System Control – Secure System Guidelines

Consultation Feedback Assessment

Summary of issues raised in submission and organisations represented in stakeholder consultation process.

The first stage of submissions was conducted between Monday 3 April 2017, 0800 hrs and Friday 5 May 2017, 1400 hrs. During this time submissions were received from the following organisations:

- Territory Generation (TGEN)
- Energy Developments Limited (EDL)
- Power and Water, System Control (System Control)

Where relevant, stakeholder comments have been addressed. A general note regarding a common issue raised during the consultation has been addressed initially. Table 2 addresses the issues raised by System Participants in detail. References to the general note will be made as appropriate throughout the detailed response.

It should be noted that the responses provided in this document are made by Power and Water Corporation in respect to the System Control license.

Acronyms and associated expansions used in this document are as follows:

Table 1: Acronym Expansions

FCAS	Frequency Control Ancillary Service
IAS	Inertia Ancillary Services
PSC	Power System Controller
PCPS	Pine Creek Power Station
RoCoF	Rate of Change of Frequency
UFLS	Under Frequency Load Shed

<u>General Information regarding Ancillary Services:</u>

In general, the issue of Ancillary Service remuneration was questioned throughout the submissions in various ways. As such, the following general information regarding Frequency Control and Inertia Ancillary Services (FCAS and IAS) have been outlined and will be referred to throughout the detailed response:

Ancillary Services Current Technical State:

- In Darwin – Katherine and Alice Springs regulated power systems the spinning reserve policy has a bundled inertia and frequency control service that is generally appropriate for the system, but is not accurate in its provision of machine responses and is technology specific (specific machine types required online for inertia).

Ancillary Services Future Technical State:

- For Darwin – Katherine the current analysis of FCAS and IAS in the secure system guidelines results in approximately the same requirement as the existing Spinning Reserve, with the difference that it is more accurate and will be appropriately allocating the amount of frequency control required.
- This allows providers of ancillary services to improve ancillary service provisions to allow generation that is restricted down (as with the current spinning reserve) to operate at more efficient levels.
- The specifications for IAS and FCAS are technology agnostic.
- As ancillary service users (system participants) take action to reduce ancillary service requirements the cost to end users may decrease.

Ancillary Services Current Regulatory State:

- The costs of ancillary services are calculated at a rate of $5.40MW/hr in accordance with the SCTC Attachment 6.11 Ancillary Services Calculations. This payment is to be made to TGEN by other generators (the SCTC implies that TGEN is the sole ancillary service provider). All system participants were involved in the consultation for SCTC Version 5.0 that introduced this provision in May 2015.
- As there is a current means for TGEN to be reimbursed for ancillary service provision, the regulatory framework is not an inhibitor to a technical implementation of the FCAS and IAS.

Ancillary Services Future Regulatory State:

- System Control, Department of Treasury and Finance, and TGEN are working to unbundle the costs of ancillary services (as per section 5.1 of the System Control Technical code).
- The intention of unbundling the ancillary services is to separate out the costs for ancillary services from the bundled energy tariff and will be utilised in the regulatory reform process.

Stakeholder	Issue (Numbered)	System Control Response
EDL	**Issue #1** **Section 5 – Inertia Ancillary Service** EDL notes the intention to introduce an inertia ancillary service and questions the level of consultation on this proposed service. Specifically, ELD is concerned that the introduction of any new ancillary service needs to ensure that end users are not being charged twice for a service that has been historically delivered as an inherent property of the system as a whole. Any analysis of the requirement for a new service should clearly answer the question as to why the new service is now required (and has not been required historically) and ensure that the introduction of the new service is not simply a transfer of value from one group of users to another. Additionally, if there is a valid requirement for a new ancillary service, the it needs to be clearly understood how that service has been delivered up until now. The value of all participants who are potentially supplying that service should be recognised and those parties should be appropriately rewarded for that service provision. EDL feels that further consultation is required to ensure all parties are fully educated as to the need for the inertia service and the value that it provides to the system. Additionally, further analysis is required to ensure that all parties who are already contributing to the provision of system inertia receive appropriate recognition under any potential new scheme.	In 2014 there were 18 UFLS events prior to a system black event in the Darwin Katherine Region. The Utilities Commission directed System Control to commission and independent study into the UFLS. During the study system control revised the spinning reserve policy constrain two “Frame 6” machines online at all times due to both their greater performance in responding to frequency events and their higher inertia, inherently slowing the rate of change of frequency (RoCoF) during frequency events. The independent consultant reviewing the UFLS events supported this change in their report. Refer to “General Information regarding Ancillary Services” section prior to the detailed response table. Further detail regarding FCAS/IAS: It is intended that by implementing the Inertia Ancillary Service and Frequency Control Ancillary Services together, machines will be independently recognised for the service they provide (and for the service they require). The changes also provide opportunities for service providers to ensure machines are tuned to provide their optimal response to frequency events and future proponents install appropriate technology for the system (e.g. small machines to limit FCAS requirements). The Inertia Ancillary Service is required to: • Limit the extent of the FCAS requirements. This ensures that the FCAS capability of the available machines can meet the system level requirements (i.e. is required for the implementation FCAS to work as designed). Theoretically a system with zero inertia would require infinite fast raise capability to handle a sudden imbalance between load and generation. The proposed inertia ancillary service establishes a minimum level of inertia such that FCAS requirements are achievable. • Ensure RoCoF is within the capabilities of machines to handle for any contingency (Multiple credible/protected events) such that pole slipping does not occur and such that UFLS can operate in an orderly manner to prevent system black.

Stakeholder	Issue (Numbered)	System Control Response
EDL	**Issue #2** **Section 19 – Special Control and Protection Requirements or Schemes** EDL recognises the need for the Pine Creek Power Station (PCPS) to change between droop mode to isochronous control in response to specific isolation events on the Darwin Katherine Transmission System (DKTS). The PCPS does not have visibility of many of these events and necessarily relies upon receipt of appropriate signally in order to make the required switching. The draft guidelines stat that PCPS receives the signals via microwave communications and pilot wire communications. These signals have historically been unreliable, resulting in system stability issues. The reliability and accuracy of these signals would need to be resolved to ensure PCPS changes from droop to isochronous control as required. In addition, the draft guideline detail that PCPS has separate and independent "Local Isoch" functions whereby circuit elements local to the power station are monitored and also cause a change to isochronous mode. There is no automatic system installed at PCPS to achieve the required switching. Any change to isochronous mode in response to local circuit elements is manually switched. EDL is open to further discussion with System Control to determine whether the current manual system for "Local Isoch" is the most appropriate, or whether an alternative solution should be developed. EDL looks forward to further discussion and consultation with System Control on the above issues. EDL is keen to ensure that PCPS operates appropriately within the DKTS, including in response to isolation events and is appropriately recognised for the value of ancillary services that it provides to the system.	This scheme is the subject of a recent power system event that is currently under investigation; EDL and System Control are actively seeking to resolve the issues. The Power System Controller undertakes to, when an outcome is reached, draft an update to the Secure System Guidelines and undergo a short consultation (expected duration of 1 week) to reflect the changes to this section. In the long term the issue of PCPS being recognised for the "value of ancillary services that it provides to the system." Is seen by the PSC as one of market reform and also the SCTC and not related to the secure system guidelines. The PSC recommends that this issue be directed to the reform/consultations in these areas. However, in the short term in accordance with following SCTC clauses: • **1.7.5 Obligations of the *Market Operator*** (a) the *Market Operator* must fulfil the responsibilities and comply with the requirements and obligations imposed upon it in Attachment 6 • ***Market Operator*** is defined as: A role fulfilled by the *Power System Controller* in accordance with clause 1.7.5 • **4.1 *REGULATING UNITS*** The Power System Controller, in consultation with the power stations, will appoint: (a) (Deleted). (b) One or more generation units as the regulating units. (c) A regulating unit in a sub-system islanded from the Grid. (d) In case of emergency, the Power System Controller will nominate a power station responsible for frequency control and maintain system frequency as detailed in clause 5.3 of this Code. The nominated power station shall comply with the instructions of the Power System Controller. • **A6.11 *ANCILLARY SERVICES CALCULATIONS*** (b) In respect of every trading interval a Generator must make a payment to Territory Generation in respect of ancillary services. The amount of the payment is to be calculated in accordance with the following formula: Payment = ASQuantity x ASPrice Where: ASQuantity = The energy produced (by one or more Generators) on a sent out basis for the Market Customers of a Generator (other than Territory Generation) in any one settlements period. ASPrice = $5.40/MWh (sent out) unless the Market Operator publishes a notice amending this price As PCPS would be appointed as a regulating station in the islanded system by virtue of the special protection scheme, it is apparent that during these times PCPS is providing the required Ancillary Services for the island. The Power System Controller as the Market Operator would publish a notice for the duration of the islanding to amend the Ancillary Service price to $0.00/MWh.

Stakeholder	**Issue (Numbered)**	**System Control Response**
TGEN	**Issue #3** TGEN has some reservations as to whether the proposed changes will deliver the best outcomes for the Northern Territory. TGEN recognises the importance of System Control having processes at its disposal to maintain a secure system; however TGEN is of the view that any changes to arrangements should aim to address one or more of the following criteria: • quantify costs, • increase efficiencies, and • act in a transparent and commercial manner. This encourages effective competition at the retail level and enables the benefits (or costs) of any changes to pass onto the consumers of electricity. To assist the consultation process TGEN provides the following observations. TGEN would welcome a more detailed and considered approach to changes which may have a significant impact on the operation and costs associated in providing a secure system.	Secure System Guidelines consultation shall take into account the following matters as per the SCTC: • government policy, • The Power System Controllers statutory obligations • historic levels of reliability • costs and benefits The criteria specified by TGEN are covered by the “costs and benefits” criteria under the SCTC listed above. In regards to these points, the government direction has formed the cost/benefit analysis used by System Control: In 2014 there were 18 UFLS events in the Darwin Katherine Region. The Utilities Commission directed System Control to take action as required to reduce the UFLS occurrences. System Control has further simplified the principle to prevent UFLS from single credible generator contingency events and prevention of system black from multiple contingent events (or protected events). This aligns with the provisions of the SCTC: **1.7.4 Obligations of the Power System Controller:** … (b) The Power System Controller has the function of monitoring and overseeing the operation of each regulated power system to ensure that the system operates reliably, safely and securely in accordance with the Ring Fencing Code, Electricity Network (Third Party Access) Code, Network Technical Code, System Control Technical Code and other relevant Codes and Standards. … **3.2.11 Reliable operating state:** A power system is in a reliable operating state if in the reasonable opinion of the System Operator, taking into consideration the appropriate power system security principles described in clause 3.2.10: (a) involuntary load shedding is not occurring; (b) involuntary load shedding will not occur if a credible contingency event occurs; and (c) the energy and capacity reserve criteria specified in the Secure System Guidelines are satisfied. In 2014, this resulted in a constraint that two “Frame 6” machines were required online at all times due to both their greater performance in responding to frequency events and their higher inertia, inherently slowing the rate of change of frequency (RoCoF) during frequency events. Refer to Refer to “General Information regarding Ancillary Services” section prior to the detailed response table. A further consultation for Secure System Guidelines will be required when the accredited values for inertia and FCAS are established from direct engagement with generator participants. As such, the current implementation of the FCAS in the Secure System Guidelines is an introduction to the FCAS principles and algorithms proposed by the PSC; it does not bear an operational/economic implication now. Current analysis indicates that the likely quantities of FCAS and IAS in the future implementation will be approximately equivalent to current Spinning Reserve requirements. It also provides incentive to improve performance of generators, to ensure existing and new system participants consider their FCAS/IAS requirements and provisions to minimise costs.

Stakeholder	Issue (Numbered)	System Control Response
TGEN	**Issue #4** **Failure to follow process** The heads of power for the Secure System Guidelines is established in the System Control Technical Code (SCTC). The code also allows for amendment of the guidelines but requires the following matters to be considered before any changes are made. (SCTC Section 3.5.4) (a) government policy; (b) the Power System Controller's statutory obligations; (c) historic levels of reliability; and (d) costs and benefits. In the documentation provided for consultation references are made to the fact that costs associated with changes still need to be considered by DTF as part of the unbundling of Ancillary Services, There are also references to future arrangements for FCAS and Inertia provisions that need to be considered before some of the arrangements can be put in place. TGEN considers that in its current form the consultation documents fail to adequately detail the consideration of required matters to allow for the Secure System Guidelines to be amended. TGEN would be keen to work with Power and Water System Control and Market Operations to further develop these matters.	Referring to the general information: Secure System Guidelines consultation shall take into account the following matters as per the SCTC: • government policy, • The Power System Controllers statutory obligations • historic levels of reliability • costs and benefits The extent of the FCAS and IAS is to align frequency control to the extent required (and nothing further than) to prevent UFLS from occurring from a single credible contingency. To do any less would be in contravention of SCTC obligations (Refer to SCTC clauses listed in response to Issue #3). The approach defines the system level minimum requirements to meet the SCTC requirements. Government influence and historic level of reliability have been addressed in the response to Issue #3. Refer to “General Information regarding Ancillary Services” section prior to the detailed response table regarding current analysis of cost change from spinning reserve to contingency FCAS and IAS being approximately zero.

Stakeholder	Issue (Numbered)	System Control Response
TGEN	**Issue #5** **Interaction with Market Operation (definitions of Ancillary Services)** The proposed amendments of the SSG include a new ancillary service requirement called inertia. However TGEN cannot readily see how this definition will be used by System Control in declaring LOS levels. TGEN is also concerned that the document does not describe how System Control would procure this service as part of its obligations under SCTC Section 5.1. If this is to be a separate service due consideration is required to establish how the Market Operator would account for both the need and acquisition of this service in their financial calculations. TGEN believes it is imperative for the success of market reforms that payments and obligations are well understood by all System Participants.	Regarding the LOS levels, System Control agrees with the comment and the LOS levels in the secure system guidelines will be updated accordingly. The LOS levels are defined based capacity of standby generation to meet the technical envelope following a contingency (starts in standby generation timeframe). LOS 1 is protected contingency – technical envelope breached LOS 2 is for credible contingency – technical envelope breached LOS 3 is no event – technical envelope breached. In regards to inertia: The available inertia to meet the technical envelope would be as defined in IAS. Fundamentally, LOS 3 would occur when IAS was in breach. LOS 2 would occur if after a single credible contingency, all available generation (if brought online) were insufficient to meet the IAS. LOS 1 would occur if after a protected contingency, all available generation (if brought online) were insufficient to meet the IAS. Currently, System Control does not procure standby reserves. Current practice involves ensuring outage planning practices allow standby reserves to be met (as per section 15 of secure system guidelines). Refer to “General Information regarding Ancillary Services” section prior to the detailed response table regarding future reforms of payment of ancillary services.
TGEN	**Issue #6** **Future Consultation** In several of the sections the SSG version three describes both a current and future state. Not only does TGEN consider this is not in alignment with the SCTC but it also believes this to be confusing for those who are to rely on the SSG, both System Control and System Participants. TGEN suggests that the document be limited to the "current state" that exists when the document comes into force and any future amendments follow the consultation process outlined in the SCTC. TGEN notes that the previous version of the SSG was released almost a decade ago. TGEN does not consider that this sufficient and is concerned that short term arrangements are likely to be inefficient if they are used to update ongoing situations.	The PSC contends that the purpose of the secure system guidelines is to outline the principles of the operating the regulated power systems in a secure manner. It is not prohibitive to outlining the intended future direction of the operation of the power system. As per the SCTC, this document should be maintained up to date, and any future inclusions will be consulted on with system participants. However, in the event a direction or short term advice must be issued in a shorter timeframe to meet SCTC obligations, the advice/discussion to affected participants will be appropriate for the level of urgency. Consultation for inclusion to SSG should occur afterwards and may result in a better implementation in the long run.

Stakeholder	Issue (Numbered)	System Control Response
TGEN	**Issue #7** **Timeframe for Implementation** TGEN believes that both the timeframe for consultation and the timeframe for implementation is too short. TGEN would suggest that any arrangements that are proposed should be trialled so as to ensure processes and systems are robust, otherwise arrangements that appear sufficient on paper may prove to be inadequate due to misunderstandings between System Control and System Participants. TGEN believes that mid-June as indicated by the Consultation Impact Statement is an unrealistic target.	Many of the changes made to the secure system guidelines are current practices. In areas with substantial changes, the implementation date and trial periods may be discussed and these will be reflected in the secure system guidelines. System Control is aware that the FCAS and IAS sections will require further consultation to determine dates of trials and implementation. System Control is not aware of other provisions in the secure system guidelines that are vastly different from current practices that could lead to confusion.
TGEN	**Issue #8** **Misc items:** The NEM operates with interruptible load models – the I-NTEM does not - hence the FCAS model should factor this into the process.	We do not restrict interruptible loads from providing FCAS. There are currently no contracted interruptible loads in the NT regulated systems. Our FCAS model factors this into the process such that all FCAS provision currently would have to be provided by generating units (only source of FCAS). Future technology such as interruptible load, batteries, flywheels etc are not restricted from providing FCAS.

Stakeholder	Issue (Numbered)	System Control Response
TGEN	**Issue #9** **Misc items:** The Power System Controller (PSC) needs to provide reasoning as to directions over & above either Spinning Reserve model or the FCAS model when introduced. There is little incentive for TGEN to develop efficient and/or innovative options as the PSC has the power to override without explanation or accountability to meet standards that have not been previously established through consultation.	The provisions under a planned outage requiring further risk mitigation may at times differ from the standards of operation set out in secure system guidelines. This information is provided to TGEN when it effects the operation of generating plant via System Risk Notifications. Typically System Risk notifications for planned outages are provided to TGEN well in advance of the work and TGEN have opportunity to respond or propose alternatives. In all cases where the Power System Controller has overridden requirements set out in Secure System Guidelines (spinning reserve) on an ongoing basis it has been via short term advice. The Short Term Advice is issued to immediately address an ongoing system security risk. The Short Term Advice are issued to TGEN and TGEN may respond at any time. Where practical the Power System Controller will discuss with TGEN (and relevant participants) to get the best solution prior to issuing a Short Term Advice, however often the urgent nature of the issue requires the advice to be issued immediately. Following the issuing of Short Term Advice, System Control has endeavoured to communicate with relevant participants and find ways to minimise the impact. It is intended that these instructions are adopted into the secure system guidelines with opportunity for all participants to consult on the long term adoption of these changes. Furthermore, the Power System Controller is accountable for all actions taken and where a dispute is unable to be resolved between the Power System Controller and the participant, the Utilities Commission is to be involved for dispute resolution (SCTC 1.5). The PSC understands that the proposed FCAS model provides the framework for TGEN to develop innovative options such as improving the FCAS capabilities of current machines or implement alternative technologies. The proposed FCAS framework provides the means by which such improved performance would be taken into account. Whereas the existing spinning reserve model does not provide opportunities for recognition of improvements.

Stakeholder	Issue (Numbered)	System Control Response
TGEN	**Issue #10** **Misc items:** The NEM FCAS model is based on the principle of "Causer Pays" – there is no demonstrable process whereby the Draft Secure System Guidelines Draft 3 – clearly annunciates the cost penalty for dynamic loading and load management. - All the impact is on the operating of the generation units to the satisfaction of the Power System Controller.	System Control contends that there are incentives to develop efficient or innovative options to meet FCAS and IAS requirements. Currently the Spinning Reserve approach to frequency control does not consider the performance of machines responding to frequency disturbances. System Control had to instigate a short term advice to counter this issue which constrained online Frame 6 machines at the appropriate level to provide this (with the less effective alternative being an increase to the total spinning reserve figure). The FCAS implementation will allow each machine (or other enabling technology) to individually be accredited with an appropriate FCAS provision reflective of its performance. This allows only the required FCAS to be dispatched at any one time to cater for the largest single credible contingency rather than an arbitrary figure. TGEN are likely to reduce costs by improving performance such that FCAS provision can meet requirements whilst machines are operating at more efficient levels. These requirements must be met to fulfil the SCTC obligations for Power System Security. By setting the minimum requirements dynamically to reflect the largest contingency, the issue is being dealt with in a manner that limits the economic impact (as opposed to an arbitrary spinning reserve figure and constrained inertia requirement). Refer to "General Information regarding Ancillary Services" section prior to the detailed response table.
TGEN	**Issue #11** **Misc items:** The I- NTEM FCAS model should be introduced as a 'Trial' arrangement which hallows for the system participants to understand the impacts of the model and the communications processes as it should result in more dynamic communications processes.	We have put out the framework in the Secure System Guidelines, many tools for the actual implementation are in development. These will run side by side to ensure accuracy etc. This will be a trial arrangement and as part of the development, generators (or other applicable participants) will be engaged to accredit their technology appropriately prior to establishing and consulting on the commencement date.
TGEN	**Issue #12** **Misc items:** There does not appear to be any allowance/mechanism for TGEN to bid a generator at partial loading in an isochronous mode. The units appear to be bid as available as Base Capacity configuration.	Droop control mode is a requirement for generating units set out in the Network Technical Code and the bid structure is part of the INTEM design; neither are part of this consultation.

Stakeholder	Issue (Numbered)	System Control Response
TGEN	**Issue #13** **Section 3 Determining Base Capacity** *para 5 - … a conservative approach in accrediting Base Capacity of a generating unit. An Untested increase in Base Capacity may be accredited at a lower value than the participants' advice until there is an appropriate opportunity to test under the worst expected seasonal ambient conditions.* The conservative approach needs to be defined to provide consistency and predictability. There needs to be accountability placed on the PSC. (Note in Section 12 – the Network Operator is responsible for determining the ratings which is different in this section)	Base capacity and transmission ratings are fundamentally different in application. Transmission ratings set operational limits where if exceeded a transmission asset may overload and fail. Base capacities are the maximum continuous performance of a generating unit. The generating unit has the capability of limiting fuel flow to reduce the power output over a steady state period, whereas a transmission asset has no such dynamic control. The PSC agrees that the approach does need to be defined. The PSC invites TGEN to work with the PSC to establish a procedure. It should be noted that the approach must ensure there is no over-provision as a generator's base capacity is relied on to ensure capacity reserves are met and currently for determination of spinning reserve. This could involve ensuring the base capacity figure does not exceed relevant historical base capacities of units, and in the case that it does a test is undertaken promptly to verify.

Stakeholder	Issue (Numbered)	System Control Response
TGEN	**Issue #14** **Section 4 Determining Standby Reserve** *LOS1 Condition* *…..a protected contingency event involving the loss of the largest generation node…….* This fundamentally refers to CIPS arrangements at Channel Island Substation (132kV) What is the implications for the declaration of LOS1? do TGEN need to respond? *LOS2 Condition* *…. the occurrence of a single credible contingency event involving the loss of the largest generation unit available in the power system, ….* This de-rates the CIPS units as the HRSG is factored into the calculation. – what action is required? *LOS3 Condition* *…operating outside of the technical envelope, the minimum spinning reserve of FCAS raise has been breached……* What actions? What can be requested of TGEN? How does the market respond? – what expectations?	LOS 1: Node is non-specific to CIPS arrangement. A protected contingency impacting a generation node could be any single point of failure that results in the loss of multiple individual generators. An example contingency could be where a power station is connected to the network by two transmission lines with a common tower. All the generating units at the power station will be under a single protected contingency event which may trigger LOS1. These security notices are for the purpose of advising of standby reserve issues to the Utilities Commission and all other system participants. Under the provisions of the secure system guidelines no action will be specifically required of the generator to resolve this. Unrelated to the provisions of the secure system guidelines the PSC may be directed by the Utilities commission or ministers to take further action. The PSC may identify that this contingency cannot be managed to prevent system black event occurring and may direct as required to resolve this. LOS 2: There is no de-rating to the CIPS units, they are still the same generating units with the same capacity. LOS 2 will be declared in the case that the largest generation unit is a combined cycle unit. The PSC will recall, cancel or not approve planned outages as appropriate to return or maintain LOS levels above the LOS 2 margin. LOS 3: As with LOS 2, the PSC will recall, cancel or not approve planned outages as appropriate to return or maintain LOS levels above the LOS 2 margin. In this case the PSC may take actions as per the SCTC provisions for emergency demand reduction, or direction to participants (such as to a generator to focus work as required to make a generator unit available for service). The market has no involvement in this, security constraints are applied over market merit order. At this point, all available machines would be dispatched or requested online, and it would be insufficient to meet load.

Stakeholder	Issue (Numbered)	System Control Response
TGEN	**Issue #15** **Section 5 Inertia Ancillary Service** *Para 5. The current assessed allowable initial RoCoF is 4Hz/sec. This figure is preliminary and further assessment is required,….* What if the RoCoF is deemed to be reduced … what actions will PSC undertake? Impact on TGEN – being required to operate additional generation. How will these be updated. *Para 6 … The Power System Controller may take actions to constrain additional inertia online where required or other constraints to minimise the contingency size to prevent system black from a protected contingency event.* What type of action will the PSC undertake and it's impact on TGEN? *Regional Application* … All three systems do not have implementation Dates or Minimum IAS……	Additional synchronous inertia will have to be dispatched. This may involve dispatch of additional generation. Other factors may include limits placed on the output of credible contingencies that exceed the RoCoF threshold. The RoCoF threshold may be reduced for either two reasons: • It is identified UFLS is insufficient to prevent system black for RoCoF at this level (UFLS is expected to be sufficient based on preliminary studies). • Generation equipment is unable to withstand RoCoF at 4Hz/s (reasonably possible, Coal fired generation in the NEM have difficulty withstanding 1 or 2Hz/s) If the RoCoF threshold is reduced, additional inertia may be dispatched or the contingency(s) that cause RoCoF may be limited. Potentially, a mix of the two measures may be appropriate. Updates may come initially as short term advice (depending on urgency), but long term this will be updated by consultation on secure system guidelines. A short term advice has been released by System Control and included as a submission to this Secure System Guidelines consultation to cover a protected contingency event (loss of C4/C5 node). This short term advice: • limits the contingency size; • specifies the required online inertia (post contingent); and • ensures the contingency size does not exceed UFLS allocation The implementation dates are not fixed as full implementation requires further development of tools and input from generator participants to accredit inertia and FCAS provisions.
TGEN	**Issue #16** **Section 6 Determining adequate Regulating Reserve** What is the mechanism for determining and publishing the Minimum Regulating Reserve *Para 5 . System Load Rate of Change will require to take into account anticipated load changes such as rain storms approaching populated areas.* How will TGEN be notified of the PSC determination at the time the decision is taken?	Currently the decision process for regulating reserve is manual and actions to ensure sufficient regulating reserve are at the discretion of the System Controller. The provisions in the Secure System Guidelines are set out to determine a framework for these decisions. System Control has not yet established a method for publishing the minimum regulating reserve. This is intended to be implemented via a SCADA trackable point. The SCADA update is currently planned to be undertaken at the same time as the FCAS/IAS SCADA implementation later this year. When implemented in SCADA, this point will be tracked and provided to participants. Decisions and manual changes will be tracked in a log by System Control. The method for relaying this information to relevant participants is yet to be determined and your engagement on this matter will be beneficial to determining the appropriate solution.

Stakeholder	Issue (Numbered)	System Control Response
TGEN	**Issue #17** **Section 7 Contingency Frequency Control Ancillary Service (FCAS) / Spinning Reserve** TGEN would expect a trial period to allow the processes developed to be 'tested' and for participant feedback. The PSC is 'having an each way bet' ….The minimum spinning reserve is requiring specific generation arrangements at CIPS and at the same time they are specifying an FCAS model … TGEN would recommend that the FCAS operation be part of a separate document and the Proposed Secure System Guidelines present what will be the requirements when enacted. There is no incentive for networks or the PSC to source intelligent forecasting to manage the embedded PV contribution. As a result, the generation base capacity is usually increased to manage the PV by PSC. It is increasingly apparent that the PSC dispatches high levels of spinning reserve to manage the variability of load - particularly as the load variations are increasing and are being amplified by the embedded PV. The FCAS model proposed, does not factor in any signals to manage the load variability or provide a model to signal to the base capacity generation provider(s) the variability of forecasts.	The provisions in the FCAS are subject to consultation on the implementation date and will replace the Spinning Reserve requirement. Both will not be applied at the same time for any given regulated system. Pending input from generator participants, the FCAS accreditation can be undertaken and real time tracking of the FCAS provisions and requirements will serve as a trial prior to a changeover date being implemented. This allows System Control to determine any shortfalls in the FCAS arrangement without adjusting dispatch from the spinning reserve. Under section 18 of the secure system guidelines there is a generator and load registration threshold introduced to ensure embedded PV generation of sufficient size to impact regulation requirements will be managed appropriately. Refer to "General Information regarding Ancillary Services" section prior to the detailed response table.

Stakeholder	Issue (Numbered)	System Control Response
TGEN	**Issue #18** **Section 9 Determining adequate Reactive Power Reserve for the System** How will LORR's be notified? *LORR2 – PSC may initiate commensurate actions…* TGEN would like to review the procedure associated to the LORR process to enable the process to be embedded in it's Remote Operations Centre.	LORR's will be notified by an email to participants including the Utilities Commission. As appropriate it may also be included in Bi-Annual reports and relevant Major/Minor reportable event incident reports to the Utilities Commission. LORR2 actions are at the discretion of the Power System Controller. It may require dispatch of additional machines to meet reactive reserve requirements, placing more capacitor banks in service, or if other options are not available, disconnection of loads/transmission elements.
TGEN	**Issue #19** **Section 11 Determining adequate energy for the System.** This process will require a Process / Procedure to be developed in TGEN for notification to the PSC. *…Due to the complexity of arrangements required to deal with shortfalls in fuel supply, or departures from quality standards, it is necessary that there be a Preliminary Alert level………. Has the potential to result in an Alert level being reached in the next 18 hours.* The requirement is being modified from the SCTC V5 that specifies 8hours. The requirement may result in an increased holding cost – that TGEN needs to model before agreeing to this additional requirement. *….these measures may include suspension of Market operations or making Directions as provided for by the SCTC.* What is the mechanism to suspend the market?	The provisions are in accordance with the SCTC that requires an 8 hour alert level and alert levels to be specified within the Secure System Guidelines. There is no expectation that there would be additional costs associated with the preliminary alert level. This preliminary alert level is to be provided to System Control 18 hours prior to an alert level being reached such that System Control may prepare to take measures when the alert level is reached. The PSC agrees that processes will need to be in place by TGEN. Processes should already be in place in accordance with the provisions of the SCTC to provide an 8 hour alert level. There is no mechanism to suspend the market. The PSC will amend the SSG accordingly.

Stakeholder	Issue (Numbered)	System Control Response
TGEN	**Issue #20** **Section 14 System stability** *…The AEMO Power System Stability Guidelines definitions of stability are used in this section.* Should extract and AEMO information and reproduce here any specific requirements and variation adopted in NT.	This will be reformatted to make clear what is sourced from AEMO Power System Stability Guidelines. Regardless, the definitions in the section are intended to be used for determining power system security.
TGEN	**Issue #21** **Section 15 Adoption of Reliability Criteria for networks** *…The Power system is operated under the principle that credible contingencies wherever possible shall not result in involuntary load shedding….* *There are single contingency events that are plausible to occur……..These events may be reclassified as credible if the Power System Controller deems necessary due to an identified increase in risk.* If the reclassification deems additional generation or restraint to normal / bids – is there any compensation to TGEN. How will the FCAS model work?	The reclassification is consistent with the SCTC requirements. The re-iteration of the reclassification of contingencies in Secure System Guidelines is for clarity. If a protected event must be reclassified as credible due to an identified increase in risk, the contingency will be managed as a single credible contingency such that UFLS will not occur as a result. If this is unachievable for any available dispatch this will trigger LOS 2 or LOS 3 as applicable. Currently the mechanism to compensate TGEN for complying with this requirement of the SCTC is an ancillary service charge. Refer to “General Information regarding Ancillary Services” section prior to the detailed response table. This may be an appropriate issue to provide to the appropriate forum for regulatory reform.

Stakeholder	Issue (Numbered)	System Control Response
TGEN	**Issue #22** **Section 20 Black Start** *…The SCTC requires that each Generation site capable of Black Start shall submit to the Power System Controller a procedure to start generation plant and prepare to take load when connected to the power system.* Not sure that each site needs black start. Is system restart different to regional restart? When is testing required? Is this consistent with codes etc? (by agreement)	As per the SCTC: The Power System Controller will designate power stations that have black start capacity as black start power stations. The requirement to have black start capability at a power station may also come as a result of a direction from the Power System Controller. The PSC is unclear where the terms “System Restart” and “regional restart” are referenced in this context. As stated in Section 20, testing is to be tested in a manner that will be agreed by the parties.

System Control invites participants to respond to this submission:

Stakeholder	Issue
System Control	**Issue #23** The attached Short Term Advice was issued to System Participants on Friday 28 April 2017. It makes changes to details that are included in the proposed Secure System Guidelines that is currently being consulted on. It is intended that this is considered by system participants in regards to the Sections 5 and 7 (Regional Application) of the proposed Secure System Guidelines. Relevant extracts of these sections follows: From Section 5 Inertia Ancillary Service: For a protected contingency event, there is a large demand/supply mismatch and the post-contingent inertia online is a determining factor for the Rate of Change of Frequency (RoCoF). Frequency control ancillary services are not intended to prevent loss of supply in such situations; the under frequency load shedding (UFLS) scheme is designed to operate to prevent a cascading failure leading to system black. For protected contingency events a minimum amount of post contingent inertia is required to limit the initial RoCoF. This is required to ensure RoCoF is sufficiently low such that: • Orderly UFLS or OFGS occurs and; • RoCoF remains within the capabilities of the dispatched generation to prevent pole slipping (leading to cascading failure).

The current assessed allowable initial RoCoF is 4Hz/sec. This figure is preliminary only and further assessment is required, however in the interim it will be used to manage protected events until the RoCoF limits are accurately determined for each system.

The Power System controller may take actions to constrain additional inertia online where required or other constraints to minimise the contingency size to prevent system black from a protected contingency event.

From Section 7 Contingency Frequency Control Ancillary Service (FCAS) / Spinning Reserve:

Regional Application
Darwin/Katherine
Minimum Spinning Reserve:
- 25 MW of Spinning Reserve at all times.
- 15 MW of the Spinning Reserve requirement is to come from Frame 6 machines at all times.
  - This is to be dispatched on at least two Frame 6 machines.
  - A node (i.e. [C4/5 Node], [C2/3 Node], [C1/7 Node]) can contribute a maximum of 7.5 MW of Frame 6 Spinning Reserve
  - Frame 6 Spinning Reserve must be provided by 2 or more nodes.

These changes are the result of recent system security risk analysis of a high consequence low probability event. The changes are expected to significantly mitigate the consequence of that risk.
System Control proposes that this specification is included in the Darwin/Katherine Regional Application Sections for Inertia Ancillary Service (Section 5) and Spinning Reserve (Section 7) of the Secure System Guidelines.

ATTACHMENT AVAILABLE ON MARKET OPERATOR WEBSITE IN PDF FORMAT (Power and Water, System Control Submission)