GHD
Advisory

AS Engineering and Technical Review

PSOWG Briefing – D Bones

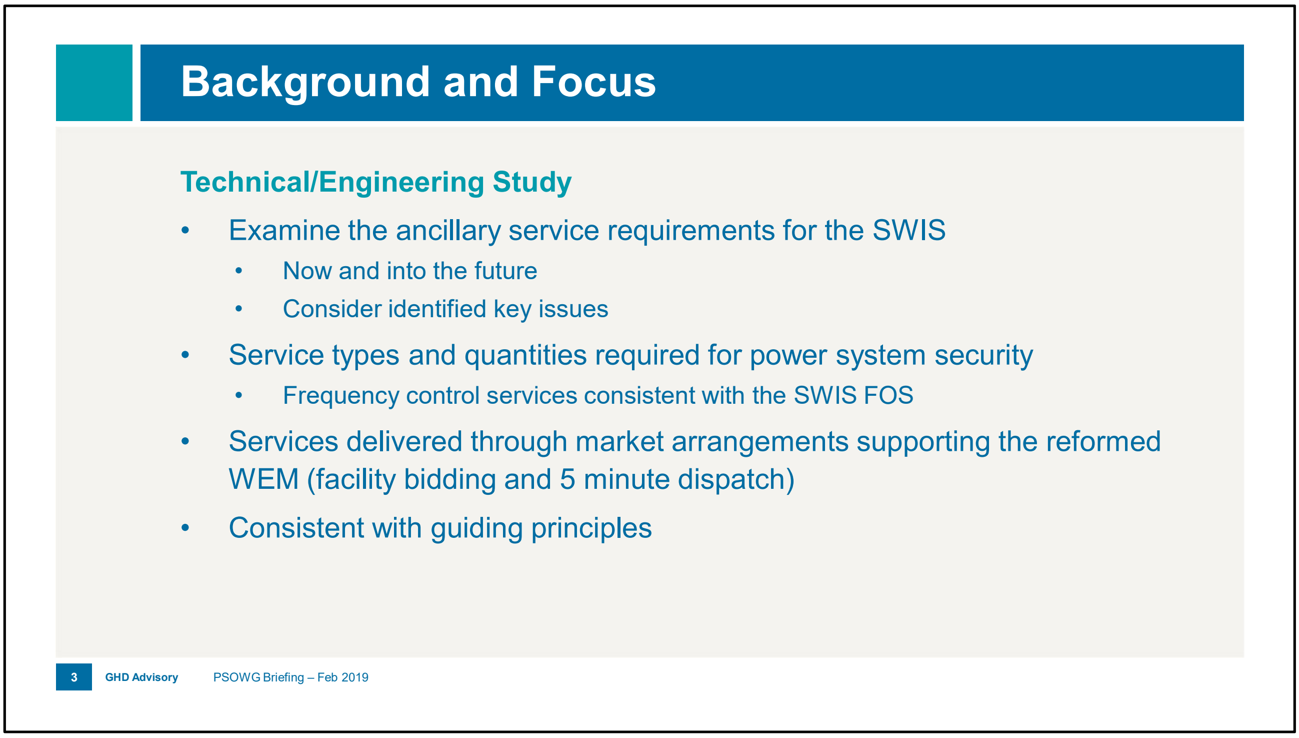
11 February 2019

Objective: Overview of AS review GHD Scope

Outline

- Background & Areas of Focus
- Motivation for Change
- Guiding Principles and Key Issues
- Approach
- Key Results and Recommendations
  - Contingency Frequency Control
  - Frequency Regulation
  - System Strength
- Next Steps and Consultation Process

This slide provides an outline of the presentation today which provides an update on the technical/engineering review of AS that GHD has undertaken. Our review is focussed on matters covering the types of service and the specification of the amount of service as distinct from market design issues.



The aim of the study has been to identify key deficiencies with the existing AS arrangements and articulate the AS services that will best meet the current and future needs of SWIS. Our assessment and review is focussed on defining a set of services that can deliver power system security and support the proposed changes to the WEM.

Motivation – Current Issues

The current Ancillary Service framework present difficulties for managing system security:

- **Relies on AEMO being able to access services via the Synergy portfolio**
- **Unsuitable for propose market changes**

These difficulties present an immediate motivation for change

Theme	Issues	Impact
Definition and specification of services	Lack of alignment between setting requirements and meeting FOS Service definitions not technology neutral	Under specified → System security Over specified → increased cost Reduced competition → increased cost
Energy market interaction	No co-optimisation Longer dispatch interval → greater forecast errors	Increased cost Increased regulation requirement
Response to contingencies	Counting of LFAS for Spinning Reserve Response delivered in 6s Primary response not currently supported by any frequency restoration service	Potential system security issue Too slow to meet FOS in all conditions Need secondary response services
Regulation of frequency	Currently masking many issues 72 MW market figure may not represent accurate usage of regulation service	Difficult to define required amount Replenishment difficult to manage without portfolio

3 GHD Advisory PSOWG Briefing – Feb 2019

The existing AS framework encompasses:

- the regulations defining each ancillary services
- the way the required quantity for each service is specified and
- The arrangements for making those services available to the power system

The current framework has several problems that have been noted and investigated in many previous reviews. Generally the ability of AEMO to utilise the Synergy portfolio to acquire services has helped deliver system security but often masks some underlying issues. This definitely needs addressing with any move to implement facility bidding.

The table identifies the key areas of concern grouped under four themes. The table provides a summarised view of the impacts created by each issue:

<u>Definition and specification of services</u>

Various reviews have identified problems in the way services are defined. Key issues include:

- Inconsistency between the service definition and the time specified in the FOS, or services defined in a manner that does not linked directly to the FOS. These create difficulties in demonstrating a clear alignment between the service requirement and that level of service required to maintain system security i.e. meet the FOS. If the service requirement is too high this can potential lead to higher than necessary costs, if the service requirement is insufficient this creates a power system security risk
- Hard coded quantities in the rules, requirement for overlap
- Underlying assumption that System Management will restore frequency using “other” mechanism
- Definitions and terminology that implies delivery of the service by a particular technology, e.g. spinning reserve suggests a service provided by a rotating machine. This can lead to a presumed bias for service to come from particular technologies which may reduce competition and increase costs. Furthermore the AS PSOP specifies AEMO’s process for certifying AS providers. The SR section clearly assumes service is only provided from either a scheduled generation or a load facility, i.e. would exclude non-scheduled generators, or a BESS from being classified to provide SR. Another example is calling the regulation service load following when it fact the LFAS acts to correct all manner of things that cause a deviation in frequency

Energy market interaction

There are issues that arise due the interaction of ancillary service requirements and the energy market. Key issues include:

- Currently services and the dispatch in the energy market are not co-optimised. Co-optimisation would allow increased efficiency by allowing targets in the energy market to be adjusted to minimise the total cost of energy and ancillary services. For example if a contingency service was in short supply and highly priced, co-optimisation might adjust dispatch to reduce the size of the largest contingency and hence reduce the requirement
- The longer dispatch interval leads to greater forecast errors and the longer dispatch period means a greater delay before any utilised services can be replenished. This can increase the requirement for regulation service and create a greater need for services providing secondary and tertiary response

Response to contingencies

Currently the arresting of the frequency change following a contingency relies on LRR and SR services. Some of the key issues with these services include:

- The regulations specify that LFAS_up capacity is counted as contributing to meeting the SR requirement while there is no similar provision in the regulations for counting LFAS_down capacity towards meeting the requirement for LRR. GHD agrees with other assessments that the different treatment of the LFAS_Up and Down capacity is difficult to justify. The analysis we have undertaken however does raise some concerns with the practice of counting LFAS towards meeting the SR requirement. We understand that there is a perception that this practice leads to reduced cost for meeting the SR requirement, however it does mean that maintaining sufficient LFAS raise range is very important to prevent breaching the FOS following a generator contingency.

  The 4s SCADA data for the SWIS clearly shows that the level of LFAS service available at any time varies as it is continually being used to regulate frequency. Assuming 72 MW upwards LFAS is available for SR and then procuring less SR creates a risk that if a contingency occurs when there is less than 72 MW of LFAS range available, the frequency may fall below the limits specified in the FOS and trigger UFLS. This practice exposes the system to being insecure. To minimise the risk of being insecure, AEMO is encouraged to avoid having less than 72MW of upwards LFAS range. This potentially gives rise to adjusting dispatch to refresh used LFAS range more often than would be the case if LFAS was not counted toward SR.

  Adopting a practice of not counting LFAS towards meeting SR provides several advantages including:
    - greater confidence that the FOS will not be breached, thereby improving system security
    - greater clarity regarding the differing roles performed by LFAS and SR service. This may be important in deciding appropriate compliance and performance standards and for making economic trade-off decisions (e.g. largest contingency size)
    - Potentially reduces the need for secondary response service (to be discussed further later in the presentation)
- The SR service is currently specified as delivering a 6 second response. Analysis shows that in practice, the response that the power system actually receives is faster than 6s which actually acts to ensure the FOS is maintained. GHD recommends that this be reflected in the revised Ancillary Service design.
- Additionally, as the power system evolves and we get lower levels of synchronous generation, it will become increasingly important that a significant amount of the primary frequency response is delivered in a much quicker time frame than 6s. Sticking with the current 6s definition will not identify a service requirement which is sufficient to meet the FOS under all conditions
- Currently the SR requirement allows for class A, B and C service with class A service need only be sustained for 60s. Primary frequency response services that are sustained are of greater value as they help to avoid the need for secondary frequency response. The current pricing arrangements do not allow for that differentiation of value for these different timeframes.
- In the slides presented by AEMO, an alternative model for contingency frequency management was presented. GHD have adopted this terminology and modelling approach as an appropriate framework to use for in this ancillary services study. In the rest of the presentation we will refer to the same types of terminology (e.g. Primary Frequency Response, Secondary Frequency Response)

Regulation of frequency

LFAS is the ancillary service relied upon for regulating frequency to 50 Hz, correcting the moment to moment imbalances in load and generation. There are many factors that give rise to the need for regulation services, some of these are influenced by the behaviour of market participants, others by energy market design while others reflect inherent uncertainty in being able to predict demand requirements and the generation from renewable energy generators. Some of the things that can give rise to a need for regulation include:

- Errors in the ability to accurately forecast the demand and renewable generation that will be present at the end of the dispatch interval at the time the dispatch solution is run – forecast errors.
- Errors in scheduled generators following their dispatch target

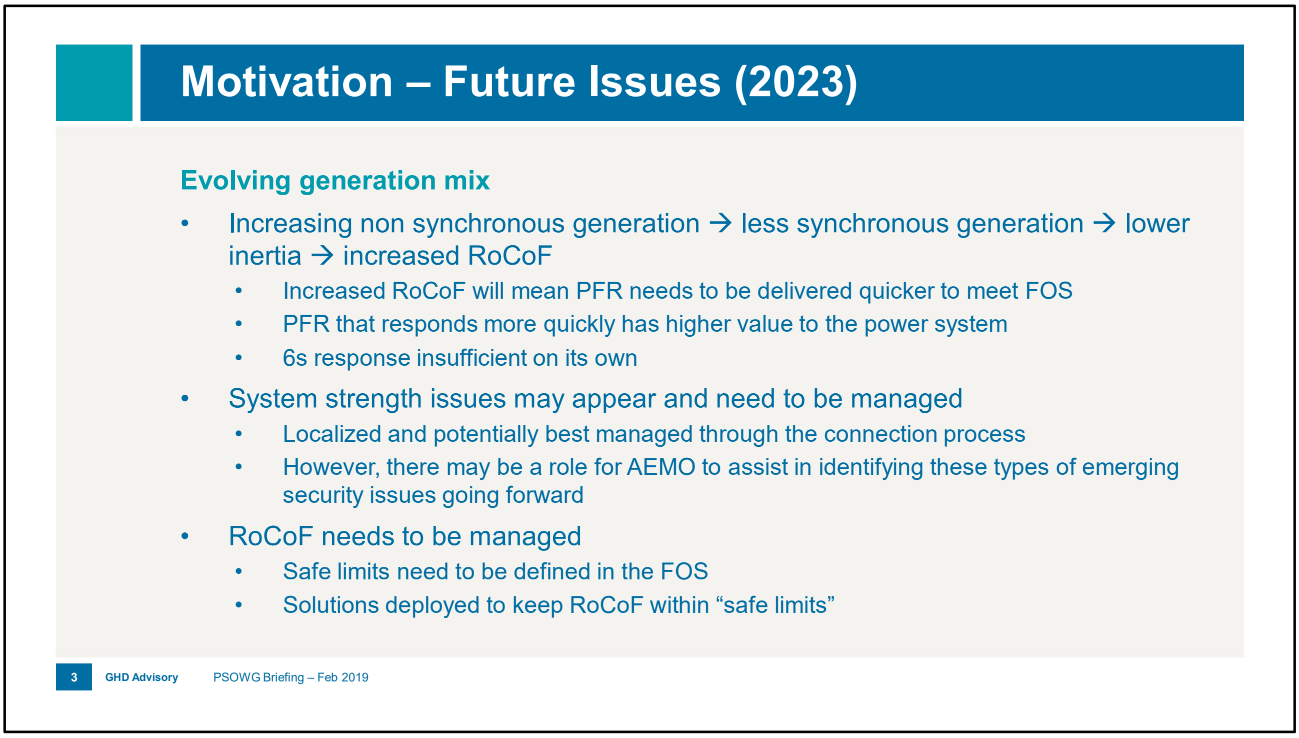
- Scheduled generators ramping quickly at the start of a dispatch interval to their new dispatch target and out stripping the change in demand supplied from scheduled generation
- Ramping of demand outstripping the capability of units dispatch in the energy market

When they occur, each of these creates a load/generation imbalance and a deviation in frequency which triggers an almost immediate correction achieved by the AGC system issuing a revised target to generators enabled to provide LFAS. While the combined effect of all of these factors can be seen it is very difficult to observe the individual contribution of each towards the requirement amount of regulations service.

The ability to call on the Synergy portfolio to provide LFAS and fast re-balancing provides AEMO with a manageable process for replenishing regulation service when it is used, and effectively increasing the amount of range available to cope with emerging weather events such as a large cloud bank passing over Perth Metro area. This coupled with the current process for paying for the service has meant that the actual LFAS requirement is poorly defined lacking a clear link to the FOS.

To adopt facility bidding and rely on a market for the replenishment of LFAS capability the requirement needs better specification.

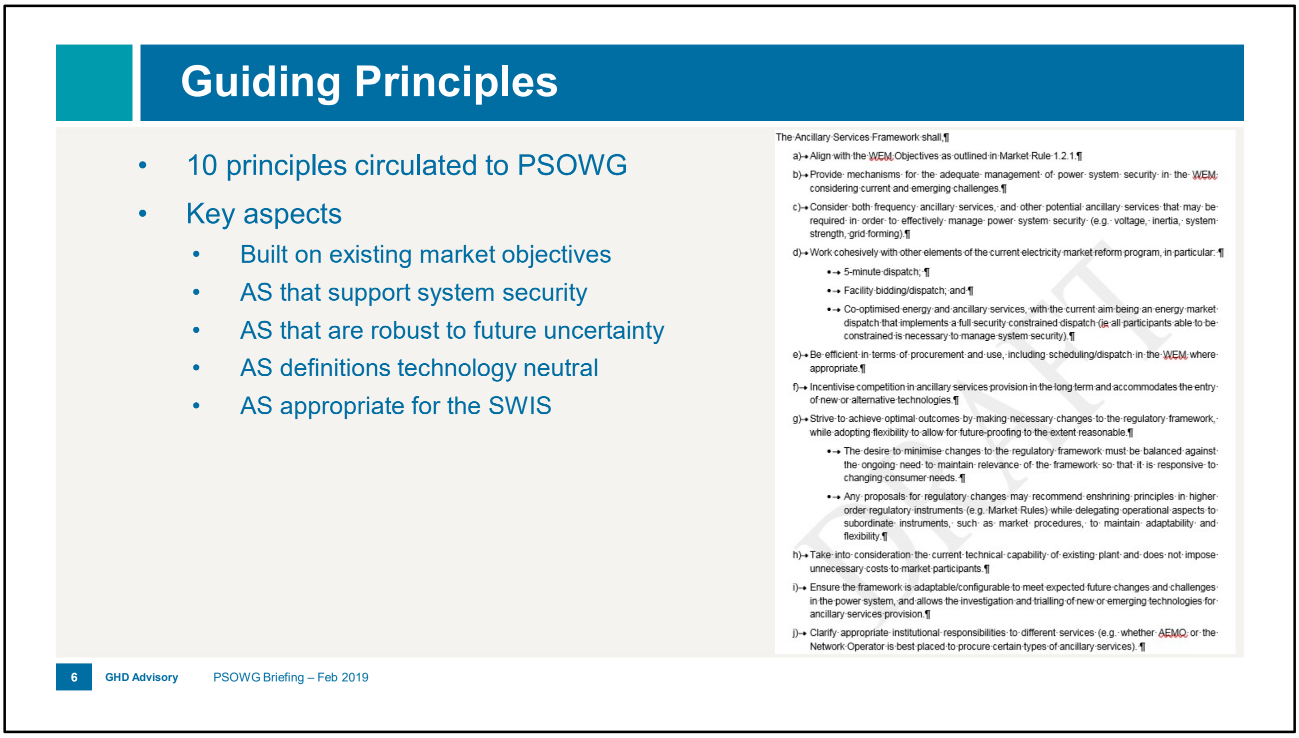
Understanding the actual current utilisation of the service is valuable as it sets a benchmark for where the service requirement might be set in the future taking into account a move to a shorter dispatch period which will generally reduce the LFAS requirement below that benchmark.



The continue growth in non-synchronous generation will cause a need for revisions to the ancillary service frameworks. In some instances reinforcing the case to address the previously identifies concerns while also giving rise to new issues.

A key change that arises with more non-synchronous generation is less synchronous generation resulting in lower inertia and therefore a higher RoCoF for the same size contingency event.

- As RoCoF increases, the speed of response delivered by primary frequency response providers needs to increase to ensure the frequency Nadir stays above the levels specified in the FOS
- With less synchronous generation online, it will become more important for ancillary services to be provided from a greater set of service providers
- As the level of non-synchronous generation grows, there will be an increasing potential for the inertia on the system to fall well below the levels typically experienced on the SWIS. Minimum load conditions are likely to be where this issue emerges first. As a point of reference, the studies we did using the minimum demand condition from 2018 had approximately 12000 MWs of inertia. Studies undertaken for the same condition in 2023 indicated inertia levels at or below 6000 MWs are likely.
- At these lower levels of inertia, the management of RoCoF becomes an issue and risks increasing to a level which exceeds a safe operating point. In today's terms, typically a severe generator contingency on the SWIS would result in a RoCoF of around 0.5 Hz/s. The simulations undertaken for 2023 minimum demand conditions indicate that could increase toward 2 Hz/s. It is important therefore that any AS reform consider putting in place measure that could help control RoCoF.
- To that end, GHD recommends building appropriately timed PFR sub-services. Initial studies indicate required timeframes are likely to be 1s and 250ms going forward



As noted when we last presented to the PSOWG the set of guiding principles included in this slide have bee used to guide the review

Analysis Themes

Theme	Key Issues Considered
Increased non-synchronous generation	Reduced inertia → changes required amount of PFR and required speed of response Less Synch Gen → Services required from other providers Declining inertia → increased RoCoF → new service
Service Types and Quantities (RoCoF, PFR, SFR and Regulation)	New service required to keep RoCoF within plant capability (add to FOS) PFR and RoCoF service sufficient to arrest frequency to FOS limits SFR sufficient to recover back to 50 Hz within FOS specified timeframes Regulation sufficient to stay within normal band as specified in FOS Simulation and statistical analysis to specify requirements
Specification	Service defined clearly removing inappropriate overlaps and linking to the FOS
Ready Reserve Standard	What is this really? How does it relate to SFR and a 5-minute dispatch framework with reference to ancillary service recovery
Technology Neutral	Avoid service specifications that exclude provision of service from some providers
System strength & voltage control	When and where? Appropriate solutions? Are there potential economic trade-offs?
Equity	Better quantify service provided from mandatory capability

5 GHD Advisory PSOWG Briefing – Feb 2019

The review has considered a extensive list of current and future AS related issues identified through a range of previous reviews and feedback from market participants and stakeholders. The key Issues list was presented to the September PSOWG. This table provides a summary grouping the issues by theme and identifying for each theme the key considerations arising from the engineering study.

A key theme is the articulation of the required set of services and the quantities required for different dispatch conditions.

A second theme is coping with the evolving generation mix as more renewable generation connects displacing synchronous generation. This gives rise to a number of areas of concern and requires a revised set of frequency control services.

By simulating the recovery to 50 Hz following generation and load contingencies the AS review is exploring the role of a ready reserve standard, and what this means in relation to SFR and ancillary service recovery. This assessment overlaps with studying the requirement for secondary frequency response and the benefits of not counting regulation or LFAS capacity toward meeting the primary frequency response target.

The specification of the contingency response services and in particular definitions for how long the services are sustained need to be carefully considered against the ready reserve standard. The ready reserve standard is intended to be used when assessing outage requests to ensure that there is sufficient additional capacity available that can be brought online following a contingency and replenish the response provide through the combination of contingency response services. It is important that definitions of response times and quantities for the ready reserve service align with the defined performance requirements for the contingency response service.

Other issues have generally been explore by simulations that vary type and quantity of services, to establish the combination required to meet the Frequency Operating Standard (FOS) using the models established by AEMO

Approach

Separately considered frequency regulation, contingency frequency response and system strength

- **Frequency Regulation**
  - 2018 LFAS review recommended using forecast error to set regulation requirement
  - Extended statistical analysis of forecast errors to investigate impact of 5 min dispatch and trends that might support a dynamic regulation requirement
  - Further investigation required into the other sources of regulation and their impacts in a 5-minute dispatch environment
- **Contingency Frequency Response**
  - Used both lumped DIgSILENT model and AEMO aggregate model
  - DIgSILENT Time domain studies to investigate the capability of different technologies to provide future faster PFR services
  - Aggregate model provides the best methodology for analyzing future quantities required to maintain security
- **System strength**
  - DIgSILENT fault level studies using WP detailed model for the SWIS

The focus of the engineering study has been on frequency control. We have separately considered the service types and requirements needed now and into the future to manage both:

- The regulation of frequency i.e. continually correcting imbalances between load and generation keeping the frequency within the normal band and controlled to 50 Hz
- The control of frequency following large load and generation contingencies.

Different tools and approaches were used for investigating each aspect of frequency control. The objective in each case is to define a set of services that would allow frequency to be controlled within the SWIS FOS while supporting the evolving WEM (i.e. facility bidding, 5 minute dispatch, co-optimisation etc.).

We have also investigated emerging system strength issues. This work is indicative seeking to illustrate the problem and inform decisions regarding the best approach to address the issue.

The different simulation tools and analysis methods applied are listed on the slide. The following slide highlights some of the key differences between the lumped and aggregate model.

Lumped vs Aggregate Model

DIgSILENT	Aggregate
Individual gen response	Aggregate system response
Accurate simulation requires accurate governor model, generator output reflects governor response to simulated frequency	Assumed a level of response in a specified timeframe (e.g. 2s and 6s)
Accuracy varies with generator and dispatch point	Accuracy depends on assumed response matching that provide by PFR providers
Slow to simulate large number of events and difficult to adapt model for very different dispatch scenarios	Quick to simulate, allows relationship between PFR and inertia to be assessed
Only applicable for PFR timeframe	Simulates both PFR and SFR timeframe

In the presentation before the break Leon provided a good deal of information on the Aggregate model and the motivation for developing it. This slide builds on that by outlining the key differences between the lumped model and the aggregate mode.

Both models have been used to study the PFR requirement for the actual 2018 minimum demand conditions, studies of contingencies have established a reasonable level of alignment between the two models for the 2018 minimum load case. In addition AEMO has reviewed a range of recorded under-frequency events and confirmed that the aggregate response observed can be reasonably replicated with the aggregate model.

The Aggregate model has been used to assess the requirement for PFR. SFR and RoCoF service required both in the current timeframes, and in future years for dispatch scenarios with significantly reduced minimum demand to be supplied by synchronous generation and hence much lower inertia. It is well suited to this analysis as it is quick to run multiple scenarios allowing the variation of PFR requirements with system conditions to be established.

The Aggregate model has also been extended to model the frequency recovery period and assess the level of SFR required.

The review of historical data coupled with the parallel simulation of events using DIgSILENT and the Aggregate model provide a level of validation of the Aggregate model.

GHD supports the use of the AEMO aggregate model to analyse and set the quantities of ancillary service going forward.

Key Results and Recommendations - Services

Service	Specification and potential suppliers
Primary Frequency Response (PFR)	Service that arrests frequency following a contingency event with the level specified by the quantity of response achieved in a specified timeframe (2s and 6s) Faster responding PFR required as RoCoF increases Should not count regulation service towards meeting PFR requirement Service from generator, load or BESS that responds automatically to locally sensed frequency
Secondary Frequency Response (SFR)	Service that responds to instructions issued by AEMO to restore frequency to the edge of the normal band Service provided by generator, load, BESS able to moderate output in response to AGC command including potential demand side response
Frequency Regulation	Service that continuously responds to AGC issued instructions to correct frequency errors within the normal band Service provided by generator, load, BESS able to moderate output in response to AGC command
RoCoF control service	Service required to prevent RoCoF exceeding “safe level” in future years 2 Hz/s across 250ms – synchronous inertia 1 Hz/s across 1s – synchronous inertia or fast frequency response Provided by synchronous inertia, FFR from BESS, fast interruptible load, synthetic inertia

It is proposed that a new set of services be adopted to replace the existing SR, LRS, and LFAS. The new services are listed on this slide together with a description of some of the key attributes of each service. We have been careful to define the service in terms of the control action provided rather than the technology used. This technology neutral specification and naming should help encourage more competition in the provision of services.

The rest of the presentation provides results regarding the services required for:

- Contingency frequency response
- Frequency regulation
- System Strength

In presenting the results I will focus on how they demonstrate a clear need for change. The recommendations present the directions that changes should take to keep pace with the evolving generation mix. Our recommendations are intended to provide a view of an appropriate ancillary service framework, rather than focusing on required quantities. The recommendations and results do help describe the key attributes of a revised AS framework and are presented as a means of allowing stakeholder feedback on the proposal.

Further work would be required to operationalize any of the recommended changes. Through that more detailed design process it is expected that further refinement would take place.

The “safe level” for RoCoF has been set to the minimum performance standard for generator ride through specified in the draft generator performance standard guideline released by WP in December 2018 to GIA generators. That level is also consistent with the minimum ride through requirement in the NER.

Mandatory requirements retained

Technical Rules include requirements for synchronous generators to provide a minimum standard of frequency response

- response available subject to the output
  - 4% droop response once the frequency deviation exceeds +/-0.025 Hz
  - no raise required above 85%, no lower beyond technical min
  - 10% of raise response sustained, 30% of lower response sustained

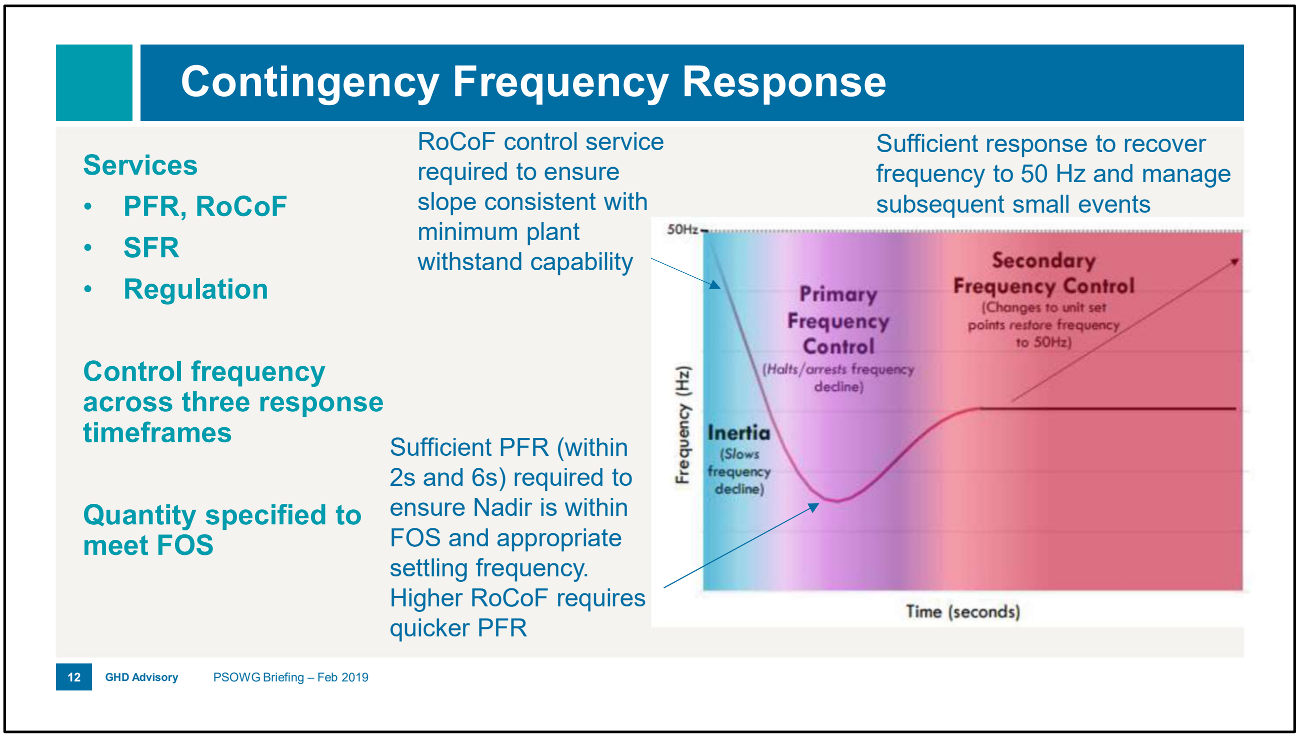
Recommend that this be retained but not seen as AS

- Added capability provides a more robust and resilient power system
- Avoids serious pitfalls of the alternative approach evident in the NEM
- Consistent with international practice
- Lower level of performance than expected from AS providers

We recommend that the existing mandatory requirements in the Technical Rules are maintained, meaning that synchronous generators continue to have a dead band set at 0.05 Hz and a 4% droop with that response provided subject to the power output of the generator. This means that it is likely under many conditions into the future that some contribution to frequency control will come from the mandatory provisions. This offers a capability which is slightly better than would be the case if we relied solely on the services sourced from AS providers. However the lower performance specifications and impact of dispatch level on service provided means that the mandatory response cannot be relied upon on its own to meet FOS requirements

We believe the retention of the mandatory requirements is appropriate as:

- It provides a shared contribution that maximises the capability available without constraining any non-AS providers
- This additional capacity can be very useful in providing a more robust and resilient power system
- Practical experience in the NEM has identified the alternative approach of relying just on capacity provided from AS markets has led to a much less robust and resilient power system particularly with respect to frequency control.
- In the NEM, this has led to increased potential for contingency events to result in load shedding and growing deterioration of frequency regulation
- In the future, consideration should also be given to extending the mandatory response requirements to non-synchronous generators. This idea is reflected in the generator performance standard guidelines released by Western Power to GIA generators prior to Christmas



The studies completed support moving from the existing set of services (LFAS, SR and LRR) to services that are better aligned with meeting the FOS as illustrated in this slide.

- Service names describe the control action the service delivers rather than the technology used to provide the service
- A new service to control RoCoF has been introduced to keep RoCoF within the minimum withstand capability of generating plant and thereby avoid the risk of escalation of a contingency if further generators were to trip. This will become more important into the future with declining inertia;
- PFR is the service that responds to arrest the change in frequency resulting from load and generation events, keeping the Nadir point within the FOS and settling to an appropriate frequency;
- SFR is the additional service accessed via AGC assist to drive frequency back to the outer edge of the normal band (49.8 Hz). This recovery would normally occur within minutes of the event. There is currently no explicit SFR service defined as part of the WEM AS framework although in practice the capability is achieve through a combination of the sustained response from SR and LRR providers, adjustments made to the Synergy fleet and other LFAS service providers to drive frequency back to 50 Hz. Those adjustments are currently made via a combination of AGC instructions and verbal request to unit controllers.
- Regulation service is provided by generators in AGC-base-full that respond to signals issued by the AGC system to correct small perturbations in frequency and return frequency from to 50 Hz.

The recommended set of services and quantities has been set to deliver the FOS.

RoCoF and PFR

High RoCoF may have undesirable consequences

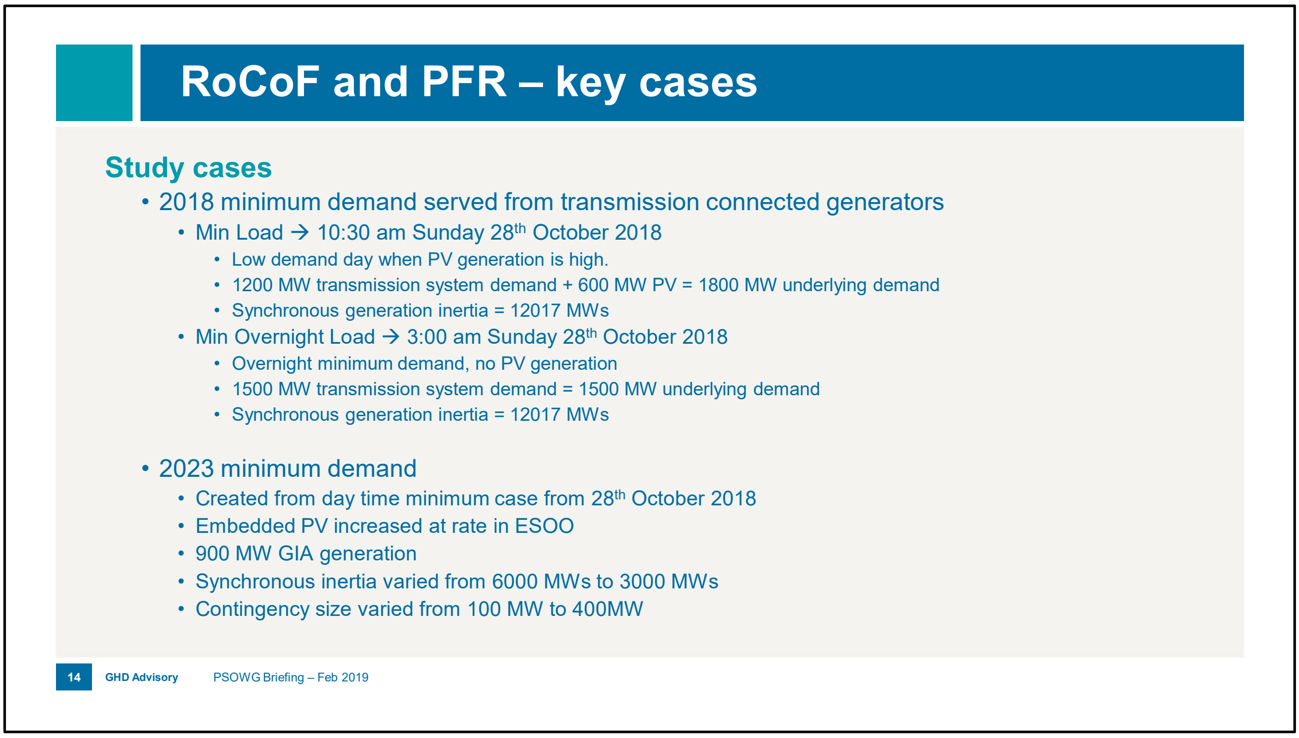
- High RoCoF may exceed generator ride through settings → plant trip to avoid damage → exacerbate frequency contingency → partial system collapse
- High RoCoF reduces time for control actions → insufficient time for UFLS → multiple contingency leads to system black (eg South Australia in 2016)
- Suggest need to control RoCoF to a “safe level”

Less synchronous generation → lower inertia → higher RoCoF → quicker PFR

- PFR requirement is dependent on RoCoF, both quantity and speed of response
- Specifying RoCoF control service helps define PFR requirement
- Currently there is sufficient inertia by default to meet minimum RoCoF requirements
- Over the next 5 years with growing large scale renewable generation and embedded PV, RoCoF will increase beyond a safe level, giving rise to a need for a RoCoF control

There is currently no service devoted to the control of RoCoF. Without such a service, the lower levels of synchronous generation likely to be experienced over the new 5 year will increase RoCoF to potentially unsafe levels.

Minimum demand conditions were studies to assess both the need for RoCoF control and the adequacy of PFR.



Over the next couple of slides I want to present and discuss some results that we have developed using the AEMO aggregate model and the lumped DIgSILENT model. Our studies focused on minimum demand conditions as that condition highlights the interaction between inertia and primary frequency response requirements.

Minimum demand cases present arduous conditions for control of frequency following contingencies. The low levels of synchronous generation means that under these conditions:

- There is little additional response available other than that contracted to provide ancillary services
- The RoCoF will be higher as a result of the lower level of inertia
- The reduced load reduces the contribution from load relief (studies considered load relief between 1.0% and 1.5%)
- We can best observe how the PFR requirement varies with inertia and the size of the contingency using minimum demand cases
- We can observe the benefit of separating out a requirements for slower and faster PFR

The slide is intended to provide context for the results that follow and shows how we have developed a 2023 minimum demand case from that which happened in 2018.

While other loading conditions were considered, minimum demand was found to be the most limiting.

We studied both overnight and daytime minimum load cases but found that the daytime case was more limiting particular for future conditions due to the impact of continued growth in PV generation.

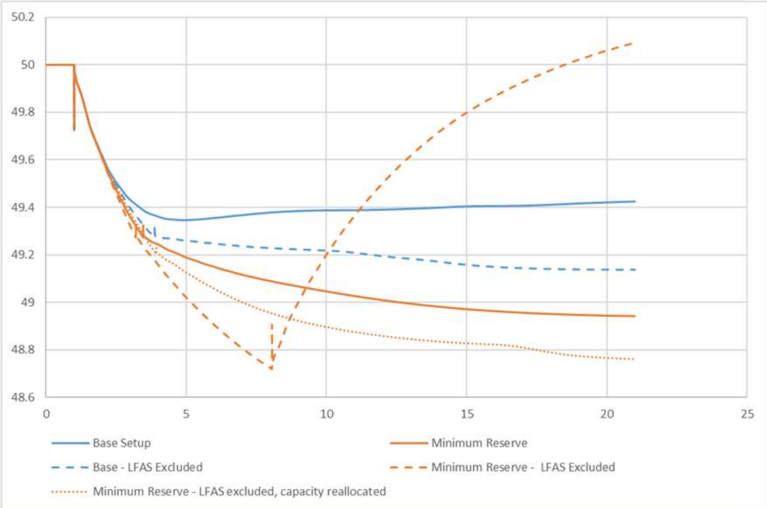
RoCoF and PFR – 2018 results (min load case)

FOS met if

- PFR excluding LFAS Capacity = 70% of contingency
- PFR including LFAS Capacity = 70% of contingency, provided no depletion of LFAS prior to contingency
- Result confirmed using Aggregate model and load relief factor of 1.3%
- Modelled actual capability providing 2s and 6s response

FOS breached if

- PFR including LFAS capacity = 70% of contingency and LFAS depleted prior to contingency
- Current approach of counting LFAS as SR is not guaranteed to meet FOS

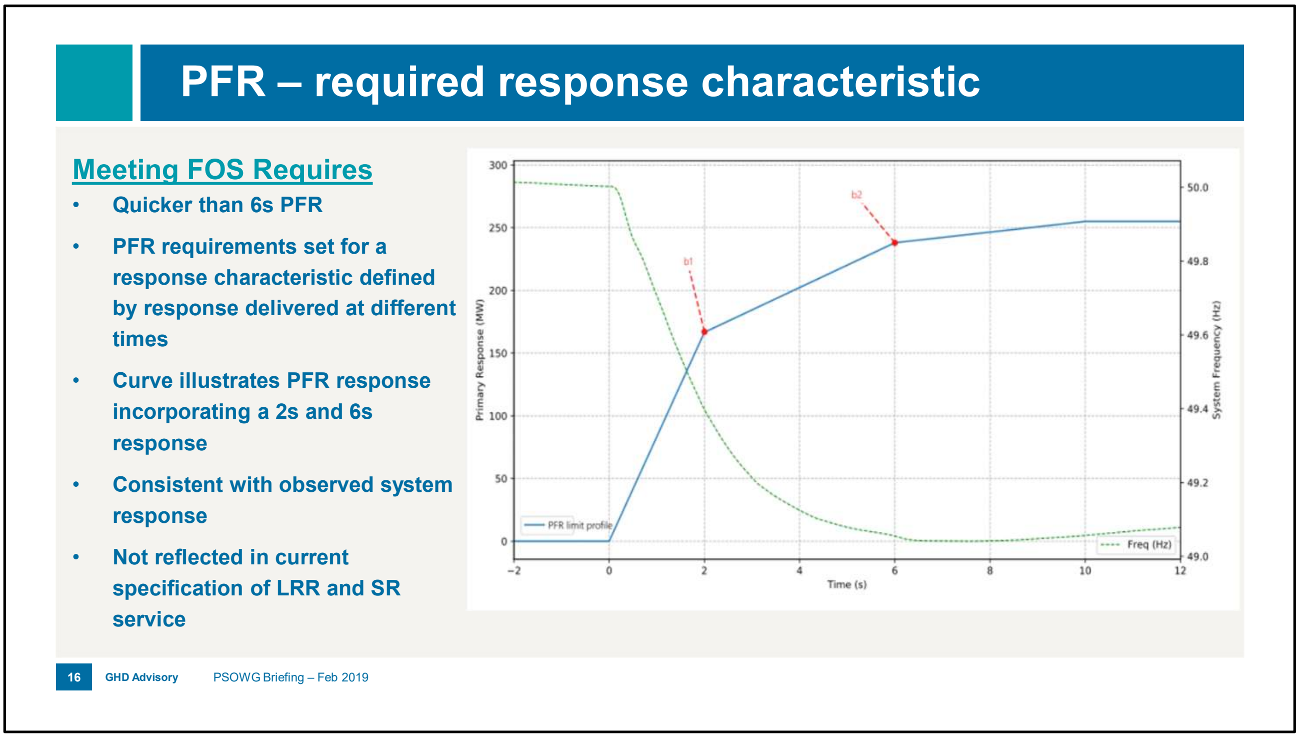


Studies of the limiting conditions in 2018 indicated that a 2s and 6s PFR service is able to restrict the degradation of frequency to the limits described in the FOS. Both single and multiple contingencies were assessed and found to keep a safe level of RoCoF and frequency nadir within the FOS, with one exception.

The current practice of counting LFAS capacity as SR exposes the SWIS to having insufficient contingency response in a scenario where the LFAS range was depleted prior to the contingency occurring. This has been confirmed by AEMO as evident in recent power system incidents.

This risk could be avoided if the LFAS range was no longer counted towards meeting the SR requirement.

Maintaining the current practice of counting LFAS toward SR runs the risk that a single contingency triggers uncontracted UFLS. This would be inconsistent with the FOS and is not recommended by GHD



Historical analysis of actual under frequency events shows that PFR defined in terms of 2s and 6s response provides a reasonable match for the current power system.

This implies that:

- generators providing spinning reserve are delivering a more valuable response than specifically defined by a narrow interpretation of the current SR and LRR service specification (i.e. response builds with time achieving appreciable response in 2s and greater response by 6s)
- The PFR chart shown here from the AEMO paper illustrates the point. With the blue line showing the aggregate PFR response which has been matched to the response observed in the power system. That response is clearly delivering a substantial amount of response before 6s. The current SR definition would allow a response that build more slowly as the requirement is to respond appropriately within 6s. Currently the PSOP specifies that to be classified for spinning reserve, the service from a scheduled generator must be provided by governor droop response which would suggest a response that increases with time.
- The actual response delivered ahead of 6s is very important for being able to meet the FOS particularly achieving the frequency Nadir above 48.75 for larger generator contingencies occurring when there is reduced inertia on the system and hence a higher RoCoF

The same is somewhat true for the response to over frequency events, however the reduced size of the contingency generally means a slow rate of increase of frequency meaning that a 2s response under current inertia levels for an over frequency event is less important.

As we move toward 2023, periods with lower inertia will become more frequent and the studies found that the PFR needs to be quicker than 6 s response currently specified for SR to meet the FOS.

This slide shows a dual break point characteristic for specification for PFR that was tested. We also considered a variant which also included an amount of 1s response, providing both FFR (to control RoCoF) and PFR

PFR delivered by a service provider could be specified by their response delivered by 2s and 6s assuming a specified frequency trace (say 1Hz/s for 1 s). We can then sum the contributions at 2s and 6s from offered services and select those offers that meet the PFR requirement at least costs. This is a variant on the approach illustrated in section 4.1 of the AEMO paper which offers the potential to also consider a 1s capability in the future as a means to manage RoCoF and keep the frequency Nadir within the level specified in the FOS.

The example in the AEMO paper specifies the PFR requirement as the capacity delivered by 6s assume a fixed portion of that is available within 2s. This approach is likely to be quite appropriate for current system conditions and would as demonstrated in the paper, potentially allow a requirement that changed by recognising the inertia available on the system and the size of the contingency. It is also consistent with system response actually observed during the event on 12 October 2016.

As the inertia decreases however, there may be value in separating the 2s and 6s requirement. This is illustrated with the results on the following slide.

RoCoF and PFR – 2023 results (min load case)

Load Relief = 1%	3000MWs						4000MWs					
Contingency Size (MW)	1s	2s	6s	2s EX	RoCoF (250ms)	RoCoF (1s)	1s	2s	6s	2s EX	RoCoF (250ms)	RoCoF (1s)
400 (Using 300MW PFR levels)					2.966772	1.967175					2.27492	1.658444
300	250	256	256	487	2.15682	1.226602	208	256	256	367	1.663584	1.084657
275	215	231	231	404	1.990748	1.178092	172	231	231	302	1.538852	1.048707
250	180	206	206	325	1.824808	1.129614	136	206	206	243	1.414196	1.012777
225	145	181	181	255	1.659008	1.081169	100	181	181	191	1.28962	0.976867
200	109	156	156	193	1.494364	1.036609	0	152	156	152	1.15586	0.905513
175	74	131	131	140	1.328832	0.988225	0	122	131	122	1.015256	0.807705
150	0	102	106	102	1.151168	0.893727	0	92	106	92	0.874752	0.710074
125	0	73	81	73	0.964984	0.766776	0	62	81	62	0.73434	0.612617
100	0	44	56	44	0.778964	0.64011	0	32	56	32	0.594028	0.515334

5000MWs						6000MWs					
1s	2s	6s	2s EX	RoCoF (250ms)	RoCoF (1s)	1s	2s	6s	2s EX	RoCoF (250ms)	RoCoF (1s)
				1.856884	1.467361					1.570748	1.312982
162	256	256	293	1.365952	0.999278	0	252	256	252	1.160616	0.917989
126	231	231	242	1.265712	0.969284	0	221	231	221	1.066228	0.850953
0	202	206	202	1.158708	0.912913	0	190	206	190	0.971884	0.784002
0	171	181	171	1.04588	0.833843	0	159	181	159	0.877584	0.717137
0	141	156	141	0.932804	0.753694	0	128	156	128	0.783328	0.650356
0	110	131	110	0.820104	0.67486	0	97	131	97	0.689116	0.58366
0	79	106	79	0.707464	0.596142	0	66	106	66	0.594952	0.517049
0	49	81	49	0.59458	0.516349	0	35	81	35	0.500828	0.450521
0	18	56	18	0.482068	0.437864	0	3	56	3	0.407004	0.385076

This slide presents the results simulated for several variants of the 2023 minimum demand case. The variants considered:

- Inertia ranging from 6000 MWs to 3000 MWs
- A range of contingency sizes from 100 MW to 400 MW

The levels of inertia considered are significantly lower than that experienced in the SWIS today, however they could be reached under minimum demand conditions in 5 years time assuming growth of roof top PV consistent with the AEMO SOO and new non-synchronous GIA generation.

These numbers are results of simulations and would need to be refined for operational implementation by AEMO.

The red shaded cells identify RoCoF levels that exceeded the “safe limits” if PFR delivers a 2 s and 6 s response similar in shape to that on the previous slide

RoCoF exceeds safe levels for various sizes of contingency once inertia falls below 6000 MWs.

The PFR requirement was assessed for different contingencies and different levels of inertia. The requirement was specified as a PFR defined by three break points (1s, 2s and 6s). With the response delivered at each break point selected to keep the frequency nadir within the level specified in the FOS. We found that at the higher RoCoF levels, without the break point at 1s the amount of 2s service significantly exceeded the 6s requirement. The column 2s EX shows the 2s requirement if there was no additional 1s service. In this context a 1s service means a capability delivered at 1s which exceeds the level of service delivered assuming a linear increase in output to the 2s level.

If services are procured from traditional sources like synchronous generators, then a 2s requirement that is much greater the 6s required would seem quite challenging to deliver. Other technologies such as a BESS provide a greater capability to customize the service delivered to system requirements although even those devices would tend to have a set of controls tuned at the time of commissioning and then adjusted infrequently.

These considerations therefore suggest that it would be preferable during future low inertia conditions to be able to access 1s, 2s and 6s services. These could be collective described as the PFR.

The studies showed that an increased amount of 1s service was required to keep RoCoF below safe limits. Those levels of 1s service to stay within the “safe” RoCoF level are shown on the next slide.

Similar results can be produced for over-frequency events although the reduced contingency size means RoCoF is not as high

Recommendations – RoCoF Control

Recommendations

- RoCoF control required when inertia < 6000 MWs
- As an alternative to RoCoF service consider constraining dispatch to limit largest contingency
- Maintaining RoCoF across 250 ms below “safe limit” best achieved via inertia
- FFR and other non-inertia options able to control RoCoF across 1 s below “safe limit”
- Consider inertia from synchronous condensers installed to provide system strength in setting any RoCoF requirement

Further Work

- Safe limit may be increased through re-design of UFLS and verification of ride through capability of all generators.

18 GHD Advisory PSOWG Briefing – Feb 2019

While the very low levels of inertia necessary to give rise to RoCoF issues are unlikely to immediately. By 2023, minimum demand conditions could give rise to unsafe levels of RoCoF. It is therefore recommended that as part of the new AS framework, consideration be given to introducing appropriate mechanisms to control RoCoF.

One option is a RoCoF service which would be required at levels of inertia below 6000 MWs. The amount of RoCoF service would vary with the inertia available and the size of the assessed single and credible multiple contingency. It would be appropriate to consider multiple contingencies as a high RoCoF following a multiple contingency that exceeded safe levels could result in further generator trips exacerbating the RoCoF.

The chart on this page shows the level of fast frequency response services that would be required to keep the RoCoF across the first second following the contingency to a safe level.

Other options for controlling RoCoF would be to constrain on additional synchronous generators to provide increased inertia, source additional inertia from synchronous condensers or constrain dispatch to limit contingency sizes.

FFR and synchronous condensers have least impact on dispatch and are therefore potentially easier to integrate with the energy market.

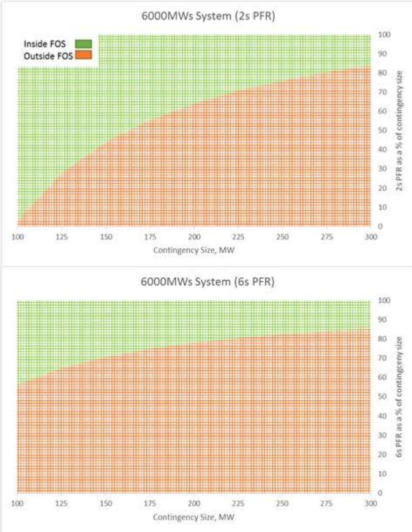
Recommendations – PFR

Key recommendations

- Level of PFR varies with inertia and size of contingency.
- Raise and lower requirement should be individually specified
- As inertia falls more PFR is required for the same size contingency
- As inertia falls PFR is required more quickly than 6s. It is recommended that PFR providers specify the service level achievable within 2 s and within 6 s
- Regulation capacity should not be counted as meeting the PFR
- PFR that is available post contingency, and can be increased and sustained has the potential to offset SFR requirements
- PFR should be encouraged to make unused capacity available via AGC assist to restore frequency to the normal band.
- Mandatory droop requirement should be retained and extended to non-synchronous generation (subject to energy source limitations).
- FFR can be a provider of RoCoF and PFR services

Further work

- The analysis assumes 100% of offered services is delivered, in practice it would be prudent to allow an appropriate operating margin to cater for the risk that the delivered service is less than offered
- The PFR service specification should define the frequency signal against which the 2s and 6 s response characteristic is defined
- AEMO should commence work on a technical specification for the new PFR framework to provide further clarity to participants
- Detailed design should also define appropriate ways to assess whether offered service has been delivered



19 **GHD Advisory** PSOWG Briefing – Feb 2019

The slide list key recommendations regarding PFR

The main recommendation is the AEMO aggregate model can be used to evaluate whether a given combination of service will be sufficient to meet the FOS for a specified contingency size and inertia level. The model allows different combinations of PFR service offerings to be considered and evaluated to establish whether they meet the FOS.

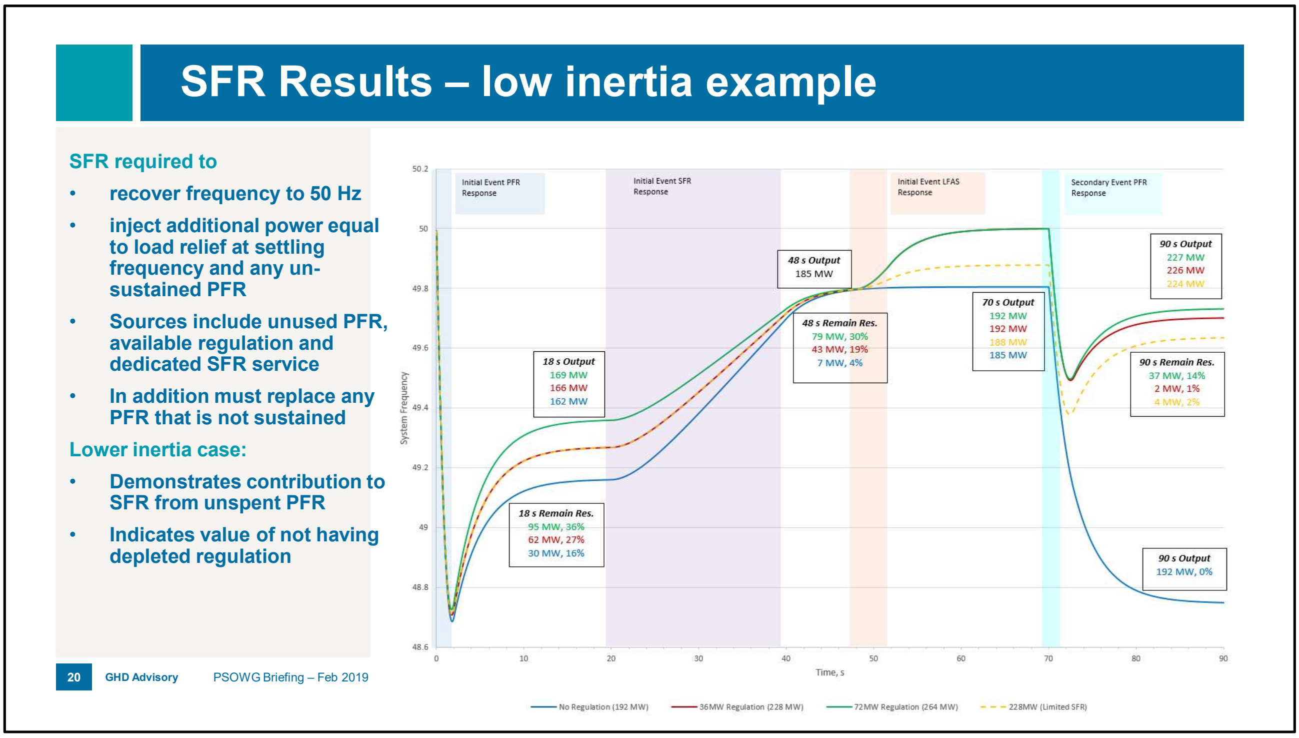
Our recommendation is that the PFR required be specified in terms of a 2s and 6s capability with consideration given to specifying a 1s and 250ms requirements to manage RoCoF in the future.

One of our main recommendations is to discontinue counting regulation capacity as meeting PFR. This is to prevent insecure operation in the event that a contingency occurs at a time when some of the regulation range is depleted. This risk of insecure operation may become greater with changes to a 5 min market and facility bidding for the Synergy portfolio as both lead to potentially less frequent replenishment of regulation range by AEMO.

There is scope particularly under higher inertia conditions to have PFR requirements that are less than 70% of the largest contingency and conversely at lower levels of inertia and larger contingencies the PRF requirement is likely to exceed 70% of the largest contingency.

While there appears to be a case for considering lower PFR limits i.e. less than 70% of the contingency size, before implementing that change it would be appropriate to consider a prudent operating margin that recognizes that there is a risk that some PFR capability might be lost if the generator that trips is also a service provider and to address the risk that the delivered PFR service is less than that offered. One approach that we recommend be investigated further is developing an appropriate level of redundancy in the PFR requirement such that the requirement can still be met if the largest service provider’s contribution is discounted and does not respond (i.e. an N-1) standard

Another area of further work would be to define the performance assessment processes and assumptions to be made by service providers in specifying their PFR capability



In general, following a contingency event, the frequency will achieve a settling frequency. Additional power then needs to be injected to drive the frequency back to 50 Hz. The additional power required is equal to the load relief at the settling frequency. There are several potential sources for that additional power:

- Unspent PFR – potentially accessed via AGC or even verbal instructions
- Regulation capacity
- Dedicated SFR service

Having recovered to 50 Hz, it is important that sufficient reserve remains such that a small subsequent event does not cause load shedding

These concepts were explored by modelling the recovery of frequency following a generator contingency using the future scenario with approximately 3000 MWs of inertia. The figure illustrates the response to a 192 MW generator contingency and illustrates the ability to recover to 50 Hz and sustain a small subsequent load event while avoiding UFLS. The subsequent event is a load increase of approximately 45MW

The colours on the chart differentiate four cases:

- Case 1 (blue line) – with regulation capacity of 0 MW,
- Case 2 (red line) – with regulation capacity of 36 MW,
- Case 3 (green line) – with regulation capacity of 72 MW.
- Case 4 (orange line) – modified version of Case 2 with Secondary Frequency Response (SFR) restricted by 40 MW.

The callout boxes identify at particular times the level of response remaining and the level of response dispatched. In this chart the response is the sum of regulation and PFR

The simulation suggests that the quantity of SFR service may be reduced if the following conditions are met:

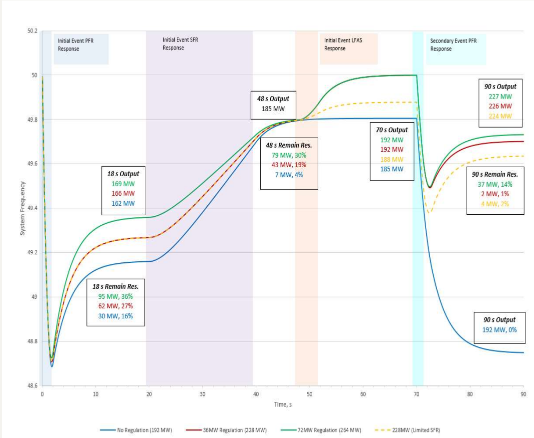
- PFR sustained for 5 min
- Regulation not counted as part of PFR and therefore available to provide SFR
- Unused PFR is available to respond via AGC assist and help recover frequency to lower edge of normal band

This allows for economic trade-offs to be made between PFR and SFR in dispatch

SFR Results

Key recommendations

- Something is needed in the SFR timeframe to restore frequency to 50Hz. This can be provided by
  - AGC assist for generators with this capability, or
  - Potentially by demand side response
- SFR quantities can be reduced if the following conditions are met
  - PFR is sustained
  - Unused PFR is controllable by AGC
  - Regulation capacity not counted toward meeting the PFR requirement
- The amount of load relief at the settling frequency + any PFR that is not sustained could used to set the SFR requirement



Further work

- Investigate whether a PFR service that is not sustained beyond say 60s and a SFR that responds from 30s will deliver a more cost effective result than sustained PFR?
- AEMO should commence work on a technical specification for the new SFR framework to provide further clarity to participants

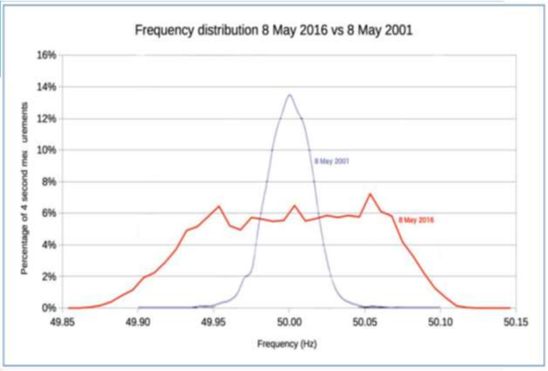
Frequency Regulation

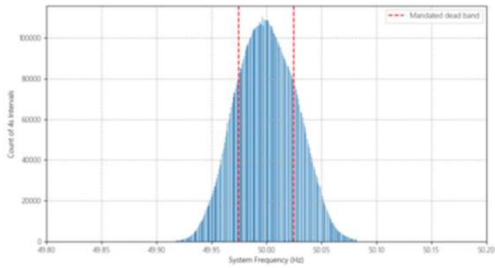
WEM has good frequency regulation

- Top chart show the deterioration of NEM frequency regulation since the removal of mandatory droop and dead band requirements
- Bottom chart shows WEM regulation May 2016 – June 2019
- The WEM has mandatory requirement for governor response within the normal band i.e. dead band +/- 0.025 Hz, which complements AGC and reduced LFAS requirements
- In the NEM, 6 s FCAS does not respond until frequency leaves the normal band. Regulation relies on AGC only

Establishing requirements

- Forecast error analysis - complete
- Analysis of SCADA data – approach defined, analysis pending
- LFAS test – test complete, analysis pending





AEMO has recently conducted an on-line test to investigate how droop response interacts and supports frequency regulation.

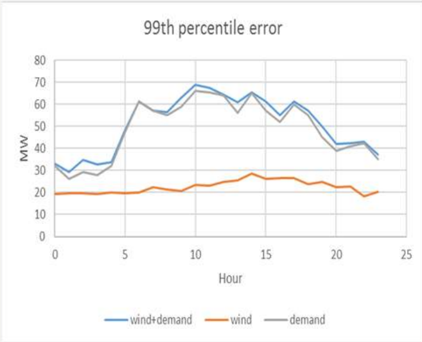
Frequency Regulation Requirement

5 min ahead forecast error

- **99th percentile 5 minute ahead wind and demand forecast errors**
  - Differs between night and day, with lower errors at night
- **Variability visible in PV and wind generation forecasts**
  - Various variability measures examined - complete
  - None provided a reliable predictor of forecast errors in forecast generated 5 minutes ahead of dispatch

Likely to underestimate requirement

- Usage of LFAS for other reasons not captured:
  - Ramping at start of interval
  - Rebalancing across synergy portfolio
  - Errors in scheduled generators meeting targets
  - Wind and solar variability within 5 minutes



While some interesting results have come from the analysis of 5 minute ahead forecast errors, it would not be prudent to rely solely on that to set the regulation requirement. The chart shown on the right shows the 99th percentile error of the combined wind and demand 5 min forecast errors four each hour in 2018. The demand forecast error can be seen as the dominant source of error. The demand forecast error incorporates errors as a result of the inability to predict underlying demand, and those due to difficulties in predicting the generation from embedded sources such as roof top PV. The trend shown suggests that more regulation may be required during the day than at nights.

The analysis of forecast errors can be repeated for dispatch intervals of differing length. That analysis shows that in general as the dispatch interval reduces, so does the forecast error. This creates an expectation of a lower regulation requirement with a 5 minute dispatch. It does not follow that the requirement once 5 minute dispatch is in place will be less than 72 MW currently settled in the WEM. This is because the actual amount of LFAS used currently often exceeds 72 MW.

While AEMO seeks to maintain about 72 MW of raise and lower capability, as the range is depleted, AEMO adjusts the dispatch of the Synergy portfolio restoring regulation range. These changes include adjusting the dispatch targets of generators not providing LFAS to restore range on the LFAS units, or enabling more service by changing the AGC control mode of units in the Synergy portfolio.

As noted on the slide, there are a range of factors in addition to the 5 min forecast errors that can give rise to the need for frequency regulation in the SWIS, Those additional factors could increase the requirement beyond that shown on this slide. For now we recommend that this chart be seen a an indicator of the lower end of potential future regulation requirements

To complement this analysis, further work needs to be done analyzing 4s SCADA data to extract greater insights into current usage. The difficulty with the SCADA data analysis is it is not generally possible to extract the relative contribution to the LFAS requirement of all to the factors that drive the need for regulation.

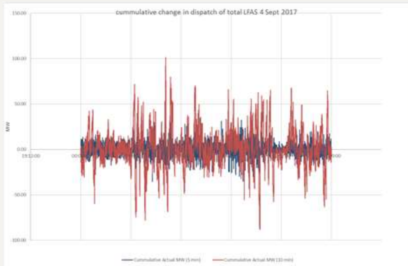
Market changes like a move to 5 minute dispatch have the potential to impact some of the drivers for current LFAS usage, but it is difficult to be quantify the benefit that will come from those changes.

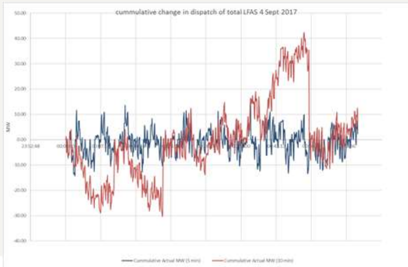
Frequency Regulation Requirement

Historical regulation usage

- Proof of concept result from 4 September 2017
  - Charts show cumulative LFAS use across different time periods for an hour and the entire day. Table shows range of results
- Further work is required to develop statistically valid results and explore each of the following
  - Distribution of LFAS usage across hours of the day to see if the usage varies with time of day as suggested by the 5 min forecast error analysis
  - LFAS usage in the first 5 minutes of each half hour to assess significance of ramping issue

Cumulative change in dispatch of LFAS generators (MW) across different periods			
Period	1 min	5 min	10 min
Daily Max	44	67	101
Daily Min	-35	-66	-87





An initial set of analysis has been performed to see whether it is possible to assess the LFAS usage across a period by calculating the cumulative change in the output of enabled LFAS generators. While the initial analysis looks promising, further work is required to address some data errors in the proof of concept and to validate that it can be applied across other days. This slide shows the results achieved from analysis of a day of 4s SCADA data from 4 September 2017.

One of the issues that arises is that AEMO regularly replenishes LFAS range by adjusting the dispatch target of generators in the Synergy fleet. This process of rebalancing results in movement of the LFAS generators which is not really related to regulating frequency. That movement is captured in the cumulative total and may serve to underestimate the LFAS used across some periods and overestimate the usage across others. The results shown here don't correct the impact of adjusting the dispatch of the Synergy fleet.

Recommendations - Regulation

Recommendations

- Do not count regulation requirement toward meeting PFR requirements
- Maintain requirement for mandatory governor response within normal band
- Allow regulation requirement to vary between night and day if supported by analysis of LFAS usage
- Maintain discretion for AEMO to increase requirement if available range is expected to be exhausted

Further Work

- Complete LFAS usage analysis proof of concept
- Complete LFAS usage analysis across sufficient number of days to yield reliable results
- LFAS usage across a 5 minute period used to set initial regulation requirement taking into account details of regulation and energy market design
- LFAS test analysis informs
  - Contribution from mandatory governor response → regulation ability with no LFAS → when to exercise discretion
- Routine review of regulation performance and forecast errors to assess need to change requirement

25 GHD Advisory PSOWG Briefing – Feb 2019

As noted elsewhere the practice of counting regulation toward meeting PFR requirements is not recommended as it exposed the power system to insecure operation and places potentially unnecessary importance on maintaining available regulation range. With a 5 minute market and during periods of high ramping to meet morning and evening load, we can expect to see the regulation service utilized quite heavily across dispatch periods. With a 5 min market, the regulation reserve is also replenished with each new dispatch run. That process may however lead to increased likelihood of having depleted available regulation capacity compared to the current practice. This is a further reason for not counting the regulation requirement towards PFR.

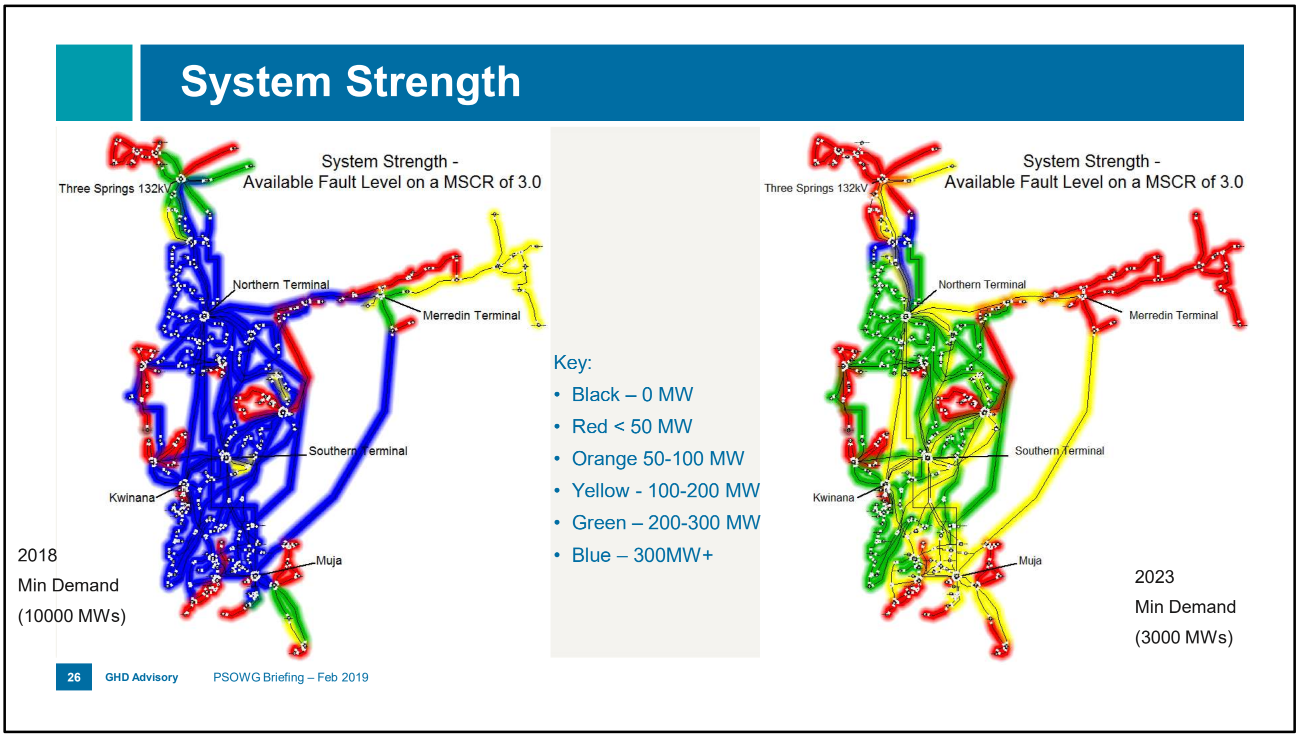
There is a need for a regulation service to keep frequency controlled around 50 Hz. Further work is required to develop a recommended requirement suitable for implementation within a 5 minute dispatch. The further analysis of historical LFAS usage should be developed to a proof of concept and then used to set the initial level of regulation capacity for the 5 minute market. In setting the level specific, design aspects of the market should be considered.

There are likely to be periods where the regulation range is at risk of being exhausted within dispatch intervals. The analysis of the LFAS test will allow a better understanding of how well the mandatory governor response can regulate frequency in the absence of the AGC regulation service. This knowledge should be used to inform the extent and urgency with which AEMO might decide to increase the regulation requirement on occasion.

The 5 minute market would allow AEMO the opportunity to change requirements within 5 minutes of recognizing an issues such as an encroaching storm front signaling a need for more regulation service. Removing the existing flexibility provided by the management of the Synergy portfolio and only allowing regulation requirements to be updated via the market engine and will delay the speed with which AEMO can make adjustments to the amount of available service and respond to unexpected events like the trip of a regulation service provider.

It would not be prudent to impose these restrictions on AEMO's ability to change the level of regulation service available. It is therefore recommended that AEMO retain the power to directly set which service providers are enabled by setting AGC flags directly and not waiting for the new market dispatch cycle.

It is recommended that within 12 months of the start of the 5 minute market, the regulation performance be reviewed by analyzing regulation utilization across dispatch intervals. This information coupled with the distribution of frequency deviations from 50 Hz should be used to assess the opportunity for revised regulation requirements. The forecast performance should also be reviewed each year to assess whether accuracy is falling with increased penetration of renewables. This could provide a need for an increase in regulations service particularly if coupled with a deterioration in performance and evidence of more frequency exhaustion of the regulation range.



The available system strength assessment process described in the AEMO system strength impact assessment guideline was applied to the detailed DIgSILENT model using the minimum demand case in 2018 and 2023.

This analysis is indicative for the purposes of assessing overlap with Ancillary Services, and is not intended to replace or supplement any (more detailed) analysis being conducted by Western Power.

This approach assesses the SCR at a bus and calculates how much additional inverter connected generation could be connected without the SCR falling below the minimum level required for stable operation of inverter connected generators. For these indicative studies we assumed a minimum SCR (MSCR) of 3.0.

The figures shows the system strength variation across the network. The one on the left is for the minimum demand case in 2018 and the one on the right is for 2023. Both diagrams are calculated for system intact conditions. The colours indicate varying levels of system strength.

Generally the strongest part of the network are the 330 kV transmission ring and areas of the transmission network with significant levels of synchronous generation. As the level of synchronous generation on-line reduces, so does the system strength. The more remote parts exhibit a lower system strength. The locational variation of system strength does not lend itself to solution via services procured through a central market.

Before connecting new non-synchronous generation to areas of the transmission network with low system strength, a detailed assessment of the stability on non-synchronous generation should be undertaken. This would normally involve studies with an EMT type model.

System strength can be improved by connection of supplementary devices such synchronous condensers. These devices also add inertia and can therefore improve RoCoF. The converse is also true, adding additional inertia to manage RoCoF can also assist with system strength, however the network impedance also has a significant impact on system strength. The network impacts create locational issues and can reduce the appeal of developing a single solution addressing both RoCoF and System Strength. The issues are however closely related and it is therefore appropriate that economic analysis is performed to investigate the potential benefits of coordinated solutions addressing both RoCoF and system strength.

Recommendations – System Strength

Recommendations

- Issue is likely to emerge with falling levels of non synchronous generation → appropriate management mechanisms need to be in place
- Localised issue → best managed through the network connection process
- Can be supported by AEMO in terms of assessing future needs (similar to the current process in the NEM)
- Potential solutions considered in determining contingency frequency response requirements

Caveats

- Analysis is indicative and applies techniques used for preliminary assessment in the NEM
- Low system strength would signal a need for more detailed assessment with EMT studies
- Important for WP and AEMO to know minimum stable Short Circuit Ratio for inverter connected generation. GHD assessment assumed MSCR of 3 at the HV transmission connection point.

Next Steps

Stakeholder Consultation

- Draft paper is being prepared to present the findings from the engineering/technical study
- Aim is for release to stakeholders during February
- Further work will then be required to operationalize recommended changes to the ancillary services in the WEM

GHD
Advisory

ghd.com/advisory