Energy Transformation Implementation Unit

Transformation Design and Operation Working Group Meeting 11

29 April 2020

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- Please keep questions relevant to the agenda item being discussed.
- If there is not a break in discussion and you would like to say something, you can 'raise your hand' by typing 'question' or 'comment' in the meeting chat. Questions and comments can also be emailed to TDOWG@energy.wa.gov.au after the meeting.
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- Please state your name and organisation when you ask a question to assist with meeting minutes.
- If there are multiple people dialling in through a single profile, please email TDOWG@energy.wa.gov.au with the names of the attendees to be recorded in the minutes.
- If you are having connection/bandwidth issues, you may want to disable the incoming and/or outgoing video.

Agenda

- Actions from last meeting
- RoCoF safe limits
- Storage participation in the Reserve Capacity Mechanism
- Development of Market Procedures

WEM Reform: ROCOF Limits for the SWIS

TDWOG Meeting 11
29 April 2020

Taskforce Design Decision: Rate of change of frequency (RoCoF) Control

From the *Market Settlements* information paper:

AEMO will determine a safe RoCoF limit through appropriate technical studies and include it in the Frequency Operating Standard and the dynamic frequency contingency model used in dispatch. Initially, it may be prudent to set the limits conservatively, and explore relaxing them as experience is gained and confidence improves. However, because the RoCoF Control service by its nature requires (higher marginal-cost) synchronous generators to run instead of cheaper intermittent renewable generators, setting limits conservatively has the potential to add significant costs.

The causer-pays approach to cost recovery is a key part of uncovering true capability of different facilities, incentivising them to improve their ride-through capability, and expanding the secure operation zone. As the secure operation zone expands, the requirement for a RoCoF Control service reduces, implying the cost of providing the service will also reduce. This is a desirable outcome as it both improves overall system security and reduces the costs of the service to its lowest economically efficient value.

In advance of market start, AEMO will conduct modelling to determine an upper RoCoF ride-through limit, above which no RoCoF Control service would be required (i.e. the maximum RoCoF if only primary frequency response was available). In other words, AEMO will need to determine the maximum RoCoF in the absence of a RoCoF Control service across the range of expected system conditions.

Before we begin…

- National Grid in the UK recently contracted 6 years x 12.5 GWs @ $640M (£328M) for Stability Services
  - Includes system strengthening / reactive power services in addition to inertia
  - "0 MW" dispatch on demand (full details available online)
- Direct proportional costs of $8M / year for SWIS (50 GW vs 4 GW systems), however scale of problem is 4x larger:
  - Recent major UK load shedding event 1 GW contingency / 50 GW system (2%)
    - C.f. SWIS 340 MW contingency / 4 GW system (8.5%)
  - ¼ equivalent system resources (non-contracted inertia, load relief, competitive market size)
- Realistic indicative benchmark $10M – 30M / year for the SWIS
  - manages all of system strength, reactive power, inertia

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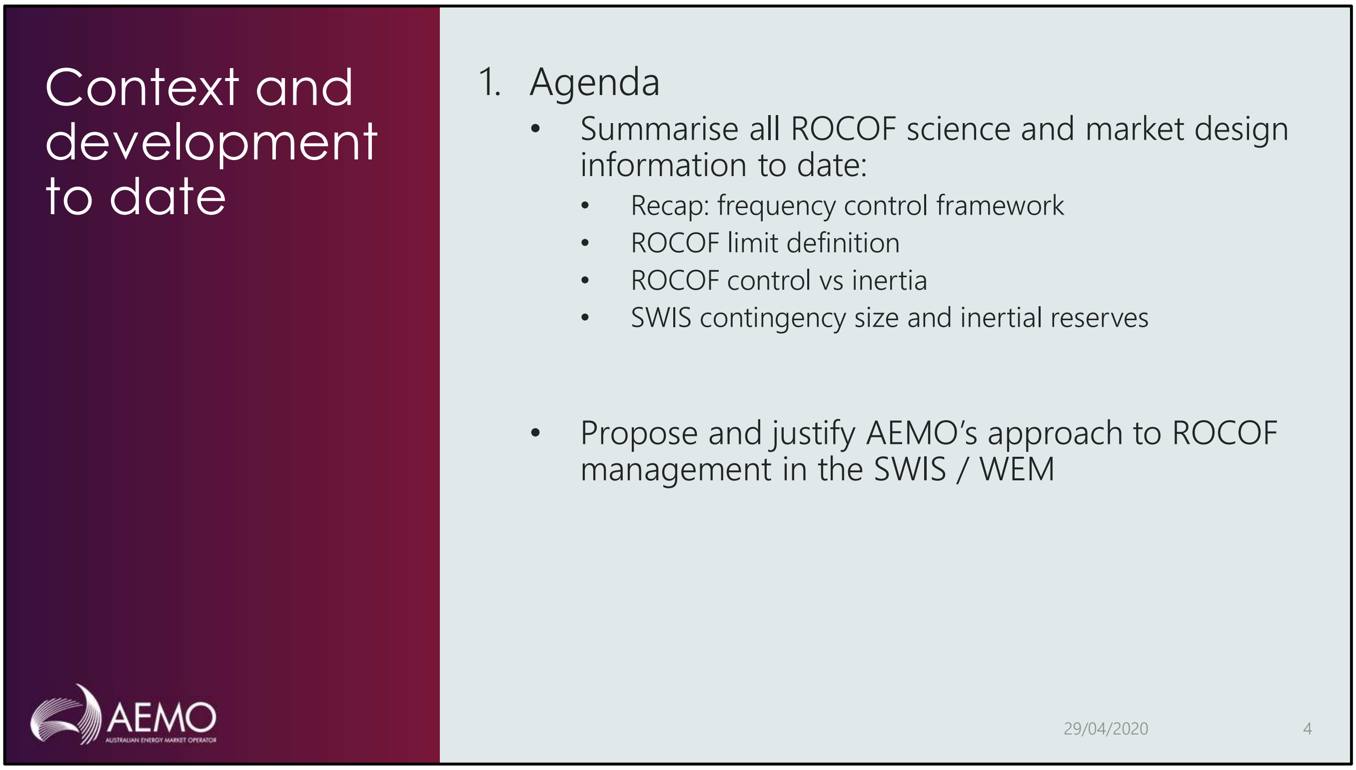
Later slides will put the scale and meaning of (quantify) a hypothetical equivalent 1 GWs purchase into context: this is approximately equal to 1x 150 MW open-cycle (heavy) gas turbine facility.

Seen from the UK perspective, the "value proposition" is inverted: consider if it were $3M / year to "disappear" (or delay) the problems of inertia, reactive power and system strength in the SWIS using a relatively simple approach.

It is often possible to manage (or defer) uncertainty and risk by paying a premium, however the equivalent approach could consume the entire Energy Transformation budget within 2-3 years to solve these select security issues alone.

Premise for this presentation: *is a more sophisticated and head-on approach justified in the WEM?*



Rate of Change of Frequency refers to the speed of acceleration a power system experiences following a major disturbance (contingency event).

Although not fundamentally more complicated that other security constraints in a power system (e.g. provision of Spinning Reserve in the current WEM), management of ROCOF management of is a relatively new consideration for the industry as a whole.

As such, there is limited experience in both plant capability and proven market designs to structure ROCOF requirements + create efficient management frameworks. Although AEMO is leveraging international experience and reconditions where possible, as a smaller + islanded system, the SWIS faces higher security risks due to ROCOF limits in terms of both :

- time available before until ROCOF constraints impact market operation; and
- Severity of impact / resources available to management.

In this context, this presentation:

- summarises all relevant information and decisions so far into the *Energy Transformation*; and then
- presents AEMO's
    - analysis to date; and
    - proposed approach to establishing ROCOF limits for the SWIS + management

of these limits within the WEM.

The aim is for participants to understand the reasoning and key implications of the approach.

Recap: frequency control framework

Key References

1. Technical Reports:
    1. GHD Advisory Report: ESS Technical Framework Review
    2. AEMO Technical Proposal: Contingency Response in the SWIS
    3. AEMO Future Power System Security Program:
        1. International Review of Frequency Control Adaptation
        2. Technology Capabilities for Fast Frequency Response

2. ETIU Information Papers:
    1. Frequency Control ESS
    2. Frequency Control Technical Arrangements
    3. Revised Frequency Operating States
    4. ESS – Scheduling and Dispatch

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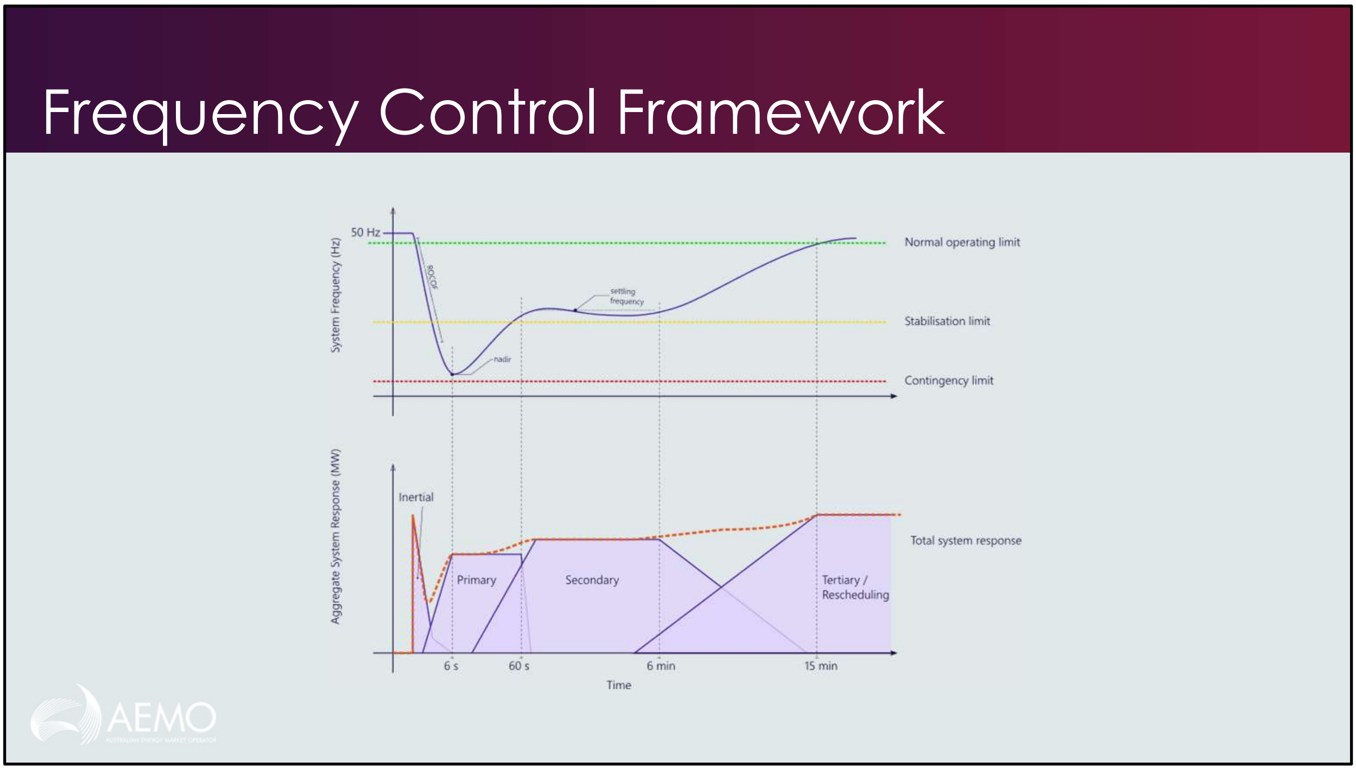
Frequency Control Service Glossary

Current WEM Ancillary Services	Future WEM Essential System Services	
Load Following (Up and Down)	Frequency Regulation (Raise and Lower)	
Spinning Reserve	Contingency Response	Contingency Reserve (Raise and Lower)
Load Rejection		
None		ROCOF Control

Refer: ESS and Scheduling and Dispatch information papers



This image summarises AEMO's frequency control framework: the fundamental view of the problem, as well as the terminology applied to system limits and the fleet resources available for management.

ROCOF refers to the slope of system frequency in the immediate moments (first ~1000ms) following a major system disturbance.

Within this initial timeframe:

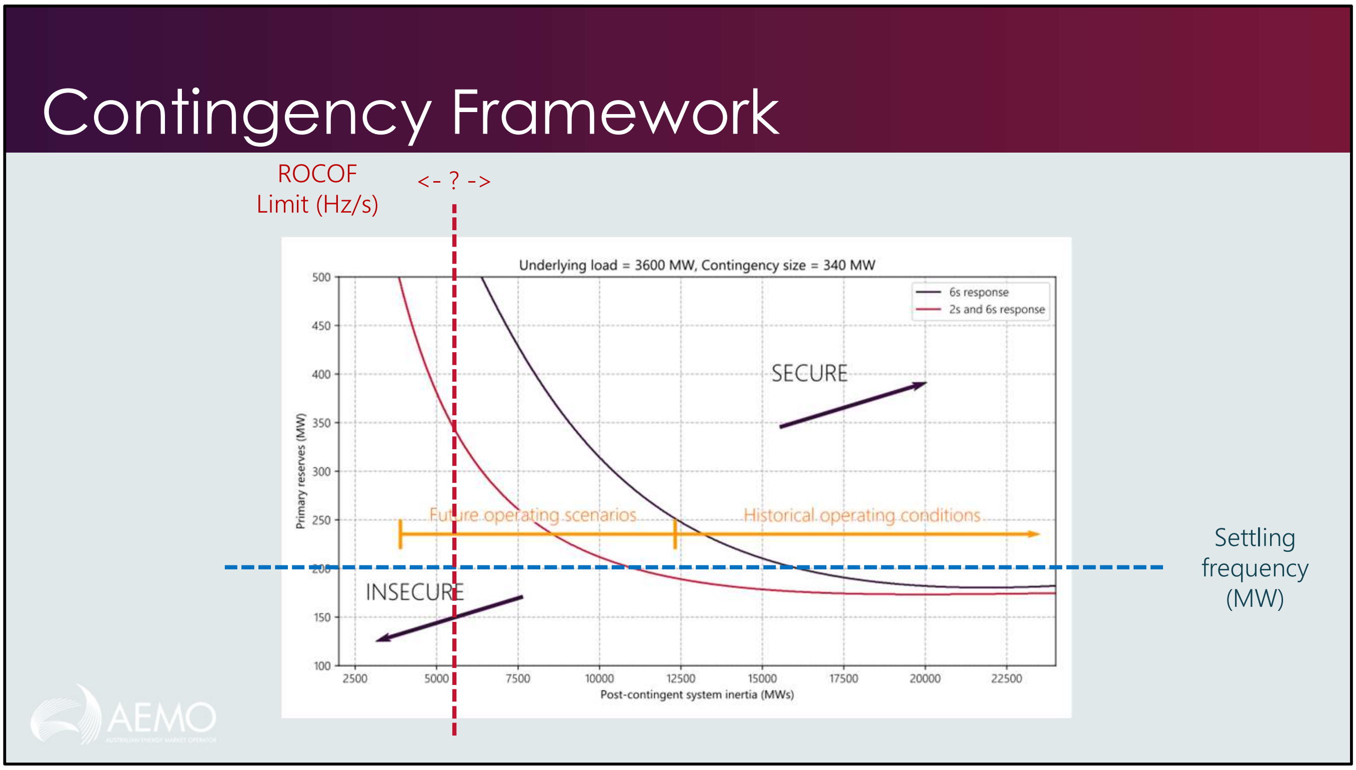
- primary control systems of traditional synchronous machines will not be able to respond quickly enough; while
- (current) power electronic / inverter generators struggle to reliably identify area frequency movements (as distinct from transient noise in measurements – this is discussed further in a later slide)

In practice there is no clear boundary between ROCOF and PRIMARY (or any response class) and always a degree of interaction (as shown in the diagram): the treatment of this will be discussed in later slides.

Notwithstanding this, in maintaining secure operation two key variables are available to the system operator:

- System inertia

- Size of the largest credible contingency



This image attempts to convey the concept of a secure operating zone in an intuitive picture.

- The (hyperbolic) curves describe the possible trade-off between system inertia and primary frequency response.
- Faster primary response ("2s and 6s" curve) allows for a greater secure operation zone (better trade-off between inertia and headroom).
- Yellow lines show the historical (measured) inertial operating reserves (more on this later)

(Click)
The safe or **secure ROCOF limit** appears as the vertical line on the left hand side. This value follows from physical properties and may have catastrophic consequences: in an under-frequency event, the loss of an additional generation facility will immediately cascade to a full system loss within seconds. This line is therefore a hard operating limit and cannot be compromised.

This line moves to the left (secure operating zone grows larger) as the maximum tolerable ROCOF (Hz/s) increases.

The **"safe limit" for ROCOF is unknown**: having never been a constraining factor for

power systems, equipment has:
- never been tested under controlled circumstances (e.g. during commissioning) let alone realistic conditions; nor
- designed to maximise tolerance

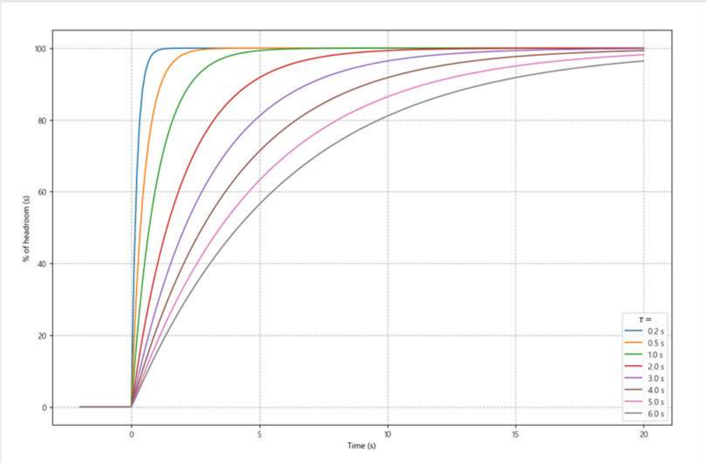
All said however, provision of additional ROCOF service can *also* reduce the requirement of **contingency response reserves** needed to maintain the **secure nadir limit**.

There is therefore a second (higher) optimal inertial level that is a product of both physical requirements AND market participant behaviour / bidding strategies.

(Click)
The settling frequency is comparatively straight forward: it is determined by the system load response + can be directly measured at the system level. It sets the requirement for secondary frequency reserves.

Optimisation of dispatch along the nadir-line: the subject of a future presentation.

Single Segment PFR



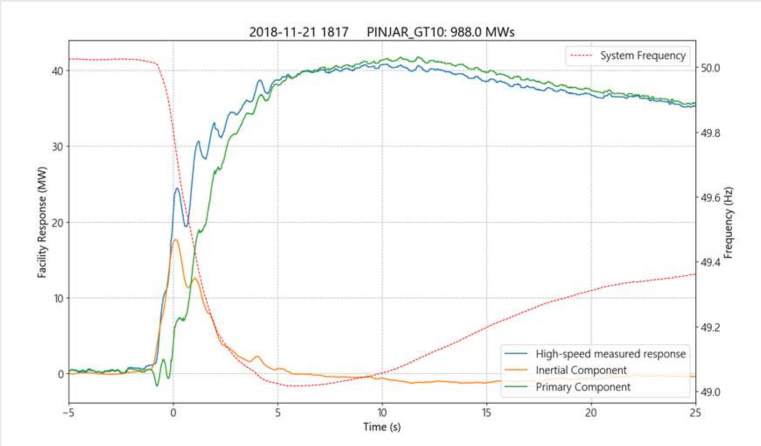
Refresher from the SCED presentation:

ETIU market design direction is to minimise the number of segments in the contingency market.

AEMO has developed a technical classification scheme that accredits with a performance factor according to the speed of their response.

The system has some further complexities (refer to the ESS SCED paper / future) but overall, facilities will be credited / incentivised for faster response.

Measured Example



Plot showing the measured response of an existing generator. The Pinjar machines have reliably provided contingency response over may years to date in the SWIS; these facilities have been used to calibrate the theoretical model that will used to set the "speed factor" of other SWIS participants (τ = 2.0 s, KE≈1000 MWs).

The formal method has not been defined, but the proposed concept is sketched above:

Assuming turbine speed follows the locally measured frequency, the orange curve is the theoretical response of a 988 MWs spinning mass. This is subtracted from the measured MW response (blue) to separate the remaining primary response.

ROCOF Control Vs Inertia

Taskforce Design Decision – ROCOF Control Service

3.5.1 in the *Technical Arrangements* information paper:

1. A RoCoF Control Service will be defined separately from Contingency Response
2. RoCoF Control Service will be defined in terms of inertial megawatt-seconds (MWs) or MWs equivalent
3. AEMO will monitor dynamic system conditions and facility performance to investigate possible MWs approximations, to allow future non-synchronous providers to accredit and participate directly in the RoCoF Control Service

In defining the quantity of RoCoF Control Service a given facility can provide, the performance, reliability and impact of synchronous inertia in managing RoCoF are well-understood and established, with large bodies of supporting research and evidence. The quantity of inertia is unambiguously measured from a machine's physical rotating mass (commonly expressed in megawatt-seconds, the rotational kinetic energy at 50 Hertz). The contribution of a given facility thereby serves as an appropriate baseline definition for the RoCoF Control service.

The fast-response capability of inverter-connected facilities can mimic the effect of physical inertia during contingencies, but cannot act as a direct substitute, as it differs in two key aspects, namely that:

1. *it relies on electronic detection of area-frequency, which is subject to noise and inherently requires a delay (on the order of several hundred ms) during the critical response period; and*
2. *rotating inertia is physically coupled to the electrical system, and fundamentally cannot fail in response to a contingency. As technology develops and the capability of fast response technology becomes better understood through live deployment, it is likely to emerge that an inertial equivalent for these facilities can be securely formulated, and thereby enable direct participation on the RoCoF Control Service.*

This policy follows AEMO's advice after reviewing the available literature and operational data available to date: while conceptually capable of providing very fast response (i.e. in the inertial timeframe), inverter-based connections suffer from fundamental limitation in detection and communications for **reliable** inertial response.

This treatment (separate inertial and fast response) is consistent with all other jurisdictions to date – refer for example:

- EirGrid DS3 program (http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/)
- National Grid: Enhanced Frequency Control Capability Program (example next slide)
    - Original objective: "*Development of new EFCC (RoCoF-based) frequency response balancing service*", defined at <500ms response
    - Objective not met: "*Since the bid submission, significant changes to the energy landscape impacting system requirements presented newer operational challenges. This has led to the business shifting its focus from the development of a single EFCC product to developing a suite of new, faster-acting frequency response products incorporating the learnings from the EFCC project"*
        - Since implemented as the "*Dynamic Containment*" suite of services.

ROCOF Control vs Inertia

Reference:

National Grid -
[The Enhanced Frequency Control Capability (EFCC) Project]

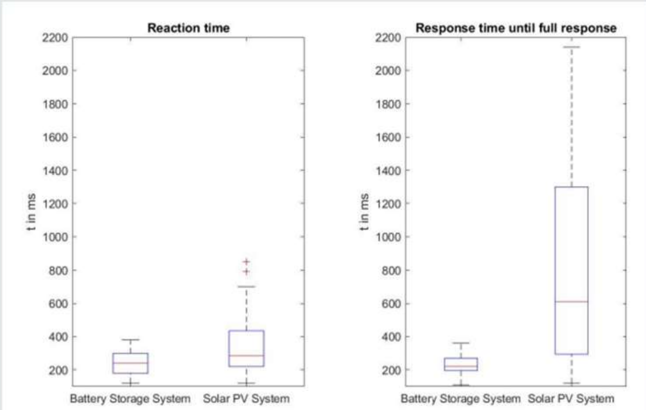


Figure 32: Reaction and response time analysis of the individual hybrid resources battery and solar PV system logged during the hardware in the loop test series.

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Example of requisite level of detail and analysis of a measured response:

"

The frequency response times were found to:
- *take an average of 880ms until full response after receiving data from the LC*
- *have a fastest response time of 120ms*
- *have a worst case response time of 2140ms.*

The longer response times are due to the plant's specific current-voltage characteristics, as well as low-pass filters in the inverters which are there to prevent oscillations. Another factor that affects the reaction time is the MODBUS communications protocol used at the site. The tests found that the data traffic between the control system and the PV inverters was not consistent due to the MODBUS communications channel being shared with other parties. This meant the response times of the plant is nondeterministic and could not be guaranteed…

…For the standard 2014 central converter-based solar PV farm, a fast reaction time was not considered during the design. The communication topology inside the solar PV farm was never meant to be fast, so retrofitting with a good network design and fast switches is necessary to provide frequency response."

Note after receipt from the LC: Local Controller – times above do **not** account for fundamental detection of a frequency event, which itself may already exceed most of the inertial timeframe budget.

High-performance measurement + communications capability places additional design restrictions: it may not be cost effective to implement, even if technically capable.

Fast Frequency response meanwhile, is:
- relatively simple to implement;
- already proven through real operation; and
- will be immediately rewarded under the WEM-SCED framework, in such a way that also accounts for the overlap between inertial and primary responses (more on this later).

ROCOF Limit Definition

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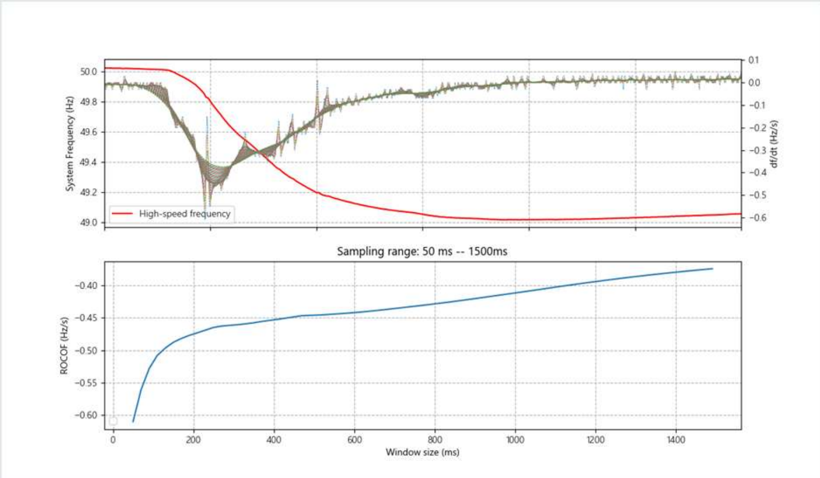
Duration of measurement

Setting proposal:

ROCOF limit is set over a single 500 ms timeframe



The base units for ROCOF are Hz/s – however a further complication exists in that the sustain time is also critical.

This problem can be considered from two angles:
- In general, a machine can support an increased ROCOF if the overall time is reduced
- Sensors / recording devices are such that ROCOF can only be measured over timescales on the same order as the critical period (~500ms).

Example EirGrid case study (refer *International Review of Frequency Control*), generators were given deadline assess ROCOF tolerance to 1 Hz/s:
  - In most cases, unable to determine in practice
  - It was generally agreed (TNSP, turbine OEM, system operator experience) that existing synchronous machines can comfortably sustain 0.5 Hz/s for 500 ms.

The first of these "angles" is the true physical driver for consideration of sustain time, however it is the second (limitation is measurement capability) that actually determines operating policy.

The top plot shows the most extreme generation contingency on record (both Alinta WGP units simultaneously tripped Nov 2018).

The frequency is shown in RED, along with a rolling average slope.

In general: a certain ROCOF over a given measurement window (sustain time) can be shown to be equivalent to a lower ROCOF at a longer window.

For example: for this event ROCOF is equivalently measured -0.45 Hz/s over 410 ms, or -0.4 Hz/s over 1100ms.

The exact relationship is less import (and won't hold over more extreme events): it is more critical that the measurement be consistent, repeatable (across multiple events) and calibrated to facility tolerance.

The linear relationship no longer holds at very short windows (<200ms): this is due to the noise in the signal.

Limit vs Response vs Service

Security limit	Response	Facility Characteristic	Service
Frequency nadir: e.g. 49.0 Hz	Primary: >1s	Speed of response / time constant τ (s)	Contingency Raise: MW of reserved headroom. Must be sustained for up to 15 minutes
Settling frequency e.g. 49.5 Hz within 5 minutes	Secondary: >60s	Ramp rate (MW / minute)	
ROCOF Limit e.g. 0.5 Hz/s over 500 ms	Inertial: <1s	Inertia (MWs)	ROCOF Service: full MWs of unit(s) whenever synchronised.

Ride-through capability

ROCOF Limit	Observations

Up to 0.5 Hz/s (over 500 ms)	Known safe zone:
	- Stated "comfort" level from turbine OEMs
	- No known catastrophic failures (industry-wide)
	- Historical operating region in SWIS. Maximum observed ROCOF 0.44 Hz/s
	    - Protection relays will not mal-operate
	    - Special network schemes perform as designed

0.5 Hz/s – 1.5 Hz/s	Limited industry experience (<5 known events, no available detail or data) Possible failure of synchronous machines (turbine and motor) - Older turbines at higher risk (lower end of range) - Gas-fired turbines at high risk on over-frequency - Simulation investigations only (no confirmed cases) - separate PSS-driven instability risk Possible failure and/or mal-operation of electro-mechanical relays Possible measurement errors, settling errors or nuisance tripping of protection systems Possible distributed PV tripping due to frequency and/or islanding protection
Approx. 3 Hz / s	Failure of current UFLS designs
Approx. 4 Hz/s	Achievable tolerance for inverter-connections

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Highlights of industry review: refer to the technical references in the earlier slide (available online) for further detail.

Limit Considerations

- Gradual onset of system changes
  - Physical limit only binds for select (e.g. low-demand) windows
- New market design
  - System (IT, plant capability, process) “teething” and tuning
  - Economic learning (bidding strategies) and settling of prices
- Chicken-egg problem of equipment limits + requirements
  - Ultimately, live demonstration is the only reliable confirmation of performance
- Transition should be well-defined, gradual and predictable
  - MPs: allow reasonable time (~years) for commercial planning
  - AEMO: allow system monitoring and tuning with operational experience

One robust (basic) approach would be to set a fixed minimum ROCOF Service quantity based on the 0.5 Hz/s limit, and purchase this amount via direct contract to guarantee availability and security.

In practice, the onset of physically-binding (minimum) ROCOF limits only occurs initially during select periods (investigated in subsequent slides). While secure, a “fixed” approach is very likely to be excessively conservative during the initial period.

At the same time, introduction of the suite of WEM changes will need time for initial tuning and to establish more stable operation (market and power system).

The framework of performance requirements and market incentives needs to be structured to create meaningful (financial) industry pressure to investigate and the resolve uncertainty in ROCOF withstand capability;

> Ultimately, the strongest incentive, technical demonstration and testing regime is experience through real time operations (i.e. allowing conditions to generate higher ROCOF conditions)

The transition should be well-defined, gradual and predictable to allow operators reasonable time and opportunity to make effective commercial decisions.

> Attempting to increase requirements too rapidly may significantly disrupt or prove unfeasible for large-scale facilities (load and generation). In the worst case, it may incentivise misrepresentation of capabilities, and lead to catastrophic consequences during system events.

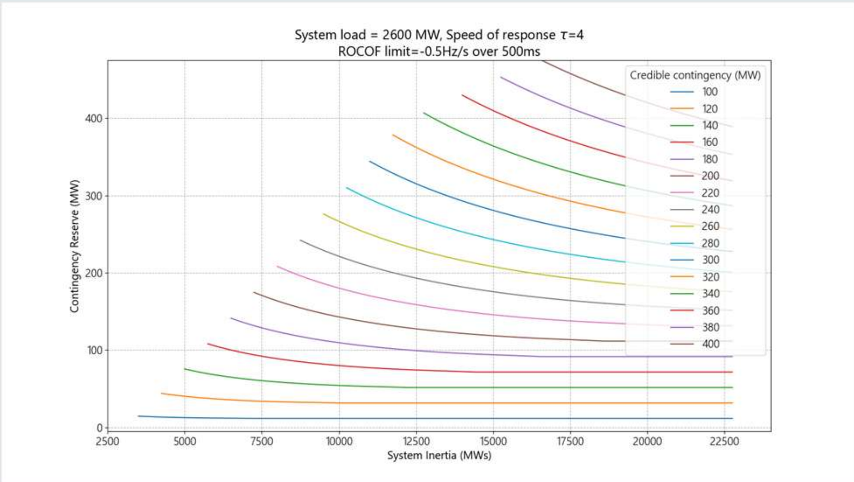
Overall, a pragmatic balance needs to be struck to trend toward a more efficient + dynamic arrangement, without compromising security and reliability in the process.

Contingency Size and Inertial Reserves

Recall that 2 controllable variables are available to manage ROCOF:

- Contingency size
- ROCOF control service (inertia)

Impact of contingency size
(τ=4s, 0.5 Hz/s)



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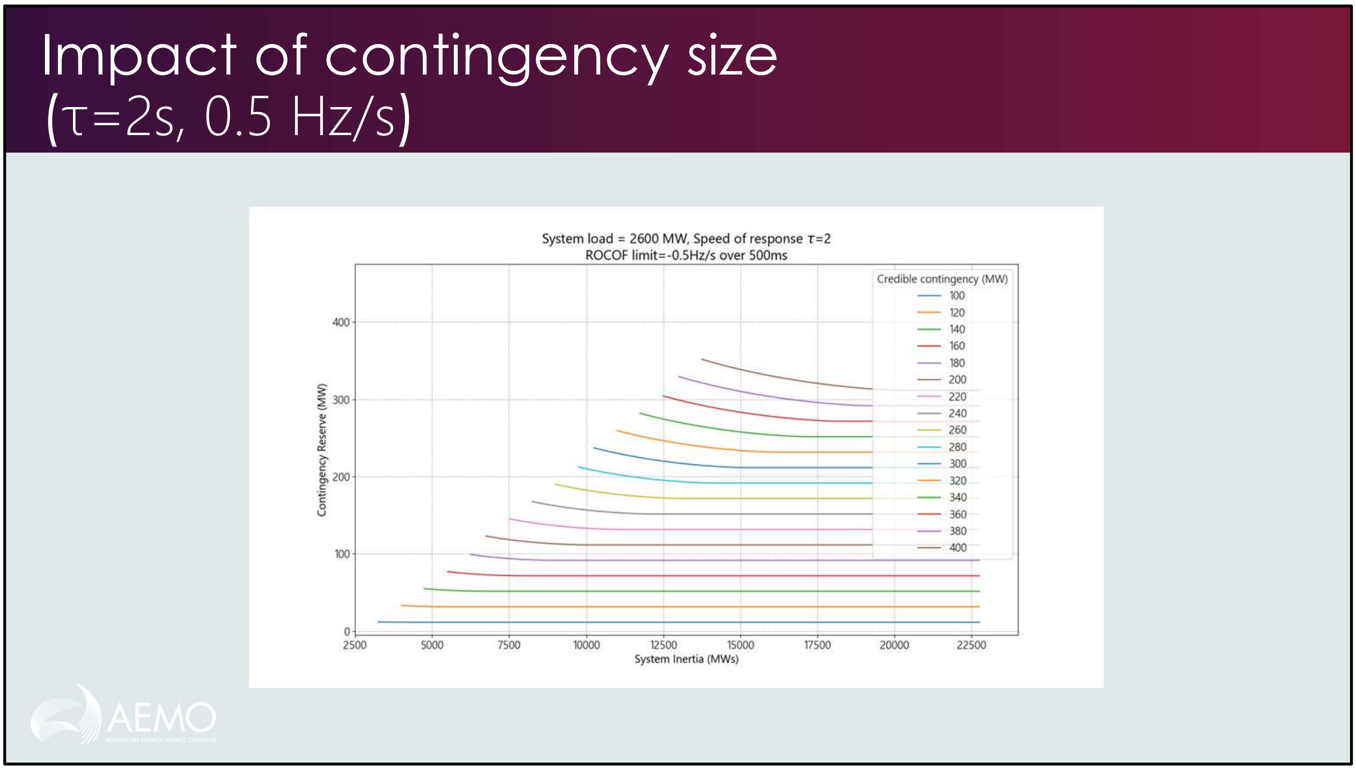
This figure shows a different cross section of the secure zone: a fixed speed of response (at approximately that of steam turbine) over a range of credible contingency sizes.

The simulations used to develop this plot were run starting from 3000 MWs: this is the observed “load inertia” observed through high-speed recordings (the amount remaining without any inertial plant synchronised)

Above 3000MWs, the lines stop at the minimum inertia required to maintain 0.5 Hz/s

Key observations:

- minimum inertia increases ~linearly with with reduced contingency size
- Also depends weakly on speed of response, system load,
- At very low contingency size (e.g. <~160 MW), line is basically flat: inertia + speed of response irrelevant.
- Transition from nadir limit to settling frequency limit is “smooth”: set to same value



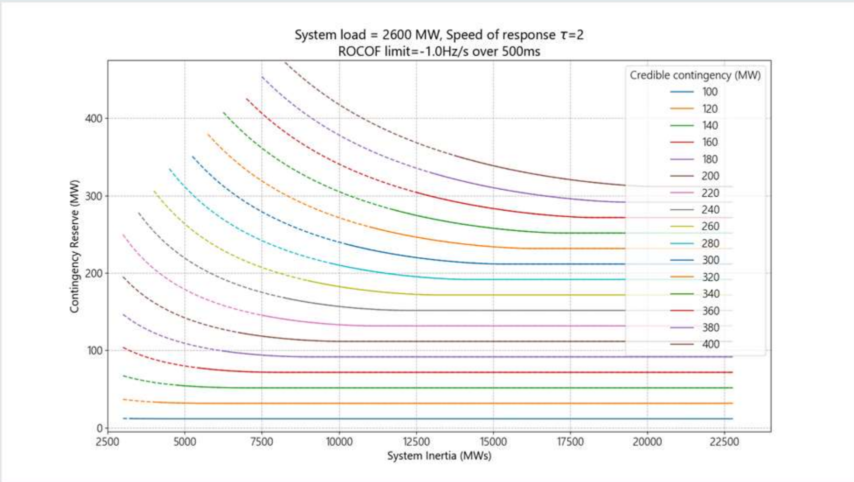
Same plot, tau = 2s (that of fast GT)

Overall, the lines are "compressed" significantly: need less reserve to manage nadir limits

Minimum ROCOF also shifted slightly to the left
- e.g. 340 MW: 12,600 MWs @ 4s, 12,400 MWs @ 2s

This is due to the interaction of inertial and primary response:
- Results based on perfect simulation responses: **needs to be monitored very carefully and validated from true operation (i.e. measured + observed)**
    - Uncertainty managed using *operational margins*
- In the clearing engine, a *slower facility cannot contribute at inertia lower than it's minimum* (performance factor of 0)

Impact of contingency size
(τ=2s, 1.0 Hz/s)



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tau = 2s (that of fast GT)

Dashed lines show additional secure operating range if the ROCOF limit is increased.

Operation in this region is uncertain and carries significant security risk, but the service requirements grow exponentially (and therefore the potential for high system operation cost / efficiencies through the co-optimised market).

Expected SWIS ROCOF Service Capability

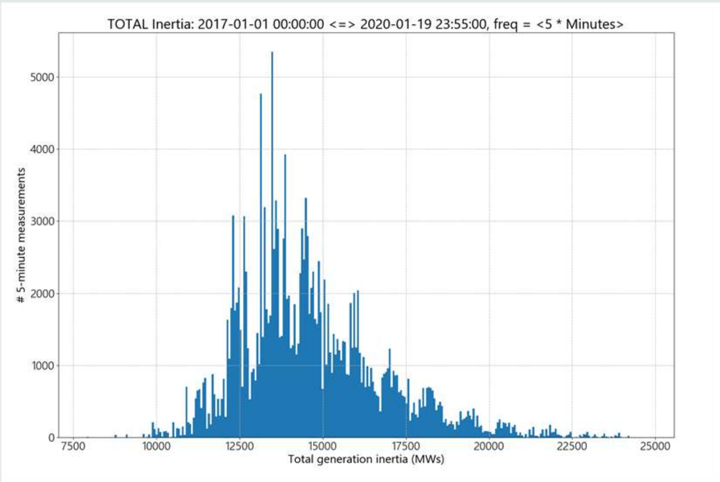
Unit	Inertia
Steam turbine	800 - 1500 MWs
Open-cycle gas turbine	700 – 1000 MWs
Combined-cycle turbines*	2000 MWs+
Aero-derivative gas turbine	250 MWs

*i.e. multiple turbines synchronised

ROCOF service capability for a synchronous machine is fixed for a given configuration: it is (proportional to) the rotating mass of the unit.

These numbers are typically given in terms of s, i.e. MWs / MW (or MWs / MVA) – idea here is give a rough sense of where per-facility service quantities will sit in respect of the slides to come.

Historic inertial reserves

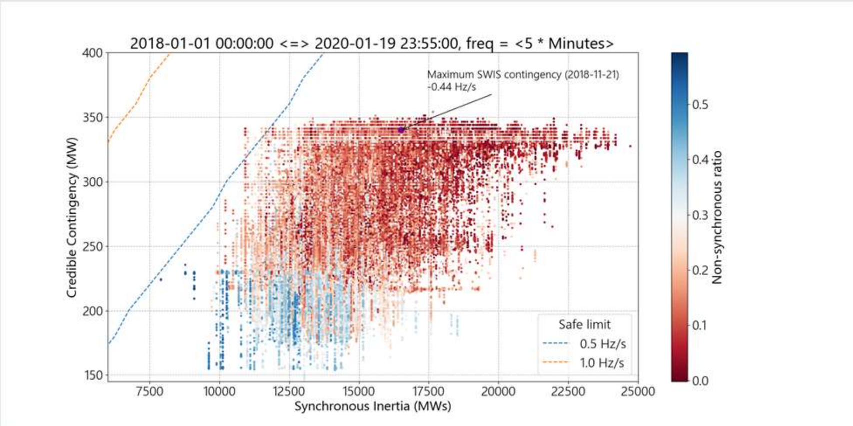


Total inertia of synchronous units visible to AEMO back to ~2017 (inertia first started being tracked).

Sum of spinning units only: does not include approximate 3000 MWs available from load inertia. For service quantities however, this is counteracted by the simultaneous loss of around 1000-2500 MWs with the largest credible MW contingency.

The “spikes” in the data follow from the block nature of inertia enablement.

Historic inertial reserves



Same inertia data, now presented as a function of the other critical variable: Credible Contingency

The lines on this plot correspond to the secure levels of inertia at 0.5 Hz/s and 1.0 Hz/s limits shown previously.

At present, AEMO has only limited control over the maximum contingency size (Portfolio only), however inertia also naturally follows a beneficial trend. In the main, lower contingencies sizes are coincident with lower inertia.

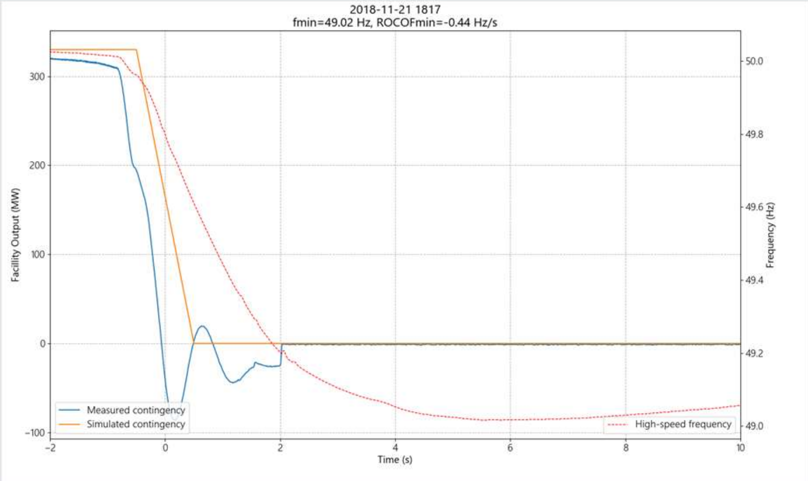
The most critical periods are when low load + high intermittent generation create negative pricing: by definition, scheduled facilities are looking to either desynchronise or minimise output during these periods.

Changes to dynamics in the short to medium (2-5 year) horizon:
- Lower demand as distributed IMG continues to increase (←)
- Connection of additional utility-scale IMG facilities (← and ↑)
- SCED (co-optimisation + causer-pays costing):
    - Credible contingency co-optimisation (↓)
    - ROCOF Service (→)

For example: by bidding into ESS markets, a gas facility could be credited to supply (scarce) inertial reserve + contingency raise through a negative energy pricing period (where it would otherwise not be profitable to supply energy alone).

These dynamics will take time for participants to understand and develop trading strategies in new markets to make use of their plant's flexibility. To assist with this, the reform is also enhancing forward market visibility through processes such as Pre-Dispatch and PASA

Maximum recorded SWIS contingency (non-credible)



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Why does the measured -0.44Hz/s contingency appear relatively “far” from the secure limits?

1) Maximum ROCOF scales like 1/inertia (non-linear response)

2) Maximum generation contingency on record was closer to 400 MW due to the (non-credible) simultaneous loss of two facilities at once, rather than the single credible unit loss.

Units appears to “motor” for and additional -100 MW during first 500 ms, before settling at -10 MW (site load). Measured power drops to 0 MW once the site circuit breaker closes.

The limit simulation uses a 1s “step-down” contingency input, which is indicative of observed credible losses in the SWIS.

The “non-ideal” aspects of reality are managed through *operating margins* and the separate Frequency Operating Standards for non-credible events.

ROCOF Limit Proposal

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Taskforce design decision
Minimum ROCOF control

From the *Market Settlement* information paper:

The approach to allocating the Minimum RoCoF Control Requirement cost is to split the total RoCoF Control service in a dispatch interval in three parts and allocate as follows:

1. Generators in the RoCoF ride-through band would be required to fund one-third of the minimum RoCoF Control requirement cost. This one-third share would be allocated to generators in proportion to their share of generation. As generators demonstrate their ability to ride-through safely, their exposure to the costs of the service would reduce.
2. All loads, initially, with a mechanism requiring AEMO to investigate the true ride-through capability of loads to be used as input into future safe limit reviews. The loads' one-third share would be allocated to individual loads in proportion to their share of consumption. As loads demonstrate their ability to ride-through safely, their exposure to the costs of the service would reduce.
3. To Western Power, based on its network ride-through capability. Western Power would fund one-third of the Minimum RoCoF Control Requirement cost if its network is unable to ride-through the RoCoF safe-limit. If Western Power were to amend its network settings to improve its ride-through capability, then the Minimum RoCoF Control Requirement cost would be split two ways between generators in the RoCoF ride-through band and loads.

ETIU cost allocation design / decision: costs split across *connection classes*, with equitable option for performance-based (ROCOF tolerance) exemption.

The minimum ROCOF Control service corresponds to the ROCOF limit (e.g. 0.5 Hz/s or 1 Hz/s as shown earlier)

AEMO technical proposal has been made to ensure secure operation, with mind to the cost allocation methods.

Declaration of ROCOF Ride-Through Capability

- Participant: self-assessment + declaration of capability
  - Can be made ahead of market start
- AEMO: system risk due-diligence assessment
  - Loads: loss during high-ROCOF *assists* with frequency recovery
    - Declaration may amount to acceptance of own disconnection risk
      - Supply interruption and possible damage to plant
  - Generators: loss during high-ROCOF cascades to total system loss
    - Declaration must give defensible engineering assessment (e.g. OEM certification, live testing)
  - Network: range of consequences
    - Expect different approaches for different classes of assets

Aside: Acceleration control in GE turbine-governor model GGOV1

- Excerpt from NERC Reliability Guide
  - [Application Guide for Modeling Turbine-Governor and Active Power-Frequency Controls in Interconnection-Wide Stability Studies (June 2019)]

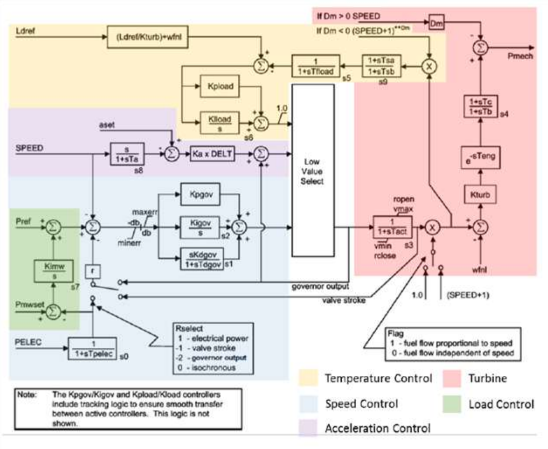


Figure C.1: Annotated GGOV1 Model [Source: Adapted from PSS®E][71]

AEMO

GGOV1 turbine governor model originally developed (through the 90's / early 00's) to represent GE gas turbines at a level of detail appropriate for system level operations, balance of

- critical settings and limits for machine operation with
- as much simplification where possible to support requirements of (computational) performance and high-level control from the network / system operator.

Since established the standard (or basis) for many modern electronically-controlled power gas turbine models (e.g. used for the KWINANA_GTs)

The set of highlighted control components includes an Acceleration Control block. From the cited guide:
"Acceleration control mode is rarely active while the unit is on-line and operational. It is typically active during startup and during a sudden speed change, such as a breaker opening. If the control mode is enabled, default values are typically used. Parameters aset, Ka, and Ta represent an acceleration limits and can be disabled by setting asset to a large value, so it is not selected in the low value select logic. These parameters are not typically verified by test due to the difficulty of conducting such tests."

Historically, the balance of economics/risk relative to the cost and difficulty of parameter testing has not been favourable, however the *acceleration control has always been* *recognised as a critical limit in turbine operation*. Consider e.g. the testing and investigation necessary for jet-engine application.

This context of this presentation is that acceleration (i.e. ROCOF) control is becomes relevant for electrical generation applications.

Proposed ROCOF limit schedule

1. Phase 1 (Market Start):
   - 0.5 Hz/s limit:
     - All connections without declared Ride-Through Capability deemed = 0.5 Hz/s
     - Constant input to dispatch solution
   - "Banding" of cost allocation for higher tolerance
     - e.g. what proportion to facility with 0.51 Hz/s tolerance (investigation ongoing)

2. Phase 2 (+2-5 years):
   - deemed 1.0 Hz/s tolerance for non-declared loads
     - AEMO to conduct ongoing monitoring:
       - Incident reviews
       - Industry developments
       - Participant advice
   - Dynamic dispatch input:
     - Lowest active facility tolerance
     - Possible per-interval application (investigation ongoing)

AEMO

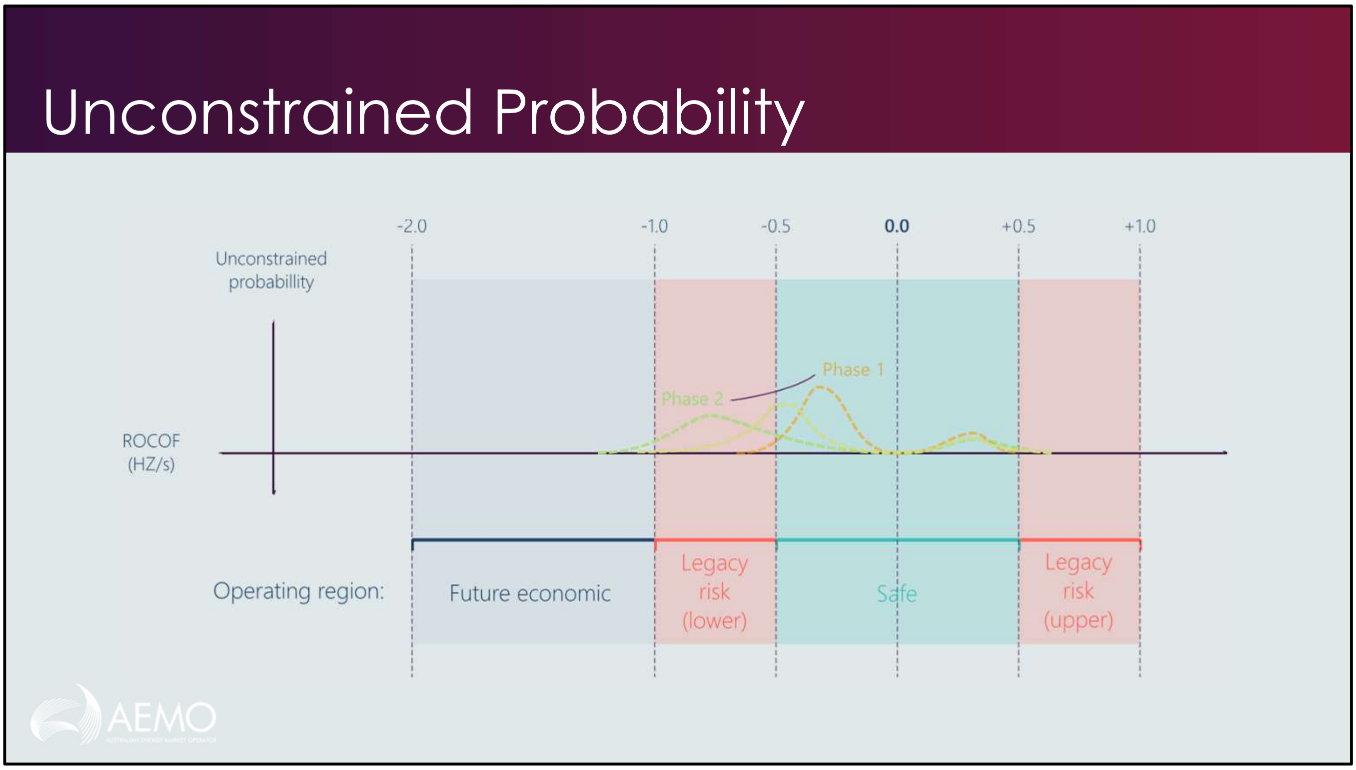
The limit is proposed to be deployed in two stages:

Initially with a fixed 0.5 Hz/s input to the dispatch engine, coinciding with the array of changes at market start. This simplification allows for initial testing of new market systems + establishing of processes alongside the relatively limited forecast needs for ROCOF service in the near-term

One possible outcome is very limited procurement of the service during low-demand (low-inertia) periods, that amounts to a net *payment* to baseload plant to ride through these troughs. This is a net win for the SWIS. With limited impact, it may not be necessary to complicate the system any further for some time.

A second phase is envisioned with a variable start date: key feature is a shift to a dynamic dispatch input to match the least-tolerant active facility. The timing of this switch is primarily determined by:

- Observed market dynamics: once the new systems are established, market conditions dictate whether further the introduction of further complexity is beneficial
  - E.g. ongoing costs of ~$100,000's / annum spread across wide userbase unlikely to warrant changes
- Development in understanding of ROCOF limits and physical characteristics



Highly stylised diagram to further illustrate the concept.

Dashed line shows the approximate probability of optimal dispatch in the absence of any ROCOF constraint (e.g. as dispatched today).

In Phase 1:

- Any operation inside +/-0.5 Hz/s has 0 economic relevance (constraint does not bind): all facilities are tolerant
- ~No probability of operation > 0.5Hz/s due to lower credible load contingency size
- the tail <-0.5 H/s will always bind due to load withstand limit
    - Costs shared between relatively large base
- Use this time to:
    - test suitability and performance of ROCOF dispatch mechanism / iron out operational issues + tweak settings
    - allow participants to adapt bidding + operational strategies, assess outlook for

Phase 2 (+2-5 years)

- Economic relevance varies according to facility performance (including Network) and bidding strategy (not forecastable)
- Tail <-1Hz/s will always bind on load limit

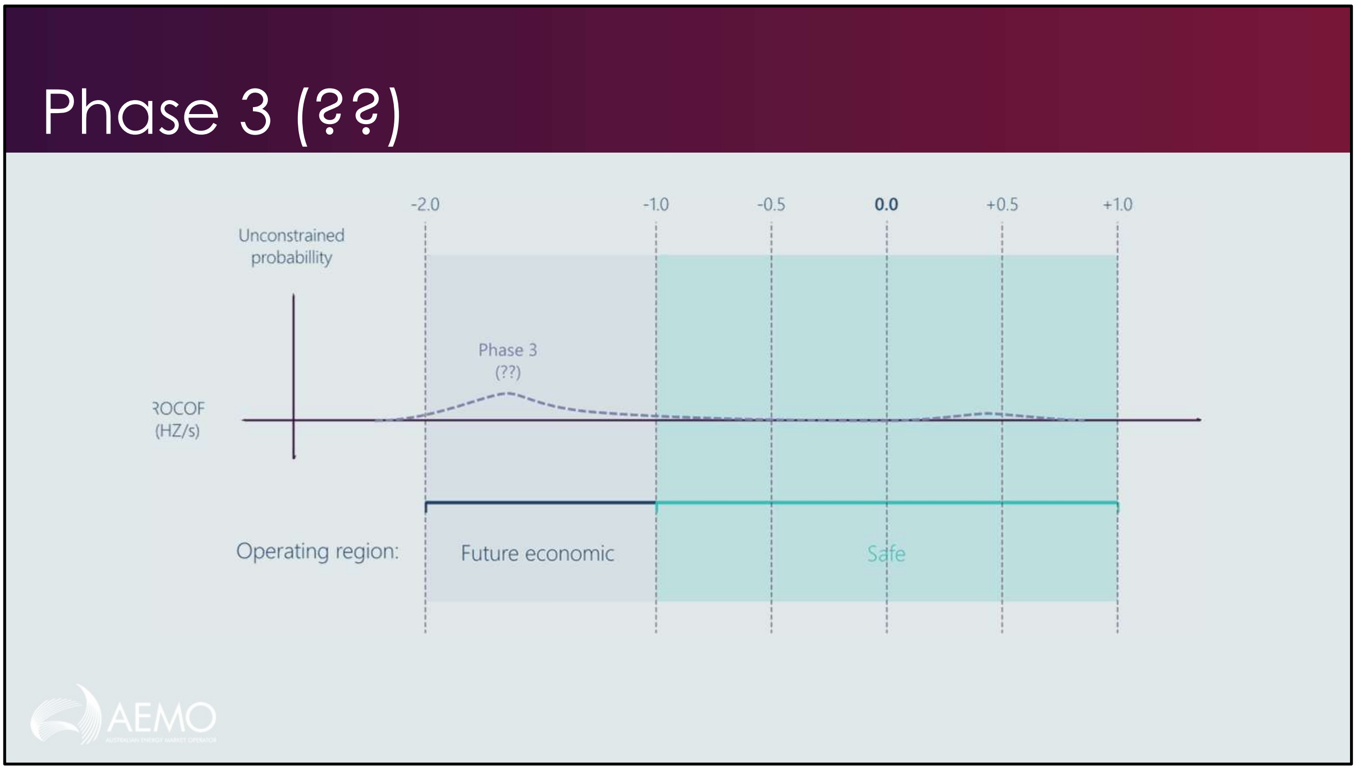
- Use this time to:
    - Gradually steer system into higher-uncertainty operating zone + gather performance data

Key variables that may be adjusted following operational experience:
- timing of stage transition
- threshold of load tolerance

E.g. brought forward if SCED shows early promise / high engagement from load facilities + industry development.

Summary

- Outlook for ROCOF service is *uncertain,* both required volume and prices
  - framework is designed to adaptively stage time and flexibility in response
    - Incentivise investigation + development of facility tolerance
    - Allow time (~years) for more predictable market development and commercial planning
- Option to assess and declare ROCOF tolerance is immediately available
  - A facility with >1.0 Hz/s tolerance is unlikely to constrain the SWIS in the near-term
    - Faces ~0 cost in Phase 1 (2-5 years), likely minimal cost through Phase 2 (5-10+ years)
- Costs are otherwise initially allocated over relatively large userbase
  - Will concentrate progressively as other participants certify, and with the shift to Phase 2
- Running strategy option to avoid operation during high-cost periods
  - E.g. low-demand / low-inertia / negative energy price conditions (but likely high ESS prices too)
- If the progression reaches 1.5 – 2.0 Hz/s, need for any ROCOF service (and therefore cost) is effectively eliminated



Conceptually, this framework + schedule suggests a future operating state at significantly decreased / near-0 scheduled inertia.

Perhaps 10+ years from market start: it is meaningless to forecast these things operationally, conceptually however, the framework lends itself to a natural path forward.

In general, a situation with ROCOF > 1.0 Hz/s will almost certainly bind on nadir limits first.

For this operating regime, the frequency operating range (contingency) would also have to be adjusted: something to consider at a later date…

Energy Transformation
Implementation Unit

Storage participation in the Reserve Capacity Mechanism

Agenda

The Reserve Capacity Mechanism

Functions to ensure that there is enough capacity in the SWIS to meet the Planning Criterion

The WEM Rules require AEMO to use different methods to certify the capacity that can be provided by different types of facilities

However, the underlying basis remains the same – it is an assessment of the facility's contribution to meeting peak demand

There is currently no bespoke method for accrediting storage facilities or enabling their participation in the RCM

Existing methods of accreditation

Scheduled generators

Accreditation method

- Accredited for what the facility can produce at an air temperature of 41 degrees Celsius
- Requirements for fuel supply, availability and transport

Obligations once assigned capacity credits

- To make capacity available in every interval.
- Dynamic refunds apply where obligations are not met.

Difficulty in applying to storage facilities

- Fuel supply, transport and availability requirements would preclude storage being accredited
- Storage facilities cannot be available in every interval

Intermittent generators

Accreditation method	• Accredited based on estimation of likely contribution during peak LSG (load for scheduled generation) intervals • Based on Relevant Level Methodology
Obligations once assigned capacity credits	• Reserve Capacity Obligation Quantity is zero
Difficulty in applying to storage facilities	• Assumptions in the RLM that don’t translate well for storage facilities • Reasonable to impose some obligations to make capacity available given controllability

Demand side providers

Accreditation method

- The amount by which the demand from the load can be curtailed
- Based on relevant demand in 200 peak hours in the previous capacity year

Obligations once assigned capacity credits

- RCOQ applies from 8am – 8pm each day.
- RCOQ falls to zero if they have been dispatched for a certain number of hours within a day or year

Difficulty in applying to storage facilities

- Market signals should (generally) be incentivizing storage facilities to discharge at peak
- Cannot be available in every interval from 8am-8pm

Alternative method for storage facilities

Derating

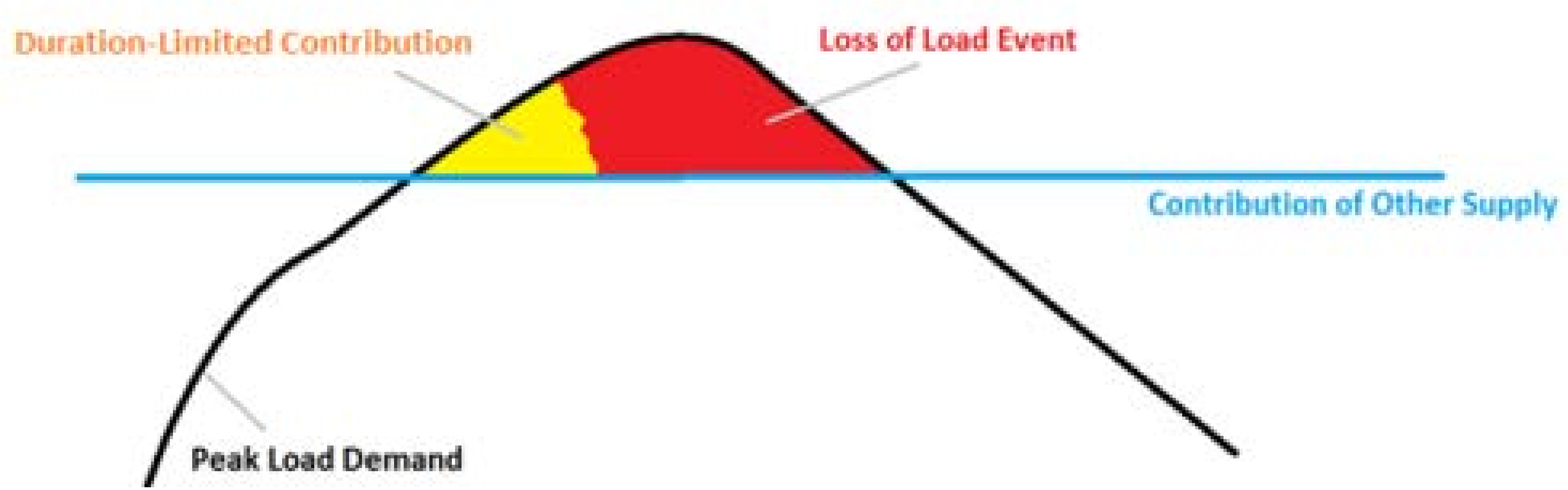
Determine capacity and duration

- Assess ability to sustain certain level of output over a given time period.

De-rate based on duration

- Account for the differences between the contribution that resources of different durations make to reliability by derating

Premise of derating



Source: https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf

International examples
United Kingdom

Final De-Ratings Per Duration in Hours	2021/22
Storage Duration: 0.5h	17.89%
Storage Duration: 1h	36.44%
Storage Duration: 1.5h	52.28%
Storage Duration: 2h	64.79%
Storage Duration: 2.5h	75.47%
Storage Duration: 3h	82.03%
Storage Duration: 3.5h	85.74%
Storage Duration: 4h +	96.11%

International examples

Ireland

	Hours of Storage											
Unit Size (MW)	0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0	5.5	6.0 or greater
1 -> 10	0.251	0.429	0.556	0.646	0.708	0.751	0.780	0.801	0.819	0.838	0.862	0.888
11 -> 20	0.244	0.422	0.550	0.640	0.701	0.744	0.773	0.794	0.812	0.832	0.856	0.881
21 -> 30	0.237	0.415	0.544	0.633	0.695	0.737	0.766	0.787	0.806	0.826	0.849	0.875
31 -> 40	0.231	0.409	0.538	0.627	0.688	0.730	0.759	0.781	0.799	0.819	0.843	0.868
41 -> 50	0.228	0.406	0.536	0.624	0.685	0.728	0.757	0.779	0.798	0.818	0.842	0.866
51 -> 60	0.229	0.407	0.537	0.625	0.686	0.730	0.760	0.782	0.802	0.823	0.846	0.868
61 -> 70	0.228	0.405	0.535	0.623	0.684	0.729	0.759	0.782	0.803	0.825	0.846	0.867
71 -> 80	0.224	0.400	0.528	0.617	0.679	0.724	0.755	0.779	0.801	0.823	0.844	0.864
81 -> 90	0.219	0.394	0.521	0.610	0.673	0.718	0.750	0.774	0.797	0.819	0.841	0.861
91 -> 100	0.215	0.387	0.513	0.602	0.665	0.711	0.744	0.769	0.792	0.815	0.836	0.856
101 -> 110	0.211	0.381	0.506	0.595	0.659	0.705	0.738	0.763	0.787	0.809	0.830	0.850
111 -> 120	0.208	0.376	0.500	0.589	0.652	0.699	0.731	0.757	0.781	0.803	0.824	0.844
121 -> 130	0.206	0.371	0.494	0.583	0.646	0.692	0.725	0.751	0.775	0.797	0.818	0.838
131 -> 140	0.203	0.367	0.488	0.577	0.640	0.686	0.719	0.745	0.768	0.791	0.812	0.831
141 -> 150	0.200	0.362	0.483	0.570	0.633	0.679	0.712	0.739	0.762	0.785	0.805	0.825
151 -> 160	0.197	0.357	0.477	0.564	0.627	0.673	0.706	0.733	0.756	0.779	0.799	0.819
161 -> 170	0.195	0.352	0.471	0.558	0.620	0.667	0.699	0.727	0.750	0.773	0.793	0.812
171 -> 180	0.192	0.347	0.465	0.552	0.614	0.660	0.693	0.721	0.744	0.767	0.787	0.806
181 -> 190	0.189	0.342	0.459	0.545	0.608	0.654	0.687	0.715	0.738	0.760	0.780	0.800
191 -> 200	0.187	0.338	0.453	0.539	0.601	0.648	0.680	0.709	0.732	0.754	0.774	0.794

Reserve Capacity Obligation Quantity (RCOQ)

Considerations

Need to impose obligations to be available in the energy market to ensure that the reliability standard can be met

Need to ensure appropriate flexibility for energy limited resources given range of services that can be provided

Proposed option

Storage facilities will have some obligations to make energy available to the market

This obligation will be for a limited, defined number of hours per day, recognising the duration limited nature of storage facilities.

Obligation to be determined and advised in advance.

Reserve capacity refunds

Refunds for Demand Side Providers are adjusted to reflect their availability requirements

- Price used to calculate refunds for Demand Side Providers: Reserve Capacity Price ÷ 400
- Price used to calculate refunds for Scheduled Generators: Monthly Reserve Capacity Price ÷ number of intervals in the month

Refunds for storage facilities will calibrated to reflect that they don’t have the same availability requirements

Hybrid facilities

Hybrid conventional/storage facility

Accreditation method

- Assess capability of scheduled generation component and storage component separately using respective accreditation methods.

Obligations once certified

- RCOQ associated with capacity credits for scheduled generation component apply at all times.
- RCOQ associated with capacity credits for storage components apply in relevant intervals.

Hybrid intermittent/storage facility

Accreditation method

- Assess capability of intermittent component and storage component separately using respective accreditation methods.
- Split out output behind the meter to calculate relevant level for intermittent component.

Obligations once certified

- No RCOQ for intermittent component as per current Rules.
- RCOQ associated with capacity credits for storage component to apply in relevant intervals.

Individual reserve capacity requirement (IRCR)

IRCR for storage facilities

Current state	Future state
• To fund capacity procured through the RCM, Market Customers incur an Individual Reserve Capacity Requirement (IRCR) obligation based on their consumption during certain peak periods.	• Registration taxonomy will only include Market Participants. Market Generators and Market Customers will not exist. • Market Participants who consume during relevant intervals will incur an IRCR. This will include storage facilities. • Consideration will need to be given to circumstances where a facility is instructed or directed to consume during peak

Trigger for review

Review of arrangements

A requirement to review the arrangements for the way that storage facilities participate in the Reserve Capacity Mechanism will be included in the Wholesale Electricity Market Rules.

Meeting close

- Questions or feedback can be emailed to TDOWG@energy.wa.gov.au

- Next meetings:
  - **TDOWG 12** - Thursday 30 April, 10am – 11:30am: DER Roadmap
  - **WRIG 2** – Thursday 7 May, 9:30am – 12noon.
  - **TDOWG 13** - Tuesday 26 May, 9:30am – 12noon.