2014 ancillary service standards and requirements study

Report to the Independent Market Operator

(Imo00039)

4 November 2014

Building a better working world

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4 November 2014

2014 Ancillary Service Standards and Requirements Study

Dear Allan,

In accordance with our agreement dated 12th October 2014 (the "Novation Agreement"), Ernst & Young ("we" or "EY") has been engaged by the Independent Market Operator (the "IMO", "you" or the "Client") to prepare a review of ancillary services in the Wholesale Energy Market ("WEM") (the "Services").

Purpose of our Report and restrictions of its use

The results of our work, including the assumptions and qualifications made in preparing the Report, are set out in the enclosed report ("Report"). You should read the Report in its entirety including the appendices. A reference to the Report includes any part of the Report. We understand that this Report will be used by the IMO for the purpose of informing the 2014 Ancillary Service Standards and Requirements Study (the "Purpose"). It will also be made public principally by posting it on the IMO website.

This Report was prepared on the specific instructions of the IMO for the Purpose and should not be used or relied upon for any other purpose.

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Scope and nature of our work

The scope and nature of our work, including the basis and limitations, are detailed in our Novation Agreement and in this Report.

In particular, we note that the IMO undertakes a five year review of ancillary service requirements, processes and standards. This is undertaken to comply with the Wholesale Electricity Market Rules (Market Rules). The IMO has commissioned EY to conduct research, analysis and modelling to fulfil the 2014 review.

EY has undertaken this with a focus on analysing the appropriateness of ancillary service arrangements for the current system and in light of likely changes that may occur over the next five years. The basis under which we have conducted the engagement is outlined in the Report.

Limitations

There have been no limitations that have impacted our ability to address the scope outlined above.

A draft of this Report was released for public consultation on 24th September 2014. This final Report was completed on 31st October 2014. Our Report does not take into consideration any other event or circumstances arising after the date it was first completed.

This letter should be read in conjunction with our detailed Report, which is attached.

Thank you for the opportunity to work on this project for you. Should you wish to discuss any aspect of this Report, please do not hesitate to contact Michael Fenech on 07 3243 3753 or Ben Vanderwaal on 07 3227 1414.

Yours sincerely

Michael Fenech
Partner

Ben Vanderwaal
Executive Director

Executive Summary

In accordance with the Wholesale Electricity Market Rules (Market Rules), the Independent Market Operator (IMO) undertakes a major review of ancillary services and settings in the Wholesale Electricity Market (WEM) at least every five years. This review process aims to identify any shortcomings in the requirements, uncertainties in the standards or opportunities for improvements in the operation of ancillary services.

Ernst & Young Limited ("EY") has undertaken this review in 2014. EY conducted an extensive investigation and benchmark of the current ancillary services provisions in the WEM compared to various international markets, focusing on:

- Appropriate time scales and requirements for ancillary services
- Operation and structure of the ancillary services market
- Initiatives to minimise the need for and usage of ancillary services
- Technical developments and improvements in ancillary service procurement

EY used historical WEM data to create models to analyse current requirements and predict future requirements for Load Following Service (LFAS), Spinning Reserve Service (SR) and Load Rejection Reserve Service (LRR). In particular, EY was tasked with examining the impact of increasing intermittent solar and wind generation on LFAS requirements, and the impact on system frequency associated with altering the amount of SR and LRR procured. The System Restart Service (BSS) was also analysed and benchmarked internationally. A summary of EY's findings from the international benchmarking exercise and modelling of LFAS, SR and LRR is provided below.

As a result of this comprehensive analysis, EY has identified a set of recommendations for improvement. These recommendations range from improvements which will be relatively straight-forward to implement in the short term and longer term, more complex structural changes. Therefore all recommendations have been grouped according to EY's judgement of the likely time frame or complexity to implement. For ease of reference, the recommendation numbers are consistent with the order in which they appear throughout the text of the main report.

Findings of EY's International Benchmarking Exercise

EY's international benchmarking exercise found that the current explicit ancillary services in the WEM, combined with other market rules and practices, currently provide a complete coverage of the necessary frequency control roles. However, EY has identified a number of instances where Market Rules and/or PSOPs are ambiguous or not strictly in agreement with normal practice in the WEM. Furthermore, there are some examples where the current ancillary services and related Market Rules may not be sufficient under all future conditions. It is these areas that EY's recommendations above are concerned with.

EY found that all prescribed frequency ranges in the SWIS Operating Standards (including generator deadband settings and normal and contingency frequency ranges) and time requirements are similar to the international markets reviewed by EY and consistent with EY's assessment of best practice.

The costs of frequency control in the WEM are higher than those in any other market studied. This is particularly due to the WEM's LFAS costs. EY found that regulation requirements vary significantly depending on the nature of a system and that the particular nature of the market services, structure and also the type of generation assets available heavily dictate the necessary regulation requirements. The WEM's relatively small size, lack of inter-connectedness, load concentration and absence of significant hydro generation in particular are all factors contributing to high regulation (LFAS) requirements and therefore high LFAS costs. EY has made a number of recommendations for actions that would help to minimize LFAS requirements based on international experience and review.

Owing to the ambiguity and difficulty in interpreting and implementing the LFAS standard, System Management instead uses the practice of procuring at least 72 MW of each upwards and downwards LFAS. By observation this has been found to be sufficient to contain the system frequency to the Normal Range 99.9% of the time. However, the SWIS Operating Standards state that the Normal Range need only be met for 99% of the time. EY's international benchmarking exercise found that containing frequency to its normal range for 99.9% is much more onerous than typical frequency standards elsewhere; in the markets EY reviewed, the performance standards varied between 97% and 99%. Recommendation 9 seeks to address this area.

In the role of contingency reserve requirements (primary, secondary and tertiary response), the WEM standards and settings were found to be broadly consistent with international markets. However, in all cases except for the WEM, standards and settings are designed to avoid involuntary load-shedding under a single credible contingency. EY has identified that more explicit forecasting of load relief (the response of system loads to increases or decreases in frequency) could allow for more efficient procurement of contingency reserves, and thus minimize the impact of disallowing load shedding on a single credible contingency event.

All international markets reviewed by EY require that the capacity equal to the full size of any credible contingencies is able to be replaced within a reasonable timeframe. That is, that the secondary response must deliver an equivalent capacity to the size of contingency without support from load relief or load shedding. Subject to some relatively minor changes to properly clarify the Ready Reserve Standard (see Recommendation 5), the provisions in the WEM for replacement of capacity lost in a contingency event are appropriate.

In the case of system restart services (also known as black start services), EY found that the WEM's regulations for the System Restart Service (BSS) broadly comparable to other international markets and are consistent with industry best practice when geographical factors are taken into account. However, several specific areas of improvement or opportunities to increase clarity have been identified and are captured by the recommendations for this service.

EY's international benchmarking exercise also looked at initiatives aiming to reduce the amount of ancillary services required, and the usage of those services. Broadly categorised, these initiatives focus on reducing the time between dispatch instructions, increasing flexibility, offering generator performance incentives for consistent and best delivery of ancillary services, increased control of intermittent generators and improved forecasting, particularly of system load and intermittent generation. All of these areas are relevant to the WEM.

Findings of EY's LFAS Modelling

EY's LFAS modelling has shown that there is greater impact on the total LFAS requirement associated with a 50% increase in wind penetration than a 50% increase in solar penetration. An increase in wind capacity of 280 MW in the WEM would result in increasing the overall LFAS requirement by about 10 MW. In contrast, adding 162.5 MW of solar PV capacity to the WEM would make a negligible change to the LFAS requirement. These differences can be attributed to a greater increase in actual capacity for wind than for solar, as well as the average capacity factor of wind generators being double of that for solar generators (35% versus around 17%).

Findings of EY's SR Modelling

The findings of EY's SR modelling are illustrated in Figure 1, which shows the level of SR required to avoid load shedding during the largest single credible contingency (assumed to be 330 MW) given the typical load relief available in the WEM at different demand levels. Also illustrated are the three levels of SR settings EY was asked to evaluate (50%, 70% and 90% of the largest single credible contingency). The SR requirement in Figure 1 is the total required in the system[1]. This shows that at minimum demand, the SR required to keep frequency above 48.75 Hz and hence avoid involuntary load shedding is closer to 90% of the contingency than the current setting of 70%. Even at median demand the SR required to keep the frequency above 48.75 Hz is higher than the 70% level. However, at maximum demand levels, the SR required is closer to 50% of the contingency, due to the extra load relief provided.

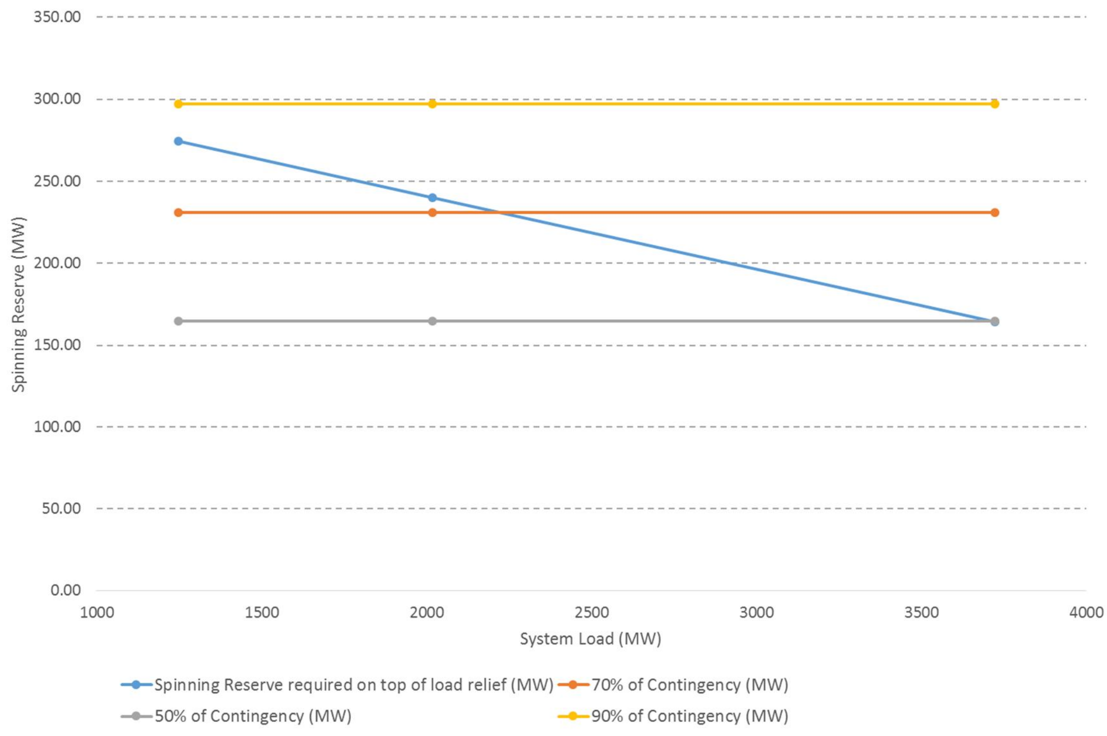

Figure 1 – Calculated Spinning Reserve Service requirements

Findings of EY's LRR Modelling

EY's LRR modelling investigated LRR procurement levels of 90 MW, 120 MW (the current requirement) and 150 MW. This modelling showed that there is a wide range of operating states in which the system will meet the SWIS Operating Standards with any of these three LRR procurement levels. Most operating states seen in the WEM in 2013-14 would have been able to cope with a loss of load contingency event of at least 150 MW without exceeding the relevant frequency standard. EY's modelling also found that a loss of load in excess of 200 MW would almost certainly breach the SWIS Operating Standards. Should a loss of load of around 300 MW occur in the WEM, not even increasing the LRR requirement to 150 MW could ensure the frequency standard is met.

[1] Note, however, that 42 MW of SIL was assumed in all modelling; given its significantly faster response, the modelling outcomes may not be the same if the SIL was replaced with governor response.

The ERA determined the current cost of LRR to the market to be zero “because it did not have information demonstrating that the Load Rejection Reserve Ancillary service is provided at a particular (unremunerated) cost to any market participant” [1]. EY notes however that feedback from some stakeholders disagreed that the cost to LRR providers of providing the service is zero. Noting this, it is nonetheless currently the case that, regardless of EY’s findings, reducing the LRR requirement would not decrease market costs but would increase the risk of breaching the SWIS Operating Standards. Conversely, increasing the LRR requirement would not necessarily be simple or cheap. System Management has suggested that increasing the level of LRR procurement could be costly. There is limited incentive to investigate a more dynamic setting which would be able to reduce the LRR, given that procurement costs are currently negligible.

There is an economic trade-off inherent in setting the LRR requirement; to procure sufficient levels of LRR to cope with very rare but large events is likely to be prohibitively expensive. Considering the modelling results and the current and expected costs of procuring LRR, EY determined that the current requirement of 120 MW was appropriate for the review period.

Short Term Recommendations

Recommendations are numbered according to the order presented in this report, and so short term and long term recommendations are not sequential.

Recommendation 1 – Ensure requirements for ancillary services facilities are technologically neutral
The Market Rules and Power System Operation Procedures (PSOPs) currently include lists of allowed provision methods for ancillary services. For example, facilities providing Spinning Reserve are currently limited to the methods set out in Sections 2.2.6, 2.2.7 and 2.2.8 of the PSOP: Ancillary Services. Setting these methods out explicitly could preclude the same services being provided by another technology in a different manner. This creates unnecessary conflict between the clearly defined “performance” standards (including response times and sustain periods) and the technical implementation. EY recommends that the definitions in the Market Rules and/or PSOP: Ancillary Services be revised to be based on performance requirements, rather than explicit methods of provision. This will ensure that emerging providers of ancillary services (such as those discussed in Section 8.2) can compete on an equal footing, and encourage competition in line with the Wholesale Market Objectives. The current list of permitted technologies could be provided in a comment box or similar in the PSOP: Ancillary Services as examples of the possible ways that these services could be provided. EY notes, however, that the introduction of non-conventional providers could incur additional costs for the market. For example, providing LFAS through a communication method other than AGC could require significant changes to System Management’s systems and procedures. Therefore, the PSOPs may still need to impose some technology requirements on providers, and appropriate cost-benefit analysis would need to be undertaken for any new procurement methods.

Recommendation 1A –Ensure that all generators meet prescribed governor settings
All generators in the WEM are required to enable their governors (if they are technically able) and adopt the deadband and droop settings prescribed in the Technical Rules. If some generators are not conforming (e.g., by applying a wider deadband setting than specified), a disproportionate burden for controlling frequency excursions will fall to those generators that are compliant.

EY recommends that System Management confirm that all generators are meeting their connection requirements with respect to governor settings.

Recommendation 2 – Eliminate time overlap in Load Rejection Reserve Service
EY recommends eliminating the overlap in the two classes of the Load Rejection Reserve Service. EY favours setting the Class A response and sustain times to 6 seconds and 2 minutes respectively, which lines up with the first over-frequency event restoration time stated in the SWIS Operating Standards. EY favours setting the Class B response and sustain times to 2 minutes and 30 minutes respectively to eliminate the overlap with Class A and to tie-in with the Balancing market trading interval period. EY also favours reducing the Class A sustain time over extending the Class B response time because it is more likely to allow future technologies such as storage to participate. This reduces the potential for future duplication or over-provision of the Load Rejection Reserve Service, and also avoids discrimination against emerging technologies, which is consistent with Wholesale Market Objectives (c) and (d).

Recommendation 4 – Alter the treatment of LFAS providers in SR and LRR to be consistent and cognizant of constraints on the delivery of the services
Under the current Market Rules, Upwards LFAS is explicitly counted towards the SR requirement, but there is no corresponding provision for Downwards LFAS to count towards the LRR requirement. In reality, some LFAS facilities can and do provide both SR and LRR in addition to LFAS. On the other hand some LFAS providers may not be able or willing to provide either SR or LRR on technical or economic grounds. Further, if units enabled for LFAS are also counted towards the SR and RR requirements, there will necessarily be periods of the year when those LFAS units will not physically be able to provide the service, as they will have already been partially or even fully utilised in the provision of LFAS. However, to exclude providers of LFAS from SR/LRR will increase the costs of ancillary services in the WEM. Given that operational experience has not identified a significant problem related to SR and LRR availability, and that ancillary services costs are already perceived as high in the WEM, EY's opinion is that it is reasonable that the WEM continues to allow LFAS facilities to provide SR or LRR at the same time, provided the facilities are technically able to do so. Therefore EY recommends that the Market Rules be revised such that IPP LFAS providers are not automatically assumed to provide SR and LRR. System Management should be able to use the same facilities to meet the requirements if they are technically and contractually able to do so, but the Market Rules should not assume that this will always be the case. As SKM recognized in their 2009 review, increased LFAS usage will increase the likelihood of a contingency event coinciding with near maximum LFAS usage. This means that LFAS usage should be carefully monitored and reviewed moving forward to determine whether LFAS usage approaches its maximum feasible levels increasingly often, in which case the WEM may be at risk of breaching the SWIS Operating Standards. Should this risk increase significantly, then EY recommends that introduction of a limit on the proportion of SR and LRR that may be provided by LFAS.

Recommendation 5 – Make the Ready Reserve Standard indifferent to the nature of SR and LRR providers
The current Ready Reserve Standard (Clause 3.18.11A of the Market Rules) is not robust enough to deal with future scenarios where capacity procured for Spinning Reserve

Service cannot be physically called upon for longer periods. For example, energy limited plant, including battery storage facilities, may be able to provide 15 minutes of response, but not have sufficient energy for longer term (up to four hours) supply. The Ready Reserve Standard would therefore not provide a sufficiently strong planning criterion for System Management. EY recommends that the IMO review this clause to state that there must be enough generation or demand side response available that can be brought online (within 15 minutes or four hours for the two sub-clauses, respectively), to replace the capacity lost in the contingency event.

Recommendation 12 – Begin to procure synthetic inertia capability

The WEM may face low inertia conditions in future, particularly if the number of wind turbines installed continues to increase. Wind turbines can provide synthetic inertia to support the system.

EY recommends that the provision of synthetic inertia, or, if possible, the ability to be retrofitted for it, be considered as a preferred capability for future wind turbines in the WEM as a way of future-proofing the system.

This will ensure the WEM can continue to avoid discrimination in the market against a particular energy option in line with Wholesale Market Objective (c).

Recommendation 16 – Add energization capability for 330 kV connected Black Start units

EY recommends System Management adopt a new requirement for Black Start units connected at 330 kV to be capable of energizing a 330 kV line section and a 330/132 kV 490 MVA transformer. This would make the physical requirements of candidate BSS units more transparent to the market which would facilitate an efficient and fair procurement process.

Recommendation 17 – Annual testing of Black Start units

EY recommends System Management consider adding an explicit requirement for an appropriate annual black start test for all Black Start units. This test does not replace any other test requirements for the facility. The number of tests per year must be considered against the cost of undertaking these tests.

Recommendation 19 – Procure additional Black Start providers in the South Country sub-network

All BSS units procured in the WEM are currently located in the North and South Metropolitan sub-networks. Procuring BSS sources in the South Country sub-network would help to ensure restoration times are minimized for the WEM, especially in the event of transmission issues between the South Metropolitan and South Country sub-networks. BSS facilities close to Muja would therefore be able to energies these coal facilities sooner in the event of issues like this. The longer that coal facilities are off-line, the longer they may take to synchronize, and the more likely they are to suffer an unplanned outage. Quantification of these risks is a significant exercise and was not considered in this scope of works.

Possible existing candidates for the provision of System Restart services in the South Country sub-network are Synergy's Kemerton gas turbine units or Alinta's Wagerup units, which could potentially be retro-fitted with black start capability. Another option would be to utilize and/or augment TTHL capabilities on some of the coal units in the Muja area, but this may not be feasible.

This would increase the reliability of the electricity supply in the WEM in line with Wholesale Market Objective (a) of the Market Rules by helping to minimize the likely time major load is disconnected in a system blackout situation.

Recommendation 21 – Geographically diversify Black Start units
There is a reasonable chance that any single unit may fail to start, but the simultaneous failure of two units to start is very unlikely. However, retaining two BSS units per black start sub-network to cover this possibility (that is, four, or even six were three black start sub-networks to be established) would be excessively costly for a network the size of the WEM. Therefore EY suggests that three units should be adequate, but these BSS units should not be all located in the same sub-network so as to avoid common cause failures of equipment, such as shared transmission assets. EY considers it highly probable that both Kwinana BSS units would be unavailable simultaneously in the event of a geographically isolated disturbance such as an earthquake or fire. In such an event, only the Pinjar BSS unit, located at in the North Metropolitan sub-network, could provide start-up energy. This may not be adequate. EY therefore recommends that the BSS requirements be tightened to specifically state that BSS units procured must be located in at least two of the three sub-networks, with preference given to procuring BSS units in all three sub-networks. This would increase the reliability of the electricity supply in the WEM in line with Wholesale Market Objective (a) by helping to minimize the likely time major load is disconnected in a system blackout.

Long Term Recommendations

Recommendations are numbered according to the order presented in this report, and so short term and long term recommendations are not sequential.

Recommendation 3 – Monitor emerging ancillary services markets
Changing conditions in the WEM, such as decreased inertia levels, or increased variability in net load, could increase the vulnerability of the WEM to frequency drops, even if Class A Spinning Reserve is available. Several markets are investigating the creation of explicit markets for shorter timescale primary response, to cope with these pressures. EY does not consider there is a need for additional ancillary service markets in the WEM within the current review period. EY recommends that the IMO continue to monitor the proposed changes to ERCOT and other ancillary service markets, with a view to the longer-term implementation of a shorter timescale Spinning Reserve Service. This will assist the WEM in accepting an increased penetration of renewable energy sources, in line with Wholesale Market Objective (c).

Recommendation 6 – Clarify the Market Rules and PSOPs regarding the expected response characteristics of SR and LRR providers
EY recommends that the Market Rules and PSOPs should clarify the precise responsibilities of SR/LRR providers, especially in terms of primary and secondary response, including

stating whether it differs between classes of SR and LRR.

Recommendation 7 – Simplify the Spinning Reserve Service standard

EY recommends that Clause 3.10.2 of the Market Rules be altered to remove any reference to the particular volume of Spinning Reserve Service that must be procured (where volume here refers to the 70% value specified in Clause 3.10.2(a)). Instead, the clause should state that the volume of Spinning Reserve Service to be procured must be sufficient to deliver the performance specified in the SWIS Operating Standards (Clause 2.2.1(c)). This implies that the policy of allowing the possibility of load shedding on a single credible contingency event would be abandoned, and therefore will result in a maximum procurement that exceeds the 70% of the largest credible contingency level currently procured (under normal circumstances). This will potentially lead to increased SR procurement costs therefore EY recommends that this be implemented in tandem with Recommendation 13 which aims to improve the sculpting of SR requirements according to factors such as load relief so as to minimize the required ancillary service volumes.

Additionally, the Market Rules should require that System Management and/or the IMO be responsible for developing and publishing in a procedure a methodology which System Management will use on an ongoing basis to determine the necessary SR levels to maintain compliance with the SWIS Operating Standards.

Recommendation 8 – Simplify the Load Rejection Reserve Service standard

EY recommends that Clause 3.10.4 of the Market Rules be altered to remove any reference to the frequency standards that must be delivered with the Load Rejection Reserve Service. Instead, the clause should state that the volume of LRR to be procured must be sufficient to deliver the performance specified in the SWIS Operating Standards (Clause 2.2.1(c)).

Additionally, the Market Rules should require that System Management and/or the IMO be responsible for developing and publishing in a procedure a methodology which System Management will use on an ongoing basis to determine the necessary LRR volumes to maintain compliance with the SWIS Operating Standards.

Recommendation 9 – Simplify the Load Following Service standard

Given the difficulty of defining an appropriate methodology for determining the required levels of Load Following Service within the context of the Market Rules, EY recommends that Clause 3.10.1 of the Market Rules be altered to remove any reference to a particular quantity of load following service or methodology. This should be replaced with a statement that the level of load following service procured must be sufficient to deliver the frequency performance levels defined as the Normal Range in the SWIS Operating Standards (Clause 2.2.1(c)).

Additionally, the Market Rules should require that System Management and/or the IMO be responsible for developing and publishing in a procedure a methodology which System Management will use to determine the necessary LFAS levels to maintain compliance with the SWIS Operating Standards. EY notes that the development of a formal methodology to determine the LFAS requirement would typically depend on accurate measurements of historical LFAS usage. As EY describes in Section 9.1, these measurements are not currently available, mainly due to the way in which the Synergy Balancing Portfolio is dispatched to meet its Balancing and LFAS obligations. EY therefore expects that in the first instance the options for developing a robust methodology are limited.

Recommendation 10 – Reduce dispatch interval time step
Shorter dispatch intervals reduce market regulation requirements by allowing full economic re-dispatch to occur more often and allowing regulation (LFAS) units to be returned to their setpoints (where they have the maximum capability to deliver the service) more frequently. The WEM currently operates on a 30 minute dispatch interval, although the end of interval targets can be revised twice (every 10 minutes) within that 30 minutes. EY recommends that moving to a true 10 minute dispatch interval (with dispatch instructions based on forecasts for the end of the 10 minute dispatch interval rather than the end of the associated half hour) be considered for the WEM. Consideration could also be given to a five minute dispatch interval, as per the NEM. The resulting reduction in LFAS requirements would improve the economic efficiency of the WEM in line with Wholesale Market Objective (a).

Recommendation 11 – Allow System Management to vary ramp rates without triggering constrained on/off payments
System Management must currently dispatch all units at their BMO ramp rates, or the facilities may be eligible for out-of-merit payments. This can increase discrepancies between generation and load, and increase the LFAS requirement. EY recommends that Rule changes be explored to allow System Management to dictate ramp rates within dispatch instructions without triggering constrained on/off compensation, subject to the technical capability of the generators. The resulting reduction in LFAS requirements will improve the economic efficiency of the market in line with Wholesale Market Objective (a). It is also likely to minimize the long-term cost of electricity supplied to customers in line with Wholesale Market Objective (d).

Recommendation 13 – Factor dynamically forecast load relief into the Spinning Reserve Service requirement
In this study, EY investigated the system frequency impact of procuring Spinning Reserve levels of 50%, 70% or 90% of the largest credible contingency. Procuring 50% of the largest credible contingency would mean the system is often operating in a state where the largest contingency would result in a breach of the 48.75 Hz frequency standard. Procuring 90% of the largest contingency at all times would be unnecessarily onerous. Procuring 70% of the largest contingency is the current standard, and is a balance between system security and the cost of procuring Spinning Reserve in line with the objective of the market to provide economically efficient, safe and reliable supply of electricity. However, 70% of the largest contingency is not enough to cover, for example, the loss of Collie at full load, and this can result in load shedding on a single contingency. EY considers that this is not in line with international best practice or the market objectives. Also, at times of very high demand, a Spinning Reserve requirement of 70% is unnecessarily high. EY recommends System Management investigate extending the calculation of the Spinning Reserve requirements to include load relief from expected demand as well as the largest contingency. The Spinning Reserve requirement required would then be calculated as the largest credible contingency minus the expected load relief. At times of low load, this will result in a Spinning Reserve requirement greater than 70% of the largest credible contingency, but at times of high load, it may be significantly less than 70%. Ideally load

relief would be assessed for every dispatch interval, but even assessing it 2 – 3 times per day could represent significant cost savings and an increase in system reliability, in line with the Wholesale Market Objectives (a) and (d).

Recommendation 14 – Factor dynamically forecast load relief into the Load Rejection Reserve Service requirement

EY investigated the system frequency impacts of procuring 90 MW, 120 MW or 150 MW of Load Rejection Reserve Service.

System Management advises that a single loss of load contingency is likely to be between 150 – 200 MW. The current 120 MW Load Rejection Reserve Service requirement is likely to keep the frequency below 51 Hz in the event of a contingency of this size. However, it may not be sufficient if a large (200 – 250 MW) loss of load occurs (e.g. through a transmission failure), or if the system is at very low loads. If the system is at greater than average load, or the contingency is smaller, the 120 MW is significantly higher than is required.

Given that the ERA regards that the current procurement cost of Load Rejection Reserve Service is essentially zero, EY does not recommend any changes to the settings of this service. Should the cost of procuring Load Rejection Reserve Service become material, it is best practice to ensure the amounts procured are minimized so as to minimize cost. Should this situation arise, EY recommends that System Management put into practice the setting of Load Rejection Reserve Service requirements dynamically based on the largest loss of load contingency and expected load relief from the demand. Ideally factoring of the load relief would be done for every dispatch interval, but setting the assumed load relief 2-3 times per day may be a practical trade off in complexity and accuracy.

Recommendation 18 – Investigate an availability requirement for Black Start units

EY recommends System Management consider setting a minimum availability requirement for Black Start units. This would be consistent with international best practice.

Recommendation 20 – Recognise geographic considerations within a restart sub-network in the BSS requirements

EY recommends that relative geographic and network advantages be included in the evaluation criteria for assessing tenders for BSS.

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Glossary

Acronym/term	Definition
AGC	Automatic Generation Control allows generators to respond to signals received over the SCADA system every 4 seconds, without involving manual dispatch instructions or response
Balancing Portfolio	The set of Synergy's Registered Facilities other than Stand Alone Facilities, Demand Side Programmes, Dispatchable Loads and Interruptible Loads
Contingency Event	Unexpected and sudden changes to power system, including a generator tripping (i.e., suddenly no longer supplying power), changes to load (e.g., a major industrial user suddenly going off-line) or loss of a network element such as an high voltage transmission line (due to lightning strike, bushfire or other natural or man-made reason)
Deadband	A band of frequency change within which a generator will not respond, so as to avoid hunting of generators for small changes in frequency. In the Wholesale Electricity Market (WEM), generators are required to have a deadband of ±0.025 Hz
Droop	Defines the response of a generator to changes in system frequency. It is measured as a percentage change in generation output per unit change in frequency. Droop settings can be adjusted. The SWIS Technical Rules currently require 4% droop settings on all connected generators
Dispatch interval	Period between subsequent dispatch instructions
Frequency	The SWIS operates on an AC system. AC power systems operate at a designated frequency; for example the WEM operates at a nominal frequency of 50Hz. Many generators and machines are frequency dependent and can be damaged if not maintained at their design frequency. Frequency can become unstable over a short time frame due to an immediate failure of a system element or over a longer time frame of tens of seconds to several minutes due to continued imbalances in the system.
Governor Response	Automatic response of thermal generators to change in the power system frequency. The response of governors to a change in system frequency is determined by the droop and deadband characteristics, and the ability of the turbine to respond to a signal to change output.
Inertia	Inertia describes a power system's resistance to change in frequency, and is a property of both generators and loads. Physically, it is related to the mass of all the synchronously rotating generators and motors operating in the system. In the event that supply is not equal to demand (e.g., after a generator outage), a system with high inertia will experience slower rates of frequency change than one with low inertia, as additional energy is added to or subtracted from a greater mass of turbines.
RoCoF	Rate of change of frequency, measured in Hz/second. It is commonly used by protective devices in loads and generators to detect when a frequency event is threatening the load/generator and thus to disconnect from the grid.

Acronym/term	Definition
Ramp Rate	The defined rate in MW/second or MW/minute at which a generator can change its output power. Thermal generators have maximum ramp rates limited by their operating characteristics to manage mechanical stress on the turbine. Wind and solar panels have few or no physical ramp rate limitations but ramp rates can be imposed through the electrical control system.
SCADA	Supervisory Control and Data Acquisition (SCADA) systems monitor power system characteristics such as generation and frequency. In the WEM, all generators output and frequency is recorded every 4 seconds.

1. Introduction

The Independent Market Operator (IMO) of Western Australia's Wholesale Electricity Market (WEM) undertakes a five year review of ancillary service requirements, processes and standards. This is undertaken to comply with the Wholesale Electricity Market Rules (Market Rules). The IMO has commissioned EY to conduct research, analysis and modelling to fulfil the 2014 review.

EY has undertaken this with a focus on analysing the appropriateness of ancillary service arrangements for the current system and in light of likely changes that may occur over the next five years.

In particular, EY has identified opportunities for changes to ancillary services (and related factors) that would assist in meeting the Wholesale Market Objectives outlined in Clause 1.2.1 of the Market Rules, namely:

> *1.2.1. The objectives of the market are:*
> - *(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;*
> - *(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;*
> - *(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;*
> - *(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and*
> - *(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.*

1.1 Changes since last review

The previous major review of ancillary services in the WEM was conducted by Sinclair Knight Merz (SKM) in 2009 [2]. Since that review, there have been several major changes in the WEM, including:

- Introduction of two high-efficiency LMS100 open cycle gas turbines (OCGT) operated by Synergy. This was in line with a recommendation of the previous review to introduce new mid-merit order generators.
- Establishment of the Balancing Market to include all power generators in balancing functions rather than just Synergy owned plant, such that the WEM is now a gross pool market.
- Recent merging of Synergy, the government owned retailer, and Verve Energy, the government owned generator, to create a vertically integrated body (Synergy)
- Establishment of the Load Following Service (LFAS) market to allow Independent Power Producers (IPPs) to participate in frequency regulation services, subject to meeting certain criteria. At the time of writing, this has only been taken up by one non-Synergy generator, NewGen Kwinana.
- System Management has begun issuing dispatch instructions three times per trading interval. The dispatch targets for the end of the interval are now updated at five and fifteen minutes into the interval, with instructions taking effect ten and twenty minutes into the interval, respectively. Initial dispatch instructions are issued ten minutes before the beginning of the interval.

1.2 Public Consultation

This document constitutes EY's Final Report for the 2014 Ancillary Service Standards and Requirements Study. The Draft Report for public consultation was published by the IMO on its website and stakeholders were invited to make submissions. Four formal submissions were made. Changes made to the report following the public consultation period include:

- clarification of the Trip to House Load (TTHL) capabilities of units in the WEM;
- incorporation of stakeholder views on LRR costs;
- correction of the stated details of the capacity provided under Perth Energy's BSS Ancillary Service Contract;
- removal of the incorrect statement that all fast start generators in the WEM are owned by Synergy;
- Adding a new Recommendation 1A to confirm that all generators are meeting their connection requirements with respect to governor settings;
- withdrawal of Recommendation 15 which suggested increasing the minimum size of BSS facilities;
- withdrawal of support for setting a minimum fuel reserve of 48 hours runtime for BSS facilities;
- changes to the suggested requirements regarding the transmission energization methods for 330 kV connected BSS facilities;
- clarification of Recommendation 20 regarding the potential alteration of the South Country System Restart sub-network; and
- increased discussion of technological neutrality and an extension of the recommendation to make SR requirements technologically neutral (Recommendation 1) to all ancillary services.

1.3 Structure of this report

Section 2 provides a brief overview of the need for ancillary services and the roles that must be fulfilled in all large AC power systems. This is not intended to be a comprehensive review of ancillary services; references are provided to more detailed reviews.

This report then reviews the current ancillary services in the WEM, including whether they are sufficient to achieve the WEM performance standards, well defined and with appropriate boundaries. Section 3 outlines the specific ancillary services currently defined in the WEM, while Section 4 evaluates how well each services addresses the necessary roles identified in Section 2, as well as comparisons to international benchmarks conducted by EY. Section 5 then considers whether the ancillary services are well defined and in particular whether there are any conflicts across the standards and requirements.

Section 6 considers international experiences in ancillary service markets and Section 7 reviews international efforts to minimise ancillary service requirements. Section 8 reviews the impact of technological developments on ancillary service requirements and provisions.

Section 9 is the first of two major modelling studies by EY, reviewing the impact that wind and solar generation is likely to have on Load Following Service requirements. Sections 10 and 11 describe the other major modelling which analyses the impact on system frequency should the levels of Spinning Reserve and Load Rejection Reserve Services be altered.

Section 12 provides a detailed review of the System Restart Service.

2. The Purpose of Ancillary Services

This section describes the reasons why ancillary services are essential in an electricity market. The term *ancillary services* can be used to describe any function which supports the reliable function of an electricity system. At the highest level, there are three key functions that must be fulfilled in an AC grid, and each of these may then be decomposed into parts. The three key functions are:

1. Frequency control;
2. Black start, or system restart capability, and;
3. Voltage control.

Typically, for each of these functions, one or more ancillary services are created. The number and specific design of these ancillary services depends on many factors, including the design of the electricity market and the nature of the generators and loads in the market. The following sections describe the purpose of each of the key functions in more detail, and also describe practical ways these functions can be decomposed.

2.1 Frequency control

It is a fundamental requirement of all electricity systems for supply to match demand at all times. Furthermore, modern electricity grids must be maintained at or close to an agreed system frequency setting. If more energy is required than is currently being supplied by generators, the additional energy is extracted from the rotational kinetic energy of spinning turbines, causing them to slow down and hence result in a drop in the system frequency. Conversely, if system demand is less than supply, turbines will speed up and the system frequency will rise. At the extremes, high or low frequencies (beyond a couple of percent from the standard) can cause damage to both generators and loads, and corrective action must be taken by the system operator before reaching these levels.

To maintain the frequency, some capability to rapidly increase or decrease generation (and load) must be kept in reserve at all times to respond to both expected and unexpected changes to generation or load. The ways in which this capability is procured and then used may be referred to as *frequency control ancillary services*.

It is useful to classify the roles that must be covered by frequency control ancillary services or other arrangements to ensure the stable operation of a large AC grid. EY has broadly adopted the naming conventions of the North American Electric Reliability Corporation (NERC) [3], [4]. This structure was also used by the International Council on Large Electric Systems (CIGRÉ) in a recent working paper [5], which involved participants from a large number of global markets; it provides a comprehensive framework for assessing and comparing frequency control ancillary services. There are four basic roles defined for frequency control ancillary services: regulation, primary response, secondary response and tertiary response. These roles primarily are defined based on their purpose, rather than any other form of classification.

2.1.1 Regulation

The role of regulation is to respond to the expected level of general mismatch between load and generation caused by normal system operation, especially within a dispatch interval.

In systems with long periods between dispatch instructions, regulation may also be separated into a fast regulation service and a slower “balancing” or “load following” service covering more predictable (net) load movement. (See for example Figure 5-3 of [6])

Typically, requirements and performance of the regulation service are only determined for periods of normal system operation, although regulation reserves might contribute to contingency reserves.

Regulation needs to be provided on a continual basis and is typically adjusted every few seconds. Thus it is often controlled via Automatic Generation Control (AGC) which typically send signals to generators every four seconds. Governor response may also contribute to the role of regulation by way of assisting to contain frequency deviations.

2.1.2 Operating Reserve Capacity

While the regulation role is to do with responding to expected mismatches in supply and demand, the role of Operating Reserve Capacity is to respond to unexpected mismatches in supply and demand. For example, a load or generator trip results in an unexpected mismatch in supply and demand. These types of events are normally referred to as contingency events.

Operating Reserve Capacity is further broken down into three roles: primary response, secondary response and tertiary response.

Primary Response

The role of primary response is to provide the initial response to a significant deviation in system frequency from the setpoint, designed to *arrest* the frequency deviation but not necessarily to restore the frequency to the setpoint.

Primary response must typically be delivered very quickly in order to arrest the potentially rapid fall (or rise) in frequency, which is the main reason why it is typically driven by local control systems rather than by centralised instructions from a system operator. Primary response therefore is typically controlled by governor response or local control systems (such as under frequency relays) which may trip generation (or load) in response to a high (or low) frequency measurement. Some primary response is also provided by load relief, which is the aggregate behaviour of motors connected to the grid slowing or speeding up as a result of the shifting frequency.

Secondary Response

The role of secondary response is to *restore* the frequency to the system setpoint.

Secondary response takes over from the primary response (which arrests the frequency deviation), but may technically be provided by some or all of the same generation plant. During a contingency event resulting from a loss of generation, its job is to ramp up to replace the generation that was lost. During a contingency event resulting in the loss of load, its job is to ramp down to restore the supply-demand balance. Secondary response must be sustained for longer than primary response, including continuing after the frequency has been restored to the setpoint. This means secondary response must typically commence within seconds and sustain for potentially tens of minutes, depending on the market design.

Plant acting in a regulation role may also contribute to providing secondary response since both services provide frequency restoration.

Secondary response is typically delivered by centralised methods controlled by the system operator. AGC, manual dispatch and fast start are all commonly used methods.

Tertiary Response

Eventually, alternative generation sources must take over from the sources providing primary and secondary response to ensure that those faster acting sources are available again in case of a new frequency event.

Tertiary response covers this role of replacing primary and secondary response providers, and may occur through an explicit "replacement reserve" market or through regular system dispatch and/or balancing processes, depending on the timescales involved – a shorter system dispatch interval allows this replacement to occur through re-dispatching the units in the system. The timeframe in which tertiary response must be delivered and sustained stretches from minutes through to hours, depending on the market design.

Tertiary response is typically delivered by centralised methods controlled by the system operator. AGC, manual dispatch and fast start are all commonly used methods.

2.1.3 Key factors influencing frequency control

To place the above services in context, it is useful to consider the timescales and timeline of frequency management in typical electrical markets.

System dispatch and balancing

At the highest level, balancing is achieved through re-dispatching some or all generators at regular intervals (typically between five minutes to one hour). In *gross pool* markets, such as the WEM's Balancing Market and the NEM energy market, most generators are required to submit bids and are dispatched in economic merit order. In *net pool* markets, such as in the UK, generators only offer a certain portion of their capacity (typically that portion not covered by bilateral contracts) into the market, although the market operator is usually permitted to issue instructions to all capacity if this is deemed necessary for system security.

The system operator dispatches generation to meet the forecast demand for the next dispatch interval. Demand forecasting can take into account recent conditions, historic trends, and specific forecasts of future events. If demand forecasting and dispatch were perfect, this would ensure that the frequency would remain at its setpoint; in practice, variations arise.

Regulation

Between dispatch intervals, ongoing adjustments are required to keep the system in balance. This is typically provided through a *Regulation* service, where certain units are dispatched up or down to correct small imbalances in supply and demand (which manifest in the system as small deviations in system frequency). In most cases, the output of these units is controlled by *Automatic Generation Control* (AGC), meaning that those units respond automatically to generation targets issued by the system operator (System Management in the WEM) up to every four seconds[2]. The movement of units providing regulation is coordinated centrally by System Management based on the current and recent frequency deviations, and calibrated to previous operational experience. Generation targets for units providing regulation will continue to be sent through the AGC system on a four second cycle until the frequency returns to the setpoint.

[2] Note, however, that units can be "on AGC" but not be providing a regulation service; in this case, AGC simply provides a convenient method of issuing regular generation targets to generators.

Governor response

Additional support to maintain the system frequency (that is, on top of regulation service controlled via AGC) is usually provided through the *governor response* of spinning turbines. Most conventional generation units have *governors* that can be enabled to provide an increase or decrease in generation in response to deviations from the system frequency setpoint. To ensure that the system remains stable and that all enabled units share the role of frequency management equally, all generators typically share a consistent governor *droop setting*, which determines the percentage change in generation as a proportion of the percentage change in frequency detected.

Governors will usually have a *deadband* range configured where they will not respond (typically between 0.01 to 0.025 Hz). Within this range, the frequency will be managed by regulation units; outside of this range, governor response and regulation work together.

As an example, if the frequency drops below the governor deadband range (e.g., due to an unexpected increase in load), all governor enabled generators will increase their output according to the droop setting. When the frequency has fallen far enough that all generators have increased their output sufficient to match the increase in load, the system will be in equilibrium. Using the frequency control roles defined above, this can be categorised as a *primary response*, as it arrests frequency deviation, but it cannot restore the frequency to its setpoint (e.g., 50 Hz) since the response is proportional to the frequency deviation. Additional action (e.g., by units providing regulation) is required to adjust the setpoint of one or more units and increase their output, restoring the system frequency. As the frequency is restored, the governor response will decrease proportionally, eventually to nothing.

In some markets, including the WEM, all units must have their governors enabled if they are available, while in other markets, governor response is procured under a specific service. Governor response contributes both during "system normal" conditions, and during contingency events (as discussed below). In the WEM, a generator will not normally have to contribute governor response for long unless they are providing Spinning Reserve or Load Rejection Reserve Services.

Load relief

Motor loads on the system will also provide a supporting role when the frequency rises or falls. Higher frequencies cause motors to run faster and consume more power, therefore reducing the oversupply of generation; the opposite applies to low frequency events. As with governor response, this contribution cannot persist once the frequency is restored, and is therefore a form of *primary response.*

Interruptible loads, load shedding and generator tripping

For even larger frequency excursions, the system operator may be forced to disconnect loads, or generators may automatically disconnect, depending on their protection settings. *Interruptible loads* may offer to be disconnected for a period of time if a reduction in load is required in return for a payment as an alternative to sourcing an increase in generation. *Load shedding* refers to the unexpected and unwanted disconnection of load (i.e., "blackouts"), and is usually an action of last resort for the system operator.

As mentioned above, as a self-preservation measure generators may *trip* (automatically disconnect from the network) if the frequency goes too high or too low. For high frequencies (an excess of generation) this will help the system, but for low frequencies, a generator trip will exacerbate the supply-demand imbalance.

Figure 2.1 shows the relative range of frequencies and the typical responses used to stabilise the frequency in each range. This figure is based on the WEM; other markets will feature the same bands, but the specific frequency cut-offs may vary according to the specific market settings.

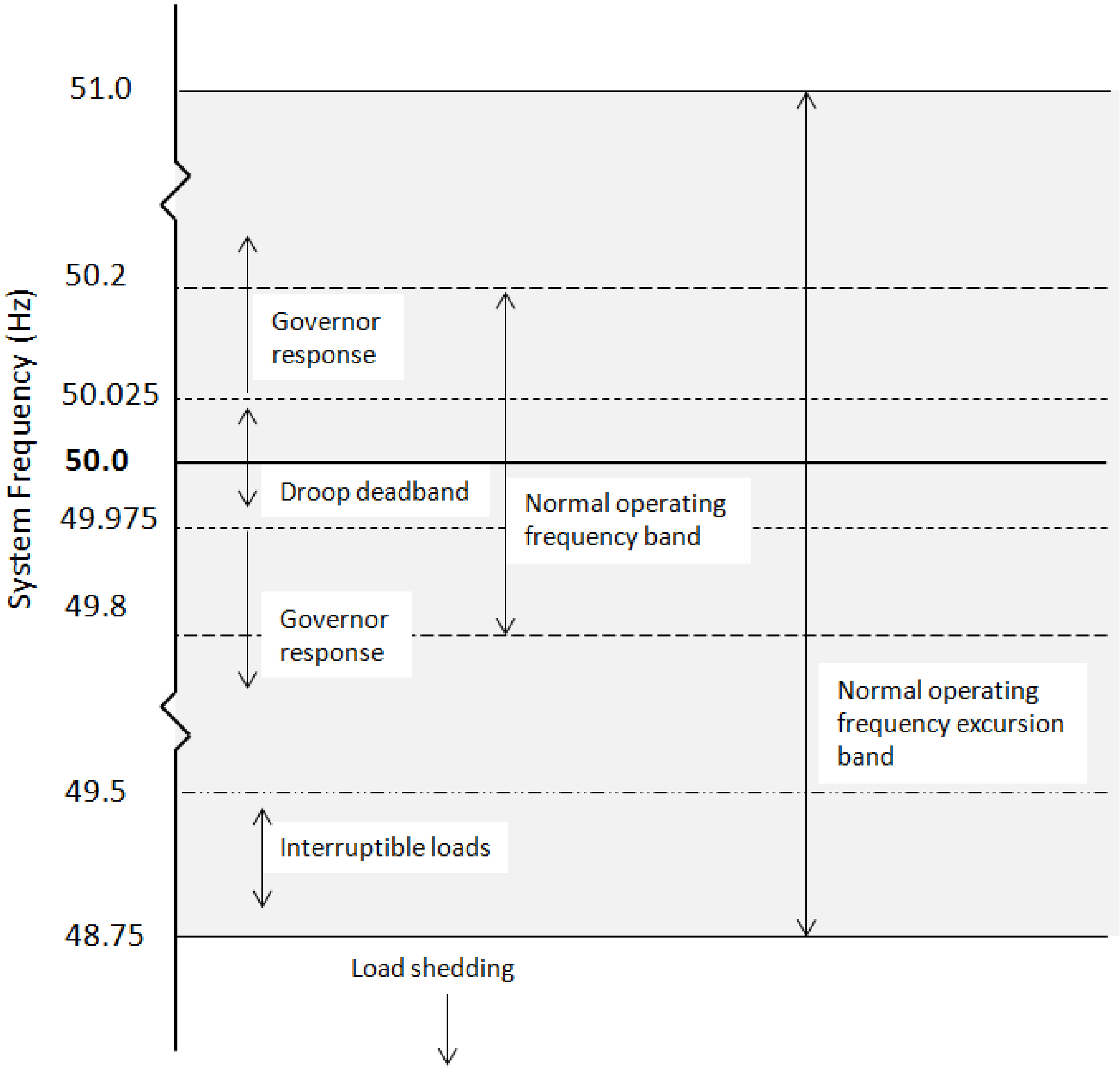


Figure 2.1 – Key frequency ranges in the WEM

Operating reserves and contingency events

Governor response is only available if there is sufficient headroom available on a unit so that it can increase or decrease its output. For example, a generator dispatched to its full capacity cannot provide any increase in generation from its governor response. Therefore, it is advantageous to reserve some headroom during normal operation.

2.2 System Restart

Large thermal generators typically cannot restart without significant electrical input. Smaller generators which are able to start independently using on site battery or diesel backup are contracted to provide a system restart, or black start service. This involves starting the unit without any electrical input from the grid, and generating sufficient energy to energise the grid sufficiently to allow other generators to progressively be brought back online.

2.3 Voltage Control

Voltage across the system is maintained within an operating window to ensure the stable operation of generators and loads. Voltage control ancillary services are typically contractual arrangements entered into by system operators to obtain voltage support for the grid from generators, loads or transmission providers. Voltage control services are specific to the layout of a grid and the distribution of load and generation in that grid.

Voltage control ancillary services were not included in the scope of works of this review and so are not considered further in this document.

3. Ancillary Services in the WEM

This section introduces the key existing ancillary services in the WEM, including their definitions, requirements and current providers. EY has also reviewed ancillary service provisions in various international markets. Summary tables describing all reviewed markets may be found in Appendix C, and the following sections compare arrangements in the WEM with these. Section 4 then assesses how well these services provide the fundamental frequency control roles identified in Section 2.1; that is, regulation, primary, secondary and tertiary response. Section 5 provides a review of the ancillary service standards and requirements currently defined for the WEM, and particularly whether any conflicts exist within and between these services.

3.1 Load Following Service

Clause 3.9.1 of the Market Rules defines LFAS as:

> *3.9.1. Load Following Service is the service of frequently adjusting:*
> *(a) the output of one or more Scheduled Generators; or*
> *(b) the output of one or more Non-Scheduled Generators,*
> *within a Trading Interval so as to match total system generation to total system load in real time in order to correct any SWIS frequency variations.*

3.1.1 Provision of Load Following Service

LFAS is centrally controlled, and is directed by System Management. Plant providing LFAS must therefore be able to continually respond to signals from System Management. This is implemented by having plant controlled through AGC via which System Management sends target output levels for the unit every four seconds.

Historically, regulation (LFAS) was only provided by Synergy plant. This was changed in July 2012, when a competitive market (the LFAS Market) was introduced. In this market, other eligible generators are able to bid offers to provide upward or downward LFAS. These offers include, for each trading period, one or more price-quantity pairs. Synergy is required to submit offers to cover the entire LFAS Requirement for each trading interval so as to ensure there will be no shortfall. The LFAS will be allocated between the Balancing Portfolio and any other LFAS Facilities based on their offered prices. Currently, only one generator, NewGen Kwinana, has been certified for LFAS outside Synergy's portfolio.

3.1.2 Amounts currently procured

Sufficient LFAS must be procured to satisfy clause 3.10.1 of the Market Rules.

> *3.10.1. The standard for Load Following Service is a level which is sufficient to:*
> *(a) provide Minimum Frequency Keeping Capacity, where the Minimum Frequency Keeping Capacity is the greater of:*
> *i. 30 MW; and*
> *ii. the capacity sufficient to cover 99.9% of the short term fluctuations in load and output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average.*
> *(b) [Blank]*

However, sufficient LFAS is also required to meet the market SWIS Operating Standards which state that system frequency must be maintained within 49.8 to 50.2 Hz for 99% of the time [7]. These two standards are currently combined by System Management to create the requirement that frequency is maintained between 49.8 – 50.2 Hz for 99.9% of the time. This is the benchmark against which System Management measures its performance each year [8]. EY has explored the implications of these combining these two standards in Section 5.3.

System Management's 2013 Ancillary Services Report states that during the period 1 July 2012 to 30 April 2013 the average upward LFAS enabled was 96 MW, while the average downward LFAS enabled was 90 MW. This exceeds the default 72 MW LFAS Requirement set by System Management through observation of historical performance. System Management report that this does not necessarily reflect an increased need for load following but is because when (Synergy) generators are enabled for LFAS, they bring on specific amounts in a 'blocky' manner, rather than specifically the minimum to meet the requirement [8]. System Management may bring on additional reserves above the minimum, however, if there is a short-term increase in requirement (e.g., during volatile weather conditions or the commissioning of a large unit with an uncertain timeline). System Management may also exercise similar discretion to reduce the LFAS Requirement during times of low need.

LFAS is designed to maintain the frequency during system normal conditions; although it may also assist with frequency recovery after a contingency event.

3.2 Spinning Reserve Service

3.2.1 Classes of reserve

The Spinning Reserve Service (SR) is defined and procured on three time scales, as specified in Clause 3.9.3 of the Market Rules:

- Class A: Response within six seconds and capable of being sustained for at least 60 seconds
- Class B: Response within 60 seconds and capable of being sustained for at least six minutes
- Class C: Response within six minutes and capable of being sustained for at least 15 minutes

3.2.2 Provision of Spinning Reserve Service

Section 2.2 of the Power System Operation Procedure (PSOP): Ancillary Services lists a number of technologies for the provision of SR. For example, Class A must be provided by one of:

a. *Droop governor response, in the case of Scheduled Generators; or*
b. *Automated under-frequency relays, in the case of Load Facilities.*

while Class B and C must be provided by one or more of:

c. *Droop governor response, in the case of Scheduled Generators; or*
d. *AGC response where appropriate (with signalling requirements as per System Management's AGC interface signal protocol); or*
e. *Automated under-frequency relays, in the case of Load Facilities.*

EY has reviewed the appropriateness of these sources in Section 4.2.

SR is currently procured predominantly from Synergy generators (as the default provider of SR), plus through contracts for System Interruptible Loads (SIL) and with one IPP.

3.2.3 Amounts currently procured

The SWIS Operating Standards stated in the Technical Rules describe the frequency performance requirements for the WEM. The SR standard stated in Clause 3.10.2 is intended to deliver performance consistent with the SWIS Operating Standards. The relationship and compatibility between these standards is explored in Section 5. Clause 3.10.2 of the Market Rules specifies the level of SR required as sufficient to cover the greater of:

- 70% of the total output of the generation unit synchronised to the SWIS with the highest total output; and
- The maximum load ramp expected over a period of 15 minutes.

The SR level carried is currently reduced by the amount of upwards LFAS procured, and can be relaxed by the following amounts in the following situations:

- Up to 12% if it is expected that the shortfall will be for a period of less than 30 minutes
- Up to 100% if all reserves have been exhausted and to maintain reserves would require involuntary load shedding.

The amount of each service procured is measured in MW of response over the specified timescale. The largest unit in the WEM is the 330 MW coal-fired Collie power station. When it is operating at full load, which is common in the WEM, this means that 240 MW (rounded up) of SR must be procured.

Section 10 presents modelling exploring the SR settings for the WEM and their impact on system frequency, while Section 5.1 explores the compatibility of the Clause 3.10.2 SR standards with the SWIS Operating Standards.

Synergy is the default provider of SR in the WEM, unless a less expensive alternative is offered by another eligible facility. Currently, 42 MW of System Interruptible Load (SIL) is procured from a single provider, with another 13 MW being negotiated [8]. Additionally, one IPP is now contracted to provide SR.

Due to the “lumpy” nature of unit commitment, and the broader balancing responsibility assigned to Synergy, in practice SR levels exceeding the minimum requirements are typically made available. System Management reported that the average enablement from 1/05/2012 to 30/04/2013 was 317 MW during peak intervals and 291 MW during off-peak intervals [8].

3.3 Load Rejection Reserve Service

Load Rejection Reserve Service (LRR) provides for the rapid reduction of generation in the event of a major loss of load event. This would typically be caused by a failure of transmission element such as a line or transformer, resulting in load disconnecting from the network.

3.3.1 Classes of reserve

LRR is procured on two time scales:

- Class A: Response within six seconds and capable of being sustained for at least 6 minutes
- Class B: Response within 60 seconds and capable of being sustained for at least 60 minutes

3.3.2 Provision of Load Rejection Reserve Service

Section 2.3 of the PSOP: Ancillary Services lists a limited number of technologies that may provide LRR. Class A and Class B must be provided by one of:

a. *Droop governor response; or*
b. *AGC response where appropriate (with signaling requirements as per System Management's AGC interface signal protocol); or*
c. *Local operator action to reduce power output of the Scheduled Generator, including by tripping the unit if required*

LRR is currently procured exclusively from Synergy generators. System Management manually schedules LRR to allocate it between Synergy generators. EY has been advised by System Management that it is not difficult to source the currently required amount of LRR from the Balancing Portfolio, however it should not be assumed that any increase would be simple or cheap to procure.

3.3.3 Amounts currently procured

As is the case for SR, the SWIS Operating Standards in the Technical Rules set the frequency performance requirements for the WEM. The SWIS Operating Standards are then reflected in Clause 3.10.4 of the Market Rules for LRR. The Market Rules have a less prescriptive standard for LRR than for SR:

> *3.10.4. The standard for Load Rejection Reserve Service is a level which satisfies the following principles:*
> *(a) the level sufficient to keep over-frequency below 51 Hz for all credible load rejection events;*
> *(b) may be relaxed by up to 25% by System Management where it considers that the probability of transmission faults is low.*

The failure of a large industrial load is not considered in setting the LRR requirement, as it has never occurred and has therefore been reclassified as a non-credible contingency. Based on an assessment of the historical losses of load, System Management has set the LRR requirement at 120 MW [8].

There is no requirement in the Market Rules that capacity enabled for LFAS be counted toward the LRR requirement (i.e., no corresponding clause 3.10.2(b) as for Spinning Reserve Service). However, System Management often counts the enabled Downward LFAS capacity, if it is being provided by Synergy, towards the LRR requirement. This means that the general LRR required is 48 MW (120 less 72 MW of Downward LFAS capacity) [8].

The LRR requirement could change if load growth occurs in areas weakly connected to the grid, such as Kalgoorlie [8]. This would increase the amount of load which could be lost as a result of a single transmission fault.

Section 11 presents modelling exploring the LRR requirement for the WEM and its impact on reliability, while Section 5.2 explores the compatibility of standards and requirements defined for this service in the Market Rules and Technical Rules.

3.4 System Restart Services

Clause 3.7.1 of the Market Rules requires System Management to make operational plans and preparations to restart the WEM in the event of a system shutdown. The System Restart Service is discussed in detail in Section 12.

4. Frequency Control requirements

In this chapter, EY has considered whether the current ancillary services and Market Rules fulfil the critical frequency control roles identified as necessary for the functioning of a large AC grid in Section 2.1. Comparisons are drawn with some of the international markets reviewed. The frequency control ancillary services that currently exist in the WEM were described in Section 3.

Appendix C contains a set of tables describing various properties of the international markets reviewed by EY. Section C.2 in particular contains details of how these markets fulfil the key roles needed for frequency control (that is, using the framework outlined in Section 2.1).

4.1 Regulation

4.1.1 Provision

In the WEM, the regulation service is delivered through LFAS. Section 2.1 of the PSOP: Ancillary Services requires providers of LFAS to respond to AGC signals, and this is the only accepted method of control. This is consistent with international markets, and EY recommends no change.

Additionally, System Management may dispatch additional generation (either fast-start units or spare capacity on operating units) in response to high or low frequency conditions. This provides an additional “coarser” form of regulation, and potentially reduces the total amount of LFAS procured. The implications of this are discussed further in Section 9.3.

4.1.2 Setting of requirements

In general, the required level of regulation response in a market is strongly dependent on the market characteristics, including dispatch interval, load volatility and penetration of variable renewables.

International settings

Regulation requirements can vary significantly depending on the nature of a system. Table C.5 shows the requirements in a range of international systems. EY has found that these requirements are typically set via operational experience and refined over time, rather than determined by way of a formal methodology. Internationally, reviews and recommendations for more dynamic setting of requirements are only under consideration or just beginning to be implemented.

In most markets, the regulation requirement is calculated in advance (ex-ante) and is typically set at a fixed value in all hours or over pre-defined time periods (e.g., peak, shoulder, off-peak, etc.) [9]. For example, in the PJM market, the regulation requirement (as of December 2013) is set at 700 MW in peak periods (5am to midnight), and 525 MW in off-peak periods (all other times). Although this provides a simple and transparent approach, a flat reserve level is likely to be insufficient for difficult periods and economically inefficient for low volatility/low ramp periods. Most markets allow the system operator to activate additional reserves if they are deemed necessary in real time.

In other markets, the reserve requirement is set through an empirical model, providing additional reserves at times of anticipated higher need. In the PJM market, the regulation requirement was previously set at 1.0% or 0.7% of the peak/off-peak system load [10]; the implicit assumption here is that the size of load fluctuations (needed to be covered by the regulation service) will be proportional to the system load.

The NEM regulation market uses a more sophisticated approach, where the regulation reserve is varied between a minimum and maximum level in response to the time error of the system [11]. These levels have been determined by the system operator (AEMO) through operational experience. In this case, the implicit assumption is that if the frequency cannot be stabilised over a protracted period, additional intra-dispatch interval reserves should be brought online.

Sculpted requirements

In the future, a more sculpted approach to procuring reserves will likely reduce total costs and provide clearer price signals to participants [12]. For example, the PJM Renewable Integration Study made a number of recommendations, including the procurement of additional regulation at times of high solar or wind, as determined by day- and hour-ahead forecasting.

In particular, when wind and solar are operating at low levels, their contribution to variability is also likely to be low. For wind, contribution to variability is likely to be highest when wind farms are operating at the midpoint of their power curve [9].

Currently, this type of sculpting is not common. California schedules regulation reserve separately for each hour of the day in the day-ahead market. The requirement is based on the forecast changes in generation, inter-ties, demand and the start-up or shut-down of units [13]. In the real time dispatch, more or less regulation can be procured as required due to outages or deviations in demand from the forecast. This system had teething problems when introduced in 2011, with 24 instances where the regulation energy scheduled in the day-ahead market could not be delivered in the real time market. The causes of these shortages were [14]:

- Inconsistent ramp rates used to schedule ancillary services
- Ancillary services scheduled which, due to changes in the energy market, would have resulted in a generator operating outside its capability
- Inability for the market to accept energy scheduled for one ancillary service to be used for another, e.g. using spinning reserves for regulation if regulation is scarce
- Load forecast errors requiring manual adjustment which disconnected the day-ahead market from the real time market
- Insufficient bids from other capable generators which would have been able to resolve shortages.

These issues have been mostly resolved, with only one scarcity event in each of 2012 and 2013. They highlight the complexities of implementing real time regulation requirements. There are a number of levels between the WEM's current static reserve requirement and California's day-ahead requirement settings.

Comparison to the WEM

Figure 4.1 and Figure 4.2 show the amount of regulation (LFAS) required in the comparable markets to the WEM, as a percentage of peak and annual average demand in 2012-13. Requirements in the WEM are broadly similar to the requirements in other markets based on either metric[3].

The regulation requirements for the mainland NEM in its entirety are much lower than in the WEM. This is to be expected due to the shorter dispatch interval in the NEM, and also the higher robustness of the larger system. The requirements for Tasmania and South Australia (when

[3] In the NEM, AEMO has determined the amount of load following required for the mainland and Tasmania separately in normal operation. This is because Tasmania does not have an AC connection to the mainland. There are also regulation requirements for subsets of the mainland NEM, if islanding should occur. The regulation requirement for an isolated South Australian system is also shown, but this is a rare occurrence.

isolated from the other regions) are higher than in the WEM due to the local penetration of wind relative to their size. New Zealand also has a five minute dispatch interval, which reduces regulation requirements.

California is not included in this chart due to the dynamic setting of its regulation requirements. The other markets surveyed do not explicitly procure regulation, but use the responsive generation procured for operating reserve and the mandatory governor response of units to maintain a stable frequency.

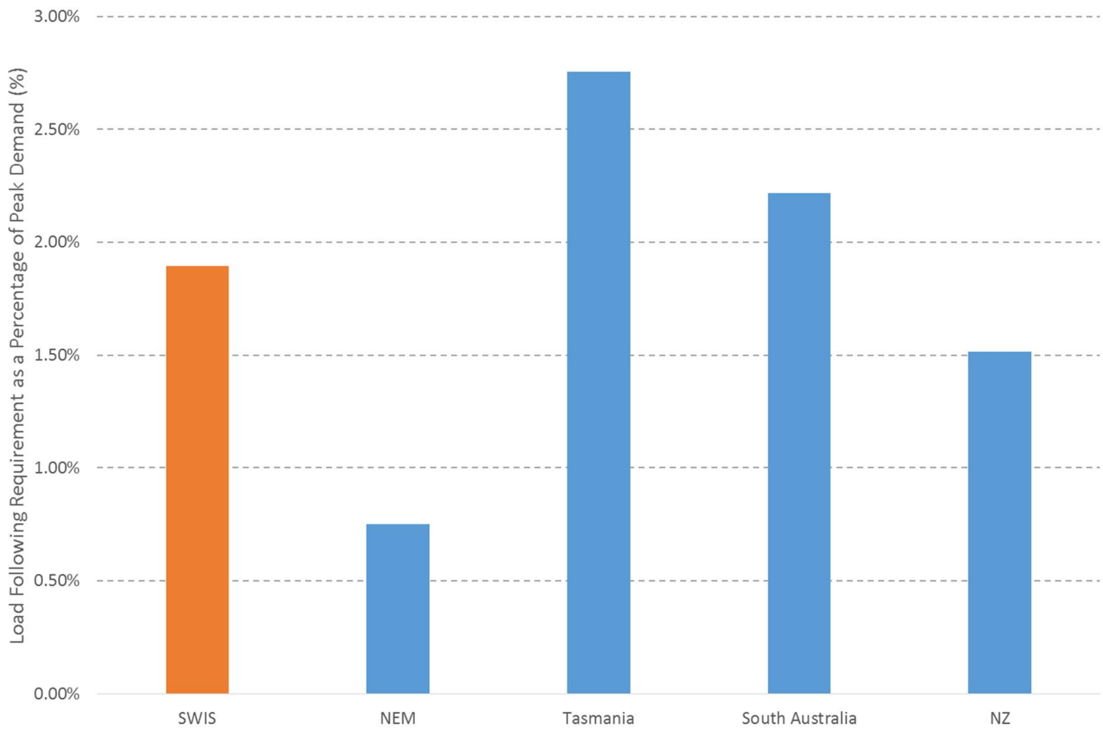


Figure 4.1 – Load Following Requirements as a percentage of peak demand

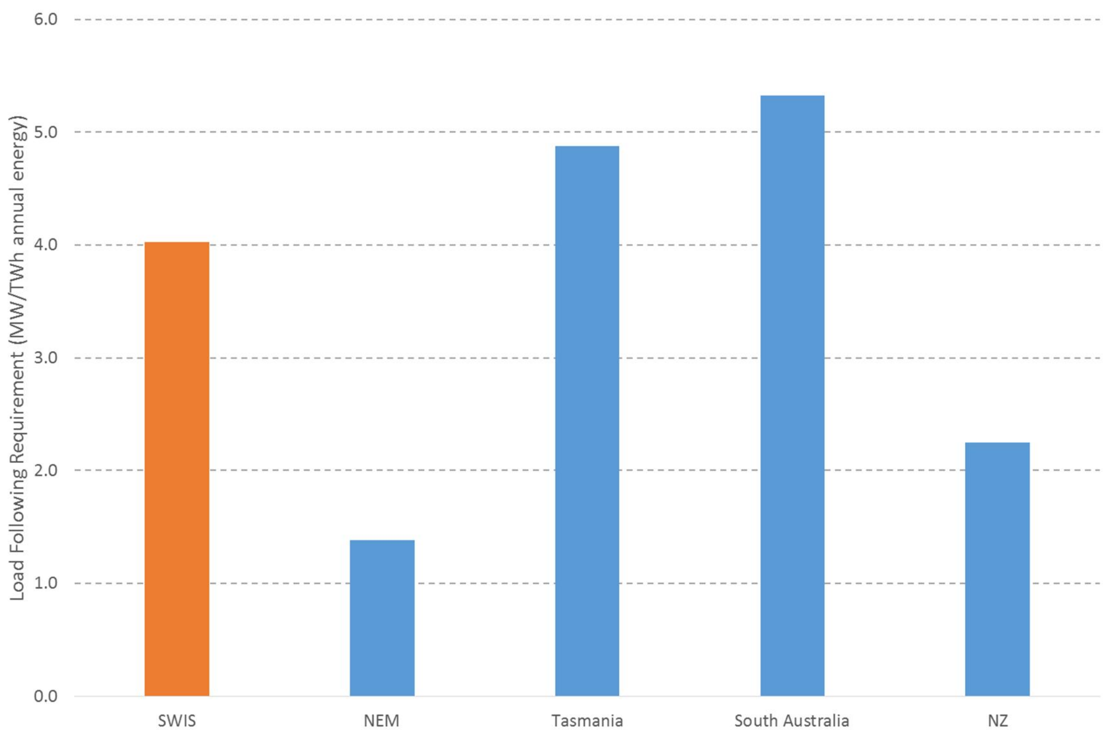


Figure 4.2 – Load Following Requirements as a percentage of average annual demand

4.1.3 Timescales of response

In the WEM, generators receive AGC signals up to every four seconds. This is consistent with international markets, and operational experience suggests it provides a sufficient resolution of control for providing the service of regulation.

4.1.4 Dispatch of LFAS

In real-time, the actual provision of LFAS (i.e., the directed reduction or increase in output from LFAS providers) is dictated by a control algorithm that assesses the current frequency deviation as well as the recent cumulative time error. The parameters of this algorithm are set based on operational experience, as is the case in all markets, and provide a balance between rapidly correcting frequency changes and being overly sensitive and thus risking sending the frequency in the opposite direction. EY considers the current approach to be appropriate.

4.2 Primary response in the WEM

4.2.1 Provision

Primary response in the WEM is provided through the following mechanisms:

- SR for under-frequency events and LRR for over frequency events;
- Load relief;
- Mandatory governor response; and, if necessary,
- Load shedding.

Of these responses, only SR and LRR are procured as an explicit service. This is due to the following factors:

- the level of available load relief is not under System Management's direct control;
- mandatory governor response is a requirement of participation in the market, and;
- load shedding is used if necessary to prevent large frequency drops (as is the case in all markets).

SR and LRR are the methods with which System Management provides the remainder of the required primary response not provided by these mandated responses, and are therefore the focus of this section of the report.

The physical delivery of SR and LRR is currently provided by way of governor response or the triggering of interruptible loads by under-frequency relays. This is consistent with the international markets surveyed where primary response other than load relief is physically delivered by one or more of:

- the physical governor response of generators;
- the tripping of interruptible loads; and,
- in rare cases, the tripping of generators.

EY notes that, in general, tripping a generator is not a desirable form of primary response, as bringing a unit back online can take an hour or more. However, sometimes this can be the best option available. In the region of Tasmania in the NEM, a special protection scheme exists which will trip generation in the event of a loss of the Basslink DC interconnector when it is exporting to the mainland, due to the large size of the interconnector (which may be exporting up to 630 MW) relative to the Tasmanian system size (peak local load is 1,756 MW) [15]. Tripping of generation provides a rapid rebalancing of local supply-demand in Tasmania. In many markets, however, including the current WEM, the necessary amount of LRR is able to be procured from other sources. However, this is highly specific to the nature of the load in a system, and therefore this may change in the future.

Currently, the allowed methods of provision are listed explicitly in the PSOP: Ancillary Services (Section 3.1). EY believes that this is a source of potential misunderstanding for the provision of these services. For example, primary response cannot be provided by a unit solely responding to AGC signals, as the timescale of such response are not adequate. However, a provider of primary response can still respond to AGC signals, meaning it may also provide additional services to the market such as secondary response or regulation.

As another example, emerging technologies (such as storage) that do not have AGC or governor response may still be able to provide primary response through a different mechanism. EY does not see a compelling reason to artificially exclude these sources from providing primary response.

EY therefore questions whether it is necessary to prescribe, even in the PSOPs, the specific technologies for the provision of this and other ancillary services, as opposed to an "outcomes based" definition. Internationally, markets are moving towards a more "technology neutral" approach to the provision of ancillary services. For example, NERC [4] describes primary response sources as any source which can "provide an immediate response based on local (device-level) control systems".

Recommendation 1 – Ensure requirements for ancillary services facilities are technologically neutral
The Market Rules and Power System Operation Procedures (PSOPs) currently include lists of allowed provision methods for ancillary services. For example, facilities providing Spinning Reserve are currently limited to the methods set out in Sections 2.2.6, 2.2.7 and 2.2.8 of the PSOP: Ancillary Services. Setting these methods out explicitly could preclude the same services being provided by another technology in a different manner. This creates unnecessary conflict between the clearly defined "performance" standards (including response times and sustain periods) and the technical implementation. EY recommends that the definitions in the Market Rules and/or PSOP: Ancillary Services be revised to be based on performance requirements, rather than explicit methods of provision. This will ensure that emerging providers of ancillary services (such as those discussed in Section 8.2) can compete on an equal footing, and encourage competition in line with the Wholesale Market Objectives. The current list of permitted technologies could be provided in a comment box or similar in the PSOP: Ancillary Services as examples of the possible ways that these services could be provided. EY notes, however, that the introduction of non-conventional providers could incur additional costs for the market. For example, providing LFAS through a communication method other than AGC could require significant changes to System Management's systems and procedures. Therefore, the PSOPs may still need to impose some technology requirements on providers, and appropriate cost-benefit analysis would need to be undertaken for any new procurement methods.

Provision of governor response by other units

In the WEM, all synchronous generators are required to enable their governors (if technically viable) and hence contribute to primary response. After an initial response (approximately 10 seconds), local control loops are expected to restore generator output to its setpoint, even if that change is in a direction that hinders frequency recovery. Only units enabled for SR/LRR continue their governor response for the duration of the event.

This is consistent with many international markets, particularly markets in the US, where mandatory governor response is a condition of connection. This may be used in place of a primary response market, with mixed success [16]. In these systems, this response may be limited, whether because generators run un-throttled (controlling output by steam supply) or because of outer-loop control systems designed to return the generator to its setpoint. [17]

For example, in studies of the US Eastern Interconnection portfolio, nearly 80% of units should theoretically be providing fast response; in practice, modelling only 32% of units responding provided a better fit to observations. [16]

Similar to the WEM, most generators in this market return to their setpoints, withdrawing some of this primary response. This can lead to situations where primary response initially arrests the frequency, but as the response is withdrawn the frequency falls again until the secondary response can be activated.

Because of these, and other, complications, many systems are now proposing explicit markets for procuring primary response [18].

In contrast to such markets, the NEM does not mandate that units enable their governors. Furthermore, although it is expected that generating units providing the fastest primary response services (the *fast raise* and *fast lower* services) will deliver this by enabling their governors, they are not obligated to; providers of ancillary services are free to use any technology, provided it delivers the required response. In practice, many generators in the NEM do leave their governors enabled, providing additional system support.

The SR requirements in the WEM have been set based on the desired levels of performance even in the absence of the system wide governor response. EY therefore does not recommend changes to procedures at this time. In particular, EY does not recommend relying on mandated governor response for the WEM's primary response.

Recommendation 1A –Ensure that all generators meet prescribed governor settings
In accordance with the Technical Rules, all generators in the WEM are required to enable their governors (if technically viable), and adopt deadband and droop settings as specified by System Management. If some generators are not conforming (e.g., by applying a wider deadband setting than specified), a disproportionate burden for controlling frequency excursions will fall to those generators that are compliant, EY recommends that System Management confirm that all generators are meeting their connection requirements with respect to governor settings.

4.2.2 Setting of requirements

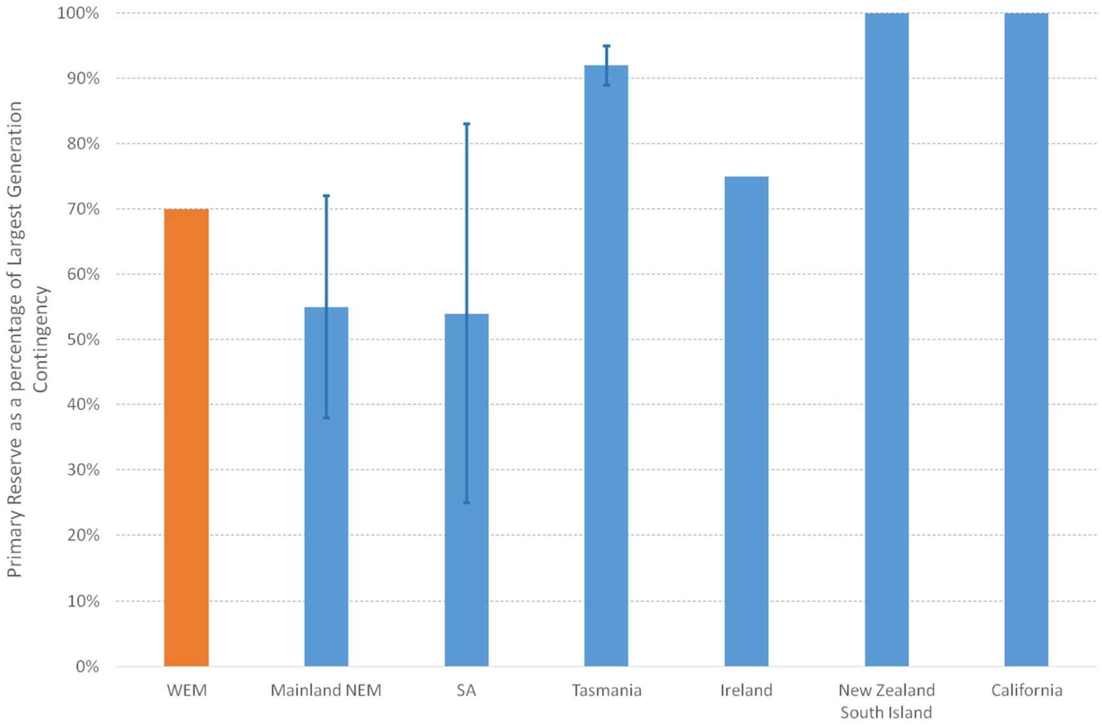
The purpose of primary response is to arrest a significant frequency deviation and in doing so, avoid tripping of generators and load (including load shedding). This is typically defined in terms of minimum and maximum frequency values that the frequency must be contained to following a single credible contingency, and a timeframe in which frequency must be restored to 'normal' levels. Other boundaries may be set for multiple contingency situations. Various methods may be employed to determine the amount of primary response that must be procured to deliver this performance. The values will vary (as listed in Table C.5) but can often be expressed in terms of the percentage of the largest credible contingency. In many cases, reviews and recommendations for more dynamic setting of requirements are only under consideration or just beginning to be implemented.

The majority of markets reviewed by EY have a dynamic setting for contingency reserve requirements based on the largest credible contingency event, similar to the WEM. Requirements for primary response are designed to limit load-shedding for a single credible contingency [19] in all markets surveyed with the exception of the WEM, which does allow some load shedding after a very large single credible contingency.

Many of the markets reviewed have primary response requirements that are less than 100% of the largest credible contingency. In most cases, this is due, either implicitly or explicitly, to the contribution from load relief (and in the case of the WEM, load shedding).

For example, in the NEM [20], the *fast* and *slow raise* requirements are given by the largest contingency risk net of the expected load relief (which is calculated based on different frequency conditions for each service).

Figure 4.3 shows the primary response provided by a number of markets as a percentage of the largest credible generation contingency. In practice, operational experience will inform these assessments, as the response timescales and the quantity of system inertia also play a role in determining the system response. This may mean future systems need higher or lower levels of reserves.

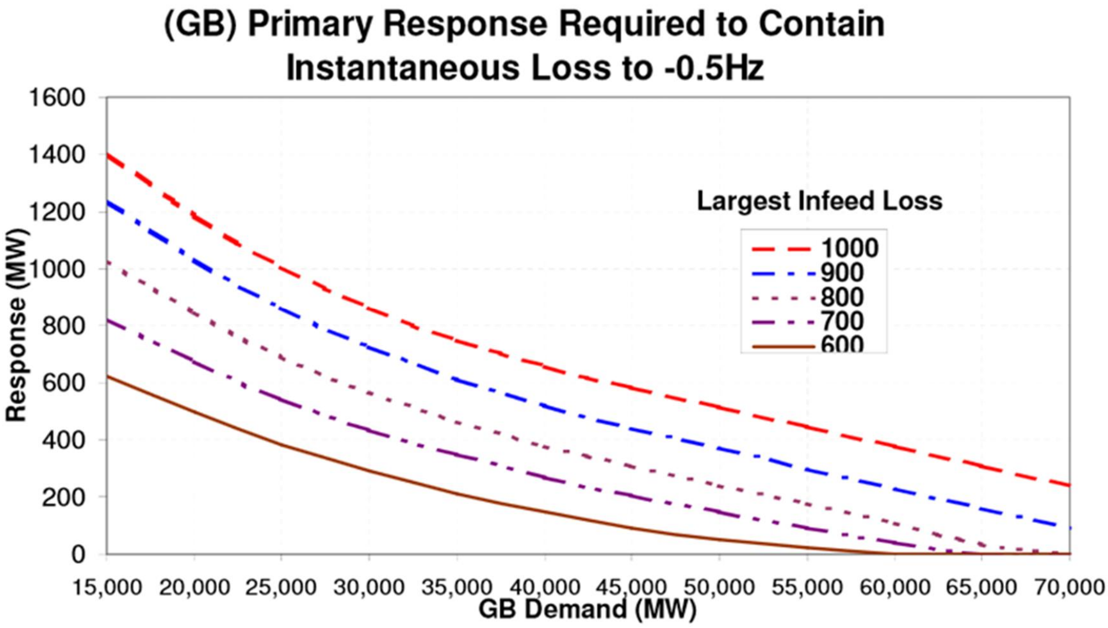


Uncertainty bars indicate requirement varies with system load

Figure 4.3 – Primary response as a function of largest credible generation contingency

The error bars for the NEM data points reflect the fact that the *fast raise* requirements are varied based on the system load at the time, which varies considerably in the mainland regions. *Fast raise* requirements are also presented for Tasmania, which has a more relaxed frequency standard than the mainland, and South Australia in the event of islanding. If South Australia is islanded, its frequency standard is relaxed even more. The relaxation of the frequency standard means that there is more load relief available as the frequency can deviate further from 50 Hz before the frequency standard is breached. Of critical importance is that under frequency load shedding settings are configured in line with varying acceptable operating frequency bounds.

The Great Britain market has a similarly variable requirement for its primary response (Figure 4.4), which is set to limit frequency movement to 0.5 Hz on a single contingency event [21].



Reproduced from [21]

Figure 4.4 – Primary response in Great Britain market as function of demand and contingency size

EY therefore finds that the qualitative requirements of the WEM (that is, procuring less than the size of the largest contingency) are consistent with international best practice. The specific parameters for the WEM, and whether they fulfil the appropriate standards, are explored in more detail in Sections 10 and 11.

Load Rejection Reserve

In general, the above discussion is applicable to both raise and lower primary response services (SR and LRR in the WEM), although it is often more difficult to quantify the largest credible loss of load event. For example, in Ireland and California, the primary response requirement is symmetrical (up and down) while in Spain, the downwards response is 50-100% of the upwards response, depending on system demand. The NEM is one of the few markets which evaluates the loss of load likely on a single network contingency every dispatch interval, with appropriate reserves procured for each interval.

4.2.3 Timescales of response

Classes of service

As described in Section 3.2.1, a portion of primary response in the WEM is provided through SR and LRR. The Market Rules define three classes of SR (Class A, B and C) and two classes of LRR (Class A and Class B).

Although primary response can be provided by a single service (for example in Germany and the UK), this requires providers to be able to provide a response that is both rapid and sustained. For example, in Germany, primary response must be fully activated within 15 seconds and be sustained for 15 minutes. This potentially imposes overly onerous requirements on a single provider, or more importantly, prevents the possibility of sourcing the service from providers that cannot physically meet these requirements in the entirety.

Splitting the required primary response into separate timescales is likely to provide clearer signals to markets and be more efficient, even if the same capacity is used to provide multiple services. This allows generators to provide their maximum feasible response to the market. For example, steam-turbines may not be able to sustain response for long durations, and hydro generators with large head heights may have delays associated with the time it takes water to travel from the reservoir down to the turbines.

Although all classes of SR/LRR are currently provided by the same units, EY considers that maintaining these separate classes provides valuable flexibility for the system and the potential for increased market participation and therefore competition.

Overlap of services

In general, EY considers that non-overlapping services (where overlap is defined by the timescale of full deployment) provide the most efficient delivery. For example, the NEM ancillary services include *fast* and *slow* raise and lower services, with explicit requirements on how the “handover” between services should be managed.

The current WEM Rules for the SR are interpreted to include a six second overlap between Class A and Class B provision, and a 60 second overlap between Class B and Class C. If these services are ultimately provided by different entities, this will result in periods where an excess of SR response will be available. However, these periods of overlap will be brief, and not likely to be a source of significant market inefficiency.

The two classes of LRR have a similar structure, but the overlap is approximately five minutes since Class A must sustain for 6 minutes but Class B must be available within 60 seconds. EY considers that this overlap is unnecessary. This overlap could be eliminated by making the Class A LRR sustain time shorter, or by making the Class B response time later. The best approach may be to revise the response and sustain settings to line up with existing consequential timings.

Recommendation 2 – Eliminate time overlap in Load Rejection Reserve Service
EY recommends eliminating the overlap in the two classes of the Load Rejection Reserve Service. EY favours setting the Class A response and sustain times to 6 seconds and 2 minutes respectively, which lines up with the first over-frequency event restoration time stated in the SWIS Operating Standards. EY favours setting the Class B response and sustain times to 2 minutes and 30 minutes respectively to eliminate the overlap with Class A and to tie-in with the Balancing market trading interval period. EY also favours reducing the Class A sustain time over extending the Class B response time because it is more likely to allow future technologies such as storage to participate. This reduces the potential for future duplication or over-provision of the Load Rejection Reserve Service, and also avoids discrimination against emerging technologies, which is consistent with Wholesale Market Objectives (c) and (d).

Response time requirements

The fastest response class of both SR and LRR requires providers to respond within six seconds of a contingency event. This is consistent with the majority of international markets, where a primary response must be provided within 5-10 seconds (but up to 30 seconds for large disturbances), thereby limiting the absolute drop in frequency. The required minimum response is, in all systems, set by the system operator based on past experience and engineering calculations.

EY considers that these response times reflect both system requirements and practical limitations. In particular, turbine governor response is typically delivered in a few seconds, limiting the speed with which a traditional system can respond.

The SR and LRR response times are adequate if there is sufficient inertia in the system such that the supply-demand balance can be re-established before the frequency falls or rises beyond those levels. Based on operational evidence, including modelling conducted by EY reported in Sections 10 and 11, the current response times and typical system inertias in the WEM (and international markets) are sufficient to maintain the published frequency standards.

Furthermore, the frequency modelling and data analysis undertaken in this review by EY suggests that these response times are consistent with the physical capabilities of the current WEM plant and, that such response is physically able (at least at present) to maintain the system frequency within the limits provided by the Market Rules.

EY therefore considers that the response times for the fastest SR and LRR classes are appropriate for the current review period, and consistent with international markets. The appropriateness of the separate classes and the sustain times are explored in subsequent sections.

Sustain time requirements

Once the frequency is stabilised, the primary response must be sustained until alternative reserves can be brought online. Generally, a sustain time of 10-30 minutes is found to be sufficient in the markets surveyed by EY, with the length of their dispatch interval often being a significant determining factor.

There may also be physical limitations associated with a specific source of response. For example, greater output of steam turbines in the short-term comes at the expense of lower steam pressure, and cannot be sustained without additional action. This reinforces the rationale for defining higher “resolution” services.

The WEM Technical Rules state that the frequency must recover to the normal operating band of 49.8 – 50.2 Hz within 15 minutes. If this operating standard is achieved, it will mean sufficient secondary response has been provided and no further primary response will be required beyond this point. Therefore the 21 minute sustain time of Class C would be sufficient. Furthermore, the Class C sustain time is sufficient to cover the maximum time between dispatches (10 minutes) plus a reasonable ramping period for additional online units to ramp up. Similarly, it would be sufficient for a fast-start unit to be dispatched.

EY considers this to be sufficient time for System Management to issue dispatch instructions to these units, such that they will transition to providing a secondary response as the frequency is restored[4], or to dispatch spare capacity on alternative units. Importantly, 15 minutes would be sufficient time to bring a fast-start unit online if necessary to provide additional secondary response (that is, to inject energy into the system). Class B provides a bridge between Class A and C services.

Therefore, EY expects that the current sustain period of 21 minutes for Class C SR is sufficient and consistent with international best practice.

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[4] Without any revised dispatch instructions, these units could be expected to decrease their output as the frequency is restored and, at best, would be required to return to their pre-contingency setpoint after the sustain time specified in the PSOP: Ancillary Services.

Class B LRR must be provided for up to 66 minutes. This is likely to be in excess of the minimum level required to maintain system frequency, as regular system dispatch should be able to ramp down or shutdown excess generation over that timescale. However, LRR should generally be less onerous than SR because a reduction in plant output is generally more readily available and easier to sustain, for example by units being run at their minimum loads for extended periods. This is consistent with international experience (e.g., [4]).

EY therefore does not propose any changes to the LRR Class B sustain period, but we note that if a market for LRR is introduced in the future, this timescale should be reviewed to ensure this requirement is not discouraging potential providers.

Future conditions

Lower levels of inertia may result in faster frequency falls after a contingency, and system frequency may rise or fall to levels that would cause involuntary load or generator shedding before the primary response can respond. Therefore, some markets have proposed the introduction of faster timescale ("very fast") primary response markets. For example, ERCOT has proposed a Fast Frequency Response service [22] which would be expected to "provide instantaneous increase in active power output from a Resource or instantaneous reduction in demand, following a frequency event that is fully deployed within 30 cycles (0.5 seconds) at a specified frequency threshold and sustained for at least 10 minutes". This could be achieved through storage [23], or load response from sources including aggregated domestic air conditioners or commercial refrigeration [24].

Establishing a separate market also acknowledges that sources of very fast response are likely to be more valuable (on a per-MW basis), particularly to low inertia systems; that is, very fast response reserves can better maintain the frequency standard, because they can stabilise the frequency faster, limiting the initial drop.

EY notes that interruptible loads in the WEM currently respond within 0.5 seconds. If additional interruptible loads can be procured under the current SR requirement, this would be expected to improve the resilience of the WEM to contingency events.

An alternative or complementary approach to managing low inertia conditions is to impose a minimum requirement on system inertia, an approach also considered by ERCOT. A very fast reserve market may not eliminate this requirement, but would reduce the necessary inertia levels.

In the future, new generation will not necessarily have the same response patterns as existing generation. New generation types may show a faster response (for example, storage and inverters may be able to respond in less than a second) but for shorter periods of time (for example, wind farms may be able to provide additional output within 6 seconds or less, but not sustain it for the full 60 seconds). Higher resolution markets allow each generator to contribute its capabilities and thus drive increased competition in the market(s).

Recommendation 3 – Monitoring emerging ancillary services markets
Changing conditions in the WEM, such as decreased inertia levels, or increased variability in net load, could increase the vulnerability of the WEM to frequency drops, even if Class A Spinning Reserve is available. Several markets are investigating the creation of explicit markets for shorter timescale primary response, to cope with these pressures. EY does not consider there is a need for additional ancillary service markets in the WEM within the current review period.

EY recommends that the IMO continue to monitor the proposed changes to ERCOT and other ancillary service markets, with a view to the longer-term implementation of a shorter timescale Spinning Reserve Service.

This will assist the WEM in accepting an increased penetration of renewable energy sources, in line with Wholesale Market Objective (c).

4.2.4 Governor droop and deadband settings

International markets typically use droop settings of between 4% and 5%, compared to the WEM's 4% setting. Wider droop settings provide greater response to a given frequency change, and therefore a tighter envelope, but at the risk of an overly variable system frequency. Narrower deadband settings result in tighter frequency control, but at the expense of greater wear and tear on units, which is generally undesirable.

The WEM deadband setting was found to be consistent with international settings. Therefore EY does not recommend any changes to these settings at this time.

4.2.5 Counting LFAS towards SR/LRR

Upwards LFAS versus Downwards LFAS

Under the present Market Rules, Upwards LFAS is counted towards meeting all classes of the SR requirement (Clause 3.10.2 of the Market Rules), while downwards LFAS is *not* explicitly counted towards meeting the LRR requirements. In practice however, System Management currently does take the quantity of downwards LFAS enabled into account when ensuring that the LRR requirement is met [8] which EY considers to be consistent with, but not prescribed by, the LRR standard in Clause 3.10.4 of the Market Rules.

EY does not consider there to be a valid reason for this discrepancy in the Market Rules and therefore this should be resolved, independent of whether the additional aspects of are adopted.

Provision of SR/LRR by IPP providers of LFAS

Providing LFAS and SR/LRR involves distinct requirements: LFAS providers must respond to AGC signals, while SR/LRR providers (at least Class A) typically utilise a local control system such as governor response or an under-frequency relay.

If LFAS is provided by Synergy units, EY has been advised that the Synergy units currently have their governors enabled and most have their control systems set to provide a sustained governor response following a contingency. Therefore, they will be able to provide SR/LRR in addition to LFAS.

In the future, however, providers of LFAS may or may not be able to provide SR/LRR. For example, plants may not be able to provide appropriate SR response (or less than their LFAS response) in an appropriate timescale, or may exceed emissions limits if they were to do so.

Furthermore, non-Synergy providers of LFAS are currently expected to act like other IPP units and quickly act to restore their output to the setpoint dictated by their AGC signal after a governor response, if such a response is actually provided. These units may *not* therefore be providing the required SR/LRR, even if they are technically capable. However, the requirement for a sustained response from governors would typically be accompanied by an increase or decrease in required LFAS generation; if so, AGC signals would direct the generators to maintain their output, or to return to that level as soon as they are able.

Risk of unavailability of Spinning Reserve and Load Rejection Reserve Services

An important distinction must be made between the level of SR/LRR procured and the level of response actually available. In particular, if units enabled for LFAS are also counted towards the SR/LRR requirements, there will necessarily be periods of the year when those LFAS units will not physically be able to provide those services, as their capacity will have already been utilised in the provision of LFAS.

For example, a unit providing Upwards LFAS may be dispatched to its maximum in response to rapidly rising demand; if a generator trip occurs at this time, it will not be able to contribute any additional energy to arrest the system frequency. In effect, its maximum possible SR contribution is zero.

As an example, Figure 4.5 and Figure 4.6 show the availability duration curve of actual SR response under two scenarios: a large contingency scenario (330 MW) and low contingency scenario (150 MW). Assuming that 72 MW of LFAS is enabled and the same capacity is counted towards the SR, these figures show the actual amount of response that could be called upon following a contingency[5].

Both figures show that total procured level of response would only be available for approximately 35% of the year. Note that occasionally, excess response would be available due to LFAS units being ramped down to below their setpoint. Under a low contingency, less than half the level of SR required to avoid load shedding would be available. This would increase the risk of load shedding on a single contingency.

[5] These charts based on EY's modelled LFAS usage, rather than actual historical usage, but should be representative of real conditions. We note that in our modelling, LFAS use is asymmetric, i.e., upwards LFAS is utilised more than downwards LFAS. This is discussed in Section 9. A more symmetric usage changes the quantitative but not qualitative result.

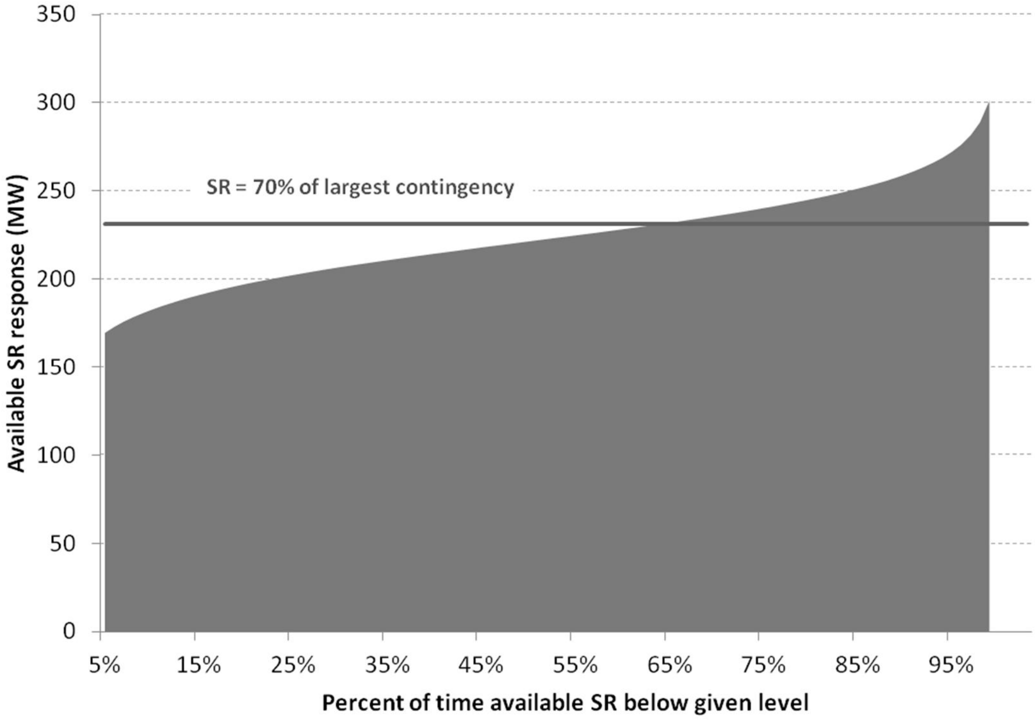

Figure 4.5 – Actual availability of SR if LFAS counted towards SR (high contingency period)

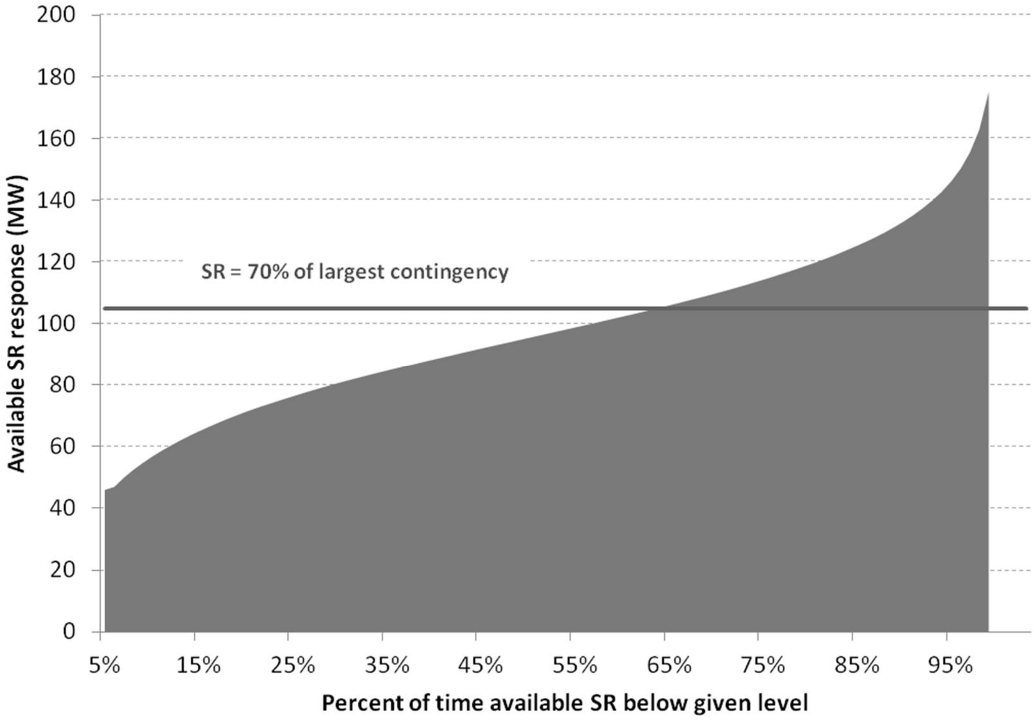

Figure 4.6 – Actual availability of SR if LFAS counted towards SR (low contingency period)

The above analysis is generally applicable to LRR as well, although the requirement for this service (relative to the contingency size) is less prescriptive in the Market Rules.

International markets

EY's international benchmarking exercise found examples where regulation services are not counted towards primary response. For example, the NEM does not allow plant providing the *regulation* services to contribute to the primary response services (the *fast and slow raise* and *lower* services).

These markets typically do however include any regulation service as part of their secondary response for planning purposes. For example, the NEM does allow *regulation* services to contribute to their secondary response markets (the *delayed raise* and *lower* services).

Impact on the WEM

The contribution of LFAS towards the SR/LRR requirements is potentially troubling, particularly if, in the future, the LFAS quantity becomes larger or contingency sizes are regularly smaller.

One possible resolution is to *not* to count LFAS towards these services. This would ensure that the desired level of SR/LRR is procured at all times, and would likely drive an increase in system reliability at the expense of increased system costs.

However, the majority of contingency events are likely to be smaller than the largest allowed contingency. Accordingly, the largest generator contingency occurring at the same time LFAS is fully utilised is rare and should not be considered a "single contingency" for planning purposes. Therefore, the additional cost associated with excluding LFAS capacity from contributing to SR may not be justified. There is already precedence for a relaxation of the total SR requirement, in the form of Clause 3.10.2(c), which allows for a partial relaxation for a brief period, especially if this would reduce the need to bring on an expensive fast-start generator.

An alternative, intermediate, option would be to specify a minimum level of SR/LRR response that must be provided by facilities that are not also providing LFAS. This would ensure that this level of response would be available at all times. This would represent a moderate change to the Market Rules, and would require a revision of the settlement equations.

Ultimately, operational experience will determine whether or not the impact on WEM reliability is likely to be significant. The cost of procuring additional SR/LRR (if LFAS is not counted towards those services) will need to be weighed against the risk and cost of load shedding.

Recommendation 4 – Alter the treatment of LFAS providers in SR and LRR to be consistent and cognizant of constraints on the delivery of the services
Under the current Market Rules, Upwards LFAS is explicitly counted towards the SR requirement, but there is no corresponding provision for Downwards LFAS to count towards the LRR requirement. In reality, some LFAS facilities can and do provide both SR and LRR in addition to LFAS. On the other hand some LFAS providers may not be able or willing to provide either SR or LRR on technical or economic grounds. Further, if units enabled for LFAS are also counted towards the SR and RR requirements, there will necessarily be periods of the year when those LFAS units will not physically be able to provide the service, as they will have already been partially or even fully utilised in the provision of LFAS. However, to exclude providers of LFAS from SR/LRR will increase the costs of ancillary services in the WEM.

Given that operational experience has not identified a significant problem related to SR and LRR availability, and that ancillary services costs are already perceived as high in the WEM, EY's opinion is that it is reasonable that the WEM continues to allow LFAS facilities to provide SR or LRR at the same time, provided the facilities are technically able to do so.

Therefore EY recommends that the Market Rules be revised such that IPP LFAS providers are not automatically assumed to provide SR and LRR. System Management should be able to use the same facilities to meet the requirements if they are technically and contractually able to do so, but the Market Rules should not assume that this will always be the case.

As SKM recognized in their 2009 review, increased LFAS usage will increase the likelihood of a contingency event coinciding with near maximum LFAS usage. This means that LFAS usage should be carefully monitored and reviewed moving forward to determine whether LFAS usage approaches its maximum feasible levels increasingly often, in which case the WEM may be at risk of breaching the SWIS Operating Standards. Should this risk increase significantly, then EY recommends that introduction of a limit on the proportion of SR and LRR that may be provided by LFAS.

4.3 Secondary response in the WEM

The purpose of secondary response is to return the frequency to the normal frequency range after the primary response has arrested the change in frequency.

4.3.1 Provision

In the WEM, no explicit market or service exists for secondary response. Secondary response is provided, in practice, from a number of sources, including:

- Units providing SR/LRR adjusting their control settings in response to dispatch instructions from System Management, including through AGC signals, such that they will maintain their response (previously provided through governor response) even as the frequency recovers;
- The ramp up or down of units providing SR/LRR beyond the response provided by governor response, provided spare capacity is available (i.e., the available headroom on the unit was not fully used in provision of the primary response);
- The ramp up or down of other units in the system, but particularly in the Synergy portfolio, to assist with restoring the frequency. This includes capacity reserved under the Ready Reserve Standard (Clause 3.18.11A of the Market Rules);
- For an under-frequency event, starting up fast-start generators, such as gas turbines. This includes capacity that System Management must ensure is available under the Ready Reserve Standard (Clause 3.18.11A of the Market Rules).

Figure 4.7, provided by System Management, demonstrates the handover of primary and secondary responses for a Synergy gas-fuelled unit:

- The rapid increase in output in response to a drop in frequency (primary response). This response is expected by all generators in the WEM;
- The continued smooth rise in output, limited by its ramp rate, while the frequency remains depressed at 49.5 Hz (secondary response). Units not providing SR would be expected to return to their dispatch setpoint at this time;
- The continued rise in output even as the frequency is recovered, demonstrating the conversion of its primary response to secondary response. Providers of SR not receiving

other instructions would typically be expected to return to their original setpoints as the frequency recovers;

- Its sustained output once the frequency recovers (secondary response);
- The reduction in its output over time as either additional replacement generation sources are brought online or load decreases (load and other generators not shown on this diagram).

Also not shown on this diagram are the primary and secondary responses from other generators, which would have also contributed to the frequency recovery.

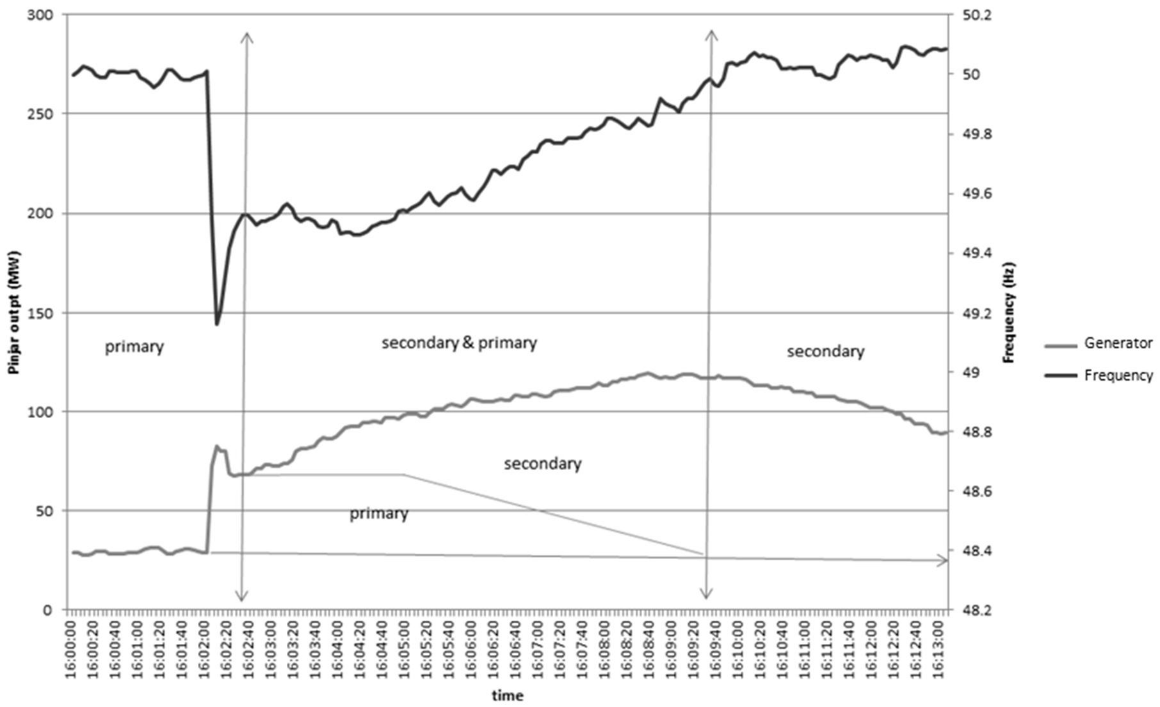

Figure 4.7 – Transition of a primary response to a secondary response

Secondary response is controlled by System Management through AGC and manual dispatch instructions. This includes both spinning- and non-spinning reserves, such as fast-start plant that can be started remotely by System Management.

4.3.2 Setting of requirement

All international markets reviewed by EY require that the full capacity of credible contingencies be able to be replaced within a reasonable timeframe. That is, that the secondary response must deliver an equivalent capacity to the size of contingency without support from load relief or load shedding.

This is in contrast to primary response, where load relief (and, in the WEM, load shedding) may be acceptable responses. In general, load relief is only counted towards primary response. For example, in the Irish markets, primary response (POR and SOR[6]) is set at the level of 75% of the

[6] POR (Primary Operating Reserves) and SOR (Secondary Operating Reserves) are both primary reserves within the context of this report, being sourced through local frequency detection such as governor response (see, for example, item 14 of [151])

largest contingency [25], while secondary response must be 100% of the largest contingency. This is because in order to recover the system frequency, the full replacement capacity must be available from the secondary response.

EY therefore considers the WEM Ready Reserve Standard, as discussed below, to be appropriate.

4.3.3 Timescales of response

The WEM frequency must be returned to the normal operating range within 15 minutes of a single contingency event. Therefore secondary response must be provided to restore the frequency within this time frame. Secondary response must also be provided before any primary response expires, however as the minimum sustain period of the SR/LRR response is 21 minutes, this is not a limiting constraint.

Any secondary response must be sustained until alternative resources can be brought online. Internationally, this varies significantly, depending on the dispatch interval in the market, the flexibility of alternative supply, and the relative costs. WEM sustain times are discussed below in Section 4.3.4.

4.3.4 Delivery and control of secondary response

LFAS assist

As described by System Management, a number of units in the WEM are set to what is called an "LFAS assist" mode, which means they will receive and respond to AGC instructions when the frequency is outside the normal operating range (i.e., 49.8 to 50.2 Hz). Instructions to increase or decrease their output, at the specified ramp rates, will automatically be issued after a contingency.

System Management has advised that units enabled for SR and LRR are set to operate in this LFAS assist mode if they are connected to the AGC. Therefore, in the event of a contingency, it is likely that these units will be utilised at least temporarily to provide secondary response.

EY considers that this is an appropriate response, although System Management is not restricted to providing secondary response through these units. In particular, if sufficient alternative capacity is available and it is more economical to dispatch than the SR/LRR units (as determined by the BMO), EY understands that System Management would dispatch this capacity in preference. Units not on LFAS assist, including SR/LRR units not be connected to the AGC system, would provide response as directed by System Management including through telephoned instructions.

While providing a secondary response, units enabled for SR/LRR would *not* be available to provide the SR or LRR if a new contingency event were to occur. EY considers this an acceptable outcome, given the Ready Reserve Standard discussed below.

The Ready Reserve Standard

SR provides up to 70% of the largest credible contingency (see Section 10), with the remainder of the response being provided by load relief or, if necessary, involuntary load shedding. Therefore, additional response from the system is required to inject additional energy to restore the frequency to the normal operating range and recover the load relief and/or load shedding.

System Management is required to ensure that this additional capacity is made available through the Ready Reserve Standard:

3.18.11A. The Ready Reserve Standard requires that the available generation and demand-side capacity at any time satisfies the following principles:

(a) Subject to clause 3.18.11A(c), the additional energy available within fifteen minutes must be sufficient to cover:

i. 30% of the total output, including Parasitic Load, of the generation unit synchronized to the SWIS with the highest total output at that time;

ii. plus the Minimum Frequency Keeping Capacity as defined in clause 3.10.1(a).

(b) Subject to clause 3.18.11A(c), and in addition to the additional energy described in clause 3.18.11A(a), the additional energy available within four hours must be sufficient to cover:

i. 70% of the total output, including Parasitic Load, of the generation unit synchronized to the SWIS with the second highest total output at that time;

ii. less the Minimum Frequency Keeping Capacity as defined in clause 3.10.1(a).

(c) System Management may relax the requirements in clause 3.18.11A(a) and (b) in the following circumstances:

i. where System Management expects that the load demand will be such that it exceeds the second standard deviation peak load forecast level, as described in clause 3.17.9(a), used in the most recently published Short Term PASA for that Trading Interval;

ii. during the four hours following an event that has caused System Management to call on additional energy maintained in accordance with clauses 3.18.11A(a) or (b).

This means that within 15 minutes of a generation contingency event, sufficient capacity must be made available to replace the other 30% of the largest credible contingency as well as freeing up any response provided by those units enabled for LFAS (which currently contribute to SR). Therefore, within 15 minutes of a contingency, the frequency will be restored, but the SR providers will still be fully utilised and thus not available to provide further SR.

Within four hours, *additional* capacity must be made available to replace the response from SR units, therefore ensuring that the system can again be in a state where it can respond to a new contingency. EY considers that this timescale is appropriate and is consistent with international best practice.

EY considers that the timescales and capacities procured are sufficient to ensure frequency recovery standards can be met, subject to the discussion below.

Availability of secondary response

The current procedure assumes that any provider of SR will also be available to provide an ongoing response for to four hours. This is currently the case, as SR is provided either by:

- Generating units who are not energy limited, and can therefore increase their generation or be reduced to minimum (or cycled) for extended periods if issued dispatch instructions; or

- Interruptible load contracts which are specified for durations longer than four hours.

However, the current PSOP: Ancillary Services only requires Class C SR to sustain its response for up to 15 minutes. Therefore, an energy limited provider (e.g., battery storage facility) may be unable to offer energy over longer timescales. Similarly, interruptible load contracts for 15 minutes of load reduction would technically be eligible to provide SR, but would not necessarily be available to provide a longer-term response.

EY therefore proposes that the existing Market Rules be clarified to address this discrepancy. There does not appear to be any such conflicts for over-frequency (LRR) events.

Recommendation 5 – Make the Ready Reserve Standard indifferent to the nature of SR and LRR providers
The current Ready Reserve Standard (Clause 3.18.11A of the Market Rules) is not robust enough to deal with future scenarios where capacity procured for Spinning Reserve Service cannot be physically called upon for longer periods. For example, energy limited plant, including battery storage facilities, may be able to provide 15 minutes of response, but not have sufficient energy for longer term (up to four hours) supply. The Ready Reserve Standard would therefore not provide a sufficiently strong planning criterion for System Management. EY recommends that the IMO review this clause to state that there must be enough generation or demand side response available that can be brought online (within 15 minutes or four hours for the two sub-clauses, respectively), to replace the capacity lost in the contingency event.

4.4 Tertiary response in the WEM

Some markets employ a third frequency control ancillary service, referred to as tertiary response, which ensures that sufficient capacity is available to rapidly replace secondary response (either through an explicit service, or through being available for normal market dispatch). The boundary between “secondary” and “tertiary” response, however, may be more semantic in some markets, particularly if there are markets or services spanning multiple timescales.

In some markets (e.g., Ireland), particularly those with longer dispatch intervals, tertiary response providers are brought online as part of the sequence of restoring system-normal operation after a contingency. In this scenario, tertiary response providers replace secondary response providers (freeing them for the next event) and then are themselves replaced through market dispatch.

In other markets, particularly those with shorter dispatch intervals (e.g., the NEM), capacity to replace secondary response providers is first sourced through the normal market dispatch process, with either no tertiary response procured or reserves kept as a backup option (such as if insufficient ramping capacity is available from the market).

4.4.1 Applicability to the WEM

The WEM has no explicit tertiary response market, as there are no units explicitly designated as "secondary response" that need to be replaced[7]. Therefore EY considers the current arrangements in the WEM cover the tertiary response role adequately.

4.5 Completeness of frequency control ancillary service provisions in the WEM

The analysis and international comparisons in the sections above demonstrate that the current explicit ancillary services in the WEM combined with other market rules and practices currently provide a complete coverage of the necessary frequency control ancillary services. However, EY has identified a number of instances where Market Rules and/or PSOPs are ambiguous or not strictly in agreement with normal practice in the WEM. Furthermore, there are some examples where the current ancillary services and related Market Rules may not be sufficient under all future conditions. It is these areas that EY's recommendations are concerned with.

It became apparent that there is ambiguity regarding the specific responsibilities of capacity procured for SR and LRR under the current set of Market Rules, Technical Rules and PSOPs. Clause 3.9.2 of the Market Rules describes SR as being for the purpose of retarding the frequency decline associated with a loss of generation (or transmission) from the system:

> *3.9.2. Spinning Reserve Service is the service of holding capacity associated with a synchronised Scheduled Generator, Dispatchable Load or Interruptible Load in reserve so that the relevant Facility is able to respond appropriately in any of the following situations:*
> *(a) to retard frequency drops following the failure of one or more generating works or transmission equipment; and*
> *(b) in the case of Spinning Reserve Service provided by Scheduled Generators and Dispatchable Loads, to supply electricity if the alternative is to trigger involuntary load curtailment.*
> *(c) [Blank]*

Based on this, according to the Market Rules, SR providers must provide at least a primary response. System Management has advised EY that it assumes SR and LRR to be primary response services only.

However, the IMO has noted that the PSOP: Ancillary Services in place at the commencement of the WEM stated that "*The aim of the Spinning Reserve Service Is to restore frequency back to within the normal frequency operating band, or close to that band, in as short a time as is practical."* and that the Class B and Class C SR and Class B LRR was intended to *restore* the system frequency. This is certainly a secondary response role. Requirements for SR and LRR providers to contribute an ongoing response after the frequency is restored are not explicitly stated in any current documents, although the settlement arrangements in Sections 6.16A and 6.16B appear to be compatible with this interpretation. Also, the current PSOP: Ancillary Services states that Class B and C SR *may* be provided through AGC, which is also compatible with the provision of secondary response.

EY therefore considers that the current Market Rules and PSOP: Ancillary Services do not clearly describe the same service as that defined in the original PSOP: Ancillary Service. Consideration of the historical evolution of these documents was not investigated further.

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[7] Arguably, the four hour replacement capacity required under the Ready Reserve Standard could be considered "tertiary reserves". We have not adopted that definition in this report.

Recommendation 6 – Clarify the Market Rules and PSOPs regarding the expected response characteristics of SR and LRR providers
EY recommends that the Market Rules and PSOPs should clarify the precise responsibilities of SR/LRR providers, especially in terms of primary and secondary response, including stating whether it differs between classes of SR and LRR.

4.6 Boundaries between services

As part of this review, EY was tasked to undertake a technical review of whether the current boundaries between governor response, LFAS, Balancing, Spinning Reserve Service and Load Rejection Reserve Service achieve a best practice outcome in terms of addressing the Wholesale Market Objectives.

Figure 4.8 show the typical frequency boundaries and timescales these different WEM services and responses are active. All frequency ranges (including deadband and normal operating frequency range) are similar to the international markets reviewed by EY, and are also consistent with EY's assessment of best practice.

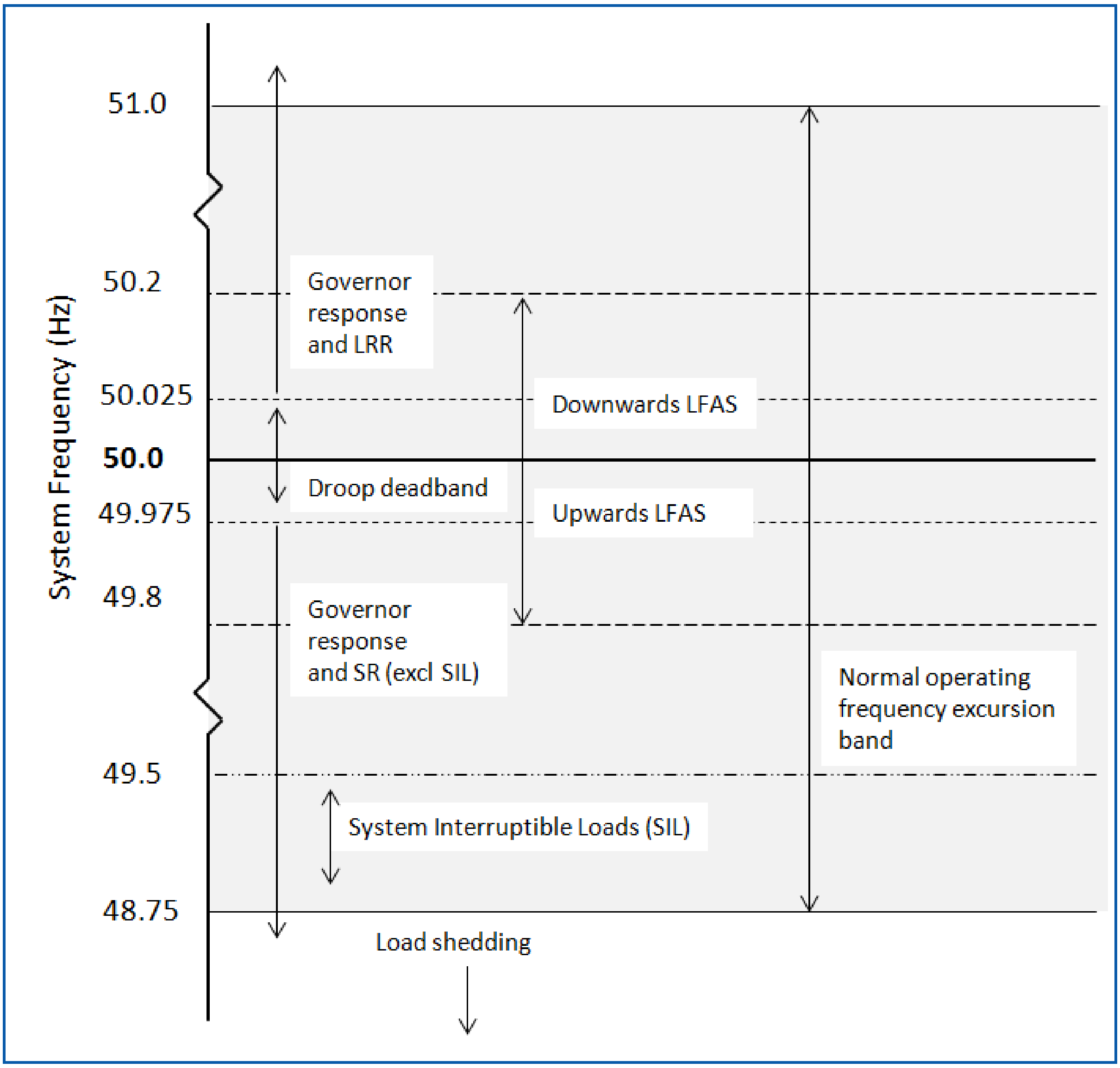

Figure 4.8 – Frequency ranges for WEM ancillary services and responses

The response of each of these services will typically overlap through time; this is consistent with all international markets, and reflects the separate roles and responsibilities that each service is procured for. For example, LFAS provides ongoing corrections to the system frequency, which will operate in parallel with the governor or SR/LRR response in the event that the frequency exceeds the governor deadband settings. The two services provide complementary, rather than competing, responses to the market, and EY considers this an appropriate and best practice outcome consistent with the Wholesale Market Objectives.

EY notes that during a frequency disturbance, after the period of mandatory governor response from all generators[8] some of those generators (those providing the SR/LRR service) will transition into a sustained SR/LRR response, while others are required to return to their setpoints. This is a reasonable arrangement, and EY does not recommend any changes to this arrangement.

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[8] That are technically able to provide such response

As discussed elsewhere in the report (particularly Section 9), LFAS and Balancing will necessarily be dependent on each other, in that a longer period between dispatch instructions will require a greater LFAS requirement. A shorter dispatch interval would reduce the LFAS requirement, and potentially reduce consumer costs. This is being considered by the IMO. Likewise sub-classes of SR and LRR stretch over more than one Balancing interval. This is reasonable and in fact necessary; SR and LRR procurements effectively guarantee that plant will be available by reserving it ahead of time.

In general, the timescale boundaries that separate the three frequency control ancillary services in the WEM, and the sub-classes of SR/LRR, are reasonable and compatible. EY has identified a potential inefficiency with the overlap of Class A and Class B LRR, which should be addressed in anticipation of future efficiencies.

More significantly, EY has identified that the automatic counting of LFAS providers towards SR/LRR may not be technically or economically feasible for those providers, or necessarily desirable from a system reliability perspective. As with all services, there will be a trade-off between cost and risk; this specific issue is discussed in detail in Section 4.2.5.

EY's view is that, subject to the relevant recommendations of this report, the governor response, LFAS, Balancing, Spinning Reserve Service and Load Rejection Reserve Service achieve a best practice outcome in terms of addressing the Wholesale Market Objectives.

5. Review of Ancillary Service Standards and Requirements in the WEM

The terms ‘standard’ and ‘requirement’ have been used interchangeably to date in the context of the WEM. The IMO and System Management propose to improve clarity by adhering to the Market Rules interpretations of these terms more consistently. These are as follows:

- A ‘Standard’ is defined as something described in the Market Rules or Technical Rules that specifies a performance level that must be delivered in the system.
- A ‘Requirement’ is defined as a setting or limitation that System Management determines is necessary to adequately fulfil and/or implement the Standards. Requirements may vary over time and ideally would not be stated explicitly in the Market Rules. Rather they would appear in other supplementary documents and the procedures such as PSOPs.

Another important definition regards what is meant by something that is ‘performance’ based versus something that is ‘volume’ based. At the highest level, a performance based standard may be considered to be something that defines a desired outcome, whereas a volume based standard is one that defines how to achieve a desired outcome. The SWIS Operating Standards are a good example of a performance based standard: they state (amongst other things) that the WEM should be kept within the normal frequency range (49.8 Hz to 50.2 Hz) for 99% of the time.

Another point of distinction is that performance based standards are typically specified over a period of time, while volume based standards are typically defined at an ‘instant’ in time. The NEM provides us an example of the distinction here. There is a system reliability standard which states that ‘the maximum amount of electricity expected to be at risk of not being supplied to consumers, is 0.002% of the annual energy consumption for the associated region or regions per financial year [26]’. This is a performance based standard; it states a desired outcome of the market. For the purposes of identifying how much generation is required to deliver this desired outcome, the reliability standard is translated into an ‘instantaneous’ value called the Minimum Reserve Level (MRL). The MRL is the amount of installed capacity above the forecast peak demand that is required to be carried in the market to ensure that the long term reliability standard is delivered. The MRL therefore is an example of something that is volume based, rather than performance based. AEMO calculates MRL values that are necessary to meet the reliability standard. In this example, the volume based requirement is an interpretation of the overriding performance based standard.

A potential problem area is when performance based and volume based standards are established independently, which creates the possibility of a conflict between them. In practice, this means one standard could be more restrictive than another or in the worst case, the conflicting standards could be mutually exclusive.

It is essential that any performance based standard be translated into a volume based requirement in order to operate the system in accordance with that performance based standard. This may be referred to as ‘operationalising’ the requirement. However, the volume based interpretation does not need to be incorporated into the Market Rules; EY considers a better approach is to define a transparent methodology for establishing volume based requirements from a performance based standard. The natural place for such a methodology, and the requirements it computes, is in a PSOP or similar document. This approach allows the requirements to be revised easily and transparently to respond to market changes while ensuring the performance standard is maintained[9].

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[9] Assuming the methodology that determines the volume based requirements is sound, of course.

Volume based requirements are necessary for system operation, but these should be assessed based on the performance standard and described in a relevant document such as a PSOP rather than in the Market Rules. Agreed methodologies for use in translating standards into requirements should also be documented transparently in those PSOPs. EY considers that performance based standards allow more flexibility for the system to adapt to changed conditions and therefore should help drive efficiency gains in line with the Wholesale Market Objectives. In the context of this, each of the ancillary services is studied in more detail in the sections that follow.

5.1 Spinning Reserve Service standards

SKM identified a potential conflict between performance and volume based SR standards in the WEM in their 2009 Ancillary Services Review. This potential conflict remains, as the definitions have not since been changed or clarified.

Clause 3.10.2 of the Market Rules states:

> *3.10.2. The standard for Spinning Reserve Service is a level which satisfies the following principles:*
>
> *(a) the level must be sufficient to cover the greater of:*
>
> *i. 70% of the total output, including Parasitic Load, of the generation unit synchronised to the SWIS with the highest total output at that time; and*
>
> *ii. the maximum load ramp expected over a period of 15 minutes;*
>
> *(b) the level must include capacity utilised to meet the Load Following Service standard under clause 3.10.1, so that the capacity provided to meet the Load Following requirement is counted as providing part of the Spinning Reserve requirement;*

This standard is volume based; it defines an amount of capacity that must be held in readiness at all instants in time (other than the exceptional conditions outlined in the Market Rules).

Clause 2.2.1(c) of the Technical Rules states that the system frequency is to be held to within 49.8 and 50.2 Hz for 99% of the time under system normal conditions, and to between 48.75 and 51 Hz under a single contingency event with restoration to the normal range within 15 minutes. Clause 2.2.1(d) states that:

> *The frequency operating standards must be satisfied, provided that there is no shortage of spinning reserve in accordance with clause 3.10.2 of the Market Rules, without the use of load shedding under all credible power system load and generation patterns and the most severe credible contingency event.*

This is a performance based standard; it naturally cannot be assessed at any single instant in time.

As SKM stated in their 2009 review, although there is disconnect between these two standards, they are not necessarily in conflict; if the *volume* based standard is sufficient to deliver the *performance* based standard, they are compatible with each other [2]. There still exists the possibility that the volume based standard is too demanding though which would result in delivering in excess of the performance standard, which has an impact on market cost and efficiency.

The issue with such definitions comes from the general inflexibility of volume-based standards. When only performance based standards are specified, the necessary volumes of a service required to meet them can be altered to match. This opens up the potential for time of day or time of year based volumes, or for the volume methodology to be reviewed, or for other market factors to be taken into account as they arise. Volume based standards do not have this flexibility unless they are extremely well specified, which means that Rules must be changed to respond to changed market conditions. A higher degree of freedom should drive a more efficient market outcome which is in keeping with the Wholesale Market Objectives.

To illustrate this point, if the SR standard was found to overestimate the amount of the service required to deliver the SWIS Operating Standards, the Market Rules would have to be amended to allow a lower amount of the service to be procured. For example, if it was determined that carrying SR equal to 50% of the output of the largest online unit (instead of 70%) was all that was required to deliver the frequency requirements stated in the Technical Rules, then the Market Rules could not accommodate reducing the SR volume. If only the performance based standard was stated, then the Market Rules could accommodate this without issue.

Recommendation 7 – Simplify the Spinning Reserve Service standard
EY recommends that Clause 3.10.2 of the Market Rules be altered to remove any reference to the particular volume of Spinning Reserve Service that must be procured (where volume here refers to the 70% value specified in Clause 3.10.2(a)). Instead, the clause should state that the volume of Spinning Reserve Service to be procured must be sufficient to deliver the performance specified in the SWIS Operating Standards (Clause 2.2.1(c)). This implies that the policy of allowing the possibility of load shedding on a single credible contingency event would be abandoned, and therefore will result in a maximum procurement that exceeds the 70% of the largest credible contingency level currently procured (under normal circumstances). This will potentially lead to increased SR procurement costs therefore EY recommends that this be implemented in tandem with Recommendation 13 which aims to improve the sculpting of SR requirements according to factors such as load relief so as to minimize the required ancillary service volumes. Additionally, the Market Rules should require that System Management and/or the IMO be responsible for developing and publishing in a procedure a methodology which System Management will use on an ongoing basis to determine the necessary SR levels to maintain compliance with the SWIS Operating Standards.

5.2 Load Rejection Reserve Service standards

LRR standards are defined in the Ancillary Service Standards (in the Market Rules) and are as follows:

> *3.10.4. The standard for Load Rejection Reserve Service is a level which satisfies the following principles:*
>
> > *(a) the level sufficient to keep over-frequency below 51 Hz for all credible load rejection events;*
> >
> > *(b) may be relaxed by up to 25% by System Management where it considers that the probability of transmission faults is low.*

This performance based standard does not attempt to state the volume of LRR that must be carried; it simply states what over-frequency conditions must be met.

The SWIS Operating Standards state virtually the same obligations in terms of the allowed frequency range for over-frequency events. The SWIS Operating Standards also specify that in such an event, the frequency must be returned below 50.5 Hz within 2 minutes.

These two standards are therefore compatible and there are no potential conflicts in the Market Rules concerning LRR. EY's recommendation for this service therefore relates to eliminating duplication between the Market Rules and the SWIS Operating Standards.

Recommendation 8 – Simplify the Load Rejection Reserve Service standard
EY recommends that Clause 3.10.4 of the Market Rules be altered to remove any reference to the frequency standards that must be delivered with the Load Rejection Reserve Service. Instead, the clause should state that the volume of LRR to be procured must be sufficient to deliver the performance specified in the SWIS Operating Standards (Clause 2.2.1(c)). Additionally, the Market Rules should require that System Management and/or the IMO be responsible for developing and publishing in a procedure a methodology which System Management will use on an ongoing basis to determine the necessary LRR volumes to maintain compliance with the SWIS Operating Standards.

5.3 Load Following Service standards

Another potential disconnect exists for the Load Following Service. In this case the standards are given in a mix of volume and performance based terms. Firstly, the frequency operating standards in the Technical Rules in clause 2.2.1(c) as stated in the sections above apply; that is, the frequency is to be kept between 49.8 and 50.2 Hz for 99% of the time. Secondly, Clause 3.10.1 of the Rules states that:

> *3.10.1. The standard for Load Following Service is a level which is sufficient to:*
> *(a) provide Minimum Frequency Keeping Capacity, where the Minimum Frequency Keeping Capacity is the greater of:*
> *i. 30 MW; and*
> *ii. the capacity sufficient to cover 99.9% of the short term fluctuations in load and output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average.*

The Minimum Frequency Keeping Capacity specification is something of a hybrid volume based and performance based standard. However, a bigger problem with this standard is that it is ambiguous; it is unclear what the "variance of 1 minute average readings around a thirty minute rolling average" actually is or how to would be calculated. Owing to this and its questionable capability to deliver an appropriate outcome, this calculation is currently not used. Instead, System Management has determined (via observation) that 72 MW of each upwards and downwards load following capacity is sufficient to contain the system frequency to the Normal Range 99.9% of the time. However, the SWIS Operating Standards state that the Normal Range need only be met for 99% of the time. EY's international benchmarking exercise found that containing frequency to its normal range for 99.9% is much more onerous than typical frequency standards elsewhere; in the markets EY reviewed, the performance standards varied between 97% and 99% (see Table C.4).

Recommendation 9 – Simplify the Load Following Service standard
Given the difficulty of defining an appropriate methodology for determining the required levels of Load Following Service within the context of the Market Rules, EY recommends that Clause 3.10.1 of the Market Rules be altered to remove any reference to a particular quantity of load following service or methodology. This should be replaced with a statement that the level of load following service procured must be sufficient to deliver the frequency performance levels defined as the Normal Range in the SWIS Operating Standards (Clause 2.2.1(c)). Additionally, the Market Rules should require that System Management and/or the IMO be responsible for developing and publishing in a procedure a methodology which System Management will use to determine the necessary LFAS levels to maintain compliance with the SWIS Operating Standards. EY notes that the development of a formal methodology to determine the LFAS requirement would typically depend on accurate measurements of historical LFAS usage. As EY describes in Section 9.1, these measurements are not currently available, mainly due to the way in which the Synergy Balancing Portfolio is dispatched to meet its Balancing and LFAS obligations. EY therefore expects that in the first instance the options for developing a robust methodology are limited.

5.4 System Restart Service standards

All aspects of EY's review of the System Restart Service, including examination of the standards and requirements, are described in in the Section 12.

6. Service Procurement in International Markets

The following section provides some key comparisons from EY's international benchmarking exercise, including the costs of energy and ancillary services, standards and settings relevant to ancillary services and any future developments which are being proposed.

More detail on these markets is provided in the tables of Appendix C.

6.1 Structure of markets

6.1.1 Economic comparison to the WEM

The costs of frequency control ancillary services in the WEM, presented as dollars spent on ancillary services per MWh of annual energy in 2012-13, are compared to the surveyed markets in Figure 6.1. The WEM, New Zealand, California and the NEM separate frequency control services used for regulation from those used following contingency events. The UK, Spain, Germany and Ireland use reserves procured for contingency events to provide regulation and therefore do not recognise two different services.

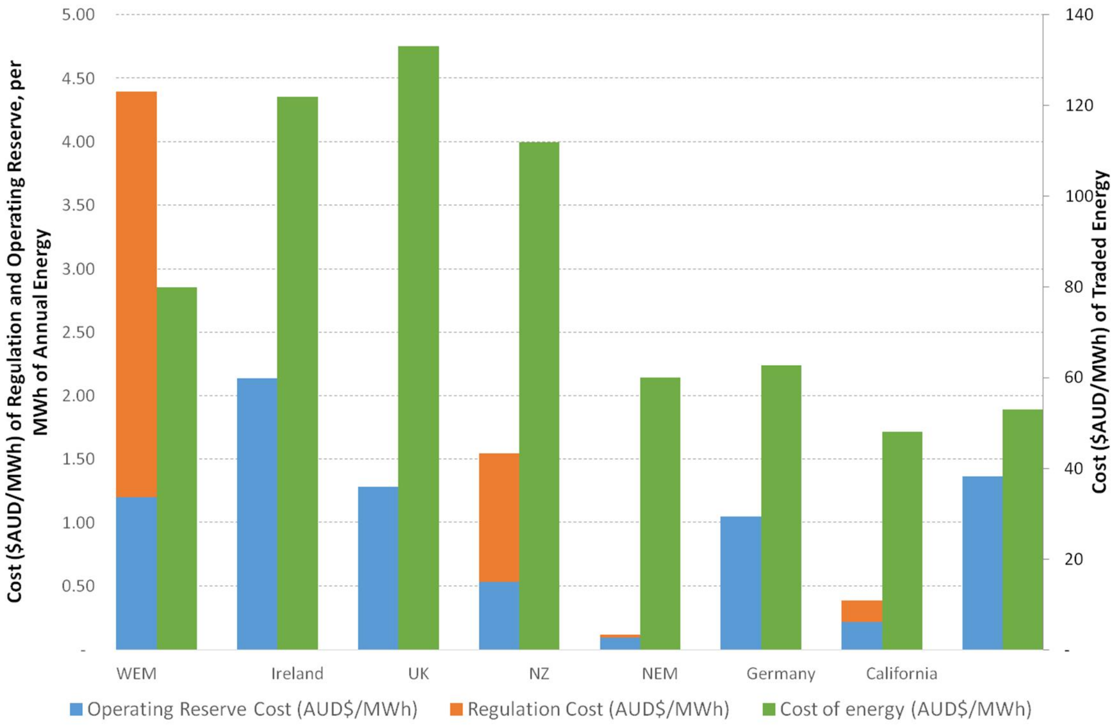


Figure 6.1 – Comparison of Costs of Frequency Control

The cost of frequency control in the WEM is higher than those in any other market studied. There are three main factors driving costs differentials between markets.

Market Services

The costs in Figure 6.1 include only frequency control ancillary services. However, other services which are procured at a cost to the market may influence the costs of frequency control.

For example, in Spain and Ireland, generators are scheduled in day ahead markets. On the actual day, the system operators dispatch to meet network constraints or unexpected changes which may arrive, and generators are compensated for differences between their dispatch and their day ahead schedule [27], [28]. These constraint payments may include changes to generation which would be counted as LFAS in the WEM, or frequency keeping in NZ.

Ireland and Spain also do not remunerate generators for primary frequency response [29], [30]. To the extent, however, that this service imposes a cost on providers, EY expects that this implicit cost must be recovered through other payments (e.g., higher energy prices). Section 4.2.1 also discusses that implicit primary response may be an inferior service.

The amount of reserve and regulation required is also different in each market. Therefore, Figure 6.1 should be read as an indication of the costs of frequency control, but not necessarily a complete picture.

Market Structure

The dispatch interval of the market also influences the costs of ancillary services. The NEM, California and NZ have a five minute dispatch interval which reduces the cost of regulation services.

EY notes that the NEM is the only market in which all frequency control ancillary services are procured through markets which operate on the same dispatch interval as the energy market. EY expects this to be more economically efficient than having a regulated tariff for all services, as in Ireland, or tendered contracts for longer periods of time, as in the UK and Germany.

The NEM's relatively short dispatch interval (5 minutes) and the prevalence of generators capable of receiving AGC signals mean that regulation is not a difficult service to provide. Many large generators in the NEM also operate with some headroom so can provide regulation at low cost. These factors contribute to the low cost of regulation in the NEM. The value of delayed lower service over 5 minutes is also low as the largest loss of load is not always significantly larger than the change in generation possible due to market dispatch. This is a function both of the market structure, and the generation assets in the market.

Generation Assets

Markets which have a significant fleet of generators able to provide ancillary services at low cost will be at an advantage. As mentioned above, the NEM has a large fleet of responsive generators which can provide regulation and operating reserve at relatively low effort and hence cost.

New Zealand and California have a sizeable hydro fleet which can provide ancillary services at low cost, due to low fuel costs and, more importantly, high flexibility. However, the size of the market also influences cost. For example, costs in the smaller New Zealand system are still quite high despite being provided by hydro. Generally, larger markets have lower per-unit costs as they are more robust, including levels of higher inertia, more flexibility, more providers and smaller contingencies compared to market size. Costs in Germany and California are relatively low as they are both large, well-interconnected markets.

There is a correlation between cost of generation and cost of ancillary services. If the prevailing energy cost is cheaper, it will also generally be cheaper to procure capacity to remain on standby for operating reserve. However, this is not a strong trend. Costs of energy in Spain are quite low, but its ancillary services costs are relatively high. The cost of energy in Germany is almost half that of the UK, but their ancillary services costs are similar. This illustrates the impact on the market, particularly any extra charges which may be split out from energy costs in some markets and included in others.

The WEM

The WEM does not have many advantages in the categories listed above. It is a relatively small and isolated system, with no hydro and relatively high fuel costs and does not procure all ancillary services through transparent markets. However, the regulation costs in the WEM are much higher than in other markets, which suggests some room for increased economic efficiency in the market structure.

6.2 New types of ancillary services

6.2.1 Ramping services

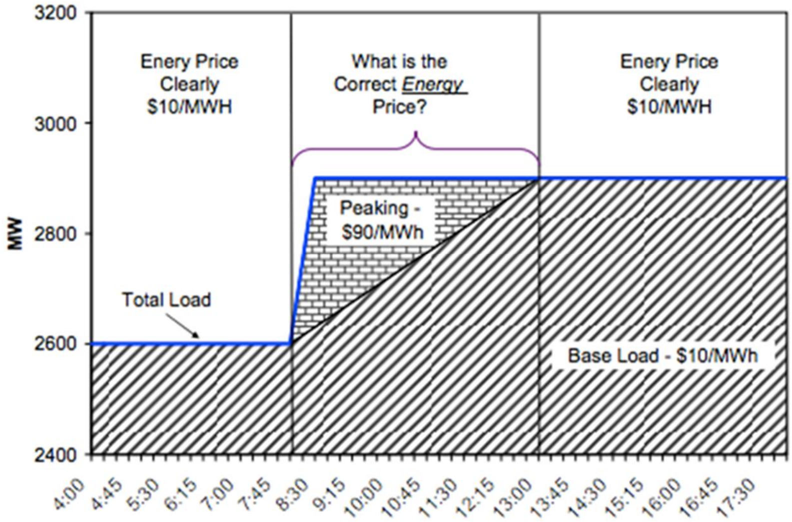
One of the major differences in a market dominated by renewable energy is likely to be the longer term fluctuations in supply. A prime example of this is the increase in solar generation in the morning, and corresponding decrease at night. This can combine with changing demand in these periods to result in significant ramps in the net demand to be met by the remaining generators. In particular, a fall-off of solar PV during the evening peak ramp-up could cause severe stress for future systems.

Ramp-rate limitations on inflexible generators may require peaking generation to assist in the short-term. Alternatively, if sufficiently flexible generation cannot be procured through the dispatch process or if the ramp occurs within a dispatch interval, other operating reserves (primary or secondary) must be utilised (and, hence, will not be available for their typical roles). Consequently, some markets are considering a new ancillary service, incentivising flexible generation.

A separate ancillary service for procuring this capacity is being considered for two main reasons [19] [31]. Firstly, explicitly procuring ramping capacity will ensure that system operators have this capacity available both from a long-term planning perspective, but also dispatch interval to dispatch interval. That is, a well-priced market or a multi-period look-ahead dispatch engine could incentivise (and compensate) fast-ramping generation to withhold[10] energy (and hence revenue) in early periods in anticipation of high requirement periods to come.

Secondly, ramping markets can provide more explicit and efficient price signals and cost recovery. For example, Figure 6.2 shows a potential scenario where ramp-rate limits would typically cause energy prices to rise to the level of a peak generator, providing a windfall gain to the inflexible base load generators and, potentially, a *disincentive* for generators to provide ramping response. (For example, this issue is currently being explored in the NEM [32].) A separate price for the ramping service could potentially provide a more efficient and lower cost outcome.

[10] It is this withholding of energy in anticipation of future requirements that makes it an “operating reserve”.



Reproduced from Figure 11 of [31]
Figure 6.2 – Possible situation requiring ramping market

A market for ramping has been considered in both California and the Mid-West ISO.

In California, a flexibility market has been proposed to provide additional reserves between the 15 minute and 5 minute dispatch periods, and will be determined both on a day-ahead forecast and near real-time. The minimum requirement for flexible capacity will include the existing contingency requirement to ensure this is not double counted. Generators will be assessed based on their minimum output level, start-up time and ramp rate to determine their flexible capacity. The payment rate and market structure has not yet been determined [33].

In the Mid-West, the ISO has determined that creation of new ancillary services, ramp-up capability and ramp-down capability, would allow the system to cope with increased changes in demand more cost efficiently than increasing regulation or spinning reserve requirements [34].

Applicability to the WEM

EY does not consider that there is a short-term requirement for a ramping market in the WEM, as the now gross-pool market design, more frequent opportunities for re-dispatch and the significant flexibility afforded System Management by the Balancing Portfolio means that sufficient ramping capability is likely to be available.

Prior to the introduction of the balancing market in the WEM, procuring additional balancing support at peak times may have had value. However, with the move towards more frequent dispatch instructions in the WEM, EY considers that there is no need to pursue a ramping market at this time.

6.2.2 Alternatives to ancillary services markets

Some smaller systems have chosen a non-market approach to frequency control. For example, the Mt Isa electricity system, which supplies the town of Mt Isa and surrounding mines, controls frequency through proactive load shedding. If a generator fails, the same amount of load is shed almost instantly (within a fraction of a second). This methodology is employed because the system is very small and isolated. It is uneconomic to rely on generators to provide sufficient spinning reserve to avoid load shedding on the loss of the largest generator.

Applicability to the WEM

The WEM already procures some SR from a SIL and is in the process of signing a second contract with another load. The use of further SIL contracts, particularly in smaller blocks, could continue to benefit the system. A more explicit market to foster competition between loads and generators to provide spinning reserve could encourage more loads to become technically able and willing to provide SR.

6.3 Measurement of ancillary services usage

Measuring usage of ancillary services is important for two reasons. Firstly, system operators need confidence that the offered level of ancillary services is in fact being delivered by the providers. If participants regularly provide less than their directed response, system security can be compromised. Secondly, if consistently more ancillary services are being procured than used, the requirement may be excessive and could be reduced.

Additionally, monitoring of performance is important for determining financial compensation. In most international markets, ancillary services are paid a “capacity” payment – effectively, an opportunity cost payment for not offering their energy into the energy market or for running out of merit. For these markets, appropriate payments depend upon the generator being available when called upon. Some markets offer energy payments for the actual usage of ancillary services; this can involve payments within the energy market, or at a separate price (typically dependent on the energy price). Payments for actual operation therefore adjust the ongoing opportunity cost.

In general, measurement of ancillary services usage is done by comparing the dispatch target with the actual generation of enabled plant. The deviations between these will be due to the ancillary services employed. The detailed methodology for regulation will be discussed for the NEM, while the methods for measuring contingency response will be discussed for Ireland and the NEM.

6.3.1 Measurement of regulation

Limited information is publicly available about current measurement procedures for regulation. Although all markets require some form of verification of capability (e.g., annual or once-off tests), it appears that many markets measure only “capability” rather than the response actually provided.

In the NEM, actual regulation provision is not currently monitored in a continuous fashion. Generators are paid based on the MW of regulation they are dispatched to provide, rather than actual energy provided. However, in the last quarter of 2013, the Australian Energy Regulator (AER), with AEMO’s assistance, began to investigate and track how generators in the NEM were complying with their regulation dispatch.

To assist the AER in this matter, AEMO developed a methodology to assess the performance of regulation FCAS providers[11]. AEMO collected data on actual power output and AGC targets for each regulation FCAS service provider over a period of time. AEMO then determined those instances where the system frequency was above or below the nominal 50Hz target, and in those

[11] https://www.aer.gov.au/sites/default/files/quarterly%20compliance%20report%20oct-dec%202013.pdf

instances, assessed the amount by which generators who were enabled for regulation FCAS differed from their AGC target control signal.

This calculation is not directly in line with the kind of measurement currently desired in the WEM, as it focuses on how each individual generator is supplying its allocation of regulation FCAS, rather than the aggregate amount of regulation service being supplied to the market. However, EY expects that it would be relatively straightforward to calculate the aggregate of regulation service from this data.

This methodology may be applicable to the WEM for judging the amount of LFAS that non-Synergy generators provide to the market, since their Balancing dispatch target is known on a facility-by-facility basis. A similar procedure is being undertaken to measure the response of IPP providers of LFAS. However due to the present nature of the Balancing Portfolio dispatch, separating LFAS from balancing actions is not a simple process, as is discussed in Section 9.

6.3.2 Measurement of Contingency Services

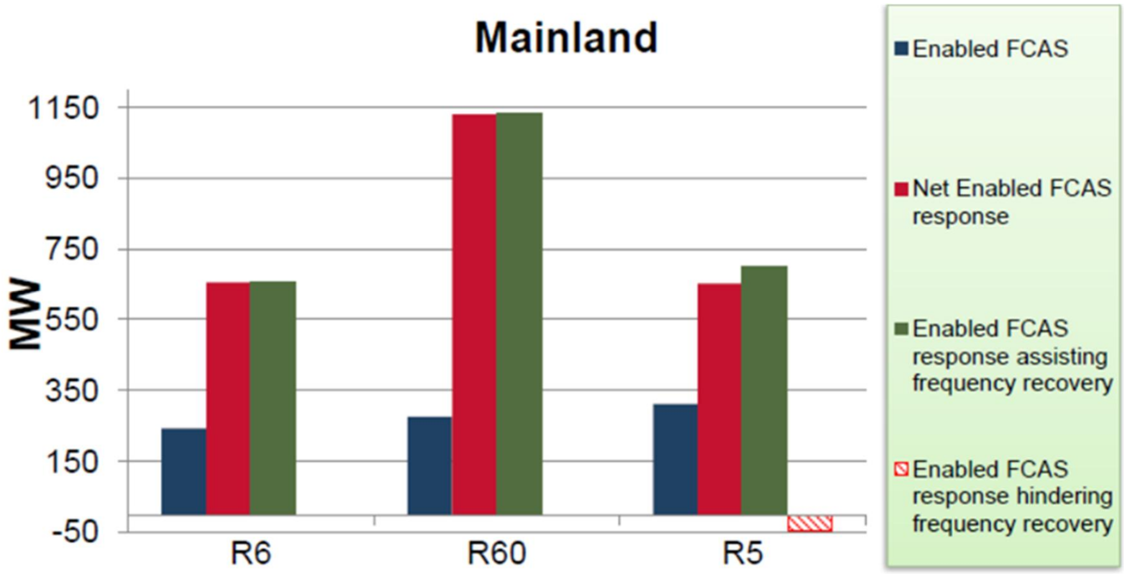
NEM

In the NEM, AEMO does not measure actual frequency response behaviour as a normal market function. AEMO requires all generators providing frequency control ancillary services (FCAS) to record high speed 20 millisecond generation data and to provide this data upon request. This is in addition to the 4-second SCADA data that is provided by all generators.

AEMO publishes a monthly Frequency and Time Error Monitoring report which records any frequency events in a region, and the accumulated time error. If there is a significant frequency event, AEMO will request the high speed generation data from the units enabled for FCAS and use this to investigate their response. The last major frequency event which was investigated occurred in Victoria in June 2012 when an earthquake caused multiple units to trip in both South Australia and Victoria.

Figure 6.3 shows the enabled and actual available capacities for each of the FCAS raise response time categories: *fast* (R6), *slow* (R60) and *delayed* (R5). It shows the amount enabled for each category in blue. There is slightly more response enabled in each category, to enable the frequency to recover after the event. The net enabled FCAS response column in red shows the actual increase in generation produced by the generators which were enabled for FCAS. This is measured as a MW difference between the generation before the event and the generation in the appropriate time frame. For the *fast raise* service, the response is the increase in generation seen by the end of the six second period, as given by the high speed data. For the *slow raise* service, it is the average increase between 6 – 60 seconds, and for the *delayed raise* the average increase between 60 seconds and 5 minutes.

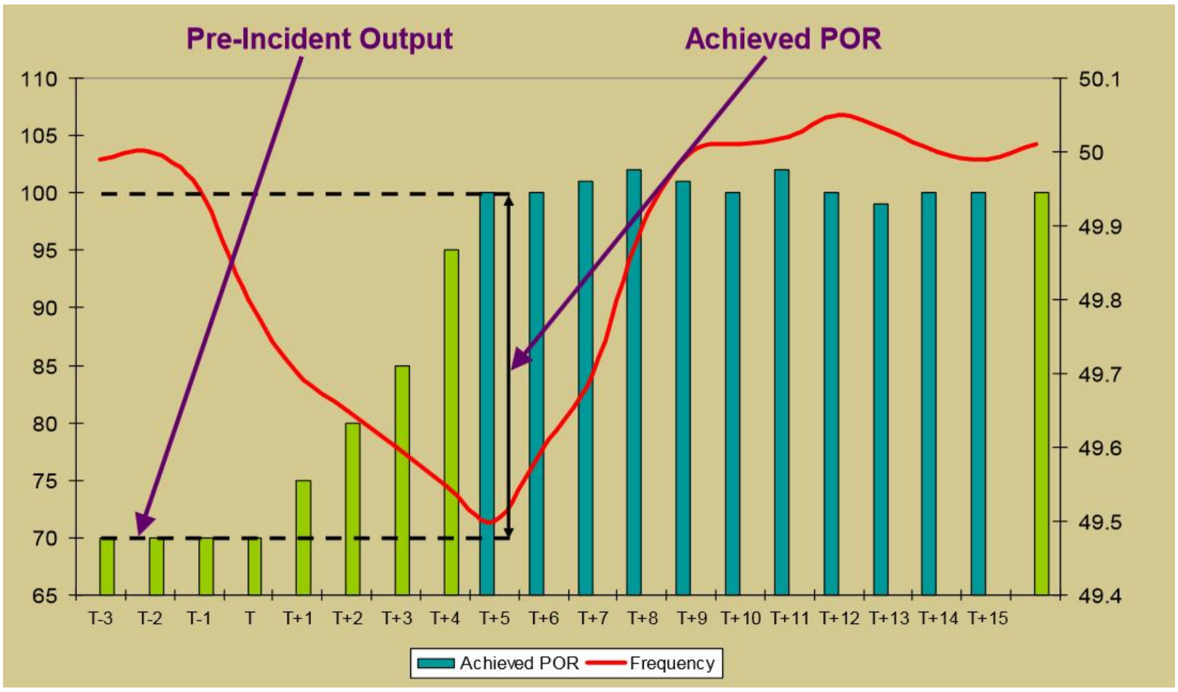
Although the generators which were enabled for FCAS provided more than they were contracted to, they were only paid for the amount enabled. AEMO also notes that some other generators which were not enabled provided frequency response (not included on chart). These were not paid for this response. This extra response, both in terms of extra units responding and enabled units responding more than required, is common in the NEM and contributes to the robust frequency in the NEM [35]. The main reason for the response arises from the spare capacity in partially loaded coal-fired generating units, which are not economic to cycle off in lower demand periods, resulting in excess reserve being available.



Reproduced from [35]
Figure 6.3 – Available FCAS capacity in the mainland NEM in response to a multiple contingency event.

Ireland

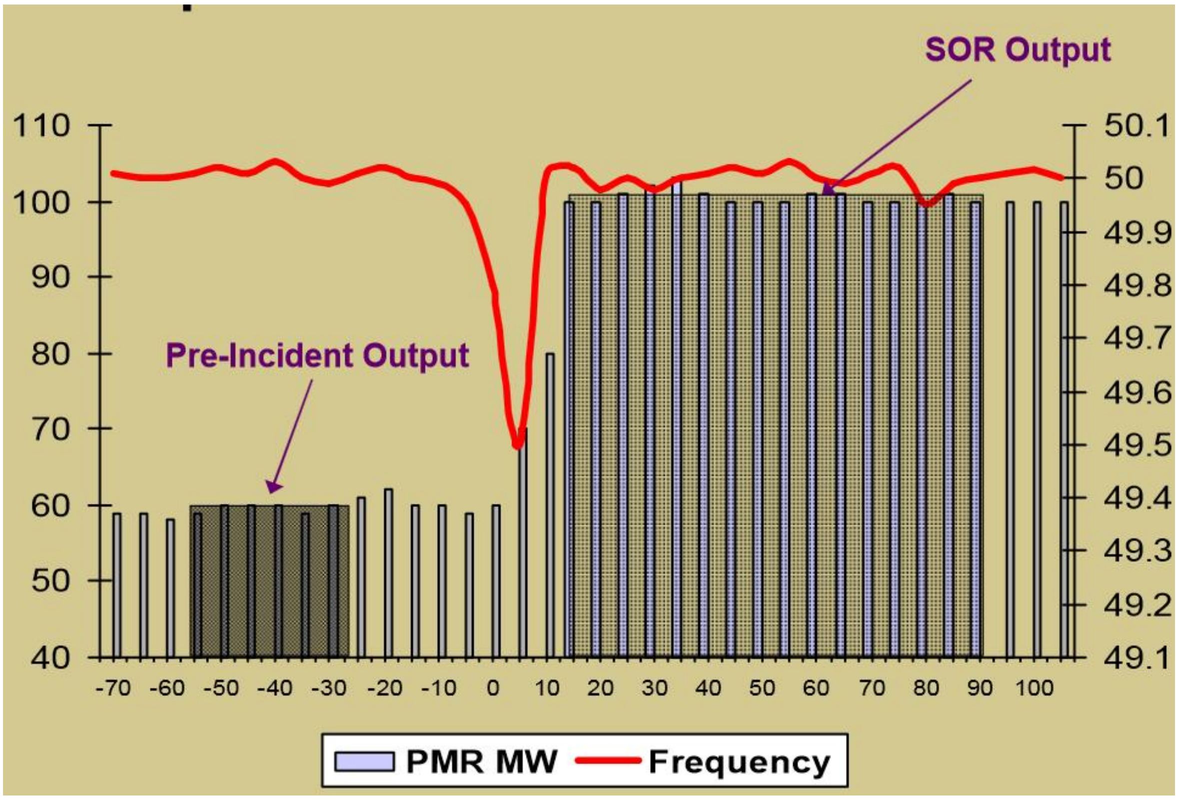
In Ireland, units have declared reserve characteristics, dependent upon their energy dispatch level and availability. Therefore, when an incident occurs, the system operator expects units to provide a defined amount of reserve energy to the system, over each applicable timescale. In order to determine whether a generator adequately responded to the incident, the system operator, EirGrid, compares Achieved operating reserve (OR) to its expected OR. The Achieved OR is simply the difference between a generator’s production before and after an incident. Figure 6.4 shows the calculation of the achieved Primary Operating Reserve (POR) of a generator following a frequency incident. Primary response covers the period up to six seconds after the incident. As the frequency nadir occurs within this time, the achieved reserve is calculated as the increase in output at that point, compared to the pre-incident output.



Reproduced from [36]

Figure 6.4 – Calculation of Achieved Primary Operating Reserve in Ireland

A similar calculation is undertaken to determine the reserve provided over the secondary timescale (15 – 90 seconds after the event). As this is after the frequency has recovered from its nadir, the achieved reserve is determined by comparing the average output over the secondary timescale to an average of its pre-incident output as shown in Figure 6.5.



Reproduced from [36]

Figure 6.5 – Calculation of achieved Secondary Operating Reserve [36]

If these calculations show that the generator exceeded its expected reserve provision by more than 10% over the primary or secondary timescales, it will be paid a bonus for this excess. In contrast, if the generator fails to provide more than 90% of its contracted reserve, it will be required to pay a rebate to the system operator. The bonus payments are reconciled from the rebates paid by other generators for the given event. [37].

Thus, Ireland uses the rebate-bonus payment mechanism to incentivise increased system security in responding to contingency events. Aside from the rebates/bonuses paid, generators are only paid for the expected reserve, rather than their delivered reserve.

Other markets

More generally, many markets implement (or plan to implement) regular tests of the physical or technical capabilities of generators proposing to provide reserve. For example, ERCOT has proposed to conduct biennial tests of generator governor responses [22].

7. Initiatives to minimise ancillary services

Internationally, both markets and academic institutions are actively researching the key drivers of ancillary service requirements and methods for reducing the quantity of services required.

7.1 Reducing dispatch interval time step

Market design can have a significant impact on requirements for regulation (LFAS) reserves [38]. In particular, faster energy markets (i.e., shorter intervals between full system dispatch) will reduce the regulation requirement by allowing regulation units to be returned to their setpoints (where they have the maximum capability to deliver the service) more frequently [39].

Recommendation 10 – Reduce dispatch interval time step
Shorter dispatch intervals reduce market regulation requirements by allowing full economic re-dispatch to occur more often and allowing regulation (LFAS) units to be returned to their setpoints (where they have the maximum capability to deliver the service) more frequently. The WEM currently operates on a 30 minute dispatch interval, although the end of interval targets can be revised twice (every 10 minutes) within that 30 minutes. EY recommends that moving to a true 10 minute dispatch interval (with dispatch instructions based on forecasts for the end of the 10 minute dispatch interval rather than the end of the associated half hour) be considered for the WEM. Consideration could also be given to a five minute dispatch interval, as per the NEM. The resulting reduction in LFAS requirements would improve the economic efficiency of the WEM in line with Wholesale Market Objective (a).

7.2 Increased flexibility

More flexible units reduce the likelihood of ramping constraints [39], particularly within a dispatch interval but also across multiple dispatch intervals when there are high ramps in load (see Section 6.2.1).

In the NEM, dispatch instructions contain both a target and a ramp rate that achieves a linear trajectory between dispatch points. As discussed in Section 9, this reduces the regulation requirements within a dispatch interval, because all units are now dispatched more closely to typical load trajectories.

Recommendation 11 – Allow System Management to vary ramp rates without triggering constrained on/off payments
System Management must currently dispatch all units at their BMO ramp rates, or the facilities may be eligible for out-of-merit payments. This can increase discrepancies between generation and load, and increase the LFAS requirement. EY recommends that Rule changes be explored to allow System Management to dictate ramp rates within dispatch instructions without triggering constrained on/off

compensation, subject to the technical capability of the generators.

The resulting reduction in LFAS requirements will improve the economic efficiency of the market in line with Wholesale Market Objective (a). It is also likely to minimize the long-term cost of electricity supplied to customers in line with Wholesale Market Objective (d).

7.3 Generator Performance Incentives

All markets have a grid code or set of rules which specifies the capabilities a generator must have to connect to the system. The SWIS Technical Rules [7] specify requirements which are in line with, or more onerous than those in most other markets [40]. This ensures that generators do not have an adverse impact on the network. However there is little if any incentive for generators to exceed the minimum requirements.

In Ireland, decreasing provision of ancillary services from new thermal generation, as well as an increased number of wind farms connecting to the grid, prompted the introduction of Generator Performance Incentives (GPI) [29]. Under these, generators which fail to meet the designated standards are penalised, and those which provide extra support receive extra payments. Some standards are universal, such as governor droop, which must be capable of 4%. Others are set by the generator at time of connection, such as minimum generation, reactive power capability and minimum start up time. If the generator fails to meet any of the standards, for example, by taking too long to start, it will be charged for each trading period in which it is non-compliant, according to an annual schedule of charges for these non-compliances [41].

The payments and charges for GPIs form a part of the ancillary services market. Generators are levied/paid on a per MWh basis for energy they do or don't deliver whilst exceeding or failing to meet requirements. In 2012-13, this essentially formed a type of causer-pays recovery of ancillary services costs, with charges accumulating to around 7.5million euros, or around 1/7th of the cost of procuring reserve [42].

7.4 Control of intermittent generation sources

Presently, renewable energy generators are price takers, which means they generate as much as technically possible to maximise revenue. However, several markets are exercising more control over renewable energy output to minimise ancillary service requirements, and allowing renewable energy to provide these services. In particular, restrictions are being considered on:

- Ramp rates: ramping requirements to meet renewable energy changes in production can be significant. In Denmark, for large wind farms, a maximum upward ramp rate can be imposed to reduce stress on the system if they are deemed during the connection approval process to be connecting to a vulnerable part of the grid. The ramp rate limit then applies at all times [43].
- Curtailment to reduce reserve requirements: modelling in Germany indicated that reducing wind output when operating reserves were running low would reduce the pressure wind generation places on reserve requirements. This could reduce the additional reserve requirements introduced by wind power up to 70%, with a loss of power production of less than 1%. [44] This would require significant communication and co-operation between system operators and wind farms to identify times of low reserve and the level of curtailment required.

In both cases, wind farms would forego energy to assist with system stability. Most markets already allow for wind farms to be curtailed at times of low demand or network congestion, but this typically corresponds to times of low prices, or curtailment is managed competitively through bidding. Therefore, appropriate price signals through existing or new ancillary services are likely to be required.

7.5 Improved forecasting

Inaccuracies in forecasting demand and intermittent generation contribute a significant proportion of ancillary service requirements. On the timescale of a dispatch interval, an inaccurate forecast can mean that plant assigned to the regulation ancillary service must be used to cover the difference between actual and forecast load, reducing its ability to support other variations in net load. Improving these forecasts could reduce the need for this regulation. Inaccurate forecasts over longer timescales can result in suboptimal unit commitment decisions, which may result in less efficient system dispatch, and may or may not affect the quantity of ancillary service required.

7.5.1 Demand

Demand forecasting error is a significant source of regulation reserve requirements, as demonstrated for the WEM in Section 9. In some markets, providers of demand forecasting services have financial incentives or penalties, to encourage higher performance standards.

7.5.2 Intermittent Generation

Forecasting Technique

The generation from intermittent sources must be forecast to create dispatch targets. In the WEM, the most basic wind forecasting method is used, persistence. For the short projection times that apply to the three forecasts made for the end of each trading interval (40 minutes, 25 minutes and 15 minutes), persistence performs reasonably well compared to other techniques. However, there are well-established wind forecasting techniques that can be employed to reduce the forecast error in these timeframes, such as a more sophisticated time-series approach, and using numerical weather prediction systems. Using off-site observations can also help to improve the accuracy of predicting the timing of rapid changes in wind power on these short projection times. Other than forecasting techniques, several markets have introduced initiatives to reduce forecasting errors.

Centralised Forecasting

Spain, the UK, Ireland and Germany all have some level of aggregation in the forecasting of wind farms so that the errors in forecasting, and natural variability of wind farms, are smoothed. In Spain and Ireland, control centres receive wind generation forecasts from each generator and aggregate these into a central dispatch target. In Ireland, the control centres can also curtail the active power of wind farms to further reduce variations [45]. In Germany, the aggregated forecasts are used to procure services across all four transmission zones to maximise efficiency [46].

If a more sophisticated wind forecasting technique is introduced in the WEM, the variability in this could be reduced by aggregating it across a larger geographical area.

Performance Incentives

In the UK, a wind forecasting initiative is being trialled in which the system operator has monthly error targets for their aggregated forecasts of wind generation. They are paid, or pay, the electricity regulator if their error is lower, or higher, than the targets [47]. Spain and India have put the onus on individual wind farms to meet accuracy targets. Spanish wind farms are required to provide forecasts for each four-hourly dispatch schedule and are charged, depending upon their contract, for deviations greater than 20% from the forecast value [48]. In India, a forecasting system with rules to impose penalties on individual wind farms for inaccuracies has been in planning since 2012. EY expects a set of rules to be enforced during 2014. In each market, improved forecasting has been identified as being able to reduce both balancing and regulation costs.

The WEM could benefit from performance incentives as a way to encourage improved forecasting and promote innovative forecasting techniques.

The contribution to variability from wind and solar generation in the current WEM, and the predicted impact of increased penetration, is explored in Section 9.

7.5.3 Embedded generation

International markets have seen a surge in embedded generation (specifically rooftop PV). This reduces transparency for the system operator, in the absence of direct metering, and increases difficulties in load forecasting.

8. Technological developments and improvements

8.1 Future requirements for ancillary services

Section 7.1 discussed some of the efforts to minimise ancillary service requirements through stricter grid codes, limitations on the behaviour of intermittent (and other) generators or changes to market structure. Rather than technological developments for specific technologies, changes to ancillary service requirements are more likely to be due to these evolving standards (which may or may not increase the cost of the renewable resource).

Nevertheless, declining capital costs for renewable generation are likely to be responsible for a significant increase in the penetration of renewables. This includes behind the meter generation such as rooftop PV, which is presently “invisible” to the market operator and may contribute to greater variations in demand and hence higher regulation requirements. This issue is considered by EY in Section 9, and is also being considered by many international markets. In particular, AEMO is developing an Australian Solar Energy Forecasting Systems (ASEFS) which will eventually provide forecasts of both large-scale and small-scale (distributed) solar PV generation [49].

The WEM should therefore proceed on the expectation that future penetration of intermittent generation will increase, with a corresponding increase in requirements for at least some ancillary services (assuming no other changes to market design). At the same time, however, there will be more sources of ancillary services available to the market as discussed in Section 8.2.

8.2 Future provision of ancillary services

A number of developments in demand-side response, renewable generation and emerging technologies such as storage are likely to increase the ability of these sectors to contribute to meeting ancillary service requirements.

8.2.1 Storage

Energy storage can contribute to ancillary services both by providing very fast response after a system contingency and by acting as a regulation service, smoothing demand within a dispatch interval. For systems with both rapid charging and discharging, both upward and downward regulation and contingency services can be provided. [50]

Some of the major types of storage are:

- Hydro: uses two or more connected dams, at different elevations. At times of low demand and electricity price, electricity is consumed to pump water to the higher dams. At times of high demand and price, water flows back to the lower dams and generates electricity. For example, Norway’s pumped hydro storage capabilities are being investigated to determine their best utilisation to facilitate wind integration in continental Europe [51]. Due to the delay in releasing water and resulting generation (which depends on the distance between the dam and the turbines), hydro can typically provide secondary and regulation response but not primary response.
- Batteries: can provide regulation as well as primary response, if sustain times are not too onerous. These are already commonly used in small remote area power systems to provide energy balancing. Incentives for battery storage have encouraged developments in two US markets. A battery storage system has been installed in PJM [52] alongside a wind farm to allow the wind farm to provide constant power and ancillary services. In New York [53] battery storage has been used to reduce peak demands and customer costs in large

buildings. Low priced energy is purchased overnight to charge the batteries. This energy is then used during peak price periods to meet the building's common-area cooling needs. This can be sustained for up to four hours.

- Compressed Air Energy Storage (CAES): compressing and releasing air is being investigated as an alternative regulation and primary response provider to batteries. Germany is investigating ways to increase storage, particularly CAES, by removing grid charges from storage facilities [50].
- Flywheels: can provide inertia response as well as very fast primary and regulation response. The inertia contained in a large spinning wheel will counteract frequency changes. A 20 MW flywheel has been in operation in New York since 2011 [54]. It participates in the frequency regulation market through bids and is automatically dispatched by the ISO. Thermal generators can operate as flywheels if in synchronous condenser mode, that is, synchronised but not producing active power.

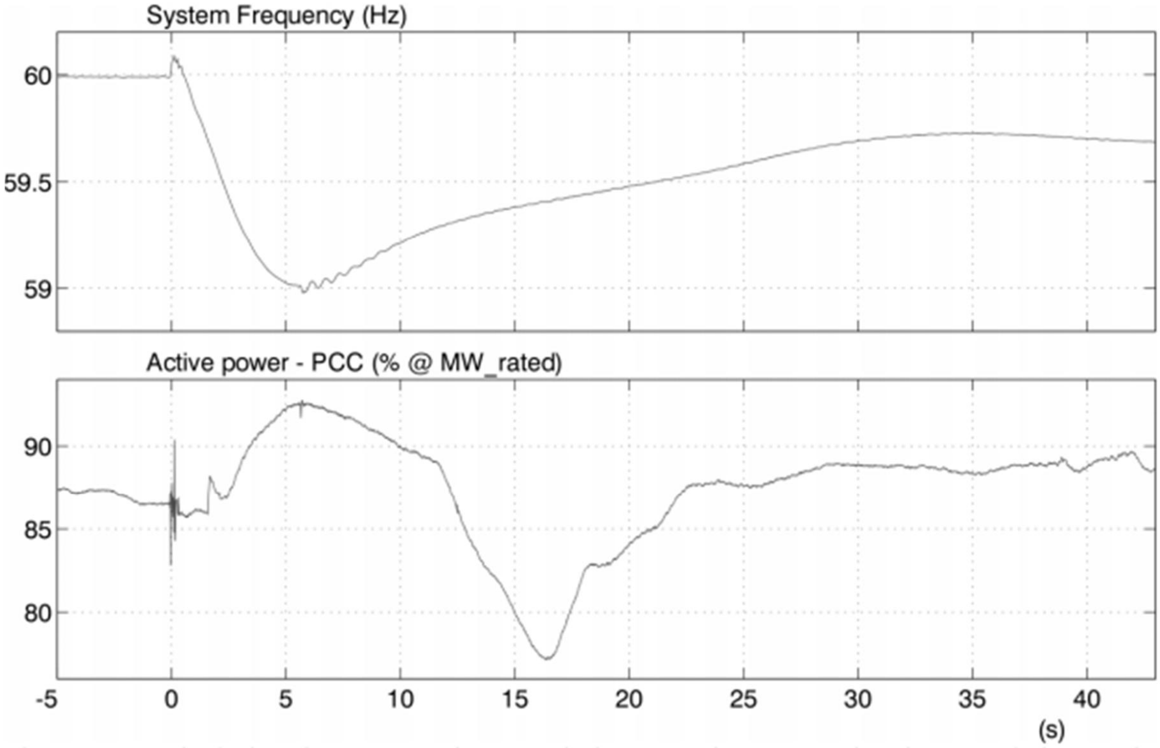
Storage has generally been used to supply the majority of fast response requirements in markets which have implemented such a service [55]. Well placed storage can also serve dual roles, such as avoiding or delaying transmission or distribution expenditure. EY expects that storage will have an important role to play in the provision of the WEM ancillary services, and rules should be designed to be as technologically neutral as possible. Forecasting a timeframe for storage to become a significant part of energy or ancillary services markets is difficult, given the pace of technological innovation. EY does not expect that storage will be a significant contributor in the WEM within the next five years due to the current high costs of such capacity.

8.2.2 Synthetic Inertia/Simulated response of wind turbines

There is increasing research into how to emulate the ancillary service capabilities of thermal generators with renewable energy generators [56]. There has been a particular focus on using the kinetic energy of wind turbines when generating to simulate inertia by providing some power increase in response to frequency drops.

Figure 8.1 shows the "synthetic inertia" power response of a wind turbine to a frequency event. Initially, power output increases, as kinetic energy created from the normal spinning operation of the wind turbine is released from the turbine, achieved by increasing the torque resisting the rotation of the blades. However this must be compensated for by a decrease in power output immediately after the event [57] as the wind turbine's speed must then be increased back to its pre-fault level.

Compared with ramp rate limitations or wind farm curtailment discussed in Section 7.4, using synthetic inertia from wind turbines does not require pre-fault curtailment of the wind farm (i.e., wind farms do not need to have previously withheld some of their capacity in order to provide this service; rather, the energy is "borrowed" from future generation). This means that reserves can be effectively provided at zero ongoing cost. The technology for providing synthetic inertia is available in the newer inverter type wind generators.



Reproduced from Figure 3 of [58]
Figure 8.1 – Output of wind farm providing synthetic inertia following a contingency

This shows that wind turbines have potential to provide some inertia-like behaviour, although this would have to be carefully managed and deployed to ensure turbines can recoup power soon after the event without endangering the system, or exacerbating the event.

Inertia versus very fast primary response

It is not evident, yet, that synthetic inertia can provide the same role as physical inertia, which slows the timescale of any frequency drops through physical size (a passive role), thus allowing more time for the governors of synchronous generators to respond. Instead, frequency drops would slow due to the smaller mismatch between generation and load, provided the synthetic inertia can be activated quickly enough. A low (physical) inertia system, however, is more vulnerable to large swings, which could make stabilising the system frequency difficult.

However, electronic power systems can respond on a timescale of milliseconds (as opposed to seconds for governor response), meaning that fast response capacity is likely to be very valuable to a system operator, although it cannot provide the same levels of inertia as thermal generation. The existing Rules may not allow system operators to count this response towards primary response [59], but as the technology matures this is likely to become commonplace. Additionally, new markets may be available for very fast response (for example, ERCOT's proposed Fast Frequency Response [58]), allowing the system to cope with lower levels of inertia and larger changes in net load.

Presently, although some system operators are looking into the operation of low inertia systems [60] [15], there are no developed market proposals including financial incentives for providing inertia which would promote concepts such as synthetic inertia from wind turbines to be commercially deployed. An alternative approach would be to mandate the provision of synthetic inertia as a requirement for grid connection. In either case, synthetic inertia is unlikely to be able to be retrofitted to generators once built, meaning that if this service is required long term, early intervention could reduce the burden on future generators.

Recommendation 12 – Begin to procure synthetic inertia capability
The WEM may face low inertia conditions in future, particularly if the number of wind turbines installed continues to increase. Wind turbines can provide synthetic inertia to support the system. EY recommends that the provision of synthetic inertia, or, if possible, the ability to be retrofitted for it, be considered as a preferred capability for future wind turbines in the WEM as a way of future-proofing the system. This will ensure the WEM can continue to avoid discrimination in the market against a particular energy option in line with Wholesale Market Objective (c).

Curtailment to provide reserves

Another option is the curtailment of renewables to provide reserve: at full output renewable energy generators cannot contribute to spinning or regulation reserve. However if they are curtailed to below their maximum output this would be possible. This is technically straightforward but involves a loss of generation revenue, which is problematic for markets with additional renewable energy markets, such as Large-scale Generation Certificates in Australia. Modelling in California indicates that curtailing wind generation so it could participate in regulating reserve markets could reduce operating costs, and increase revenue, if enacted at times of high wind production [61].

8.2.3 Demand side provision

Demand side provision, in the form of voluntary load shedding of large loads, is used in many markets around the world, including the WEM, to provide operating reserves. The load shedding is usually triggered by an under-frequency relay with an agreed setpoint, and will return when frequency stabilises, or after an agreed period has elapsed. This is distinct from demand side response requested (or notified) several hours in advance, for example in response to forecast high demand.

All markets surveyed had potential to, or had engaged, contracts with large scale loads to provide demand side response. Historically, this has been provided by single, large loads, but increasingly aggregators are offering demand side response from multiple, smaller commercial and industrial sources, including refrigeration, food processing and air conditioning [62].

The ability for load to provide more nuanced frequency regulation is being investigated, particularly through the development of smart grids.

Smart grids

“Smart grids” has become a buzz phrase for the changing electricity industry, encompassing everything from changed customer tariffs to minutely monitored systems with loads responsive to generation or system signals. Smart grids could enable system support in the form of controllable load.

In Germany, for example, the potential to use controllable domestic washing machines has been assessed as providing up to 7 GW of balancing power [44]. A large-scale grid study in Germany also assessed that Demand Side Management, particularly through the use of domestic

Combined Heat and Power (CHP) units as a controllable load, could provide 60% of energy increases needed to meet shortfalls in generation (positive balancing energy) and 2% of energy reductions needed to manage generation oversupply (negative balancing energy) by 2020 [63].

Achieving demand side response through smart grids would necessitate significant overhauls to electricity markets, meaning such initiatives must gain major public support and engagement. Widespread deployment of such systems is unlikely within the next five years.

9. Impact of increased intermittent generation on LFAS requirements

9.1 Introduction and overview

For this report, EY was requested to analyse a full year of historical data with the primary objective of estimating the impact on the LFAS requirement from increasing wind and solar penetration in the WEM by 50%. To do this, EY has built on a methodology developed by the IMO and System Management to investigate the causes of LFAS. We note, however, that the absolute values produced by this methodology do not necessarily represent the capacity of LFAS that should be procured from the market, due to a variety of reasons discussed in subsequent sections.

Causes of LFAS

In order to set an LFAS requirement it is useful to understand the main causes of the need for LFAS on a fine time-scale. A one-minute (1-min) data set can be used for this, where 1-min generation data is constructed using the 1-min average of 4-second SCADA readings as recorded by System Management. The IMO and System Management developed a methodology for analysing the causes of LFAS using this 1-min data (IMO/SM methodology), and published their initial results in a report in October 2013 [64] and later updated parts of the methodology in [65]. Four primary causes of LFAS were identified, plus a fifth source, as described below. The fifth source and some other possibilities of additional causes are still under investigation by the IMO and System Management. EY was unable to estimate the fifth source due to lack of data on auxiliary loads.

1. Load forecast error: Variations between forecast and actual system load;
2. NSG forecast error: Variations between forecast and actual Non-Scheduled Generator (NSG) output;
3. Deviations from dispatch: Deviations of IPP Scheduled Generators (SGs) from their Dispatch Instructions;
4. BMO ramping: Variations between the 1-min profile of IPP SGs being dispatched at their Balancing Merit Order (BMO) ramp rates, and using a linear ramp rate[12];
5. Aux estimation: Variations from errors in estimating the auxiliary loads of all SGs since the load forecast is produced in as-generated units.

Each of the first four causes was analysed separately and the calculated variations/deviations for each cause were presented with percentiles. The 1-min variations were summed to provide the percentiles of the net LFAS generation needed. However, the sum of the 1-min variations from the four causes is not the same as the overall LFAS needed. This is because the actual usage of LFAS is not transparent due to Balancing Portfolio not following its notional dispatch instructions. The deviation from a notional dispatch instruction is not necessarily representative of the physical movement of any Balancing Portfolio generator. If the Balancing Portfolio was dispatched according to its notional dispatch instructions, this would allow any improvements in accuracy in operating the WEM, such as an improvement to the load forecast accuracy, to be directly realised through reduced LFAS. Currently, such improvements may have no impact as any improvements in the dispatch instructions are not used directly to dispatch any generator in the Balancing Portfolio. In addition to this, if data were available on which Balancing Portfolio generators were LFAS-enabled and what their setpoints were, this would allow:

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[12] This is a cause of LFAS because the SG Dispatch Instructions are inherently based on linear movements towards the generator dispatch targets.

- Full transparency for analysing LFAS usage and causes. This allows the LFAS requirement to be estimated more accurately than presently using standard international practices.
- Full competition in the LFAS market as the full requirement is better estimated.

The current arrangements often reduce the movement required from non-LFAS enabled Synergy units, as they do not have to physically respond to each notional dispatch instruction. However, Synergy may from time to time provide more LFAS than the quantity allocated to it through the LFAS Market, either from additional AGC enabled plant or through manual dispatch of plant that is not consistent with its notional dispatch instructions. For example, a load forecast error might be absorbed through the manual re-dispatch of the Balancing Portfolio, rather than specifically by an LFAS-enabled plant.

Synergy is not currently compensated for any additional LFAS provision or for any adjustments made to account for unintended fluctuations of individual Balancing Portfolio units. Therefore, if the Balancing Portfolio was to be dispatched on an individual facility basis (i.e. the same as for IPP facilities), then the amount of LFAS usage in the WEM may increase, at least in the short term. EY considers that the implications of moving towards transparent dispatch of the Balancing Portfolio needs to be thoroughly investigated by the IMO before taking that path.

Data sources

EY obtained the following data for the 12-month period 1st April 2013 to 31st March 2014 to perform the analysis:

- 1-min average actual (SCADA) generation from each individual generator, in as-generated units,
- 1-min average system frequency,
- Load forecasts issued every 10 minutes for the end of each 30-minute trading interval (EOI), in as-generated units (for each EOI, there is an initial load forecast made to apply from the beginning of the trading interval followed by two revisions applying from 20 minutes and 10 minutes before the EOI),
- The actual dispatch instructions issued to each individual IPP generator and the notional dispatch instruction issued for the Balancing Portfolio, on the same time frames as the load forecasts,
- The Balancing Merit Order (BMO) stack that applied to each 30-minute trading interval, and
- Flags determining if the generators used for LFAS in the WEM were enabled for LFAS or not on a trading interval basis.

EY also had access to the data and workings used for the IMO's and System Management's monthly LFAS analyses for January, February and March 2014. This includes metered 1-min generation from each individual generator in sent-out units.

Modelling methodology

To perform the required analysis, EY has written a software program that is capable of analysing a year (or more) of 1-min data. In this program, EY has mostly emulated the IMO/SM methodology outlined in the two IMO documents referenced above. During the course of the project, EY implemented the following modifications to the IMO/SM methodology:

- More stringent rules for removing trading intervals affected by erroneous load forecasts. Erroneous load forecasts were present in the first few months of the data set. In April 2013, the IMO/SM methodology removed around 10% of the data due to erroneous load forecasts, while EY has removed around 17%.
- EY identified a number of trading intervals where the actual dispatch instruction data contained at least one instruction issued outside the 10-minute re-dispatch cycle time frame. These were removed from the analysis.

- Since EY was only provided actual sent-out generation data for January to March 2014, EY developed a line of best fit based on this data to convert the as-generated data for the whole year to sent-out units.
- To calculate the contribution to LFAS from a generator deviating from its dispatch instructions, a minute-to-minute effective dispatch instruction needs to be constructed from the end of interval dispatch instructions issued. To do this, EY used the same method as the IMO/SM methodology, except starting from the previous target instead of the actual output level. This is based on the premise that if LFAS are being used at the end of a 10-minute interval due to a generator deviating from its dispatch target, this LFAS usage can only be reduced over the subsequent minutes in the following 10-minute interval as fast as generator ramp rates allow.
- EY has removed trading intervals where generators experience forced outages while the RTDE has not been updated and issues dispatch instructions for them.

Section outline

The remainder of this chapter is as follows:

- Section 9.2 benchmarks the results from EY's analysis against the analysis undertaken by System Management using the IMO/SM methodology for the month of February 2014;
- Section 9.3 shows EY's LFAS contribution results for the full 12 months of data, and;
- Section 9.4 shows the modelled impacts of increasing wind and solar penetration in the WEM.

9.2 Benchmarking EY's results for February 2014

EY has taken the approach of first benchmarking its software program results against those produced by System Management using the IMO/SM methodology for the month of February 2014. This allowed EY to verify that the software program produced outcomes broadly consistent with the IMO/SM methodology (subject to minor differences in the methodology used). With the software program validated, EY was then able to use it to analyse the full year of data to form a basis of percentile results to which the increased wind and solar penetration scenarios can be compared.

EY used the same data filtering as the IMO/SM methodology for this benchmark, which resulted in only removing two trading intervals for this month, due to frequency excursions outside 50 ±0.32 Hz.

Table 9.1 and Table 9.2 show System Management's results and EY's results respectively. Results are presented as percentile of time that the LFAS needed for a given source (as defined in Section 9.1) exceeds the specified value. The "total net" LFAS usage represents the combined impact of all sources, noting that on a 1-minute basis different sources of deviations may cancel each other out, or may add to an even greater amount. The extreme percentiles (99.95% and 0.05%) are most relevant to the LFAS planning standards, but are driven by a very small number of periods, and so are particularly susceptible to subtle changes in methodology; hence, relativities rather than absolute values should be considered in this analysis.

Table 9.1 – Percentile estimates for LFAS needed for February 2014 from System Management's analysis

Percentile	Load forecast error	NSG forecast error	Deviation from dispatch	BMO ramping	Total net
99.95%	-88	-83	-55	-74	-88
99.50%	-70	-38	-44	-52	-70
99%	-63	-30	-38	-44	-63
98%	-56	-24	-13	-36	-56
97%	-52	-20	-9	-31	-52
96%	-48	-18	-5	-27	-48
95%	-46	-16	-4	-24	-46
90%	-37	-11	0	-15	-37
50%	-10	0	6	0	-10
10%	18	11	17	15	18
5%	27	15	28	24	27
4%	30	17	41	27	30
3%	34	18	43	31	34
2%	39	21	45	37	39
1%	47	26	49	47	47
0.50%	55	32	60	56	55
0.05%	75	56	93	89	75

Table 9.2 – Percentile estimates for LFAS needed for February 2014 from EY's analysis

Percentile	Load forecast error	NSG forecast error	Deviation from dispatch	BMO ramping	Total net
99.95%	-88	-92	-24	-74	-105
99.50%	-70	-43	-11	-52	-81
99%	-62	-35	-7	-44	-72
98%	-56	-28	-5	-36	-61
97%	-51	-23	-3	-31	-55
96%	-48	-21	-2	-27	-51
95%	-45	-19	-1	-24	-48
90%	-37	-13	1	-15	-36
50%	-10	0	6	0	-2
10%	18	13	23	15	40
5%	27	18	45	24	55
4%	30	20	46	27	61
3%	33	22	48	31	67
2%	38	25	51	37	76
1%	46	31	58	46	86
0.50%	54	37	63	55	98
0.05%	75	62	108	84	141

The differences in NSG forecast error can be explained by the following:

- In calculating the NSG forecast error, System Management does not include the Mumbida wind farm. Since Mumbida is a large wind farm and the persistence forecast method used by System Management creates large variances, this contributes to making the need for LFAS due to NSG forecast error larger.

EY has included Mumbida in the NSG forecast error calculations.

The differences in Deviation from dispatch can be explained by the following:

- An error System Management's formulae for calculating the implied 1-min BMO dispatch targets for Muja 1 and Muja 2. It appears that the actual SO data for both Muja 1 and Muja 2 is accidently set to zero for the whole month of interest (even though this is not the case) and, thus, the formulae do not give correct BMO dispatch targets.

EY has included Muja 1 and Muja 2 in totalling the BMO dispatch target.

The differences in BMO ramping can be explained by the following:

- An error in System Management's formulae for calculating the implied 1-min BMO ramp rate dispatch targets and 1-min linear ramp rate dispatch targets. It appears that Muja 1, Muja 2, NewGen Neerabup and the Alinta Wagerup units had their actual SO data set to 0 (even though this is not the case).

EY has included the missing units in calculating the variance due to BMO ramping.

Lastly, due to the linear-fit conversion of AG to SO generation data, EY's SO data may have a small number of 1-min data blocks that differ materially from System Management's SO data.

9.3 Full year LFAS results (Base case)

EY performed its LFAS cause calculations for the full year of data, using the methodology described above. 13.8% of trading intervals were deemed inappropriate for LFAS usage analysis based on the causes listed in Table 9.4 and described in Section 9.1.

Table 9.3 – Data removed from the full year due to the different categories

Category	Percentage data removed	Number of TIs removed
Missing Load Forecasts	7.6%	1338
Generator outages	6.2%	1093
Frequency Excursions	0.2%	36
Load Forecast Errors - AG	0.2%	36
Unusual Dispatch Instructions	0.2%	37
TOTAL Erroneous Data	13.8%	2418

Table 9.4 shows EY's percentile results for the full year of data. The extreme ends of the distribution for the LFAS causes (the very high/low percentiles) are all higher for the full year than they were for February 2014, except for NSG forecast error where they are about the same. The results in Table 9.4 are shown graphically in Figure 9.1. EY notes that these results do

not necessarily represent the LFAS needed to be procured in the market due to a variety of factors described earlier, including:

- the lack of auxiliary data;
- the IMO and System Management's investigations on the causes not yet being complete; and
- the sensitivity of the extreme percentile results to individual trading intervals.

Table 9.4 – EY's percentile estimates for LFAS needed based on the full year of data

Percentile	Load forecast error	NSG forecast error	Deviation from dispatch	BMO ramping	Total net
99.95%	-106	-83	-62	-101	-130
99.50%	-73	-45	-24	-62	-83
99%	-63	-36	-12	-50	-71
98%	-53	-29	-7	-38	-58
97%	-47	-24	-5	-32	-51
96%	-42	-22	-4	-27	-46
95%	-39	-19	-3	-24	-41
90%	-28	-13	-1	-14	-28
50%	2	0	6	0	10
10%	31	13	20	14	48
5%	41	19	26	24	62
4%	45	21	28	27	66
3%	49	23	30	32	71
2%	55	27	33	38	79
1%	65	34	41	48	93
0.50%	76	43	56	58	107
0.05%	105	75	91	94	146

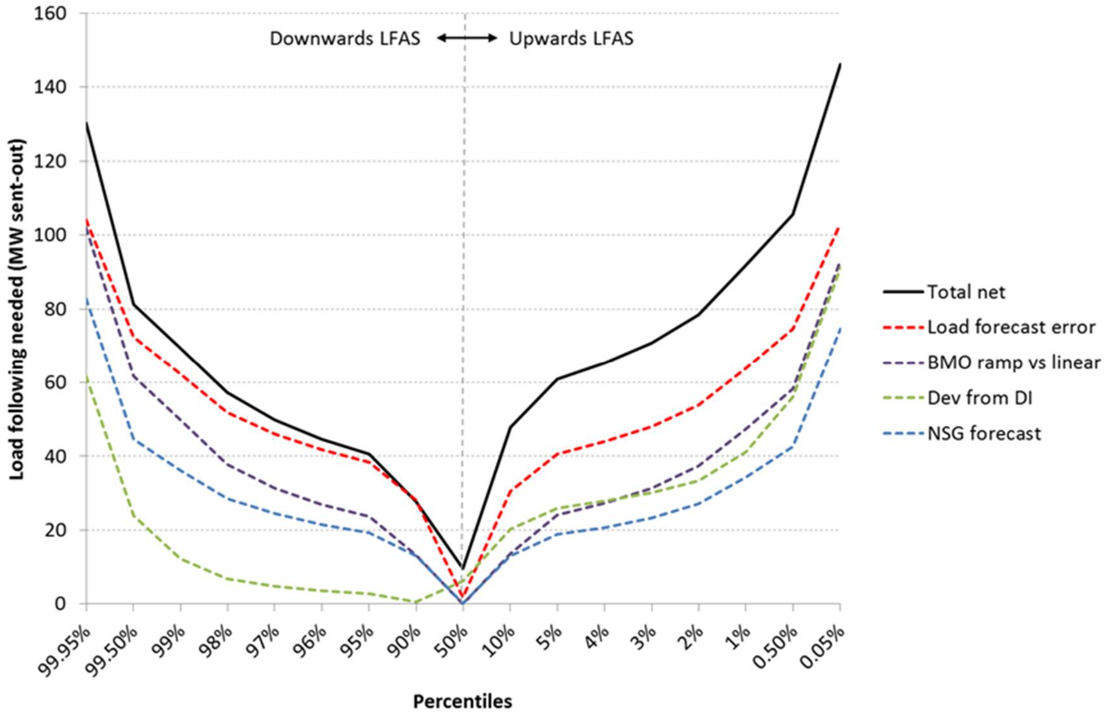


Figure 9.1 – EY percentile estimates for LFAS needed based on the full year of data

Of the causes presented in Figure 9.1, only deviation from dispatch instructions is clearly non-symmetrical for downwards and upwards LFAS. As discussed in the IMO and System Management's report on LFAS analysis [64], this is because generators are in general able to ramp down accurately according to their dispatch instructions, but are less accurate at ramping upwards. This asymmetry in the deviation from dispatch instructions is reflected in the total net of all causes.

As presented in Recommendation 11, EY recommends that generators do not receive out of merit payments if dispatched at other than their Balancing Submission ramp rate limits. Instead, dispatching generators with a ramp rate which will drive them to move linearly toward their dispatch targets, subject to their technical capabilities, will reduce LFAS requirements. Given that linear dispatch instructions exactly complement linear load forecasts, cause 4 (BMO ramp rate versus linear ramp rate) would be greatly reduced. In addition to this, it is expected that the contribution to LFAS requirements from cause 3 (deviation from dispatch instructions) would decrease. This is because the required linear ramp rates are often likely to be less than the present BMO ramp rates and it is expected that generators will be able to comply with smaller upward ramp rates with more success than they currently do with the full BMO ramp rates (refer to the asymmetry in the LFAS needed from cause 3 discussed above and presented in Figure 9.1). EY understands that allowing System Management more flexibility in the ramp rates it uses for dispatch without requiring constraint payments is being considered by the IMO.

9.4 LFAS results from increasing wind or solar generation

EY analysed the full year of 1-min data to provide the IMO an estimate of the likely increase in LFAS requirements due to future plausible increases of wind or solar generation in the WEM. The first step in evaluating the increase in LFAS causes due to increased wind or solar generation is to create an appropriate 1-min wind/solar generation profile to represent the increase. The methodologies used to do this for wind and solar are described in Appendix A. These profiles are then used to estimate the changes in the relevant LFAS cause contributions (as per Table 9.5 and Table 9.6).

As extra generation capacity is available from the NSG (wind or solar) penetration, for a given load forecast there will be less scheduled generation required to meet this forecast. That is, for a given instance of the BMO, the amount of low-bidding NSG capacity is increased so that the total capacity that must be met by the scheduled generators in the stack is reduced. For each scenario, EY therefore developed new dispatch instructions for all generators based on the historical BMOs applying in each period. This methodology was benchmarked against the historical year to ensure that historical dispatch instructions could be accurately reproduced, and was found to be highly accurate, subject to a few periods of out of merit dispatch instructions due to system constraints, which were ignored for the purposes of this section. EY then re-calculated the sources of LFAS using the same methodology as described in Section 9.1, above.

9.4.1 Increasing wind generation

Approach

Table 9.5 describes the likely change in each of the four contributions to LFAS analysed due to an increase in wind generation.

Table 9.5 – LFAS contributions from increasing wind generation

LFAS cause	Change in LFAS cause contribution due to increase in wind
Load forecast errors	No change as actual load and load forecast are not changed.
NSG forecast errors	Material change due to increase in NSG.
SG deviation from DI	Negligible change and beyond the scope of this work.
Dispatch at BMO ramp rate	Potentially material change due to different dispatch instructions from the change in the net load forecast.

Results

Figure 9.2 shows the results for the LFAS causes contribution for the 50% extra wind generation case from the NSG forecast cause as well as the total net contribution from the all four primary LFAS causes. The BMO ramp rate cause is not shown in Figure 9.2 because the change in its contribution due to the increase in wind generation is negligible. Figure 9.2 shows that while the increase in wind generation results in an increase in the LFAS needed from the NSG forecast error at the extremes (percentiles 0.05% and 99.95) of 20-30 MW, the overall increase in the LFAS needed (Total net) is about 10 MW. This is due to the NSG forecast error being materially anti-correlated with the other LFAS causes.

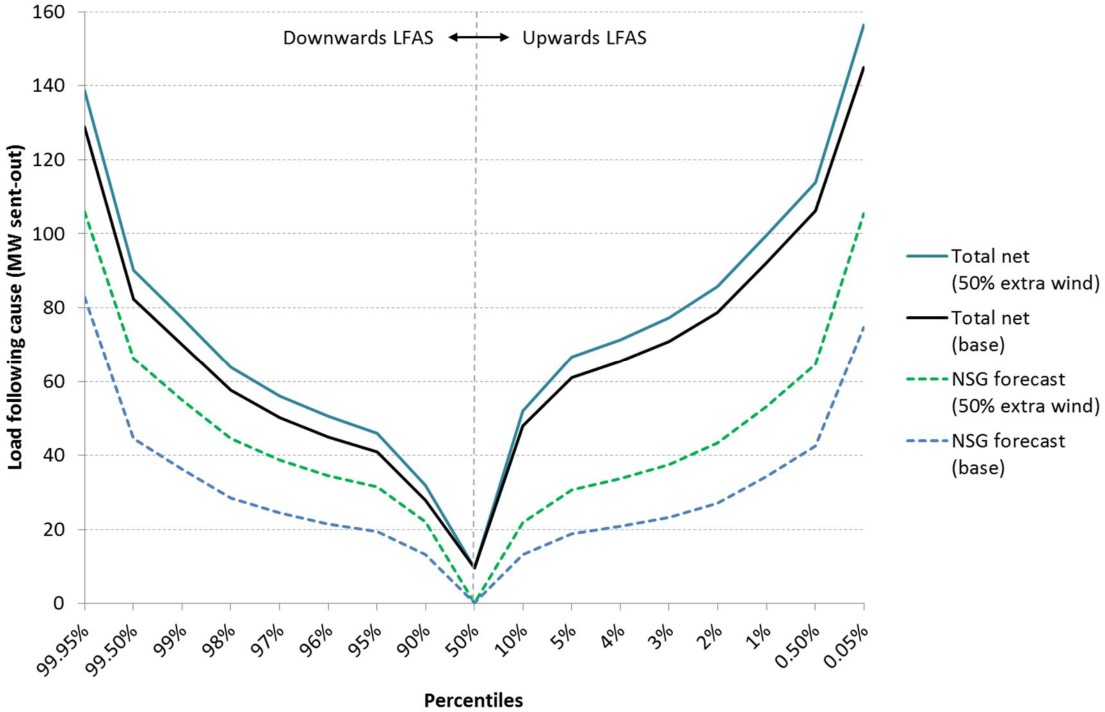


Figure 9.2 – Load following percentiles for the base case and increasing wind generation

9.4.2 Increasing solar PV generation

Approach

As described in Appendix A, EY increased solar PV generation in the WEM by increasing large-scale solar generation by 12.5 MW, and rooftop PV generation by 150 MW. The increase in large-scale solar generation can be treated the same way as wind generation in the previous section – see Table 9.5. However, rooftop PV generation is not currently forecast in the same way as large-scale solar generation in the WEM – it is incorporated into the load forecast and EY was therefore not able to produce a new retrospective load forecast for an additional 150 MW of rooftop PV generation for this study. Instead, EY considered two cases for increasing rooftop PV, which reflect worst- and best-case forecasting scenarios:

Case 1. The rooftop PV generation is added to the original NSG generation and this is forecast using the persistence method. This case assumes no solar PV specific forecasting methodology is used and represents the worst case in terms of the contribution of additional rooftop PV to LFAS requirements.

Case 2. The rooftop PV values at the end of every trading interval are netted off the load forecast targets and the 1-min load forecast is recreated using the linear interpolation method. The full 1-min rooftop PV trace is then netted off the actual load when calculating the load forecast error LFAS causes contribution. This case assumes that the additional rooftop PV trace is forecast perfectly at the end of each trading interval, but is expected to ramp linearly from one trading interval to the next. There is an additional contribution to LFAS from the additional rooftop PV due to the intra-dispatch interval variations in the rooftop PV generation. Aside from forecasting the rooftop PV generation with a more sophisticated approach on a minute to minute basis, this represents a best case approach to reducing the contribution of additional rooftop PV to LFAS requirements.

Table 9.6 describes the likely change in each of the four contributions to LFAS analysed due to an increase in rooftop PV generation with respect to these two cases. These changes are in addition the impact of the additional 12.5 MW of large-scale PV as discussed above and as per Table 9.5.

Table 9.6 – LFAS contributions from increasing rooftop PV generation

LFAS cause		Change in LFAS cause contribution due to increase in rooftop PV
Load forecast errors	Case 1	No change as actual load and load forecast are not changed.
	Case 2	Material change due to netting off rooftop solar PV.
NSG forecast errors	Case 1	Material change due to increase in NSG.
	Case 2	No change as NSG capacity is not changed.
SG deviation from DI		Negligible change and beyond the scope of this work.
Dispatch at BMO ramp rate		Potentially material change due to different dispatch instructions from the change in the net load forecast.

Results

Figure 9.3 shows the results of the LFAS causes contribution for the NSG forecast cause as well as the total net contribution from all four primary LFAS causes for both the base case and 50% extra solar generation as in Case 1. As with the wind increase, the BMO ramp rate LFAS cause is not shown due to negligible changes from the base case. Figure 9.3 also shows although there is additional solar PV in the NSG aggregate, only a small increase NSG forecast error occurs.

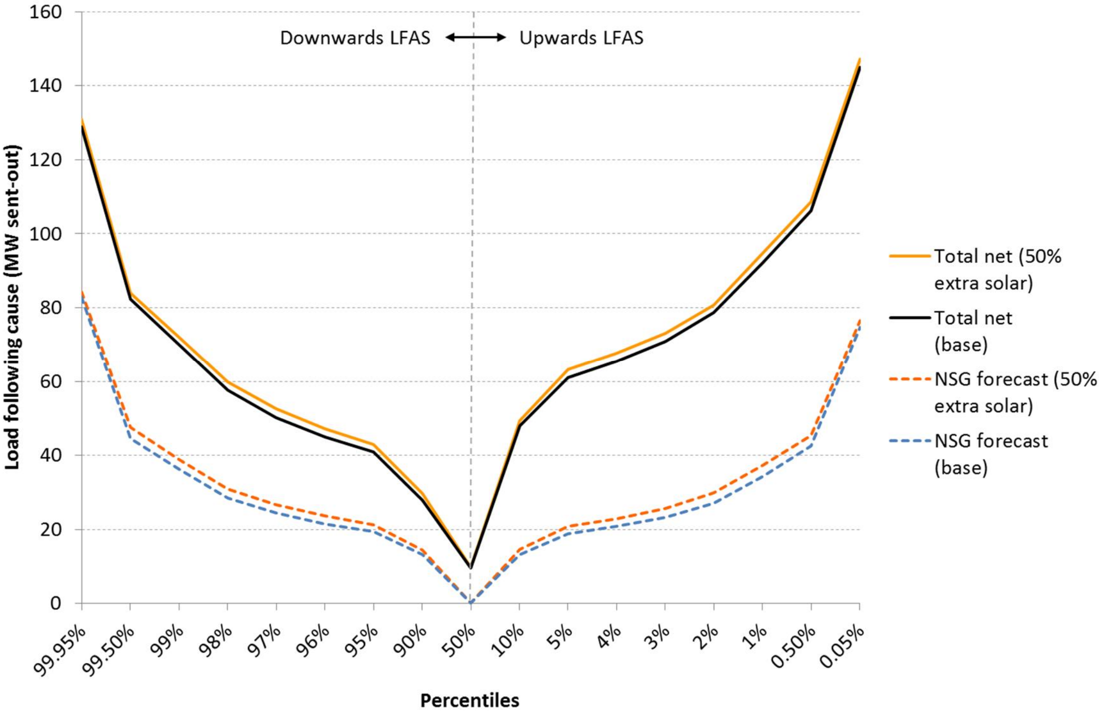


Figure 9.3 – Load following percentiles for the base case and increasing solar (Case 1: NSG increase)

Figure 9.4 shows the results of the LFAS causes contribution for the load forecast cause as well as the total net contribution from all four primary LFAS causes for both the base case and 50% extra solar generation as in Case 2. Once again, the BMO ramp rate LFAS cause is not shown due to negligible changes from the base case. The additional contribution from NSG forecast errors due to the additional 12.5 MW of large-scale solar PV was also negligible and as such is not shown in the figure. As can be seen in Figure 9.4, the changes in load forecast error due to the netting of the rooftop PV trace are very small.

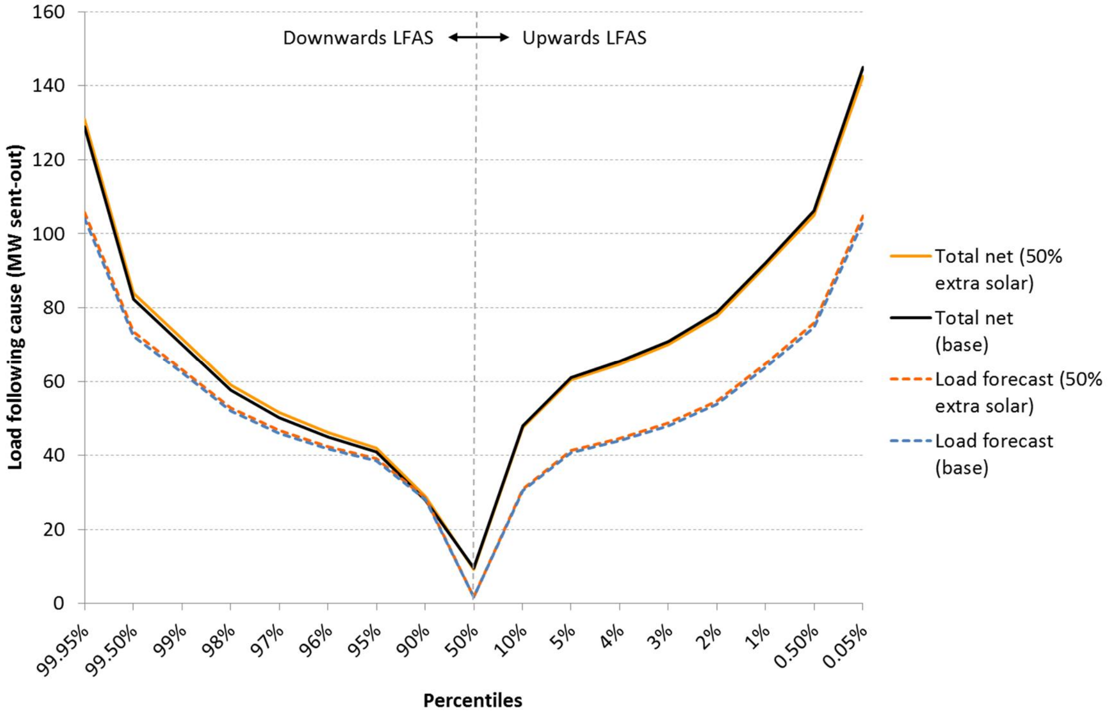


Figure 9.4 – Load following percentiles for the base case and increasing solar (Case 2: reducing the net load forecast)

9.4.3 Summary

As the results suggest, there is greater impact on total LFAS causes contribution due to a 50% increase in wind penetration than compared to either case of the 50% increase in solar penetration. For the WEM, this difference can be attributed to a greater increase in actual capacity for wind (as above, 281.4 MW) than for solar (as above, 162.5 MW), as well as the average capacity factor of wind generators (typically 35%) being double of that for solar generators (as above, 17.2%).

In summary, according to the modelling on the data analysed, an increase in wind capacity of 280 MW in the WEM would result in an increase in the overall LFAS requirement by about 10 MW. In contrast, adding 162.5 MW of solar PV capacity to the WEM would make a negligible change to the LFAS requirement.

10. Assessment of Spinning Reserve Volumes

EY has conducted an assessment of the volumes of SR and LRR necessary to keep the system within its operating bounds within a range of system operating conditions. According to the SWIS Operating Standards, sufficient volumes of the services should be procured to keep the frequency above 48.75 Hz and below 51 Hz after a single contingency.

EY obtained detailed data from System Management and Western Power on the technical operation of WEM units, including inertia levels, turbine models and other parameters, as well as typical system parameters, such as available interruptible load settings and expectations of load relief. Based on analysis of this data, EY developed a simplified turbine model of the WEM's behaviour in response to a contingency using MATLAB/Simulink. A more detailed explanation, including block diagrams of the Simulink model is provided in Appendix B.

10.1 Important concepts in assessment of spinning reserve

EY has conducted simulations of the system over a large range of frequency, inertia, reserve, load and contingency size conditions, to determine the range of parameters under which a given contingency size can be weathered (i.e., the frequency can be maintained above 48.75 Hz). These parameters each have a significant impact on the frequency response of the system to a contingency.

10.1.1 Inertia

Inertia is the resistance of a system to change, and relates to the fact that large spinning turbines have physical mass and so can keep spinning and resist a decline in frequency in the face of a contingency.

In power systems, inertia is measured in Megawatt-seconds (MWs). Each generator has an inherent level of inertia, depending upon their type and capacity. A generator's inertia is provided in full to the system once it is online and synchronised, regardless of its loading. That is, Collie provides 1,196 MWs of inertia whether it is operating at full or minimum output.

System load also provides inertia, as discussed in Section 10.1.2.

The effect of reduced inertia in a power system is that, following a contingency event, the rate of frequency fall is higher. Generally, if the system inertia is halved, the rate of frequency reduction doubles and vice versa. With a higher rate of change of frequency, the minimum frequency is lower, and also the time at which the system stays at that lowest frequency is shorter. The rate of recovery is also faster as less energy input is needed from the SR plant to restore the frequency.

The WEM in 2013-14 operated with levels of inertia from around 10,000 MWs to 25,000 MWs. EY has conducted simulations from 1,000 MWs to 29,000 MWs. This incorporates systems of lower inertia which may be a result of increasing penetration of wind and solar generation (and correspondingly lower large rotating plant).

10.1.2 Load Relief

Load relief is the change in load provoked by a frequency change. Many loads include motors which contribute inertia to the power system in the same way as conventional generators do. A decrease in frequency will prompt load to slow down and reduce electricity consumption and vice versa. Provided that the frequency remains within normal operating limits, this response will be automatic and load will be restored when frequency recovers. The inertia of each load in the system is difficult to compute precisely. However, the response of all load in a system to changes in frequency has been aggregated to the following equation [66]:

$$Disturbed\ Load = Nominal\ load * \left(\frac{disturbed\ frequency}{nominal\ frqeuency}\right)^{\substack{load\ frequency \\ index}} \quad (1)$$

The load frequency index depends upon the level of load and its make up at the time. System Management provided EY a range of observed load indices. Figure 10.1 illustrates the range of load relief expected if frequency drops to 48.75 Hz as a function of load online.

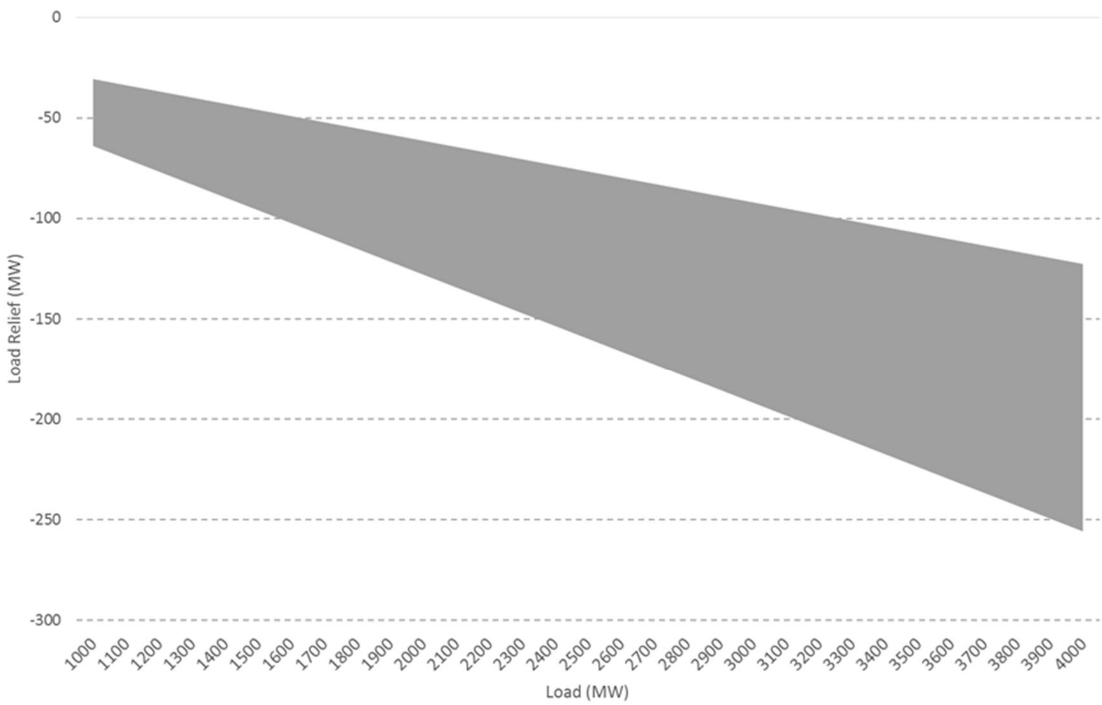


Figure 10.1 – Range of Load Relief Available on a Frequency Drop to 48.75 Hz

10.1.3 Load

From equation 1, it can also be seen that the nominal load, that is, the load before the disturbance, impacts on the disturbed load. A system at higher load will experience a greater change in load for the same frequency disturbance. There will then be less pressure on the generation to provide reserve and the frequency drop will be lower for the same amount of load relief.

The one minute system load duration curve from April 2013 – March 2014 is shown in Figure 10.2.

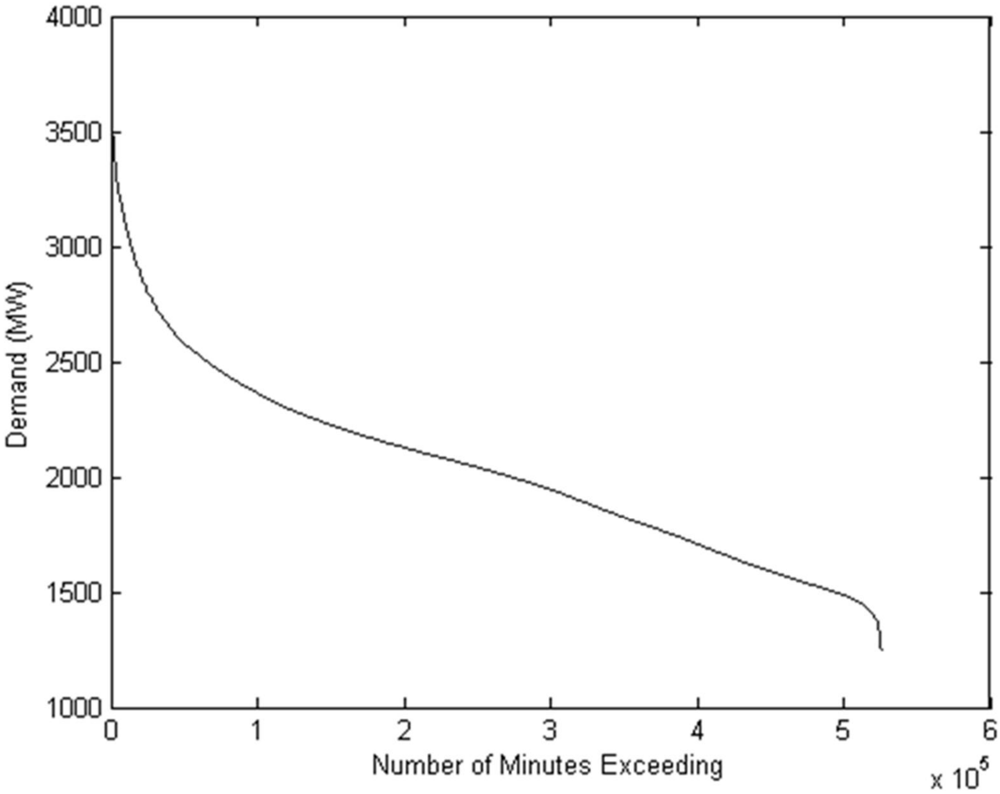


Figure 10.2 – Duration Curve April 2013 – March 2014

The following analysis will focus on the maximum, minimum and median demands. The duration curve is quite spread out at each end, so that the maximum and minimum demand represents the extreme ends of the system's operation.

Table 10.1 gives the generation and inertia at these demand points. The inertia given here does not include the contribution of Collie, as it is assumed to be the largest generator online and therefore is tripped off in the model to simulate the contingency event.

Table 10.1 – Range of Generation and Inertia Levels in the WEM

	Generation (MW)	Inertia (MWs)
Minimum	1248	8,836
Median	2019	14,421
Maximum	3722	23,156

10.1.4 Contingency Size

All other factors being equal, an increase in contingency size will stress the system more by creating a larger drop in frequency and making it more difficult to stabilise the frequency after the event. Conversely, a system that faces only smaller contingencies will require less inertia and reserves.

The minimum frequency will occur at almost the same point in time, regardless of the size of contingency event. The size of the contingency has limited impact on the rate at which SR plant can begin to provide frequency response. A larger contingency event provokes a faster change in frequency which reaches a lower minimum frequency before the SR plant can reverse this change.

The largest generation contingency in the WEM is the trip of the Collie power station, which has a normal maximum output of 330 MW. EY has investigated contingency sizes ranging from 150 MW to 330 MW, representing the likely generation of Collie in normal operation.

10.1.5 Spinning Reserve

The amount of SR available influences the minimum frequency and the frequency at which the system stabilises. SR providers cannot change the initial rate of change of frequency, which is determined by the inertia of the system before the reserves can take action. The lower the level of reserve, the longer it takes to limit the frequency fall and the minimum frequency reached will be lower. At the extreme level, insufficient SR will not be able to stabilise the frequency, resulting in load shedding. Higher levels of SR will also increase the frequency to which the system is stabilised, as more generation is available, meaning the response from load is lower and the frequency deviation is smaller.

EY's simulations investigated three scenarios of SR volume; with reserves set at 50%, 70% or 90% of the size of the contingency event. All investigations include the assumed 42 MW of interruptible load, which trips offline 500ms after the contingency event. The rest of the SR is made up by coal and gas plant, nominally set so that the coal plant provides one-third of the response and the gas plant provides the rest. This represents a likely spread of the SR allocation between coal and gas generators at a range of operating states. These simulations do not consider response from any other generators.

When the second interruptible load contract comes into place, the total amount of interruptible load is expected to increase to 55 MW. This will reduce the amount of SR required to be provided by generators. The interruptible loads are valuable as instantaneous load reduction, which can be faster than responses from generators. While this will improve the robustness of the system, the second interruptible load is quite a small amount compared to the amount of SR required and is not expected to materially change the outcomes presented in the following section.

10.2 Model Benchmarking and Calibration

In order to investigate the accuracy of the model, System Management and Western Power supplied EY with detailed high-resolution data surrounding two events:

- A trip of Collie power station on the 26/11/2013, and;
- An over-frequency event resulting from a voltage dip, causing reduced load on 29/03/2014.
-

The following discussion focuses on the trip of Collie as EY considered it a more appropriate starting point for the exploration of different SR settings. The over-frequency event was used to provide more certainty in the calibration of the model.

To compare the model output to historical behaviour, EY investigated the response of each generator in the WEM after the contingency events. In the supplied data, not all generators were observed to respond as would have been expected (i.e., to provide governor response at 4% droop for 10 seconds (for IPPs) or indefinitely (Synergy units). By analysing the responses, EY categorised the plant as responsive or non-responsive (i.e. having a negligible response) to frequency deviation as shown in Figure 10.3.

Many units did not have a discernible response in the immediate aftermath of the event, while some responded significantly but only 10 to 15 seconds after the event. The delayed response is assumed to be AGC action rather than governor response. The response of some of these units may have been invisible in the four second data. Additionally, System Management stated that some units have higher or lower response capabilities, and that these are being improved over time.

For the benchmarking periods, the remaining gas plant which did not discernibly respond were included in the model with a constraint limiting their response such that their response was not as per their theoretical governor characteristics. This indicates that these plants were not meeting their technical requirements to provide governor response for the first 10 seconds after an event. This non-compliance is worthy of investigation, as having this response will make the system much more robust.

For the modelling around the SR/LRR requirements, underlying the key recommendations of this section, the precise response of non-SR/LRR units is not significant. In particular, because EY's frequency model is specifically concerned with the short-term frequency nadir, we believe that System Management must procure SR capacity in preparation for a "worst case" scenario, that is, where only generators which are enabled for SR respond to the contingency. For example, although there is likely to be additional response from other generation (including IPPs), this cannot be relied upon by System Management. Alternatively, if in the future, this additional response is regularly available, a reduction in the amount of Class A SR required may be appropriate, or these generators should become eligible to provide SR.

All supplied turbine models were reviewed in detail and EY concluded that using one representative model for steam units and another for gas units would provide a reasonable trade-off between model detail and computational feasibility. Further details are given in Appendix B.

Aside from technical compliance, this service is also dependent upon the generators being loaded to less than their capacity, or more than their minimum load, and thus being able to modify their generation in response to a contingency event. Thus, the actual dispatch at each interval will have a significant impact on the frequency response to a contingency.

All modelling also included 42 MW of interruptible load which tripped offline immediately following a contingency event and stayed offline for the duration of the modelled period.

10.2.1 Benchmarking Results

The comparison of the generation from the modelled responsive coal generators and their actual 4 second records is shown in Figure 10.3 for the 20 seconds after the Collie trip. This shows that these generators are responding in line with their expected governor response. However, there are differences between the modelled and the actual response. As shown in the diagram, one unit had a response that is lower than the model and another had a higher and slightly irregular response. EY has not investigated the individual generator's responses. Our model uses a small subset of reserve which is usually available so that individual discrepancies should not impact the model significantly.

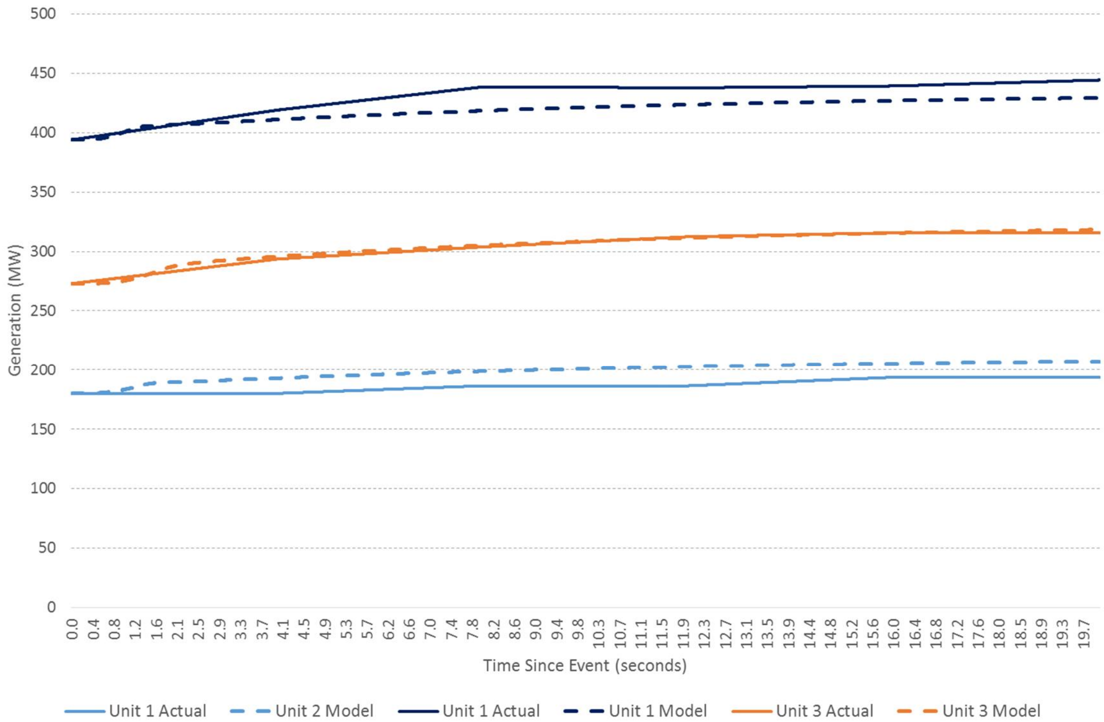


Figure 10.3 – Actual and Modelled Response of Coal Units to Collie Trip

The more significant discrepancies were between the total generation and load in the model and in the measured data. EY adjusted the load relief factor for the period to provide a best-fit to the load and generation data, within the range of load relief factors observed by Western Power. Figure 10.4 shows the resulting load and generation. (The initial drop in generation represents the contingency event.) The initial discrepancy, where the modelled generation drops lower and rebounds is likely to be a limitation in the four second data at recording actual fast governor responses of the generation. In this picture, the 42 MW intermittent load is the difference between the generation and the load as the system stabilises.

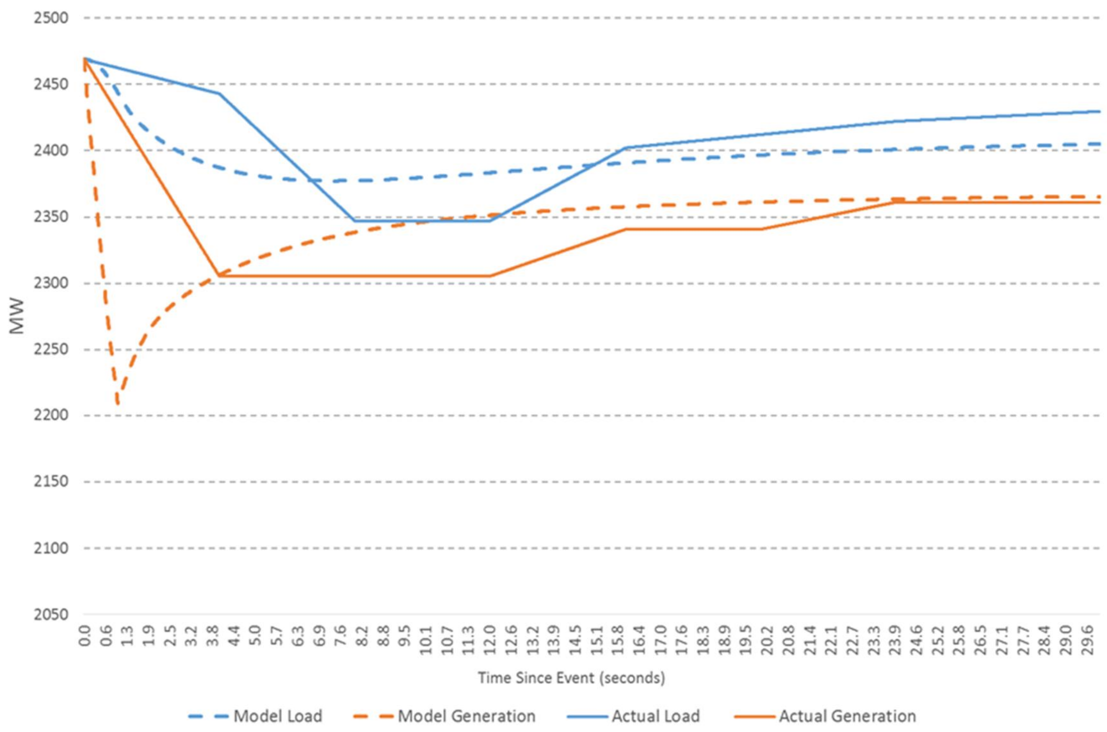


Figure 10.4 – Actual and Modelled Generation and Load Response to Collie Trip

The frequency resulting from this model is shown with the recorded frequency in Figure 10.5. Unlike the four second generation and load data, the frequency was measured at 100 Hz so has a much finer resolution.

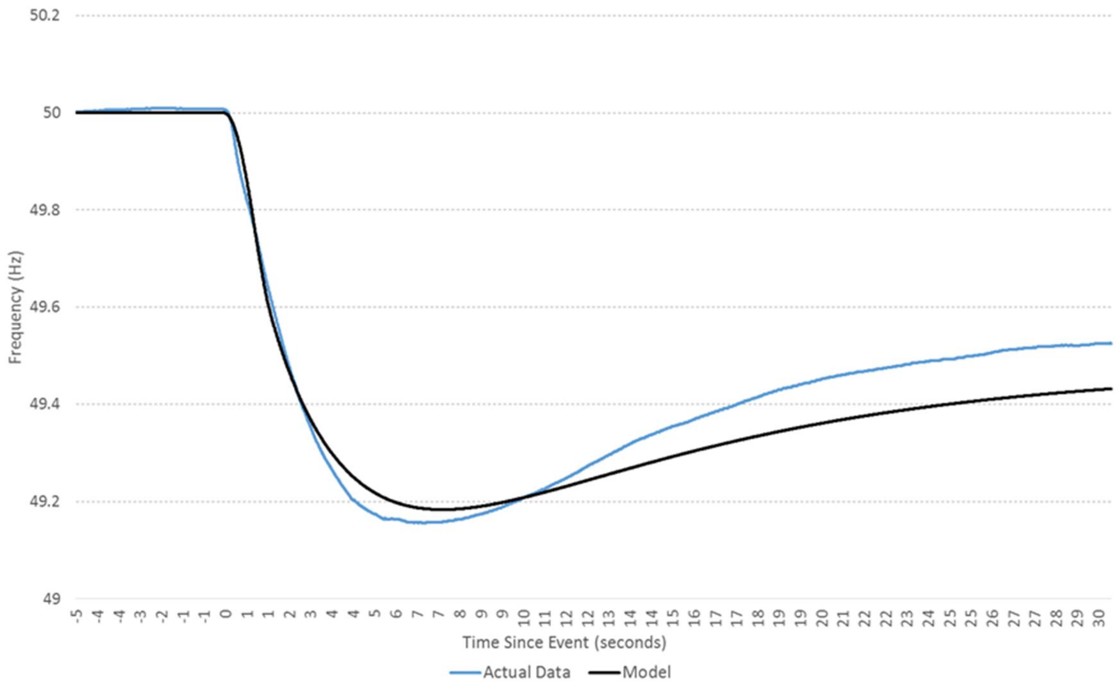


Figure 10.5 – Actual and Modelled Frequency Response to Collie Trip

The frequency model is therefore well benchmarked against history, and suitable for assessing the SR requirements in the WEM.

10.3 Results

10.3.1 70% Spinning Reserve

The present SR standard is to have suitable reserve enabled to cover 70% of the largest credible contingency. Figure 10.6 shows the minimum operating states to maintain frequency above 48.75 Hz for the range of load, inertia and contingency size scenarios described above. In Figure 10.6 and Figure 10.8 and Figure 10.9 further on, the line between the dark blue and the light blue bands represents the minimum operating state to be able to cope with a 300 MW contingency. If the system is in a state above that line, frequency will not dip below 48.75 Hz. Similarly, the line between the dark blue and red bands represents the minimum operating state required to cope with a 250 MW contingency. The coloured bands of operation are aggregation only. Any particular point in the green band may not be able to cope with a contingency up to 200 MW, and instead it might be only able to cope with a contingency of 160 MW. For example, at the system's minimum demand, represented by the red dot, the combination of 8,800 MWs of inertia and 1250 MW of system load was not able to cope with the loss of Collie at 180 MW. If that contingency had been reduced to 150 MW though, the system frequency would have stayed above 48.75 Hz.

Figure 10.6 shows that, for high levels of inertia, decreasing inertia has a relatively small impact on the system security. However at low levels of inertia the amount of load required to provide sufficient load relief to maintain frequency above 48.75 Hz increases steeply. For a contingency of 300 MW frequency cannot be maintained above 48.75 Hz even with a 3,900 MW system load if system inertia is less than 2,000 MWs.

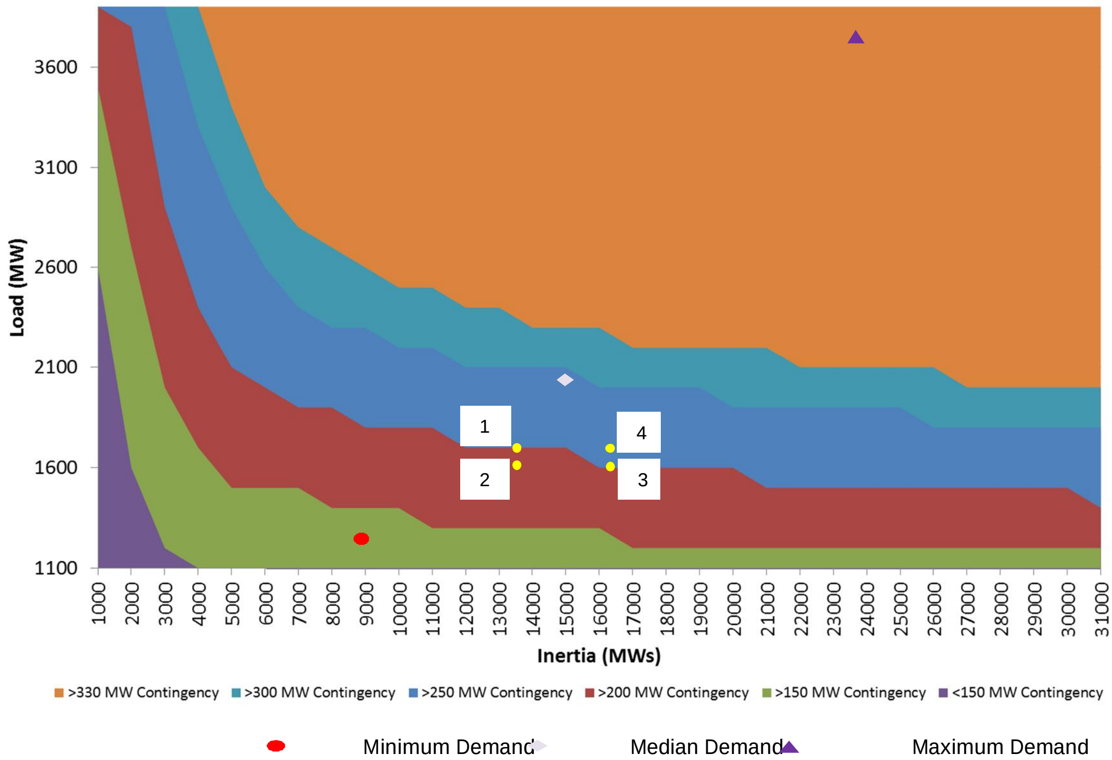


Figure 10.6 – Regions of Safe System Operation with 70% Spinning Reserve Enabled

The minimum, median and maximum levels of operation from 2013-14 are shown as points on the graph above. The inertia values here do not include Collie's inertia contribution as the contingency event is assumed to be the trip of Collie. This shows that with 70% of the contingency enabled as SR, the system at median demand would be able to cope with a contingency above 250 MW. However if Collie is generating above 300 MW, the system may be at risk of load shedding on a single contingency. This illustrates that at low load and low inertia levels the system must be carefully monitored as, if there is a large generator online, the system is vulnerable.

Figure 10.7 illustrates the frequency response at the points marked 1-4 on Figure 10.6 above after a 250 MW contingency. The lines of the same colour have the same load. These stabilise to the same level, as the load relief and reserve available is the same. This results in the same level of response being extracted from the load, leading to the same frequency deviation. However, with lower inertia, the frequency nadir is lower. The lines of the same inertia, that is the two solid lines, have the same rate of change of frequency after the event. With higher load, there is extra load relief available to stabilise the frequency more quickly and to a higher level. Points 1 and 3 are close to a frequency of 48.75 Hz, represented by their position on the line between the red and blue sections of Figure 10.6. Point 4 has a larger margin in coping with the contingency, and is therefore further into the blue section. The 250 MW contingency creates a frequency nadir below 48.75 Hz for point 2 as it is in the red section in the graph, unable to cope with a contingency greater than 250 MW.

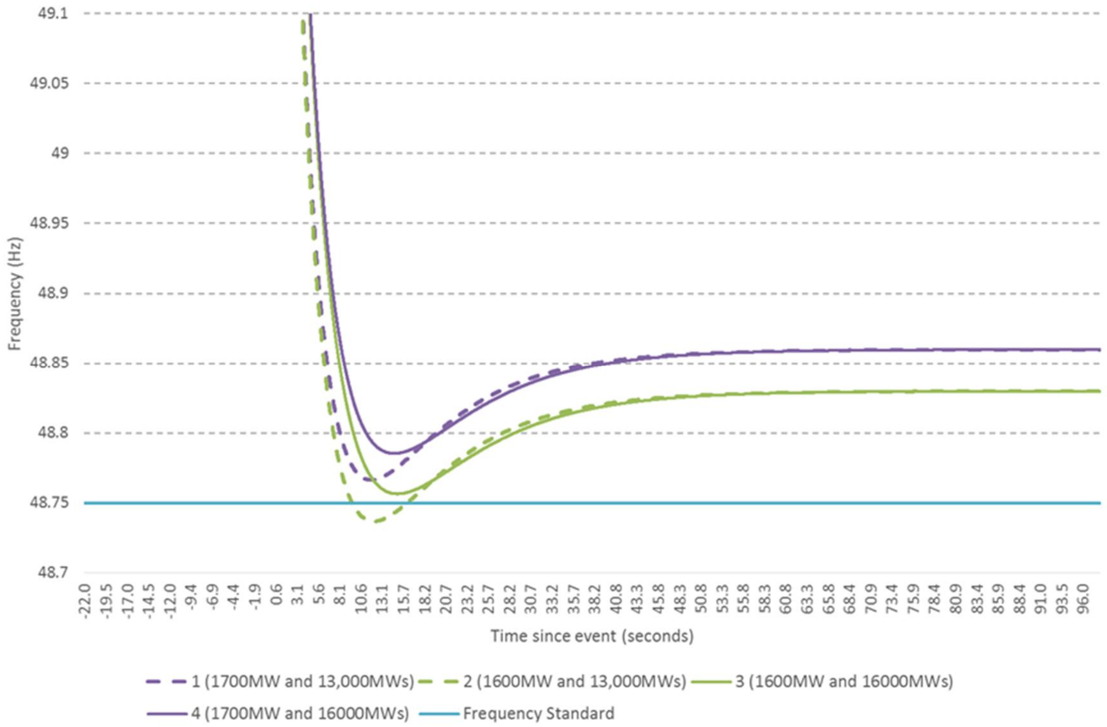


Figure 10.7 – Sample Frequency Responses relative to Frequency Standard

10.3.2 90% Spinning Reserve

If the SR standard were to be increased to 90% of the output of largest credible contingency, the system becomes much more robust. Figure 10.8 shows that once the inertia is over 9,000 MWs, the system can handle any contingency up to 300 MW. The same points of minimum, median and maximum demand are denoted on the chart. EY has not conducted further simulations to determine the exact contingency size which could be withstood without breaching 48.75 Hz. Even with the increased reserves available, the increase in load required to withstand contingency events is still extremely steep as inertia decreases below 9,000 MWs. Again, for a 300 MW contingency the frequency can never be maintained above 48.75 Hz with inertia less than 2,000 MWs (assuming the current SR providers - if more interruptible load were to be procured this could increase the size of contingency which the system could withstand before breaking the 48.75 Hz threshold). This highlights the vulnerability of systems operating at low inertia levels, and the difficulty in making these systems secure through other means, such as increased load, increased reserve or decreased contingency size.

If the system had this 90% SR setting, in its minimum demand state the system would be able to maintain system frequency above 48.75 Hz even after a 300 MW contingency. This is a very high level of operation of Collie for such a low demand. It indicates that procuring SR levels of 90% of the largest credible contingency is likely an unnecessary expense.

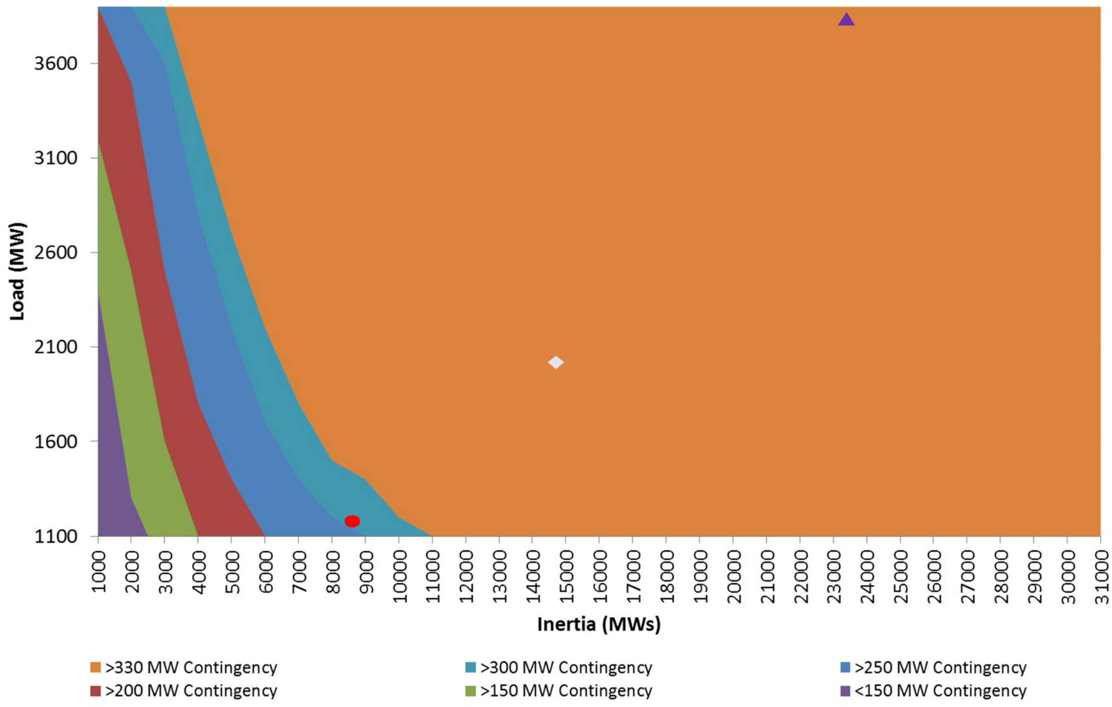


Figure 10.8 – Regions of Safe System Operation with 90% Spinning Reserve Enabled

10.3.3 50% Spinning Reserve

Decreasing the SR to 50% of the largest credible contingency has the opposite effect to increasing the SR to 90%. Figure 10.9 shows that a contingency of 150 MW will always cause a system with less than 1,700 MW of load to breach the frequency standard. A system with less than 5,000 MWs of inertia will not be able to withstand a contingency of 300 MW, regardless of the load level before contingency. At the median load of the WEM, the largest credible contingency would have to be contained to around 150 – 200 MW. Decreasing the SR to 50% of the contingency would endanger the system in normal operating conditions and dramatically increase the risk of load shedding on a single contingency.

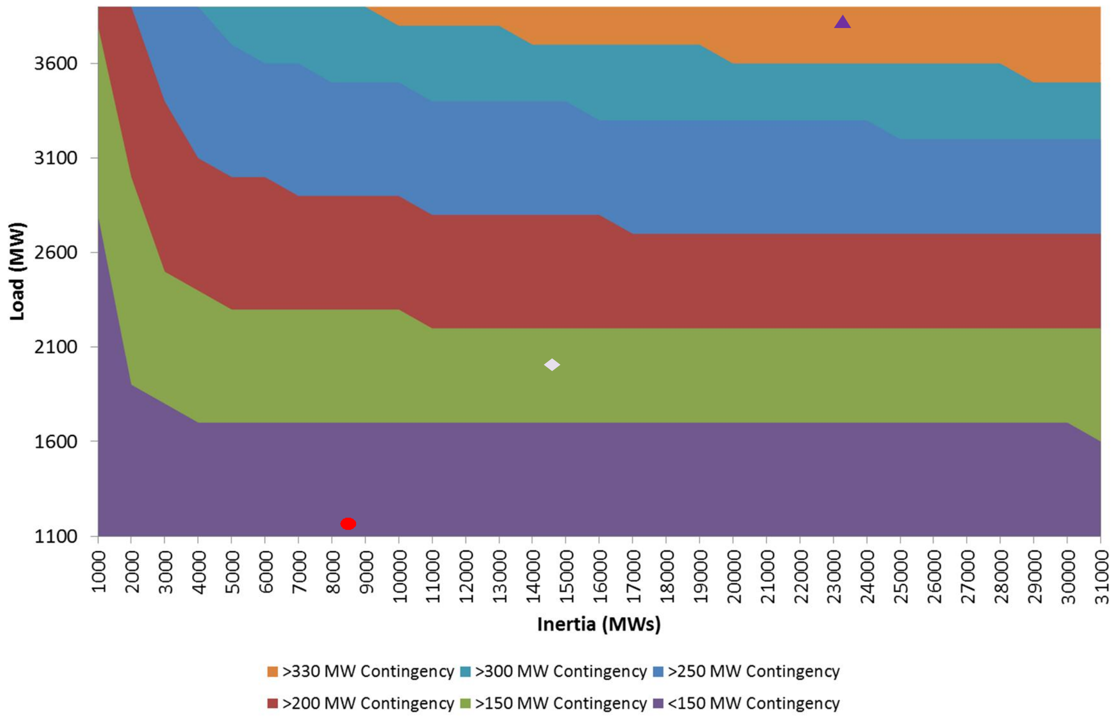


Figure 10.9 – Regions of Safe System Operation with 50% Spinning Reserve Enabled

10.4 Recommendations

EY does not recommend adopting a SR standard of 50% of the largest credible contingency. This setting would leave the system unable to keep frequency above 48.75 Hz in most operating configurations.

Setting the SR standard at 90% of the largest credible contingency event was shown to result in a very robust system that can maintain the system frequency above 48.75 Hz in virtually any likely operating conditions.

With the current SR standard of 70% of the largest credible contingency, the system is vulnerable to hitting the 48.75 Hz threshold and requiring load shedding on a single contingency for significant portions of the year. System Management has acknowledged that 70% of the largest contingency is not always adequate to meet the frequency standard and that there is often load shedding on a single contingency. Allowing load shedding on a single contingency is not consistent with international best practice.

EY found that the current 70% SR level is broadly consistent with other markets. For example, Ireland has a requirement of 75% of largest contingency enabled for primary response [37]. In the WEM this level is not always adequate due primarily to the relatively small size of the WEM. At or below median demand levels, there is insufficient load relief available to maintain frequency above 48.75 Hz. In order to be consistent with international best practice, which is to avoid load shedding on a single contingency, the SR requirement would have to be increased. The 90% SR level would be able to deliver this.

However it must be recognised that the cost of procuring this additional SR is likely to be significant. At high loads, even the 70% setting is higher than required to maintain frequency above 48.75 Hz. Increasing the requirement at all times would further increase the number of hours and amount of SR which is unnecessarily procured.

The requirement to have some percentage, rather than the entire contingency, enabled as SR stems from the recognition that load relief will be provided by the system. Based on an average load frequency index, Table 10.2 shows the load relief which will be provided on loss of Collie's generation at minimum, median and maximum demand. This can then be used to determine the SR level required to be enabled to meet the rest of the contingency and maintain frequency above 48.75 Hz. The load is taken from the actual minimum, median and maximum of the 2013-14 data. Collie's generation is always assumed at its maximum of 330 MW. This represents a "worst case" scenario. At minimum demand, Collie is unlikely to be at maximum output and the SR requirement would therefore be lower.

Table 10.2 – Load Relief Response and Spinning Reserve Calculations

	Load (MW)	Load Relief (MW)	Contingency Size (Collie generation MW)	Spinning Reserve required on top of load relief (MW)
Minimum Demand	1248	55.60	330	232.40
Median Demand	2019	89.94	330	198.06
Maximum Demand	3722	165.81	330	122.19

Figure 10.10 illustrates the SR requirement as calculated based on the load frequency index, compared to 50%, 70% and 90% of Collie's generation. The SR requirement in Figure 10.10 is the total required in the system[13]. This shows that at minimum demand with a 330 MW contingency, the SR required to keep frequency above 48.75 Hz without involuntary load shedding is closer to 90% of the contingency than 70%. Even at median demand the SR required to keep frequency above 48.75 Hz is higher than the 70% level. However, at maximum demand levels, the SR required is closer to 50% of the contingency, due to the extra load relief provided.

[13] Note, however, that 42 MW of SIL was assumed in all modelling; given its significantly faster response, the modelling outcomes may not be the same if the SIL was replaced with governor response.

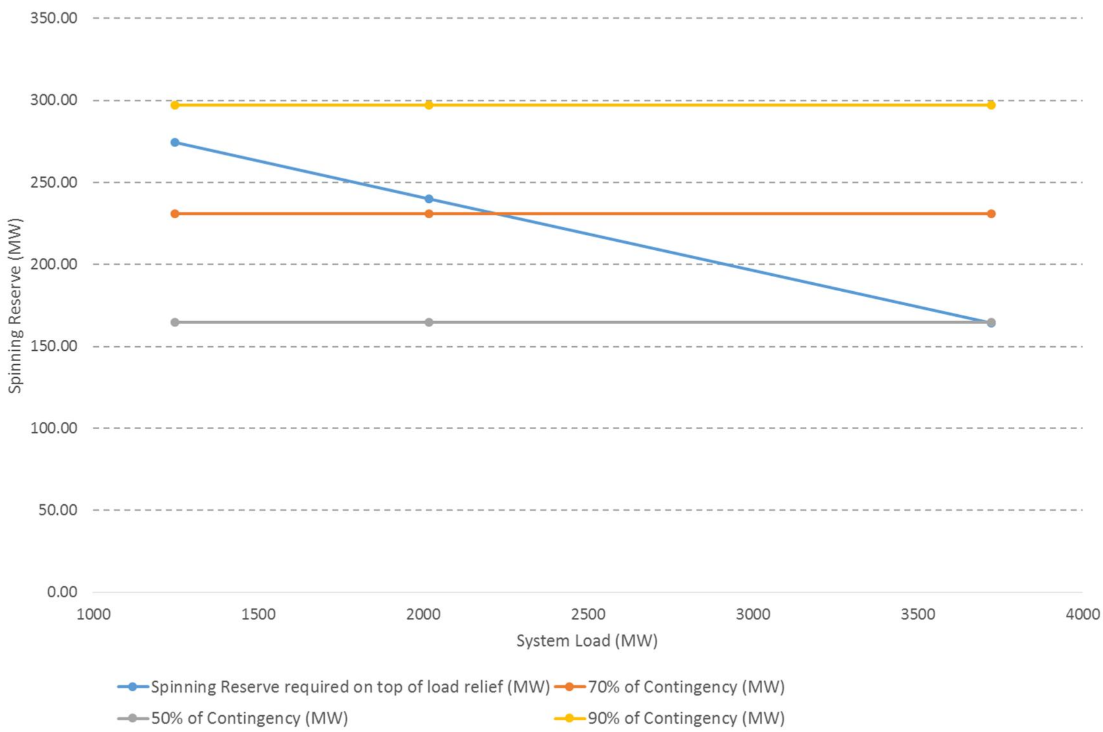


Figure 10.10 – Calculated Spinning Reserve Service requirements

These calculations have been based on an average load index as provided by Western Power. Implementation of a dynamic SR setting would benefit from a close to real time estimation of the load frequency index (or, alternatively, may require a more pessimistic approach), as well as the current largest credible generation contingency (which usually equates to the output of Collie). Due to these multiple dependencies, this chart does not necessarily map the full relationship between the two methods of determining SR. However, it illustrates that there could be potentially large savings in SR requirements at high demand times by moving to a dynamic setting, based on the largest credible contingency and system load at the time. This would be offset by an increased requirement at times of low demand should the WEM adopt a policy to avoid load shedding on a single contingency. As high demand periods are often also high priced periods, there are also market efficiency gains associated with reducing SR requirements in these times, since there would be more plant available to provide energy instead of SR capability. Therefore, both the cost of providing SR and the cost of energy could potentially be reduced.

Recommendation 13 – Factor dynamically forecast load relief into the Spinning Reserve Service requirement
In this study, EY investigated the system frequency impact of procuring Spinning Reserve levels of 50%, 70% or 90% of the largest credible contingency. Procuring 50% of the largest credible contingency would mean the system is often operating in a state where the largest contingency would result in a breach of the 48.75 Hz frequency standard. Procuring 90% of the largest contingency at all times would be unnecessarily onerous. Procuring 70% of the largest contingency is the current standard, and is a balance between system security and the cost of procuring Spinning Reserve in line with the objective of the market to provide economically efficient, safe and reliable supply of

electricity. However, 70% of the largest contingency is not enough to cover, for example, the loss of Collie at full load, and this can result in load shedding on a single contingency. EY considers that this is not in line with international best practice or the market objectives. Also, at times of very high demand, a Spinning Reserve requirement of 70% is unnecessarily high.

EY recommends System Management investigate extending the calculation of the Spinning Reserve requirements to include load relief from expected demand as well as the largest contingency. The Spinning Reserve requirement required would then be calculated as the largest credible contingency minus the expected load relief. At times of low load, this will result in a Spinning Reserve requirement greater than 70% of the largest credible contingency, but at times of high load, it may be significantly less than 70%. Ideally load relief would be assessed for every dispatch interval, but even assessing it 2 – 3 times per day could represent significant cost savings and an increase in system reliability, in line with the Wholesale Market Objectives (a) and (d).

10.5 Provision of Spinning Reserve

The simulations above assumed coal provided one-third of generator-provided SR and gas the remaining two-thirds. Whether the response to a contingency is provided by gas or coal has a significant impact on the frequency as shown in Figure 10.11 for three possibilities:

1. All SR is provided by gas plant (labelled 70% gas)
2. All SR is provided by coal plant (labelled 70% coal)
3. 40 MW of SR is provided by coal plant, with the rest provided by gas (labelled 70% with 40 MW coal)

Figure 10.11 shows the simulated frequency response under the three scenarios assuming the maximum load and inertia levels in 2013-14 as specified in Table 10.1 and a contingency of 280 MW.

Gas plant responds significantly faster than coal, meaning that the frequency is arrested sooner. However, the time delay of coal plant response also means it can continue to respond beyond the frequency where gas response would have stabilised with load response. This is why the frequency is stabilised slightly higher in the case with 40 MW of SR provided by coal and the rest by gas. This also leads to the rise of frequency after its nadir when coal plant is providing SR, whereas when gas plant provides it, the frequency stabilises at its lowest point.

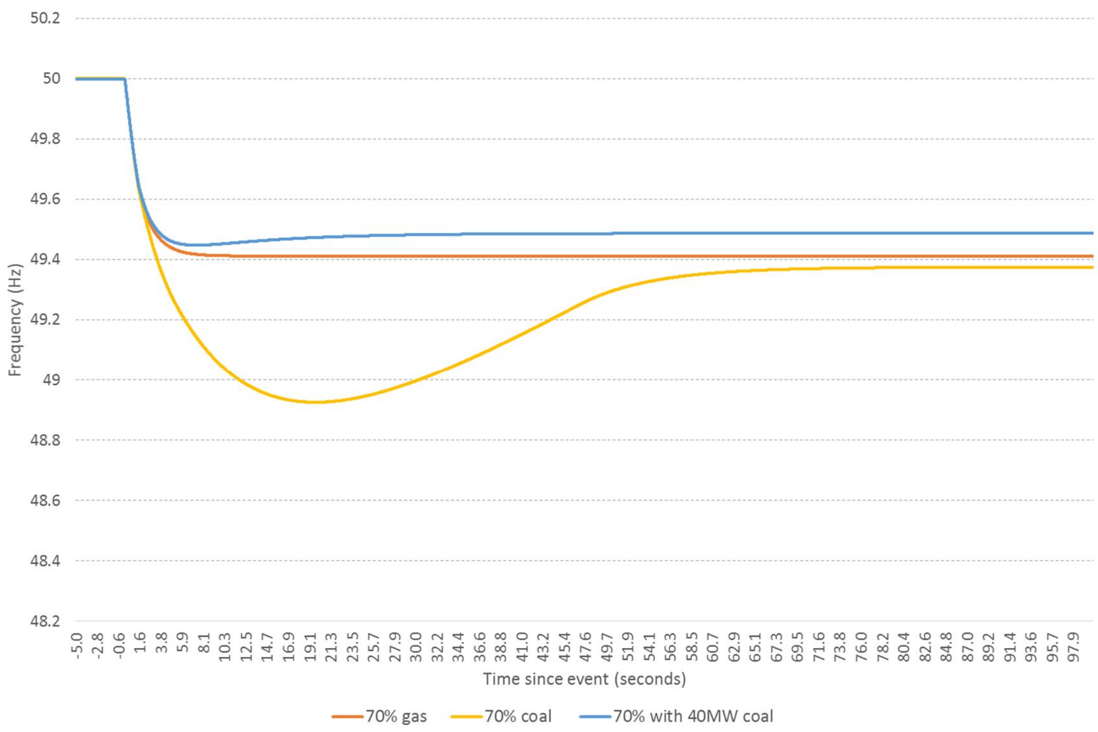


Figure 10.11 – Frequency Response with a Mix of Coal and Gas Spinning Reserve

The modelling above assumed that two-thirds of the SR was provided by gas plant, and one-third by coal plant. The results shown in Figure 10.6, Figure 10.8 and Figure 10.9 could be improved if the SR response was all provided by gas plant. Conversely, if the response was all provided by coal plant, the system would have been more vulnerable to a frequency nadir below 48.75 Hz. This is particularly important at times of low demand when coal plant is more likely to be providing SR and the system is already less secure.

EY notes that the 70% coal scenario above is only illustrative, and System Management would avoid such a scenario. In particular, the response time limitations of coal plant are already taken into account in System Management's PSOP: Ancillary Services [67], and the amount of SR provided by a unit is set by the maximum change in its output possible over the applicable time period. EY considers this to be appropriate.

11. Assessment of Load Rejection Reserve Volumes

The frequency standards in the WEM stipulate that frequency is kept below 51 Hz on a single load contingency. This could be a large industrial load, or loss of a network element that causes a loss of load. The model described in Section 10 can also be used to assess the LRR requirements.

11.1 Assessment of Load Rejection Reserve

11.1.1 Inertia

For this analysis of LRR, EY utilised the same range of inertia as was used in the SR analysis; 1,000 MWs to 29,000 MWs.

11.1.2 Load Relief

The amount of LRR required will be dependent upon the expected load increase from the system at 51 Hz. Figure 11.1 shows the range of load increase expected from minimum to maximum demand, at a range of historical load frequency indices. Even at minimum demand and minimum load index, 30 MW of load increase can be expected. At maximum demand and maximum load index, over 150 MW of load increase can be expected.

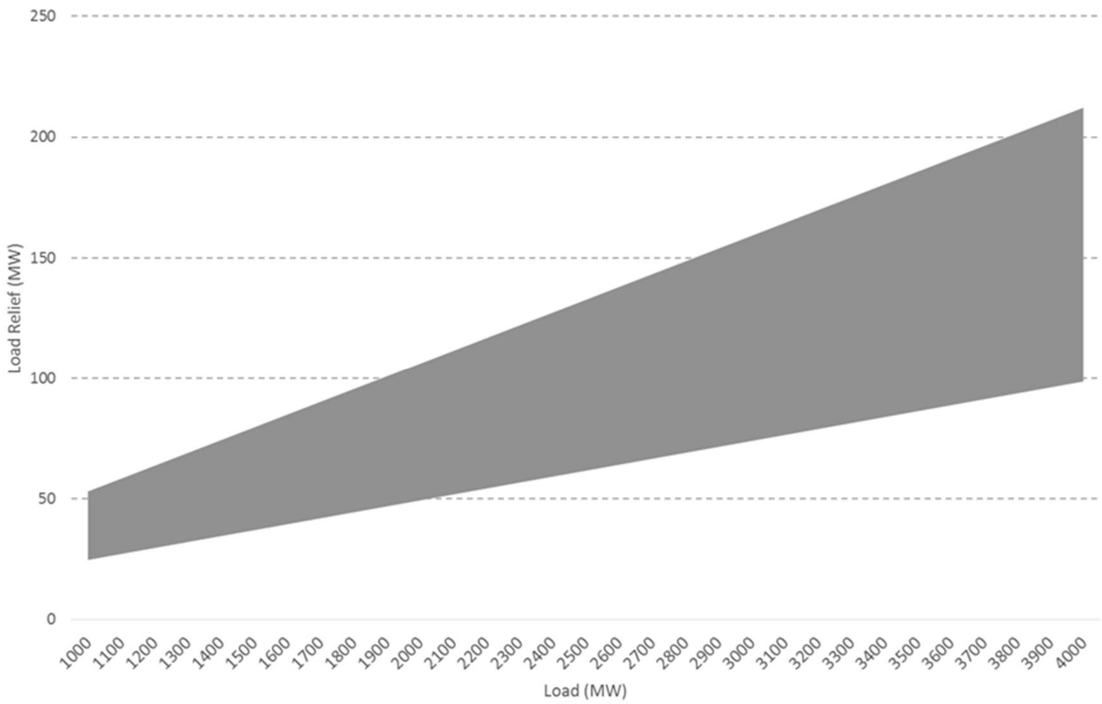


Figure 11.1 – Range of Load Increase Response on a 51 Hz frequency excursion

11.1.3 Load

The same range of load was investigated for LRR as was done for SR; 1,100 MW to 3,900 MW.

11.1.4 Contingency Size

EY has investigated a range of load loss events, from 100 MW to 300 MW. System Management advises that the largest loss of load event to occur was 300 MW, while the planned contingency event is in the order of 150 – 200 MW.

11.1.5 Volumes of Load Rejection Reserve Service examined

In the model, the amount of LRR available is set by specifying the minimum level generators can reach. The amount of LRR will influence the maximum frequency the system reaches after a loss of load. As is the case with SR, if there is not enough LRR, the frequency will never be able to stabilise. With increasing amounts of reserve, the maximum frequency reached will reduce.

The following analysis assesses the maximum frequency reached for the range of contingency, load and inertia for three distinct levels of LRRS:

- The present level of 120 MW
- A decrease to 90 MW, as is already enacted at times when the risk of transmission fault is low
- An increase to 150 MW

11.2 Results

11.2.1 90 MW Load Rejection Reserve Service

With only 90 MW of LRR, the system will never maintain frequency below 51 Hz for a loss of load greater than 250 MW as shown in Figure 11.2. At median demand the system will meet the frequency standard for a contingency of 150 MW, but at low load (below around 2,000 MW) the system will be unable to maintain frequency below 51 Hz for a contingency of 150 MW.

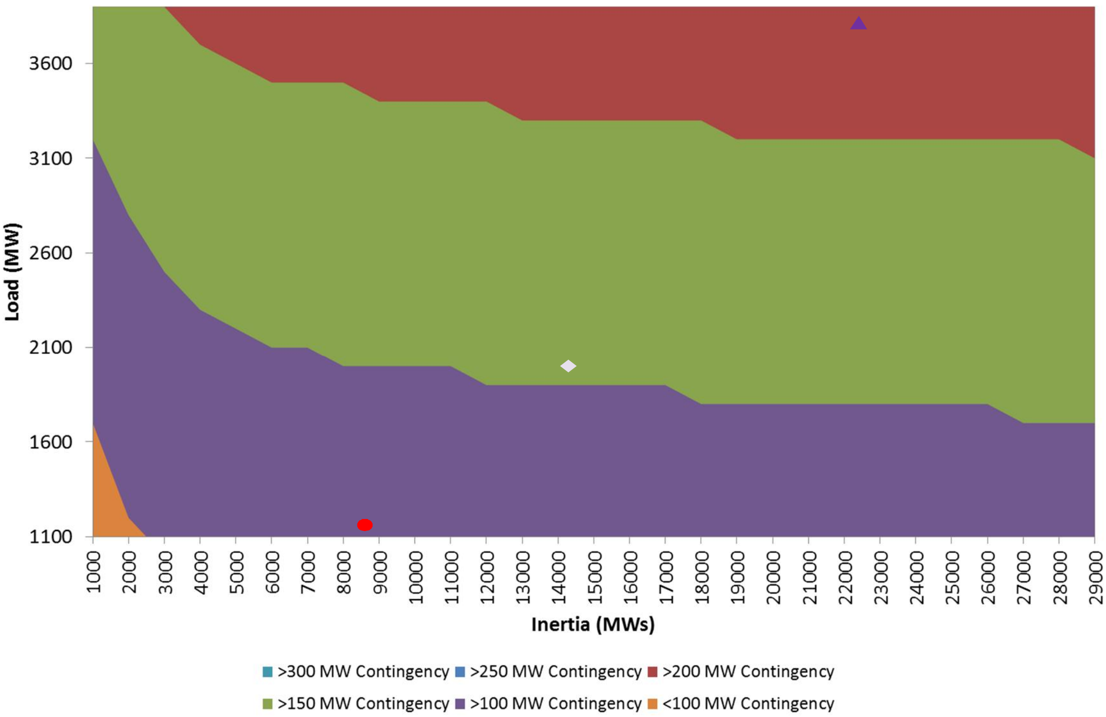


Figure 11.2 – Regions of Safe System Operation with 90 MW of LRRS

11.2.2 120 MW Load Rejection Reserve

With the current usual level of LRR, the safe system operating states are shown in Figure 11.3. For most periods of the year, the WEM would be able to suffer at least 150 MW loss of load without exceeding the frequency standard. At higher loads and inertia, a loss of load of 200 MW would still not cause the frequency to exceed 51 Hz.

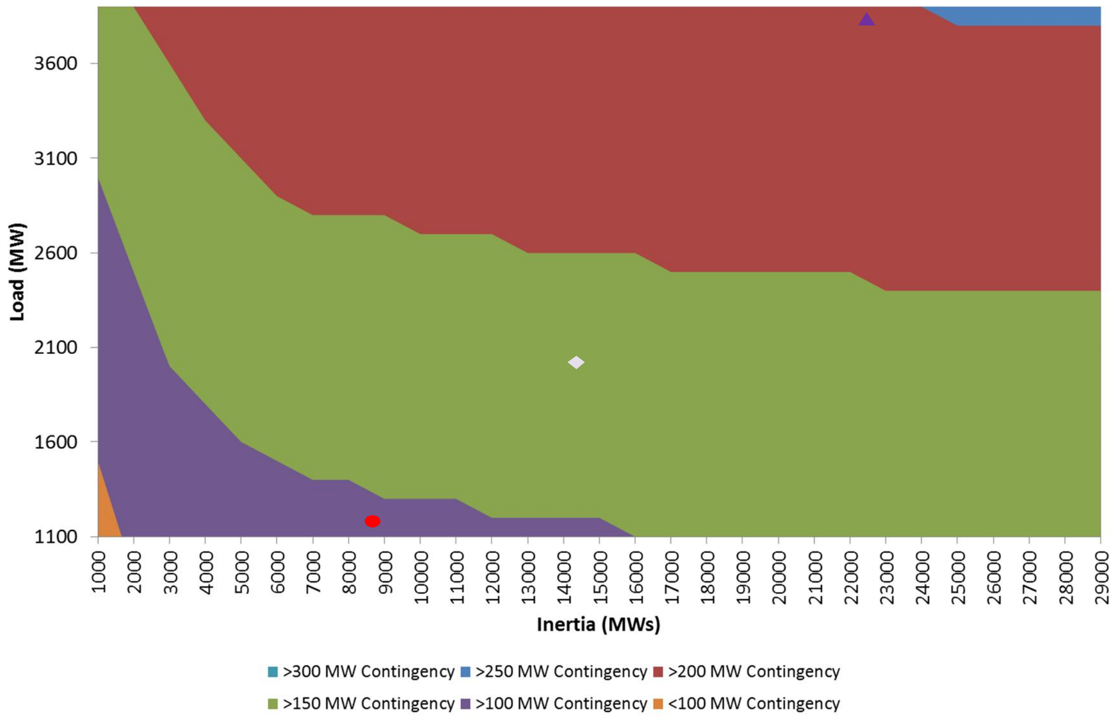


Figure 11.3 – Regions of Safe System Operation with 120 MW of LRRS

11.2.3 150 MW Load Rejection Reserve

If the LRR requirement were to be increased to 150 MW, the system would be able to cope with a higher loss of load before the 51 Hz standard is exceeded. This is shown in Figure 11.4. Although there is 150 MW of LRR available, a 150 MW loss of load will still cause the frequency standard to be breached if system inertia is less than 5,000 MWs and load is around 1,100 MW. This shows that the rate of change of frequency would be so high that the reserve could not respond in time, although there is enough available to completely recover the frequency. At loads greater than around 2,000 MW, there will usually be enough load relief for the system to cope with contingencies greater than 200 MW. A 300 MW contingency will always cause the frequency to rise above 51 Hz, no matter the inertia or system load.

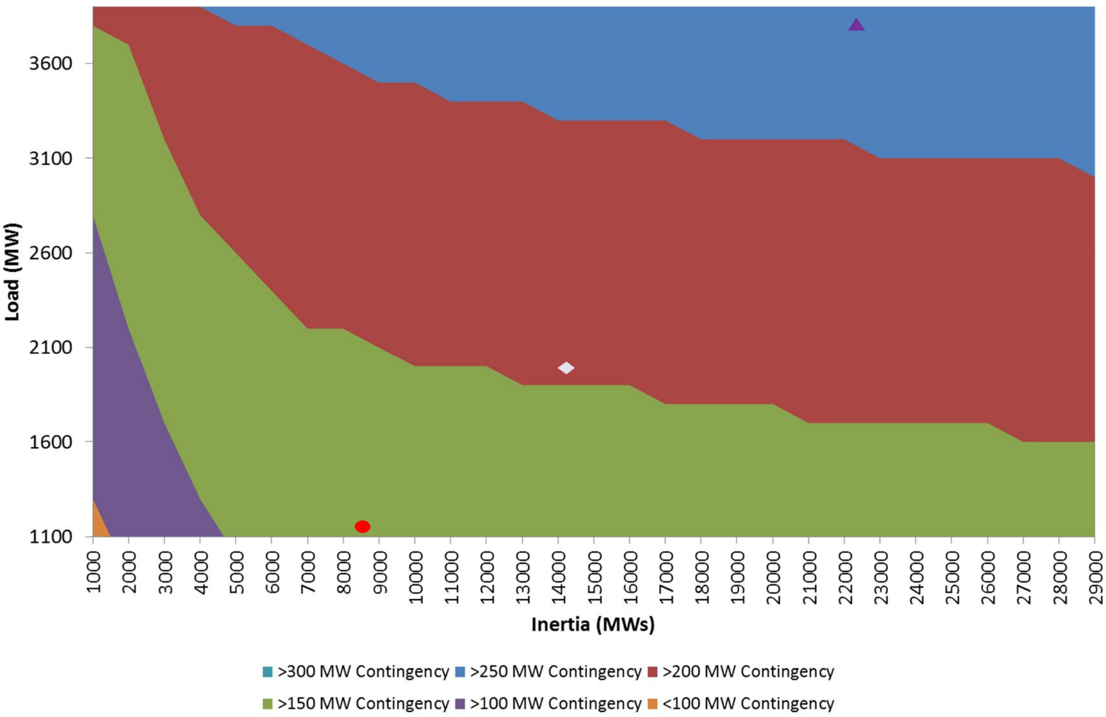


Figure 11.4 –Regions of Safe System Operation with 150 MW of LRRS

11.3 Recommendations

Figure 11.2, Figure 11.3 and Figure 11.4 show that there is a wide range of operating states in which the system will meets its frequency standards with any of three levels of LRR EY assessed. Most operating states seen in the WEM in 2013-14 would have been able to handle a contingency of at least 150 MW without exceeding the frequency standard. In terms of safe system operation, this is then an appropriate level of LRR to procure.

However, if a load loss of 300 MW is seen in the WEM again, not even 150 MW of LRR could ensure the frequency standard is met. System Management currently reduce the standard to 90 MW if the risk of loss of load is assessed to be low. EY recommends that System Management investigate ways to assess the amount of load at risk of being lost in a single contingency on a more dynamic time frame. This could take the form of a LRR requirement based on the largest loss of load, similar to the 70% of largest contingency procured in SR.

These calculations are based on the system being able to maintain frequency below 51 Hz immediately following a loss of load event. This relies on the system load responding by increasing as frequency rises. There would still need to be sufficient capacity for generator reduction on a longer time frame (beyond 15 minutes), to bring frequency back to 50 Hz and allow load to return to its pre-event state. This could be problematic at times of low demand when generators are running close to their minimum output already. This may become more of an issue as wind and solar penetration increases and thermal generation must run at lower output. However in the minimum demand period in 2013-14, there would have been sufficient room to reduce coal generation by 100 MW, even assuming a conservative 50% minimum operation of coal plant.

The ERA determined the current cost of LRR to the market to be zero “because it did not have information demonstrating that the Load Rejection Reserve Ancillary service is provided at a particular (unremunerated) cost to any market participant" [1]. EY notes however that feedback from some stakeholders disagreed that the cost to LRR providers of providing the service is zero. Noting this, it is nonetheless currently the case that regardless of EY's findings, reducing the LRR requirement would not decrease market costs but would increase the risk of breaching the SWIS Operating Standards. Conversely, increasing the LRR requirement would not necessarily be simple or cheap. System Management has suggested that increasing the level of LRR procurement could be costly. There is limited incentive to investigate a more dynamic setting which would be able to reduce the LRR, given that procurement costs are currently negligible. However, it should be noted that if there was a loss of load event greater than 200 – 250 MW, the frequency standard would almost certainly be breached.

Recommendation 14 – Factor dynamically forecast load relief into the Load Rejection Reserve Service requirement
EY investigated the system frequency impacts of procuring 90 MW, 120 MW or 150 MW of Load Rejection Reserve Service. System Management advises that a single loss of load contingency is likely to be between 150 – 200 MW. The current 120 MW Load Rejection Reserve Service requirement is likely to keep the frequency below 51 Hz in the event of a contingency of this size. However, it may not be sufficient if a large (200 – 250 MW) loss of load occurs (e.g. through a transmission failure), or if the system is at very low loads. If the system is at greater than average load, or the contingency is smaller, the 120 MW is significantly higher than is required. Given that the ERA regards that the current procurement cost of Load Rejection Reserve Service is essentially zero, EY does not recommend any changes to the settings of this service. Should the cost of procuring Load Rejection Reserve Service become material, it is best practice to ensure the amounts procured are minimized so as to minimize cost. Should this situation arise, EY recommends that System Management put into practice the setting of Load Rejection Reserve Service requirements dynamically based on the largest loss of load contingency and expected load relief from the demand. Ideally factoring of the load relief would be done for every dispatch interval, but setting the assumed load relief 2-3 times per day may be a practical trade off in complexity and accuracy.

12. System Restart Ancillary Services

System restoration following a major system outage is challenging from both an organisational and technical perspective. The primary function of system restart is to supply power to restart power station assets; supply restoration to customer loads is a secondary objective. It is critical that black start units re-energise critical thermal generation as quickly as possible so that significant start-up delays associated with cold starts are reduced or avoided.

There are three sets of resources required for a system restart scheme:

1. Designated generating units which can start up without an external power source. These units are needed to re-energise transmission lines so that other generating units can be restarted.
2. Non-black-start units that can quickly return to service after offsite power has been restored and then can consequently participate in further system restoration efforts
3. Transmission equipment, controls and communications to connect and manage the system restoration, even without external power.

Optimising the restoration duration is the key to minimising the economic impacts of possible system outages. That optimisation involves establishing a black start scheme with the aim to re-energise the system as quickly as possible, but minimising the risk of re-collapsing the system [68].

The location of the system restart units will materially affect the duration of the restoration process. Unit located in close electrical proximity to a large non-black-start generator that can ensure the rapid availability of more than one large thermal unit will significantly reduce system restoration times.

A very good high level requirement list describing the necessary types of diversity needed in system restart units is found in the NEM's Interim System Restart Standard [69]. It focuses on the need for diversity amongst such units in terms of the following aspects:

> *Electrical - diversity in the electrical characteristics shall be considered particularly with respect to whether there would be a single point of electrical or physical failure;*
>
> *Technological - diversity in technologies shall be considered to minimise the reliance of services on a common technological attribute;*
>
> *Geographical - diversity in geography shall be considered to minimise the potential impact of geographical events such as natural disasters; and*
>
> *Fuel - diversity in the type of fuel utilised by services shall be considered to minimise the reliance on one particular fuel source.*

12.1 Sub-Networks

A system restart scheme can involve managing the system as several sub-networks in which generation and load is restarted from black and stabilised. The complex restoration process involving multiple sub-networks can then be managed by re-energising the network from several locations in parallel. These sub-networks can then be synchronised and reconnected to build the strength of the network as a whole [70].

This process of network re-energization via multiple sub-networks is known as the “Build-Up Approach”. Conversely, the “Build-Down” approach focusses on re-energising major transmission paths before connecting loads and generation [71].

Historical data and numerous studies have shown that implementing multiple sub-networks in a Build-Up strategy reduces restoration time duration considerably and mitigates the risk of system re-collapse affecting large areas of the partially energised network. For these reasons, the Build-Up strategy is predominately used worldwide for network restoration [71].

12.2 System Restart Technologies

Typical types of generating units that can provide system restart services and are commonly used around the globe include:

- Hydroelectric Generation: Hydro generators require very little initial power to open the intake gates and have very fast response times to provide power to thermal stations. There are no significant hydroelectric generators in the WEM and none are likely owing to the lack of suitable sites in the region, except for possible future pumped storage hydro projects in hilly locations.
- Diesel Generation: These units require only a storage battery power source to start and can be quickly deployed to provide power to larger thermal units. Owing to their typically small size, they cannot usually be used to energise major transmission elements. The WEM has a number of diesel generating sets connected to the grid.
- Gas Turbines: These units can be fitted with the componentry which allows them to start remotely with the help of local battery power. They can be started in a short amount of time and have a good ramping ability which can assist with network stability. The WEM has many gas turbines connected to the grid though currently few are fitted with black start equipment. However, one gas turbine can start multiple adjacent gas turbines and provide a substantial generation capacity quickly.
- Trip to House Load (TTHL): Immediately following a trip from the grid, TTHL schemes are designed to reduce the loading on a generating unit from supplying full capacity to supplying the auxiliary load of the power station. This process is performed by complex control systems that rapidly reduce fuel combustion, feed water and air systems in response to turbine output. TTHL enables large thermal stations to ‘float’ off-grid, where they are readily available to re-energise the network and reconnect loads [72]. EY understands that the coal and cogeneration power stations in the WEM are not currently suitable to act in this manner for system restart purposes, but the potential does exist for some coal units to be configured in this manner.

The number of system restart units in an electrical sub-network can significantly affect the duration of the restoration process. The availability of the system restart units is fundamental for all stages of restoration including the stabilisation of the system, establishing transmission paths to non-black-start generation and the subsequent energization of load. System restart units need to be deployed in a way which maximises the overall available generation capability [73].

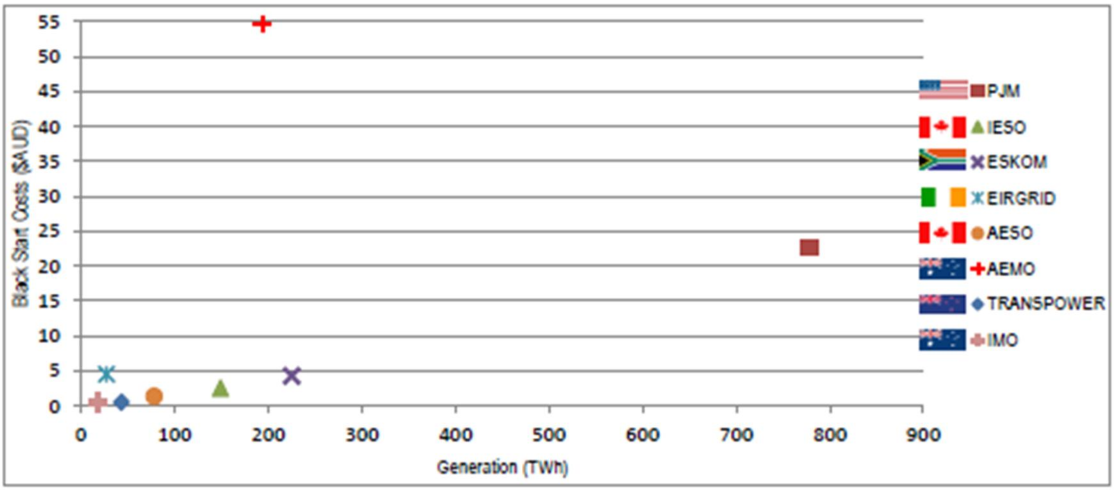
It is important for system operators to provide adequate but not overly redundant system restart capabilities to enable system restoration at a reasonable cost. The value of acquiring additional system restart units can be evaluated in terms of reduction to overall system restoration time (and thus, decreased unmet customer load, which is typically referred to as Unserved Energy).

12.3 International System Restart Service Procurement

The overwhelming majority of international network operators procure system restart capacity as significant system outages are a risk for all large, interconnected power systems. To benchmark procurement of this service in the WEM, several international system restart schemes behave been investigated and compared.

National Electricity Market (NEM)

In the NEM, the system restart ancillary service is referred to as SRAS. According to AEMO's draft report in the 2013 SRAS review [74], the NEM has one of the most expensive system restart schemes (on a cost versus total energy delivered basis) when compared to international practices, as seen in Figure 12.1.



Reproduced from [74]

Figure 12.1 – International cost comparison of system restart ancillary services

The current review of system restart ancillary services procurement in the NEM seeks to address the issues associated with the considerable expense. The review has proposed to reduce the number of system sub-networks from ten to six and the number of SRAS units from twenty-one to seven. Table 12.1 outlines the existing and proposed NEM SRAS scheme details.

Table 12.1 – Proposed NEM SRAS scheme[i]

	Existing SRAS scheme			Proposed SRAS scheme		
Region	Sub-networks	SRAS units per sub-Network	SRAS units procured	Sub-networks	SRAS units per sub-network	SRAS procured
QLD	3	2	6	1	1	1
NSW	2	2	5	1	1	1
QLD-NSW	0	-	-	1	1	1
VIC	2	2	4	1	1	1
SA	1	3	3	1	1	1
TAS	2	2	3	1	2	2
Total	10	-	21	6	-	7

The proposed changes to SRAS procurement in the NEM have been viewed as risky by some NEM participants. Opponents to the changes say the probability of large system black-outs has been underestimated[14], as has the impact of delayed system restoration on sensitive loads and large generating units which are prevalent in the NEM [75].

12.3.1 England and Wales

The England and Wales (UK) transmission network is owned and operated by the National Grid Company (NGC). The NGC network has a peak demand of 56,000 MW with generating capacity of approximately 80,000 MW. The AC transmission network includes voltages ranging from 132 kV to 400 kV and has both AC and DC interconnections as shown in Figure 12.2.

Reproduced from [76]

Figure 12.2 – NGC network area [77]

In accordance with its obligations in the Grid Code, NGC procures black start capacity for the UK system through negotiated contracts with market generators who offer this service. NGC determines the required level of black start capacity on an ongoing annual basis. Costs for black start services are recovered through network tariffs charged to generators and end consumers.

NGC outlines technical criteria that must be met when procuring possible sources of black start capacity. These technical requirements of a black start unit include:

- Be able to start up at least one main generating unit and part of the transmission system within two hours of instruction.
- Have a capacity of at least 200 MW.
- Be able to accept instantaneous load blocks within the range of 35 to 50 MW and have the ability to control frequency and voltage levels within acceptable levels.

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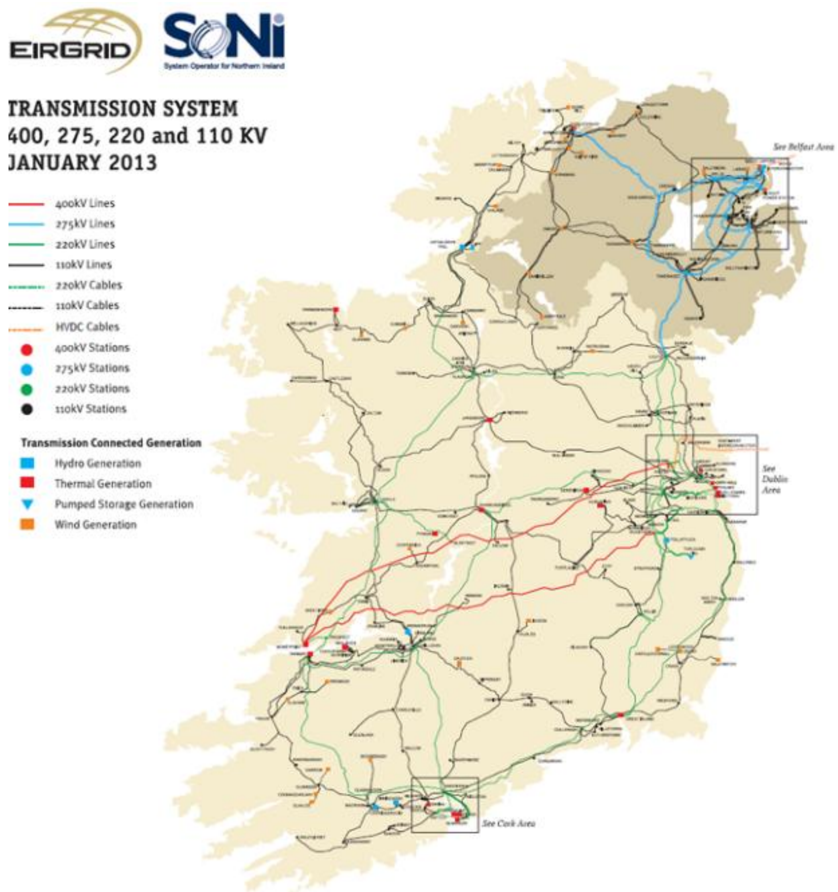
14 Research shows that large system black-outs occur at higher probability than expected by extrapolating the frequency of smaller black-outs.

- Be able to provide three sequential black starts to allow for possible system re-collapse during the restoration process.
- Have a minimum back-up fuel supply, ideally in the range of three to seven days following a black start instruction.
- Have the ability to ensure a high service availability on main and auxiliary plant, typically 90%.
- Have a reactive capability to charge the immediate transmission element. The level of capability is dependent on the local network, however 100 MVAR leading is considered a typical amount for charging network elements with operating voltages greater than 275 kV.

NGC does not publish specific market information reports on procured black start services as these are bilaterally agreed contracts between both parties. However, according to DNV KEMA's report to AEMO for the NEM SRAS review [78], NGC plan to restore the system via six sub-networks, each of which contain two system restart units [79].

12.3.2 Ireland

The Irish transmission system is owned and operated by the state-owned EirGrid plc (EirGrid). The transmission network, not including Northern Ireland, has a peak demand of 4,700 MW and contains a generating capacity of approximately 7,400 MW. Therefore it is comparable to the WEM in terms of system size. The AC network comprises of 6,500 km of overhead line ranging from 110 kV to 400 kV and has both AC and DC interconnections, illustrated in Figure 12.3.



Reproduced from [80]

Figure 12.3 – Area covered by EirGrid [81]

EirGrid procures sources of black start capacity through a competitive tendering process or, if necessary, direct negotiation. Each black-start service is negotiated on an individual basis to reflect the technical characteristics of the units.

Black start services in 2013 were provided predominately by hydro generation units, as seen in Table 12.2. These units are divided between four sub-networks.

Table 12.2 – System restart providers in the Irish grid

Service Provider	Technology	Number of system restart units	System restart capacity (MW)	Rate (€/h)
Aghada	OCGT	3	270	64.71
Ardnacrusha	Hydro	4	86	22.84
Erne	Hydro	4	65	22.04
Lee	Hydro	2	27	9.82
Liffey	Hydro	2	15	8.02
Turlough Hill	Hydro	4	292	81.63
Total		19	754	209.6

Payments for making black start capacity available are made to the service provider at an agreed rate. The rates are based on the recovery of capital costs, operational and maintenance costs and an appropriate rate of return. The service provider receives this rate during trading periods where the black start service is considered available. Black start ancillary services cost EirGrid approximately €1.66mil per annum, assuming an availability factor of at least 90% [82].

12.3.3 Germany

There are four transmission system operators (TSOs) in Germany who control the entirety of the German grid; Amprion, TransnetBW, TenneT TSO and 50Hertz Transmission. Their jurisdictions are shown in Figure 12.4. The total installed generation across Germany was approximately 184,691 MW in December 2013, serving a peak demand of approximately 81,858 MW in 2012 [83].

Reproduced from [84]

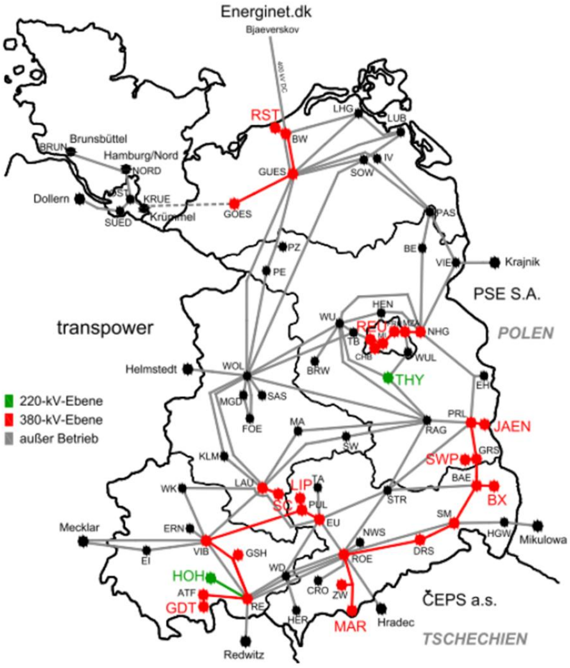
Figure 12.4 – Location of German transmission areas

In 2011, Germany spent approximately €752 mil on ancillary services[15]. The smallest portion of these service costs was from black start capacity, which cost approximately €7mil (1%) of the total expenditure on ancillary services [85].

All four networks procure system restart capacity. However EY could only find detailed information on this for the 50Hertz network in North-East Germany. This TSO is responsible for approximately 7,035 km of 380 kV lines and 2,870 km of 220 kV lines as well as a small amount of underground 150 kV and 400 kV cable. Their network covers approximately 109,360 km^2 and includes 76 substations. In 2013, the 50Hertz grid served 58,114 GWh and a historical peak load of 15 GW in September 2012. [86]

Within the 50Hertz network there are seven TTHL thermal power stations and four black start power stations (gas and hydro), making for a total of 11 system restart units throughout the network, as seen in Figure 12.5. The red and green text and lines indicate the locations of these units and the proposed re-energization paths for the 50Hertz network.

[15] This includes primary balancing power, secondary balancing power, minute reserve, reactive power, national and cross-border dispatch, national and cross-border countertrading and black start capability.



Reproduced from [87]

Figure 12.5 – 50Hertz grid SRAS providers and re-energization paths

12.3.4 Spain

The Red Electrical company is responsible for the management and operation of the Spanish network. The Spanish grid comprises of over 42,000 km of overhead lines, ranging in voltage levels from 110 kV to 400 kV.

The network is divided into two systems; the Spanish mainland known as the ‘Peninsular System’ and the ‘Extra-Peninsular System’, which consists of the island regions surrounding the mainland. The total Spanish system has a total transformer capacity of 80,295 MVA to deliver an average demand of 30,000 MW and contains a generating capacity of approximately 108,000 MW [88].

System Restart as an official ancillary service is still being developed in Spain. The system managers will designate generators that will need to provide this service on an annual basis. The amount of black start capacity required is calculated according to contingency plans for the different zones of the country [89].

Generators receive no payments for this service; rather it is a requirement of their grid connection agreements.

12.3.5 California

The Californian electricity network consists of over eight transmission system operators, managed by the California Independent System Operator (CAISO), which covers approximately 80% of California. The CAISO managed network, shown in Figure 12.6 has a peak demand of approximately 47,500 MW which is supplied by a generating capacity of approximately 61,000 MW [90].

Reproduced from [91]

Figure 12.6 –CAISO transmission area [92]

The ancillary services market is also managed by CAISO, who administer competitive auctions and bilateral contracts for services. CAISO determines the quantity and location of black start capacity according to the system contingency information. Black start providers are required to respond to an event within ten minutes and provide black start services for a period for twelve hours following the initial grid failure.

12.4 The System Restart Ancillary Service in the WEM

Clause 3.9.8 of the Market Rules defines the System Restart Service. The acronym BSS is adopted for this service (corresponding to Black Start Service) in this report so as to distinguish it clearly from SR in the text (the Spinning Reserve Service). A BSS provider must be a registered generation facility that can start after a complete system shutdown without requiring energy from a Network. The Market Rules require System Management to prepare a System Restart Plan, which takes into account designated restart sub-networks and data from procured BSS providers.

The Market Rules outline both regulatory and technical requirements for the procurement of BSS in the WEM. These requirements will be outlined and investigated in the following sections.

12.4.1 Regulatory Requirements

Section 3.7 of the Market Rules requires that system restart capacity is procured in the WEM to minimise the magnitude of unserved energy and reduce the time for restarting the network following a significant system disturbance. The Market Rules regarding BSS procurement require that an appropriate authority (System Management) is responsible for managing system restart and that all market participants are responsible for supplying accurate data as necessary for the management of a system restart plan.

EY's review of WEM regulations for BSS procurement has concluded that all requirements are comparable to other international markets and are consistent with industry best practice.

12.4.2 Existing Technical Requirements for BSS Units

To ensure sufficient facilities will be available, System Management enters into contracts with various generators for the provision of BSS. Generators providing the BSS will be required meet specific standard performance criteria to ensure that the WEM can be restored to normal operation as soon as possible. The following section outlines the current technical requirements for BSS units as specified in System Management's current Position Paper as published on their website [93]. EY also includes commentary on a draft Position Paper authored by System Management in December 2013, which has not been circulated to the market in general. The requirements in this new Position Paper are planned to be in effect for procurements from 2016; that is, following the expiration of existing BSS contracts.

> *Each Black Start Unit should have a nominal power output of not less than 20 MW.*

System Management's December 2013 Position Paper proposes increasing this 20 MW minimum rating to 40 MW. This new value is based upon a rough doubling of the minimum stable generation value of the next unit in the startup procedure. After considering all stakeholder input, EY believes more information is required to determine the necessary minimum size of system restart facilities and therefore to justify any increase to the requirement. The minimum stable generation of units that would likely be next in the system restart procedure may be 20-25 MW (such as Frame 9 gas turbine), however EY understands that this is not reflective of the true minimum generation capability of the units, and is more typically related to environmental constraints. Using approximately double the minimum generation of the next facility is a good rule of thumb but should depend on physical plant limitations rather than environmental ones (some environmental restrictions should be able to be reasonably waived in a system restart situation). The minimum required capacity will naturally depend on exactly which units are to be started, how much transmission system energization or auxiliary load needs to be catered for, and other factors that cannot be accounted for except by way of detailed system studies. Also of critical importance is the degree of resolution System Management has over the reconnection of load; it is important to match the load to the generation available in a progressive manner as more of the system is brought back online.

Internationally, there are other markets which have higher capacity requirements for procured BSS units. These include NGC in the UK which require a minimum capacity of 200 MW. The size of BSS units procured by EirGrid ranges from 15 MW to 292 MW, which averages to be 125 MW across all six procured units. Presently in the NEM, all BSS units have the technical requirement of having a rated capacity of no less than 100 MW; this requirement may however be reduced to 50 or 75 MW based on the outcome of the review process that is currently underway. The average capacity of units in the NEM is higher than the WEM, and therefore it is expected that the WEM would have a lower entry requirement. The WEM also has more a more limited choice of facilities, so it is sensible that the minimum capacity define what is required, not what would necessarily be optimal in terms of sizing.

Recommendation 15 has been withdrawn following stakeholder feedback
Sufficient fuel reserve should be available to run each Black Start Unit for a minimum of 48 hours during a system black out.

EY expects that 48 hours would be easily sufficient for the restart requirements for the WEM and is comparable to the NEM and other international markets. EY does note that some international markets require a minimum fuel reserve for much longer periods of time, such as the UK which requires three to seven days reserve. This requirement may be taking fuel security risks particular to the region into account. However, it may be that 48 hours is greater than is actually necessary, as EY understands that the expectation is that a Black Start scenario would not persist for longer than around 12 hours. Setting the minimum requirement too high may lock out potential black start providers so this requirement should be carefully considered by System Management. EY suggests that System Management might set a lower minimum fuel reserve but state that greater fuel reserves would be regarded as favourable in System Management's assessment of potential providers of the service.

> *The ability to provide at least three sequential black starts, to allow for possible tripping of the Transmission/Distribution System(s) during the re-instatement period and possible tripping of the Black Start Generator during the black start starting sequence itself.*

EY believes this technical requirement for BSS units is very important as there is a high risk of tripping the unit and/or re-collapsing the network during the restoration process. For this reason it is appropriate for all BSS units to be capable of multiple starts.

> *A mitigation plan is required for common mode failure in critical starting equipment that renders black start units inoperable. For example, install an emergency hook up for a mobile generator to replace a failed diesel starting generator.*

This requirement of mitigating the risk of common failures in BSS equipment is important for ensuring the probability of BSS being available is maximized.

> *Permission from the environmental authority to waiver air pollution restrictions for extended operation of a Black Start Unit at reduced load levels during a black start event.*

EY supports this requirement to ensure that the restoration of the WEM is prioritized. Extended outages across the network could result in larger environmental impacts when compared to pollution produced by extended BSS operation.

> *Stable operation under low loads between 1 MW and 5 MW.*

EY believes this requirement is important for all potential BSS units. Units need to be stable under low loading before loads can be connected and must not risk tripping and re-collapsing the partially restored network. System Management's new Position Paper revises the low load rating down to 0 MW. EY agrees with this change, which EY interprets as the unit being able to operate with virtually no external grid load.

> *Each Black Start Unit must be able to operate in isochronous governor mode to automatically regulate frequency.*

This requirement is essential for network restoration as the BSS unit needs to keep the fundamental frequency of the system without deviation, even when it is the sole generator in a sub-network.

When not operating in isochronous mode each Black Start Unit must operate during re-energization of the SWIS in droop governor mode with governor response enabled, at a minimum response value of 4% droop.

Once larger amounts of generation are returned to operations the BSS unit should then be capable of switching to a droop governor mode to ensure flexible operations. EY supports this requirement as frequency deviations will be expected during the restoration process from the re-instatement of generation and load. Droop control will allow the BSS unit to share generation with other connected units without risk of overload.

The control systems of each Black Start Unit must be capable of setting generator output at fixed MW values, and of setting generator terminal voltage to regulate at fixed voltage values.

EY agrees that BSS units should be capable of meeting these fixed outputs as it will provide System Management with the ability to maintain stable power flows and voltage levels in the network which will help mitigate risks of system re-collapse during system restoration. This is particularly the case as loads are progressively reinstated.

Each Black Start Unit must be capable of operating in a voltage range between 95% and 105% of its rated terminal voltage.

This requirement is important for BSS units as voltage management is necessary to maintain supplies to loads within statutory limits.

Each Black Start Unit must be capable of absorbing reactive power from the SWIS while operating within the stable under excitation area of its generator capability curve (leading VARs).

EY supports this requirement as under-excitation of BSS units is a common requirement during the restoration process to ensure significant over-voltages in the system are minimised. This requirement is comparable to the NEM and other international markets.

Of each Black Start Unit that is not manned 24/7, SM may require remote control from its System Operations Control Centre (SOCC) in a system shutdown event for the purpose of system re-energization.

EY considers that it is appropriate for System Management to require remote operations for unmanned generating plant, particularly at remote sites. This will ensure that in a system black event, System Management will be able to promptly utilise all plants capable of assisting with the restoration process.

Each black start facility must maintain an SM approved emergency communication system with SOCC.

Adequate communications are essential for System Management's co-ordination of the restoration process. This is comparable to the NEM and other international markets which have their own communication standards in place.

Each black start facility must maintain an SM approved emergency communications plan for mobilisation of its operating personnel to meet a 60 minute time response.

EY understands the requirement of this time response is to have personnel mobilised within 60 minutes of the initial request. This target response time is realistic for the situation and ensures that restart capabilities will be available shortly after the initial request. System Management's new Position Paper proposes that this response time be shortened to 30 minutes.

12.4.3 New Technical Requirements for BSS Units

As mentioned in the preceding section, EY was provided with a draft Position Paper by System Management which has not yet been made public. This Paper introduced some new requirements for BSS units. These requirements are discussed below.

[Black Start] Generators connected at 330kV must be capable of energising a 330kV line section and 330/132kV 490MVA transformer to enable load connection. This should be achieved by allowing generator excitation to commence whilst its generator circuit breaker is closed.

EY supports the notion that 330 kV connected black start units must be capable of energizing the relevant line section and transformer. This technical requirement ensures that a BSS provider connected to the high voltage backbone in the WEM is physically capable of providing enough reactive power to energise the HV transmission line and the step-down transformer of the load supplying substation. However, based on stakeholder feedback, EY is not convinced that the only way this is feasible is for generator circuit breakers to be closed during generator excitation. Stakeholders noted that this is a non-standard configuration for generator control systems and thus could prevent some potential providers from being able to offer the service (or else it could attract considerable cost to implement). EY suggests that instead of prescribing this, it would be more appropriate to state that the method by which the generator achieves line and transformer energization must be agreed and verified in consultation with System Management.

Recommendation 16 – Add energization capability for 330 kV connected Black Start units
EY recommends System Management adopt a new requirement for Black Start units connected at 330 kV to be capable of energizing a 330 kV line section and a 330/132 kV 490 MVA transformer. This would make the physical requirements of candidate BSS units more transparent to the market which would facilitate an efficient and fair procurement process.

Generators providing the BSS may be required to undertake testing, both at the procurement stage and during the period of the contract, to prove that black start generators can comply with the requirements of the published performance standard. The facility would require testing every 6 months.

Regular testing is essential for ensuring the availability of BSS units in the event of a major system outage. The NEM and other international markets have strict testing requirements for BSS units. EY supports testing of BSS units and encourages System Management and the IMO to ensure testing frequency and requirements are appropriate.

In other comparable markets an annual test is the most common arrangement. Increased testing requirements placed on BSS providers usually incurs an increased procurement cost.

Recommendation 17 – Annual testing of Black Start units
EY recommends System Management consider adding an explicit requirement for an appropriate annual black start test for all Black Start units. This test does not replace any other test requirements for the facility. The number of tests per year must be considered against the cost of undertaking these tests.

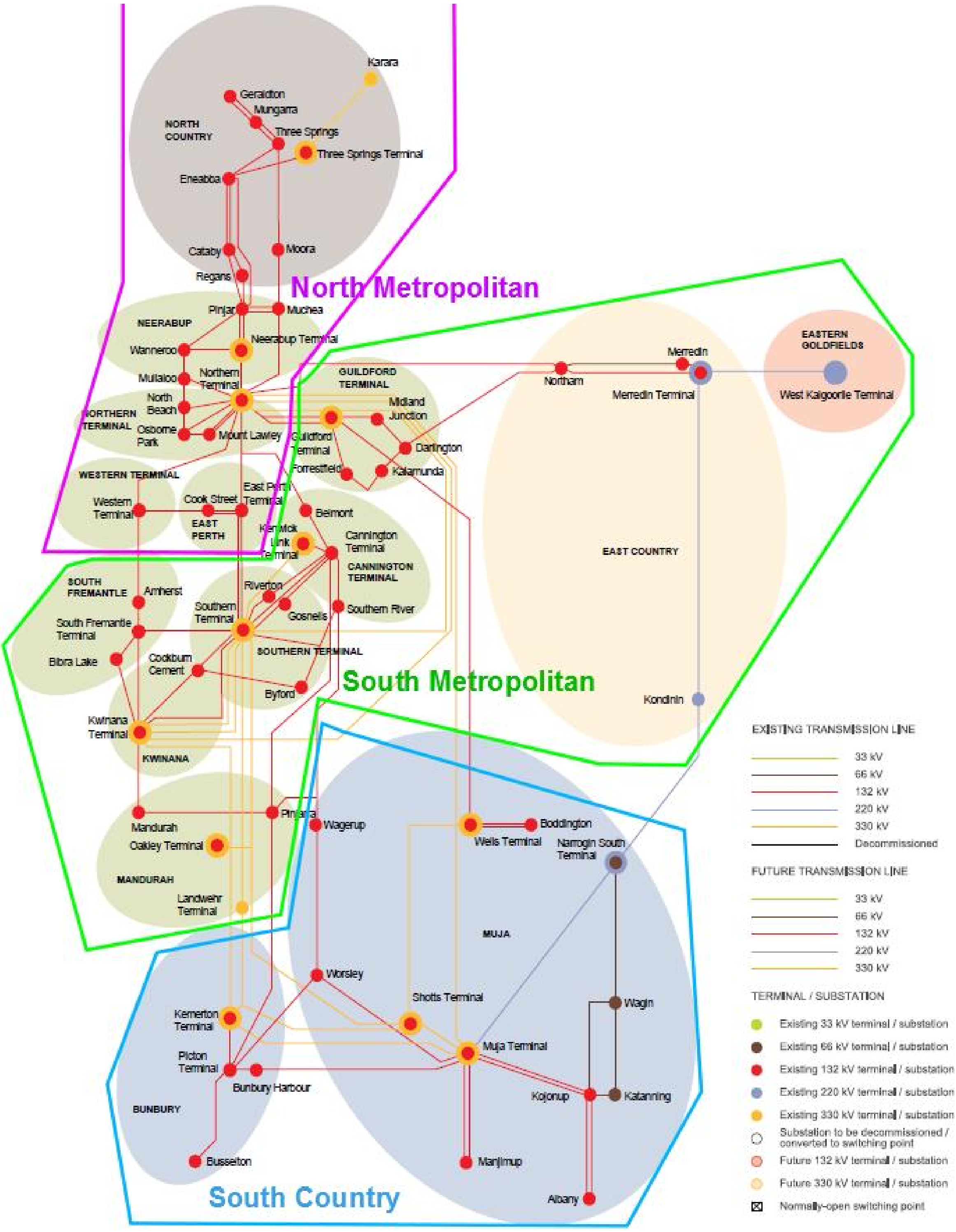
A further requirement EY recommends System Management investigate is an overall availability requirement for Black Start units. The NEM has a requirement that all primary SRAS units have an overall availability greater than 90%. The NGC require a similar availability.

Recommendation 18 – Investigate an availability requirement for Black Start units
EY recommends System Management consider setting a minimum availability requirement for Black Start units. This would be consistent with international best practice.

12.4.4 Present Restart and Synchronizing Plan

The Market Rules give System Management overall authority and responsibility for power system restoration. System Management has developed a system restoration plan for the WEM.

System Management's system restart plan has determined that the initial stages of the restoration procedure will involve restarting the network via the use of sub-networks containing the designated Black Start units. The current System Management restoration plan, as documented in Ancillary Service Report 2013 [94], divides the system into three sub-networks: North Metropolitan, South Metropolitan and South Country. Note that the current Ancillary Services PSOP [67] describes five sub-networks, but on advice from System Management, that grouping is no longer used. These system restart sub-networks are made up of groupings of the standard Western Power network 'zones'. The zones and the system restart sub-networks are shown in Figure 12.7 below:



Network diagram from [95]

Figure 12.7 – WEM system restart sub-networks

Ideally, BSS providers would be procured in all sub-networks. In light of this, System Management states that all BSS units must not be in the same sub-network. System Management also states that neither the Eastern Goldfields part of the South Metropolitan sub-network, nor the North Country part of the North Metropolitan sub-network, contain suitable locations for BSS providers owing to network constraints (note that both these areas are relatively remote from the main load and generation in the system). EY agrees with the general exclusion of these areas. The BSS providers currently procured by System Management can be seen in Table 12.3.

Table 12.3 – BSS units in the current system restart plan

BSS Unit	Technology	Provider	Capacity (MW)	Sub-Network
Kwinana GT	GT	Synergy	20	South Metropolitan
Perth Energy Kwinana GT1	GT	Perth Energy	120 (4 x 30)	South Metropolitan
Pinjar GT3/5	GT	Synergy	65 (from both units)	North Metropolitan

System Management has stated that the BSS procurement costs approximately $520,000 annually, which is $180,000 for each BSS provider annually.

All existing BSS providers are located in the two Metropolitan sub-networks. Of note is that there is no provider in the South Country sub-network. Assuming System Management's Black Start unit requirements as stated in the December 2013 position paper are implemented (as EY recommends), only the Pinjar unit is of sufficient size to meet the increased capacity requirement. Therefore future BSS providers may be quite different to the current providers.

EY has not conducted detailed power system studies for restoration analysis and therefore recommendations are of a general nature. Noting this, potential opportunities for improvement in the System Restart scheme with regards to sub-network configuration and BSS provider location are:

Recommendation 19 – Procure additional Black Start providers in the South Country sub-network
All BSS units procured in the WEM are currently located in the North and South Metropolitan sub-networks. Procuring BSS sources in the South Country sub-network would help to ensure restoration times are minimized for the WEM, especially in the event of transmission issues between the South Metropolitan and South Country sub-networks. BSS facilities close to Muja would therefore be able to energies these coal facilities sooner in the event of issues like this. The longer that coal facilities are off-line, the longer they may take to synchronize, and the more likely they are to suffer an unplanned outage. Quantification of these risks is a significant exercise and was not considered in this scope of works. Possible existing candidates for the provision of System Restart services in the South Country sub-network are Synergy's Kemerton gas turbine units or Alinta's Wagerup units, which could potentially be retro-fitted with black start capability. Another option would be to utilize and/or augment TTHL capabilities on some of the coal units in the Muja area, but this may not be feasible. This would increase the reliability of the electricity supply in the WEM in line with Wholesale Market Objective (a) of the Market Rules by helping to minimize the likely time major load is disconnected in a system blackout situation.

Recommendation 20 – Recognise geographic considerations within a restart sub-network in the BSS requirements
EY recommends that relative geographic and network advantages be included in the evaluation criteria for assessing tenders for BSS.

Recommendation 21 – Geographically diversify Black Start units
There is a reasonable chance that any single unit may fail to start, but the simultaneous failure of two units to start is very unlikely. However, retaining two BSS units per black start sub-network to cover this possibility (that is, four, or even six were three black start sub-networks to be established) would be excessively costly for a network the size of the WEM. Therefore EY suggests that three units should be adequate, but these BSS units should not be all located in the same sub-network so as to avoid common cause failures of equipment, such as shared transmission assets. EY considers it highly probable that both Kwinana BSS units would be unavailable simultaneously in the event of a geographically isolated disturbance such as an earthquake or fire. In such an event, only the Pinjar BSS unit, located at in the North Metropolitan sub-network, could provide start-up energy. This may not be adequate. EY therefore recommends that the BSS requirements be tightened to specifically state that BSS units procured must be located in at least two of the three sub-networks, with preference given to procuring BSS units in all three sub-networks. This would increase the reliability of the electricity supply in the WEM in line with Wholesale Market Objective (a) by helping to minimize the likely time major load is disconnected in a system blackout.

EY’s international benchmarking exercise has shown that the cost of BSS in the WEM is relatively inexpensive when compared to other markets, and particularly the NEM. Therefore it should be noted that the implementation of EY’s recommendations will possibly increase the cost of this service to the market, as the recommendations generally tighten rather than loosen the BSS requirements. Note that all recommendations on the System Restart Service are based upon basic qualitative and quantitative comparisons. Any changes to System Restart plans must be first tested with detailed system studies and analysis.

13. Works Cited

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Appendix A Methodologies to increase wind and solar generation

A.1 Increasing wind generation

EY modelled the case where the wind generation (in annual energy terms) is increased by 50%, relative to the total annual energy from wind in the year of data. Simply scaling up the existing wind generation by 50% was not considered appropriate because this would not allow for any diversity from potential new wind farms in the WEM being installed in different locations to the existing fleet. Instead, this would likely exacerbate the fluctuations from increased wind generation and lead to an overestimate of the increase in LFAS requirements. To allow for diversity, EY selected two very small existing wind farms (Denmark and Mount Barker) to scale up since they provide wind generation profiles at two different locations in the WEM. These two wind farms have a negligible contribution to the diversity in the existing aggregated wind generation in the WEM due to their very small size. EY also selected the smallest medium-large sized wind farm, Mumbida, to scale up to add a third site to the diversity. EY also considered the small Blairfox wind farm, but chose not to use it due to apparent regular outages in its generation that were not typical of larger wind farms.

A large wind farm with 10 wind turbines or more typically exhibits less variability in its generation from minute to minute than a smaller wind farm. EY modified the scaled up generation profiles for Denmark and Mount Barker wind farms with a moving window average smoothing function to achieve a profile with a similar amount of variability from minute to minute as is observed in the generation profiles of the larger wind farms. Through trial and error, EY found a window size of 9 data points resulted in a profile with an appropriate amount of variability. Table A.1 summarises the wind farm profile changes made to create an appropriate wind farm profile with 50% extra generation in the WEM overall. In total, an extra 281.4 MW of wind capacity is added to the existing fleet to achieve the additional 50% of annual energy from wind.

Table A.1 – Wind farms scaled up to model 50% increase in wind generation

Wind farm	Existing capacity	New capacity	Window smoothing applied
Denmark	1.4 MW	84.8 MW	Yes
Mount Barker	2.4 MW	145.4 MW	Yes
Mumbida	55 MW	110 MW	No

A.2 Increasing solar generation

EY modelled an increase of 50% in solar PV generation in the WEM with the following additional capacity:

- 150 MW additional rooftop PV, and
- Increasing the capacity of Greenough solar PV station from 10 MW to 22.5 MW.

The increase in rooftop PV is based on an average of 335 MW of rooftop PV installed in the WEM over the year of data analysed.

The effect that the additional 150 MW of rooftop PV would have on LFAS depends on the way the rooftop PV is handled in the load forecasting system. To estimate an upper and lower bound for what this effect might be, EY calculated the results for the additional rooftop PV using the two cases presented in Section 9.4.2.

The rooftop PV generation trace was created using 1-min solar radiation measurements taken from a single solar panel on the roof of System Management's control centre. Since this trace would have a lot more variability compared with the likely output from multiple rooftop PV systems installed across hundreds of roofs in Perth, EY applied a smoothing function to obtain a more realistic PV trace. This smoothing function involves shifting the original trace by 10 one-minute intervals either side of the original trace and adding this collection of traces together. EY then scaled the trace with a 90% maximum and obtained a final rooftop PV trace with a capacity factor of 17.2%, which is in line with the IMO's estimates on the capacity factor of rooftop PV in Perth [96]. Figure A.1 shows a comparison of the solar radiation intensity trace and EY's rooftop PV trace for a capacity of 150 MW for a day in April 2013.

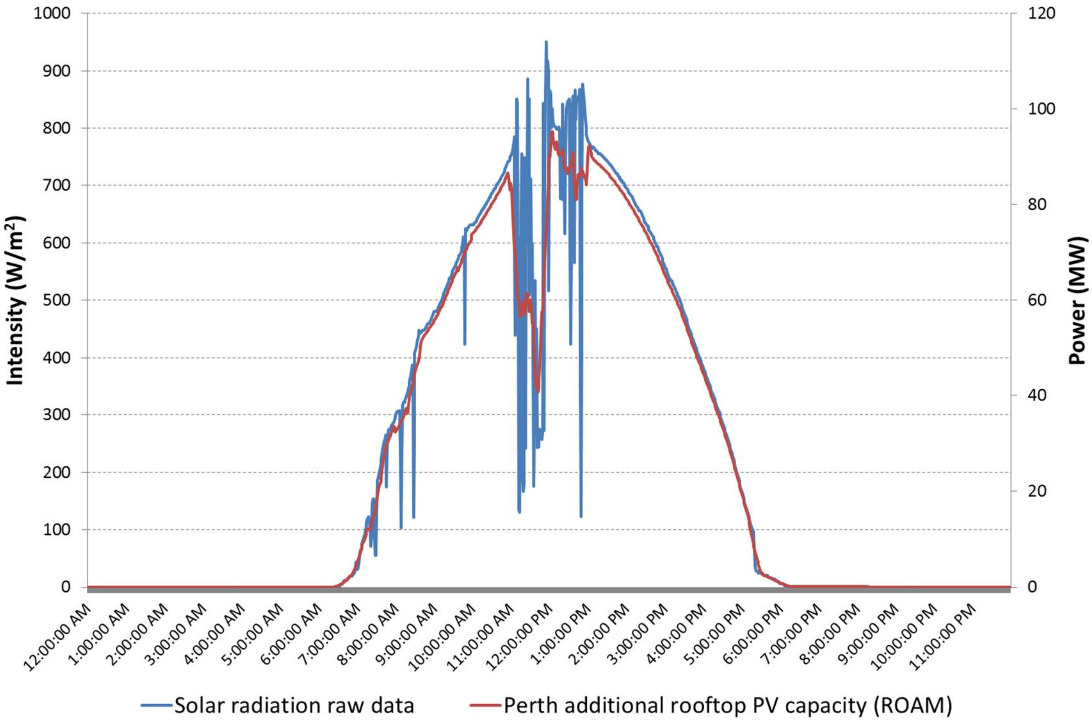

Figure A.1 – The System Management control centre's solar radiation data and EY's derived rooftop PV trace for Perth for 3 April 2013

Appendix B Frequency Modelling

B.1 Generator and Load Model

For a single generator supplying power to a load, the rate of change in electrical frequency due to a difference between the power supplied and the power consumed by the load can be calculated as

$$\frac{df(t)}{dt} = \frac{f_s \cdot (P_{Gen}(t) - P_{Load}(t))}{2H_{Gen}} \tag{2}$$

where $P_{Gen}(t)$ and $P_{Load}(t)$ is the output of the generator and load, respectively, and f_s is the nominal frequency (50Hz), and H_{Gen} is the inertia of the generator, turbine and all other connecting plant in *MWs*. This is known as the Swing Equation [97].

For a system with *M* generators and *N* loads, if we are only interested in the average system dynamics (ignoring the inter-machine oscillations), we can model the system as a single-machine [98] and apply the Swing Equation accordingly by summing the contribution of each generator and load. That is,

$$\frac{df(t)}{dt} = \frac{f_s \cdot \left(\sum_{i=1}^{M} P_{Gen_i}(t) - \sum_{j=1}^{N} P_{Load_j}(t)\right)}{2\sum_{i=1}^{M} H_{Gen_i}} = \frac{f_s \cdot (P_G(t) - P_L(t))}{2H} \tag{3}$$

where $P_G(t)$ and $P_L(t)$ is the system generation and load, respectively, and H is the centre of inertia (COI) of the system supplied by active generators. Expressing the Swing Equation in terms of a transfer function in the *s*-domain gives

$$\frac{F(s)}{P_G(s) - P_L(s)} = \frac{f_s}{2H \cdot s} \tag{4}$$

which is used to form the basis of the generator model after replacing absolute values $P_G(s)$, $P'_L(s)$, and $F(s)$ with small signal representations $\Delta P_G(s)$, $\Delta P_L(s)$ and $\Delta F(s)$.

Power system loads consists of a variety of electrical devices. For resistive loads, such as lighting and heating loads, the electrical power is independent of frequency. Motor loads, however, are sensitive to changes in frequency. The amount of sensitivity depends on the composite of the speed-load characteristics of all the driven devices. Here, we model speed-load characteristic of a composite load as

$$P_L(t) = P'_L(t) \cdot \left(\frac{f(t)}{f_s}\right)^m \tag{5}$$

where $P'_L(t)$ is the total system load in the absence of frequency deviation and m is the load-frequency index.

B.2 Governor Turbine Models

The response of generators to frequency changes is determined by their governor-turbine model. The equipment such as the speed governor controller and the governor itself cannot respond instantaneously in the presence of system frequency change. Instead, exponential responses governed by time-constants, or time delay responses, or in some cases more complex response types are to be expected. Similarly, components associated with the turbine such as fuel controllers, valve positioning devices and temperature controllers also display responses limited by time constants. The combination of different responses from governors and turbines can have a significant influence on the system frequency response.

Governor turbine model information was provided by Western Power in confidence for this study.

Appendix C International market review

C.1 Surveyed markets

EY has reviewed ancillary service markets in a number of jurisdictions. These were chosen due to either their comparability to the WEM, particularly in terms of size, interconnection and generation mix or because they have conducted a significant review of their ancillary services in recent times.

Table C.1 – Markets reviewed as compared to the WEM

Market	Comparability to the WEM
Ireland	Similar generation make up to the WEM; mostly thermal and wind generation. Only connected via DC links to UK so is a 'frequency island' About double the size of the WEM in total capacity and demand terms
UK	Much bigger than the WEM Some hydro plant but mostly thermal and wind generation. DC connection to Ireland and France
New Zealand	Dominated by hydro which has different ancillary service capabilities and drawbacks Similar size in capacity and demand terms, and is an 'island' system like the WEM
Eastern Australia (NEM) focusing on Tasmania and South Australia	Where possible, information is presented for Tasmania and South Australia separately. Tasmania is dominated by hydro with only DC connection to the mainland so is a 'frequency island' like the WEM If isolated from the Victoria, South Australia is a frequency island of similar size to the WEM, with a similar generation make up
Germany	Large, strongly interconnected system but undergoing significant transformation to increase renewable energy penetration, which includes review of ancillary services
Spain	Large system but weakly interconnected with the rest of Europe High penetrations of wind and increasing solar power
Mt Isa	Small, isolated system in North West Queensland with alternative ancillary service requirements
California	Large system, interconnected with rest of western US. Has ambitious renewable energy targets, centered around solar energy, which will require adjustment of ancillary services

The following sections present an overview of the key facets of the ancillary services in these markets.

Table C.2 – Overview of Ancillary Service Markets

	WEM	Ireland	UK	New Zealand	NEM	Germany	Spain	California
Dispatch Interval	30 minutes	30 minutes [42]	30 minutes [99]	5 minutes [100]	5 minutes [101]	15 minutes	1 hour [102]	5 minutes [33]
Energy Market Design (gross/net dispatch pool)	Gross pool SRMC bidding and capacity payments	Gross pool SRMC bidding and capacity payments [103]	Net pool In 2014 introduced capacity auction [104]	Gross pool [105]	Gross pool [101]	Net pool [106] Energy-only [107]	Net pool [108]	Net pool [109]
Annual Energy Market Volume (approx)	17,881 GWh in 2012-13 [96]	26,100 GWh in 2013 [110]	364,000 GWh in 2012 [111]	44,494 GWh in 2011 [112]	195,525 GWh in 2013 [101]	551,200 GWh in 2012 [113]	246,166 GWh in 2013 (Peninsular) [114]	231,800 GWh in 2013 [115]
Annual Peak Demand (approx)	3.7 GW in 2012-13 [96]	4.5 GW in 2013 [116]	57.4 GW in 2012 [111]	6.4 GW in 2013 [105]	33.6 GW in 2013 [117]	79.3 GW in 2010 [118]	40.3 GW in 2013 (Peninsular) [114]	45.1 GW in 2013 [119]
Total Capacity	6,086 MW (capacity credits) in 2014 [120]	9,774 MW in 2013 [103]	81,742 MW in 2012 [111]	9,200 MW in 2012 [105]	50,000 MW in 2013 [101]	167 820 MW in 2011 [121]	102,281 MW in 2013 (Peninsular) [114]	N/A

	WEM	Ireland	UK	New Zealand	NEM	Germany	Spain	California
Generation Mix (Share of Energy)	In 2013: Coal – 49% Natural Gas – 36% Natural Gas/Coal – 4% Natural Gas/Diesel – 2% Renewable – 9% [96]	In 2012: Coal – 22% Hydro – 7% Natural Gas – 43% Other Renewables – 18% Peat – 7% [122]	In 2012: Coal – 39.7% Hydro – 1.5% Natural Gas – 27.7% Nuclear – 19.5% Oil – 0.8% Other – 0.8% Other renewables – 4.2% Solar – 0.3% Wind, wave – 5.4% [111]	In 2011: Coal – 10% Cogeneration – 3.9% Diesel – 1.8% Geothermal – 7.3% Hydro – 54.4% Natural Gas – 15.9% Other – 0.6% Wind – 6.1% [105]	In 2013: Coal – 74% Natural Gas – 12% Renewables – 14% [101]	In 2011: Coal – 42% Diesel, pumped storage, other – 5% Hydro , biomass, other renewables – 10% Natural gas – 14% Nuclear – 18% Solar – 3% Wind – 8% [121]	In 2013 (Peninsular): Coal – 14.9% Hydro – 15.5% Natural Gas – 9.5% Non-renewable thermal – 12.0% Nuclear – 21.2% Renewable thermal – 1.9% Solar – 4.7% Wind – 20.2% [114]	In 2013: Biogas, biomass, waste – 2% Geothermal – 4% Hydro – 8% Imports – 28% Natural gas – 40% Nuclear - <8% Solar – 2.4% Wind – 5.5% [115]
Annual total cost of traded energy (excl capacity payments)[16]	AUD975m	EUR2.31bn [123]	GBP29.82bn [30]	NZD5.883bn [30]	AUD11.4bn in 2012-13, based on price and demand data (RC derived)	EUR25bn [124]	EUR9.56bn [27]	USD10.7bn [115]
	AUD975m	AUD3.2bn	AUD48.4bn	AUD5.0bn	AUD11.4bn	AUD34.6bn	AUD13.25bn	AUD11.1bn
	AUD55/MWh[17]	AUD122/MWh	AUD133/MWh	AUD112/MWh	AUD60/MWh	AUD62.8/MWh	AUD53/MWh	AUD48/MWh
	AUD0.26m/MW peak	AUD0.71m/MW peak	AUD0.84m/MW peak	AUD0.79m/MW peak	AUD0.37m/MW peak			AUD0.25m/MW peak

[16] Currency conversion to Australian Dollars is calculated using the annual average exchange rate for 2013 [150].
[17] EY notes that as this excludes capacity payments, which lack market transparency, it is difficult to compare the WEM with the NEM, for example.

	WEM	Ireland	UK	New Zealand	NEM	Germany	Spain	California
Procurement: Frequency Control (market, contracts, fixed amount etc.)		Mandatory contracts with fixed rate tariffs [82]	Non-co-optimised markets for secondary response (weekly), tertiary response (monthly) Non-Tendered Contracts for primary response [30]	Half hourly market, co-optimised with energy for regulation and upward reserve Non-tendered contracts for downward reserve [125]	5 minute market, co-optimised with energy	Tendered Contracts (weekly for tertiary response, monthly for primary and secondary) [126]	Primary response is non-remunerated. Hourly market for secondary and tertiary response [126]	tendered contracts [127]
Procurement: Black Start	Non-tendered contracts	Non-tendered Contracts [30]	Non-Tendered Contracts [30]	Non-tendered contracts [125]	Invitation to tender	Non-tendered contracts	Not procured [30]	Not procured [128]
Cost of frequency control ancillary services	Regulation ~57.1m Operating Reserve ~AUD21.5m [8]	Primary response: ~EUR16.3m (AUD m) Secondary response: EUR16m Tertiary response: EUR8.2m. [129]	Primary response: GBP133m (AUD239m) Secondary response: GBP54m (AUD97m) Tertiary response GBP102m (AU184m) [30]	Regulation: NZD53m (AUD45m) Operating Reserve: NZD28m (AUD23.9m) [30]	Regulation: AUD4.5m Operating Reserve: AUD18.8m	Primary response: EUR90m (AUD132m) Secondary response: EUR 270m (AUD395m) Tertiary response: EUR70m (AUD102m) [124]	EUR244m (AUD 336m) [27]	Regulation: USD36m (AUD39m) Operating Reserve USD48m (AUD51m) [127]
Cost of black start ancillary services	~AUD0.5m [8]	EUR8.5m (AUD11m) [82]	~GBP15m (AUD24m) [30]	~NZD0.5m (AUD0.4m) [30]	AUD54.7m	EUR7m (AUD 9.7m) [85]	Not remunerated [30]	Not remunerated, market under construction [128]

	WEM	Ireland	UK	New Zealand	NEM	Germany	Spain	California
Governor Droop and Deadband Settings for significant scheduled units	Deadband: ±0.025Hz Droop: 4%	Deadband: ±0.015Hz Droop: 4% (settable to between 2 – 10% on instructions from the TSO) [42]	Deadband: ±0.015Hz Droop: normally 4% (settable to between 3 – 5% on instructions from the TSO) [99]	No deadband requirement. Droop: set between 0 – 7%[18] [130]	Deadband 0.025Hz Droop 4%	Deadband: ±0.020Hz [131] Droop: 4 – 8%, settable according to instructions from the TSO [132]	Deadband: ±0.010Hz Droop adjustable according to instructions form the TSO [102]	Deadband: ±0.036Hz Droop: 5% (typically) [133]

C.2 Ancillary services provision

C.2.1 Regulation response

All markets surveyed provide regulation response using units on AGC.

C.2.2 Contingency response

Table C.3 outlines the services and/or methods by which each market responds to contingency events, using the framework outlined in Section 2.1.

[18] Different generators have interpreted these settings in different ways in New Zealand. For example, some generators have not implemented a deadband at all and others are not responsive at all within the “normal frequency band” of 50±0.2Hz. Consultation is currently being undertaken around proposed changes to the Participation Code to specify a deadband no greater than 0.025Hz and a non-adjustable droop setting agreed with the system operator for each generator which is to be “as low as practical and at no more than 7%” [155]

Table C.3 – Classes and timescales of operating reserves in international markets

Country		Primary Response	Secondary Response	Tertiary Response
WEM (upward response) [134]	Name of service/s in market	Discussed in 4.5	Discussed in Section 4.5	No services procured as market dispatch provides longer term generation increases
	Time to respond by			
	Time to sustain response			
	Provision			
WEM (downward response)	Name of service/s in market	Load rejection Class A/B	Load Rejection Class B No additional services procured as market dispatch provides longer term generation decreases	
	Time to respond by	6 seconds/6 seconds		
	Time to sustain response	6 minutes/60 minutes		
	Provision	Governor Response		
UK [135], [136], [137], [138]	Name of service/s in market	Upwards: - Mandatory Frequency Response (FR) (primary and secondary[19]) - Frequency Control through Demand Management (FCDM) Downwards: - High (over-)frequency response	Fast Reserve	Short Term Operating Reserve (STOR) Balancing Market (BM) Start-up

[19] Although this is called "secondary" response, it is consistent with primary response as defined in this report

Country		Primary Response	Secondary Response	Tertiary Response
	Time to respond by	Mandatory FR: - Primary: 10 seconds - Secondary: 30 seconds High freq: 10s FCDM: 2 seconds	2 minutes	STOR: 4 hours BM Start-up: 90 minutes
	Time to sustain response	Mandatory FR: - Primary :30 seconds - Secondary: 30 minutes High freq: indefinite FCDM: 30 minutes	Minimum of 15 minutes	STOR: 2 hours BM Start up: indefinite
	Provision	Governor Response/ Under Frequency Relay	Electronic Dispatch instruction (e.g., AGC)	Custom Dispatch Instructions
Ireland [42], [37], [60]	Name of service/s in market	Primary Operating Reserve (POR) Secondary Operating Reserve (SOR)[20]	Tertiary Operating Reserve 1 (TOR1) Tertiary Operating Reserve 2 (TOR2)	Replacement Substitution
	Time to respond by	POR: 5 seconds SOR: 15 seconds	TOR 1: 90 seconds TOR 2: 5 minutes	Replacement: 20 minutes Substitution: 4 hours
	Time to sustain response	POR: 15 seconds SOR: 90 seconds	TOR 1: 5 minutes TOR 2: 20 minutes	Replacement: 4 hours Substitution: 20 hours
	Provision	Governor Response	Electronic Dispatch Instructions	Electronic Dispatch Instructions

[20] EY notes that despite the names Primary Operating Reserve and Secondary Operating Reserve, these are both primary response services split into two timescales, each based on local frequency sensing and designed to arrest the frequency

Country		Primary Response	Secondary Response	Tertiary Response
Germany [139], [131], [140]	Name of service/s in market	Primary Control	Secondary Control	Minutes Reserve
	Time to respond by	15-30 seconds21	30 seconds - 5 minutes	15 minutes
	Time to sustain response	15 minutes22	15 minutes	Several hours
	Provision	Governor Response	Automatic Activation by TSO (e.g., AGC)	Dispatch (Electronic or manual)
Spain [27],	Name of service/s in market	Primary reserve	Secondary reserve	Tertiary Reserve / Slow reserve
	Time to respond by	30 seconds	100 seconds	15 minutes / 30 minutes
	Time to sustain response	15 minutes	15 minutes	2 hours / 5 hours
	Provision	Governor Response	AGC	Dispatch Instructions
California [33], [141]	Name of service/s in market	California procures only one time class of spinning reserve, which must have fully reached its capacity by 10 minutes after instruction. This reserve will begin to come on earlier, and plant with governor response will respond immediately, but response is not monitored until 10 minutes after the event.		Spinning reserve/non-spinning reserve
	Time to respond by			10 minutes
	Time to sustain response			105 minutes
	Provision			Dispatch instructions

[21] Depending on the size of the contingency event
[22] But typically declines after 30 seconds

Country		Primary Response	Secondary Response	Tertiary Response
NEM [142], [20]	Name of service/s in market	Fast Response Slow response	Delayed response	No services procured as market dispatch provides longer term generation increases/decreases
	Time to respond by	6 seconds 1 minute	5 minutes	
	Time to sustain response	1 minute 5 minutes	10 minutes	
	Provision	Governor Response High or low frequency relay	Governor Response High or low frequency relay Fast-start generation	
New Zealand [143], [144]	Name of service/s in market	Fast Instantaneous Reserve Over frequency reserve	Sustained Instantaneous Reserve	No services procured as market dispatch provides longer term generation increases/decreases
	Time to respond by	Six seconds Over frequency reserve: 0.5 seconds	60 seconds	
	Time to sustain response	1 minute Over frequency reserve: indefinite	15 minutes	
	Provision	Dispatch Instructions/ Under Frequency Relay	Dispatch Instructions	

C.3 Frequency standards

Table C.4 – Frequency Standards in International Markets (Hz)

	WEM	Ireland [42], [145]	UK [99], [145]	New Zealand [130]	NEM [146]	Central Europe (including Germany and Spain) [145]
Normal Frequency Band	49.8 – 50.2	49.8 -50.2	49.8 - 50.2	49.8 - 50.2	49.85 – 50.15	49.95 – 50.05
Minimum time within normal band	99%	98% (maximum of 10,500 minutes outside)	~97% (maximum of 15,000 minutes outside)	Fluctuations must be maintained below a schedule of occurrences for a range of frequency excursions	99%	~97% (maximum of 15,000 minutes outside)
Frequency limits during normal operation	Not used	49.5 – 50.5	49.5 – 50.		49.75 -50.25	49.8 – 50.2
Minimum Frequency on single contingency	48.75	Maximum deviation of 1	Maximum deviation of 0.8	48	49.5 (generation or load) 49 (network)	Maximum deviation of 0.8
Maximum Frequency on single contingency	51			50.5	50.5 (generation or load) 51 (network)	
Restoration Schedule	Normal frequency band within 15 minutes	49.5 – 50.5 within one minute. Normal band within 20 minutes	49.5 – 50.5 within one minute. Normal band within 10 minutes	49.25 within 1 minute	After network event: 49.5 – 50.5 within one minute All: normal operating range within 5 minutes	Restored within 15 minutes

C.4 Ancillary service requirements

Table C.5 – Regulation and Operating Reserve Requirements in International Markets

	Ireland	UK	New Zealand	NEM	Germany	Spain	California
Minimum level of upwards primary response	75% of largest in-feed/export in primary and secondary response and 100% of largest in-feed/export in tertiary response [25], with a minimum of ±75115 for Republic of Ireland depending on time on day and ±50MW for northern Ireland	Calculated based on demand levels, availability of large power stations and largest generator/ import interconnector loss [99]	Function of maximum credible contingency – to maintain frequency above 48 Hz after the event [130]	Calculated based on largest credible contingency, minus load relief response[23] [20]	±3000 MW primary response for European synchronous area, attributed yearly to each country [147] and -2,200MW/ +2,700MW secondary response (within 5 minutes) and -2,400 MW/ +2,300 MW of tertiary response (within 15 minutes) [140]	Usually 6 times '√Pmax' where Pmax is the max forecasted hourly demand for secondary response and the largest unit +2% of the forecast load for tertiary response [102]	the maximum of 5% of forecasted demand met by hydro-electric resources plus 7% of forecasted demand met by thermal resources, or the largest single contingency [13]
Minimum level of downwards primary response		Calculated based on demand levels, availability of large power stations and largest load/ export interconnector loss [99]	Function of maximum load loss – to maintain frequency below 55Hz [130]	Calculated based on largest load contingency event, minus load relief response [20]		50 – 100% of up reserve depending on system conditions [102]	

[23] Load relief response is calculated for each time scale of contingency response required in the NEM based on the frequency containment standards.

	Ireland	UK	New Zealand	NEM	Germany	Spain	California
Required regulation response	Included in contingency reserve		±50MW [148]	±50MW for Tasmania ±70MW for South Australia if islanded [142]	Included in contingency reserve	Included in contingency reserve	Set each hour for up and down regulation independently based on inter-hour changes in scheduled generation, inter-tie schedules, forecasted demand and number of units starting up or shutting down. [13]