Territory Generation – Regulatory Reform Submissions, 29 March 2019

Table of Contents

1 Introduction

This paper constitutes Territory Generations' (TGen) formal submission to the Power & Water consultation on Generator Performance Standards and the Department of Treasury and Finance consultation on NTEM Functional Specification consultation.

TGen welcomes the opportunity to provide feedback on these consultations to ensure:

- continued reliability and security of the power system
- removal of barriers to the adoption of new technologies
- electricity costs are kept to a minimum in the territory
- market reforms are conducted transparently and efficiently
- sufficient governance and compliance arrangements provide protection from unintended consequences

TGen believes providing enough time to establish the correct coordinated governance arrangements as well as certainty with policy decisions made well in advance are imperative to attracting future investment in the electricity sector.

1.1 Preamble

TGen welcomes the opportunity to provide feedback on this consultation. TGen as a Government Owned Corporation carries out important functions for the Northern Territories electricity industry. In addition to supplying electricity, TGen also provides services that are necessary or expedient for the security or reliability of the three regulated power systems. TGen also impacts the wider energy industry through the necessary purchase of fuel for its thermal generators.

TGen has a key interest in ensuring electricity reforms are undertaken in a manner which will:

- Allow the continued reliability and security of the power system;
- Allow a co-ordinated and predictable adoption of technologies;
- Provide increased governance to resolve issues quickly;
- Minimise implementation costs to the industry as a whole.
- Be provided in a timely and efficient manner

To this end, TGen believes that a co-ordinated approach is the most effective way forward as it mitigates any unintended consequences and paves the way for a successful implementation of the Government reforms.

Following the disclosures from recent industry workshops, TGen considers that the various consultations currently underway would benefit from a comprehensive, consistent approach to the regulation of electricity. TGen is concerned that where there is no central coordination of these consultations, it is likely to lead to inconsistent application of regulations in the three regulated networks and possibly not provide the predictability needed for new investment. A greater level of coordination would also allow the government to conduct a cost benefit analysis of the regulatory changes to ensure unintended costs are kept to a minimum.

TGen is also cognisant of the time critical need to support the entry of new solar generation as part of Government's Roadmap to Renewables strategy. Given the prevailing time constraints, TGen considers that a transitional arrangement will be required. The most plausible transitional arrangement is the pursuit of an incremental approach to the current regulatory framework.

This has already been recognised in the current set of consultations that highlight either further regulatory changes or cut down transitional arrangements are to be undertaken in 2019.

If an incremental approach can be taken to ensure solar generators can connect in 2019 then TGen believes an opportunity exists for the reforms to be co-ordinated under a single unit to ensure benefits from the reforms can be provided to electricity customers without being eroded by increased costs of implementation and compliance.

This would include addressing all of the services provided by TGen which are currently not defined and therefore not explicitly recognised or adequately compensated for. As such, currently the full costs of electricity production are not evident and transparent to the potential industry participants who may provide innovative ways to reduce this cost.

1.2 Governance

TGen considers that the governance structure must be well established and understood in order to drive successful reform. The governance structure should address the appropriate body to coordinate the reforms and undertake the consultations, as well as ensuring a clear alignment with the hierarchy of documents, including relevant Acts, Regulations and Codes.

TGen considers that the various consultations currently underway would benefit from a coordinated approach to the regulation of electricity. For example the market fees for System Control are being considered prior to the obligations for System Control being established under the other consultation papers. TGen considers that as the consultations will ultimately require approval from the Utilities Commission for changes to the Codes, and that they will ultimately need to arbitrate on any disputes or non-compliance in the future, the Utilities Commission (UC) would have been best placed to centrally coordinate all consultations. However, the level of resourcing at the UC's disposal would need to be reviewed so this could be undertaken adequately. This would include technical, regulatory, legal and administrative.

The consultations taken so far have not established what the implications are for breaches of the various documents. For example the Generation Performance Standard has an automatic standard that may not be reached by most generators, however no minimum has been set, with documentation stating negotiations can take place on a case by case basis. This environment will be likely to lead to disputes between participants and Power and Water, particularly as further new entrants look to enter the market. This may be further complicated due to the lack of independence between the Network Operator, System Controller and Market Operator, all being functions of Power and Water. How these disputes are handled and what consequences resultant breaches have on the supply of electricity need to be considered before the new regulations are finalised.

This is further complicated with the economic regulation of the Network Operator now residing with the Australian Energy Regulator.

TGen

1. Considers that the independence of the System Controller and Market Operator should be part of the reforms
2. Requires clarification on the role of the Utilities Commission.

The above are pivotal to the sustainability of investment in renewables and other generation going forward.

Providing sufficient time to establish correct governance arrangements is imperative to attracting future private investment in the electricity sector. It is possible that the versions of the reliability, capacity and other market functions proposed as transitional arrangements are likely to diminish investor confidence in the absence of a clear transition plan.

2 Generator Performance Standards Consultation

2.1 Overview

This section of this document is in relation to the following documents issued by Power & Water between December 2018 and March 2019:

- Generator Performance Standards Consultation Overview Paper
- Network Technical Code Proposed Draft Version 4
- System Control Technical Proposed Code Draft Version 6
- Secure System Guidelines Draft Version 4.1
- SUPPLEMENTARY CONSULTATION PAPERS, “FRAMEWORK FOR THE FUTURE”
- SUPPLEMENTARY CONSULTATION PAPER, Contingency Frequency Control Ancillary Services (C-FCAS)

2.1.1 Governance

The consultation includes changes to both codes and guidelines at the same time. The changes to the codes cannot be made by System Control or the Network Operator without approval of the Utilities Commission. However the Secure System Guidelines are more easily changed by System Control. TGen suggests that a review of the document hierarchy is undertaken by the Utilities Commission to confirm which items should be included in a code, and which should have the flexibility for System Control to change without approval in the guideline.

2.1.1.1 Separation of powers

As part of the Reform Process the PWC Networks are now under the economic regulatory oversight of AER. However oversight of licensing and trading of energy is regulated by the Utilities Commission. TGen believes that the consultation underway should separate the obligations for the System Controller and the Network Operator as much as possible. In addition, for a generator or a load, the interaction with the Network operator and the interaction with the System Controller should be separated as much as possible. Therefore TGen believes the current consultation should separate requirements of connection and operation of the Network into the Network Technical Code.

This code would then form an input into any additional requirements from the System Controller which would be codified under the System Control Technical Code. This would assist all participants understanding of how the overall regulatory framework is established as well as whose authority is required to perform which functions.

If this is not separated at this stage it will become increasingly difficult establish requirements of future technology and increase adoption of NEM rules.

2.1.1.2 Ring fencing of entities / conflict of interest

The consultation is being conducted by the Market Operator on behalf of both System Control and Network Operator. Given the ring fencing of these PWC entities, oversight by the Utilities Commission who will ultimately approve the documents should be provided.

2.1.1.3 Procedural process for dispute resolution

TGen currently fulfils the role of supplier of last resort. As such TGen has often provided uneconomic services to address system emergencies. TGen is therefore concerned regarding the compliance with code obligations under consultation.

A process to quickly and fairly resolve disputes arising from noncompliance with Generation Performance requirements should be part of the consultation. Clear guidelines regarding how entities can appeal decisions by either the Network Operator or System Controller should be considered.

2.2 Grandfathering

TGen own and operate around 50 generating units at six power stations in the three regulated power systems with commissioning of units dating back to 1966. The deemed compliance provisions, or grandfathering, relating to the proposed changes is of particular significance to TGen.

TGen understands that it is unlikely that its generating units will meet all of the new compliance standards. TGen will be seeking the grandfathering provisions to all generating units.

The proposed grandfathering provisions in the Network Technical Code (NTC) requires TGen to document compliance or non-compliance of all generating units against the proposed new requirements. There is no detail as to how and when this is to be achieved, other than by agreement. To avoid foreseeable concerns, TGen suggests that a requirement be placed on the Network Operator to produce Guidelines on how compliance with the new provisions can be demonstrated for new plant and assessed for existing plant. Further, the developed guidelines should be cognisant on the cost of achieving this assessment for existing plant, particularly seeking to avoid physical testing which is costly. Provisions on arbitration also should be stipulated.

The NTC proposed grandfathering provisions requires that any modification to plant that has exemption of compliance under grandfathering provisions, requires that the plant is required to comply with the new requirements. TGen suggests that this is a disincentive to upgrade any part of existing plant as the entire plant would need to be upgraded to full compliance. For most of TGen's fleet, upgrade to full compliance would require replacement.

The proposed changes to the System Control Technical Code do not include any grandfathering provisions for existing generators. An issue that is immediately apparent in the proposed changes is the transfer of plant nomenclature provisions from the NTC to the System Control Technical Code. In the absence of grandfathering provisions, TGen will almost certainly need to make comprehensive nomenclature changes to all existing power stations at a not insignificant cost. On the expectation that this is not the intent, TGen recommends that grandfathering provisions be incorporated into the System Control Technical Code.

2.3 Network Technical Code Proposed Changes – specific comments:

2.3.1 Governance

Has or will the Utilities Commission be undertaking a legislative review to ensure changes and modifications to these two codes and one guideline do not result if conflicts between their governing acts and regulations?

2.3.1.1 Outdated references

There are many references in the Network Technical Code that are outdated or incorrect. It appears that the amendments proposed have not included any substantive review of the remainder of the Code. Clause 1.9(d) of the Code requires that the Network Operator reviews the operation of the Code at intervals of no more than 5 years. The current version 3.1 was approved to take effect in December 2013. Thus a complete review is overdue and should be done in addition to the changes proposed relating to the Generator Performance Standards.

Of particular importance is in relation to the Legislative power. In 2015 changes were made to the Electricity Reform Act and the Electricity Networks (Third Party Access) Act that included moving the legislative power of the NTC to the Electricity Reform Act. In the Part A of the NTC the Legislative requirements make reference to the Electricity Networks (Third Party Access) Act as the legislative power of the NTC. The Consultation Paper states that 'No changes are introduced' in regards to Part A 'Legislative Requirements' of the NTC. TGen suggest that changes should be introduced to ensure alignment with the relevant Act.

TGen recommends a complete review of the NTC in conjunction with this consultation.

2.3.1.2 Adequacy of explanation of changes

The proposed changes to the code are significant. The impact of the proposed changes is often not adequately described in the accompanying consultation documentation. TGen has made some assessments of anticipated impacts in the detailed sections that follow, however has not been able to address all impacts.

For example the impacts of the changes by proposed clause 3.3.6.1. The consultation document 'Description of proposed amendment' simply states:

> Remote Monitoring: Incorporate the provisions from NTC clauses 3.3.3.1 & 3.3.3.2 with suitable amendments.

TGen's detailed discussion on this clause is found in section 2.3.2.11 of this document. This is a significant change however as it has not been highlighted as such in the consultation framework, TGen is concerned that there are likely other proposed amendments that are of significance and have not been identified during this consultation process.

2.3.1.3 Use of National Electricity Rules

There are several instances where the proposed changes have used the National Electricity Rules (NER) as the basis of a proposed clause. In many such instances the NER wording includes defined terms and the proposed NTC clause uses the same terms but does not provide the NER definitions or, in some cases, any definition of the terms at all. This has the potential to leave interpretation of the clause open.

2.3.1.4 Classification of Generation

There appears to be confusion and inconsistency regarding the classifications of Generation. The Network Technical Code discusses semi-scheduled or non-scheduled generation while the proposed changes to the SCTC removes one but maintains the other.

2.3.1.5 Consistency of definitions and references – Spinning Reserve and C-FCAS

There are several references to C-FCAS throughout the two code documents. The definitions of these seem to only be incorporated in the SSG which is a subsidiary document to the SCTC. Would it be more appropriate to locate the definitions into a code, not the subsidiary document?

Currently C-FCAS has not been implemented in any of the power systems and all are running under a spinning reserve arrangement. The term is generally used through this consultation as though C-FCAS is currently implemented. The proposed amendments generally move away from using the term Spinning Reserve towards C-FCAS in relation to capability. NTC sections 2.2.2, 13.9 and 16.3 all reference the term 'spinning reserve'. This interchanging of terms is confusing and TGen recommends PWC adopt a consistent approach to this in all documents.

2.3.1.6 2016 proposed amendments by TGen

In 2016 TGen proposed changes to the NTC to the Network Operator. All seven proposed amendments were rejected by the Network Operator. The reason supplied was "that the proposals were unlikely to have a material effect on the safe and reliable operation of the Power Network and as such do not warrant a revision of the Code at this stage." This consultation has made no reference to the 2016 proposed amendments.

The current PWC proposed amendments to the NTC supersede five the 2016 TGen proposed amendments. However the first and seventh 2016 proposed amendments are still relevant.

2016 proposed amendment 1:

Proposed amendment 1 of the 2016 submission by TGen to PWC's Power Networks to make amendments to the NTC reads:

> Addition to section 2.2.2 New point (h):
>
> In the case of operation above 52 Hz all Generation Units shall remaining connected to the Network Operator's network for a period of at least 2 seconds.

Included with this proposed amendment there was also discussion about implications affecting the generator requirements clause 3.3.2.8 which is now proposed to be replaced (in relation to frequency) with 3.3.5.3.

PWC's Power Networks rejected this proposed amendment and provided the following reason:

> More onerous requirement, not adequately supported/justified, system improvement achievable without Code change.

This response was surprising to TGen because it was proposed as a result of investigations into the 30 January 2016 Alice Springs System Black. If this proposed change had been implemented prior to 30 January 2016, then the event would have unlikely progressed to a system black event.

TGen request that PWC reconsider this 2016 proposed amendment to clause 2.2.2 and TGen now further recommend that above 53.5 Hz instant trip is allowed.

If this is agreed, then PWC proposed 3.3.5.3 would need to be modified accordingly by adding a 'box' from 52 to 53.5 Hz, 2 second of continuous uninterrupted operation.

2016 proposed amendment 7:

Proposed amendment 1 of the 2016 submission by TGen to PWC's Power Networks to make amendments to the NTC reads:

Section 2.2.2(d)

Current clause:

With sustained operation below 47 Hz, under frequency load shedding schemes may disconnect load on the network to restore frequency to the normal operating range, in accordance with clause 3.2.8.1.

Needs re-write to match what is currently done. The 47 Hz reference is incorrect. The word sustained could imply time longer than 150 milliseconds.

The discussion highlighted that this change was to ensure that the rules match what was currently undertaken in practice. PWC's Power Networks rejected this proposed amendment and provided the following reason:

Not required. Refer System Control Technical Code.

PWC's Power Networks further advised that they did not believe that the clause was in conflict with current practice but accepted that the wording could be improved to provide clarity. It was further advised that System Control managed the under frequency load shed arrangements under the SCTC and this took precedence over the NTC. Further that this hierarchy resolved any conflict should any exists. PWC Power Networks did not support changes to the NTC at that time.

TGen disagrees with PWC's 2016 reason for rejection. The SCTC obligations on under frequency load shedding refer to the frequency standards that are set out in the NTC. NTC clause 2.2.2 is the frequency standard for the power systems and they remain unclear. TGen was, and still is, seeking to clarify the standard. TGen requests that this proposed amendment be reconsidered.

2.3.2 Comments on specific clause amendments

TGen has not undertaken an exhaustive review of the all the proposed clause amendments. This section contains commentary on key areas.

2.3.2.1 Proposed Clause 3.3.1, Outline of Requirements

The clause attempts to determine which generators the performance standards apply to. The clause makes reference to registration thresholds set out in the Secure System Guidelines. TGen questions the validity of this clause's governance as it proposes that a Code defer to a Guideline for details on where it applies.

2.3.2.2 Proposed Clause 3.3.2, Application of Settings

TGen notes that all six paragraphs of this proposed clause are essentially reworded NER S5.3.4. The statement in the Consultation Overview Paper seems to have confused the commentary with proposed clause 3.3.1.

TGen questions the relevance of the third paragraph in the Northern Territory power systems. The paragraph relates to intra-regional power transfer capability. Can PWC explain how this might be applicable to the NT regulated power systems?

2.3.2.3 Proposed Clause 3.3.5.1, Reactive Power Capability

The changes proposed to this requirement are twofold:

(i) The reference point for determining this requirement has changed from the generator terminals to the point of connection. This means that the reactive impedance of the generator transformers, where one exists, needs to be taken into account.

TGen requests that PWC include, in a compliance guideline document, expectations on how this is to be undertaken and take into account that, in practice, all testing of machines occurs at the generator.

(ii) The magnitude of capability has reduced for supplying reactive power (lagging) and increased for absorbing reactive power (leading).

Whilst detailed analysis has not been undertaken by TGen, it is likely that most (if not all) generators are capable of meeting the required lagging capability and few (if any) are capable of meeting the required leading capability. If there was, at any time, a requirement to meet compliance, it is likely that the alternators and control systems would require replacing at an extreme cost. Clearly grandfathering this requirement, independent of any change to any generating unit, is essential to TGen.

2.3.2.4 Proposed Clause 3.3.5.3, Generating Unit Response to Frequency Disturbance

The proposed change reduces system security, due to removing any requirement to stay connected above 52Hz. The current proposed draft would indicate that a generator can trip instantaneously as soon as frequency rises to 52 Hz.

If the TGen's 2016 proposed NTC amendment 1 is agreed, as outlined in section 2.3.1.2 of this paper, then PWC proposed NTC clause 3.3.5.3 would need to be modified accordingly.

2.3.2.5 Proposed Clause 3.3.5.4, Generating System Response to Voltage Disturbances

The proposed change to the NTC section 3.3.5.4 put a much greater requirement on generator to stay connected during voltage disturbances than the current standards. The biggest change is for voltages greater than 110% of normal. The current standard is for 110% to 115% is for 0.9 second, the proposed new requirement is for 20 minutes. This duration increase is 1333 times, or three orders of magnitude.

TGen is unclear as to how to determine if equipment is capable of this new requirement without potentially destructive testing. TGen notes that the alternator voltage is used in almost every control \ protection system found on a generating unit:

- Prime mover control system can have it for synchronising purposes which mean over voltage protection setting may also be present.
- Automatic voltage regulator (AVR) will have a voltage reference. AVRs also have over voltage protection setting.
- Protection will have a voltage reference. Protection will have over voltage protection setting.

If TGen's existing plant is capable of meeting the new standard, to meet the new standard would almost certainly require change to the protection settings which may require a protection relay testing. Changing the prime mover control system may require governor testing. Changing the AVR may require AVR testing.

Allowing high voltage levels for the proposed extended durations may also require a number of other protection settings to be reviewed, such as any protection involving impedance, voltage, watt or vars.

All such analysis, setting changes and testing comes at a cost.

It is recognised by TGen that the proposed changes are similar to the current requirements in the NER S5.2.5.4(a). However, there are two notable exceptions:

i) The NER has identified minimum standard requirements, S5.2.5.4(b) which are similar to the current NTC requirements for voltages greater than 110% of normal. The NER has a negotiated access standard framework whereas the proposed NTC changes provide only a 'do no harm' requirement where the onus is placed on the generator to demonstrate.

ii) The introduction of subsection (9) which is a requirement to maintain continuous uninterrupted operation when the connection point is zero volts for 0.5 seconds.

TGen understands that there are proposed grandfathering arrangements that mean that TGen's generators will (presumably) have deemed compliance status. However, under the proposed grandfathering arrangements, any changes to any part of the generating unit will require it to be made compliant in this requirement unless TGen endeavoured to demonstrate that the existing capability 'does no harm'. This would likely require a full power system voltage management and reactive reserve study to be undertaken in the relevant power system, which is the responsibility of System Control not a generator.

TGen questions the appropriateness of proposed NTC 3.3.5.4(9) being included in this section. This section is for voltage disturbances. The equivalent NER specification covers a range from 70% to 130% of normal voltage for varying duration. However, proposed NTC 3.3.5.4(9) introduces a requirement of zero volts. A zero volt requirement is a fault ride through capability. Fault ride through capability is specified in proposed NTC 3.3.5.5. TGen suggests removing proposed 3.3.5.4(9).

2.3.2.6 Proposed Clause 3.3.5.11, Frequency Control

TGen notes that this proposed clause is based on NER S5.2.5.11 as far as the automatic standard is concerned. There are a number of terms used in this clause that have been copied from the NER that are defined terms in the NER, but are not given definition in this document. For example 'market ancillary services', 'adequately damped' etc. Other terms used in the NER version are indicated as defined terms but are not indicated as such in the proposed NTC, but the terms are defined in the proposed NTC, eg 'control system', 'frequency control mode', 'generating system', 'connection point' etc.

2.3.2.7 Proposed Clause 3.3.5.12, Impact on Network Capability

TGen notes that this proposed clause is based on NER S5.2.5.12 as far as the automatic standard is concerned. The '(a)' reference could be deleted. There are a number of terms used that are defined terms but not indicated as defined terms which leaves the clause open to interpretation.

TGen questions what the applicability of this clause is to the NT power systems?

2.3.2.8 Proposed Clause 3.3.5.13, Voltage and Reactive Power Control

The proposed amendment appears to be no change from the current provisions. However, the new numbering of subclauses provides some confusion as to which provisions apply to what generator type.

There are some references to generator unit or generator power station sizing for applicability of some provisions. Has there been a review of the application of these thresholds across the three regulated power systems?

2.3.2.9 Proposed Clause 3.3.5.14, Active Power Control

TGen notes that this proposed clause is based on NER S5.2.5.14 as far as the automatic standard is concerned. However, the subsection (c) is not a part of the NER S5.2.5.14. This subsection appears to be duplicated from proposed new clause 3.3.5.13(xi) relating to reactive power control. It seems that the provision is picking the most advantageous, to PWC, provisions of the NER and the existing NTC. Yet there is no discussion around the selection nor rationale for the proposed requirement.

There are a number of terms used in the proposed clause that are defined terms but not indicated as defined terms which leaves the clause open to interpretation.

The proposed standard requires that generators must be capable of receiving and responding to AGC signals. PWC's System Control does not provide AGC control of the Tennant Creek power system. At present, the power system is managed by TGen's power station PLC. To change the status quo would be at considerable expense to both TGen and PWC. Presumably the status quo will have deemed compliance for this requirement under the grandfathering provisions, but this deemed compliance is only valid until a change is made.

Is it PWC's intent to apply this provision to all regulated power systems?

2.3.2.10 Proposed Clause 3.3.5.15, Inertia and Contingency FCAS

Neither Inertia nor Contingency FCAS appear to be defined within the NTC. They should be defined terms.

In Figure 9, the vertical axis is labelled 'Inertia (MW.s/MVA)'. The horizontal axis is on a scale of 'pu of rated active power'. Thus one scale is related to rated MW capacity and the other on MVA rating. TGen suggests that this could lead to confusion and that it might be more appropriate to modify the vertical axis to 'MW.s/rated active power'.

Question: Where a generator exceeds the adequacy threshold, can this excess capability be utilised to contribute or assigned towards compliance for other generators?

2.3.2.11 Proposed Clause 3.3.6.1, Remote Monitoring

The consultation overview paper states that this incorporates provisions from existing NTC clauses 3.3.3.1 and 3.3.3.2. These existing clauses are titled 'remote monitoring' and 'remote control' respectively. The proposed NTC 3.3.6.1 is titled 'Remote Monitoring', however this title is misleading as it now incorporates remote control. TGen requests that Remote Monitoring and Remote Control are two separate requirements and be separated into appropriately titled clauses.

Proposed NTC 3.3.6.1(4) requires all generators to provide remote control capability to System Control, without exceptions. This is a significant change from the existing NTC requirement (3.3.3.2) which provides conditions that a user must meet if remote control capability is not provided to System Control.

For example, the Tennant Creek Power System does not currently have remote control capability provided to System Control as the existing conditions of 3.3.3.2(b) are met. Whilst TGen understands that this requirement will be grandfathered under the provisions of proposed NTC 12.2. However, if TGen were to make any changes to any Tennant Creek generating unit, after the proposed changes come into effect, then TGen would be obligated to provide remote control capability of that generating unit to System Control. If a new generating unit were installed in Tennant Creek then there is no discretion and remote control capability would be required to be provided to System Control for that new unit, but not for the existing units. Remote Control of a single unit in a power system by System Control would be of little to no benefit to System Control but at considerable expense to the generator. The proposed amendment removes any flexibility available to both the generator and System Control, and it would be a breach of the NTC to not provide it.

TGen suggests that the existing provisions of NTC 3.3.3.2 (Remote Control) be retained in their entirety and it be restored as a subsection separate to the 'Remote Monitoring' provisions.

2.3.2.12 Proposed Clause 4.5.1, Network voltage control

TGen questions the appropriateness of the NTC deferring to a subsidiary document of the SCTC. This is the proposed change made to 4.5.1(e) however there is no discussion as to why this change is proposed and the implications of it.

2.3.2.13 Proposed Clause 4.7.6, Directions by the Network Operator

The Consultation Paper indicates the proposed changes in this clause are made to 'focus on un-licenced Users'. The amendments proposed appear to give the Network Operator rights to require customers to undertake actions related to security of the power system. The clause previously referred to the Power System Controller making such directions. It is TGen understanding that the responsibility for maintaining power system security is the responsibility of the Power System Controller, not the Network Operator.

PWC should explain how this proposed amendment fits within the regulatory powers bestowed on the Network Operator, why the change is proposed and how they expect this to be carried out in practice?

2.3.2.14 Proposed Clause 4.7.7, Disconnection of Generation Units and/or associated loads

The proposed amendment moves the authority to disconnect from the Power System Controller to the Network Operator. This proposed change is not detailed in the Consultation Paper. Can PWC explain the rationale behind this proposed change?

2.3.2.15 Proposed Clause 4.9, Nomenclature standards

TGen have expressed elsewhere its concerns about this requirement moving to the SCTC which has no grandfathering provisions.

2.3.2.16 Proposed Clause 12.2, Networks and facilities pre and post 1 April 2019

The proposed clause 12.2(a)1) requires TGen to demonstrate compliance of all generating units with NTC Version 3.1. NTC Version 3.1 clause 12.2 states that all plant and equipment connected to the network existing at 1 September 2012 was deemed to comply with the NTC (Version 3.1). TGen interprets this to mean that anything commissioned prior 1 September 2012 is deemed to comply with the proposed code Version 4 changes and anything commissioned between 1 September 2012 and the date that the proposed Version 4 changes are formally adopted needs to have demonstrated compliance with the provisions of Version 3.1 of the NTC. If this interpretation is the correct, then TGen requests that this clause be amended to make this clear.

Proposed clause 12.2(a)2) requires TGen to document compliance or non-compliance of all generating units against the proposed new requirements. This assessment is to be undertaken ‘using an agreed methodology and within the timeframe agreed between the User and Network Operator’. Under the current arrangements, it is TGen’s experience that demonstrating compliance with Version 3.1 of the NTC has proven to be problematic. There are neither testing guidelines nor template test plans provided by the Network Operator as to what tests and what test programs are to be undertaken to demonstrate compliance. Test plans are currently developed on a case by case and ad hoc basis with incremental tests determined by System Control during compliance testing. Presumably System Control acts as the agent for the Network Operator in this? The cost of demonstrating compliance is met by TGen and the cost of having PWC witness and endorse compliance is being recovered from TGen by PWC. TGen has a number of questions in relation to the proposed new arrangements:

- Will guidelines and templates for compliance requirements be developed by PWC?
- What are the means by which agreement will be reached, in relation to proposed 12.2(a)2), on methodology and timeframe between the User and Network Operator? If there is dispute, how will this be arbitrated? What are the consequences of non-compliance?
- Will System Control continue to act as the Network Operators agent in regards to compliance or will Power Networks be undertaking this directly?
- Is there an expectation that the User will pay for the Network Operators costs associated with a User meeting its obligations in relation to proposed 12.2(a)2)?

Proposed clause 12.2(c) requires TGen to meet full compliance with the NTC if the existing plant is modified. As mentioned earlier, TGen has a number of non-compliances that will likely be grandfathered. In particular compliance with the proposed Reactive Power Capability, clause 3.3.5.1, would likely require replacement not upgrade. If TGen were to make a modification to one part of a generating unit that has grandfathering provisions, say the control system, then the current drafting would require upgrading of the entire generating unit to full compliance. This is a dis-incentive to make any upgrade to a generating unit or power station. TGen recommends that the modifications provisions in proposed clause 12.2(c) be reconsidered.

2.3.2.17 Proposed Clause 16.3, Frequency stability criteria

The proposed amendment introduces ‘rate of change of frequency’ criteria for each power system. TGen recommends that more information be provided around what is meant by this definition and why it has been introduced. Should it be a defined term?

TGen also notes that proposed clause 3.3.5.3 makes reference to ‘rate of change of frequency’ and stipulates that 4 Hz/sec is the value. If the use of this in proposed clause 3.3.5.3 is in the same context as it is stated in this proposed amendment, then TGen suggests it reference this section as the source rather than state the value.

TGen also notes that this term is used in clause 3.4.10.1(2). TGen also questions if this is raised in the same context and perhaps a defined term is a more appropriate way forward.

2.4 System Control Technical Code Proposed Changes – specific comments:

2.4.1 Governance

TGen has some suggestions on governance regarding the operations of System Control. TGen suggests:

- Greater Transparency in decisions and operations of System Control
  - Publications and archiving of incident investigations, reports, findings and progress on implementation of historical findings
  - Publication and archiving of procedures, templates and guidelines
  - Publication of explanations on system constraints
  - Publication of timetable of proposed reviews such as under frequency load shedding
  - Publication of (summary) findings of reviews

2.4.1.1 2015 SCTC Consultation

In 2015 PWC consulted on changes to the SCTC prior to the I-NTEM commencement.

TGen made submissions to the SCTC consultation that included 82 comments to the draft SCTC issued for consultation. In the response released by PWC, there were 14 instances where the response statement identified as 'Power System Controller Response' was:

> This matter has been noted for future review of the Code.

The response document is located on PWC website at:

> https://www.powerwater.com.au/__data/assets/pdf_file/0004/98500/System_Control_Technical_Code_-_Consultation_Feedback_Assessment.pdf

Within that document, the relevant comment reference numbers are: 21, 28, 30, 31, 34, 56, 63, 64, 70, 71, 72, 73, 74 & 75.

In the documentation for this consultation, PWC make no mention of that previous consultation and of the outstanding issues raised during that consultation. This current consultation does constitute a 'future review of the Code' (SCTC). TGen requests that the comments submitted in 2015 be re-considered as part of this consultation as agreed in the response made in 2015.

2.4.2 Proposed amendment clause 3.2.3, Generator Classification

The proposed amendment removes the semi-scheduled classification of generators. TGen does not agree with this proposed amendment and discusses this further in section 2.7.3.2 of this paper.

2.4.3 Proposed amendment clause 3.3.3, Responsibility of the Network Operator

Amongst the proposed amendments within this clause is the introduction of an obligation on the Network Operator to oblige unlicensed Network Users to establish an operating protocol with the Power System Controller.

- If a licensed generator fails to renew a licence, or has its license removed, does this proposed amendment provide some opportunity for that entity to continue generating?
- SCTC 1.7.4(d) places the onus on the Power System Controller to establish an operating protocol, the current drafting indicates that the obligation is on the un-licensed Network User.

2.4.4 Proposed amendment clause 3.11.1, Load Forecasts

The proposed obligation applies to all generators including dispatchable synchronous thermal generation such as the generating units that comprise TGen's fleet of generators. TGen sees this new requirement as extremely onerous and will require considerable system implementation and ongoing administrative resource to meet this obligation.

It appears that the requirement for this is driven by the imminent connection of a number of solar PV farms. If this is the case, then maintaining the semi-scheduled generator classification in place and establishing these requirements on that classification would seem to be a cleaner approach than is currently proposed. TGen suggests that the NER 3.7B may provide some insight on this for the NT.

The proposal is that the details of the requirements are specified in a subsidiary document. TGen suggests that the details of requirements for this obligation would appropriately sit in a Code. However, the proposal is confusing because the 'PART A – CAPACITY FORECASTING' of the second supplementary paper proposes that there will be a new clause 3.3.5.17 in the NTC that sets out some requirements on forecasting. What is not stated is will this proposed amendment to SCTC 3.11.1 now reference NTC 3.3.5.17 or the SSG as it is currently drafted!

Given earlier identified grandfathering concerns raised by TGen, if the obligation for capability is located in the NTC, then TGen would be able to seek exemption. However, with the requirement in the SCTC calling on this to be provided, there is no proposed grandfathering arrangement.

Can PWC please answer the following questions?

- Is the scope of this requirement intended to include synchronous thermal generation?
- If this is to include synchronous thermal generation, is there intended to be grandfathering provisions for existing generation?

2.4.5 Proposed amendment clause 6.5.1, Performance issue outages

TGen is cautious in commenting on this proposed change at this stage. The current procedures on plant outages are not comprehensive. TGen requests that the amendment include requirements on the Power System Controller to produce, publish and maintain procedures, templates and guidelines on Plant Outage requirements.

2.4.6 Proposed amendment clause 6.7.4, Operating Protocol

The current provision on operating protocol is SCTC 1.7.4(d). 'Operating Protocol' is not a defined term. This proposed amendment and other proposed amendments seem to be placing more importance on the Operating Protocol going forward.

TGen suggests that the Power System Controller clarify what exactly is meant by this term and introduce requirements to produce templates and guidelines showing what will be in such a document and how it is practically intended to be used.

2.4.7 Proposed amendment clause 6.14, Plant Numbering, Nomenclature and Drawings

TGen have expressed elsewhere its concerns about this requirement moving to the SCTC which has no grandfathering provisions.

2.5 Secure System Guidelines Proposed Changes – specific comments:

2.5.1 Governance

TGen is concerned that the Secure System Guidelines seems to be utilised as a document to introduce definitions or rules that is not appropriate to the hierarchy of this document in relation to other regulatory instruments - Acts, Regulations, Codes & Guidelines. Generally TGen would expect that the higher level documents would set out the requirements and definitions. The Guidelines should provide a guide or examples on how the requirements and definitions are interpreted and implemented.

By way of example, TGen suggests that the specification of FCAS would be more appropriate in a Code rather than a Guideline. The Guideline would be an appropriate document to locate examples of interpretation. With both documents 'opened up' under the same consultation would be an ideal opportunity to address governance issues.

2.5.2 C-FCAS Update

Notwithstanding the comments on the appropriate hierarchy of regulatory documents, TGen notes the following:

During the UC consultations on generator licence applications of large scale solar PV, SC made various representations on proposed Generator Performance Standards that have led to this current consultations. Amongst which was the inclusion of some examples on meeting the C-FCAS and inertia requirements, 'Attachment B'. In those examples, there were highlighted deficiencies in the SSG C-FCAS specifications including a standard ramp rate curve to apply to determining the C-FCAS quantities. TGen suggests that these changes be included to Section 8 in this round of consultation to the SSG.

SSG Section 8 of the SSG currently states that all three regulated power systems are not operating under C-FCAS requirements, rather all are still operating under 'spinning reserve' requirements. Will all three power systems be changed over to C-FCAS prior to the GPS being enacted?

2.5.3 Other clarifications

Appendix A – refers to a constraint that is no longer applicable due to reconfiguration of connections at Channel Island Power Station. TGen requests that the Appendix be deleted.

2.6 SUPPLEMENTARY CONSULTATION PAPER, Contingency Frequency Control Ancillary Services (C-FCAS) – specific comments:

TGen acknowledges that the intention of releasing this document was to assist parties in assessing the impacts of the proposed NTC 3.3.5.15. However, there are a number of statements made in the document that raise questions that TGen seeks clarification on.

What follows is a combination of questions and commentary by TGen on this supplementary paper.

2.6.1 Proposed Approach to C-FCAS Capability - Compliance testing

The fourth paragraph in this section states that the System Controller will test capability accreditation, in conjunction with the Network Operator. It is TGen's view on reviewing the existing and proposed NTC accreditation clauses that the accreditation of compliance with the NTC lies with the Network Operator. Under what regulatory authority does System Controller propose to exercise this testing?

2.6.2 C-FCAS Operating Availability and Payment – Alice Springs and Tennant Creek Power Systems

This section introduces a phrase 'security constrained load following' and states it is the existing arrangement and expected to remain. TGen does not understand what is meant by this. PWC to explain what is meant by this phrase and under what regulatory basis it is determined?

The second paragraph states that there is no 'mechanism to pay another generator to provide a greater share of C-FCAS'. TGen suggests that SCTC clause 5.1 provides the requirement for the Power System Controller to develop and implement a framework of procurement that would negate the need for a generator to pay another generator for such services.

2.6.3 C-FCAS Operating Availability and Payment – Darwin-Katherine Power System

In addition to the specific responses to the issues raised in the paper below, TGen also seeks improved definition of the type and quantum of ancillary services, such as:

- Inertia requirements going forward
- Timetable of change from spinning reserve to C-FCAS requirements
- Network Support requirements

2.6.3.1 I-NTEM - Current

Currently the Darwin-Katherine power system operates under a 'spinning reserve' arrangement. C-FCAS has not been implemented. This section appears to be describing the system as though it operates under a C-FCAS arrangement at present. Does System Control intend to implement C-FCAS, if so when and how?

There is also no mention of inertia dispatch constraints that are currently operating under the spinning reserve and proposed under C-FCAS arrangements. TGen understands, from System Control publications, that Inertia and C-FCAS are inextricably linked.

This section indicates that TGen is paid a rate to compensate it for C-FCAS, this rate is embedded in the SCTC and will be reviewed in the near future. TGen has made previous requests to review this rate in the past and asks when will this rate be reviewed and by whom?

2.6.3.2 I-NTEM - Future

The section indicates that the existing I-NTEM arrangement will continue and only TGen will be scheduled to provide C-FCAS and other ancillary services. This section also indicates that 'as soon as practicable an arrangement will be introduced whereby C-FCAS can be scheduled from other facilities'. Given that currently C-FCAS has not been implemented, TGen asks how is this to be arranged?

2.7 SUPPLEMENTARY CONSULTATION PAPERS, "FRAMEWORK FOR THE FUTURE" – specific comments:

2.7.1 Framework for the Future

The discussion seems to focus on the immediate future, being the imminent connection of grid scale asynchronous solar PV and the existing synchronous generators connected. TGen suggests that a future proof framework should also consider other technologies that are possibly required in the future. In particular technologies that are capable of providing ancillary services or energy storage or both. These technologies may require new asset classifications.

TGen seeks clarification about the following statement:

> No current market for power system security services in the Darwin to Katherine Interconnected System (DKIS) and will not exist in Alice Springs or Tennant Creek systems.

As discussed in section 2.6.2 of this paper, there is a requirement for the Power System Controller to develop a regulatory mechanism for the procurement of ancillary services. This includes Alice Springs and Tennant Creek. There is no restriction on other providers of ancillary services being contracted in these power systems. Thus the statement that there will not be a market for power system security services in Alice Springs and Tennant Creek would seem to indicate that there is no intention for the Power System Controller to fulfil its obligations under SCTC 5.1.

2.7.2 Part A – Capacity Forecasting

TGen has made comment on this in section 2.4.4 of this paper.

2.7.3 Part B – Scheduled Generator classification

2.7.3.1 Amount of reserve

The paper indicates that the amount of reserve to cover unexpected changes in supply is traditionally based on the failure of an on-line generating system and that this is proposed to remain the case.

TGen notes that System Control have previously release 'Attachment C in response to the UC generator licence application consultations. This document referred to impending increase in generation along the 132 kV line from Channel Island to Katherine and the likely result that there will be a flow north of power into Channel Island that will, under some circumstances, create a requirement for greater reserves to cater for this loss. So reserve requirements needed to cater for a specific network interruption.

TGen seeks clarification on this.

2.7.3.2 Generation Classification

The following statement is made:

> Due to this it is critical that the supply can be relied upon to meet the energy demand and reserve requirements, these features are only provided by scheduled generation. Without confidence in capacity forecasts (predictability) and dispatchability, this cannot be achieved.

It seems that the whole basis of removing semi-scheduled generation classification is based on this statement. TGen questions the validity of the statement that only having scheduled generation is the means to achieve this.

A further statement is made:

> Classification of non-scheduled or semi-scheduled are only applied to generation that is not capable of being scheduled.

The current definition of ‘semi-scheduled generating unit’ is that the output is intermittent. This would seem to fit the proposed large scale solar PV generators.

The reason provided for deleting the classification is stated as so that ‘active power control arrangements and the capacity forecasting mechanism’ can be enforced on solar PV generators that exceed a given threshold. TGen suggests that introducing these requirements for ‘semi-scheduled’ generation and cleaning up definitions through this GPS consultation would seem to be a means of achieving the intended outcomes. This seems more appropriate than ‘making’ these generators ‘scheduled’.

The proposed ‘one size fits all’ classification for generators does not appear to fit the capabilities or potential of renewable and other technologies such as batteries, and is likely to impose more onerous constraints on all forms of generators, including thermal.

2.8 Additional items for consideration

2.8.1 Frequency Standards, NTC 2.2

Further to requests to reconsider 2016 proposals to make changes to the frequency standard as set out in section 2.3.1.2 of this paper, TGen requests a review of frequency standards with consideration of:

- Changing the form of the standard
- Removing time error correction requirements

2.8.1.1 Frequency Standard Form

The current form of 'normal operating' frequency band has hard limits. TGen recommends adopting limits similar to the NEM where there is a limit required to be achieved for a percentage of time.

TGen observes that in Alice Springs, the normal frequency band in Alice Springs is frequently breached with no abnormal conditions apparent. This is usually observed when there is high solar PV variability apparent. To comply with the current hard limit standard could no doubt be achieved, but would require additional expense. There does not seem to be any concern with short movements outside the existing limits. So TGen proposes that the standard be adjusted to a form that allows this and is consistent with the NEM.

2.8.1.2 Accumulated Time Error Correction

Current situation:

NTC 2.2(b) stipulates a time error of less than 15 seconds for 99% of the time to apply to all three regulated power systems. SCTC 4.5(c) requires that the Power System Controller correct time error of an islanded system prior to reconnection.

NEM Review:

In the NEM, the Frequency Operating Standard[1] (FOS) stipulates a time error in all regions of less than 15 seconds 'except in an island or during supply scarcity'. A 2017/18 review[2] of the FOS saw the Mainland regions of the NEM relax this from 5 seconds to the now 15 seconds. During the first stage of the review, AEMO were requested to provide advice[3] to the review in relation to the requirement for accumulated time error, AEMO stated:

> System security considerations
>
> AEMO considers that there are no system security (or reliability) benefits specific to conducting time error correction. This aligns with the reasoning of the North American Electric Reliability Corporation (NERC) in its recommendation to remove the obligation of time error correction in the US. If there remain some consumers dependent on an accurate grid time-keeping service, in AEMO's view this would better characterised as a power quality issue rather than a security or reliability issue.
>
> Costs, benefits and implications of relaxing or removing the standard
>
> Relaxing the requirement for a limit on accumulated time error could be implemented at minimal cost to AEMO, and may involve solely changing time-keeping parameters in the Energy Management System (EMS).

---

[1] https://www.aemc.gov.au/sites/default/files/2019-02/NER%20-%20v119_0.PDF
[2] https://www.aemc.gov.au/markets-reviews-advice/review-of-the-frequency-operating-standard
[3] https://www.aemc.gov.au/sites/default/files/content/9a79771b-9794-45da-8493-e22842d45275/AEMO-Advice-%E2%80%93-Stage-one.pdf

There are reasonably common instances where time error correction acts in a manner contrary to good frequency control. This means that time error correction results in poorer frequency control, which impacts system security negatively (noting that the impact is not regarded as severe). This is a topic that has been investigated through work with the Ancillary Services Technical Advisory Group (AS-TAG) on frequency control degradation within the normal operating band.

This counter-frequency action driven by time error correction occurs legitimately based on how accumulated time error is corrected. For example:

- If frequency has been above 50 Hz for some time, the time error will be positive. That is, clock time as measured from the grid frequency will be fast.
- To correct this, the grid frequency needs to be reduced, and is done so by reducing generation supply.
- In the instance that a disturbance on the power system occurs concurrently (such as the trip of a generator) which results in the frequency falling below 50 Hz, then the adjustment factors for time correction will be countering the adjustment factors for frequency correction.

This counter-action feature is by design, and is consistent with other jurisdictions internationally. When time error is generally very low, this behaviour is relatively insignificant. However, if the management of frequency control within the normal operating band deteriorates such that frequency is less tightly bound around 50 Hz, time error often accumulates to significant amounts. This can then become an issue for good frequency control. AEMO's analysis has shown that this 'counter frequency' behaviour can occur up to 20% of the time. A relaxed time error requirement would allow AEMO to use less aggressive time error correction settings, better prioritising good frequency control. Eliminating the obligation to contain time error entirely will eliminate these conflicting objectives and more fully prioritise good frequency control.

From a more general perspective, removing unnecessary obligations is prudent as it streamlines operating practices.

The Panel has also asked whether, to AEMO's knowledge there are any critical processes or equipment that would be adversely impacted by the removal or relaxation of the requirement to limit accumulated time error. AEMO is not aware of any critical processes or equipment that would be adversely impacted by these proposed changes. AEMO is also unaware of any complaint being received concerning time error. However, those potentially impacted may not be customers with whom AEMO has typically had direct interaction.

Overall, AEMO is supportive of a removal or relaxation of the requirement, subject to satisfactory consultation to understand and evaluate any as-yet unknown impacts to customers. AEMO believes that the removal of the obligation to limit accumulated time error could be implemented relatively quickly as it would not force any immediate changes. AEMO is also able to phase in changes as appropriate.

Proposal:

TGen proposes that the removal of time error correction requirement be considered. As identified by AEMO, it would enhance system security and reduce requirement of ancillary services. The only concern is that there may be some unknown impact on customers and consultation should be undertaken first.

2.8.2 Other types of assets for dispatch

TGen is of the understanding that other technologies, such as batteries, are proposed to be classified as generators. New technologies are available for specific ancillary services and for energy storage, or even both. TGen suggests that additional classifications be considered for these new technologies rather than a 'one size fits all' approach.

2.8.3 System Controller Forecasting obligations, SCTC clause 3.11

Proposed SCTC 3.11.1 places requirements on generators to provide forecasts of active power capability. The need for this change has been explained as the introduction of new technology intermittent generation. However, there have been no proposed corresponding changes to System Control's obligations in forecasting.

NER 3.7B places obligations on AEMO to prepare a forecast of all semi scheduled generators and on those generators to submit forecasts to AEMO. TGen suggests that introduction of obligations on intermittent generators to submit forecasts should also have reciprocal forecasting obligations placed on the Power System Controller akin to the obligations on AEMO in NER 3.7B.

In particular, the impacts of behind the meter solar PV has become significant in maintaining reserves in real time dispatch. For example in the Alice Springs and Tennant Creek power systems, the Power System Controller requires generators to undertake dispatch of generation and reserves. To have a 'look-ahead' forecast in real time of aggregated solar PV would enable more efficient dispatch whilst maintaining security reserves.

2.8.4 Generator of last resort

PWC have indicated that there are further consultations expected this year regarding implementation of NTEM and other reforms.

TGen queries whether there an intention under the current reforms to define a 'generator of last resort' role and if so how would last resort capacity be contracted?

3 NTEM Functional Specification

3.1 Overview

The NTEM draft consultation paper states:

> "The purpose of this consultation is to invite comment from stakeholders on the NTEM Consultation Draft Functional Specification. DTF also welcomes comments on any other matters related to the design, implementation or operation of NTEM that are beyond the scope of the Consultation Draft Functional Specification.
>
> Specific matters that DTF considers stakeholders may wish to comment on but which are beyond the scope of the Consultation Draft include some governance arrangements (market bodies and rule makers) and transition timelines. However, DTF welcomes and will consider comments on any matters related to NTEM raised by stakeholders in submissions."

Furthermore the paper states:

> "Two packages of regulations implementing modified chapters of the NER commenced on 1 July 2016 and 1 July 2017, and the AER and PWC are in the final stages of the process to determine PWC's revenue requirement for the 2019–24 regulatory period.
>
> Work is underway on the third package of regulations to be in place by 1 July 2019. This package will include further metering obligations and a framework for connections to the network, noting the current Territory connections framework under the Electricity Networks (Third Party Access) Act is legislated for repeal on 1 July 2019."

TGen believes the first thing to establish is the coverage of the NTEM and more importantly arrangements for regions outside of the Darwin Katherine area. For example what arrangements will be in place Tennant Creek and Alice Springs? Are the rule makers and market bodies associated with Darwin Katherine the same as the other regulated regions. What processes will be common including compliance and dispute resolution process.

Perhaps most importantly for the Government's Renewable strategy what trading arrangements will be available to new entrants?

Another important statement from the consultation paper is:

> "There is an imperative for the NTEM to commence in 2019 to permit the entry of prospective new entrant generators in the Darwin-Katherine system. The short timeframe for commencement of the NTEM will require the Territory to develop transitional arrangements to apply from 1 July 2019 ahead of the implementation of the full market design at a later date. Key transitional arrangements are proposed for Ancillary Services, the Reliability Standard and the Capacity Mechanism."

It is TGen's understanding the rules to achieve these transitional arrangements will be documented in the SCTC which is currently under a consultation. The changes to these documents do not differentiate between the propose NTEM and non-NTEM regions. In addition TGen believes it would be unrealistic for the "rules" to be established and any subsequent system or operational changes to be made by all parties to allow the new arrangements to come into place in the proposed timeframe.

Participants will therefore be forced to make alternative contracting and operational process arrangement to ensure fuel supply and maintained activities can continue to be funded. TGen believe it is sensible to assume that from 1st July current trading arrangements are more likely to be in force for all three regulated regions.

3.2 Alternative Option - NTEM

TGen recognises that the arrival of the new generators in 2019 will need to be accommodated. It is important to highlight however that the current progress of the reforms has already had significant implications for TGen.

The NTEM consultation paper states that TGen is currently operating under a single, full cost recovery, energy-based tariff. This was the case for the period 2014-15 to 2016-17. However, in 2017-18, in the absence of a fully developed market design, the Government accepted for TGen to forgo its return on capital and recognise the decreased value of TGen's assets through impairment. TGen is facing an uncertain financial future given the limited time to implement new (transitional) arrangements as currently proposed in the consultation papers. Currently its revenue stream is secured with bilateral agreements with retailers for a bundled price.

Without the final form of the market it will not be possible to continue these contracts in their current form nor separate them with any certainty. This will increase the financial risk for all participants in any transitional period.

The consultation paper states:

> "The I-NTEM is a virtual market in that all commercial transactions occur through bilateral contracts between generation and retailing entities. These contracts continue the practice of bundling electricity in a single tariff that includes energy, capacity and ancillary services, with network charges separate. I-NTEM applies only to the Darwin-Katherine Interconnected System and was implemented through amendments to the existing System Control Technical Code under the *Electricity Networks (Third Party Access) Act*. However, the interim systems and process cannot accommodate multiple new entrant generators and require further development to provide a fully functional market mechanism. "

TGen believes that the solving the specific issues with the current systems under the existing framework is a more practical way of addressing the urgency created by the arrival of solar farms.

In view of Jacana entering into long-term power purchase agreement (PPA) with various proponents, an extension of out of balance payments at settlements and a simplified dispatch mechanism may suffice for the next 12 months. If adopted this would allow contracting between retailers and generators to be undertaken for a similar period.

The alternative option put forward here would still have consequences for TGen as during this period, it is envisaged TGen will have to provide ancillary and inertia services that are not being supplied by other independent power producers to ensure system security and reliability. While this will have a financial impact on TGen it is imperative that the correct price signals are established in any market, hence if an alternative arrangement proceeds, the rate used for ancillary services in the System Control Technical Code will need to be updated.

A twelve month extension to July 2020 will allow the necessary time for the market in its final form to be delivered with the concerns regarding governance, transparency, cost minimisation to be adequately addressed. For this to be meaningful, an implementation plan for the final regulatory arrangements should be published to participants both current and prospective so that it is clear when the interim arrangement would expire and new obligations would commence.

TGen also believes that the reforms should be undertaken by an independent agency, such as the Utilities Commission and supported by a working group. During the I-NTEM TGen participated in Stakeholder Working Group. TGen believes that there is considerable value in re-establishing this group and as such would dedicate the required resources as needed.

3.3 Specific Issues to be addressed by Market Design

This section provides feedback on the NTEM functional specification with regard to the final NTEM.

The paper states the NTEM has three separate arrangements.

- Capacity
- Energy
- Ancillary Services

This is similar to the WEMS in South Western Interconnected system in Western Australia.

However it is unclear how these three mechanisms interact with each other in the NTEM. For example the turning on of a facility to meet capacity will create energy, as will running a facility in a particular manner may provide ancillary service but will also create energy.

What if a facility fails to deliver its capacity or ancillary service will it be penalised for the lack of energy produced or just the lack of service?

The paper also expresses the view that some but not all Ancillary Services may be met without cost by the Generation Performance Standards of connected generators.

Further the process for dispatch indicates that dispatch will account for security requirement's but not take into account bilateral arrangements, in essence creating a gross pool for energy. The out of balance price will then be calculated ex-post and set as the marginal price for all out of balance energy.

A number of scenarios should be worked up to provide understanding on how dispatch, pricing and settlement would be undertaken. Currently in the I-NTEM there are numerous periods where the price has been set to zero due to the mechanism for calculation. This will extend to the Capacity Market as retailers would not be able to bundle energy and capacity obligations with any certainty.

For System Control it is also unclear whether they are co-optimising energy and ancillary services. If they pay for Ancillary services but not for GPS services or Energy there is a clear conflict of interest.

In addition for the actual dispatch decisions it is unclear how often the any optimisation would occur. Are all facilities being treating equally once committed or is energy from cheaper machines being maximised while energy from expensive machines is minimised.

Given these unknowns TGen believes other arrangements such as pay as bid rather than marginal price could be considered.

TGen is also concerned regarding its current role of generator of last resort. If capacity, energy or ancillary service is not provided is there a requirement for TGen to be able to supply any shortfall. How does the market incentivise the correct behaviours or are these matters for compliance. The requirements regarding this situation will have significant impacts on investment decisions for TGen.

TGen also has a concern for the number of entities contemplated in the NTEM Functional Specification. The following is a list of the entities involved.

- Generators
- Retailers
- PWC Networks
- System Control
- Market Operator

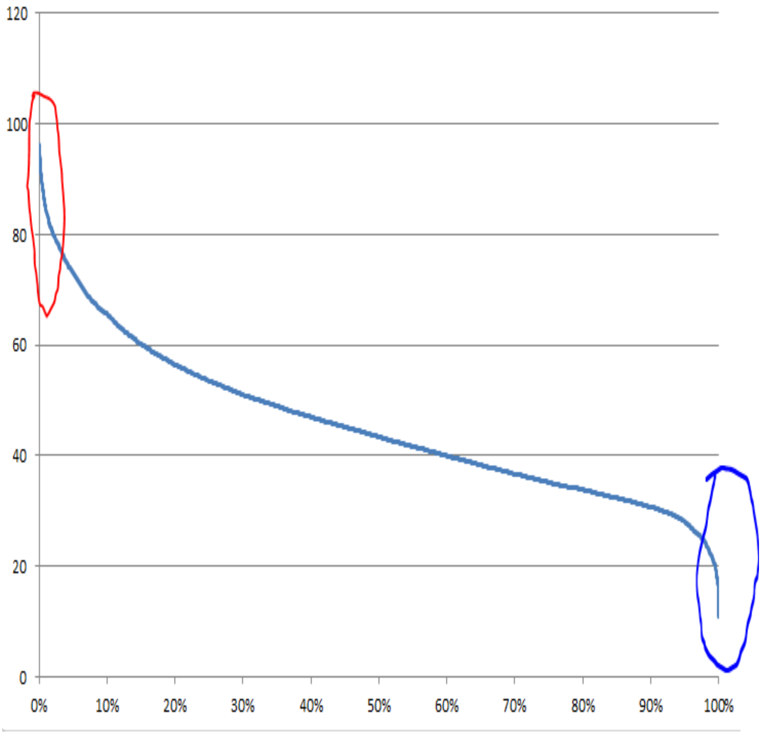
- Meter Data Agent
- Reliability Manager
- Utilities Commission
- Market Rule Maker
- Department of Treasury and Finance
- Australian Energy Regulator

The paper states that the rule maker should be independent of PWC given its role as System Controller and Market Operator. In addition TGen believes that the establishment of an independent system operator separate from PWC Network would assist in providing transparency and governance. The areas where overlap is identified in the NTEM paper includes network support, ancillary services and the relationship with the GPS definitions. Inertia is another area where it is expected that the obligation on the Network provider will be established.

In addition to providing clarity the separation would assist in the regulation of Networks being undertaken by the AER.

An issue that does not appear in the reforms proposed is the ensuring that ancillary services are available to manage the lower end of the load duration curve. The following diagram is a load duration curve modelled on actual values in the Alice Springs power system. The red circled area is the peak load on the power system and is addressed by the Reliability Standard, the GPS and the proposed Capacity Mechanism.

The emerging issue in the NT power systems is managing the capability for keeping power systems secure at times where the requirements on traditional generation is low due to increasing levels of distributed behind the meter generation. This is the blue circled area at the lower end of the curve. To manage this there are other capabilities that need to be deployed that do not necessarily have any generation capacity related. There needs to be a means of providing investment signals in these capabilities as there is currently no mechanism within the existing framework. TGen acknowledges this is a system security issue not a reliability issue. However, TGen believes it worth highlighting this issue and looks forward to it being addressed in the forthcoming reforms.



3.4 Implementation Plan

The functional specification does not provide clarity on the timing of changes between Transitional, full NTEM and future arrangements. Several functions within the document (Network Support Contracts, Reliability Standard etc) are indicated to move from one entity to another.

If TGen's suggestion of removing transitional NTEM arrangements is adopted, TGen believes a new timeline of the reform process should be established by a single entity to better co-ordinate the reforms.