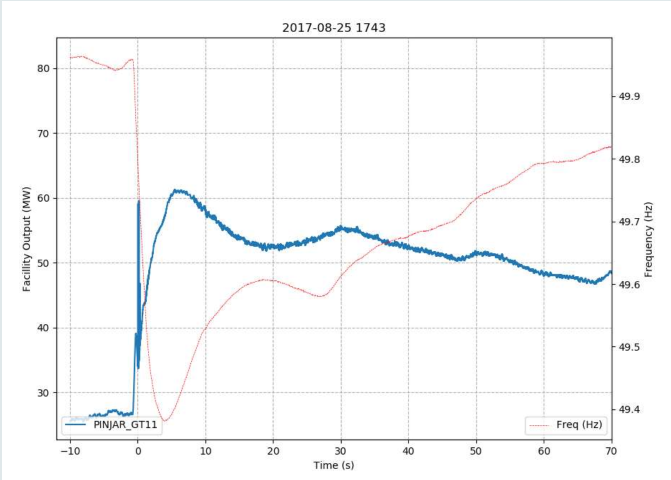
Pre-fault 340 MW

Sudden decline (~1-2s) due to a station fault. Note that the facility does not go to 0 MW

Frequency drops but is arrested at 5-6s, stabilises approximately 20s

Return to normal operating band ~1 minute

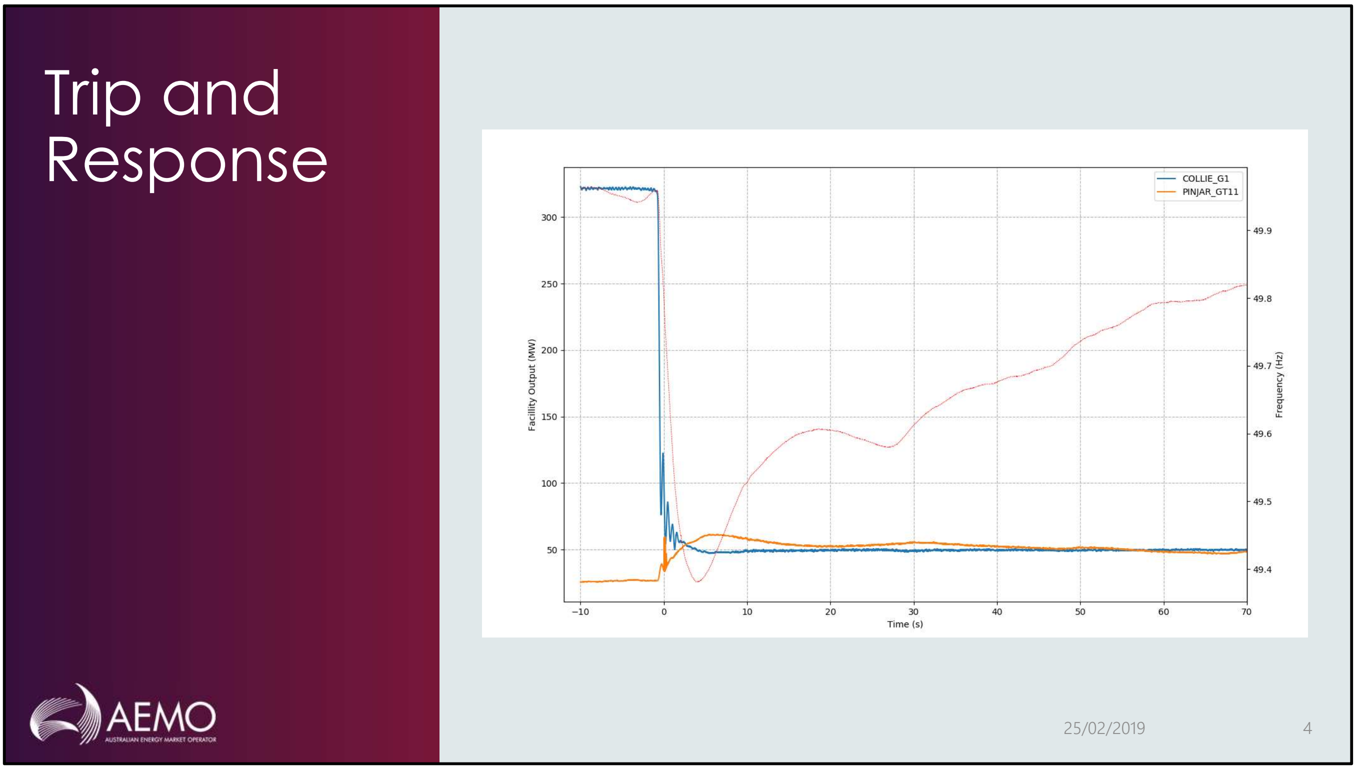
PINJAR GT11



Pre-fault ~25 MW. Unit is synchronised purely for spinning reserve.

Spike and very fast increase @ ~6s, stabilise at 20-30s

Pinjar was used to “catch” the generator trip: machines sit in reserve 24x7 in case of contingencies



Pinjar “only” replaced 35 of ~300 MW; other machines in the fleet made up the rest.

Leaving machines on reserve is a lost MW opportunity.

- Which facilities should provide reserve?
    - Consider both performance and cost
- When does it make sense to start a new machine?
- How can AEMO coordinate across the fleet in real-time?

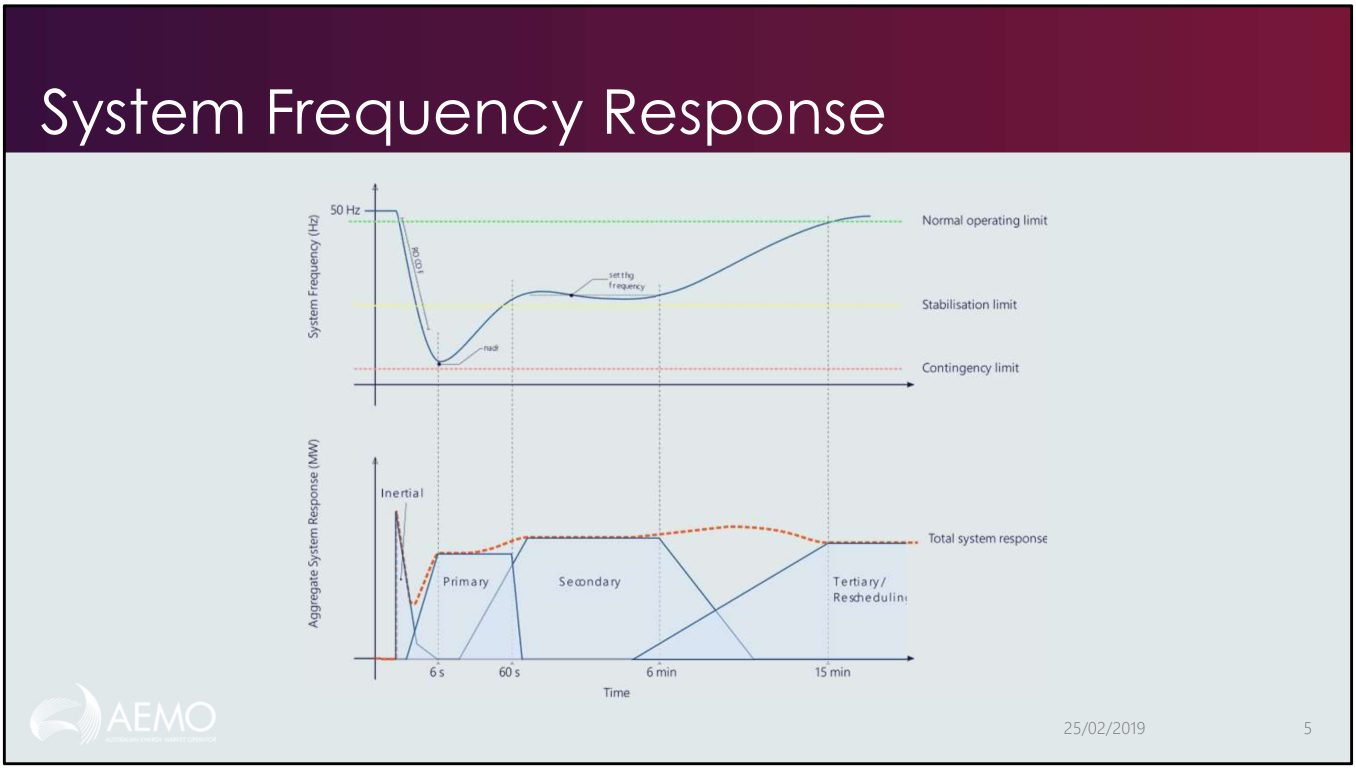
Concept of *co-optimisation*

Not all lost capacity needs to be immediately replaced, but exactly how much?

Not obvious what the correct level of reserve is!

Problem of risk with low probability and extreme consequences – many inputs, limited / unreliable information, limited control moving parts.

Classic “wicked” problem.



So how to we add some structure to manage this problem?

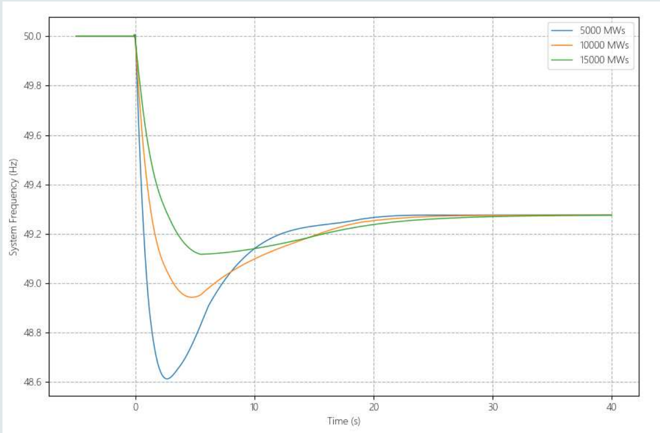
Shared time axis in the plot; indicated timings are approximate.

Three key frequency characteristics to manage:
- ROCOF: load shedding threshold, acceleration fault in sync machines
- Nadir frequency: load shedding threshold
- Settling frequency

- Can break down the response into "Inertial, Primary, Secondary, Tertiary", get back (hopefully) to normal dispatch ~15 minutes.

Not fundamental distinctions, but reflect some physical properties of machines and useful trade-offs to be optimised

Inertial Response



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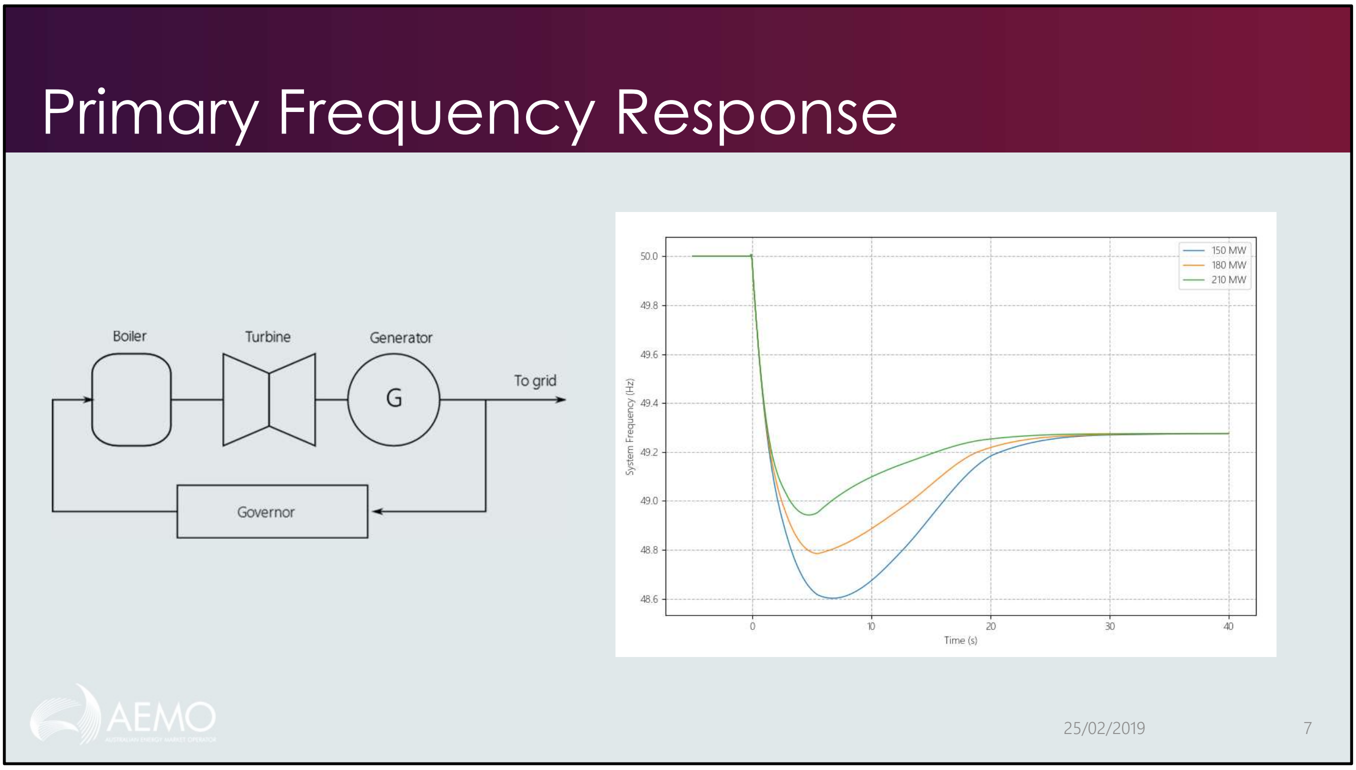
Inertia defines how quickly the frequency changes immediately after a contingency.

Traditionally, inertia is sourced from rotating machinery.

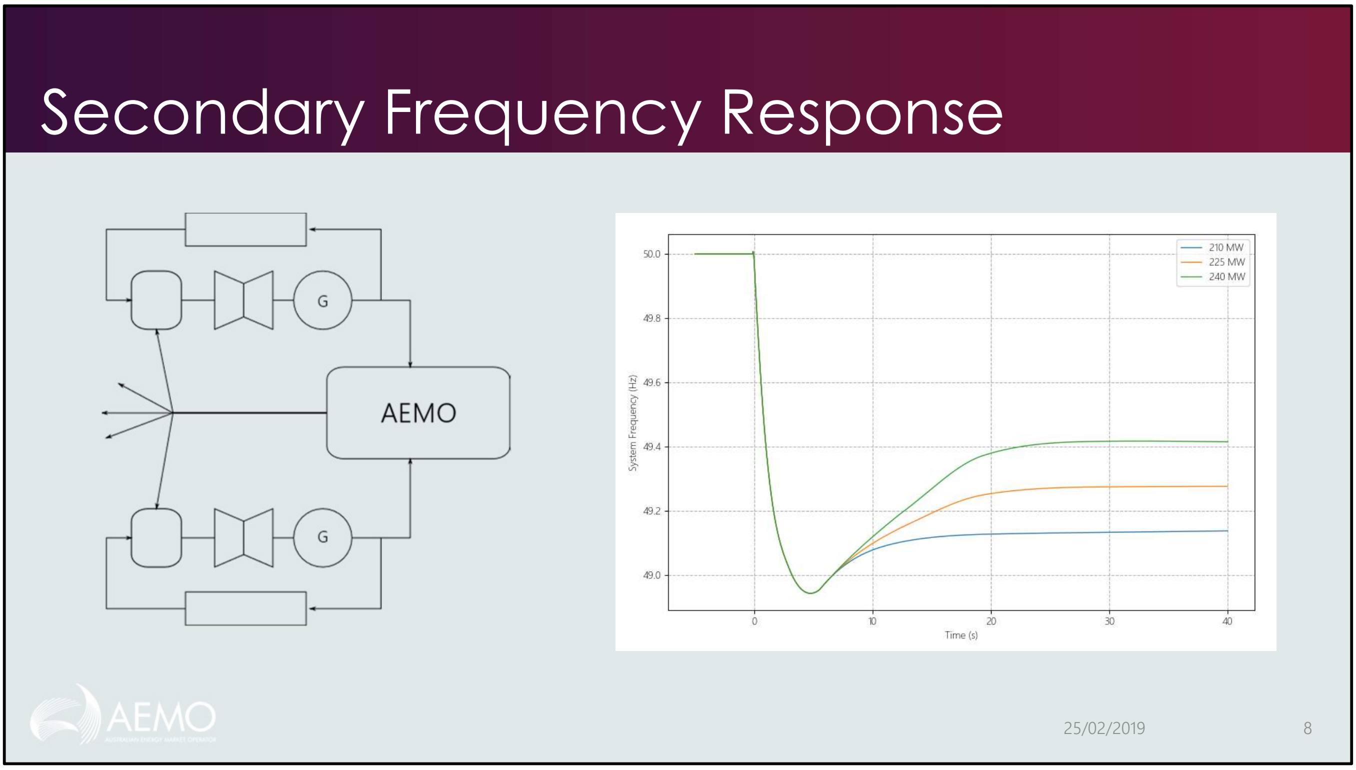
All things being otherwise equal, a lower inertia directly results in a greater ROCOF in the immediate seconds following the generation contingency. Due to the greater rate of decline, the system also reaches a lower absolute minimum or nadir frequency but will ultimately reach the same settling frequency irrespective of inertia.

From a system / frequency control perspective, the key feature is very fast response: can trade with e.g. rapid battery discharge (or ‘synthetic inertia’)



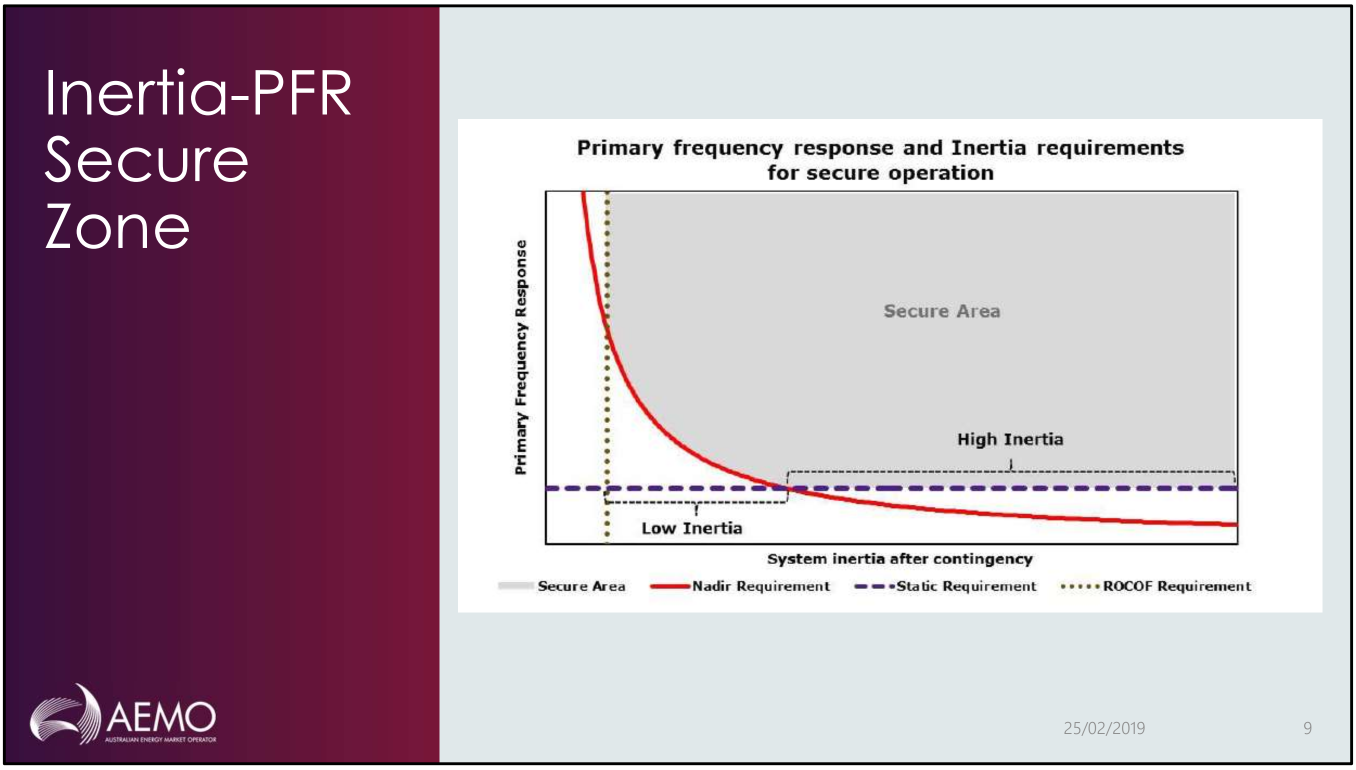
Primary control: named after the “primary control loop” in generators.

PFR is available relatively quickly: it acts to arrest the rapid decline of frequency and establish a temporary stable operating state. Due to the delay in translating a primary control signal into output MW, the critical (maximum) ROCOF is independent of PFR, however the nadir frequency is strongly impacted. Eventually, slower and more sustainable reserves take over, giving the same setting frequency.



SFR is characterised by system-wide control, typically through coordinated changes to the setpoints of multiple facilities (e.g. via an Automatic Generation Control system). Its reaction time is limited to the refresh rate of the control system (on the order of 4 – 20s) and draws on rate-limited but more stable and sustainable machine processes.

It acts in part to replenish PFR and restore the security of the system for further events, but the leading objective of SFR is to correct the remaining frequency error after the primary response. Depending on the severity of the contingency, available reserves and design of the system, the SFR may return system back to the normal operating range or to a temporary intermediary level.



The key post-contingency frequency characteristics map to the Inertia-PFR axes as a:

1) vertical line for the maximum tolerated ROCOF, indicating a minimum critical system inertia, independent of PFR;

2) hyperbolic curve for the nadir requirement, quantifying the trade-off between the two reserves;

3) horizontal line for the settling frequency (called “Static Requirement” in the diagram), independent of system inertia as expected.

The three lines define a secure area in the inertia-PFR space, wherein a system will ride through a generation (or load) contingency and meet all three frequency performance requirements.

25 August 2017: System Response

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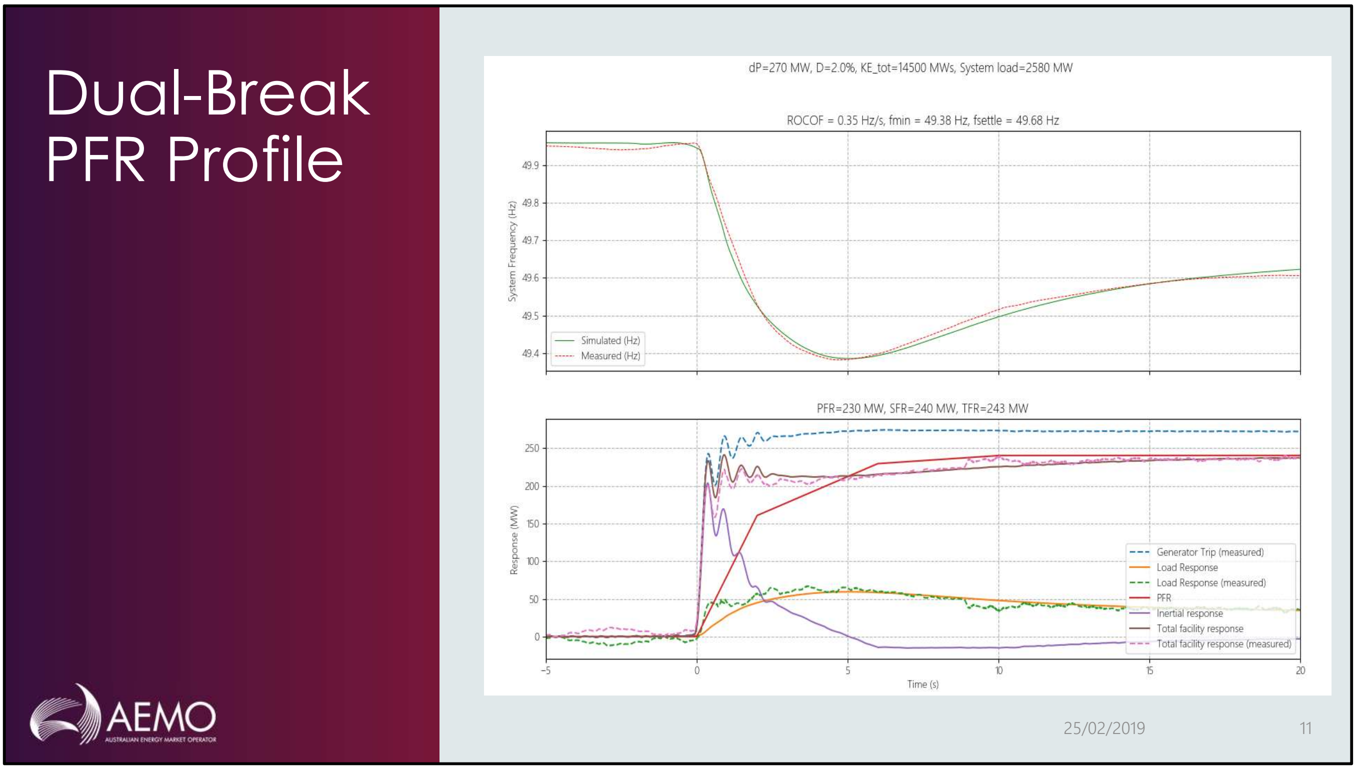
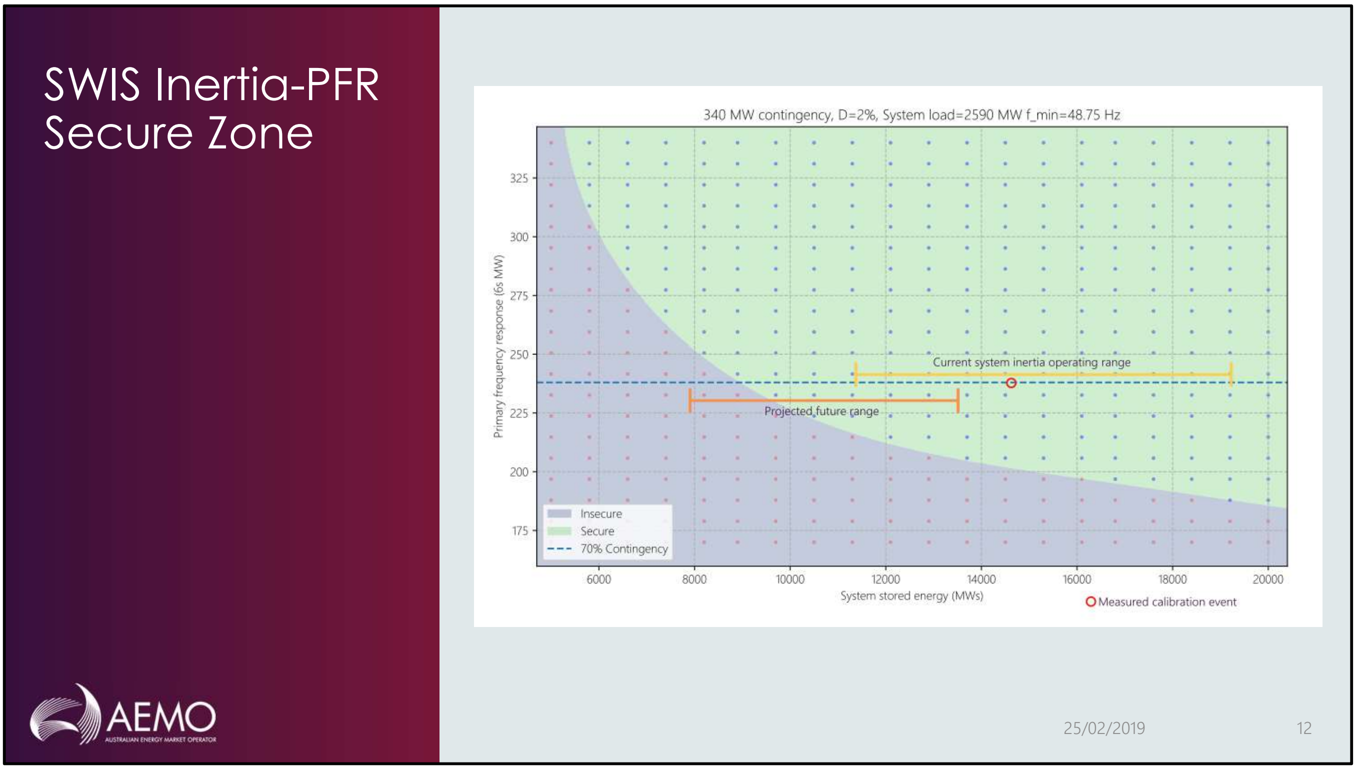
Mapped to the “frequency response” framework, the required primary response (at the nadir) was approximately 210 MW. Droop and “Other” sources provided approximately 50 MW of this, however a further 100 MW of unused Spinning Reserves was available from registered sources. This is expected, given that the contingency was <80% of the maximum credible value. Under the configuration of the SWIS AGC system, the portion of this remaining reserve available on Synergy plant was effectively deployed as secondary response.
Before the end of the 3 minutes, frequency had returned to the normal operating band, but all reserves were exhausted. An additional Synergy fast-start unit (tertiary response) was required to restore the system to a secure state (also in anticipation of loss of remaining MW of the faulted unit).



Through experimentation, a robust fit was found using a “dual break” PFR profile, characterised by an initial fast ramp from 0 – 2s, followed by a slower ramp to 6s. The best-fit profile is shown in Figure 8 (bottom), along with various other signals of interest. In these plots, dashed lines are measured values, while solid lines show simulation output.

To further constrain the possible combinations of D and the PFR, the target value and timing of each of the profile “break points” was varied to give a reasonable match between the measured and simulated Total facility response (in addition to the overall frequency characteristics). The inertial response component is also shown for the simulation only: this cannot be easily separated in measurements available at the system level.
The remaining power difference between the lost generator and the total facility response is attributed to “Load Response”: this includes true load relief, but also any frequency-independent change in system load and response from any unaccounted generation facilities (smaller generators without fault recordings, or unknown “behind the fence” machines).
The simulated output from the proportional load relief model is also plotted. It shows relatively good agreement with D = 2 at the nadir, however the measured

signal responds much faster in the 2 seconds immediately after the contingency. A likely explanation is the inertial response of unregistered smaller machines, but it may also reflect an inertial component in the system load . This has not been investigated in detail as further validation and refinement of the load model is suggested as key follow on work to this analysis.

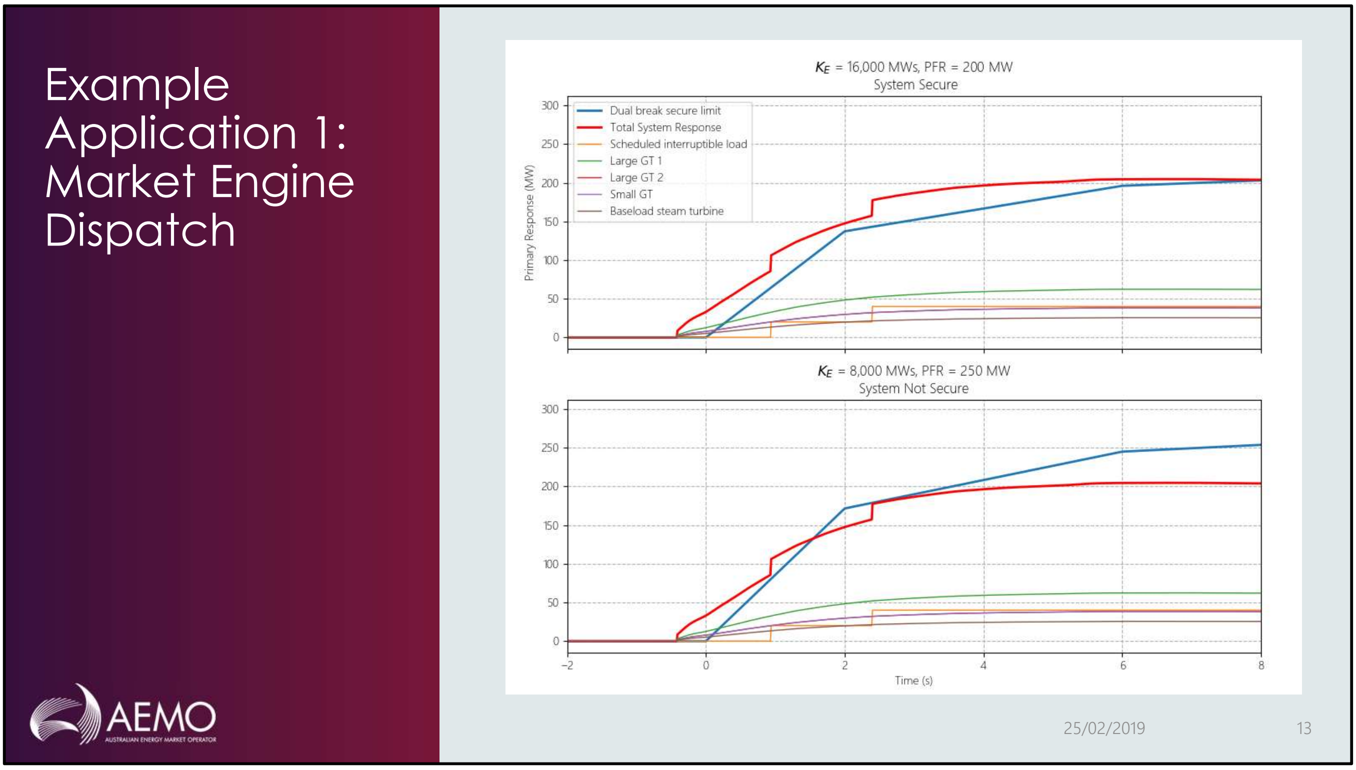


With the calibrated model, the dual-break PFR profile defines the security limit which aggregate machine response must exceed to ensure a minimum nadir frequency.

By scaling the profile and adjusting inertia, an inertia-PFR secure operating zone can be mapped for the SWIS. The diagram also shows the current 70% PFR operating practice, along with two highlighted ranges (post-contingency) along the inertia-axis, the:

current operating range, estimated from known machine parameters (see Appendix A3); and

projected future range (5 – 10 years), based on the current connection pipeline and likely displacement of existing synchronous machines.



In both panels, the secure limit (as defined by the dual-break PFR curve) is shown in blue alongside several hypothetical generation responses. The aggregate sum of the various response types is shown in red as the “Total System Response”.
The first panel shows the case corresponding to the edge of the secure zone in Figure 12 where (System stored energy, PFR) = (16,000 MWs, 200 MW). The aggregate response of all machines exceeds the secure limit, and thus the system frequency nadir would remain above the contingency limit for a 340 MW generation loss.
The second panel shows the same primary reserve configuration against the limit for the system with only 8,000 MWs of inertia. In this instance, the dispatch optimisation process would need to either:

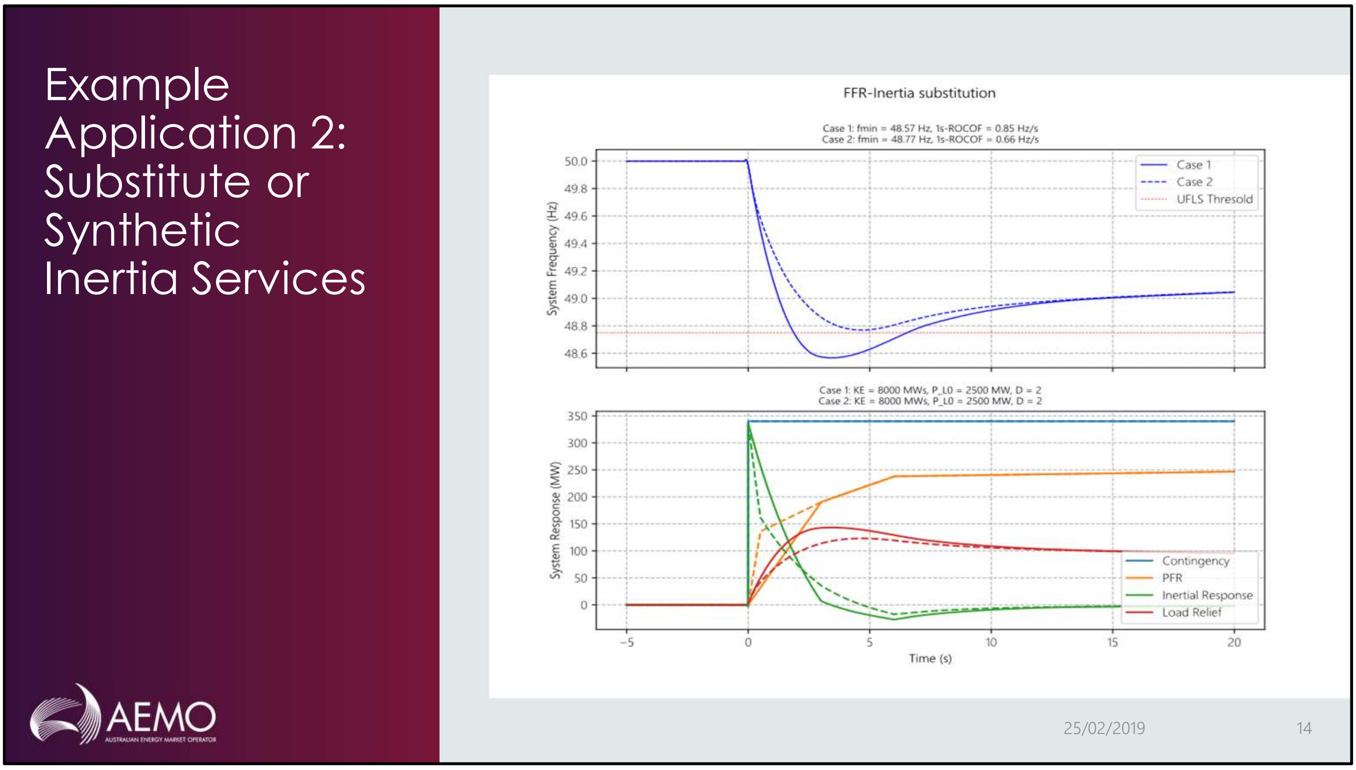
- add additional primary response;
- increase system inertia;
- reduce the maximum contingency size;

(or a combination of all three) to resecure the system. The trade-off between these options is non-trivial and as much a function of market design and dispatch engine capability as the physical detail of the power system; it has not been investigated as part of this proposal and is suggested as future work.
Similarly, application of the inertial-PFR concept would require a structured

means of testing and certifying machine response profiles for use in the co-optimisation process. The responses shown in Figure 13 are typical of current technology (proportional generation control and “switched” load shedding), however future facilities may have greater flexibility and/or limitations in their response profile. At least two solution approaches exist:

- definition of separate 2s and 6s primary ancillary service categories;
- a “scaled” dual-break response profile for each individual facility.

Again, the two options have benefits to trade-off, and would need further consideration for practical dispatch implementation.



The terms “fast frequency response” (FFR) and “synthetic inertia” both refer to the concept of technology with a fast-enough contingency response to limit system ROCOF, and thereby serve as a substitute for system inertia. While the 2s breakpoint was chosen to match the observed capability of facilities currently active in the WEM, the aggregate model provides a straight-forward means to investigate and quantify the impact of introducing faster contingency responses to the overall mix.

The plot shows an example case investigating the impact of a theoretical 100 MW, 500 ms response, as is readily achievable with current operational and demonstrated battery technology