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Market Operations
Power and Water Corporation
7th Floor Mitchell Centre
GPO Box 1921, Darwin NT 0801

Dear Market Operations

**Secure System Guidelines V3.0 Consultation**

Territory Generation (TGEN) appreciates the opportunity to provide feedback in response to the consultation on the Secure System Guidelines (SSG).

Three documents were provided as part of the consultation process:

1. Secure System Guidelines Version 2.6 (Previous version)
2. Secure System Guidelines Version 3 (Proposed document)
3. Summary of Changes and Discussion Points

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.

**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.

**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.

**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.

**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.

**Miscellaneous Items that may need interpretation**

In reviewing the documents TGEN has a number of questions that may prove to only need clarification. TGEN will provide these in a separate document so that System Control can clarify what actions System Control will undertake and what actions TGEN would be required to support.

**Summary**

In summary, while TGEN is pleased that System Control is attempting to amend a very out of date version of this document, TGEN has a number of concerns with the implications for all System Participants and System Control if this document is to become the new guideline to determine whether the system is being maintained in a secure state. TGEN believes further consideration needs to be undertaken before the guideline is amended.

TGEN remains committed to working with Power and Water System Control and Market Operations, as well as DTF to ensure the system can be maintained in a secure state as efficiently as possible.

Should you have any queries in relation to this submission please do not hesitate to contact me on (08) 8936 4737.

Yours sincerely

Neil Hay
**Manager Wholesale Markets**

5 May 2017

**Secure System Guidelines Draft 3**

The NEM operates with interruptible load models – the I-NTEM does not - hence the FCAS model should factor this into the process.

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 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.

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.

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.

**Specific Items reviewed.**

**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)

**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?

**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……

**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?

**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.

**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.

**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?

**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.

**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?

**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 )