THE UTILITIES COMMISSION OF THE NORTHERN TERRITORY

Power and Water Corporation Technical Audit 2017

SPINNING RESERVE

SEPTEMBER 2017

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SPINNING RESERVE

The Utilities Commission of the Northern Territory

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ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
FCAS	Frequency Control Ancillary Service
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
PWC	Power and Water Corporation

EXECUTIVE SUMMARY

The Utilities Commission has engaged WSP to audit Power and Water Corporation's (PWC) compliance with requirements for spinning reserve. The Commission seeks to determine whether PWC, in operating the power system and setting spinning reserve levels, is applying the policies and procedures relating to spinning reserve appropriately, complies with the System Control Technical Code and the Secure System Guidelines made under the Code.

In respect of the obligations set out in the System Control Technical Code, WSP:

- determined the obligations that relate to spinning reserve – to adopt reliability criteria and to provide spinning reserve as a part of the available responses to achieve supply reliability
- assessed compliance with these requirements.

WSP found that PWC complied with these obligations.

In respect of the requirements set out in the Secure System Guidelines, WSP established the criteria for audit as follows:

- that PWC has adequate policies and procedures relating to spinning reserve and is applying them and staff are trained in the process and procedures
- the process of calculating spinning reserve is appropriate, repeatable, and the levels of risk to system security is taken into account
- the outcomes achieved are those expected and meet the requirements of the System Control Technical Code.

WSP found that PWC complied with these requirements.

Benchmarking was also performed to determine the degree of consistency with national and interstate practices with regard to calculation methodology and levels of risk to system security. We compared the arrangements in Northern Territory with those administered by the Australian Energy Market Operator for the National Electricity Market (NEM) mainland States and Tasmania.

WSP found that:

- the Frequency Operating Standards applicable to the Northern Territory are broadly consistent with comparable standards used in the NEM, though some improvements might be made in the long term
- the operational aspects of frequency control in the Northern Territory do not currently conform to the framework operating in the NEM. However, there are changes proposed to the Secure System Guidelines that would introduce frequency control-based services into the Northern Territory network similar to those operated by the Australian Energy Market Operator in the NEM. Notwithstanding, WSP found that the lack of an active market for the trading of these ancillary services in the Northern Territory causes us to conclude that the market framework in the Northern Territory does not conform to the benchmark framework operating in the NEM.

In undertaking the review, WSP consulted with Territory Generation as an impacted party. We understand that Territory Generation is of the view that the levels of spinning reserve set by PWC System Control to ensure an adequate level of system security are overly conservative and risk-averse and result in higher costs being incurred than are necessary. We note that PWC System Control has no specific obligation to take cost into account when complying with the System Control Technical Code clause 1.7.4 "… to ensure that the system operates reliably, safely and securely …".

Territory Generation also expressed their concern that under the current and proposed future regimes, it alone bears the cost of providing the spinning reserve capacity required to ensure system security, as there is no effective mechanism for them to be compensated by or to share with other participants the cost of holding capacity in reserve; nor is there a mechanism to factor the cost of the service into the frequency control decision-making process. We note that Territory Generation, PWC System Control and the Department of Treasury and Finance are undertaking a project to unbundle the costs of providing ancillary services that would address this concern.

Based on the findings, we consider that System Control’s current calculation methodology is appropriate. We do not think, however, that the Secure System Guidelines v2.6 are adequate for the following reasons:

- Credible contingency events are defined in outcome terms and we believe that impacted parties would benefit from a definitive list of credible contingency events.
- The requirements for spinning reserve are static requirements and do not reflect the existence of a wholesale market. We note that draft version 3 of the Secure System Guidelines addresses this matter through the intent to establish a Frequency Control Ancillary Service that would replace the spinning reserve requirements.

We also note that the Secure System Guidelines v2.6 are modified by several Short Term Advices. A consolidated set of requirements for spinning reserve would ensure transparency and aid consistency in application.

1 PROJECT BACKGROUND

In 2014, WSP | Parson Brinckerhoff (WSP) undertook an audit of Power and Water Corporation's (PWC) compliance with its licence conditions. The audit focussed on issues leading to a System Black incident that occurred in March 2014. Areas of non-compliance or part-compliance are being re-assessed this year.

This audit report focusses on a new area not previously reviewed – spinning reserve.

1.1 Scope

The Utilities Commission seeks to determine whether PWC, in operating the power system and setting spinning reserve levels, is applying the policies and procedures relating to spinning reserve appropriately, complies with the System Control Technical Code, and the Secure System Guidelines made under the Code. The principal policy will be the Secure System Guidelines and any associated documentation relating to the calculation of spinning reserves and targeted levels of risk to system security.

The review is to:

→ take into account appropriate benchmarking (national and interstate comparisons), particularly with regard to calculation methodology and levels of risk to system security

→ sampling of the calculation of spinning reserve levels required by System Control in its operation of the regulated power systems in the Territory (Alice Springs, Tennant Creek and Darwin-Katherine) to determine if the approach taken by System Control is appropriate

→ consult with impacted parties, including Territory Generation

→ based on the findings, make a statement on whether it considers System Control's current calculation methodology is appropriate, and provide recommendations on an appropriate calculation methodology for spinning reserve levels if necessary.

The review will provide recommendations on changes to the secure system guidelines and any changes to existing spinning reserve calculations in accordance with best practices in the electricity industry. In conducting the audit, the auditor should include audit interviews with relevant management and staff, and consider existing policies and procedures.

1.2 What is spinning reserve?

Spinning reserve is defined as the ability to immediately and automatically increase generation or reduce demand in response to a fall in frequency.[1] The level of spinning reserve is the level of available generation on a power system above the current demand for electricity.[2]

The purpose of spinning reserve is to ensure that the power system can respond to some disruption resulting from an unexpected disconnection of generating units or items of transmission equipment.[3] In most large power systems, the frequency of the system is controlled to a narrow band and is used to identify when an increase in generation is required, including from those generators providing spinning reserve.

To assist in the understanding of frequency control, many documents use the analogy that can be drawn between a power system and the engine in a car[4]. If a car travelling at a constant velocity is presented with a change in load with no corresponding change to the power input to the engine of the car, then the car will

1 System Control Technical Code V5, p.68
2 Secure System Guideline V2.6, p.8
3 Ibid p.8
4 AEMO, 2015, Guide To Ancillary Services In The National Electricity Market

speed up (for decreases in load such as that presented by a downhill slope) or slow down (for increases in load such as an uphill slope).

In a similar manner, if the load is varied on a power system without a corresponding variation in the generation feeding that power system, the system frequency (speed) will deviate.

Importantly, a heavy vehicle will reduce/increase speed more slowly than a light vehicle when the accelerator is released/pressed. Figure 1-1 shows the effect of taking one's foot off the accelerator, where the light vehicle (the car) slows down more quickly than the heavier vehicle (the truck). Similarly, a power system with higher inertia will change frequency more slowly than one with less inertia. Hence, the inertia of a power system also needs to be considered.

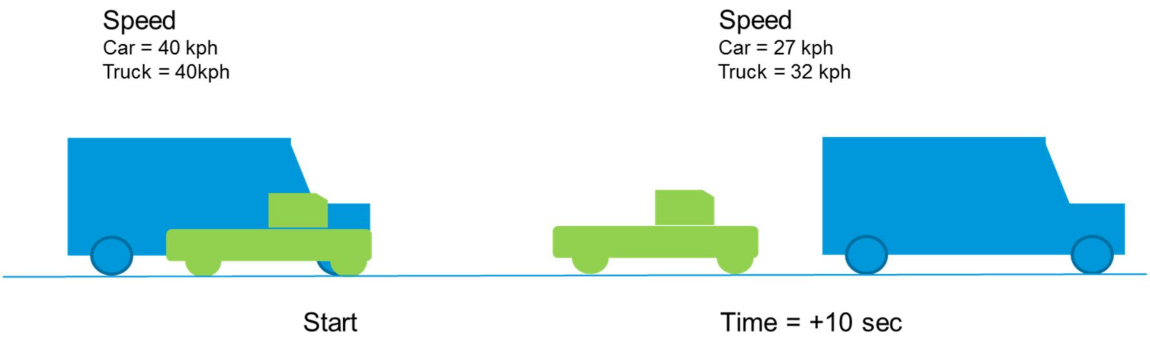


Figure 1-1 The importance of inertia

In practice, a change in load or in generation will result in a change in system frequency, with the rate of change depending on the inertia of the generators connected to the power system and the magnitude of the change in load. In response to a drop in frequency, such as would occur with an increase in load, more fuel is fed to generators' prime movers restoring the frequency to its nominal value. Should the frequency drop suddenly, such as would occur should a generator suddenly disconnect from the power system, the drop in frequency would again trigger an increase in fuel. In most generators that are based on rotating machines, a time lag occurs before the fuel can be increased and a corresponding output of the machine achieved. During this lag, the frequency of the power system will continue to fall. If the frequency falls too low, the rotating generator will slow down to a point where it cannot recover and will cease generating.

Based on this knowledge, we can see that the two key things that need to be known when determining an appropriate response to a change in frequency involve:

- understanding the technical operating parameters of generators, particularly how quickly they can be slowed down or sped up
- defining the events that might occur on the power system that the generators should be able to respond to in normal operation, and those events that might require other response mechanisms.

The typical responses to a drop in system frequency are illustrated in Figure 1-2:

Normal – spinning reserve adds additional generation availability above the current load level

Credible contingency – the loss of generation is within the spinning reserve allocation and no load is lost[5]

Non-credible contingency – the loss of generation is greater than the spinning reserve allocation and under frequency load shedding occurs

[5] Some contingencies that are credible are recognised to be too costly to manage to prevent under frequency load shedding. In the NEM, these are classified as protected events. These have been omitted from the illustration for simplicity.

Disaster - the loss of generation is greater than the spinning reserve allocation and the under frequency load shedding allocation and a system black occurs.

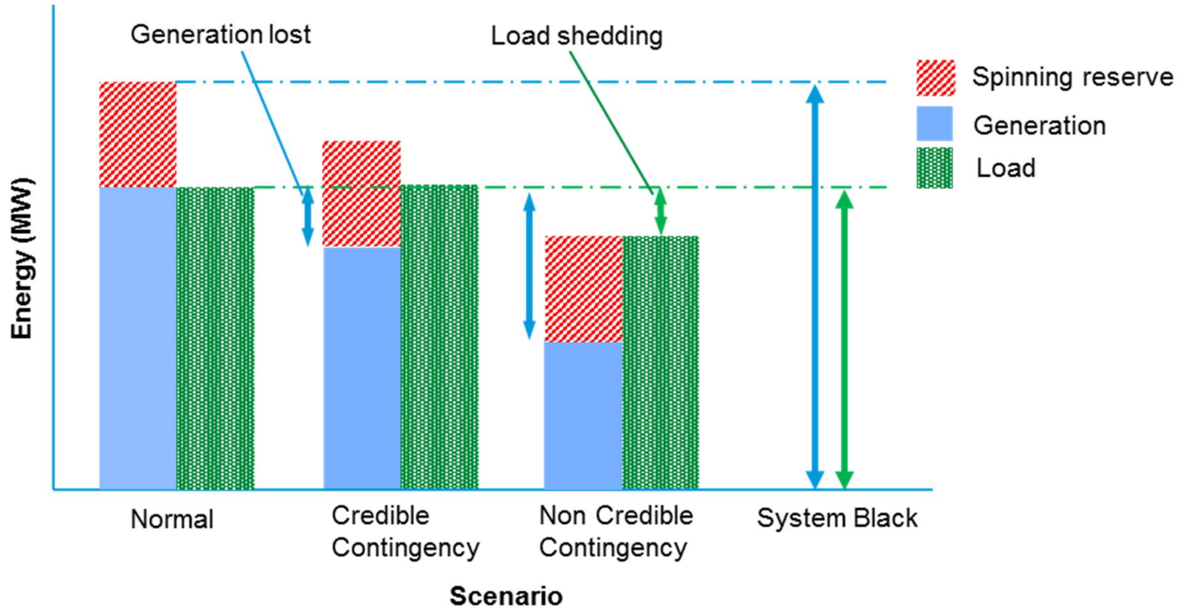


Figure 1-2 Generation scenarios under normal and contingency conditions

The calculation of spinning reserve must also take into account the ability of the transmission network (and sometimes the distribution network) to transfer the energy from the generator/s providing the spinning reserve to the load. Hence, network modelling may be required. In the event of an immediate response, the operating characteristics of the generator must be modelled and technical operating parameters set. These factors mean that the calculation methodology can be multi-facetted and complex.

1.3 Who sets the level of spinning reserve?

In all states and territories except the Northern Territory, the determination of the appropriate level of spinning reserve is undertaken by the Australian Energy Market Operator (AEMO), which is responsible for operating the interconnected network that forms the National Electricity Market (NEM). On 30 November 2015, it also assumed responsibility for the South West Interconnected System in Western Australia, previously managed by the Independent Market Operator.

In the Northern Territory, PWC as the nominated System Operator sets the level of spinning reserve.

2 REVIEW

The obligations for spinning reserve are set out in the System Control Technical Code and the Secure System Guidelines made under the Code. In this section, we discuss the obligations for spinning reserve and present our assessment of compliance against these obligations.

We also examine the consistency of the manner in which the obligations are met in comparison with the parallel requirements and obligations of the NEM rules and AEMO.

Finally, we solicited the views of the main service provider in the Northern Territory, Territory Generation, as regarding the issues and impacts that the present and future frequency control requirements have on its operation.

2.1 System Control Technical Code requirements

The System Control Technical Code sets out obligations for the Power System Controller relating to spinning reserve in two places. The first relates to establishing reliability criteria as a means of providing a required level of power system security. The second relates to the provision of spinning reserve as a part of the available responses to achieve supply reliability.

Each of these requirements is discussed below.

2.1.1 Reliability criteria

REQUIREMENT

The first requirement relates to establishing a level of spinning reserve as a means of providing a required level of power system security (N-1). The code states:

“3.2.3(d) The Power System Controller will adopt reliability criteria for generating plant generally in accordance with the following:

1. N-1, i.e. there is sufficient stand-by plant in a power system to cater for the loss of a single 'on line' Generator, though in many cases short periods of involuntary load shed may occur; and
2. The Power System Controller will utilise available **spinning reserve** in the system, quick starting or stand-by plant to reconnect customers and restore the relevant power system to normal, in accordance with the ancillary services procurement arrangements established in clause 5.1.”

ASSESSMENT

PWC has put in place a Secure System Guideline that:

- defines spinning reserve in words that are consistent with the System Control Technical Code definitions
- set out how the Power System Controller will utilise spinning reserve
- sets out the minimum spinning reserve in each of the three power system areas.

PWC showed evidence that it:

- determines the appropriate level of spinning reserve on a daily basis for each time interval
- has processes in place to assess the perceived power system risk level
- has procedures in place to restore the relevant power system to normal.

CONCLUSION

In the auditor's view, PWC complies with the System Control Technical Code clause 3.2.3(d)(2) with respect to spinning reserve.

2.1.2 Achieve supply reliability

REQUIREMENT

The second requirement relates to the provision of spinning reserve as a part of the available responses to achieve supply reliability. The code states:

"3.2.4 … Supply reliability in any power system is achieved through the continuous provision of:

(a) sufficient supply options available and in service to meet the forecast instantaneous customer demand for electricity;

(b) sufficient fast response supply reserves available either as unused generating plant actually in service (**spinning /regulating reserve**) or as interruptible customer load to cover a nominated level of impact resulting from a credible contingency event; and

(c) sufficient stand-by or short notice supply reserve to accommodate rapidly the impact of a credible contingency event, or to cope readily with multiple contingencies with a minimal period of disruption to customer demand."

The System Control Technical Code defines a credible contingency event as follows:

- Credible contingency event - A contingency event, the occurrence of which the Power System Controller considers to be reasonably possible as defined in clause 3.2.7.
- Contingency event - An event affecting a power system which the Power System Controller expects would be likely to involve the failure or removal from operational service of a generating unit or network element as defined in clause 3.2.7.

The System Control Technical Code p.68 also defines a single credible fault as a fault considered by the Power System Controller, in particular circumstances, to have the potential for the most significant impact on a power system at that time. This would generally be the instantaneous loss of the largest generating unit or a fault on a major network element on a power system. Under normal conditions, the design or operation of the relevant part of a power system would adequately cater for a single credible fault, so as to avoid significant disruption to power system security.

ASSESSMENT

PWC has not formally declared events as credible contingency events, but relies on the experience and training of its control room staff to correctly consider the credible contingency events on a daily basis.

Further, PWC does not have a dynamic system model for the Darwin-Katherine or Tennant Creek power systems and has only recently introduced a dynamic system model in the Alice Springs power system. The lack of a dynamic system model limits the ability to model the response of the power system to events and hence limits the establishment of credible events. PWC advised that it has sufficient data from operations of its Under Frequency Load Shedding Scheme in the Darwin-Katherine power system to meet its current analysis needs. It also advised that the Tennant Creek power system being a small system does not require a full dynamic model for analysis of spinning reserve requirements.

PWC showed evidence that it:

- does not currently have contracted interruptible load, reducing the obligation to one of achieving adequate spinning reserve

- considers the loss of the largest generating unit or a transmission element when setting levels of spinning reserve – this is consistent with the System Control Technical Code definitions
- undertakes a risk assessment when elements of the transmission systems are taken out of service and uses this in setting the minimum level of spinning reserve under those conditions
- considers the risk of multiple contingency events when setting the minimum level of spinning reserve, where these are reasonably likely to occur, such as common gas supplies or common points of connection to the transmission network – this is consistent with the requirements of clause 3.3.1(j)(2) of the System Control Technical Code.

CONCLUSION

In the auditor's view, PWC complies with the System Control Technical Code clause 3.2.4(b).

We note that credible contingency events are defined in outcome terms and we believe that impacted parties would benefit from a definitive list of credible contingency events.

2.2 Secure System Guidelines requirements

REQUIREMENT

The Secure System Guidelines set out obligations for the Power System Controller relating to spinning reserve in section 8. It defines spinning reserve and an adequate level of spinning reserve.

It states that:

"The Power System Controller may vary the amount of Minimum Spinning Reserve and direct the allocation of unit Spinning Reserve, to accommodate the perceived risk level of the Power System or sub-network at the time."

Short Term Advice notices are also in effect that varies the minimum spinning reserve in the Darwin-Katherine power system (typically 13 MW) to a new value (25 MW at all times) and adds requirements to have two Frame 6 machines dispatched at all times and a minimum of 15 MW from the two frame 6 machines[6]. These latter requirements are aimed at having a power system with sufficient inertia to avoid a too rapid drop in frequency that might inadvertently trigger the Under Frequency Load Shedding System.

The current version of the Secure System Guidelines is version 2.6. A draft version 3 was provided to the Auditor. This draft version incorporates all of the current Short Term Advice requirements and sets out a new Frequency Control Ancillary Service (FCAS) that, if implemented, will replace the requirements for spinning reserve. The auditor did not assess draft 3, but notes that the move to a new FCAS would appear to change from a static approach (spinning reserve) to a dynamic approach (FCAS) that should better suit wholesale energy market arrangements.

ASSESSMENT

In order to assess whether PWC complies with the Secure System Guidelines, the auditor examined whether:

- PWC has adequate policies and procedures relating to spinning reserve and is applying them and staff are trained in the process and procedures
- the process of calculating spinning reserve is appropriate, repeatable, and the levels of risk to system security is taken into account
- the outcomes achieved are those expected and meet the requirements of the System Control Technical Code.

[6] Short Term Advice issued 10 November 2014

Policies and procedures

PWC uses only the Secure System Guidelines and Short Term Advices to inform its Grade 2 controllers of the obligations regarding spinning reserve. The auditor established that:

- support staff are aware of the requirements – they calculate spinning reserve prior to the time period based on forecast demands
- Grade 2 controllers are aware of the requirements – the Grade 2 controllers' role is to determine dispatch requirements and to determine the appropriate level of spinning reserve at any given time
- all appropriate staff receive training in the requirements of the System Control Technical Code and the Secure System Guidelines
- multiple Short Term Advices have been issued to cover specific (short term) operating issues.

In the auditor view, the use of Short Term Advices to support the Secure System Guidelines requirements for spinning reserve appears appropriate.

Calculating spinning reserve

Spinning reserve is calculated using the user calculation module of the SCADA system. Inputs include the capacity of connected generators and their real time generation output. The difference between capacity and actual output is determined to be the level of spinning reserve. Generators that cannot respond quickly to changes in fuel inputs are excluded from the calculation – currently only steam driven generators.

A prior day assessment of electricity demand and spinning reserve is produced by staff in System Control who provide this information in graphical form to the Grade 2 controller for reference.

The auditor sighted the calculations for the Darwin-Katherine power system. Outputs of the user calculation module are:

- System load rate of change – this rate is used by the Power System Controller to indicate the lead time available for a new machine to be connected to the power system. Too late a connection would mean that the spinning reserve may be reduced below optimal levels before the new machine can be connected and made productive.
- Spinning reserve – the calculated amount of spinning reserve is displayed. In the Darwin-Katherine power system, the total is shown together with that available from Frame 6 machines (as is required to meet the Short Term Advice requirements).

The auditor also sighted corresponding calculations for the Alice Springs system. All of the calculations sighted appeared to be consistent with the definitions for spinning reserve, repeatable and used appropriate information.

Outcomes achieved

PWC monitors its compliance with the key requirements of the Secure System Guidelines, including the level of spinning reserve, producing bi-annual reports. The auditor found:

- PWC has established targets for achieving compliance with spinning reserve requirements, e.g. 98% of the time for the Darwin-Katherine power system
- actual performance on a monthly basis has not always met the targets; i.e. in January 2015, 40 separate events occurred on the Darwin-Katherine power system resulting in inadequate spinning reserve for 2.7% of the time.

The reasons for not achieving adequate spinning reserve range from generating machines not starting when dispatched, to generating machines being taken offline. The auditor discussed this lack of achieving the spinning reserve requirement for 100% of the time with a Grade 2 controller, who is responsible for determining the spinning reserve requirements. It is clear to the auditor that:

- strict compliance would cause generators to be started for short periods of time, as loads rise and fall throughout the day, which would add to a generator's cost unnecessarily and is considered uneconomic
- generating machines not starting or being taken off-line is not predictable and it would be unreasonable to take this possibility into account when setting the required level of spinning reserve.

The Secure System Guidelines state that the Power System Controller may vary the amount of Minimum Spinning Reserve and direct the allocation of unit Spinning Reserve, to accommodate the perceived risk level of the Power System. In practice, the Grade 2 controller uses a risk based assessment approach to determine the appropriate dispatch requirements. Given the discretion provided to the Grade 2 controller in the guideline, the auditor considers that PWC complies with the requirements of the Secure System Guidelines.

CONCLUSION

In the auditor's view, PWC complies with the Secure System guidelines version 2.6 as modified by the Short Term Advices.

2.3 Consistency with industry practice

In this section we examine the spinning reserve obligations and how they are managed by System Control, and compare them to the obligations of the NEM and how they are managed by AEMO.

We note that the focus of this review is on spinning reserve. In the NEM, the amount of spinning reserve is an outcome of the Frequency Control Ancillary Services (FCAS), which uses a market based procurement model to purchase sufficient spinning reserve and other services to meet the required Frequency Operating Standards. We examine:

- the frequency operating standards that drive the level of spinning reserve required, and
- the structure of the FCAS in the NEM and how this relates to spinning reserve.

2.3.1 Frequency operating standards comparison

Spinning reserve is the key mechanism that allows the frequency of the power system to be maintained when generation is unexpectedly disconnected. The specified frequency range affects both the rate of change required from generators providing spinning reserve, i.e. how quickly they can change generation output, and the inertia of the generators that must remain connected to prevent too quick a fall in frequency.

In the Northern Territory, the System Control Technical Code sets the objectives in relation to frequency and frequency control, and cites the normal operating frequency band set out in the Network Technical Code and the frequency to be maintained under abnormal operating conditions.

Similarly, frequency operating standards apply to the NEM. These are set by the Reliability Panel of the AEMC. The standards applicable to the mainland States are currently published in the Reliability Panel's Final Report on the Application of Frequency Operating Standards during Periods of Supply Scarcity, dated 15 April 2009.

NEM Mainland Frequency Operating Standards – interconnected system

Condition	Containment	Stabilisation	Recovery
Accumulated time error	5 seconds		
no *contingency event* or *load event*	49.75 to 50.25 Hz, 49.85 to 50.15 Hz 99% of the time	49.85 to 50.15 Hz within 5 minutes	
generation event or *load event*	49.5 to 50.5 Hz	49.85 to 50.15 Hz within 5 minutes	
network event	49 to 51 Hz	49.5 to 50.5 Hz within 1 minute	49.85 to 50.15 Hz within 5 minutes
separation event	49 to 51 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
multiple contingency event	47 to 52 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

Source: AEMC

Different standards apply to Tasmania owing to it being a smaller system connected to the mainland only via a HVDC link (Basslink) and therefore not synchronised to the mainland network frequency. The standards applicable to Tasmania are currently published in the Reliability Panel's Final Report on the Tasmanian Frequency Operating Standard Review dated 18 December 2008.

A1: Revised Tasmanian frequency operating standards – interconnected system

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
Accumulated time error (other than multiple contingency events)	15 seconds		
Normal	49.75 to 50.25 Hz, 49.85 to 50.15 Hz 99% of the time	49.85 to 50.15 Hz within 5 minutes	
Load and generation event	48.0 to 52.0 Hz	49.85 to 50.15 Hz within 10 minutes	
Network event	48.0 to 52.0 Hz	49.85 to 50.15 Hz within 10 minutes	
Separation event	47.0 to 55.0 Hz	48.0 to 52.0 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Multiple contingency event	47.0 to 55.0 Hz	48.0 to 52.0 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

Source: AEMC

The Tasmanian standards are understandably somewhat less stringent than the mainland standards, particularly with regard to system performance following the occurrence of contingency events. Table 2.1 shows examples of the key differences.

Table 2.1 Single contingency event frequency operating standards - NEM

NETWORK CONDITION	MAINLAND	TASMANIA	COMMENT
Normal operating limits	49.75 to 50.25 Hz 49.85 to 50.15 Hz 99% of the time	49.75 to 50.25 Hz 49.85 to 50.15 Hz 99% of the time	Identical
Contingency event containment limits	49.5 to 50.5 Hz	48.0 to 52.0 Hz	Wider containment limits for Tasmania
Stabilisation and recovery requirements	49.85 to 50.15 Hz within 5 minutes	49.85 to 50.15 Hz within 10 minutes	Frequency limits the same, but a longer recovery time is allowed for Tasmania

Source: AEMC

In the context of the NEM, the Frequency Operating Standards applicable to Tasmania would be more appropriate to the Northern Territory network than those of the mainland. Table 2.2 shows a comparison of the frequency standards in Northern Territory and Tasmania.

Table 2.2 Single contingency event frequency operating standards – Tasmania and Northern Territory

NETWORK CONDITION	TASMANIA	DARWIN-KATHERINE	ALICE SPRINGS	TENNANT CREEK
Normal operating limits	49.75 to 50.25 Hz 49.85 to 50.15 Hz 99% of the time	49.8 to 50.2 Hz	49.8 to 50.2 Hz	49.6 to 50.4 Hz
Contingency event containment limits	48.0 to 52.0 Hz	47 to 52 Hz	47 to 52 Hz	47 to 52 Hz
Stabilisation and recovery requirements	49.85 to 50.15 Hz within 10 minutes	na	na	na

Source: AEMC, PWC

In the Northern Territory, the System Control Technical Code cites the normal operating frequency band set out in the Network Technical Code, which is 49.8 to 50.2 Hz for the Darwin-Katherine and Alice Springs systems, and 49.6 to 50.4 Hz for the Tennant Creek system and other isolated networks.

Under abnormal operating conditions, the Network Technical Code allows the network frequency to vary between 47 and 52 Hz, and all generating units are required to remain connected for an indefinite period within this range. Between 45 and 47 Hz, generating units are required to remain connected for at least two seconds, following which, under frequency load shedding schemes may come into operation to restore the system frequency back to the normal operating range, or at least to the 47 to 52 Hz range required for continuous abnormal operation. The Network Technical Code does not specifically set requirements for multiple contingency events.

The contingency event containment limits of the Northern Territory frequency operating standards are therefore only slightly broader than those of Tasmania, despite the normal system demand being considerably less (approx. 200 MW vs. 1,200 MW).

We conclude therefore, that in basic terms, the Northern Territory frequency operating standards are consistent with comparable standards used in the NEM. However, we note that the number of network conditions for which operating standards are specified are fewer, and in the long term it might be beneficial to include additional conditions such as a statistically based operating band for normal operating limits, i.e. 99% of the time, and a frequency band for multiple contingency events.

2.3.2 Spinning reserve requirements comparison

The requirements for spinning reserve in the Northern Territory are set out in section 8 of the Secure System Guideline as modified by Short Term Advices. They require a minimum amount of reserve to be maintained as shown in Table 2.3. The Power System Controller may vary the amount of minimum spinning reserve.

Table 2.3 Minimum spinning reserve in Northern Territory

REGION	MINIMUM SPINNING RESERVE (MW)	
	STANDARD	MODIFIED BY SHORT TERM ADVICE
Darwin Katherine	13.0	25.0
Alice Springs	2.0	The greater of: 8.0 (day), 5.0 (night) OR Largest machine MW output
Tennant Creek	0.6	0.8

In contrast, requirements for generators to provide spinning reserve are not directly specified in the NEM. Rather, spinning reserve is an outcome of requirements to control frequency.

The NEM takes a market-based approach to the management of frequency control and reserve capacity. In parallel with the main energy market, the NEM has ancillary services markets for the provision of additional services required by the network to achieve and maintain network stability and reliability. These ancillary services include the maintenance of network frequency within the frequency operating standards defined by the Reliability Panel of AEMC. Maintenance of network frequency under normal and contingency events is achieved by means of the frequency control ancillary services (FCAS) markets.

Section 3 of the AEMO publication Guide to Ancillary Services in the National Electricity Market describes the operation of the eight FCAS markets that provide the following services:

→ Regulation Raise → Regulation Lower	used to correct minor variations in frequency
→ Fast Raise (6 Second Raise) → Fast Lower (6 Second Lower)	6-second response used to arrest a major variation in frequency following a contingency event
→ Slow Raise (60 Second Raise) → Slow Lower (60 Second Lower)	60 second response to stabilise frequency following a major variation in frequency
→ Delayed Raise (5 Minute Raise) → Delayed Lower (5 Minute Lower)	5-minute response to recover frequency to the normal operating band following a major variation in frequency.

The Fast Raise, Slow Raise and Delayed Raise services are generally provided by generators though spinning reserve.

We conclude that the specification of spinning reserve in a deterministic manner in the Northern Territory is different to the market based approach adopted in the NEM. We note that the System Control Technical Code allows that spinning reserve and contracted interruptible loads may be used to ensure adequate supply reserve, and that there is currently no contracted interruptible load. The market based approach as used in the NEM may encourage contracted interruptible loads to be established.

We also note that the Secure System Guidelines v2.6 are modified by several Short Term Advices. A consolidated set of requirements for spinning reserve would ensure transparency and aid consistency in application.

2.3.3 System inertia requirements comparison

System inertia is related to the combined “flywheel effect” of all the rotating plant connected to the network. It is a measure of the amount of rotational kinetic energy stored in the system, and is often expressed as the “stored energy constant” in megawatt-seconds per MVA (i.e. seconds); megawatt-seconds (i.e. megajoules) being the amount of stored energy, and MVA being the aggregate MVA capacity of the connected generators. The importance of inertia in a power system is discussed in section 1.2.

Different types of generating plant have different characteristic stored energy constants that are primarily related to the mechanical designs of the plant. Generation capacity in the Northern Territory is dominated by gas turbine generating plant, which typically has comparatively low inertia to other forms of rotating equipment. The exceptions are some industrial gas turbines such as the GE “Frame” designs that have higher stored energy constants than the aero-derivative units of comparable size (e.g. LM6000). Hence, minimum inertia requirements have been specified in the Secure System Guidelines though the issue of a Short Term Advice. They require a minimum amount of system inertia to be dispatched, including from those generators providing spinning reserve, as shown in Table 2.4.

Table 2.4 Minimum inertia requirements in Northern Territory

REGION	MINIMUM INERTIA REQUIREMENTS	
	STANDARD	MODIFIED BY SHORT TERM NOTICE
Darwin Katherine	Nil	Two frame 6 machines must be dispatched at all times Minimum of 15 MW of the spinning reserve requirement is to come from Frame 6 machines
Alice Springs	Nil	Minimum of five machines, where one of these machines must be a gas turbine
Tennant Creek	Nil	Nil

In contrast, the NEM is dominated by steam turbine driven units and hydroelectric generators that typically have high stored energy constants. As a consequence, there is no ancillary service in the NEM related explicitly to the provision of system inertia, despite the important role it can play in buffering the network’s frequency response to disturbances.[7] The Fast Raise, Slow Raise and Delayed Raise services do have timeframes specified of 6 seconds, 60 seconds and 5 minutes respectively. These time frames suit the inherent inertia of the power systems in the NEM, allowing generators to respond before the frequency drops to a level outside of the frequency standard.

It has already been observed in at least one region of the NEM that the assumption of there being sufficient inherent system inertia is being tested. The generation mix in South Australia has been undergoing significant change in recent years. High inertia plant such as the two coal-fired units at Northern Power Station have been decommissioned, whilst there has been concurrently a large increase in the commissioning of renewable generation equipment based on wind and solar PV technologies. Unless wind and solar projects are equipped with significant amounts of energy storage (e.g. batteries), they have little or no inherent system “inertia” to help the system ride through disturbances, nor do they normally have any reserve capacity as they are normally operated to take advantage of all the wind or solar resource available to them.

Various strategies are being considered to manage the anticipated changes in network characteristics that will occur in the future. AEMO is conducting the Future Power System Security Program[8], which is looking at

7 Substantial system inertia was assumed to be an inherent characteristic of a balanced mix of generation plant connected to the network that includes coal-fired base-load generation units, and it was not considered necessary to ensure that additional inertia could be procured as an ancillary service. However, the 6-second response time for the provision of fast raise and fast lower FCAS was chosen on the basis that there would be sufficient inertia to allow this response time to be effective.

8 www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis

various issues including those related to possible ancillary service markets for system inertia and fast frequency response (FFR) in shorter timescales than the existing fast FCAS markets. The AEMC is conducting its System Security Market Frameworks Review[9] which is addressing how the regulatory frameworks may need to change to adapt to the increasing importance of new generation technologies.

We conclude that the inclusion of inertia requirements in the Northern Territory is appropriate, despite there being no direct equivalent in the NEM.

2.3.4 Payment arrangements comparison

NORTHERN TERRITORY

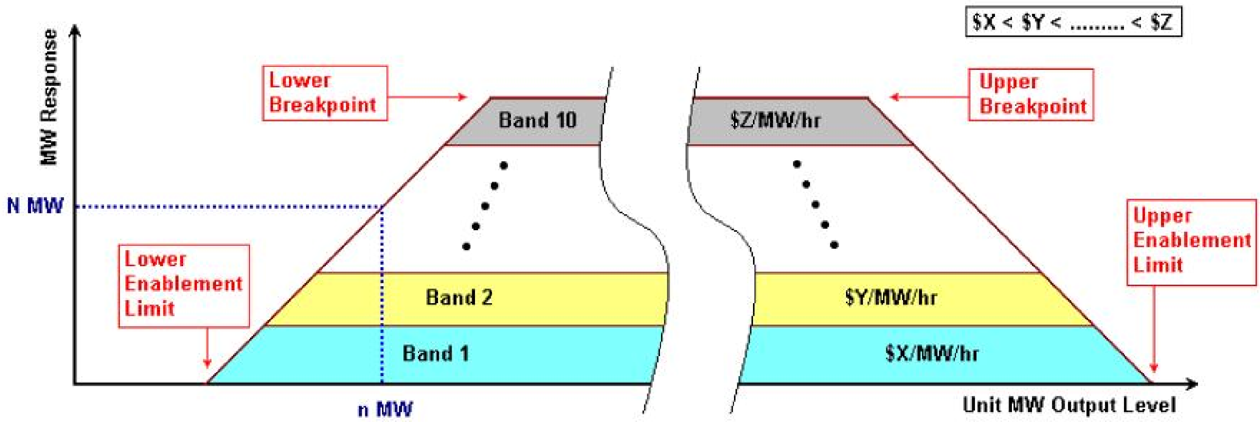
In the Northern Territory, clause A6.11 of Attachment 6 to the SCTC sets out the payment mechanism for the provision of ancillary services by Territory Generation in the Darwin-Katherine power system, under the Interim Northern Territory Electricity Market (I-NTEM). It amounts to a basic causer-pays approach, with the unit rate for the service set by regulation. The process steps are broadly as follows:

1. Market Generators jointly agree and document the methodology to be used by the Market Operator (System Control) to calculate the volume of ancillary services being used, which methodology the Market Operator shall approve.
2. Generators affected by ancillary services, either as a producer or consumer, provide ancillary services data to the Market Operator for each trading interval (i.e. half-hourly data).
3. The Market Operator determines the aggregate net ancillary services quantity (ASQuantity) for each settlement period (i.e. one calendar month) using the agreed methodology and advises the Generators in a Statement of Calculation.
4. Generators in surplus (i.e. net providers of ancillary services) invoice Generators in deficit (i.e. net consumers) at the regulated rate of $5.40/MWh (sent out).

No specific payment arrangement exists for the Alice Springs or Tennant Creek networks.

NATIONAL ELECTRICITY MARKET

In the NEM, market participants register with AEMO to participate in FCAS markets and submit bids on a $/MW/hr basis to offer reserve capacity or load to the market in up to 10 increasing price bands.

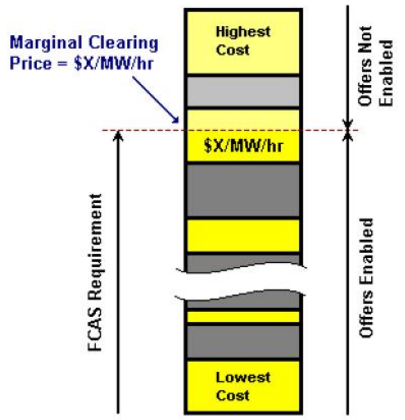


Source: AEMO

Figure 2-1 Generic FCAS trapezium

[9] www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review

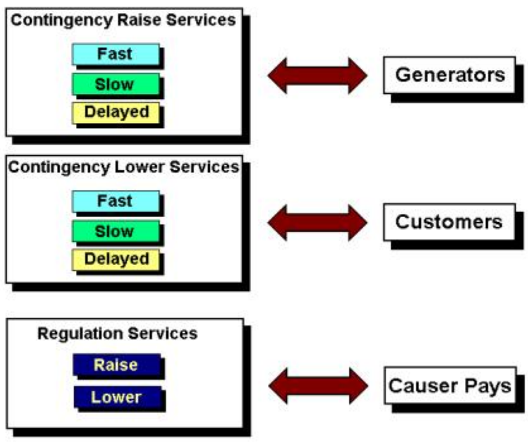
AEMO uses the National Electricity Market Dispatch Engine (NEMDE) to identify the volume of each FCAS service that would be required for each five-minute despatch interval, the merit order of the offers for each service to determine which offers will be enabled, and therefore the clearing price for each service based on the marginal price of the enabled offers.



Source: AEMO

Figure 2-2 Ancillary service marginal clearing price

Payments made to FCAS providers are recovered from market participants according to the following:



Source: AEMO

Figure 2-3 Ancillary service cost recovery mechanisms in the NEM

AEMO determines the amounts of contingency FCAS required to compensate for the occurrence of the most onerous credible contingency events on the network during each trading interval. These events are almost always the loss of the generator dispatching the largest output (for contingency raise services), or the loss of the largest load or transmission element (for contingency lower services). The cost of each contingency raise FCAS is recovered from all Generators in proportion to the volume of energy supplied during a trading interval. Likewise, the cost of each contingency lower FCAS is recovered from all Customers in proportion to their energy consumption.

We note that the simple deterministic spinning reserve requirements in the Northern Territory do not currently need a complex market as has been established for the NEM to be effective.

2.3.5 Other matters

2.3.5.1 FCAS in Tasmania

AEMO operates the FCAS markets in Tasmania in the same fashion as in the broader NEM, albeit on a smaller scale. However, problems developed with the operation of the FCAS market in that it was dominated by one Generator that was later determined to have unfairly exploited its market dominance to the disadvantage of other Generators. The matter was investigated in detail by the Office of the Tasmanian Economic Regulator, which made a determination[10] in 2009 to declare raise contingency services provided by the Generator to meet the Tasmanian local requirement as declared electrical services that would be regulated by price controls. The Office of the Tasmanian Economic Regulator published a detailed report of the findings of its investigation into the matter in December 2010[11].

As the Northern Territory network is also a small network largely dominated by one Generator, it would be important to incorporate the lessons learned from the events in Tasmania in any market framework established for the provision of ancillary services in future.

2.3.5.2 Proposed changes to the spinning reserve requirements in Northern Territory

System Control has drafted revised System Secure Guidelines[12], which are currently issued for consultation with impacted parties such as Territory Generation. The revised guidelines include the existing spinning reserve requirements as set out in the System Secure Guidelines and Short Term Advices. However, the draft guidelines also include the future implementation of an alternative frequency control ancillary service regime instead of simple spinning reserve requirements, at an (as yet) undetermined date.

The operation of the proposed FCAS regime will be largely consistent with that in operation in the NEM, but also includes the addition of another ancillary service for system inertia to replace the inertia requirements in the current arrangements. We note that in doing this, System Control is already adopting the possible outcomes of AEMO's Future Power System Security Program (see 2.3.3) in which both system inertia and fast frequency response may become NEM ancillary services in future.

The main difference between the definitions for the existing NEM FCAS and the proposed Northern Territory FCAS is in the time delay for the provision of the fast raise and fast lower services. The table below compares the draft Secure System Guidelines with those response times in the NEM.

Table 2.5 Proposed FCAS response times in Northern Territory compared to NEM

REGION	FAST REFERENCE TIMES	SLOW REFERENCE TIMES	DELAYED REFERENCE TIMES
NT Time A	0-2 seconds	2-60 seconds	60-300 seconds (1-5 minutes)
NT Time B	2-60 seconds	60-300 seconds (1-5 minutes)	300-900 seconds (5-15 minutes)
NEM FCAS	0-6 seconds	6-60 seconds	60-300 seconds

Source: Draft Secure System Guidelines V3.0

Note: Currently NT time only applies to the Darwin-Katherine System. Alice Springs and Tennant Creek will require extensive review and analysis to generate similar requirements.

In these response times, the NEM fast 6-second FCAS services would be replaced by 2-second services. The slow and delayed FCAS response times proposed for Northern Territory Time A would be the same as the NEM.

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[10] Office of the Tasmanian Economic Regulator, December 2009, Declaration of Frequency Control Ancillary Services Statement of Reasons

[11] Office of the Tasmanian Economic Regulator, 17 December 2010, FCAS Pricing Investigation Final Report

[12] System Secure Guidelines Draft 3

We note that the draft Secure System Guidelines, as is their intent, set out the technical framework for the operational aspects of ancillary services for spinning reserve in the short to medium term, and for inertia and frequency control in the long term. However, the establishment of a market and the setting down of market rules for the procurement of and payment for ancillary services are outside the scope of the Secure System Guidelines. Therefore, although it is contemplated that frequency control in the Northern Territory systems will be achieved by similar operational processes to those in the NEM, there is still no mechanism to separately pay for them, and therefore to value them from the customers' perspective.

We conclude, therefore, that whilst the operational aspects of frequency control in the Northern Territory do not currently conform to the framework operating in the rest of the NEM, the proposed changes to the Secure System Guidelines to introduce FCAS operations will align the arrangements in the Northern Territory with those in the NEM. However, the lack of an actual market for the trading of ancillary services causes us to conclude that the market framework in the Northern Territory does not conform to the benchmark framework operating in the NEM.

2.4 Consultation with impacted parties – Territory Generation

We discussed the issues resulting from the existing spinning reserve framework with Territory Generation as the most obviously impacted party. Territory Generation's primary concerns are associated with the additional costs that are incurred with the provision of spinning reserve, as well as some of the constraints that are applied that cause it to have to operate less efficient and higher cost plant than would have been dispatched were the constraints not applied.

2.4.1 Actual amount of spinning reserve

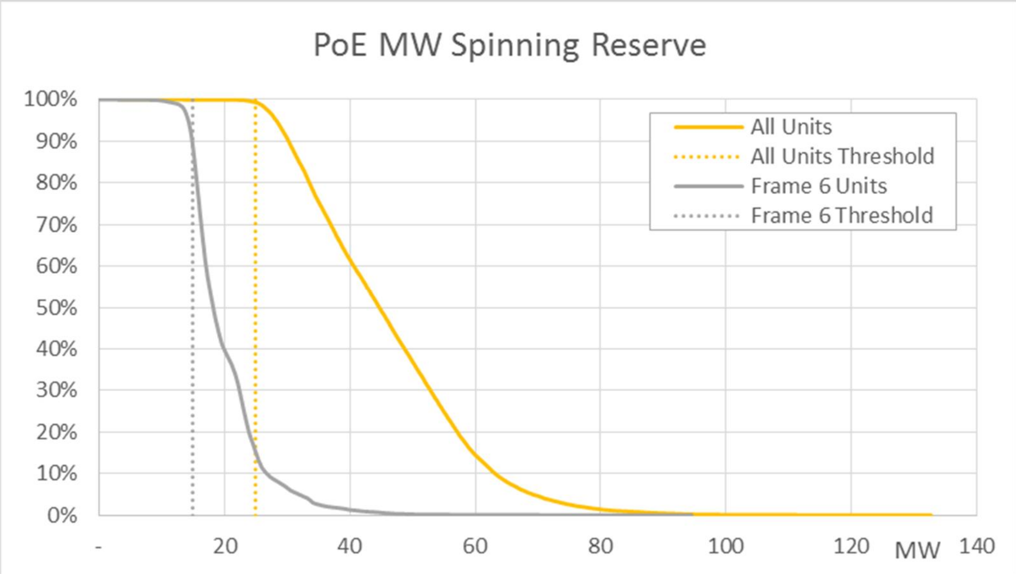
Territory Generation pointed out that whilst System Control's spinning reserve guidelines require a minimum of 25 MW total spinning reserve in the Darwin Katherine power system, the actual amount of spinning reserve available from the generating units dispatched was a long-term average of more than 40 MW. Thirty-minute data provided by System Control for the 17-month period between October 2015 and February 2017 yielded the following statistics:

Table 2.6 Actual spinning reserve Oct 2015 to Feb 2017

		FRAME 6 UNITS	ALL UNITS
Min Spin Res Threshold	MW	15.00	25.00
Max Spin Res	MW	94.50	132.68
Min Spin Res	MW	0.02	3.07
Median Spin Res	MW	18.21	44.71
Mean Spin Res	MW	20.16	46.08
Count < threshold		2,855	176
% < threshold		11.54%	0.71%

Source: PWC data, WSP calculation

The following chart shows the spread of actual spinning reserves as a probability of exceedance over the 17-month period.



Source: PWC data, WSP calculation

Figure 2-4 Probability of exceeding "X" MW spinning reserve

The Frame 6 statistics show a high proportion of periods in which the 15 MW target was not achieved; however, we note that there is a clear difference in outcomes since July 2016.

Table 2.7 Spinning reserve provided by frame 6 units

FRAME 6 UNITS	OCT 2015 – JUNE 2016	JULY 2016 – FEB 2017
Min Spinning Reserve Threshold (MW)	15.00	15.00
Max Spinning Reserve (MW)	69.22	94.50
Min Spinning Reserve (MW)	5.93	0.02
Median Spinning Reserve (MW)	16.24	22.13
Mean Spinning Reserve (MW)	18.26	22.29
Count < threshold	2,695	160
% < threshold	20.62%	1.37%

Source: PWC data, WSP calculation

Territory Generation stated that it believes that the spinning reserve thresholds are probably overly conservative and risk-averse. It seems to Territory Generation that a long-term mean of more than 46 MW and median of nearly 45 MW is excessive in a system that has a typical demand of only 200 MW.

Territory Generation stated that when establishing its operating budgets, and factoring in the requirement to have a volume of spinning reserve, it had assumed that a mix of units across its whole portfolio would be operating at reduced load and therefore reduced efficiency to give 25 MW of spinning reserve. With the outcome of a long-term average of 46 MW of spinning reserve, the assumed load and efficiency reduction has proved insufficient and has impacted the increased operating cost factored into its operating budgets. Territory Generation pointed out that the actual amount of spinning reserve in relation to the network demand meant that nearly all units were almost invariably running at part load, and therefore not at peak efficiency, with a consequent increase in fuel consumption and cost per MWh of generation dispatched.

From our discussions with System Control, we note that the minimum spinning reserve requirement of 25 MW must be achieved at all times, thus the average must be higher. We also note that:

- The number of large generating machines in the Darwin-Katherine and Alice Springs systems results in a relatively large spinning reserve requirement when compared to the system demand.
- Spinning reserve does not account for extra generation held to cover machines under testing, the effect of which is not included in our analysis.
- The level of spinning reserve can be inflated during overnight periods due to dispatch-ability issues with combined cycle units, C4/C5/C6, P1/P2/P3 and (until March 2017) with Weddell Generation gas pressure constraint, i.e. WPS could not shutdown all units due to issues starting units at the station when unmanned. This resulted in more spinning reserve being held overnight frequently as a direct result of generation required to be kept online.
- Generation units C4/C5 were considered to have met the 15 MW Frame 6 spinning reserve requirement when operating at 24 MW. When C4/C5 minimum stable load was increased to 26 MW, an additional Frame 6 machine was required online (approximately December 2016).

We conclude that the level of spinning reserve held is influenced by many factors and we are unable to assess whether the appropriate levels achieved in practice are not excessive. We note that PWC System Control has no specific obligation to take cost into account when complying with the System Control Technical Code clause 1.7.4 "… to ensure that the system operates reliably, safely and securely …".

2.4.2 Constraints on units running together

Territory Generation noted the requirement that there be two Frame 6 units dispatched to meet System Control's system inertia requirements. However, they also noted that System Control did not allow Units 4 and 5 at Channel Island Power Station to be these two units as they share a common connecting point to the network. Territory Generation acknowledged that from a system security point of view, this is reasonable as a credible contingency might be that this common connection point would be lost, resulting in both Frame 6 units, their associated steam turbine, and their combined inertias being lost to the system. However, it also meant that another open-cycle Frame 6 unit would have to be dispatched at all times.

Whilst the combined cycle module formed by Units C4/C5/C6 is Territory Generation's most energy efficient plant, the open-cycle Frame 6 units are not as efficient as the aero-derivative units at Channel Island, which means that the optimum mix of generation for energy efficiency and therefore cost of generation purposes is hardly ever dispatched.

2.4.3 Operation of units under test

Territory Generation advised that in its view, when units are under test, or have been out of service for maintenance, System Control does not seem to consider them for spinning reserve purposes.

When a unit is under test and synchronised to the network, its output is determined by the test protocol being used; it is not available for merit order dispatch by System Control, other than it is top of the list to ensure that it is run. Equally, it cannot be considered for any form of voltage or frequency control, or regulation raise/lower purposes as the generator voltage and output set points are usually also determined by the test protocol. We understand that it is also not considered for inertia purposes.

Whilst we can understand System Control's reservations regarding a unit-under-test's output-related parameters, the unit's inertia is an inherent characteristic available simply because the unit is present on the system, so excluding its inertia from consideration seems to be somewhat risk-averse. A less risk-averse approach might be to consider the loss of the machine under test a creditable contingency, unless the testing procedure requires the machine to be taken off-line or the risk of the machine disconnecting during the test is probable, in which case the inertia of the machine should be excluded.

Territory Generation also advised that some units returning to service from an outage are not considered by System Control for spinning reserve purposes until they have "proved themselves". However, the criteria for such proving were not clear to them, but seemed to be fairly subjective based on availability and reliability expected post-outage. System Control provided examples of generators that were returned to service and made available for spinning reserve. They show the use an informal risk assessment process using information provided by Territory Generation (on the Return to Service Form) and the System Controller's experience to determine whether a unit returning to service should be made available to provide spinning reserve.

In both of the above situations, it becomes necessary for other units to provide the spinning reserve required. Depending on the units that are excluded from consideration, it may be the case that the units that are selected to provide spinning reserve are less efficient and therefore higher operating cost than the optimum mix would otherwise be.

2.4.4 Start-stop cycles

Territory Generation advised that their gas turbines' maintenance frequency can be significant impacted by frequent start-stop cycles during operations. This is a well-known feature of gas turbine operations and maintenance. Some manufacturers recommend maintenance intervals based on a combination of in-service operating hours and/or number of start/stop cycles; others require the owner to accrue additional "equivalent" operating hours for operations other than normal on-load running such as starting cycles, over-firing (e.g. at peak loads), high loading rates, etc. Whichever measure is recommended by the manufacturer, it is clear that more start-stop cycles lead to increased maintenance frequency, and therefore to higher maintenance cost.

Discussions with staff at PWC System Control revealed that they were well aware of this issue and used their experience to avoid dispatching units unless they believed that it would really be necessary. For example, they advised that they would sometimes allow the minimum spinning reserve requirement to be compromised for short periods if it appeared that system load would shortly be reducing thus restoring the required spinning reserve. In these circumstances, the measured aggregate generator output might slightly increase thereby reducing spinning reserve, but the measured rate of change of frequency would also be rising slightly, indicating that actual load was falling. The operator would normally wait for generator outputs to fall and restore spinning reserve, rather than start another unit to restore spinning reserve[13].

2.4.5 Impact of draft Secure System Guidelines

Territory Generation advised that like System Control, and as has been shown to be a developing problem in certain regions of the NEM, it is also concerned about the increasing penetration of low inertia embedded generation equipment in the Northern Territory systems. It is most concerned that as more embedded generation comes to market, much of it being non-scheduled and non-market wind and solar PV generation, it may find itself with a much-reduced volume of the energy generation market, but a greatly increased responsibility to provide ancillary services such as voltage and frequency control, simply because it is the only organisation with the equipment capable of provided the services at the levels required to keep the systems stable.

We believe that Territory Generation welcomes System Control's efforts to provide the technical framework for the establishment of inertia and FCAS services in future, though it also believes that as these services clearly have some benefit of value to the network, they should be established in conjunction with a market to trade the services in an open and equitable manner.

2.4.6 Cost allocation

Territory Generation's concerns ultimately come down to the cost impacts to its operations resulting from the operational demands of System Control, and its uncertainty that these impacts are properly factored into the decision-making process for spinning reserve. Territory Generation is concerned that it has to wear the

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[13] System Control later advised that this practice was discontinued in January 2015, and they would always plan to maintain the required spinning reserve requirement. Measures used to increase the reserve capacity on the network instead of starting additional units include activating the SPRINT™ capability of LM6000 generating units.

operational cost of decisions made by System Control, whereas System Control itself has minimal financial consequences from the decisions made.

2.4.7 Summary – Territory Generation

Territory Generation is of the view that the levels of spinning reserve set by PWC System Control to ensure an adequate level of system security are overly conservative and risk-averse and result in higher costs being incurred than are necessary. Territory Generation is concerned that under the current and proposed future regimes, it alone bears the cost of providing the spinning reserve capacity required to ensure system security, as there is no effective mechanism for them to be compensated by or to share with other participants the cost of holding capacity in reserve; nor is there even a mechanism to factor the cost of the service into the frequency control decision-making process.