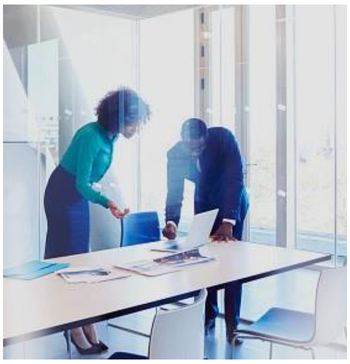
GHD Advisory



Essential System Services Framework Review

Energy Transformation Implementation Unit

18 July 2019

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1. Executive summary

The electricity sector in Australia is changing. Technological change, such as the continuing uptake of rooftop PV systems, and the increasing penetration of wind and other non-synchronous generation, has transformed power grids away from their traditional centralized generator to consumer model. The desire to facilitate this transition, and to achieve carbon emissions targets has resulted in challenges for network operators and electricity market participants.

As the sector changes, the tools and systems available to manage system security must also change to keep pace. These updates will also ensure that changing power system can be operated with the same degree of reliability and consistency for consumers as previously achieved. This information paper is intended to provide guidance to market participants and stakeholders regarding the reform of the essential system services[1] for the Wholesale Electricity Market (WEM) in Western Australia.

Various reviews into the current essential system services arrangements have highlighted areas of concern. The existing dispatch of the Synergy fleet as a portfolio and the Australian Energy Market Operator's (AEMO's) ability to continually adjust the dispatch of generating units within the portfolio masks many of the issues with the existing essential systems service framework. The planned introduction of facility bidding of the Synergy fleet and the introduction of a 5 minute dispatch interval energy market will expose the existing issues creating serious system security implications. It is therefore necessary to introduce changes to the existing essential system service framework as part of these broader WEM reforms.

The existing WEM frequency control ancillary service framework was established for a system that was dominated by synchronous generation. The generation mix across the South West Interconnected System (SWIS) is changing. With the increased deployment of large scale renewable generation occurring, and with continued growth of rooftop PV, the SWIS is moving away from a system dominated by synchronous generation. This places further importance on the reform of the essential system service framework.

The Energy Transformation Implementation Unit (ETIU) is undertaking reform of the WEM essential system services arrangements to meet Western Australia's energy challenges, and to establish an essential system services market which will be fit for purpose into the future when considering ongoing trends around renewable generation, energy storage technologies and distributed rooftop PV. The aims of the reform are to maintain a secure power system at the lowest overall cost to the electricity consumer

1.1 The case for WEM essential system services reform

The key issues with the existing essential system service framework that establish an immediate case for change have been identified and grouped under four themes.

1) Definitions and specification of services

[1] The term essential system services (referred to as Ancillary Services in the current WEM Rules) capture all services needed to maintain power system security and reliability. This term is proposed to be enshrined in the WEM Rules and will better reflect the essential nature and applicability of these services to the power system.

Various issues exist with the manner in which current services are defined. Key issues include:

- Service definitions that provide little or no alignment between the amount of service procured and the service required to deliver frequency control consistent with the Frequency Operating Standard (FOS). This can lead to system security risks and sub-optimal outcomes through an inability to demonstrate alignment between the procured amount of service and that required to operate the power system securely.
- The current definitions imply services must be provided from a narrow set of technologies. This excludes potential service providers and may elevate costs.
- Hard coding of service requirements in the WEM Rules makes it difficult to implement dynamic requirements which may provide a more optimal means of managing system security.
- Some gaps exist in the defined services such as a lack of secondary frequency response services to restore frequency to 50 Hz following a contingency. This appears to reflect an assumption that the Synergy fleet will be dispatched to provide these undefined services.

2) Energy Market Interactions

The WEM currently operates within a 30 minute dispatch interval. This leads to greater forecast errors than a shorter interval and a higher requirement for regulation services. Adopting a 5 minute dispatch cycle will improve the accuracy of forecasts and create an opportunity to reduce the required quantity of regulation services. Any reduction would be against the amount of regulation service actually required to regulate frequency with a longer dispatch period and not the notional 72 MW currently used in the settlement of the Load Following Ancillary Service (LFAS) market as it is not an accurate reflection of the actual regulation requirement.

The current Essential system Services Framework also does not allow for co-optimisation. Co-optimisation would allow increased efficiency by allowing targets in the energy market to be adjusted to minimise the total cost of energy and essential system services. For example if a contingency raise service was in short supply and highly priced, co-optimisation can adjust energy market dispatch to reduce the size of the largest generation contingency and hence reduce the requirement.

3) Response to Contingencies

As previously noted the current definition of services used to respond to contingencies do not provide a clear link between the amount of service procured and that necessary to keep frequency within the limits specified in the FOS. Additional issues exist with the current arrangements that rely on SR and LRRS. Key issues include:

- The SR service is defined as a response delivered in 6s, however maintaining a secure power system actual relies on a significant amount of response delivered well before 6s. Strictly complying with the existing SR specification would place system security at risk.
- The SR standard specifies that the LFAS raise capability (assumed to be 72 MW) should be counted as meeting the SR requirement. This practice places system security at risk whenever the actual amount of available LFAS raise capability is less than 72MW.
- Counting LFAS raise capability towards meeting the SR requirement confuses the role LFAS are expected to perform, complicating LFAS performance requirements.
- There is currently no explicit service that acts to restore frequency to 50 Hz, the framework appears to assume this will be achieve by adjusting the dispatch of the Synergy portfolio.

- The existing framework does not allow the increased value delivered by a service provider that responds more quickly than 6s to be recognised. It also does not allow the value of a sustained service to be recognised.

4) Regulation of Frequency

LFAS provides the essential system service relied upon to regulate frequency to 50 Hz. The LFAS service acts to correct moment to moment imbalances in load and generation, responding to control signals issued via the AGC system. 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 the inherent uncertainty in being able to predict demand requirements and the generation from renewable energy generators. The LFAS capability required to address each of the multiple factors that drive the current requirement frequency regulation cannot be easily identified through simple analysis of historical data. This makes it difficult to forecast the level of regulation service that might be required with changes to the energy market such as a move to 5 minute dispatch intervals and facility bidding.

AEMO's ability to call on the Synergy portfolio to provide LFAS and fast re-balancing provides them with a manageable process for replenishing LFAS services, and effectively increasing the amount of range available to cope with emerging weather events such as a large cloud bank passing over the Perth Metro area. This coupled with the current process for nominating the fixed 72 MW LFAS settlement target has meant that the actual LFAS requirement is poorly defined and 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 clearer specification.

Other existing issues

Other areas of concern have been raised with the existing essential system service framework including:

- A lack of clarity regarding the purpose and need for the ready reserve standard (RRS) and the lack of alignment between the timeframes defined in the RRS and SR standards
- The need for continued access to Dispatch Support Services (DSS).
- The continued need for mandatory droop response from synchronous generators and equity concerns arising from the fact that there is no current remuneration for the provision of this mandatory capability.

Future considerations

The existing frequency control ancillary service arrangements were not designed to cope with the low levels of synchronous generation likely to occur in the future. As the level of synchronous generation falls a number of issues are likely to arise including:

- During future minimum demand periods the level of synchronous generation is likely to be significantly lower resulting in lower inertia and increasing the rate of change of frequency (RoCoF) experienced following contingencies. If not controlled to a "safe level" the increase in RoCoF following a generation or load contingency risks causing damage to existing generation plant, or generators tripping to avoid damage, or inadvertent disconnection of generators through the operation of anti-islanding protection. Tripping of plant following a contingency can exacerbate the frequency disturbance leading to partial system collapse and/or significant levels of load shedding.
- Reduced levels of synchronous generation, will not only result in reduced inertia but will also mean that at times less frequency control service is available from synchronous generation. This creates a

requirement for the revised essential system service framework to allow different technologies to supply services.

- A higher RoCoF will also mean that the control response to contingency events need to be delivered more quickly to arrest the frequency change and keep frequency within the limits specified in the FOS. This will require a quicker response than implied by the current reference to a 6s response in the SR standard.
- Reduced levels of synchronous generation can also lead to lower levels of system strength particularly at the more remote locations in the network. If the system strength falls too far it can result in:
  - the need to revise protection systems to reliably detect fault conditions, and
  - voltage control and voltage stability issues particularly in areas with high levels of inverter connected generation. Grid following inverters require a minimum level of system strength to achieve stable operation.

Investigating essential system service requirements

GHD has undertaken a variety of analysis to identify the set of essential system services that are best suited to maintaining system security for the current system and conditions likely to emerge over the next five years.

We have focussed on examining the need for essential system services to address each of the following:

- Controlling frequency following load and generation contingencies;
- Regulating frequency to 50 Hz in the absence of large load or generation contingencies;
- Controlling the RoCoF to within safe levels; and
- Addressing system strength issues

We have completed a variety of studies simulating scenarios based on current system conditions and those that may occur over the coming 5 years. Our studies have used three different power system models and statistical analysis of historical data.

1.2 Recommendations and future work

The analysis undertaken supports migrating to an essential system service framework in which AEMO acquires the following control responses:

- Primary Frequency Response (PFR);
- RoCoF control;
- Secondary Frequency Response (SFR), and
- Frequency Regulation.

Primary Frequency Response (PFR)

PFR is a control response that arrests frequency following a contingency event. PFR is specified as the response in MW achieved in a specified timeframe (e.g. 1s, 2s and 6s). Sufficient PFR is required to keep the frequency Nadir (or maximum frequency) within the limits specified in the FOS. When multiple contingencies occur, PFR works in conjunction with automatic Under-Frequency Load Shedding (UFLS) and generator over-frequency tripping, to help arrest frequency disturbances and reduce the risk of complete system blackouts. PFR can be delivered by a generator, load or Battery Energy Storage System (BESS) that responds automatically to locally sensed frequency. PFR replaces elements of the existing Spinning Reserve (SR) and Load Rejection Reserve Service (LRRS).

The following recommendations are made regarding the PFR framework:

- The level of PFR should vary with inertia and size of largest single contingency. The aggregate model developed by AEMO[2] should be used to determine the PFR requirement (in terms of quantity and timeframe) for different dispatch conditions taking into account the available inertia and the expected largest contingency size. This approach will provide a more dynamic PFR requirement which depending on the level of inertia and size of the contingency. The requirement may be significantly different to the current requirements for SR and Load Rejection Reserve (LRR) (e.g. current SR requirement is 70% of the largest contingency).
- Raise and lower PFR requirements should be individually specified considering the largest generator and load contingency respectively.
- Regulation capacity should not be counted towards meeting the PFR requirement.
- The amount of PFR available should be sufficient to ensure frequency stays within the limits specified in the FOS for single contingencies and to control RoCoF to safe levels for multiple contingencies.
- The requirement for PFR should be set considering the required response commencing as soon as possible following the contingency event, and delivered within 1s, 2s and 6s.
- PFR providers should specify the service level based on how quickly it can commence and what is achievable within 1s, 2s and 6s.

The following activities should be progressed as part of operationalising the PFR framework:

- AEMO should commence work on a technical specification for the new PFR framework to provide further clarity to participants.
- AEMO should develop appropriate operating margins to cater for the risk that the delivered service is less than that required to keep the system frequency within the limits specified in the FOS. This work should consider raise and lower requirements separately to account for the different factors that may affect whether the actual delivered PFR response aligns with the required response.
- The PFR service specifications should be developed further clarifying the assumption that service providers should make in assessing the capability of their facility.
- AEMO should lead detailed design of the compliance framework that will apply for PFR essential system service.

RoCoF Control

RoCoF Control is a control response to prevent RoCoF exceeding “safe level” in future years. With the “safe level” defined as a RoCoF that does not exceed:

- 2 Hz/s across the first 250 ms, and

[2] Currently available in a draft form at: https://www.erawa.com.au/cproot/20570/2/Final-Draft---Contingency-Frequency-Response-in-the-SWIS.pdf

- 1 Hz/s across the first 1s

The following recommendations are made regarding the RoCoF control framework:

- Options to control RoCoF will be required in the future as the level of non-synchronous generation connected to the SWIS continues to grow displacing synchronous generation.
- The SWIS FOS should be expanded to incorporate the safe RoCoF levels defines above.
- Specification of PFR requirements that consider the needs for a 1s response coupled with the ability to adjust the energy market dispatch to either limit the size of contingencies or increase inertia should provide a sufficient set of options to control RoCoF to safe levels for credible contingencies. Appropriate mechanism should be developed to procure services and optimise energy market dispatch constraints against the cost of any RoCoF control service.

The following activities should be progressed as part of operationalising the RoCoF control framework:

- AEMO and Western Power should review the proposed safe level considering the actual ride through capability of existing generators (including embedded generators) and the design parameters for the existing emergency frequency control schemes and revise the safe level if appropriate.
- AEMO should develop tools that can identify when RoCoF is at risk of exceeding safe levels. This is likely to require monitoring the likely worst case contingency size and the amount of inertia to assess the expected worst case RoCoF.
- AEMO should investigate implementing systems to continuously monitor total system inertia
- In developing the technical specification for the new PFR framework AEMO should consider the need for a 1s PFR to control RoCoF at times of lower inertia.
- AEMO and Western Power should consider implementing a National Electricity Market (NEM) like Power System Frequency Risk Review (PSFRR) for the SWIS to consider the frequency control risks posed by multiple contingency events and to identify the most prudent option for addressing those risks.

Secondary Frequency Response (SFR)

SFR is a control response that responds to instructions issued by AEMO to restore frequency. It can be delivered by a generator, load, or BESS which is able to moderate output in response to Automatic Generation Control (AGC) commands or manual instructions. This includes demand side response. SFR replaces activities currently used to recover frequency to 50 Hz including manual dispatch of the Synergy fleet and AGC driven adjustment of generators with available capacity.

The following recommendations are made regarding the SFR framework:

- The requirement for PFR and SFR should be set such that in combination these services provide a response equal to the size of the largest single contingency and can be sustained for a sufficient time to allow replenishment through the energy market dispatch processes.
- Consideration of separate PFR and SFR requirements should be given, with the specification of the response and sustain times for PFR and SFR services selected to maximise the opportunity for facilities to participate. The response and sustain times should overlap to deliver a constant level of response.

The following activities should be progressed as part of operationalising the SFR framework:

- AEMO should commence work on a technical specification for the new SFR framework to provide further clarity to participants. The technical specification should define timeframes over which the SFR providers must be able to deliver their offered response and the period for which the response must be sustained.
- AEMO should investigate an appropriate operating margin to be applied to the SFR requirement to minimise the risk that a modest subsequent event drives frequency beyond the single contingency limits specified in the FOS. This additional margin is important particularly in scenarios where the regulation capacity is depleted.
- AEMO should lead detailed design of the compliance framework that will apply for SFR essential system service

Frequency Regulation

A control response that continuously responds to AGC issued instructions to correct frequency errors within the normal band. Regulation can be provided by a generator, load, BESS that is able to moderate its output in response to AGC commands. It replaces the existing LFAS.

The following recommendations are made regarding the regulation framework:

- The regulation requirement should not be counted towards meeting PFR requirements. The current practice of counting regulation toward meeting PFR requirements exposes the power system to insecure operation and places potentially unnecessary importance on continuously maintaining the available regulation range.
- The current requirement for mandatory governor response within the normal band should be retained.
- AEMO should retain the ability to increase regulation requirement if the available range is expected to be exhausted. AEMO should retain the power to directly set which service providers are enabled by setting AGC flags and not waiting for the new market dispatch cycle.

The following activities should be progressed as part of operationalising the regulation framework:

- AEMO should complete the analysis of historical SCADA data to extract reliable results regarding the historical level of LFAS usage across a 5 minute period. Any trends in historical usage with time of day, should be considered to assess whether it is appropriate to implement a regulation requirement that varies with time of day.
- Analysis of LFAS tests should be used to help build a more accurate methodology for modelling LFAS/regulating requirements.
- AEMO should routinely review regulation performance and forecast errors to assess need to change the regulation requirement. It is recommended that within 12 months of the start of the 5 minute dispatch interval energy market, the regulation performance be reviewed by analysing utilisation of regulation capacity 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 identify a need for an increase in regulation service particularly if coupled with a deterioration in performance and evidence of more frequent exhaustion of the regulation range.

Mandatory requirements

Mandatory requirements to provide frequency response as currently included in the Technical Rules should be maintained as they provide a shared contribution that maximises the frequency control capability available without impacting the dispatch of any facility that is not providing an essential system service. This approach will provide a more robust power system and avoid many of the issues experienced in the NEM where mandatory requirements no longer apply.

The mandatory response requirements applying to non-synchronous generators should be reviewed to address the lack of precision currently in the Technical Rules, including embedded non-synchronous generation (such as rooftop PV). Revised performance standards for non-synchronous generators have been reflected in generator performance standard guidelines released by Western Power and AEMO in December 2018 and could be used as a reference for this work[3].

System Strength

The following recommendations are made regarding the management of system strength and the impact on frequency control ancillary services:

- Appropriate mechanisms to manage system strength are required.
- System strength is a localised issue best managed through the network connection process.
- Solutions deployed to address system strength can add inertia to the power system and thereby contribute to controlling RoCoF and setting the requirement for PFR. AEMO and Western Power should collaborate to assess the need for and develop solutions that best manage system strength recognising the potential impact of those solutions on the requirement for PFR and controlling RoCoF.
- The connection of renewable generators into areas of low system strength should be assessed through detailed assessment with Electromagnetic Transient (EMT) studies. EMT studies are able to assess the potential for adverse interactions and unstable operation of inverter connected renewable generators.
- It is important for WP and AEMO to know the Minimum Short Circuit Ratio (MSCR)[4] for inverter connected generation. This information should be collected as part of the generator connection process and shared between AEMO and Western Power.
- As system strength issues emerge it is important that Western Power and AEMO collaborate on assessing options for managing the system strength. A range of options could be considered including the run-back or tripping of renewable generation to prevent unstable operation, deployment of devices such as synchronous condensers to improve system strength or devices such as static VAR compensators (STATCOMs) to provide additional voltage support.
- Potential solutions implemented to address system strength should be considered in determining contingency frequency response requirements.

Ready Reserve Standard (RRS)

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[3] https://westernpower.com.au/media/3226/generator-performance-guideline.pdf

[4] The Short Circuit Ratio provides a measure of the strength of a power system. It is the ratio between the fault current and the rated load current. The short circuit ratio varies with the distance from large synchronous generators. A small short-circuit ratio characterises a weaker part of the system that is remote from synchronous generators and therefore more likely to experience distorted voltage waveforms and fluctuations in voltage level. Inverter connected generators connected in weak parts of the system can experience unstable operation as a result of the more easily distorted voltage. The MSCR indicates the lowest short circuit ratio at which an inverter is guaranteed to operate stably. Power systems with high penetration of inverter-connected generation tend to have lower short circuit ratios.

- In the new essential system service framework the RRS should be replaced with clear and unambiguous requirements for AEMO to:
  - Sufficiently recover frequency following a contingency event to meet the requirements of the FOS (i.e. requires access to sufficient Secondary Frequency Response).
  - Restore or replenish sufficient levels of essential system services within applicable times to return the SWIS to a secure state, consistent with the FOS and other key power system operating state requirements.
  - Ensure linkages to dispatch, dispatch planning and outage planning processes are created to allow AEMO to ensure sufficient levels of service are available and scheduled when required.

Dispatch Support Services (DSS)

DSS are a generic category of essential system service that allow AEMO to contract with market participants to provide specific services that cannot be covered by other essential system services or standard dispatch arrangements, but are required to ensure power system security is maintained. It is recommended that the DSS (or similar arrangements) be maintained as part of the essential system service framework for the SWIS to provide AEMO with a mechanism to procure specific services not covered by other essential system services.

Network Control Services (NCS)

NCS are another generic category of essential system service intended to act as a substitute for transmission or distribution network upgrades. In recent years, NCS contracts have been used to connect generators with interim access arrangements, and to supplement network reliability in specific parts of the network. The ongoing requirement of NCS in a new essential system services framework needs to be fully explored, particularly, in light of other potential network-specific services (such as system strength) being developed.

Rooftop PV

While the recommended changes to the essential system service framework will help position the SWIS to operate securely with increased levels of renewable generation, other additional activities are likely to be needed particularly as the level of embedded renewable generation continues to increase. The continued growth of rooftop PV is likely to lead to continual reduction in the load supplied by transmission connected generation particularly during the day. In the future it may be difficult to dispatch sufficient synchronous generators to provide required levels of inertia and primary frequency control without the ability to constrain the output from embedded renewable generations.

While that point remains some years away it is important that work continue to develop appropriate arrangements to manage the control of frequency under those potential future system conditions. Activities that should be explored further include:

- Providing greater visibility and control for AEMO over the level of embedded generation.
- Reviewing the settings recommended in the Western Power Network Integration Guideline: Inverter Embedded Generation[5] (that implement a specific form of the Australian Standard for roof top PV Inverter systems) to ensure that those systems provide an adequate mandatory contribution to managing frequency under a range of future scenarios.

[5] https://westernpower.com.au/media/1325/network-integration-guidelines-inverter-embedded-generation.pdf

- Options to allow the aggregate response from roof top PV systems to contribute to frequency control.

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2. Glossary of Terms

Term	Description
AEMO	Australian Energy Market Operator
AFL	Available Fault Level
AGC	Automatic Generation Control
DSS	Dispatch Support Service
ETIU	Energy Transformation Implementation Unit
FOS	Frequency Operating Standard
LFAS	Load Following Ancillary Service
LRRS	Load Rejection Reserve Service
LRR	Load Rejection Reserve
MSCR	Minimum Short Circuit Ratio
NEM	National Electricity Market
NER	National Electricity Rules
PFR	Primary Frequency Response
PSFRR	Power System Frequency Risk Review
RoCoF	Rate of Change of Frequency
RRS	Ready Reserve Standard
SCR	Short Circuit Ratio
SFR	Secondary Frequency Response
SR	Spinning Reserve
SRAS	Spinning Reserve Ancillary Service
SWIS	South West Interconnected System
UFLS	Under-Frequency Load Shedding
WEM	Wholesale Electricity Market

3. Background and Context

Electricity consumers supplied by the SWIS expect a reliable and secure power system. Achieving this requires that the power system is operated such that the voltage and frequency remain within specified limits and that the system is robust enough to ride through a reasonable range of contingency events with little or no supply interruption.

Essential system services refer to range of services relied upon by network and system operators to help deliver a secure power system. Essential system services could include each of the following:

- Frequency control services;
- Voltage and reactive power control services;
- Network control services, and
- System restart services.

Some of these services such as frequency control provide system wide benefits while others provide a more localised benefit such as reactive power or voltage control. The scope of the benefits provided can influence the appropriate means for procuring a service, and the party that is best placed to manage the procurement and dispatch of the service.

This information paper explores the requirements for essential system service in the SWIS focusing mainly on frequency control services. Under steady state conditions the frequency is the same at all points across the SWIS, this means that frequency control service providers can be connected anywhere within the SWIS, which encourages competition in the provision of the service and encourages procurement through market based arrangements. Aligning the design of frequency control markets and electricity markets also offers the opportunity to improve economic efficiency through the co-optimisation of energy market dispatch and the frequency control market.

Sufficient frequency control services are required to regulate system frequency to 50 HZ under normal operating conditions, to arrest the change in frequency following generator and load contingencies and to restore the frequency to 50 Hz. A secure power system also requires the ability to replenish frequency control capability following a contingency. Delays in replenishing frequency control capability leave the power system vulnerable should a subsequent contingency occur.

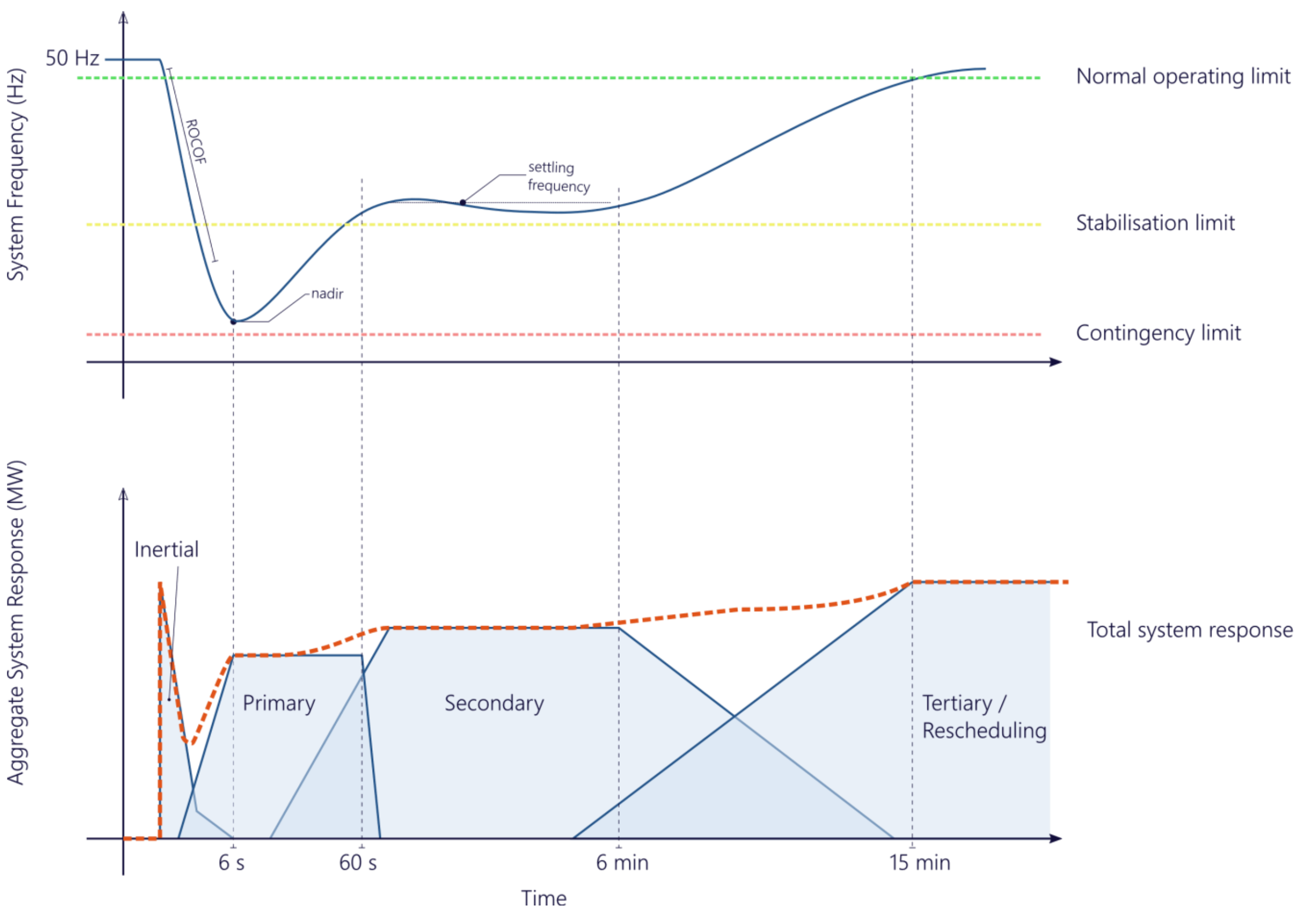
Figure 1 shows the response of a power system to a contingency event involving the trip of a generator. The upper chart shows a frequency response characterised by the initial RoCoF, the nadir or lowest frequency reached before the frequency settles to a stable point. The frequency then gradually recovers back to 50 Hz. A similar response can be drawn for a load contingency with the frequency increasing beyond 50 Hz reaching a maximum point before the settling frequency is reached.

The lower chart illustrates a typical response necessary to control frequency following a contingency. In this diagram the response includes an immediate inertial response that sets the initial RoCoF, a primary frequency response that builds over 6s and is sustained until it is replaced by a secondary frequency response. The utilised primary and secondary response capacity is replenished via re-dispatch of the energy market or from dedicated tertiary response service.

In the context of this paper, and as referred to in the AEMO report titled, "Contingency Frequency Response in the SWIS[6]", PFR is delivered by facilities that respond to a locally sensed measurement of frequency, and change the level of power injected into the system to arrest the frequency change. The frequency will generally settle within approximately 10 seconds of the contingency event.

SFR provides a further correction of frequency by adjusting the power injected into the system. The amount of power injected is closely controlled to recover the frequency back to a band close to 50 Hz where, depending on the market arrangements, regulation services then take over and recover the frequency back to 50 Hz.

Figure 1: Frequency Response of a Power System to a Contingency[7]



This information paper summarises the outcome of work undertaken by GHD for the ETIU to identify the changes to essential system services required to securely operate the SWIS and support the WEM. The primary focus of the work has been to define the type and quantity of frequency control services that are likely to be required over the next five years to deliver a secure power system in which the frequency stays within the range specified in the FOS for the SWIS[8].

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[6] https://www.erawa.com.au/cproot/20570/2/Final-Draft---Contingency-Frequency-Response-in-the-SWIS.pdf

[7] Figure 1 sourced from AEMO report, "Contingency Frequency Response in the SWIS"

[8] Defined in Clause 2.2 of the Technical Rules

3.1 Current Essential system Services

The essential system services currently provided to the WEM are LFAS, SR Ancillary Service (SRAS), LRRS, DSS, and System Restart Service (SRS).

LFAS is used to control frequency during normal system operation. This service is currently provided by synchronous generators that respond to control signals issued by an AGC system to correct fluctuations in frequency. Control signals are issued every 4 seconds and seek to keep the system frequency to within the normal range defined in the Technical Rules. LFAS in the WEM is complemented by the governor response provided by thermal generators. The Technical Rules mandate that synchronous generators connected to the SWIS after 2007[9] are fitted with governors that respond to arrest frequency deviations from 50 Hz when operating below 85% of rated output[10]. The maximum deadband allowed on governors in the SWIS is 0.05 Hz which means that all governors should respond to frequency deviations well before the frequency exceeds the normal frequency band of 50 +/- 0.2 Hz.

Contingency events that drive system frequency outside the normal operating range are managed by SRAS and LRRS. They are predominantly provided by synchronous generators supplemented by switched control provided through load interruption contracts. For more extreme contingencies causing system frequency to exceed single contingency limits, protection settings on the SWIS result in automatic under-frequency load shedding or generator tripping, which also assist to recover frequency.

- SRAS holds online capacity in reserve to respond to disturbances that cause the frequency to fall below the normal operating range (e.g. when a generating unit experiences an outage).
- LRRS requires that scheduled generators be maintained in a state where they can rapidly decrease their output to respond to disturbances that cause the frequency to increase beyond the normal operating range (e.g. a system fault resulting in the loss of load).

DSS are a generic “other” category of essential system service that allow AEMO to contract with market participants to provide specific services that cannot be covered by other essential system services or standard dispatch arrangements, but are required to ensure power system security is maintained. The service is currently defined to ensure it includes mechanisms to manage voltage levels around the power system where this is not provided under network Access Arrangements or Network Control Services.

SRS allows parts of the power system to be re-energised by black start equipped generation capacity following a full (or partial) black out. Unlike other generators, black start equipped generators can be started up without requiring a supply of energy from the network.

All power systems around the world have recognised the need to maintain control over-frequency. It is common practice for frequency standards to define a normal operating frequency band and to require that in the absence of contingency events, frequency remains within that band for a majority of time. It is not unusual for frequency to be required to, and to stay within the normal frequency band for 99% of the time.

The FOS for the SWIS is defined in the Technical Rules, which require that frequency be maintained between 49.8 Hz and 50.2 Hz for 99% of the time excluding periods impacted by load and generator contingencies. The current FOS is outlined in Table 1.

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[9] Generators connected prior to July 2007 are “deemed to comply” as per Clause 1.9.4(a) of the Technical Rules.

[10] Requirement defined in Clause 3.3.4.4 of the Technical Rules.

Table 1: Frequency operating standards for the SWIS

Condition	Frequency Band	Target Recovery Time
Normal Range:		
South West	49.8 to 50.2 Hz for 99% of the time	
Island[1]	49.5 to 50.5 Hz	
Single contingency event	48.75 to 51 Hz	Normal Range: within 15 minutes. For over-*frequency* events: below 50.5 Hz within 2 minutes
Multiple contingency event	47.0 to 52.0 Hz	Normal Range within 15 minutes For under-*frequency* events: (a) above 47.5 Hz within 10 seconds (b) above 48.0 Hz within 5 minutes (c) above 48.5 Hz within 15 minutes. For over-*frequency* events: (d) below 51.5 Hz within 1 minute (e) below 51.0 Hz within 2 minutes (f) below 50.5 Hz within 5 minutes

3.2 Guiding principles

The following set of guiding principles for the design of the SWIS essential system services framework were developed in consultation with the project working group made up of representatives from the Australian Energy Market Operator (AEMO) and the Public Utilities Office (PUO):

The essential system services framework shall,

a) Align with the WEM Objectives as outlined in Market Rule 1.2.1.

b) Provide mechanisms for the adequate management of power system security in the WEM considering current and emerging challenges.

c) Consider both frequency ancillary services, and other potential essential system services that may be required in order to effectively manage power system security (e.g. voltage, inertia, system strength, grid forming).

d) Work cohesively with other elements of the current electricity market reform program, in particular:

- 5-minute dispatch;
- Facility bidding/dispatch; and
- Co-optimised energy and essential system services.

e) Be efficient in terms of procurement and use, including scheduling/dispatch in the WEM where appropriate.

f) Incentivise competition in essential system services provision in the long term and accommodates the entry of new or alternative technologies.

g) Strive to achieve optimal outcomes by making necessary changes to the regulatory framework, while adopting flexibility to allow for future-proofing to the extent reasonable.

- The desire to minimise changes to the regulatory framework must be balanced against the ongoing need to maintain relevance of the framework so that it is responsive to changing consumer needs.
- Any proposals for regulatory changes may recommend enshrining principles in higher order regulatory instruments (e.g. Market Rules) while delegating operational aspects to subordinate instruments, such as market procedures, to maintain adaptability and flexibility.

h) Take into consideration the current technical capability of existing plant and does not impose unnecessary costs to market participants.

i) Ensure the framework is adaptable/configurable to meet expected future changes and challenges in the power system, and allows the investigation and trialling of new or emerging technologies for essential system services provision.

j) Clarify appropriate institutional responsibilities to different services (e.g. whether AEMO or the Network Operator is best placed to procure certain types of essential system services).

These guiding principles may be modified following discussion with industry participants. The agreed principles will be used to determine the preferred framework for essential system services and guide associated Market Rule changes.

3.3 Structure of the paper

This paper is arranged with section 4 explaining various issues with the current essential system service arrangements for the SWIS. This section draws on issues identified in previous reviews in addition to work developed by GHD to present a clear case for change. The section establishes that the existing essential system service arrangements present system security issues which will be exacerbated by the planned changes to the energy market such as the move to a 5 minute dispatch and implementation of facility bidding. This section also describes the approach followed to develop recommended changes to the SWIS essential system service framework.

Section 3 presents a recommended set of revised essential system service arrangements which are better able to support planned reforms to the energy market while allowing AEMO to control frequency to within the limits specified in the FOS. This section identifies the types of services required and presents recommended techniques for determining the quantities of service required to control frequency to the limits specified in the FOS. This section includes recommendations for the future work required to operationalize the recommended essential system service framework.

Section 4 presents a summary of the key recommendations and future work developed in section 3, while section 5 describes the opportunity for interested parties to provide feedback on the proposed essential system service framework.

4. The case for reform

4.1 Issues with the current essential system services framework

The existing essential system service framework encompasses:

- the regulations defining each service and the required quantities of each service;
- the arrangements that allow AEMO to access those services to manage power system security, and
- the arrangements that allow AEMO to dispatch generation to replenish the range available from essential system service providers.

Various reviews into the current essential system service arrangements have highlighted areas of concern with the existing arrangements. The existing dispatch of the Synergy fleet as a portfolio and AEMO's ability to continually adjust the dispatch of generating units within the portfolio masks many of the issues with the existing essential system service framework. The planned introduction of facility bidding of the Synergy fleet and the introduction of a 5 minute energy market will expose the shortcomings in the current framework. It is therefore necessary to introduce changes to the existing essential system service framework as part of these broader WEM reforms.

The key issues establishing an immediate case for change are outlined in Table 2. The issues have been grouped under four themes. The potential impacts from not addressing the key issues are also summarised in the table.

Table 2: Key Issues

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 SR Response delivered in 6s Primary response is currently not supported by any frequency restoration services	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 accurately represent usage of regulating service	Difficult to define required amount Replenishment difficult to manage without portfolio

4.1.1 Definitions and Specification of Services

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

- Inconsistency between the definition of frequency control services and the system frequency performance requirements specified in the FOS. For instance the time frames over which a response needs to be delivered and sustained forms part of the specification of SR service however there is no clear alignment between those time frames and the performance obligations in the FOS regarding time taken to stabilise frequency or restore frequency to 50 Hz following a contingency.

- Service requirements are not defined in a manner that establishes clear alignment between the requirement and the ability to deliver the frequency performance specified in the FOS. It is therefore difficult to demonstrate that a sufficient level of service is being provided to maintain system security.
- Currently some service requirements are hard coded into regulations such as the requirement to maintain an amount of SR equivalent to 70% of the largest generator contingency. Hard coding reduces the ability to implement dynamic requirements and may also introduce overlaps and inconsistencies. For example the current SR definition specifies services should be sustained for up to 15 minutes11, however the ready reserve standard requires full replacement of contingency response capability within 4 hours12. These times are not consistent.
- There appears to be an unstated underlying assumption that AEMO will restore frequency using "other" mechanisms as there is currently no specifically defined SFR service. Restoration of frequency to 50 HZ is currently largely achieved through manual dispatch of the Synergy portfolio.
- Definitions and terminology that either specify or imply delivery of the services by a particular technology. For example, SR is specifically restricted to being provided by scheduled (synchronous) generators or interruptible load, and the name SR itself suggests a service provided by a rotating machine. This can lead to a presumed bias implying a preference for that service to come from a particular technology. This could lead to reduced competition and increase costs. The Ancillary Services PSOP specifies AEMO's process for certifying SR providers, the terminology in that document restricts the service to only being provided from either a scheduled generation or a load facility which does not allow for a service to be provided by a non-scheduled generator, or a BESS. Another example of a terminology issue is calling the regulation service, LFAS. This has the potential to create confusion regarding the scope of service that is required. The term load following suggests the service is only required to follow variations in load across a dispatch interval whereas the service is actually relied upon to respond to all frequency disturbances regardless of their cause.

Inconsistencies between the service definitions and poor linkages to the amount of response required to maintain frequency within the limits specified in the FOS, creates difficulties in ensuring an appropriate level of service is procured. If the amount of service procured is too high this can lead to higher than necessary costs, if the quantity of service procured is insufficient this creates a power system security risk.

The current service definitions do not achieve technology neutrality and imply a bias for the services to come from particular technologies. This could reduce competition leading to higher than necessary costs or force AEMO into the use of certain technologies when alternative technologies may be available that can provide a better response.

Previous reviews have also noted that the SWIS FOS is specified differently to the NEM FOS and that benefits might flow from closer harmonisation of the two Frequency Operating Standards. Refinement of the SWIS FOS is being pursued as part of the WEM reform project, with the PSOWG providing input on proposed changes[13].

The essential system service review completed by GHD has not considered in detail proposed changes to the SWIS FOS, instead it has focussed on defining a revised set of essential system services and appropriate techniques to define service requirements which will meet frequency performance limits in the

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[11] Clause 3.9.3 of the WEM Rules

[12] Clause 3.18.11 of the WEM Rules

[13] https://www.erawa.com.au/rule-change-panel-psowg

SWIS FOS as currently specified in the Technical Rules. It would be a straight forward exercise to apply the same techniques to develop revised requirements consistent with a revised SWIS FOS.

4.1.2 Energy Market Interaction

The WEM currently operates within a 30 minute dispatch interval. This leads to greater forecast errors than a shorter interval and a higher requirement for regulation services. Adopting a 5 minute dispatch cycle will improve the accuracy of forecasts and create an opportunity to reduce the required quantity of regulation services. Any reduction would be against the amount of regulation service actually required to regulate frequency with a longer dispatch period and not the notional 72 MW currently used in the settlement of the LFAS market.

As discussed in later sections of this report the current arrangements for regulating frequency in the WEM mean that the notional 72 MW settlement target is not an accurate reflection of the actual regulation requirement.

The current essential system services framework also does not allow for co-optimisation. Co-optimisation would allow increased efficiency by allowing targets in the energy market to be adjusted to minimise the total cost of energy and essential system services. For example if a contingency raise service was in short supply and highly priced, co-optimisation can adjust energy market dispatch to reduce the size of the largest generation contingency and hence reduce the requirement.

4.1.3 Response to Contingencies

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

- 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. The faster than 6s response is necessary to ensure the frequency is controlled within the limits specified in the FOS. GHD recommends that this need for faster frequency primary response be reflected in the revised essential system service framework.
- The regulations defining the required quantity of SR specify that LFAS raise capacity is counted as contributing to meeting the SR requirement. There is no similar provision for counting LFAS lower capacity towards meeting the requirement for LRR. There appears to be no technical reason for this different treatment of the LFAS raise and lower capacity. The analysis we have performed does however raise some concerns with the practice of counting 72 MW of LFAS raise capacity towards meeting the SR requirement. While there is a perception that this practice leads to reduced cost for meeting the SR requirement, it does mean that maintaining sufficient LFAS raise range is very important to prevent breaching the FOS following a generator contingency.

  As illustrated in Section 5.5.2, 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. The current SR standard assumes that 72 MW of LFAS raise is continuously available and can be counted on to provide SR, ie the LFAS raise range has not been used up providing frequency regulation (the service that it was procured to provide) and that all of the LFAS raise response can be provided in the same timeframe as SR. This assumption will not be valid all of the time which means procuring less SR on the assumption that LFAS range is available creates a power system security risk. When a contingency occurs and there is actually less than 72 MW of LFAS range available to respond as part of SR, the SR response may be insufficient. If this occurs there may be insufficient response to prevent the frequency falling below the limits specified in the FOS and triggering uncontracted UFLS.

The practice of counting LFAS raise capacity as SR creates a system security risk and should be avoided in the revised essential system service framework.

To minimise the risk of being insecure, AEMO is encouraged to ensure 72MW of upwards LFAS range is available. This potentially gives rise to adjusting dispatch more frequently to refresh used LFAS range than would be the case if LFAS was not counted toward SR. This matter is investigated further through the analysis documented in section 5.2.1.

Adopting a practice of not counting LFAS towards meeting SR provides:

  - Greater confidence that the FOS will not be breached, thereby improving system security, and
  - Greater clarity regarding the differing roles performed by LFAS and SR services. This may be important in deciding appropriate compliance and performance standards for service providers and for making economic trade-off decisions.

- Currently the SR standard in the WEM Rules allows for class A, B and C service with class A services needing to be sustained for only 60s. PFR services that are sustained are of greater value as they help to avoid the need for SFR. The current pricing arrangement do not allow for that differentiation of value for these different timeframes. The revised essential system service framework should provide mechanisms that recognise the additional value provided by a sustained response.

4.1.4 Regulation of Frequency

LFAS provides the essential system service relied upon to regulate frequency to 50 Hz. The LFAS service acts to correct moment to moment imbalances in load and generation, responding to control signals issued via the AGC system. 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 the inherent uncertainty in being able to predict demand requirements and the generation from renewable energy generators. Some of the factors that give rise to a need for regulation include:

- Errors in the ability to accurately forecast the demand and non-scheduled renewable generation that will be present at the end of the dispatch interval at the time the dispatch solution is run i.e. forecast errors.
- Errors in scheduled generators following their dispatch target.
- The movement of scheduled generators and non-scheduled generation within the dispatch interval is non-linear and does not match linear forecast and dispatch profiles. In particular, scheduled generators ramping quickly at the start of a dispatch interval to their new dispatch target and out stripping the change in demand.
- Ramping of demand outstripping the capability of generating units dispatched in the energy market.

When they occur each of these creates a load/generation imbalance and a deviation in frequency. This triggers an almost immediate correction, with 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 in 4s SCADA data, it is very difficult to observe the individual contribution of each factor towards the required amount of regulation service. 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.

AEMO's ability to call on the Synergy portfolio to provide LFAS and fast re-balancing provides them with a manageable process for replenishing LFAS services, and effectively increasing the amount of range available to cope with emerging weather events such as a large cloud bank passing over the Perth Metro area. This coupled with the current process for nominating the fixed 72 MW LFAS settlement target has meant that the actual LFAS requirement is poorly defined and 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 clearer specification.

4.1.5 Other issues

The following additional issues to those discussed above have also been raised in previous reviews of ancillary services[14]. They were also considered in developing recommendations for a revised essential system service framework:

Ready Reserve Standard (RRS)

The RRS sets a reserve quantity threshold used when assessing outage requests. The RRS is intended to provide sufficient reserve to commence frequency recovery and replenish frequency response capability following a contingency. The timeframes and quantities in the RRS are hard coded in the WEM Rules and summarised in Table 3

Table 3 Ready Response timeframes

Ready Reserve timeframe	15 minutes	4 hours
Requirement	Sufficient to cover: • 30% of the largest unit • Plus minimum frequency keeping capacity (LFAS)	Sufficient to cover: • 70% of the largest unit • Less minimum frequency keeping capacity (LFAS)

The ready reserve response requirement available within 4 Hr is set to provide sufficient capacity to replenish the SR range, however there is a misalignment with timeframes as the 4 Hr response time is too slow when considered against the requirement for class C SR to be sustained for a at least 15 minutes.

While specifying levels of capacity to retain for outage approval purposes, the RRS is not referred to anywhere else currently in the dispatch and scheduling rules, or in the power system adequacy provisions in the WEM Rules. There is no linkage between the RRS and meeting the requirements of the FOS or any form of reliability standard.

In the new essential system service framework the Ready Reserve Standard should be replaced with clear and unambiguous requirements for AEMO to:

- Sufficiently recover frequency following a contingency event to meet the requirements of the FOS (ie requires access to sufficient Secondary Frequency Control).
- Restore or replenish sufficient levels of essential system services within applicable times to return the SWIS to a secure state, consistent with the FOS and other key power system operating state requirements.

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[14] Raised by EY in their November 2014 report to the independent Market Operator titled, "Ancillary service standards and requirements study Report".

- Ensure linkages to dispatch, dispatch planning and outage planning processes are created to allow AEMO to ensure sufficient levels of service are available and scheduled when required.

Technology Neutrality

The current set of essential system services relies predominantly on services sourced from synchronous generators due to the limitations of the specific definitions within the current essential system services framework. The current technology is able to maintain frequency within the limits specified in the FOS, however this is unlikely to be the case in the future with continued changes to the generation mix. In defining a revised essential system service framework, an opportunity exists to encourage the use of a broader range of technologies. This has the potential to deliver reduced essential system service costs over time through increased competition in the delivery for service, and to adapt essential system service provision to the changing mix of generation.

A focus of the essential system service review was to develop a revised framework that allows for the provision of services by a range of technologies not just synchronous generators. Where appropriate this paper identifies how technologies other than synchronous generators can provide essential system services.

Recognition of the benefits provided by mandatory droop response

The Technical Rules currently require that synchronous generators provide mandatory droop response. Previous reviews have raised questions regarding whether the mandatory provision of droop response is appropriate and whether generators providing mandatory response should receive financial compensation.

As part of the review this matter has been explored by investigating the value provided by mandatory droop response and the extent to which that service can be relied upon to contribute to frequency control and regulation.

4.2 Future challenges adding to the need for change

The existing SWIS frequency control ancillary service arrangements were established for a system that was dominated by synchronous generation. The generation mix across the SWIS is changing. With the increased deployment of large scale renewable generation occurring, and with continued growth of rooftop PV, the SWIS is moving away from a system dominated by synchronous generation.

At times of minimum demand the change in generation mix is most obvious. Minimum demand conditions now occur in daylight hours on days with moderate temperature and high levels of generation from roof top PV. Over time the minimum demand is expected to fall further restricting the amount of synchronous generation that will be online at this time.

The existing frequency control ancillary service arrangements were not designed to cope with the low levels of synchronous generation likely to occur in the future. The review has therefore considered an essential system service framework that can cope with growing levels of non-synchronous generation.

4.2.1 RoCoF

Continued growth in the level of non-synchronous generation connected to the SWIS will inevitably lead to lower levels of synchronous generation. During minimum demand periods the effect will be most pronounced, with significantly fewer synchronous generators being dispatched reducing system inertia and increasing RoCoF.

If not controlled to a "safe level" the increase in RoCoF following a generation or load contingency risks causing damage to existing synchronous generation plant or synchronous generators tripping to avoid damage. Tripping of plant following a contingency can exacerbate the frequency disturbance leading to partial system collapse and/or significant levels of load shedding.

An increased RoCoF may not provide sufficient time for emergency control schemes such as UFLS to act and prevent a system collapse. Records from the system back event in South Australia in August 2016 showed that the RoCoF exceeded 6 Hz/s and system frequency collapsed more quickly than the UFLS was able to act[15]. Records of the South Australian event capture a RoCoF of 6.25 Hz/s which is significantly higher than the RoCoF typically experienced in the SWIS. Analysis by AEMO of a generator contingency that occurred on the SWIS on 12 October 2016 showed a RoCoF of 0.41 Hz/s.[16]

The essential system service review has therefore investigated the need for services that are capable of maintaining RoCoF at a "safe level".

4.2.2 Reduced level of synchronous generation

Reduced levels of synchronous generation, will not only result in reduced inertia but will also mean that at times less frequency control service is available from synchronous generation. This creates a requirement for the revised essential system service framework to allow different technologies to supply services.

Even maintaining a "safe level" will allow a RoCoF that is significantly higher than the level currently observed in the SWIS. This has implications for how quickly the PFR will need to respond to arrest the frequency change and stay within the FOS. As the power system experiences a lower level of synchronous generation, it will become increasingly important that a significant amount of the PFR is delivered in a much quicker time frame than 6s. Maintaining the current 6s definition for the SR service is likely to be insufficient to keep frequency within the limits specified in the FOS under conditions with reduced inertia.

4.2.3 System Strength

Reduced levels of synchronous generation also has impacts on system strength. The system strength at a point in the power system is indicated by the short circuit ratio (SCR) which measures the ratio between the fault current and the normal load current. Synchronous generators provide fault current that is many times higher than load current. Reducing the number of synchronous generators, leads to lower fault currents, lower SCR and reduced system strength.

If the system strength falls too far it can result in:

- the need to revise protection systems to reliably detect fault conditions, and
- voltage control and voltage stability issues particularly in areas with high levels of inverter connected generation. Grid following inverters require a minimum level of system strength to achieve stable operation.

[15] AEMO report, "Black System South Australia 28 September 2016", https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Power-System-Operating-Incident-Reports.

[16] AEMO paper, "Contingency response in the SWIS", November 2018

The fringes of the network, are likely to experience system strength issues first and if not managed this may lead to more frequent and more extreme voltage variations including a higher rate of change of voltage (RoCoV).

The review of essential system services has included a preliminary investigation of the reduction in system strength that may occur in the future. The investigation is aimed at illustrating the geographic exposure and explore whether system strength is best managed through a market that centrally procures system strength services.

4.3 Investigation of issues and developing recommended changes

Section 4.1 has identified the key issues associated with the current essential system service arrangements, while Section 4.2 identified additional factors that need to be considered to develop an essential system service framework that can cope with the expected continued growth in nonsynchronous generation. This section sets out the approach adopted to investigate the issues summarised in the previous sections and develop recommended changes to the essential system service framework to address those issues.

Section 5 then presents the outcomes of the studies performed applying the modelling approach and philosophy detailed in this section.

GHD has undertaken a variety of analysis to identify the set of essential system services that are best suited to maintaining system security for the current system and conditions likely to emerge over the next five years. This section introduces the various types of analysis, explains the key assumptions upon which the analysis are based, the tools and models used, and work undertaken to confirm the suitability of those models. Table 4: Studies completed using models for current and future systems summarises the forms of analysis undertaken to assess the current and future requirement for services to control frequency and the analysis undertaken to understand emerging system strength issues. The following sections present more detailed information about the analysis undertaken and the models used:

- Section 4.3.1 describes the analysis models used and the work undertaken to confirm that the suitability of the models.
- Section 4.3.2 describes the key factors that drove our decision to focus on minimum demand conditions.
- Section 4.3.3 describes the assumed “safe level” of RoCoF.
- Section 4.3.4 describes the approach used to study the requirement for PFR.
- Section 4.3.5 describes the approach used to study the requirement for SFR.
- Section 4.3.6 provides an overview of the studies into emerging study system strength issues.
- Section 4.3.7 provides an overview of the approach used to assess frequency regulation requirements.

Table 4: Studies completed using models for current and future systems

Current System				Future System			
Service Investigated	**Study Tools/Approach**			**Service Investigated**	**Study Tools/Approach**		
	DIgSILENT Study Models				**DIgSILENT Study Models**		
	Lumped Model	**Aggregate Model**	**Full Model**		**Lumped Model**	**Aggregate Model**	**Full Model**
PFR	✓	✓		*PFR*		✓	
RoCoF	✓	✓		*RoCoF*		✓	
SFR				*SFR*		✓	
LRR	✓	✓		*LRR*		✓	
System Strength			✓	*System Strength*			✓
Regulation	*Statistical Analysis*			*Regulation*	*Statistical Analysis*		
System loads	**Load**	**Net Load**		**System loads**	**Load**	**Net Load**	
Peak Demand	4.4 GW			Peak Demand	*Not Studied*		
Off Peak Demand	2.5 GW			Off Peak Demand	*Not Studied*		
Minimum Demand	1.2 GW	1.8GW		Minimum Demand	0.8 GW	1.8GW	
Assumptions				**Assumptions**			
Rooftop PV, ~1000 MW				Rooftop PV, ~1700 MW (5 year growth)			
Existing generation dispatch philosophy				Minimum synchronous plant			
Existing generation reserve policy				Move to 5 min dispatch			
Existing FOS limits apply				Existing FOS limits apply			
Existing automatic UFLS limits				Existing automatic UFLS limits			
System inertia > 12000 MWs				System inertia reduced to between 3000 & 6000 MWs			
Largest generator trip 300 MW @ peak demand				Largest generator trip 300 MW @ minimum demand			
Existing large scale wind and solar generation				Additional 900 MW HV non-synchronous generation			

4.3.1 Modelling Assumptions and Validation

Different aspects of the current and a projected future system have been assessed using the most appropriate models. For example, system strength, which requires study of conditions at each transmission connection point, has been assessed using the Western Power DIgSILENT model as it represents the entire network.

Assessment of primary and secondary frequency control ancillary services has been carried out using two time domain models:

- A “lumped” model developed from the original Western Power DIgSILENT model; and

- An aggregate model developed by AEMO

The lumped model explicitly represents the dynamic characteristics and dispatch conditions for each generating unit allowing the behaviour of individual generators to be observed. The network details have been simplified in the model. By scaling the system load and altering generation dispatch, system frequency performance can be studied under a variety of different conditions. However it is difficult to adapt the model for a wide range of system conditions. The lumped model was therefore primarily used to study present system conditions. Another limitation of the model is that the governor models may not accurately represent the actual response observed to actual generator contingencies. Generally the DIgSILENT models need refinement and adjustment to yield responses that match actual recorded responses.

The aggregate model was developed by AEMO to allow investigation of the aggregate level of PFR that is required to control system frequency following a contingency to within the limits specified in the FOS. The aggregate model offers several advantages over the use of the lumped or full DIgSILENT model for investigating PFR requirements:

- The model can be easily adjusted to reflect a wide range of system conditions. This allows a very quick and efficient means of assessing the PFR required to keep frequency within the limits specified in the FOS and for assessing how the PFR requirement changes with demand, system inertia and contingency size;
- The model allows a flexible means of specifying the PFR which is able to reflect the response that may be delivered from different technologies, and
- The frequency response simulated with the aggregate model has been benchmarked against the recorded response to actual generator contingencies.

The aggregate model avoids some of the issues caused by the complex representations of generator dynamic models in the extended Western Power model, which can exhibit unrealistic behaviour under certain scenarios, e.g. generators operating in motor mode under significant load rejection events. Further details of the aggregate model are available in the published paper “Contingency Frequency Response in the SWIS”[17].

Both the lumped and aggregate models have been used to study the PFR requirement for the actual 2018 minimum demand conditions. Simulations show a coarse level of alignment between the two models for the 2018 minimum load case.

[17] AEMO report, “Contingency Frequency Response in the SWIS”

Figure 2: Comparison of frequency response between lumped and aggregate models for current system

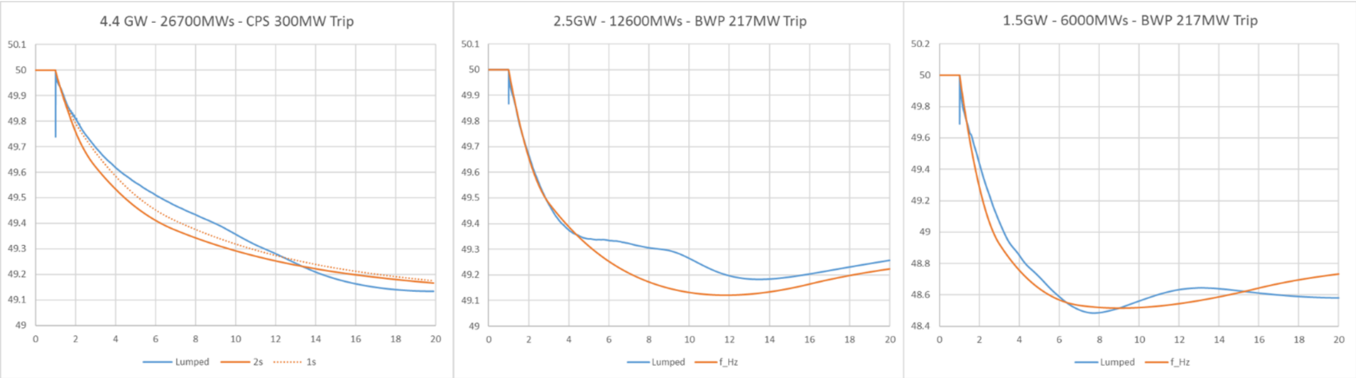


Figure 2 shows overlays of the system frequency simulated using the lumped DIgSILENT model and the aggregate model for generator contingencies under different level of system demand and synchronous inertia. In each case the similar amounts of available PFR were available in the aggregate and lumped model.

The validation against historical events documented by AEMO coupled with the comparative studies performed against the DIgSILENT lumped model confirm that the aggregate model is suitable for investigating PFR requirements that will deliver a frequency performance consistent with the FOS. The robustness of the model and simulation speed makes the aggregate model very useful for determining volumes of PFR necessary to meet the FOS and provides an efficient tool for investigating how those requirements change with future system conditions.

Having been able to compare both the DIgSILENT lumped models and the aggregate model, GHD supports the use of the AEMO aggregate model to analyse and set the quantities of ancillary service going forward.

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 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.

4.3.2 Current and Future Systems Studied

A range of studies have been carried out on the current and future systems, assessing the performance of the system against a multitude of single and multiple contingency events under a range of inertia and load conditions. At minimum demand the largest potential single contingency that has been assessed is 300 MW generator trip. The current dispatch principles for the SWIS make it unlikely that a synchronous generator will be dispatched at this output during minimum and off peak load cases. However, in the future the largest contingency on the SWIS may be the trip of a large wind farm or transmission line connecting multiple renewable generation sites, which could potentially cause a contingency of this size even under minimum demand conditions.

Both load and generation contingencies have been considered. A maximum generator contingency size of 400 MW was simulated to explore the potential response to multiple generator contingencies. A maximum load contingency of 260 MW was simulated to explore the potential response to multiple load contingencies. This matches an actual load rejection observed in 2017.

Continued growth in the level of embedded PV generation coupled with the proposed development of new large scale renewable generation projects suggests that minimum demand periods are likely to pose significant challenges for frequency control. Therefore, the focus of the analysis has been on minimum demand periods. At these times there is a reduced requirement for synchronous generation which leads to lower inertia exposing the system to higher RoCoF. The lower demand means that there is less load relief after contingencies adding to the challenges of controlling frequency. The lower level of synchronous generation will also reduce the level of frequency control available from synchronous generation. This may in turn restrict the energy market dispatch or require essential system services from non-synchronous sources.

The aggregate model allowed a significant number of studies to be completed considering a range generation conditions and potential contingencies. In the 2023 minimum demand cases, the growth in generation from renewable sources led to significant reductions in inertia to between 3000 and 6000 MWs. These are very low levels of inertia compared to levels currently experienced on the SWIS. An inertia of 3000 MWs would occur if only three synchronous generators are online (Pinjar GT10, GT11 and a single Kwinana HEGT). Approximately 12000 MWs of inertia from synchronous generation was present at the time on the 2018 minimum demand. However these very low inertia levels are not without precedent in Australia. At the time of the 2016 blackout in South Australia there was approximately 3000 MWs of inertia connected to the South Australian power system[18].

Assuming GIA generators proceed as proposed and the forecast growth in embedded PV systems proceeds, within 5 years there would be enough renewable generation to supply the entire system load during minimum load periods. While this dispatch condition is theoretically possible, we have assumed that a minimum level of synchronous inertia would be required and have therefore assumed that inertia levels remain above 3000 MWs. Operating with very little synchronous generation is not prudent, as it would expose the system to extremely high RoCoF and resulting system security concerns. This scenario was observed in South Australia during the 2016 blackout, when a very low level of synchronous generation led to a RoCoF greater than 6 Hz/s[19] following the loss of the only synchronous interconnection with the rest of the NEM.

4.3.3 RoCoF Studies

RoCoF was measured across the immediate period following contingencies; RoCoF was assessed over both 1 s and 250 ms periods and compared with the “safe limits” shown in Table 5.

Various studies and reviews including the recently completed review of the proposed generator technical performance standard rule change by the AEMC[20] and OFGEM[21], have raised concerns with high RoCoF. The AEMC review and work completed for Eirgrid suggest that some generators may need to trip if RoCoF exceeds the levels shown in Table 5 to avoid plant damage. The RoCoF limits in Table 5 reflect the minimum performance level for generator ride through in the National Electricity Rules (NER)[22] and the minimum level

[18] AEMO report, “Black System South Australia 28 September 2016”, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Power-System-Operating-Incident-Reports.

[19] Just prior to the system black event in South Australia in August 2016 a RoCoF exceeding 6 Hz/s was detected. This high RoCoF did not allow time for system defence schemes like UFLS to operate and as a result the statewide blackout occurred https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Power-System-Operating-Incident-Reports

[20] https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards

[21] https://www.ofgem.gov.uk/publications-and-updates/dc0079phase-2-frequency-changes-during-large-disturbances-and-their-impact-total-system

[22] Clause S5.2.5.3 (c)of the NER

proposed in the generator performance guideline develop by Western Power in 2018 and released to GIA generators in December 2018[23].

Reviews conducted in the UK by the ENA and OFGEM have identified concerns with the use of RoCoF to detect Loss of Mains or islanding conditions for generators embedded within distribution networks. OFGEM has confirmed that: “Existing protection settings create a limit on the RoCoF that can be permitted in operating the system. This requires significant System Operator (SO) actions when system inertia is low to avoid breaching this limit, which imposes costs on consumers.” Distribution Code modification DC0079 (phase 2) approved by OFGEM to take effect from 1 July 2018 suggests that LOM protection in the UK on legacy embedded generators may operate for a RoCoF in the order of 1 Hz/s.

Table 5: Minimum RoCoF limits in National Electricity Rules and WEM Generator Performance Guideline

Time Period (ms)	RoCoF Limit (Hz/s)
250	2
1000	1

It is unlikely that the RoCoF following a single contingency will fall below the safe level for current system conditions. Minimum demand conditions experienced in 2018 had sufficient synchronous generation dispatched to keep RoCoF below the safe limits. As the level of nonsynchronous generation continues to increase there is an increasing risk that RoCoF may approach or exceed the safe limits. Studies have been performed to examine the RoCoF likely at times of minimum demand in 2023 for both single and multiple contingencies.

While the current SWIS FOS does not specify any RoCoF limit, it is recommended that the SWIS FOS is revised to specify a safe RoCoF limit. Including the safe RoCoF limit in the SWIS FOS would support AEMO taking action to procure services or implementing other measures to control RoCoF to the safe level. Having the limit defined in the FOS would help to drive alignment between the approaches used to control RoCoF while at the same time providing clear performance expectations for generator ride through and for the design and operation of emergency frequency controls such as UFLS.

4.3.4 Primary Frequency Response (Raise and Lower)

Using the lumped and aggregate model, generation and load contingencies in current and future system scenarios were studied and the minimum level of PFR assessed. Minimum volumes for these services were assessed based on the target of maintaining frequency within the limits set in the FOS. For a single generator or load contingency this meant having sufficient PFR to keep the nadir above 48.75 Hz and the maximum frequency below 51 Hz. The minimum demand cases were found to provide the most arduous requirements with regards to system security, due to the low inertia and load relief present on the system, and hence most studies were focussed on these low load levels. Nonetheless, peak and off peak load levels were also studied to determine how requirements for essential system services could potentially change under different operating conditions for the SWIS.

4.3.5 Secondary Frequency Response

SFR was studied using the AEMO aggregate model to simulate the response required to restore frequency to 50 Hz following a contingency. The simulations considered how the level of SFR varied depending on a range of factors including;

[23] https://westernpower.com.au/media/3226/generator-performance-guideline.pdf

- the time period over which the PFR was sustained, and
- whether PFR that was not fully used to arrest the frequency deviation caused by the contingency was available to provide response to help return frequency to 50 Hz.

The simulations considered an initial generation contingency, the response required to return frequency to 50 Hz over several minutes and the ability to manage a subsequent modest (45 MW) load event without triggering UFLS. The inclusion of the additional small load event in the similar provided the ability to assess whether the quantity of SFR was sufficient to provide a robust recovery of frequency to 50 Hz.

Findings from the SFR studies were also assessed using spreadsheet calculations comparing the additional response provided to recover frequency to 50 Hz with the load relief observed at the setting frequency reached after the initial frequency disturbance was arrested.

4.3.6 System Strength Studies

System strength was assessed for both the existing system and the systems that might emerge under minimum demand conditions in 2023. All studies were performed using the full DIgSILENT model for the SWIS provided by Western Power. System strength was assessed by applying the Available Fault Level (AFL) calculation method described in AEMO's System Strength Impact Assessment Guidelines[24]. The AFL calculation method is used in the NEM to provide a preliminary assessment of system strength as part of the generator connection process.

While not intended to be an exhaustive analysis, applying this calculation technique provided a preliminary indication of the geographic spread of system strength issues to help illustrate the difficulty in addressing system strength via an essential system service.

4.3.7 Frequency Regulation Studies

As explained in Section 4.1.4, LFAS is the essential system service currently used to regulate frequency to 50 Hz. LFAS is sourced from synchronous generators that adjust their output in response to targets issues by the AGC system to correct frequency deviations. Those deviations can arise for a variety of factors. Two of which are:

- Errors in the ability to forecast the generation from large renewable generators (wind and solar farms) that will contribute to meeting demand at the end of the dispatch interval, and
- Errors in the ability to forecast the demand at the end of the dispatch interval. During daylight hours the demand forecast error is impacted by unexpected variations in the output of roof top PV systems.

As the dispatch interval is reduced it is expected that the forecast errors will reduce potentially lowering the amount of regulation required. To investigate this further GHD has completed statistical analysis of forecast errors to assess how the errors are likely to change as the forecast window is reduced to 5 minutes.

Forecast errors are not the only factors that drive the amount of regulation required. Regulation service is also required to correct frequency deviations that arise as a result of each of the following:

- Errors in scheduled generators following their dispatch target.
- Non-linear movement of scheduled and non-scheduled generation within the dispatch interval that does not match linear forecasts and dispatch profiles. In particular, scheduled generators ramping

[24] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Strength-Impact-Assessment-Guidelines

quickly at the start of a dispatch interval to their new dispatch target and out stripping the change in demand, and

- Ramping of demand across a dispatch interval outstripping the capability of generating units dispatched in the energy market.

It would be inappropriate to rely solely on analysis of forecast errors to establish the regulation requirement. Additional analysis has therefore been undertaken examining actual SCADA records showing the 4s targets issued to generators providing LFAS. The analysis involved calculating the cumulative change in the total LFAS generation across a given time period and using that as an indication of the required amount of regulation capacity used across each period. This analysis has some limitations that are discussed further in section 5.5.

The 72 MW of LFAS that is currently purchased does not actually reflect the amount of regulation used in the SWIS. The analysis of 4s SCADA records was undertaken to develop a better indication for the actual amount of regulation capacity currently used.

5. Essential System Services Requirements

The current WEM essential system services arrangements and requirements have largely remained unchanged since 2012. As discussed in section 2, a number of issues have been identified with the existing arrangements and there is a need to implement a revised essential system services framework. The revised framework should accommodate the changing generation mix and be appropriate to manage system security with reduced levels of synchronous generation producing lower system inertia.

Currently, synchronous generation is the main provider of frequency control ancillary service, much of which has a response time faster than the 6s required in the current essential system service definitions. The ability to dispatch the Synergy fleet as a portfolio has provided AEMO with an effective means to access the response required to control frequency following contingencies and to regulate frequency to 50 Hz. This arrangement masks many issues with the existing frequency control ancillary service framework. Addressing those issues will require procuring a new set of frequency control ancillary services with new approaches implemented to set required quantities of each service to deliver frequency performance that meets the limits specified in the FOS.

Studies completed by GHD have highlighted that the type and quantity of frequency control ancillary services currently procured need to change. Table 6 presents a logical set of frequency control responses that are required to deliver system security while accommodating the proposed changes to the energy market (ie a move to facility bidding and 5 minute dispatch). The control responses are defined by the control action delivered rather than the technology used. It was beyond the scope of the GHD review to recommend appropriate arrangements that would ensure sufficient amounts of each of the identified frequency control responses are made available. For simplicity we refer to each of the control responses listed in Table 6 as a service in the remainder of this paper. That should not be interpreted as implying a preferred mechanism for securing those services. Table 6 describes each service and indicates the technology available today that can deliver each service.

The following sections summarise the results of analysis performed to identify the recommended set of frequency control responses listed in Table 6 and techniques which can be used to set the required level of each service consistent with meeting the FOS, each section also presents recommendations regarding further work required to operationalise the new set of essential system services:

- The case for maintaining mandatory droop requirements is explored in Section 3.1;
- The requirement for PFR is explored in Section 3.2;
- The requirement for services to provide control of RoCoF is explored in Section 3.3;
- The requirement for SFR is explored in Section 3.4;
- The requirement for frequency regulation is explored in Section 3.5, and
- Section 3.6 presents the key results and insights gained through our preliminary investigation of system strength issues.

Table 6 Recommended set of Frequency Control Ancillary Services

Service	Specification and potential suppliers
Primary Frequency Response (PFR)	A control response that arrests the rising or falling frequency following a contingency event. PFR service is specified as the response in MW achieved in a specified timeframe (1s, 2s and 6s). Sufficient service is required to keep the frequency Nadir (or maximum frequency) within the limits specified in the FOS. Faster responding PFR is required as RoCoF increases. Should not count regulation service towards meeting PFR requirement. PFR can be supplied from a generator, load or BESS that responds automatically to locally sensed frequency.
Secondary Frequency Response (SFR)	A control response that responds to instructions issued by AEMO to restore frequency to the edge of the normal band. SFR can be provided by a generator, load, or BESS which is able to moderate output in response to AGC commands or instructions issued by AEMO. This includes demand side response.
Frequency Regulation	A control response that continuously responds to AGC issued instructions to correct frequency errors within the normal band. Regulation can be provided by a generator, load, BESS that is able to moderate its output in response to AGC commands.
RoCoF control	A control response to prevent RoCoF exceeding “safe level” in future years • 2 Hz/s across 250 ms – best supplied by synchronous inertia • 1 Hz/s across 1s – sources include synchronous inertia or fast frequency response (FFR) FFR can be supplied from a BESS, fast interruptible load and synthetic inertia.

5.1 Mandatory requirements

The Technical Rules currently specify mandatory requirements for frequency response[25]. The following requirements currently apply to scheduled generators and specify minimum performance requirements that should be met provided the generator is operating within particular regions of is capability curve:

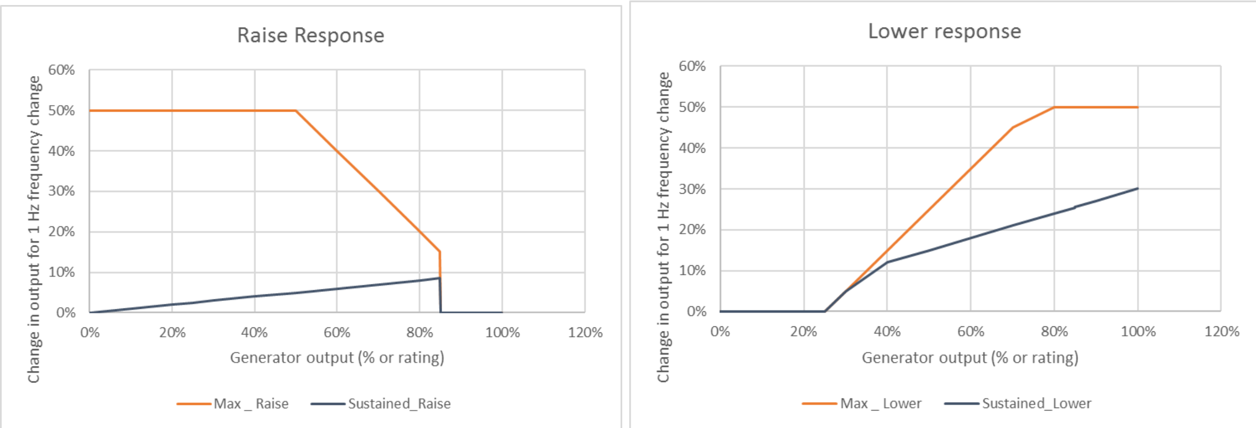
- a dead band that is no wider than +/- 0.025 Hz.
- a 4% droop when generating less than 85% of rated output.

[25] Clause 3.3.4.4 of the Technical Rules

- no requirement to provide a reduction in output in response to a frequency increase if that would require operation below the technical minimum.
- At least 90% of the response is achieved within 6s and sustained for not less than a further 10 s.
- Thermal generators must sustain at least 10% increase in output in response to an under-frequency event and at least 30% decrease in output in response to an over-frequency event (within applicable limits of the machine), with the increase or decrease in output measured with respect to the generation output immediately prior to the under or over-frequency event.

Figure 3 illustrates the response that would be expected from a thermal synchronous generator just meeting the mandatory requirements in the Technical Rules. The figure shows two graphs the one on the left shows the raise response available to response to a generator contingency, while that on the left shows the lower response available to responds to a load contingency. Each graph shows the maximum response in orange and the sustained response in blue. The responses shown assume a 1Hz change in frequency.

Figure 3 Illustration of mandatory range for thermal synchronous generators



It is worth noting that these are minimum requirements and that some generators may actually perform in excess of the minimum, in some cases where it would be more complex or costly to implement control system changes to limit the output to the minimum specifications. However, control systems of newer non-synchronous technology (e.g. BESS) require more specific configuration and so tend to be configured to match specific essential system service requirements (i.e. meet the documented requirements only and no more). It is also the case that deeming provisions in the Technical Rules allow generators that predate the Technical Rules to contribute a lower level of response than the minimum requirement specified in the Technical Rules.

The Technical Rules specify less precise requirements for frequency response from non-dispatchable generators requiring those generators to decrease output in response to over-frequency events subject to not falling below technical minimums. The mandatory technical requirements provide a shared contribution that maximises the capability available but differ from essential system services in the following important ways:

- AEMO does not move generators off their dispatch target to increase the amount of response available from the mandatory requirement.
- The amount of response available therefore varies significantly across the year and is not controlled by AEMO.

- The performance obligations (including response time and sustain time) that essential system service providers should meet will generally be higher and they will face stronger compliance obligations.

GHD has reviewed 30 minute dispatch data from 2018 to assess the amount of PFR potentially available from generators that were not contracted to provide essential system services. This calculation assumes generators not contracted to provide either SR of LFAS were able to provide a level of response consistent with the requirements specified in the Technical Rules. The output of each generator during each dispatch interval in the year, was used to calculate a sustained raise and lower response in MW consistent with the minimum requirement in the Technical Rules. For some generators, further reductions to the assessed raise and lower capability were made to align with AEMO advice regarding actual observed performance.

Figure 4 shows amount of raise response available across 2018, while Figure 5 shows the amount of lower response available. In Figure 4 the blue curve shows the sustained raise response that was calculated as being available and the proportion of the year that level of response was available.

Figure 4: Primary frequency raise response capability available from non-contracted generators

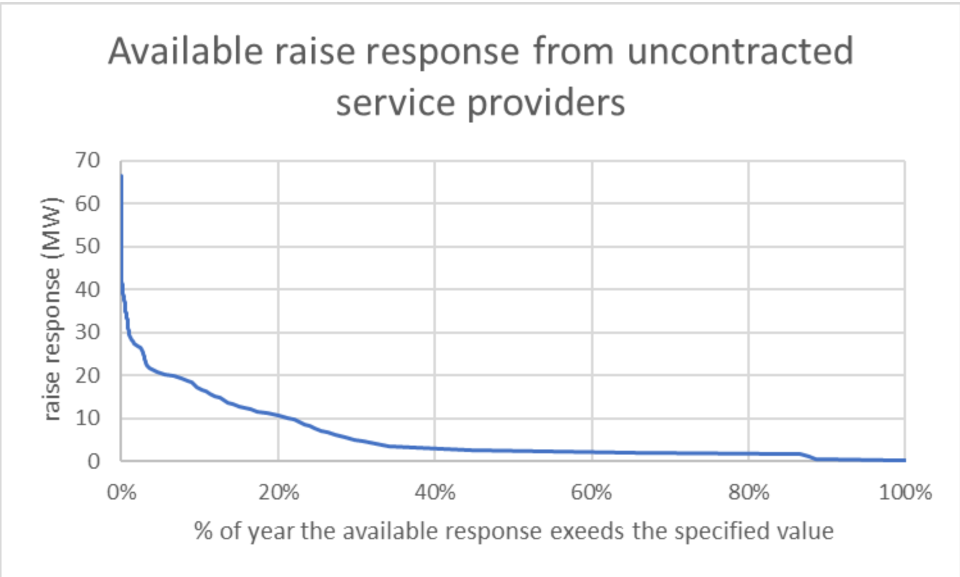


Figure 4 shows that for most of the year there is less than 5 MW of raise response available from generators not contracted to provide either SR or LFAS. The available raise response is less than 20 MW for 95% of the year and the maximum amount of unsustained response available from these generators is less than 70 MW.

Figure 5 shows two response curves. The orange curve shows the lower response calculated ignoring any contribution from renewable generators (solar and wind). The blue curve shows the lower response calculated including a contribution from solar and wind generators. The blue curve provides an optimistic view of the response available to keep the maximum frequency within the limits specified in the FOS. The Blue curve assumes the lower response available from wind and solar farms is able to operate as effectively as droop response from synchronous generators. Data gathered from AEMO indicates that some of the existing renewable generators that are configured to respond to over-frequency events rely on over-frequency relays to trigger reductions in generation. It has not been verified that the relays and runback controls have been appropriately set to deliver a response that will occur in sufficient time to prevent the over-frequency exceeding the FOS. The orange curve provides a more reliable indication of the lower response available to assist to keep frequency within the limits specified in the FOS.

Figure 5 Primary frequency lower response capability available from non-contracted generators

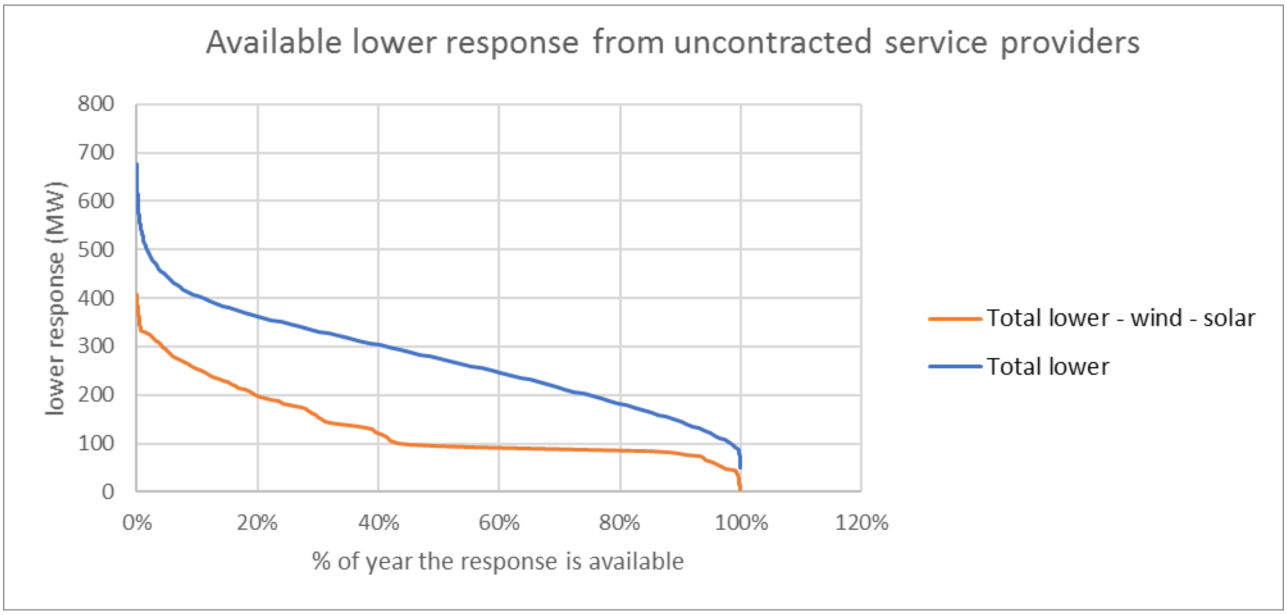


Figure 5 shows that on most occasions there is an appreciable amount of lower capability available from uncontracted generators (greater than 90 MW for 80% of the year). The increase in lower range compared to the raise range is due to the lower range available from synchronous generators operating above their technical minimum generation level. The lower range shown in Figure 5 shows two response curves. The orange curve shows the lower response calculated ignoring any contribution from renewable generators (solar and wind). The blue curve shows the lower response calculated including a contribution from solar and wind generators. The blue curve provides an optimistic view of the response available to keep the maximum frequency within the limits specified in the FOS. The Blue curve assumes the lower response available from wind and solar farms is able to operate as effectively as droop response from synchronous generators. Data gathered from AEMO indicates that some of the existing renewable generators that are configured to respond to over-frequency events rely on over-frequency relays to trigger reductions in generation. It has not been verified that the relays and runback controls have been appropriately set to deliver a response that will occur in sufficient time to prevent the over-frequency exceeding the FOS. The orange curve provides a more reliable indication of the lower response available to assist to keep frequency within the limits specified in the FOS.

Figure 5 assumes that all generators will reduce output to their technical minimum in response to an over-frequency event and the range provided takes no account of ramp rates that might be applied to limit the response.

As mentioned earlier the Technical Rules lack precision regarding the mandatory requirement for non-dispatchable generators. The increase in range indicated by the blue curve indicates that a substantial increase in lower capability may be available if the controls on renewable generators are appropriately tuned. If that was to occur then the amount of PFR lower capability available from mandatory services should be more than enough to keep frequency within the over-frequency contingency limits specified in the FOS. This suggests that encouraging renewable generators to provide lower PFR will increase competition in the provision of any lower PFR service and help to minimise cost.

The analysis demonstrates that PFR provided by generators meeting the mandatory requirements in the Technical Rules:

- are highly susceptible to the nature of dispatch in the trading interval, i.e. cannot be relied upon all of the time;
- in the case of mandated raise, unless new requirements are introduced available quantities are likely to decrease over time as the machines available to provide this are dispatched off or exit the market completely;
- would not be sufficient to meet the current SR requirement (70% of the largest contingency) and additional PFR is required, and
- could make a significant contribution to meeting the LRR requirement (120MW). This suggests that most generators are potential providers of frequency lower response indicating the potential for a highly competitive market for lower PFR.

The PFR delivered by uncontracted generators meeting the mandatory requirements in the Technical Rules complements the response procured from essential system service providers delivering more robust and resilient frequency control than would be the case if the mandatory requirements did not apply. The lower performance specifications and uncertainty regarding the amount of mandatory response available at any time means that the mandatory response cannot be relied upon on its own to meet FOS requirements.

Retention and/or improvement of the mandatory requirements is appropriate as:

- It provides a shared contribution that maximises the frequency control capability available without constraining any non-essential system service providers;
- It provides a more robust and resilient power system, and
- Practical experience in the NEM has identified the alternative approach of relying just on capacity provided from essential system service providers has led to a much less robust and resilient power system particularly with respect to frequency control. In the NEM, this has led to an increased likelihood that contingency events result in load shedding and growing deterioration in the ability to regulate frequency to 50Hz.

Consideration should also be given to reviewing the mandatory response requirements applying to non-synchronous generators, including embedded non-synchronous generation (such as rooftop PV). As mentioned the provisions in the Technical Rules that apply to these non-dispatchable generators lack precision. Revised performance standards for non-synchronous generators have been reflected in generator performance standard guidelines released by Western Power to GIA generators in December 2018. They could be used as a basis for refining the requirements in the Technical Rules applying to non-synchronous generators.

Generators wishing to be remunerated for frequency control services should be encouraged to submit bids to provide essential system services rather than receiving any revenue for providing a response consistent with the mandatory requirements in the Technical Rules. Providing remuneration for essential system services and not mandatory requirements is consistent with essential system service providers facing higher compliance standards and generally providing a more reliable service. Facilities contracted to provide frequency regulation services are also likely to experience greater changes in dispatch than generators assisting to regulate frequency through the provision of a mandatory droop response. As discussed further in section 5.5, the results obtained during the LFAS test conducted by AEMO in early 2019 should assist to illustrate the relative contribution to frequency regulation made by of LFAS providers and generations meeting mandatory requirements.

5.2 Primary Frequency Response

SR and LRR are the essential system services that currently provide PFR. SR service is provided by synchronous generators and contracted load shedding and responds to under-frequency events, while LRR service is provided by synchronous generators responds to over-frequency events.

The purpose of PFR is to arrest the change in frequency following load or generation contingencies and stabilise the frequency within the limits specified in the FOS. Procuring the appropriate amount of PFR should ensure that credible contingencies do not trigger uncontracted load shedding or generator tripping. When multiple contingencies occur, PFR works in conjunction with automatic UFLS and generator over-frequency tripping, to help arrest frequency disturbances and reduce the risk of complete system blackouts.

The current ancillary service standard[26] specifies levels of SR that:

- Require an amount of service equal to 70% of the largest generation contingency;
- Consider the maximum ramp rate expected over a 15 minute period;
- may be relaxed by 12% for a period of less than 20 minutes, and
- may be relaxed if maintaining the SR capacity would result in involuntary load shedding

The current load rejection service standard[27] requires a level of service:

- sufficient to keep the over-frequency below 51 Hz for credible load rejection events. AEMO currently sets the requirement to 120 MW to avoid this, and
- allows the requirement to be relaxed by up to 25% if AEMO considers the probability of transmission faults is low. This allows relaxation of the requirement to 90 MW as per AEMO's current practice.

One of the key issues with the definitions above are that they are completely independent of the actual FOS that they are intended to support. For example, SR simply specifies a 70% criteria without a respective frequency target to maintain (despite other requirements for AEMO to maintain frequency within the limits specified in the FOS).

The existing service standards also do not differentiate between the amount of service required and the speed with which the response is delivered, i.e. the current SR response is defined over three distinct time categories but there is no separate valuation for the different time categories[28]. Similar to the above point, the time categories and quantities specified in the currently framework also bear no specific linkage to meeting the FOS, nor do they allow for the requirements to vary with other dispatch conditions such as system inertia. These limitations need to be addressed to ensure the PFR requirements are appropriately specified and deliver secure system operation, particularly with lower levels of system inertia.

The following sections present findings of investigations into a way of structuring a PFR framework around the requirements of the FOS. The investigations involved simulating load and generation contingencies and assessing the level of PFR required to keep the frequency nadir (or maximum frequency) to within the limits

[26] WEM Rule 3.10.2

[27] WEM Rule 3.10.4

[28] WEM Rule 3.9.3 and illustrated in Figure 10

specified in the FOS. All of the studies excluded any contribution to arresting the frequency change following a contingency that might come from generators providing a mandatory response as defined in the Technical Rules. As noted in section 5.1, the amount of mandatory raise response is often quite small, and cannot be guaranteed, and so this approach is therefore appropriate for studying under-frequency events.

A more significant level of mandatory lower response may be available however on a more reliable basis. AEMO was able to provide data indicating that control and protection settings on existing renewable generators may provide a contribution to managing over-frequency events occurring during periods of high renewable generation. However further work would be required to validate exactly how those controls operate. Without that analysis it is not possible to confirm how effective existing over-frequency controls would be in helping to keep the maximum frequency following load contingencies to within the limits specified in the FOS. Some specific areas of concern include:

- Where the over-frequency response provided by renewable generators relies on over-frequency relays to initiate the response, it is unclear whether the relay and control system settings are appropriate to deliver a response in sufficient time to arrest the frequency before it exceeds the limit in the FOS. The review of the NEM system event from 25 August 2018 identified that the over-frequency response from many renewable generators incorporated delays that meant that the response was too slow to arrest the maximum over-frequency[29].
- Whether the level of redundancy in the local frequency detection and control systems is sufficient to provide a response from renewable generators that is as reliable as the droop response provided by synchronous generators.
- Whether there are rate of change limits integrated into local power control loops on renewable generators that might restrict the over-frequency response delivered.

5.2.1 Counting regulation capacity towards meeting PFR requirement

Currently LFAS raise capability is counted towards meeting the SR requirement. The potential impact of this practice on system security was examined by simulating a generator contingency at the time of the 2018 minimum system demand using the lumped DIgSILENT model. The simulation results are shown in Figure 6 which shows the frequency response following the trip of the largest generator dispatched at the time of the 2018 minimum demand. The different curves model different assumptions regarding the available level of SR:

- The solid blue curve shows the response achieved from all synchronous generators consistent with their actual generation output and the governor models in the Western Power DIgSILENT model[30]. This models an amount of PFR which is significantly greater than 70% of the generator contingency as would be expected under this particular low load condition, as generators providing a response have a large amount of headroom available. Unsurprisingly the frequency settles well within the limit specified in the FOS.
- The dashed blue curve reduces the amount of response by disabling governors on generators assumed to be providing 72 MW of LFAS. This curve simulates the response that might occur if the LFAS providers had no range left at the time of the contingency as a result of providing frequency

[29] AEMO Final Report – Queensland and South Australia system separation on 25 August 2018 https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Power-System-Operating-Incident-Reports

[30] Note that AEMO have identified a number of governor models that require review in the DIgSILENT model to confirm behaviour against actual observed results. While attempts were made to adjust the model to address identified issues, the DIgSILENT model may be optimistic in its response.

regulation (i.e. the LFAS had been all used up prior to the contingency). The simulated response settles to a lower frequency but is still well within the limit specified in the FOS.

- The solid orange curve models an amount of PFR equal to 70% of the generator contingency. This curve is intended to simulate a situation where there is only sufficient headroom on the available generators to provide the specified 70% response (this might typically occur at a higher load time). The simulation includes response from generators enabled to provide LFAS service and assumes there is headroom available on those generators to provide the full LFAS range. The frequency settles within the limit specified in the FOS, but to a lower level consistent with the lower amount of PFR.
- Similar to the previous case, the dotted orange curve models an amount of PFR equal to 70% of the generator contingency. However, in this case the governors on the generators providing LFAS are disabled and a similar amount of PFR capacity is enabled on other generators. This example simulates a situation where the available LFAS range is 0 MW (i.e. all used up) and to compensate an additional 72 MW of PFR has been sourced from other generators. The frequency settles within the limit specified in the FOS, but to a lower level than the solid orange curve which is consistent with the PFR enabled to replace that from generators providing LFAS being slower to respond.
- The dashed orange curve models an amount of PFR equal to 70% of the generator contingency, with 72 MW assumed to come from generators enabled to provide LFAS. In this case the governors on the generators providing LFAS are disabled to simulate the LFAS range being used up but with no re-allocation to other generators. The simulation models the situation that would occur if the LFAS capacity had been depleted when the contingency occurred. In this case the frequency falls outside the limit specified in the FOS, triggering automatic UFLS.

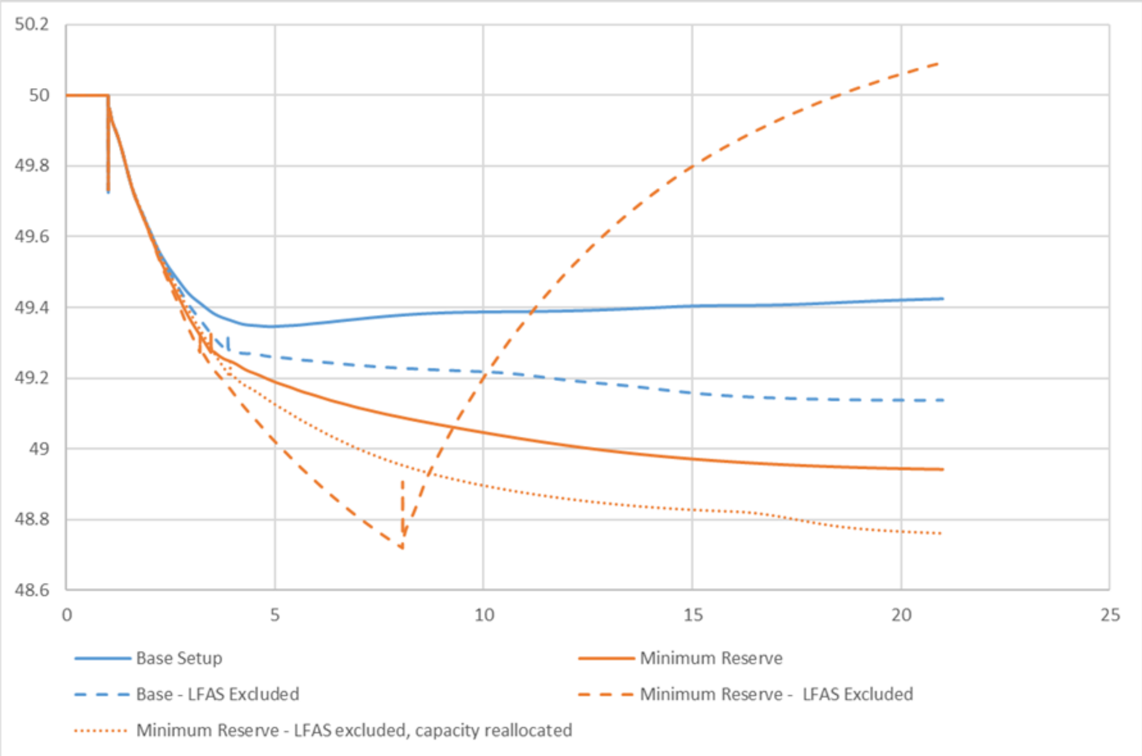
The simulation highlights the system security risk of counting regulation raise capacity towards meeting the PFR raise requirement. Under conditions where there is just sufficient PFR available to meet the requirement and some or all of the regulation range has been depleted in regulating frequency, it is likely that a worst case single contingency event will cause the frequency to move outside the limits in the FOS and trigger uncontracted UFLS.

The current arrangements that allow for the Synergy portfolio to be dispatched by AEMO, allows AEMO to quickly replenish the available LFAS capacity and this helps to reduce the risk caused by counting LFAS raise capacity towards meeting SR requirements. Counting LFAS capacity as providing SR allows less SR capacity to be procured which helps lower essential system service costs. The practise does however place greater importance on quickly replenishing LFAS range the costs of which are masked by the exist arrangement for dispatch of the Synergy portfolio and the notional level of 72 MW assumed in settling the LFAS market.

In the future with facility bidding and a 5 minute dispatch, it will become less likely that all of the regulation raise capacity will be available at any time. Continuing the practice of counting regulation raise capacity towards meeting the PFR raise requirement will pose an increased system security risk. The same applies for counting regulation lower capacity toward meeting the PFR lower requirement.

It is recommended that in the revised essential system service arrangements that regulation capacity is not counted towards meeting the PFR requirement.

Figure 6: Impact of counting regulation as PFR

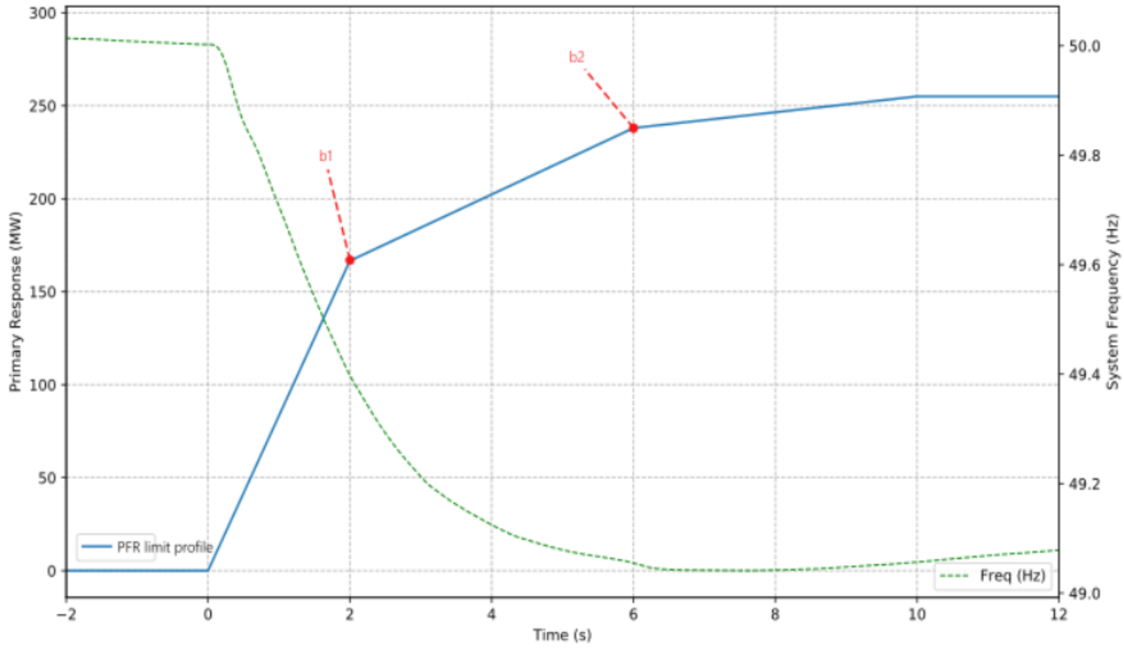


5.2.2 Impact of inertia on RoCoF and PFR requirement

The SR service is currently specified with a minimum response time of 6s. The actual response of generators tends to produce an appreciable level of response well ahead of 6s. AEMO has analysed historical under-frequency events and identified that the PFR delivered during those events can be described by a two break point PFR characteristic. Figure 7 illustrates a two breakpoint PFR characteristic, it is defined by the response reached 2s after the contingency and the response reached 6s after the contingency.

The analysis undertaken by AEMO to develop the aggregate model demonstrates that generators currently providing LRR and SR in the SWIS are delivering a much faster response than specified in the service standards in the WEM rules. The blue line in Figure 7 shows the aggregate PFR response which has been matched to the response observed in the power system for a particular under-frequency event. That response is clearly delivering a substantial amount of response before 6s. The current SR definition allows for a response that builds more slowly as the requirement is to respond appropriately within 6s which, if delivered, would actually result in significantly poorer contingency frequency management and create an increased risk of under-frequency load shedding for varying demand and contingency size scenarios.

Figure 7: Two breakpoint PFR characteristic[31]



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 that occur 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 slower RoCoF 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 requirement for a quicker PFR increases. This was investigated using the aggregate model developed by AEMO to investigate the relationship between inertia, RoCoF and the PFR requirement that would allow the frequency following a generation or load contingency to remain within the limits specified in the FOS.

The studies considered a PFR with a dual break point characteristic and a variant which included a three break point response defined by the response achieved at 1s, 2s and 6s.

The 2023 minimum demand condition was studied as it presents a challenging scenario in which it is possible for the inertia to be much lower than that typically present on the SWIS today. The very low inertia, increases the RoCoF and requires quicker acting PFR to keep the frequency within the limits specified in the FOS.

Table 7 and Table 8 show the level of 1s, 2s and 6s PFR required to keep the frequency Nadir following generator contingencies within the limits specified in the FOS for the 2023 minimum demand. The results show how the PFR requirement varies with the size of the generator contingency and the amount of inertia. The right hand columns show the RoCoF over the first 250 ms and 1 s following the contingency. The

[31] Reproduced from AEMO report, “Contingency Frequency Response in the SWIS” dated November 2018

highlighted cells show conditions where the RoCoF exceeds the safe levels specified in Table 5. Section 5.3 discusses services and other options that maybe required to manage RoCoF to within safe levels.

Table 7 : 2023 min demand PFR for generator contingencies with 3000 MWs or 4000 MWs of inertia

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

Note 1) RoCoF for 400 MW multiple contingency calculated assuming PFR for 300 MW single contingency
2) results assume a load relief factor of 1.0%

Table 8: 2023 min demand PFR for generator contingencies with 5000 MWs or 6000 MWs of inertia

Generator Contingency size (MW)	PFR requirement and RoCoF for 5000 MWs of Inertia					
	1s	2s	6s	2s EX	RoCoF (250ms)	RoCoF (1s)
400[1]	162	256	256	293	1.856884	1.467361
300	162	256	256	293	1.365952	0.999278
275	126	231	231	242	1.265712	0.969284
250	0	202	206	202	1.158708	0.912913
225	0	171	181	171	1.04588	0.833843
200	0	141	156	141	0.932804	0.753694
175	0	110	131	110	0.820104	0.67486
150	0	79	106	79	0.707464	0.596142
125	0	49	81	49	0.59458	0.516349
100	0	18	56	18	0.482068	0.437864
	PFR and RoCoF for 6000 MWs of Inertia					
400[1]	0	252	256	256	1.570748	1.312982
300	0	252	256	256	1.160616	0.917989
275	0	221	231	231	1.066228	0.850953
250	0	190	206	206	0.971884	0.784002
225	0	159	181	181	0.877584	0.717137
200	0	128	156	156	0.783328	0.650356
175	0	97	131	131	0.689116	0.58366
150	0	66	106	106	0.594952	0.517049
125	0	35	81	81	0.500828	0.450521
100	0	3	56	56	0.407004	0.385076
Note 1) RoCoF for 400 MW multiple contingency calculated assuming PFR for 300 MW single contingency 2) results assume a load relief factor of 1.0%						

The studies of the 2023 minimum demand condition showed that if a two break point (2s and 6s) PFR characteristic is assumed, many conditions required significantly more 2s response than 6s response to keep the frequency nadir within the limits specified in the FOS. This occurred for conditions with RoCoF exceeding safe levels. The amount of 2s response required in this case is shown in the column titled 2s EX in the tables. A PFR characteristic that delivers more 2s response than 6s may be difficult to achieve in practice, whereas the requirements achieved assuming a three break point PFR is consistent with service providers sustaining any 1s response.

The results presenting in Table 7 and Table 8 are indicative only and would need further refinement before being relied upon operationally by AEMO. They do however illustrate an important finding that as the level of inertia declines there is an increased requirement for PFR that responds more quickly than 6s.

It is therefore recommended that the revised essential system service framework allow the requirement for PFR be set considering the required response delivered within 1s, 2s and 6s.

The results for the 400 MW contingency shown in Table 7 and Table 8 modelled the same level of PFR as the 300 MW scenario. The RoCoF calculated therefore gives an indication of RoCoF that might occur following a 400 MW multiple generator contingency that occurred with sufficient PFR in place to manage a 300 MW single generator contingency. The results demonstrate that even though the level of 2s and 6s PFR may be sufficient to meet FOS requirements for a single contingency, at low inertia a second contingency of even just 100 MW may be enough to breach safe RoCoF limits and risk system collapse.

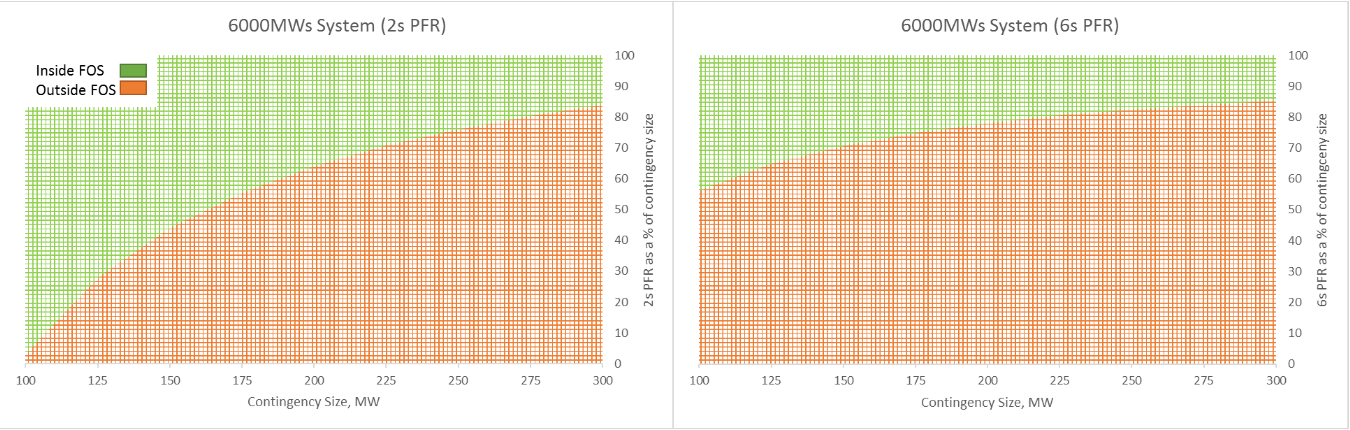
It is therefore recommended that sufficient PFR is made available to ensure stable operation within the FOS for single contingencies and sufficient to maintain safe RoCoF levels for multiple contingencies

Consideration should also be given to including the definition of the safe RoCoF level in the FOS to support the specification of appropriate PFR requirements this is discussed further in section 5.3.

The SR requirement for the SWIS is currently equal to 70% of the largest generator contingency. The results obtained indicate that it is no longer appropriate to set the PFR requirement as a fixed proportion of the largest contingency. For instance with a two break point (2s and 6s) PFR requirement and 5000 MWs of inertia, almost 100% of the 300 MW largest single contingency is required to be held in reserve.

Studies completed with the aggregate model suggest that 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 PFR requirement is likely to exceed 70% of the largest contingency. This is illustrated in Figure 8, which shows how the calculated PFR requirement (2s and 6s) varied with contingency size for a scenario with 6000 MWs of inertia. This figure demonstrates that it is no longer appropriate to specify the PFR requirement as a fixed percentage of the largest contingency size.

Figure 8 : PFR required for secure operation of the SWIS operating at 6000MWs at 2s (left) and 6s (right)



The 2023 minimum demand case was also used to study the PFR requirement to keep the maximum frequency within the limits specified in to the FOS for load contingencies. These studies considered contingency sizes up to 260 MW which corresponds to a multiple load contingency that occurred in 2017. The results shown in Table 9 indicate that the lower contingency size generally produces a lower RoCoF and there does not appear to be a need for and 1s PFR to keep the maximum frequency within the limits specified in the FOS.

When inertia fell below 5000 MWs the RoCoF experienced for the 260 MW multiple contingency exceeded the safe level which may indicate the need for specific measures as discussed in section 5.3.

The results indicate that the current 120 MW LRR requirement is sufficient to keep the maximum frequency within the limits specified in the FOS even with very low levels of inertia. This result suggests that there may be an opportunity to reduce the requirement for lower PFR by considering the likely contingency size and actual system inertia. As previously demonstrated for generator contingencies, when considering load contingencies it is no longer appropriate to specify the PFR requirement as a fixed 120 MW requirement, instead the requirement should vary with system inertia and the size of the largest load contingency.

The results shown in Table 9 are indicative only and would need further refinement before being relied upon operationally by AEMO. They have been derived using the aggregate model developed by AEMO. Further work is recommended to validate the aggregate model against actual over-frequency events.

5.2.3 Operational considerations

Using the AEMO aggregate model to study the PFR requirements for the 2018 and 2023 minimum demand conditions, provided GHD with the opportunity to understand the model and compare it with DIgSILENT lumped and full model. We found that the AEMO aggregate model is an appropriate tool to use to evaluate whether a given combination of PFR will be sufficient to meet the FOS for a specified contingency size and inertia level and can be used by AEMO to further refine the PFR requirements based on GHD's recommendations above. The model allows different combinations of PFR service offerings to be considered and evaluated to establish whether the aggregate response is sufficient to control frequency to within the limits specified in the FOS.

The results shown in the previous section demonstrated the use of the aggregate model to develop a two or three breakpoint PFR sufficient to maintain the frequency within the limits specified in the FOS. The aggregate model is able to model the PFR contributions from various service providers and assess the resulting aggregate frequency response following a contingency. It should be possible to use the model to assess whether a selected group of offers to provide PFR service will be sufficient to maintain the frequency within the limits specified in the FOS. The model could be used directly for this purpose or alternatively the model could be used to develop an acceptable aggregate PFR characteristic. That characteristic could be used in a market dispatch engine to select the optimal mix of PFR service offers that best meets the aggregate requirement.[32.]

It is recommended that the aggregate model developed by AEMO be used to determine the PFR requirement for different dispatch conditions taking into account the available inertia and the expected largest contingency size.

As explained in section 4.1 of the AEMO paper, the aggregate model can be used to define a PFR requirement that would be sufficient to arrest the frequency change and keep it within the limits specified in the FOS. The offers received from PFR providers could be compared with the requirement determined from the aggregate model and the least cost combination of offers accepted. The aggregate model could also identify the relationship between generator contingency size, inertia and the required level of service. Such a

[32] This is further discussed in the AEMO paper, Contingency Frequency Response in the SWIS.

relationship would allow the energy market dispatch to co-optimise the generation dispatch (contingency size) and the required amount of PFR.

Table 9: 2023 min demand PFR for load contingencies with 3000 MWs to 6000 MWs of inertia

Load Contingency size (MW)	PFR requirement and RoCoF for 3000 MWs of Inertia				
	1s	2s	6s	RoCoF (250ms)	RoCoF (1s)
260[1]	0	164	167	1.9648	1.4736
120	0	70	74	0.9120	0.6950
100	0	48	54	0.7655	0.5985
75	0	19	29	0.5829	0.4805
50	0	0	4	0.3945	0.3415
	PFR requirement and RoCoF for 6000 MWs of Inertia				
260[1]	0	149	167	1.4988	1.1840
120	0	63	74	0.6953	0.5577
100	0	39	54	0.5847	0.4841
75	0	10	29	0.4460	0.3906
50	0	0	4	0.2995	0.2683
	PFR requirement and RoCoF for 6000 MWs of Inertia				
260[1]	0	129	167	1.2148	0.9999
120	0	53	74	0.5635	0.4712
100	0	29	54	0.4744	0.4104
75	0	0	29	0.3596	0.3220
50	0	0	4	0.2414	0.2208
	PFR requirement and RoCoF for 6000 MWs of Inertia				
260[1]	0	108	167	1.0230	0.8710
120	0	42	74	0.4748	0.4114
100	0	18	54	0.4001	0.3595
75	0	0	29	0.3011	0.2736
50	0	0	4	0.2021	0.1875

Note 1) PFR for 260 MW multiple contingency case selected to keep frequency Nadir below 52 Hz 2) results assume a load relief factor of 1.3%

While there is a case for implementing more dynamic PFR requirements that vary with the level of inertia and the credible contingency size, before implementing that change it would be appropriate to consider a prudent operating margin that should be incorporated in any calculated PFR requirement. The selected operating margin should account for uncertainty in the ability of the modelled PFR requirement to accurately reflect all variables that could influence the actual performance achieved in response to a contingency event. The following factors should be considered when developing operational margins applied to PFR requirements determined from the aggregate model:

- A PFR requirement to should be set to achieve a nadir “above” the under-frequency load shed point (currently 48.75Hz in the SWIS), not be designed to exactly match it. Under-frequency relays all have a slight measurement error and the system frequency is not precisely the same at every location around the power system. Designing a PFR requirement that exactly meets the minimum frequency nadir will almost certainly result in some under-frequency load shed relays operating for large contingencies, therefore a frequency buffer should be applied above the nadir to avoid this.
- There is a risk that some of the PFR capability is lost if the contingency event is actually a PFR service provider (i.e. the PFR that the provider was allocated cannot be provided).
- There is a risk that a PFR provider fails to respond.
- There is a risk that in aggregate the service providers do not achieve the level of response indicated in their offers. This may be due to a variety of factors including the actual dispatch of generators at the time of the contingency differing from that assumed when the PFR offers were accepted.
- There is a risk that the load relief at the time might differ from that assumed in developing the PFR requirement.
- There is a risk that an under-frequency event causes some tripping of older roof top PV[33].
- Uncertainty regarding the level of PFR response that might come from uncontracted generators through their mandatory droop response.

GHD has identified a number of references that point to the need to consider an appropriate operating margin. The 2002 Cigre paper on frequency control in a market environment[34] noted that in order to manage the risk that the specified frequency control requirement is insufficient to prevent uncontracted load shedding, requirements are likely to include an operating margin or be determined based on conservative assumptions. PJM manual 11 on Ancillary service market operations describes margins added when specifying the requirement for synchronised reserves for the PJM system. The manual states that a margin of 190 MW + an allowance for additional reserve in anticipation of heavy load conditions is added to the size of the largest contingency when specifying the requirement for this SFR ancillary service[35]. The AEMO

[33] Systems installed before 2015 did not need to comply with AS 477.2 and Western Power has estimated that 26% of those systems may trip before frequency reached 48.75Hz - see Western Power Document DM#11545078

[34] Paper 39-205-2002 available through e-cigre

[35] PJM Manual 11 available via https://www.pjm.com/library/manuals.aspx

ESOPP Guide on confidence intervals, offsets and operating margins describes the factors that should be considered when setting an operating margin[36].

Different factors need to be considered when determining operating margins for raise and lower PFR requirements. A key example is the contribution expected from mandatory response. As demonstrated by the historical analysis presented in section 5.1 the mandatory response capability available from facilities not contracted to provide an essential system service across 2018 differs significantly between the raise and lower response. While there was often little raise response available, the analysis showed that this was not necessarily the same situation for lower response across the entire year. This suggests that it is much more likely for an appreciable mandatory contribution to addressing over-frequency events to be available than under-frequency events. This in turn may suggest it is appropriate to have a lower operating margin for the lower PFR requirement.

It is recommended that AEMO undertake further analysis of the factors that should be considered in developing an appropriate operating margin to be applied to the PFR requirement determined from the aggregate model. As different factors may apply for over and under-frequency events it is recommended that separate operating margins be developed for raise and lower PFR requirements.

It is important that essential system service providers have clarity regarding how their PFR capability is to be assessed and any compliance obligations that would apply. As part of operationalising the revised essential system service framework, a detailed description should be developed to specify what assumptions should be made in deciding how much PFR service a facility can provide. Consideration should be given to specifying a particular frequency signal against which the response capability is defined. An example might be a frequency signal that ramps at 1 Hz/s to the limits of the single contingency bands defined in the FOS.

The compliance regime that will apply to PFR service providers should also be defined. This should include specification of requirements to measure the response to under and over-frequency events and clarification of how that measured response would be used to demonstrate whether the level of response delivered was consistent with the offered response (while taking into account any energy dispatch requirements). The compliance regime should also define the arrangements that will be in place to encourage provision of a service which is consistent with the offers made to AEMO.

5.2.4 Key recommendations and future work – PFR

The following recommendations regarding the PFR essential system service can be drawn from the studies undertaken:

- The level of PFR should vary with inertia and size of contingency.
- Raise and lower PFR requirements should be individually specified.
- Regulation capacity should not be counted towards meeting the PFR requirement.
- The aggregate model developed by AEMO should be used to determine the PFR requirement for different dispatch conditions taking into account the available inertia and the expected largest contingency size, and looking at what considerations could be given to discounting the lower PFR requirement based on available mandatory lower contribution.
- The requirement for PFR should be set considering the required response commencing as soon as possible following the contingency event, and delivered within 1s, 2s and 6s.

[36] Confidence Levels, Offsets & Operating Margins:http://www.aemo.com.au/Electricity/Resources/Working-Groups/Confidence-Levels-Offsets-and-Operating-Margins

- PFR providers should specify the service level based on how quickly it can commence and what is achievable within 1s, 2s and 6s.

Further work is required to operationalise the proposed PFR essential system service. Key activities to be undertaken include:

- AEMO should commence work on a technical specification for the new PFR framework to provide further clarity to participants. The specification should provide clarity regarding times for which the PFR needs to be sustained, as discussed further in section 5.4.1.
- AEMO should develop appropriate operating margins to cater for the risk that the delivered service is less than that required to keep the frequency nadir within the limits specified in the FOS. This work should consider raise and lower requirements separately to account for the different factors that may effect whether the actual delivered PFR response aligns with the required response.
- The PFR service specification should be developed further clarifying the assumption that service providers should make in assessing the capability of their facility.
- AEMO should lead detailed design of the compliance framework that will apply for PFR essential system service.

5.3 Controlling RoCoF to a "safe level"

RoCoF immediately following a contingency is dependant primarily on contingency size and system inertia. Historically there has been no need for specific control measures or essential system services to manage RoCoF in the SWIS, as there has been ample inertia to limit RoCoF below problematic levels. Studies of the 2018 minimum demand condition confirmed that there was sufficient inertia to keep RoCoF below the safe levels noted in section 4.3.3 even in the unlikely event of two of the largest generators tripping simultaneously. The level of inertia present at the time of the 2018 minimum demand has been estimated by GHD from the published generation dispatch records[37] at approximately 12000 MWs.

As the amount of non-synchronous generation connected to the SWIS continues to increase, lower levels of inertia will become more commonplace and this poses a risk that RoCoF will increase to unsafe levels. The studies undertaken at the 2023 minimum demand level illustrate the problem. The results presented in Table 7 and Table 8 indicate that if inertia falls to below 6000 MWs larger single generator contingencies are likely to result in a RoCoF that exceeds safe levels. This suggests that the revised essential system service arrangements should consider services and practices that allow AEMO to control RoCoF to safe levels.

The WEM ancillary services market currently does not have an explicit service to control RoCoF and the FOS does not make any reference to a safe level for RoCoF. While some level of RoCoF control could be implemented within the existing framework via either a DSS or through adjusting the dispatch of the Synergy Portfolio these measures would be difficult to co-optimise with energy market dispatch and the dispatch of other frequency control service.

It is important that RoCoF is controlled to safe levels following both single contingency events and reasonably anticipated multiple contingencies. Failure to do so risks:

- exacerbating any under-frequency event if generators trip to protect themselves from damage;

[37] http://data.wa.aemo.com.au/#facility-scada

- unintended triggering of loss of mains or anti-islanding protection resulting in the trip of embedded generator which can also exacerbate any under-frequency event, and
- triggering wide spread supply disruption or a system black event if the RoCoF is too high to allow emergency frequency control schemes (such as automatic UFLS) sufficient time to operate.

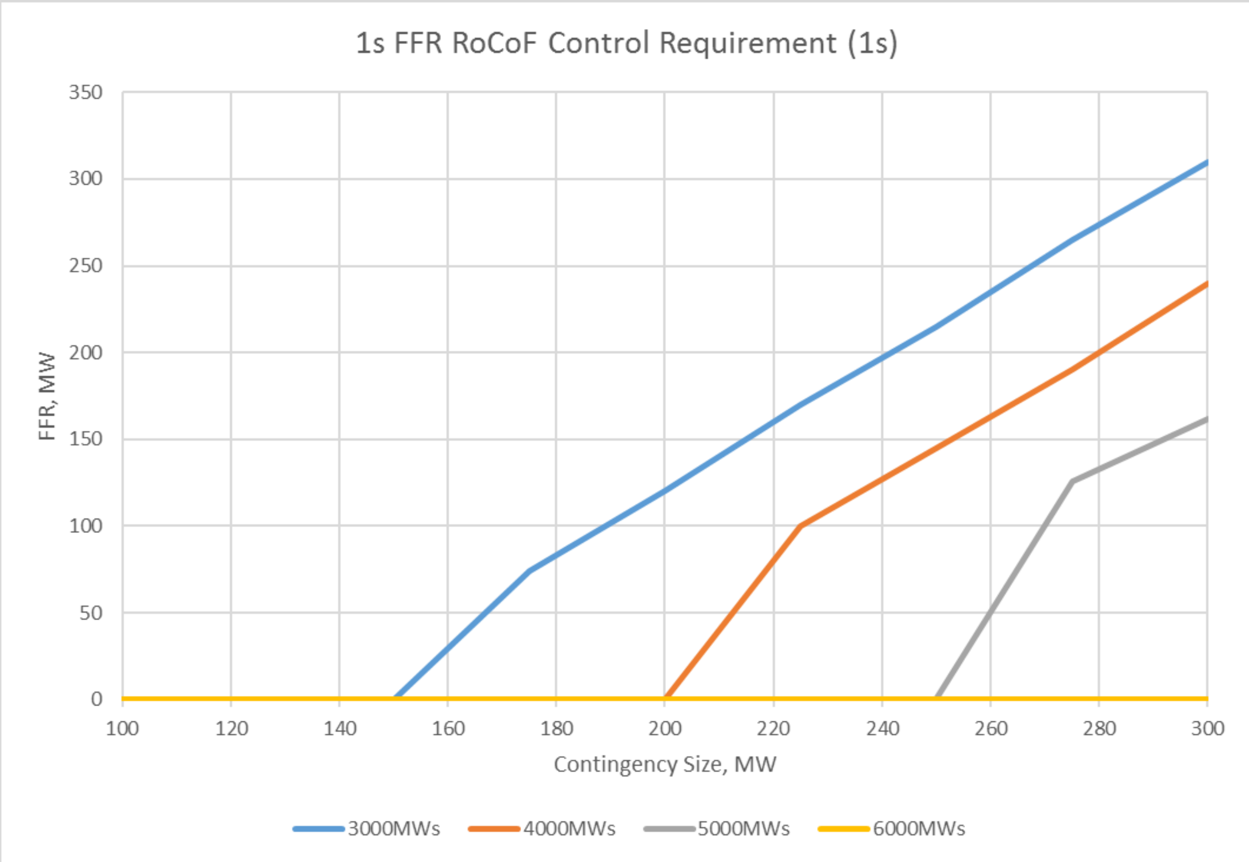
Various options are available to manage RoCoF. Limits could be placed on the loading of individual generators to limit the size of the largest generator contingency, AEMO could intervene in the market to constrain on additional synchronous generation to increase inertia, or essential system services could be enabled to control RoCoF following any contingency. To further investigate the potential for using essential system services to control RoCoF GHD has completed two sets of studies. The first set used the aggregate model and the 2023 minimum demand condition to assess how much 1s PFR would be required to keep RoCoF to within safe level. The second set of studies used the lumped DIgSILENT model to investigate limitations that might exist in relying solely on fast frequency response to control RoCoF.

Figure 9 shows the amount of 1s PFR also referred to as fast frequency response (FFR), that was simulated as being able to limit the RoCoF across 1s to 1 Hz/s in the 2023 minimum demand studies. The figure shows that there is no requirement for any service to limit RoCoF if the inertia is greater than 6000 MWs and the total generator contingency is less than 300MW. For lower levels of inertia the figure shows the amount of 1s PFR required to limit RoCoF to 1Hz/s. The requirement increases as the level of inertia falls and increases with the size of the generator contingency. The potential trade-off between size of the contingency, 1s PFR requirement and inertia is also illustrated in Table 10.

Table 10: Amount of FFR needed to control RoCoF to 1Hz/s with low levels of inertia

Load Contingency size (MW)	1s PFR requirement (MW) to limit RoCoF to 1 Hz/s for different levels of inertia			
	3000 MWs	4000 MWs	5000 MWs	6000 MWs
300	310	240	162	0
275	265	190	126	0
250	215	145	0	0
200	170	100	0	0
175	120	0	0	0

Figure 9: FFR required to control RoCoF to safe levels with low system inertia – 2023 min demand



The studies carried out with the aggregate model did not attempt to optimise various options to control RoCoF. The results however are useful in illustrating the potential to trade off between the size of the contingency, 1s PFR requirement and inertia. For instance, the studies suggest that with 3000 MWs of inertia and a 300 MW contingency size, RoCoF could be controlled to 1Hz/s with 310 MW of 1s PFR. If the size of the contingency was reduced by 50 MW the required amount of 1s PFR could be reduced by 95 MW. If instead the inertia was increased to 4000 MWs the studies suggest that the 1s PFR requirement would reduce by 70 MW. The choice between which control measures are most appropriate to control the RoCoF across 1s to safe levels is an economic one and may be best addressed my some form of co-optimisation within the market dispatch system.

The safe RoCoF level is specified as a RoCoF measured over two time periods: 250 ms after the contingency and 1s after the contingency. The studies of the 2023 minimum demand scenario indicated that with larger contingencies and inertia below 4000 MWs the RoCoF across the first 250 ms may exceed the safe level of 2 Hz/s. Controlling the RoCoF across 250 ms using fast frequency response is more challenging than controlling the RoCoF across 1s. This is because 250 ms allows very little time to deliver the response particularly if inherent measurement delays and dead bands are considered. GHD completed simulations using the lumped DIgSILENT model to understand the response delay that might be inherent in a Battery Energy Storage System (BESS) configured to deliver a fast frequency response. We modelled the following attributes of the BESS control system in these simulations:

- measurement delay required to reliably detect a RoCoF event;
- dead band to avoid the BESS responding to normal frequency variations addressed by regulation services, and

- frequency droop sufficient to provide a rapid response to a frequency contingency.

A range of control system settings were simulated with parameters selected taking into account recent functional specifications for BESS being proposed to provide fast frequency response in the NEM and in the Darwin Katherine system.

The DIgSILENT studies indicated that achieving a reliable response quickly enough to control RoCoF across 250 ms to the safe level is unlikely to be achievable with the BESS currently being specified. While technologies capable of managing RoCoF over this short time period other than inertia may emerge, currently the most reliable course of action would be to either maintain a minimum level of inertia and/or restrict the expected contingency size to avoid encroaching on the 250 ms safe RoCoF level. Maintaining a minimum level of inertia could be achieved by constraining on additional synchronous generators or by commissioning a high inertia synchronous condenser.

5.3.1 Considerations of contingencies

Contingencies require particular consideration to effectively mitigate the risk of RoCoF exceeding safe levels. As RoCoF is proportional to both the size of the contingency and inertia it is important to consider the impact of the contingency in terms of the amount of real power imbalance it creates (MW) and any resulting reduction in inertia. This is particularly important for generator contingencies. One way to address the concern would be to apply an n-1 approach to inertia when assessing exposure to unsafe RoCoF conditions following generator contingencies. This would involve assessing the RoCoF that would occur for the combination of the largest generator contingency and the loss of the generator providing the largest contribution to system inertia.

Multiple contingency events need to be considered when assessing RoCoF. It is important that RoCoF remains below safe levels following reasonably likely multiple contingencies. Processes to monitor the risk of multiple contingency events creating unsafe RoCoF should be considered. While multiple contingencies can and do occur on power systems, only contingencies occurring within 1s of each other would result in a cumulative RoCoF issue. AEMO should collaborate with Western Power to identify scenarios that are reasonable likely to trigger multiple contingency events occurring within 1s of each other. The scenarios should identify when those conditions are likely to occur. For instance, network outages placing multiple generators on a radial connection would increase the overall contingency size, or adverse weather conditions or bushfires in close proximity to transmission lines might result in multiple transmission circuits tripping and multiple generators being disconnected. Forecasting when those conditions are likely would allow AEMO to take implement measures to control RoCoF.

In the NEM, AEMO works with the TNSPs to conduct a periodic (currently refreshed annually) PSFRR. The PSFRR considers the risk posed by non-credible events such as the loss of double circuit transmission lines and where appropriate recommends the development of emergency controls and operational measure to address the risk. An example is the System Integrity Protection Scheme implemented in South Australia which operates in conjunction with pre-contingent constraints on the Heywood interconnector to manage the risk of destructive winds in South Australia tripping transmission lines and disconnecting multiple generators. Without this scheme there would be an increased risk that such an event could lead to a system black event.

A similar process to the NEM PSFRR, should be considered for the SWIS to assess the risk posed by multiple contingency events and to identify the most prudent option for addressing those risks. AEMO should investigate the Emergency Frequency Control Scheme concepts in the NEM to determine if they may be beneficial in the SWIS as well in terms of providing protection-scheme based options for helping to maintain

FOS under certain specific circumstances, to avoid these events from driving up the overall cost of market services.

5.3.2 Mandatory inertial response considerations

Currently synchronous generators provide an inertial response by virtue of the type of technology that they are, i.e. they inherently contribute to the system following contingencies. An inertial response is technically effective at controlling RoCoF and can help to discount the cost of other services that may be required to provide a fast frequency response in the absence of inertia. However, synchronous generators are also not the only source of inertia on the power system. Some inverter connected generators also being technically capable of providing a synthetic inertial response (where that does not adversely impact other slower PFR services). Battery energy storage systems can provide a rapid change in the power generated or consumed, this fast frequency response can also help to control RoCoF. Synchronous condensers also provide inertia which helps manage RoCoF. Consideration should be given to ensuring other technologies that are capable of providing an inertial response are mandated to do so in a similar way as part of their connection standards.

The market design for the revised essential system services framework does need to consider an appropriate mechanism for ensuring sufficient inertia/fast frequency capability exists on the power system to help control RoCoF. Paying for the provision of a minimum level of inertia or equivalent service could be one way to incentivise synchronous generators to stay dispatched at relatively low loadings at times of minimum demand on the SWIS to maintain an acceptable level of system inertia. This approach could also increase interest in technologies such as synchronous condensers to provide inertia which, if developed in conjunction with advice from Western Power, could significantly mitigate both inertia and system strength issues.

5.3.3 Potential options to control RoCoF

Potential providers of “synthetic inertia” such as wind farms would need to demonstrate the effectiveness of their controller models at providing such a response. Any assessment should consider the delays inherent in providing a reliable trigger for the response and any limitation on the time for which the response can be sustained and the implications on the slower frequency control service as the response time becomes compromised.

Fast frequency response could technically be provided from a range of technologies, including by providers of 1s PFR. The fast frequency response capability could be specified by the response achieved within 1s. Studies of the 2023 minimum demand scenario indicate that a PFR that builds across 1s is able to assist in controlling the RoCoF across the first second after the contingency to 1 Hz/s. To avoid inadvertent operation of fast frequency response, RoCoF measurements will typically incur delays to allow validation of a RoCoF event. Those delays may prevent achieving a fast frequency response quick enough to control the RoCoF across the first 250 ms after a contingency to 2 Hz/s.

There are a variety of approaches that might be considered for securing the appropriate level of service. Regardless of the approach taken, it is likely that options to control RoCoF will be required in the future as the level of non-synchronous generation connected to the SWIS continues to grow displacing synchronous generation. Of the options considered a 1s PFR service or inertia provided from synchronous condensers have a lower impact on dispatch and may therefore be easier to integrate with the energy market dispatch engine.

Understanding the total level of inertia on the system at any time is essential to accurately assess the potential risk of RoCoF exceeding safe levels. Currently there is no direct measurement of the total system inertial available to AEMO. GHD is aware of work currently being undertaken for the UK's "National Grid" to develop a continuous monitoring of total system inertia[38]. Implementing a similar system on the SWIS would help improve AEMO's visibility of total system inertia.

5.3.4 Key recommendations and future work – RoCoF control

The following recommendations regarding the RoCoF control can be drawn from the studies undertaken:

- Options to control RoCoF will be required in the future as the level of non-synchronous generation connected to the SWIS continues to grow displacing synchronous generation.
- The SWIS FOS should be expanded to incorporate safe RoCoF levels.
- Specification of PFR requirements that consider the needs for a 1s response coupled with the ability to adjust the energy market dispatch to either limit the size of contingencies or increase inertia should provide a sufficient set of options to control RoCoF to safe levels for credible contingencies.
- Appropriate mechanisms should be developed to acquire services and optimise energy market dispatch constraints against the cost of any RoCoF control service.

Further work is recommended to enable control of RoCoF to safe levels. It is recommended that the following areas of additional work be pursued noting that with current levels of inertia RoCoF is unlikely to exceed safe level:

- AEMO and Western Power should review the proposed safe level considering the actual ride through capability of existing generators (including embedded generators) and the design parameters for the existing emergency frequency control schemes and revise the safe level if appropriate.
- AEMO should develop tools that can identify when RoCoF is at risk of exceeding safe levels. This is likely to require monitoring the likely worst case contingency size and the amount of inertia to assess the expected worst case RoCoF.
- AEMO should investigate implementing systems to continuously monitor total system inertia.
- In developing the technical specification for the new PFR framework AEMO should consider the need for a 1s PFR to control RoCoF at times of lower inertia.
- A similar process to the NEM PSFRR, should be considered for the SWIS to consider the risk posed by multiple contingency events and to identify the most prudent option for addressing those risks which may include new or modified emergency frequency control schemes[39].

5.4 Secondary frequency response

Following a contingency, PFR will act to arrest the change in frequency and stabilise system frequency. SFR is then required to recover the frequency towards 50 Hz. Sufficient SFR is required to recover the frequency within the time frames specified in the FOS which includes meeting any timeframes for recovering frequency to intermediate frequency limits [40]. If there is sufficient regulation capacity available, once the frequency is restored to within the normal frequency operating band, regulation service could take over driving the

[38] https://www.reactive-technologies.com/inertia/

[39] NER clause 5.20A.1 describes the requirements for completing a PSFRR which includes consideration of any requirement for new of modified emergency frequency control schemes.

[40] The FOS in the Technical Rules currently requires that following a single contingency frequency is returned to within the normal range within 15 minutes and for over-frequency events the frequency is returned to below 50.5 Hz within 2 minutes.

frequency back to 50 Hz. In the NEM, 5 minute contingency response services work in conjunction with regulation services to restore frequency to 50 Hz (i.e. regulation services are counted as part of the 5-minute service).-

There is a need to replenish the capability used to respond to a contingency event and restore frequency back to 50 Hz. Replenishing the SFR, PFR and regulation capability utilised to manage a contingency restores the system to a secure state in which there is enough frequency control capability to respond to a further credible contingency. In some electricity markets around the world a tertiary frequency response service might be relied upon to achieve this. In all cases additional action is required by the system operator to input additional energy the power system in order to restore the frequency to the normal range.

In the NEM the combination of delayed FCAS[41] and regulation services typically provide this function, with the 5 minute energy market dispatch being relied upon to replenish frequency control services. Once a 5 minute energy market is implemented in the SWIS it is expected that it too will contribute to restoring frequency and replenishing frequency response capability without the need for a tertiary frequency response service. Having replenished frequency response capability, the system will again be secure and able to sustain a further contingency event.

However, this ultimately depends on the availability of plant that can provide the service being dispatched to a position to be able to replenish the service. This can be compromised where available plant is either off-line due to market clearing, or forced out of the market altogether due to other market forces. An analysis of the future availability of service providers is recommended to inform whether a PFR/SFR service would be sufficient to incentivise sufficient providers to be available for replenishment or whether a tertiary market may also be warranted.

While PFR needs to respond automatically to a frequency disturbance via local detection of deviations in system frequency, SFR need not respond as quickly. Generally there is a greater number of service providers and options capable of delivering an SFR response, although this needs to be validated for the SWIS. Facilities providing SFR are often dispatched via AGC.

At present there is no explicit SFR service in the SWIS, however the requirement for sustained SR and LRR service supports the current practice of manual re-dispatch of the Synergy portfolio for recovery of frequency to 50 Hz. SR is classified into class A, B and C services able to be sustained for 60 s, 6 minute and 15 minutes respectively, while the LRR service is classified into class A and B service able to be sustained for 6 minutes and 60 minutes respectively. Following a generator contingency a variety of actions are currently used to recover-frequency to 50 Hz. If facilities providing SR have available capacity after having arrested the frequency decline, that capacity can be dispatched either automatically under AGC control or in response to manual controls or instructions issued by AEMO. Available capacity on facilities providing LFAS can also be dispatched under AGC control. In addition the manual dispatch of the Synergy portfolio is also utilised, often by triggering the commitment of a fast start gas turbine to provide additional generation capacity.

Based on this current approach there are a number of potential issues that warrant consideration, including:

- Confirming whether there is a need for a separate SFR service or whether a sustained PFR response will provide an adequate SFR particularly given the move to a shorter dispatch interval (five minutes).

[41] In the NEM AEMO procures delayed (5 minute) raise and lower FCAS. These services provide a response within 5 minutes to recover the frequency to 50 Hz. The amount of regulation services available is taken into account when deciding how much delayed FCAS service is procured.

- Assessing the impact of uncertainty regarding the actual regulation capacity available at the time of contingency on the ability to recover-frequency to 50 Hz. This risk may eventuate if the regulation capacity is in whole or part used up prior to a generator contingency event.
- Reviewing the ability of future service providers to provide the required SFR given expected changes in future generation plant mix and technological capabilities.

To assess the above issues a range of simulations have been performed using the aggregate model of the SWIS. The studies have focussed on the following specific aspects:

- Illustrating the potential SWIS system response to an initial generator contingency event, including both PFR and SFR actions with differing levels of regulation capacity.
- Demonstrating the impact of a subsequent load variation or change in non-scheduled generation that would be expected to be addressed by normal regulation capability.
- Illustrating the potential impact on system response if some of the allocated PFR capacity cannot be sustained as a SFR response.

Figure 10: Illustrative Secondary Frequency Response studies for future system shows the simulated SWIS response for a future system with high renewable generation and low system inertia (3,000 MWs), a 192 MW generator contingency occurring at 0 s and a secondary event (45 MW load step) applied at 70 s. The frequency responses shown in Figure 10 were derived using the aggregate model to simulate the system frequency for different amounts of contingency response provided through a combination of PFR and regulation capacity.

The responses simulated reflect an initial phase in which PFR acts to arrest the frequency reduction and recover the frequency to a settling point after about 18 s. The injection of additional power then recovers frequency back to 50Hz.

The initial phase of the response was simulated assuming a PFR that increased linearly to 2s and was then sustained at the 2s level. This reflects the response that might be achieved from synchronous generators with 4% droop that were initially at 50% output prior to the contingency. The simulations assume that the total range available was 192 MW + the amount of regulation capacity.

The recovery to 50 Hz was simulated by linearly increasing the injected power between 20 s and 40 s. The different coloured responses illustrate different assumptions regarding the capacity available to arrest the initial frequency decline and restore the frequency to 50 Hz.

- Case 1 (blue line) – no available regulation capacity, giving a total available range of 192 MW. This models a situation where all of the regulation capacity is depleted at the time of the contingency.
- Case 2 (red line) – available regulation capacity of 36 MW, giving a total available range of 228 MW. This models the situation where half of the required regulation capacity has been used at the time of the contingency.
- Case 3 (green line) – available regulation capacity of 72 MW, giving a total available range of 264 MW. This models the situation where all of the required regulation capacity is available at the time of the contingency.
- Case 4 (orange line) – modified version of Case 2 with 40 MW of the additional response provided across the first 20 s is not sustained.

The initial phase of the response (through to the settling frequency being reach) varied depending on the amount of PFR that was modelled as being delivered across the first 2s. Through an iterative process the level of PFR achieved across the first 2s was adjusted until the settling frequency simulated was consistent with that expected from generators providing a 4% droop response and delivering the same injection of power. The settling frequency consistent with a response of P (MW) delivered from generators operating initially at 50% output with 4 % droop and a maximum response range of Pmax (MW) is defined by the following equation:

$f_s = 50 – P / Pmax$

For each case Pmax = 192MW + available regulation capacity and P is the PFR response after 2s. The relationship between the settling frequency, 2s PFR and Pmax is shown in the following table.

Case	f_s (Hz)	P (MW)	Pmax (MW)
1	49.2	162	192
2 & 4	49.3	166	228
3	49.4	169	264

The maximum amount of PFR available in case 1 is equal to the size of the contingency (192 MW). This maximum PFR capacity is broadly consistent with the results shown in Table 7 for a PFR defined by a 2s and 6s response[42]:

In each of the cases studied the actual PFR modelled across the first 2s was less than the maximum response available. In each simulation the PFR increases linearly to 2 s and is sustained at that level for 18 s, allowing the frequency to settle to a level well within the contingency limit (48.75 Hz) specified in the FOS.

The amount of response modelled in each case is consistent with the following assumptions:

- the frequency is arrested by droop response from synchronous generators with a settling frequency reached within 18 s. A 4% droop is assumed with generators providing the PFR initially dispatched at 50% of their maximum output, assuming that any regulating capacity is also responding automatically contributing 4% droop response;
- after 20 s additional response range (unused PFR and regulation capacity) is dispatched recovering frequency to the normal operating band within 50 s. This is achieved by modelling a linear increase in response from generators providing PFR and regulation. The available capacity is assumed to achieve a ramp rate of 46 MW/min. The assumption of a secondary response commencing after 20 s attempts to reflect delays in AGC driven responses taking over from governor responses observed during actual events, and
- available regulation capacity is utilised to recover frequency to 50 Hz sustaining the 46 MW/min ramp rate.

An iterative approach was used to select a level of PFR delivered across the first 2s, Figure 11 shows the PFR simulated for each of the responses in Figure 10. The callout boxes in Figure 10 identify at particular times the level of response range remaining and the level of response dispatched. In this chart the response is the sum of regulation and PFR. The callout box at 18 s shows response levels consistent with the PFR profiles shown in Figure 11.

[42] Table 7 shows that a 200 MW contingency required a PFR delivering 193 MW within 2 s to produce a frequency Nadir within the limits specified in the FOS. The Table shows that the amount of PFR can be reduced to 156 MW if at least 109 MW is delivered within 1 s.

Figure 10: Illustrative Secondary Frequency Response studies for future system

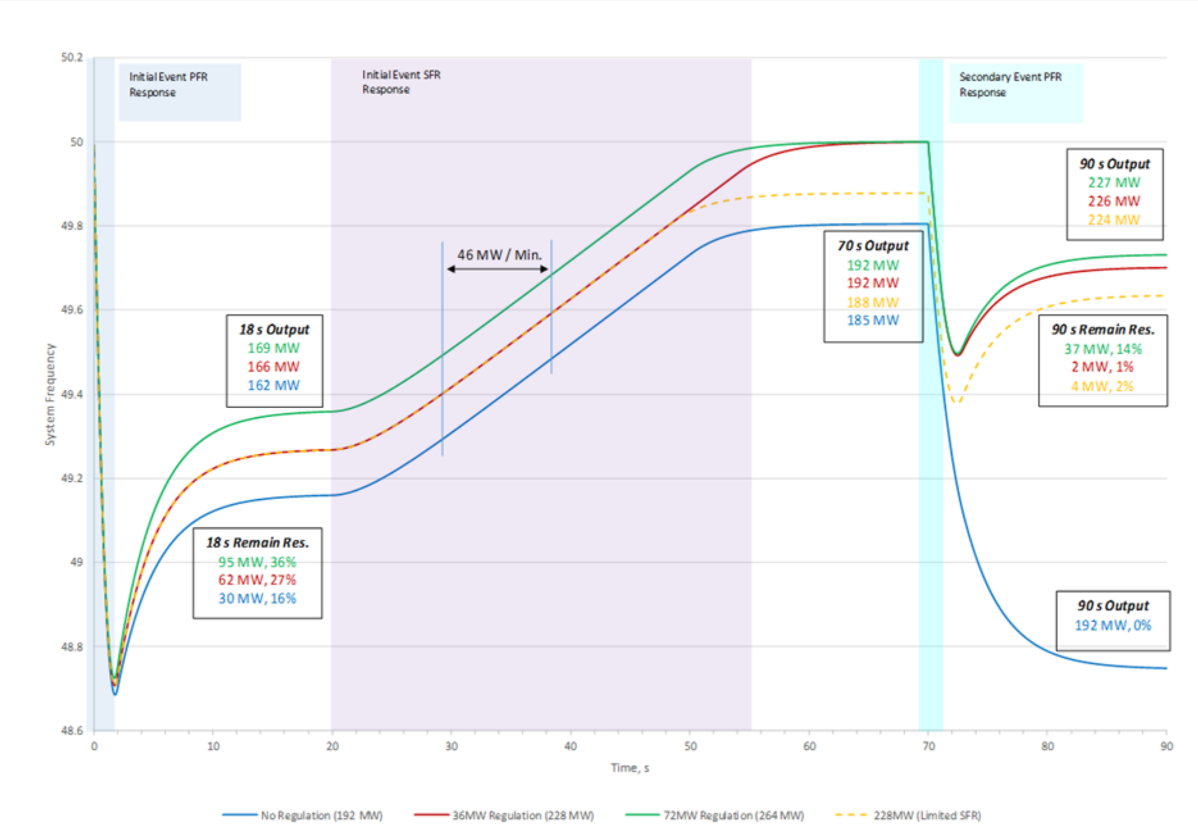
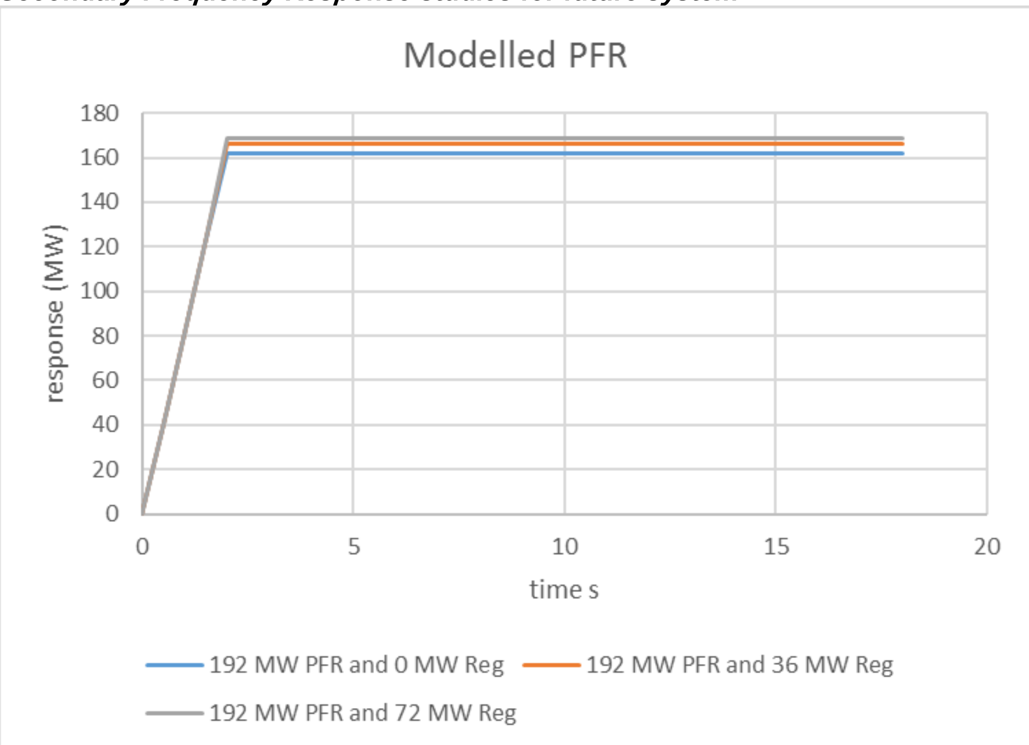


Figure 11 PFR modelled to produce initial response shown in Figure 10Figure 10: Illustrative Secondary Frequency Response studies for future system



For cases with regulation capacity available, regulation action is modelled as increasing system frequency back to 50 Hz. Regulation and unused PFR is dispatched within the SFR timeframe to recover frequency to the lower edge of the normal band, with regulation then acting to recover frequency to 50 Hz.

The blue trace shows a frequency response to 18 s consistent with 162 MW of PFR being utilised. The settling frequency is consistent with the same level of PFR being provided by synchronous generators with a 4% droop. This means that there is 30 MW of ”spare PFR” available at 18 s, comprised of unused range on generators providing PFR. The simulation models an additional injection of 23 MW across the period to 50 s as a linear increase in injected power. As a result the frequency recovers to 49.8 Hz. As there is no regulation capacity available (assuming the remaining “available PFR” is dispatched automatically via AGC “assist” mode which is only active outside the normal frequency operating bands) the frequency remains at the edge of the normal band. When a modest 45 MW load movement occurs at 70 s there is only 7 MW of spare capacity available which is insufficient to keep the frequency within the limits specified in the FOS.

In contrast the green trace shows a frequency response to 18 s consistent with 169 MW of PFR. The settling frequency is consistent with 169 MW of response being provided by synchronous generators through a 4% droop assuming the total available response range is 264 MW (192 MW from generators providing PFR and 72 MW from generators providing regulation range). This means that there is 95 MW of reserve capacity available at 18 s comprised of unused range on generators providing PFR and those providing regulation capacity. The simulation models an additional injection of 23 MW at a constant ramp rate resulting in the frequency recovering to 50 Hz. In this case, when the load movement occurs at 70 s there is sufficient spare capacity available to maintain frequency within the limits specified in the FOS.

For all cases that return frequency to 50 Hz, the total response used was 192 MW which matches the size of the contingency.

A similar over-frequency response would hold for a load contingency.

The key outcomes from simulations shown in Figure 10 can be summarised as follows:

- In all simulated cases the total response range available through PFR and regulation capacity exceeded the size of the contingency. This meant that the combination of PFR capacity and regulation capacity unused in responding to the initial generator contingency event was able to restore the system frequency to the lower edge of the normal band. This demonstrates that there is value in utilising “spare” PFR as part of any SFR response. However if the total response range available was less than the size of the contingency addition SFR would be required to recover frequency to 50 Hz.
- In the case with the regulation capacity depleted at the time of the contingency the system was not able to sustain the subsequent load event without triggering uncontracted UFLS. In this example as the amount of PFR available is equal to the size of the contingency the initial contingency can be adequately managed, however the depletion of the regulation capacity prior to the initial contingency means that there is insufficient capacity available to respond to a modest subsequent load movement. In this scenario, UFLS is avoided for the first contingency as the regulation requirement was not counted towards meeting the PFR requirement. If the current practice of counting LFAS capacity toward meeting the SR requirement had been modelled then the amount of PFR actually available to respond to the first contingency would have been 120 MW (192 MW - 72 MW) and that would have been insufficient to prevent UFLS being triggered. This reinforces the previous recommendation that regulation capacity should not be counted as meeting PFR requirements.

- Any PFR response than cannot be sustained will establish a greater requirement for SFR capacity as will any unspent PFR capacity that cannot be dispatched by AEMO after the contingency to help restore frequency to 50 Hz.

The example shown in Figure 10 demonstrates that it is not possible to specify the required amount of SFR independently of knowing whether the PFR can be sustained and whether any unspent PFR can be dispatched by AEMO. In order to recover frequency to 50 Hz the combination of PFR and SFR should be capable of sustaining a response equal to the size of the contingency.

Maintaining an additional amount of SFR would minimise the risk that a modest subsequent event drives frequency beyond the single contingency limits specified in the FOS. This additional margin is important particularly in scenarios where the regulation capacity is depleted.

The total response should be able to be sustained long enough to allow replenishment via energy market dispatch processes.

5.4.1 Optimising PFR and SFR

If the facilities able to provide PFR are appreciably different to those able to provide SFR, this can result in appreciably different costs for the two classes of service. To allow market systems to the optimise costs of providing essential system services, PFR and SFR service definitions often require that the PFR is sustained just long enough for SFR to be delivered and SFR to be sustained long enough to be replenished via subsequent energy market dispatch runs.

One example of how this could be achieved in the SWIS would be to specify that PFR is sustained for at least 60 s and that SFR is available within 60 s and sustained for 15 minutes. This sort of specification would provide for overlapping services and would allow two full dispatch intervals to replenish frequency response capability. A facility that can provide and sustain a PFR for 15 minutes could offer to provide both a PFR and SFR, so long as it is capable of receiving and responding to appropriate control signals. The timeframe for sustaining SFR should be chosen to provide sufficient time to start rapid start generators in response to market dispatch instructions as this is likely to be necessary to replenish services in the future if there are fewer synchronous generators online. In this example the amount of SFR required would be equal to the largest single contingency. As the PFR is only sustained for 60 s, the SFR needs to replace all of the generation lost in the contingency. Lower and raise SFR requirement should be specified separately.

If the majority of SFR and PFR are likely to be provided from the same facilities such as gas fired generator, load shedding or BESS, there may be little price difference between a PFR response that is sustained for 60 s and one that is sustained for 15 minutes. In this circumstance if the PFR service specification was structured such that it had a sustain time of 15 minutes with an additional requirement for any unused PFR capacity able to be dispatched by AGC, there would only be a small quantity of SFR required representing the difference between the PFR requirement and the size of the largest contingency.

In either case separate quantities for PFR and SFR need to be established and managed. The first approach is recommended as it offers the potential to maximise the number of facilities that can offer to provide the two services and should therefore better facilitate a co-optimised approach.

It is recommended that separate PFR and SFR requirements are implemented with the specification of the response and sustain times for PFR and SFR selected to maximise the opportunity for facilities to participate. The response and sustain times should overlap to deliver a constant level of response.

Establishing separate SFR and PFR requirements would allow participation by facilities that cannot provide or sustain a PFR response. This could encourage participation from delayed or manually triggered load shedding, technologies that have a slow response and cannot meet PFR timescales, and technologies that cannot sustain a response until market redispatch such as coal units.

5.4.2 Key recommendations and future work - SFR

The following recommendations regarding SFR can be drawn from the studies undertaken:

- The requirement for PFR and SFR should be set such that in combination these services provide and sustain a response equal to the size of the largest single contingency.
- Separate PFR and SFR requirement should be implemented with the specification of the response and sustain times for PFR and SFR services selected to maximise the opportunity for facilities to participate. The response and sustain times should overlap to deliver a constant level of response.

The following areas of additional work are recommended to operationalise the framework:

- AEMO should commence work on a technical specification for the new SFR framework to provide further clarity to participants. The technical specification should define timeframes over which the SFR providers must be able to deliver their offered response and the period for which the response must be sustained.
- AEMO should investigate an appropriate operating margin to be applied to the SFR requirement to minimise the risk that a modest subsequent event drives frequency beyond the single contingency limits specified in the FOS. This additional margin is important particularly in scenarios where the regulation capacity is depleted.
- AEMO should lead detailed design of the compliance framework that will apply for SFR essential system service.

5.5 Frequency Regulation

Frequency regulation refers to control actions taken to adjust the output from frequency regulation providers to correct small deviations in frequency from 50 Hz. In the absence of generation and load contingencies, frequency deviations from 50 Hz generally arise whenever there is a significant deviation between the expected and forecast level of load and generation across a given dispatch period due to:

- Wind farm forecast errors which occur when the actual windfarm output differs from the forecast generation level from the wind farm, resulting in an incorrect market dispatch. Market wind farms are visible within the AEMO SCADA data and hence the wind farm forecast error is readily observed.
- Solar farm forecast errors which occur when the actual output of large scale solar farms differs from the forecast generation level, resulting in an incorrect market dispatch. Market solar farms are visible within the AEMO SCADA data the forecast error is readily observed.
- Load forecast errors which occur when the load on the power system differs from that forecast by AEMO. The load forecast error includes the combined effect of loads varying from forecast and unexpected variations in the output of non-market generators and embedded generation such as roof top PV systems.
- Scheduled generators deviating from dispatch targets. Scheduled generators are provided with dispatch targets and are assumed to follow their bid ramp rates in moving from one dispatch target

to the next. Any deviations of scheduled generators from their dispatch targets are readily observable in the AEMO SCADA data.

- Variations between actual scheduled and non-scheduled generator ramping and assumed linear ramp profiles, within the dispatch interval.

The collective effect of these disturb the balance between load and generation and result in deviations in system frequency from 50 Hz. Frequency regulation services act to correct these deviations and drive the system frequency back to 50 Hz.

Figure 12 shows the frequency regulation achieved in the NEM while Figure 13 shows that achieved in the SWIS[43]. Clearly in the SWIS the frequency is more tightly regulated around 50 Hz than in the NEM.

The poor frequency regulation in the NEM has been linked to the lack of a specific requirement for PFR to be active within the normal band (49.8 to 50.2 Hz). In the NEM the frequency often drifts within the normal band spending significant amounts of time at the edges of the band. In the NEM frequency regulation is provided predominantly by regulation service providers who respond to AGC requests to raise or lower output to correct frequency deviations detected by the AEMO AGC system.

The lack of regulation of the frequency to 50 Hz creates some concerns including:

- A frequency that is not controlled to 50 Hz creates difficulties for plant and equipment wanting to connect to the power system. The difficulty can arise through problems in being able to follow system frequency and therefore synchronised to the power system. Generally to avoid a large disturbance when connecting to a power system, a synchronous generator or machine will attempt to regulate its speed to match the frequency of the power system. When the voltage and frequency are synchronised with the power system, the circuit breaker is closed allowing smooth connection of the generator load. A varying system frequency makes synchronisation difficult.
- If the frequency is at the edge of the lower edge of the normal band and a large generator contingency occurs the power system effectively has less time to respond to arrest the frequency decline and avoid load shedding than would have been the case if the frequency had been regulated tightly around 50 Hz.

[43] Figure 12 is sourced from the AEMC issues paper for the frequency control frameworks review https://www.aemc.gov.au/markets-reviews-advice/frequency-control-frameworks-review and Figure 13 was derived by GHD from SCADA frequency records from provided by AEMO.

Figure 12 : NEM Frequency Histograph showing deterioration in regulation performance

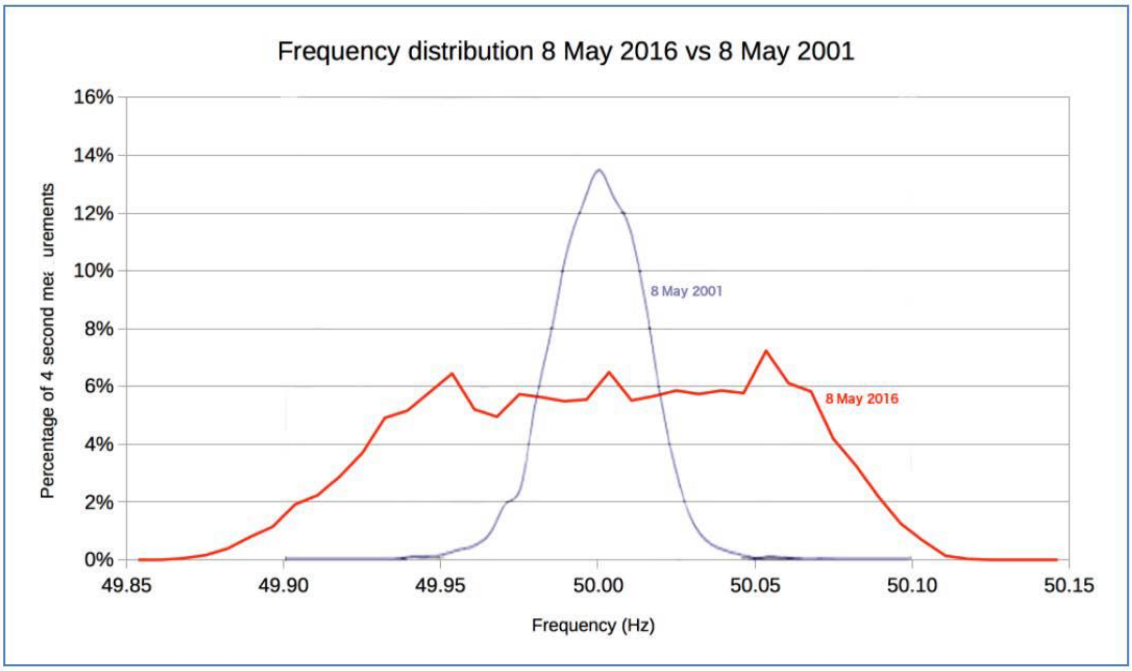
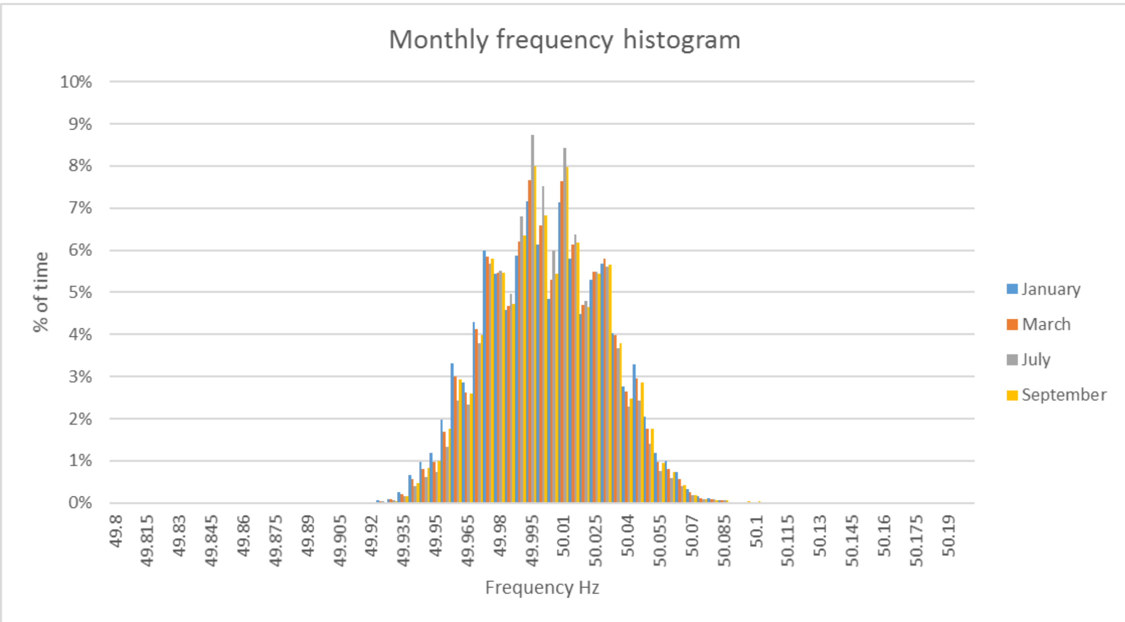


Figure 13 : SWIS Frequency Histograph



In the SWIS frequency regulation is currently achieved by:

- Generators contracted to provide LFAS regulating there output in response to signals issued from via the AGC system.
- The mandatory governor response of generators. The Technical Rules require governor dead bands be set well within the normal frequency band ensuring that the mandatory governor response helps to arrest small perturbations in frequency before the frequency moves outside the normal band.

5.5.1 Mandatory governor contribution to regulation

One issue that has been raised is whether the current approach of requiring generators that are not contracted to provide regulation to contribute to frequency regulation through their mandatory governor response should continue. A related issue is whether the currently practice of not remunerating generators for the mandatory performance is equitable.

Where governors are active within the normal operating band, the potential exists for adverse interactions between governor driven responses and those initiated by AGC requests to regulate frequency. Appropriate tuning and design of controls at the generators can normally prevent adverse interactions.

In January AEMO conducted a series of tests on the SWIS which involved temporarily deactivating LFAS services and observing any changes to the regulation of frequency and the variation in the output of synchronous generators.

The results of these tests when analysed will provide additional clarity into the ability of mandatory governor response to regulate frequency in the absence of any regulation from AGC controlled generators. The tests will also help to demonstrate the relative change in output from generators providing mandatory droop response and those responding AGC signals to regulate frequency.

AS 4777 defines the requirements for inverter connected generation and energy storage. The 2016 version of the standard included requirements for all inverter connected generators to provide a droop like response to over-frequencies commencing at 50.25 Hz and for systems incorporating energy storage to provide a droop like response to under-frequencies commencing at 49.75 Hz. As these frequencies are outside the normal band, inverter connected systems compliant with AS 4777 will generally not contribute to regulation of frequency within the normal band, but can contribute to arresting frequency following contingency events.

5.5.2 Requirement for Regulation Service

GHD has conducted a two-part analysis to investigate the appropriate amount of frequency regulation for the SWIS:

- Statistical analysis of forecast errors, and
- Statistical analysis of actual historical utilisation of the LFAS capacity.

Each of these approaches has strengths and weaknesses. The requirement for regulation once a 5 minute energy market is introduces is likely to lie somewhere between the estimates produced using the two techniques.

Requirement derived from statistical analysis of forecast errors

In early 2018 GHD undertook an investigation for AEMO of the LFAS requirement for the SWIS. The aim of this study was to identify a quantity of LFAS that would be sufficient to meet the FOS specified in the Technical Rules.

The study investigated the 99th percentile error due to load and wind forecasting errors by reviewing three years of historical SCADA data. It identified that the 99th percentile error had remained relatively constant over the three years 2015, 2016 and 2017 and identified that 99th percentile error aligned with the 72 MW of LFAS currently settled. The analysis showed that the forecast error increased significantly as the time between when the forecast was made and dispatch grew. This suggests that moving to a shorter dispatch interval may offer the advantage of being able to lower the amount regulating capacity required. Shorter dispatch intervals allow the energy market dispatch targets to be adjusted more frequently and the energy market dispatch is therefore better able to follow variations that would otherwise need to be addressed by service providers providing frequency regulation services.

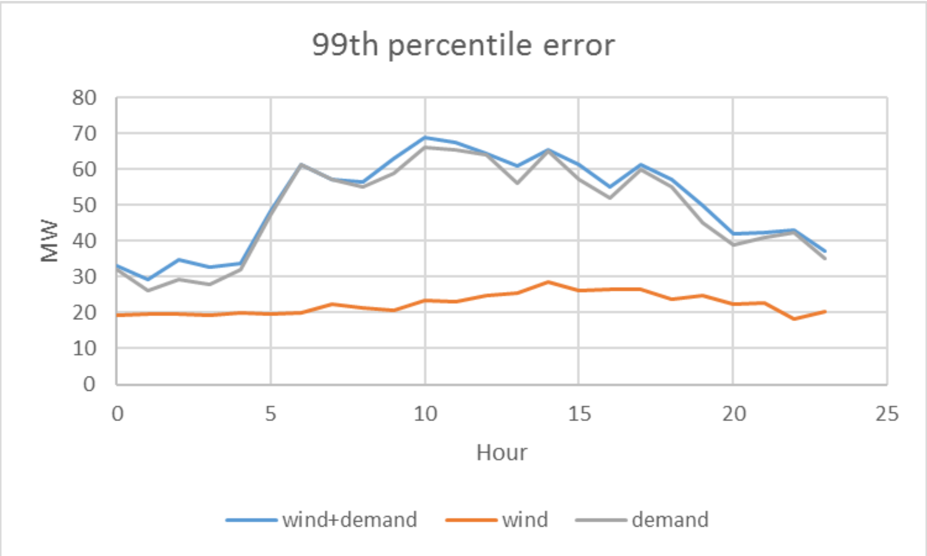
The 2018 study has been extended to extract the 99th percentile forecast errors assuming a 5 minute dispatch interval. These results are presented in Table 11. The analysis also investigated whether across the year there was any noticeable variation in the forecast errors. A repeatable variation in the forecast error with time of year or dispatch conditions may support implementing a frequency regulation requirement that varied with dispatch conditions or time of year. While there was no noticeable seasonal variation, the data suggested a potential variation with time of day.

The observation of reduced forecast errors during the night is consistent with there being no PV forecast error contribution at night. This suggests there might be a case for reducing the regulation requirement overnight. The difference in forecast error between day and night was further investigated by calculating the 99th percentile error for all 5 minute intervals falling within the same one hour period across 2017. These results are presented in Figure 14 which shows the trend in the 99th percentile across each of the hours in 2017.

Table 11: Forecast error (99th percentile) of wind on the SWIS at 30, 20 and 10 minute intervals

Quantity	Forecast source	Entire year			Night and Day	
		Days	Night	All periods	May to September	October to April
Wind	Persistence	20	17	23	24	23
Demand	Metrix	51	41	54	58	50
Wind + Demand	Metrix + Persistence	52	42	56	59	53

Figure 14: Wind and demand forecast error for maximum of 24 hour period in 2017



The 99th percentile error increases significantly between 4 am and 6 am, then remains fairly constant across the day before reducing significantly between 5 pm and 8 pm. This analysis suggests that once a 5 minute dispatch interval is adopted it may be possible to reduce the regulation requirement. The curve in Figure 14 suggests that a dynamically varying regulation requirement may be worth investigating further, subject to the discussion below around intra-interval regulation requirements.

5 minute resolution SCADA data for each day in 2015, 2016 and 2017 was analysed to assess the level of variability in traces of wind generation and demand and to investigate whether variability could be reliably used to indicate the 99th percentile forecast error and hence the regulation requirement. The analysis suggests that observed variability is not a reliable indicator of the regulation requirement.

With the data from 2018 now available it would be beneficial to include these results in the analysis to assess whether the same trends are present in the 2018 data.

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 analysis to set the regulation requirement. The 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 would however, not be correct to assume that the regulation 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. The following factors can give rise to a need for regulation service in addition to 5 minute ahead forecast errors:

- The frequency disturbances created by ramping of generators at start of dispatch intervals.
- Rebalancing across the Synergy portfolio.
- Errors in scheduled generators meeting targets.
- Wind and solar variability within 5 minutes dispatch intervals.

Market design changes such as a move to 5 minute dispatch intervals have the potential to impact some of the drivers for current LFAS usage, however it is difficult to quantify the benefit that will come from those changes.

AEMO currently 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.

The regulation requirement suggested by the analysis of 5 minute ahead forecast errors should therefore be considered as setting a lower bound on the regulation requirement.

Requirement derived from statistical analysis of historical utilisation of the LFAS capacity

To provide an alternative way of understanding an appropriate regulation requirement for the SWIS, GHD completed an initial set of analysis of historical SCADA data from 4th September 2017. The analysis sought to assess the LFAS usage across a period by calculating the cumulative change in the output of enabled LFAS generators across that period. While the initial analysis appears 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. Figure 15 shows the cumulative LFAS usage across 5 and 10 minute periods across one hour (top graph) and the entire day (bottom graph). Table 12 presents a summary of the results obtained by analyzing the SCADA data from the 4th September 2017 across three different time intervals. The results suggest that as the interval is reduced the cumulative LFAS usage also falls.

When assessed across a 10 minute period the cumulative LFAS uses across the day ranged between 101 MW of raise capacity and 87 MW of lower capacity, both of which significantly exceed the 72 MW threshold assumed in the settlement of the LFAS market.

Currently the balancing market is dispatched every 30 minutes with AEMO having the capability to develop interim dispatch targets twice within the dispatch interval, (one revision at the 5-minute mark and the second revision at the 15-minute mark). Interim dispatch solutions consider refreshed forecasts for non-scheduled generation and demand and the current generation levels at scheduled generators. The interim dispatch solutions help to reduce the amount of LFAS capacity that is needed, compared to a situation where a dispatch solution was only produced once every 30 minutes. It may be argued that the 10 minute cumulative analysis provides a better an indication of the LFAS capacity actually required across that day than the 30 minute cumulative analysis (noting the difficulty in extracting out Synergy portfolio balancing movements remains).

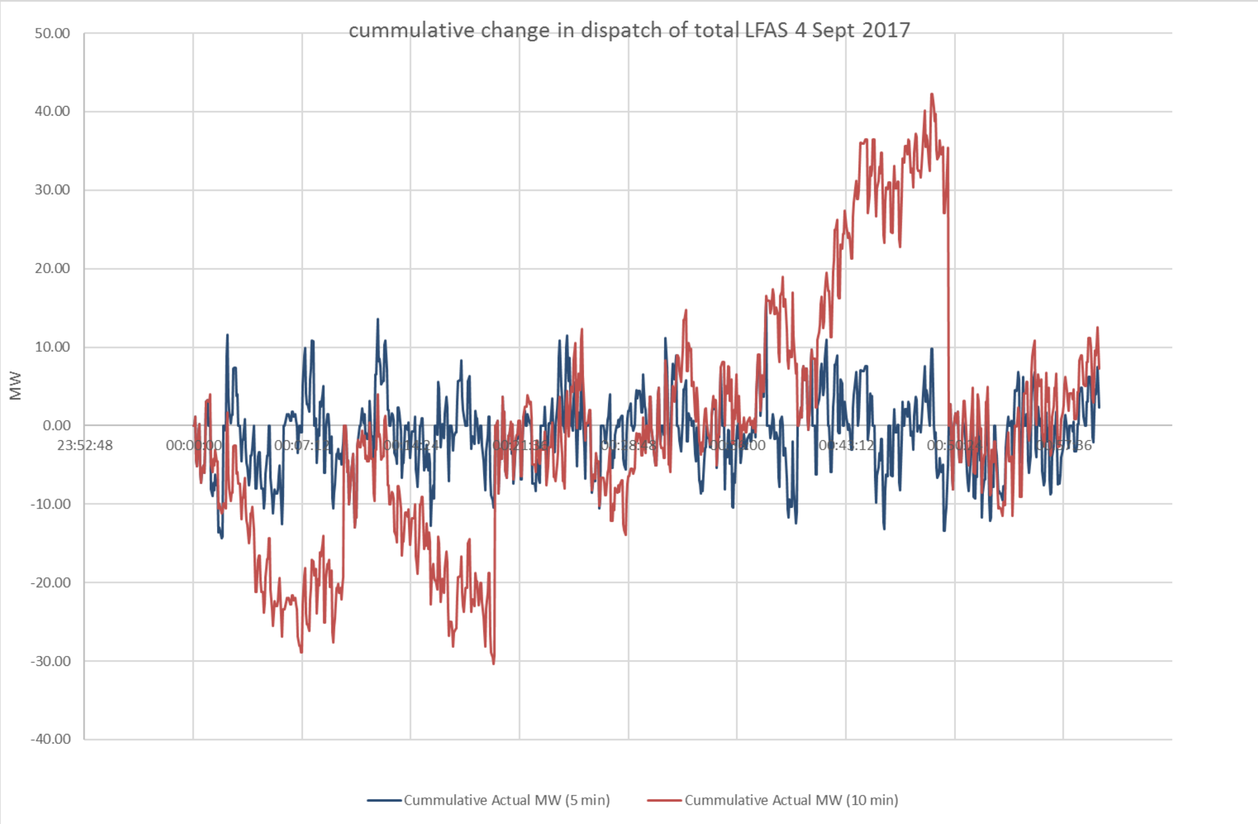
Further work is required to develop statistically valid results and explore each of the following:

- The 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.
- How governor response impacts AGC (LFAS) dispatch requirements and whether there is a potential for over/under compensation.

It is recommended that AEMO process an appropriate amount of historical SCADA data to develop a statistically valid view for the cumulative SCADA usage across a 5 minute period and that data be used to establish the initial requirement for regulation service

One of the issues that potentially distorts the regulation requirement determined through analysis of historical SCADA data is that AEMO regularly replenishes LFAS range by manually 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, but is captured in the cumulative total and may serve to underestimate the LFAS used across some periods (e.g. where manual rebalancing is not on AGC enabled machines) and overestimate the usage across others (e.g. where AGC is effectively performing both re-balancing and frequency control at the same time).

Figure 15: Analysis of SCADA data - cumulative LFAS usage across 5 and 10 minute intervals for 4th September 2017



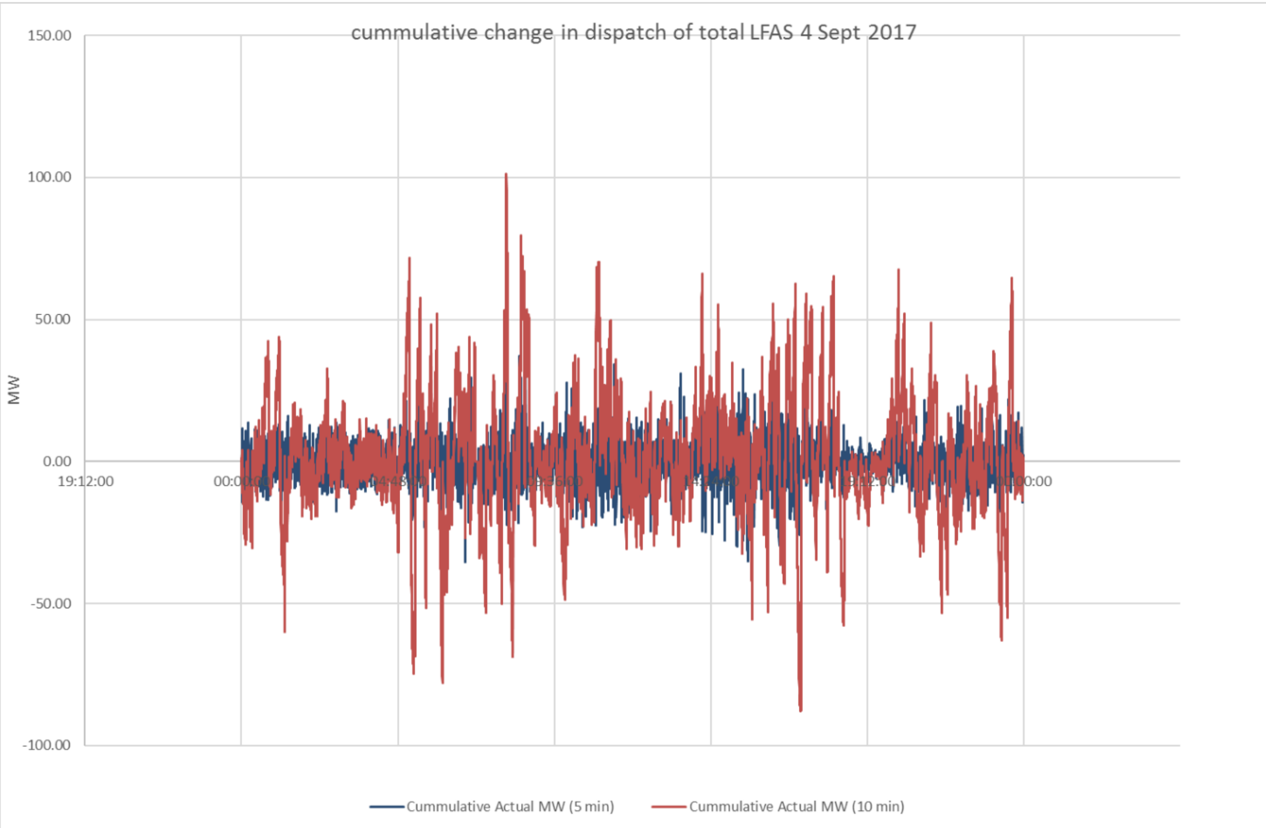


Table 12 : Statistical analysis of cumulative LFAS usage across different time intervals for 4th September 2017

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

5.5.3 Key recommendations and future work – Regulation

The following recommendations regarding regulation essential system service can be drawn from the studies undertaken:

- The regulation requirement should not be counted towards meeting PFR requirements. 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. During periods of high ramping to meet morning and evening load, we can expect to see the regulation service utilised quite heavily across dispatch periods. With a 5 minute dispatch interval market, regulation reserve can more easily be replenished with each new dispatch run. That process may however lead to increased likelihood of depleting available regulation capacity compared to the current practice of frequently replenishing LFAS capacity by manually adjusting the dispatch of the Synergy fleet when required (ie not waiting for 5 minutes). This is a further reason for not counting the regulation requirement towards PFR.
- The current requirement for mandatory governor response within the normal band should be retained.
- AEMO should retain the ability to increase regulation requirement if available range is expected to be exhausted. The 5 minute energy dispatch market would allow AEMO the opportunity to change requirements within 5 minutes of recognizing an issue such as an encroaching storm front signalling 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 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 and not waiting for the new market dispatch cycle.

Further work is required to operationalise the proposed regulation essential system service. Key activities to be undertaken include:

- Complete LFAS usage analysis across sufficient number of days to yield reliable results.
- Historical LFAS usage across a 5 minute period should be used to set initial regulation requirement taking into account details of regulation and energy market design, and looking at the role governors play in regulating frequency. Any trends in historical usage with time of day, should be considered to assess whether it is appropriate to implement a regulation requirement that varies with time of day.

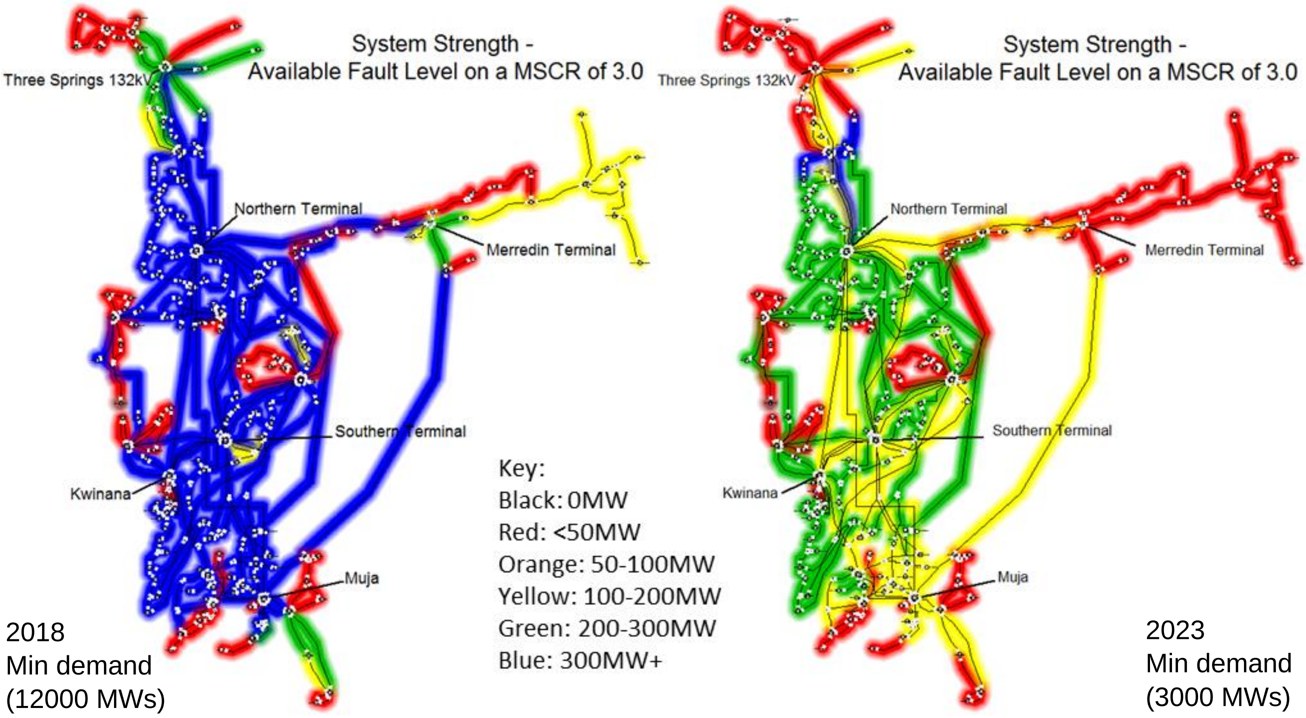
- Analysis of LFAS tests should be completed and used help inform the urgency with which AEMO should act to replenish depleted regulation capability. There are likely to be periods where the regulation range is at risk of being exhausted within dispatch intervals. The analysis of the LFAS test will allow a better understanding of how well the mandatory governor response can regulate frequency in the absence of the AGC controlled regulation service. This knowledge should be used to inform AEMO on the need to increase the regulation requirements to minimize the chance of regulation range being depleted.
- Routinely review of regulation performance and forecast errors to assess need to change the regulation requirement. It is recommended that within 12 months of the start of the 5 minute market, the regulation performance be reviewed by analyzing utilization of regulation capacity 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 frequent exhaustion of the regulation range.

5.6 System Strength

There is currently no system strength essential system service on the SWIS. System strength issues have historically not been a significant concern due to the large amount of synchronous generation. A preliminary illustration of the system strength across the SWIS was developed using the DIgSILENT model provided by Western Power. The results are shown in the heat maps in Figure 16. The map on the left shows the results of a system strength assessment carried out for a minimum demand condition in 2018 while that on the right shows the system strength for a potential 2023 minimum demand condition. Both assessments have considered an intact system with all transmission lines in service. System strength has been assessed applying the AFL technique described in AEMO's System Strength Impact Assessment Guidelines.

Colours identify how the system strength varies across the network. The results show that increased renewable generation is expected to reduce the amount of synchronous generation dispatched which in turn reduces fault levels and lowers system strength. The analysis presented is indicative only developed to assess overlaps with essential system services, and is not intended to replace or supplement any (more detailed) analysis being conducted by Western Power.

Figure 16: SWIS System Strength heat map – available fault level assuming MSCR of 3.0



The AFL approach assesses the SCR at each 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 MSCR of 3.0.

The system strength analysis for the 2018 minimum demand intact system shows a relatively strong meshed system capable of connecting a significant amount of additional renewable generation to the majority of the network while remaining above the “weak” minimum short circuit ratio of 3.0.

Fringe areas of the 2018 network were assessed as having a lower system strength. These areas are generally supplied through longer radial transmission lines which gives rise to the lower system strength. The low system strength on these fringe areas of the network may result in voltage stability issues and challenges in maintaining reliable protection operation if significant amounts of addition renewable generation connect. These areas are typically nearby to existing renewable generation installations, which consume available fault level capacity under the calculation methodology used.

The system strength analysis for the 2023 minimum demand scenario shows a significantly lower system strength, but the overall heat map indicates the potential to connect further renewable generation. The highly meshed areas of the SWIS directly connected to existing synchronous generators exhibit the higher levels of system strength with reasonable fault levels and SCR’s above the MSCR. The system strength of radial areas of the network have deteriorated significantly resulting in a significantly reduced ability to accommodate the connection of further renewable generation.

A SCR below 3.0 does not necessarily preclude further connection of renewable generation, however before connecting new non-synchronous generation to areas of the transmission network with low system strength, a detailed assessment of the stability impacts of the proposed generation should be undertaken. This would normally involve studies with an EMT type model to identify and assess any interactions with other generators that might cause voltage instability. The protection systems in areas of low system strength may also need to be reviewed to ensure they remain able to reliably detect fault conditions.

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 localised 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.

5.6.1 Market Issues

The analysis done for the current and future systems, while showing an expected deterioration in system strength with the increase in rooftop PV and connection of additional renewable generation under the GIA solution, also shows that system strength remains an issue localised only to specific areas of the network. A network wide solution implemented as an essential system service and administered by a market operator such as AEMO therefore seems unsuited to manage system strength. Instead it appears that the issue is probably best managed by Western Power through the generator connection negotiation process. An approach similar to that implemented in the NEM whereby the connecting generators make investments to remediate any degradation of system strength below those levels necessary for stable operation of connected inverter based generation could be considered to manage the emerging SWIS system strength issues.

It should also be noted that declining system strength can occur organically, e.g. through the growth of embedded generation or changing load profile. Western Power should also be given the obligation to manage this, as well as addressing any implications for adequate protection system operations, in the absence of any new connecting generators.

While recognising system strength will be an emerging issue exacerbated by the same trends influencing the requirement for frequency control ancillary services, addressing the system strength issue is best managed by Western Power and AEMO through the process used to connect new renewable generators. Solutions that may be deployed such as synchronous condensers can have implications for the required amounts of RoCoF control service. It may also be appropriate for synchronous condensers installed to manage system strength to provide RoCoF control service.

It is recommended that Western Power and AEMO collaborate to develop solutions that best manage system strength recognising the potential impact of those solutions on the requirement for PFR and controlling RoCoF.

DSS are a generic category of essential system service that allow AEMO to contract with market participants to provide specific services that cannot be covered by other essential system services or standard dispatch arrangements, but are required to ensure power system security and reliability is maintained. DSS could also be considered as one means of potentially procuring services to address system strength. As discussed in Section 5.3, DSS may also present a viable mechanism for securing services to control RoCoF.

As the generation mix evolves there may be number of security related issues that emerge that require AEMO to procure specific services. Maintaining the DSS mechanism would allow a mechanism to address these issues as they emerge.

It is recommended that the DSS, or a more efficient similar arrangement, be maintained as part of the essential system service framework for the SWIS to provide AEMO with a mechanism to procure specific services not covered by other essential system services.

5.6.2 Key recommendations and future work – System Strength

The following recommendations regarding system strength are supported by the analysis undertaken:

- System strength issues are likely to emerge with falling levels of synchronous generation and connection of greater amounts of renewable generation. Appropriate mechanisms to manage system strength are therefore required (both covering new generator connections and organic decline).
- System strength is a localised issue best managed through the network connection and network standards process.
- Solutions deployed to address system strength can add inertia to the power system and thereby contribute to controlling RoCoF and setting the requirement for PFR. AEMO and Western Power should collaborate to assess the need for and develop solutions that best manage system strength recognising the potential impact of those solutions on the requirement for PFR and controlling RoCoF.

Further work is required to operationalise arrangements for managing system strength. Key activities to be undertaken include:

- The connection of renewable generators into areas of low system strength should be assessed through detailed assessment with EMT studies. EMT studies are able to assess the potential for adverse interactions and unstable operation of inverter connected renewable generators.
- It is important for WP and AEMO to know the MSCR for inverter connected generation. This information should be collected as part of the generator connection process and shared between AEMO and Western Power.
- As system strength issues emerge it is important that Western Power and AEMO collaborate on assessing options for managing the system strength and appropriate heads of power are available to resolve the issues. A range of options could be considered including the run-back or tripping of renewable generation to prevent unstable operation, deployment of devices such as synchronous condensers to improve system strength or devices such as STATCOMs to provide additional voltage support.
- Potential solutions implemented to address system strength should be considered in determining contingency frequency response requirements.

6. Conclusions

The primary challenge of the essential system services reform is determine appropriate priorities with regards to system operational performance, economic efficiency and system security. This information paper has presented the case for changed essential system service arrangements to address clear limitations with the existing framework, support the transition to facility bidding and a 5 minute energy market, while better managing system security and allowing for the continued transition to a power system with greater levels of non-synchronous renewable generation. Previous reviews have identified serious issues with the existing arrangements for managing frequency within the SWIS and therefore frequency control services are a key area of focus for the revised essential system service framework.

Currently, synchronous generation is the main provider of frequency control ancillary service. The ability to dispatch the Synergy fleet as a portfolio has provided AEMO with an effective means to access the response required to control frequency following contingencies and to regulate frequency to 50 Hz. This arrangement masks many issues with the existing frequency control ancillary service framework. Addressing those issues will require procuring a new set of frequency control ancillary services with new approaches implemented to set required quantities of each service that are sufficient to deliver frequency performance that meets the limits specified in the FOS.

Table 13 presents a set of services or control responses that should be sufficient to deliver system security while enabling the proposed changes to the energy market (i.e. a move to facility bidding and 5 minute dispatch). The services are defined by the control action delivered rather than the technology used to provide the service. Adopting this technology neutral approach is intended to avoid service definitions that preclude or deter any particular technology or facility that is able from participating in the provision of services. This approach should enhance competition and lead to lower costs.

Table 13: Recommended frequency control ancillary services

Service	Specification and potential suppliers
Primary Frequency Response (PFR)	A control response that arrests frequency following a contingency event. PFR is specified as the response in MW achieved in a specified timeframe (1s, 2s and 6s). Sufficient PFR is required to keep the frequency Nadir (or maximum frequency) within the limits specified in the FOS. Faster responding PFR is required as RoCoF increases. Should not count regulation service towards meeting PFR requirement. PFR can be supplied from a generator, load or BESS that responds automatically to locally sensed frequency. PFR replaces elements of the existing SR and LRR service
Secondary Frequency Response (SFR)	A control response that responds to instructions issued by AEMO to restore frequency to the edge of the normal band. SFR can be provided by a generator, load, or BESS which is able to moderate output in response to AGC commands or manual instructions. This includes demand side response.

Service	Specification and potential suppliers
	SFR replaces activities currently used to recover frequency to 50 Hz including manual dispatch of the Synergy fleet and AGC driven adjustment of generators with available capacity.
Frequency Regulation	A control response that continuously responds to AGC issued instructions to correct frequency errors within the normal band. Regulation can be provided by a generator, load, BESS that is able to moderate its output in response to AGC commands. Regulation replaces the existing LFAS
RoCoF control	A control response to prevent RoCoF exceeding "safe level" in future years • 2 Hz/s across 250 ms – best supplied by synchronous inertia • 1 Hz/s across 1s – sources include synchronous inertia or fast frequency response (FFR) FFR can be supplied from a BESS, fast interruptible load and synthetic inertia.

6.1 Key recommendations

The analysis undertaken supports the following key recommendations regarding the mandatory requirements for frequency response, PFR, controlling RoCoF, SFR, frequency regulation and system strength.

Mandatory requirements

Mandatory requirements to provide frequency response as currently included in the Technical Rules should be maintained as they provide a shared contribution that maximises the frequency control capability available without impacting the dispatch of any facility that is not providing an essential system service. This approach will provide a more robust power system and avoid many of the issues experienced in the NEM where mandatory requirements no longer apply.

Primary frequency response

Sufficient PFR is required to arrest the frequency decline or increase following a contingency and prevent the frequency nadir (or maximum frequency) exceeding the single contingency limit specified in the FOS. When multiple contingencies occur, PFR works in conjunction with automatic UFLS and generator over-frequency tripping, to help arrest frequency disturbances and reduce the risk of complete system blackouts. Section 5.2 develops the following recommendations regarding the PFR framework:

- The level of PFR should vary with inertia and size of largest single contingency. The aggregate model developed by AEMO should be used to determine the PFR requirement for different dispatch conditions taking into account the available inertia and the expected largest contingency size. This approach will provide a more dynamic PFR requirement which depending on the level of inertia and size of the contingency. The requirement may be significantly different to the current requirements for SR and LRR (e.g. current SR requirement is 70% of the largest contingency).

- Raise and lower PFR requirements should be individually specified considering the largest generator and load contingency respectively.
- Regulation capacity should not be counted towards meeting the PFR requirement.
- The amount of PFR available should be sufficient to ensure frequency stays within the limits specified in the FOS for single contingencies and to control RoCoF to safe levels for multiple contingencies.
- The requirement for PFR should be set considering the required response commencing as soon as possible following the contingency event, and delivered within 1s, 2s and 6s.
- PFR providers should specify the service level based on how quickly it can commence and what is achievable within 1s, 2s and 6s.

Controlling RoCoF

Continued displacement of synchronous generators by non-synchronous renewable generators is likely to reduce system inertia causing an increase in RoCoF. It is likely to take several years before inertia falls low enough (below 6000 MWs) for RoCoF to exceed safe level. Prior to that time options for controlling RoCoF should be established. Section 5.2.2 develops the following recommendations regarding the control of RoCoF:

- Options to control RoCoF will be required in the future as the level of non-synchronous generation connected to the SWIS continues to grow displacing synchronous generation.
- The SWIS FOS should be expanded to incorporate the safe RoCoF levels defines in section 4.3.3.
- Specification of PFR requirements that consider the needs for a 1s response coupled with the ability to adjust the energy market dispatch to either limit the size of contingencies or increase inertia should provide a sufficient set of options to control RoCoF to safe levels for credible contingencies. Appropriate mechanism should be developed to procure services and optimise energy market dispatch constraints against the cost of any RoCoF control service.

Secondary frequency response

Sufficient SFR is required to restore frequency to 50 Hz following contingency event. Section 5.4 develops the following recommendations regarding the SFR framework:

- The requirement for PFR and SFR should be set such that in combination these services provide a response equal to the size of the largest single contingency and can be sustained for a sufficient time to allow replenishment through the energy market dispatch processes.
- Separate PFR and SFR requirements should be investigated with the specification of the response and sustain times for PFR and SFR services selected to maximise the opportunity for facilities to participate. The response and sustain times should overlap to deliver a constant level of response.

Frequency regulation

Sufficient regulation service is required to regulate frequency to 50 Hz. Section 5.5 develops the following recommendations regarding the frequency regulation framework:

- The regulation requirement should not be counted towards meeting PFR requirements. The current practice of counting regulation toward meeting PFR requirements exposes the power system to insecure operation and places potentially unnecessary importance on continuously maintaining the available regulation range.
- The current requirement for mandatory governor response within the normal band should be retained.
- AEMO should retain the ability to increase regulation requirement if the available range is expected to be exhausted. AEMO should retain the power to directly set which service providers are enabled by setting AGC flags and not waiting for the new market dispatch cycle.

System Strength

System strength issues are likely to emerge with falling levels of synchronous generation and connection of greater amounts of renewable generation. Section 5.6 develops the following recommendations regarding the management of system strength and the impact on frequency control ancillary services:

- Appropriate mechanisms to manage system strength are required.
- System strength is a localised issue best managed through the network connection process.
- Solutions deployed to address system strength can add inertia to the power system and thereby contribute to controlling RoCoF and setting the requirement for PFR. AEMO and Western Power should collaborate to assess the need for and develop solutions that best manage system strength recognising the potential impact of those solutions on the requirement for PFR and controlling RoCoF.

Ready Reserve Standard

In the new essential system service framework the Ready Reserve Standard should be replaced with clear and unambiguous requirements for AEMO to:

- Sufficiently recover frequency following a contingency event to meet the requirements of the FOS (ie requires access to sufficient Secondary Frequency Control).
- Restore or replenish sufficient levels of essential system services within applicable times to
- return the SWIS to a secure state, consistent with the FOS and other key power system operating state requirements.
- Ensure linkages to dispatch, dispatch planning and outage planning processes are created to allow AEMO to ensure sufficient levels of service are available and scheduled when required.

Dispatch Support Services

DSS are a generic category of essential system service that allow AEMO to contract with market participants to provide specific services that cannot be covered by other essential system services or standard dispatch arrangements, but are required to ensure power system security is maintained. It is recommended that the DSS (or similar arrangements) be maintained as part of the essential system service framework for the SWIS to provide AEMO with a mechanism to procure specific services not covered by other essential system services.

6.2 Future work

Implementing the revised essential system service framework will require further work. Key focus areas should include:

Mandatory requirements

The mandatory response requirements applying to non-synchronous generators should be reviewed to address the lack of precision currently in the Technical Rules. Revised performance standards for non-synchronous generators have been reflected in generator performance standard guidelines released by Western Power to GIA generators prior to Christmas and could be used as a reference for this work.

Primary frequency response

AEMO should commence work on a technical specification for the new PFR framework to provide further clarity to participants

AEMO should develop appropriate operating margins to cater for the risk that the delivered service is less than that required to keep the system frequency within the limits specified in the FOS. This work should consider raise and lower requirements separately to account for the different factors that may affect whether the actual delivered PFR response aligns with the required response.

The PFR service specifications should be developed further clarifying the assumption that service providers should make in assessing the capability of their facility

AEMO should lead detailed design of the compliance framework that will apply for PFR essential system service.

Controlling RoCoF

AEMO and Western Power should review the proposed safe level considering the actual ride through capability of existing generators (including embedded generators) and the design parameters for the existing emergency frequency control schemes and revise the safe level if appropriate.

AEMO should develop tools that can identify when RoCoF is at risk of exceeding safe levels. This is likely to require monitoring the likely worst case contingency size and the amount of inertia to assess the expected worst case RoCoF

AEMO should investigate implementing systems to continuously monitor total system inertia

In developing the technical specification for the new PFR framework AEMO should consider the need for a 1s PFR to control RoCoF at times of lower inertia.

AEMO and Western Power should consider implementing a NEM like PSFRR for the SWIS to consider the frequency control risks posed by multiple contingency events and to identify the most prudent option for addressing those risks.

Secondary frequency response

AEMO should commence work on a technical specification for the new SFR framework to provide further clarity to participants. The technical specification should define timeframes over which the SFR providers must be able to deliver their offered response and the period for which the response must be sustained.

AEMO should investigate an appropriate operating margin to be applied to the SFR requirement to minimise the risk that a modest subsequent event drives frequency beyond the single contingency limits specified in the FOS. This additional margin is important particularly in scenarios where the regulation capacity is depleted.

AEMO should lead detailed design of the compliance framework that will apply for SFR essential system service

Frequency regulation

AEMO should complete the analysis of historical SCADA data to extract reliable results regarding the historical level of LFAS usage across a 5 minute period. The historical LFAS usage across a 5 minute period should be used to set initial regulation requirement taking into account details of the regulation and energy market design. Any trends in historical usage with time of day, should be considered to assess whether it is appropriate to implement a regulation requirement that varies with time of day.

Analysis of LFAS tests should be completed and used help inform the urgency with which AEMO should act to replenish depleted regulation capability.

AEMO should routinely review of regulation performance and forecast errors to assess need to change the regulation requirement. It is recommended that within 12 months of the start of the 5 minute dispatch interval energy market, the regulation performance be reviewed by analyzing utilization of regulation capacity 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 identify a need for an increase in regulations service particularly if coupled with a deterioration in performance and evidence of more frequent exhaustion of the regulation range.

System Strength

The connection of renewable generators into areas of low system strength should be assessed through detailed assessment with EMT studies. EMT studies are able to assess the potential for adverse interactions and unstable operation of inverter connected renewable generators.

It is important for WP and AEMO to know the MSCR for inverter connected generation. This information should be collected as part of the generator connection process and shared between AEMO and Western Power.

As system strength issues emerge it is important that Western Power and AEMO collaborate on assessing options for managing the system strength and that sufficient heads of power are available to resolve the issues. A range of options could be considered including the run-back or tripping of renewable generation to prevent unstable operation, deployment of devices such as synchronous condensers to improve system strength or devices such as STATCOMs to provide additional voltage support.

Potential solutions implemented to address system strength should be considered in determining contingency frequency response requirements.

Rooftop PV

While the recommended changes to the essential system service framework will help position the SWIS to operate securely with increased levels of renewable generation other additional activities are likely to be needed particularly as the level of embedded renewable generation continues to increase. The continued growth of rooftop PV, is likely to lead to continual reduction in the load supplied by transmission connected generation particularly during the day. In the future it may be difficult to dispatching sufficient synchronous generators to provide required levels of inertia and primary frequency control without the ability to constrain the output from embedded renewable generations.

While that point remains some years away it is important that work continue to develop appropriate arrangements to manage the control of frequency under those potential future system conditions. Activities that should be explored further include:

- Providing greater visibility and control for AEMO over the level of embedded generation;
- Developing revised Australian standards for roof top PV systems to ensure that those systems provide a mandatory contribution to assisting to control frequency following a contingency, and
- Options to allow the aggregate response from roof top PV systems to frequency control.

7. Timeframes and next steps

This paper has presented an introduction into ongoing work to identify necessary reforms of the WEM essential system services market. The paper presents a compelling need to revise the existing ancillary service framework to address identified issues, facilitate planned reforms to the energy market while supporting the delivery of services necessary to maintain system security now and into the future. The paper presents a revised essential system service framework that addresses the identified issues.

In order to begin a process to establish definitive requirements for reformed essential system services, the ETIU and AEMO must now conduct further analysis to extend the applicability of the recommendations in this report. The analysis should ascertain:

- The ability of service providers to provide the proposed revised set of essential system, services.
- The ability of current technologies to meet revised essential system service standards.
- The suitability of revisions suggested for essential system services such as PFR, e.g. 2s and 6s service and the need for services and options to control RoCoF to safe levels.
- The potential for non-traditional essential system service providers to provide services, e.g. renewable generation in turning down for over-frequency events, offering services through load control or from BESS.

This work will set the ground for the broader essential system services framework revision which is to account for:

- The quantum of a service to be procured and how it will be procured
- How facilities will be accredited for a service provision
- How essential system services will be acquired (e.g. through real time markets or contracts or mandated standards)
- How essential system services will be co-optimised for dispatch
- Associated market power controls, and compliance and monitoring
- Cost-recovery using a causer pays principle.

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