# Review of the Northern Territory Generator Performance Standards

## Consultation paper

June 2019

PowerWater

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## Glossary of terms

| Term or abbreviation | Meaning |
|---|---|
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| ASEFS | AEMO's Australian Solar Energy Forecasting System |
| Capability | Connection requirement (in the network technical code): Connecting parties are to demonstrate that plant can supply FCAS services if the generator is in the appropriate control mode to do this and with appropriate headroom/floorroom. It does not specify a generator will be obligated to operate in this mode or curtailed to ensure provision. |
| C-FCAS | Contingency Frequency Control Ancillary Services |
| Commission | Northern Territory Utilities Commission |
| Delivery | Operation is the result of provision when a service is used. For instance if a generator tripped, other generators providing C-FCAS raise would then deliver this service by increasing their output in response to the low system frequency. |
| DKIS | Darwin Katherine Interconnected System |
| dual fuel | gas/diesel |
| Enablement | Operational requirement (SCTC): If the System Controller requires a generator to be enabled for FCAS it will only supply it if it has the headroom (for raise) or floorroom (for lower) to do so. A generator operating at maximum output can be enabled for FCAS, but be unable to supply FCAS raise as it has no headroom. In regards to lower service, a generator can provide FCAS lower if it is enabled and it is dispatched above its minimum stable load. |
| GPS | generator performance standards |
| insolation | solar irradiance forecast |
| I-NTEM | Current commercial arrangements in the NT energy market for the Interim Northern Territory Energy Market |
| Licensee | system controller |
| MW | megawatts |
| NEM | National Electricity Market |
| NER | National Electricity Rules |
| NT | Northern Territory |
| NTC | Network Technical Code |
| NTEM | NT Electricity Market |
| NTPSPR | Northern Territory Power System Performance Review |

| Term or abbreviation | Meaning |
| --- | --- |
| Power and Water or PWC | Power and Water Corporation |
| Provision | Operational requirement (in the system control technical code): If the System Controller requires a generator to be enabled for FCAS services AND its dispatch level has the headroom or floorroom to supply the FCAS service it is providing FCAS. For example, a generator dispatched below maximum capability that is enabled for FCAS is able to provide an FCAS raise service. This service is the quantity referred to in any market payment arrangements. |
| RE | renewable energy |
| R-FCAS | Regulating Contingency Frequency Control Ancillary Services |
| SCTC | System Control Technical Code |
| SSG | Secure System Guidelines |
| T-Gen | Territory Generation |
| the Application Act | National Electricity (Northern Territory) (National Uniform Legislation) Act 2015 |
| UFLS | under frequency load shedding |
| UIGF | unconstrained intermittent generation forecast |
| WEM | West Australian Energy Market or Wholesale Electricity Market (WA) |

# Part A | GPS overview

This consultation paper is intended to inform a further round of consultation on the generator performance standards. It provides a standalone record of what we are now proposing and why.

This part described the context and approach to this review.

## 1. Why are we updating the GPS and how does this fit into the NT energy reforms?

The generator performance standards (GPS) are an important pillar of the Norther Territory's (NT) power system regulatory and coordination framework that:

- enables third party private owners of generation assets to connect those assets to the power system and sell their energy
- ensures the power system remains secure and reliable, and those who drive risks and costs to the system face the costs of doing so that they can commercially minimise these.

We initiated the formal consultation on our review of the GPS requirements with publication of proposed instrument changes in late 2018. This paper and the accompanying amended regulatory instruments represents our next round of consultation. This further round of consultation seeks to provide a standalone record of what we are now proposing for the GPS and why.

This section explains:

- The multiple instruments and functions within Power and Water Corporation (Power and Water) that are required to give effect to and implement the GPS
- The NT policy content within which this GPS review is being performed
- The system context within which the GPS must perform their intended function
- The principles that have informed how Power and Water has approached this review, and how these relate to those that the Utilities Commission (the Commission) is required to apply when reviewing and approving amendments to the instruments that give effect to the GPS
- How the above point give rise to a framework for the future that has governed this GPS review.

### 1.1 Our system control role

The System Controller's role is to monitor and control operation of the NT's regulated power systems to achieve safety, security, reliability and efficiency of power system operations. In practice this means that all day every day we must balance the supply of energy coming into the power system with customers' demand for energy. To do so, we must keep energy moving through the system and account for any constraints in the power grid (poles and wires) that delivers energy from generators to customers.

In this way the System Controller's job is to 'keep the lights on' by balancing supply and demand for energy in real time. This is often called maintaining power system security, and is equivalent to the role that the Australian Energy Market Operator (AEMO) performs independently in the interconnected National Electricity Market (NEM). This System Control role differs from the Network

Operator (or grid) part of the Power and Water business who also work to "keep the lights on" but who do so by building and maintaining the grid assets that deliver energy—see section 1.2.

### 1.1.1 Relevant system control instruments

Power and Water is licenced by the Commission to perform the functions of the System Controller.[1] As System Controller we rely upon the conditions of generator connection[2] to be able to manage the power system securely, and we are responsible for two key regulatory instruments that allow us to operate generators in accordance with the GPS:

- *System Control Technical Code (SCTC)* | The SCTC sets out operating protocols, arrangements for security and dispatch, arrangements for disconnection, and any other matters relating to monitoring, operation and control of regulated power systems, which the System Controller considers appropriate for the reliable, safe, secure and efficient operation of the power systems. The SCTC is formally approved by the Commission.

- *Secure System Guidelines (SSG)* | The SSG are an instrument of the SCTC that outlines in a public document how System Control seeks to meet the requirements outlined in the SCTC. The SSG set out the principles and details for determining whether the power system is in a secure state. The SSG also contains a section on overarching power system parameters, and participant-specific sections for potentially commercial-in-confidence or ring-fenced information. The participant-specific sections are developed on an as-needs basis. The SSG is developed by Power and Water through a public consultation process, and is issued by Power and Water. Power and Water reports on compliance on the key provisions of the SSG to the Commission.

## 1.2 Our network operator role

Power and Water is also licenced by the Commission to operate three regulated electricity networks and a number of non-regulated electricity networks. The licence allows us to perform the functions of the Network Operator in those networks. As Network Operator we are responsible for delivering energy from power generators to homes and businesses in a safe and reliable way. We also connect new generators and energy users to the grid, provide and read meters to measure energy use for billing purposes, restore power after faults and emergencies happen due to severe weather events and other causes beyond our control, and communicate outage and restoration information.

### 1.2.1 Relevant network operator instruments

A key element of our role relevant to the GPS is to provide access services to parties who request to connect to the regulated NT networks. The key instrument that the network operator administers for this purpose is the *Network Technical Code (NTC)*.

The NTC has two elements: the network technical code and the network planning criteria. For the purpose of this consultation, we use the term NTC to refer to both elements.

The network technical code portion of the document is applicable to all equipment connected to our network but particularly generators and large loads. It covers:

- network performance criteria including frequency, quality of supply, stability, load shedding, reliability, steady state criteria and safety and environmental criteria

[1] The System Controller's functions are established under section 38 of the Electricity Reform Act.
[2] Which are found in the Network Technical Code.

- technical requirements of users' facilities including the connection of generators and loads and protection requirements
- inspection, testing and commissioning
- power system security[3], and
- metering.

The network planning criteria portion of the document, details the criteria used for assessing plant and equipment performance and response to power system events. These cover matters such as plant and network performance to support frequency events, voltage events, stability events, system reserve, reliability of supply and quality of supply. We apply to ensure the regulated networks:

- meet high safety standards
- provide a high quality, reliable and secure electricity supply
- meet environmental standards, and
- optimise equipment utilisation.

## 1.3 What the GPS do and why we're updating them

The GPS are established under the NTC, and the SCTC and the SSG are being updated to ensure alignment.

The GPS set conditions generators must meet for connection to the grid. These are important because they ensure that the system can be managed to balance supply and demand in real time to avoid outages or load shedding. They do so by making sure the levers that System Control needs to do its job are there when we need to call on them.

The key levers we need in the NT have been explained through our consultation to date, and are linked to dispatchability and predictability. Throughout the rest of this paper we elaborate on why these are needed and how we are proposing to ensure they remain present amid our transition to a greater level of asynchronous renewable generation.

The reasons we are updating the GPS are twofold:

- If we do nothing, we will rapidly lose dispatchability and predictability across the available generation fleet, and either:
  - be required to constrain the dispatch of asynchronous renewable generators and thereby frustrate the transition to renewable energy generation, or
  - we will not be able to perform our role of keeping the lights on, and
- Action 4(c) of the NT Government's Renewable Energy and Electricity Market Reform Implementation Plan 2018-2020 requires us to do so to play our important technical power system security role in our renewable energy transition.

[3] Applicable provisions on power system security have been moved to the SCTC as the appropriate code for power system security matters.

### 1.3.1 What do the GPS do?

The GPS describe the technical capability requirements for generators that, if met, mean the generator will automatically be connected to the power system. The GPS are the NT equivalent of the National Electricity Rules (NER) chapter 5 Schedule 5.2.

The GPS can be broadly grouped as:

- Capability to remain in continuous operation under prescribed system normal and abnormal conditions
- Capability to support power system security during abnormal conditions
- Meet a prescribed level of predictability and dispatchability.

Each of the GPS requirements whether meeting the automatic standard or a negotiated standard will be documented in the connection agreement (between the generator and Power and Water) and compliance must be maintained for the duration of the connection agreement.

The GPS provide the System Controller with the necessary supply side levers to manage power system security. However the GPS: do not describe how a generator is dispatched; do not describe power system security constraints; and do not rely on the presence or absence of an energy or ancillary services market.

The SCTC and SSG describe the framework for dispatch of generators to meet both system demand and power system security reflecting NT Government electricity market policy decisions for each regulated power system. The SCTC is the NT equivalent of NER chapter 3 and 4 (Market Operations and Power System Security).

### 1.3.2 What are we not updating?

Power and Water is not updating its processes for dispatching generation beyond what is required in terms of forecasting to accommodate intermittent renewables as discussed in this consultation process.[4] The methods of dispatch are an important consideration to maintain system security and to the economics of generators' current and prospective investments. They are thus relevant to many of the issues discussed in the GPS review consultation. However, they are unaffected by the proposed code amendments arising from this GPS review.

The revised GPS will continue to apply to all NT regulated power systems. This means their design continues to be fit for use with and without a competitive wholesale energy market.

## 1.4 Policy context and intent

These GPS address two important policy drivers:

1. Establishing fit-for-purpose NT regulatory instruments amid the transition of various aspect of NT energy regulation to the national regime, and
2. Implementing a key action from the NT Government's Roadmap to Renewables.

[4] Updates on both security and market dispatch arrangements are likely to be required in the future to facilitate competitive tensions between generators of varying technology in a secure manner.

It also seeks to support development of the NT electricity market.

### 1.4.1 Establishing fit-for-purpose NT regulatory instruments

On 1 July 2015, the NT Government introduced the National Electricity (Northern Territory) (National Uniform Legislation) Act 2015 (the Application Act), which transferred economic regulation of prescribed electricity networks from the Commission to the Australian Energy Regulator (AER), and provided for the adoption of the National Electricity Law, the NER and the National Electricity Regulations on 1 July 2016.

Consequently, the NT Government has been progressively applying the NER, with necessary derogations and transitional arrangements, through a series of reform 'packages' comprising regulations under the NT. Package 3, which includes the application of the NER Chapter 5 third party access framework, is scheduled to be in place by 1 July 2019, to align with the repeal of the NT Third Party Access Act.

Because related (NT and national) reform programs were ongoing during the development of Package 3, NER arrangements for power system security will not be applied in the NT in Package 3 and are to be deferred for consideration in a future NER application package. This includes the deferral of the consideration of:

- schedules 5.1a-5.3a which set out system and technical access standards,
- rule 5.3.4A which allows for negotiation of standards,
- system strength remediation rules including rule 5.4.4B, and
- the frequency, inertia and system strength rules at 5.20A-5.20B.

However, to ensure a functional framework, existing power system security arrangements in the NT will continue to be relied on. Where relevant, references to schedules 5.1a-5.3a and Chapter 4 are to be replaced with references to 'jurisdictional electricity legislation', as an interim measure.

As a result of these progressive changes, Power and Water must incorporate equivalent NT requirements fit for our NT power systems into the jurisdictional instruments (i.e. the NTC and SCTC).

We recognise that divergence from NEM requirements can create challenges for generators and generator proponents. Our GPS development approach has therefore been to adopt new standards based on the equivalent NER Chapter 5 Schedule 5.2 requirements, except where adoption in the NT would prevent System Control having the necessary levers of predictability and dispatchability needed to ensure power system security in the NT power systems.

In addition to the changes arising from the GPS review, Power and Water notes that the heads of power referred to in several places in the NTC and SCTC and SSG change with the repeal of the Electricity Networks (Third Party Access) Act 2000 (and the Third Part Access Code that is a Schedule to that Act) with effect from 1 July 2019. Where applicable, we have updated references in the NTC and SCTC and SSG to refer to the NT NER or Electricity Reform Act as appropriate.

### 1.4.2 Implementing the Roadmap to Renewables

The NT Government is undertaking a suite of reforms to promote renewable energy in the NT electricity supply industry, and to accommodate the growing number of proponents who have expressed interest in connecting to the NT power systems.

One of the short-term actions is to modify the network connection process to accommodate the characteristics of large-scale renewable technologies and increasing penetration of renewable energy while maintaining power system security and reliability. This action was specified in 4(c) of the NT Government's Renewable Energy and Electricity Market Reform Implementation Plan 2018-2020. Power and Water was assigned this action.

Among the key principles of the NT Government's Roadmap to Renewables are:

- a requirement to maintain energy security, reliability and stability during the transition to renewable energy, and
- a commitment to implement the transition while avoiding additional cost to customers.

This was reflected in the NT Government's response to the recommendations of the Roadmap to Renewables, wherein on the recommendation of policy alignment the NT Government stated:

> *While government will seek to utilise renewable energy, subject to its availability and ability to deliver secure, reliable and least-cost electricity, policy initiatives will need to be carefully managed to avoid unintended consequence such as price increases for other electricity consumers.*[5]

This guidance has informed our approach to this review as discussed in section 1.6.

### 1.4.3 How the GPS will fit in the NT Electricity Market (NTEM)

The GPS will affect the costs of generators seeking to connect to the system. Because these commercial drivers will affect generator's investment decisions, it is important that this round of GPS changes considers how the standards can support certainty over the foreseeable future.

We have therefore considered the two key phases of NT energy market these being:

- the Interim NT Energy Market or I-NTEM, and
- the future state NTEM.

Power and Water understand that NER arrangements for power system security are to be considered in a future NER application package and the NT Government may consider the incorporation of these GPS into Chapter 5 as schedule 5.2. We have therefore sought to establish standards that will avoid material change in the future consistent with the NT Government's NER adoption principles.

## 1.5 NT system context and consequences

To establish fit-for-purpose NT GPS requirements, their development must be firmly grounded in the physical realities of our power systems. These differ markedly from those in the NEM.

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[5] https://roadmaptorenewables.nt.gov.au/roadmap-to-renewables-expert-panel-report/government-response.

Some of the key differences to the NEM include:

- *Scale* | The size of individual generators as a proportion to the total system load is significantly higher in comparison to the NEM, which means a single generator can significantly impact system security. For example, in relative terms given the size of maximum demand between the NEM and the Darwin Katherine Interconnected System (DKIS), a 20MW generator on the DKIS is equivalent to a NEM generator of approximately 2,200MW -. This is three times larger than the largest single NEM generation unit (Kogan Creek - 744 MW). We note that some of the proposed solar farms in the NT are in the order of 50MW in size. Given their relative size these asynchronous generators present unique issues for NT system security.

- *No ancillary service market* | There is currently no market for power system security services in the DKIS and there is no intention to introduce a market in the Alice Springs or Tennant Creek systems.

- *No interconnection* | There is no interconnection to other geographically or energy source diverse markets, which means the NT systems have to be self-reliant for all system security requirements

- *PV is the dominant form of renewable generation* | The current pipeline of renewable technology is PV so there is limited diversity in energy source. Diversity from different generation sources will often result in generators naturally offsetting system limitations and energy intermittency, whereas our lack of diversity in renewable energy sources will mean our system cannot benefit from such off-setting effects.

- *Hydro is non- viable* | The NT terrain does not lend itself to long term hydro based energy storage technologies. In the NEM hydro is used for energy storage to offset intermittent sources. This is demonstrated by Tasmania's proposed 'battery for the nation' and Snowy 2.0, and underpins a lot of the NEM system security.

Power and Water operates the networks and controls the systems for three regulated power systems and operates the I-NTEM, which only operates on the DKIS.

The DKIS is the largest of the three regulated power systems in the Northern Territory. It supplies Darwin city, Palmerston, suburbs and surrounding areas of Darwin, the township of Katherine and its surrounding rural areas.

The Commission's 2017-18 Northern Territory Power System Performance Review (NTPSPR) reports that:

- The total generation capacity in the DKIS is around 476 megawatts (MW) across five power stations

- The fuel type of the generation units is made up of dual fuel (gas/diesel), gas only, heat recovery steam and landfill gas.[6]

The Alice Springs power system is the second largest power system in the NT. It supplies the township of Alice Springs and surrounding rural areas from the Ron Goodin, Owen Springs and Uterne (solar) power stations.

The Commission's 2017-18 NTPSPR reports that:

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[6] Commission, NTPSPR, (June, 2019) p.4.

- The total generation capacity in the Alice Springs power system is around 124MW across three power stations as summarised in Table 13.
- The fuel type of the generation units is made up of dual fuel (gas/diesel), diesel only, gas only and solar PV.
- The operational maximum demand in 2017-18 was 63MW.[7]

The Tennant Creek power system is the smallest of the regulated systems in the Northern Territory. This system supplies the township of Tennant Creek and surrounding rural areas from its centrally located power station.

The Commission's 2017-18 NTPSPR reports that the total generation capacity in the Tennant Creek power system is around 24MW, which includes three new Jenbacher generators. The fuel type of the generation units is made up of diesel and gas.[8]

### 1.5.1 How we run the system now

The way we currently maintain power system security reflects lessons from the past and our deep knowledge of the capabilities of the system. The current SSG was developed following a period of significant outages in 2014, and represent the results of collective learning about the levels of reserves required and reasonable contingencies management practices in our circumstances.

Two key requirements of the SSG relate to spinning reserve:

- A minimum of 25MW of spinning reserve
- A minimum of two Channel Island Frame 6 turbines spinning at 26MW or below, on different electrical points of connection.

These requirements were adopted following the December 2014 system black (and following a period of about 14 under frequency load shed events during the previous 12 months). Since that point the incidence of under frequency load shedding dropped to around 1 per year.

As our modelling conducted during this development shows clearly, the current SSG spinning reserve requirements will be unfit in a new industry with large amounts of intermittent generation, and we will need to transition to the more sophisticated approach based on managing Contingency Frequency Control Ancillary Services (C-FCAS).

With that said, for modelling purposes a base case needs to be taken and options reviewed against it, and hence we are using the existing requirements for spinning reserve contained within the SSG.

#### *Managing for credible contingency events*

Our system control practices have to recognise that the incidence of individual generator units tripping off-line is quite frequent – multiple times per week. A generator trip can be caused by a wide range

[7] Commission, NTPSPR, (June, 2019) p.32.
[8] Commission, NTPSPR, (June, 2019) p.49.

of incidents, and is one of the primary contingency events we manage from a secure system perspective.[9]

Although the SSG requires that a minimum of 25 MW of spinning reserve is held, due to the size of the generators in the system and their minimum safe loadings (and other constraints on operation), the system is actually generally operated with a higher level of spinning reserve – at an average level of around 40MW.

There have been occasions where short term changes in roof-top solar production were sufficiently large that had we been running at 25 MW of spinning reserve at the time, System Control would have had to take rapid action to avoid customer outages. As we discuss at length later in this document, as the level of solar penetration increases, the SSG will need to be significantly altered, and larger spinning reserves (or other similar contingency management actions) will be required. There is currently approximately 50MW of rooftop solar in the DKIS which is all asynchronous generation. The growth of rooftop solar has led to short term (< 5 minutes) large swings in demand. This has resulted in the spinning reserve requirements being breached on multiple occasions.

With increasing levels of large-scale asynchronous penetration, the risk of an unexpected output reduction on a PV generator due to cloud coverage occurring simultaneously with a contingency event on another generator becomes increasingly likely. This coincident event would likely cause significant disconnection of customers. A credible example of this would be if a synchronous generator dispatched at 30MW trips at the same time as a cloud causes a 25MW drop in an asynchronous generator's output. This would result in a 55MW drop in production and would (to a high likelihood) cause load shedding under the current spinning reserve arrangements.

If you take this to the extreme of the largest proposed asynchronous generator and the largest synchronous generator dropping output simultaneously, the system could see more than 90MW reduction in output.

We have conducted modelling to understand the risk and consequences as follows:

- We have conducted a simulation of 2017, using actual demand and offers from Territory Generation (T-Gen) and EDL units, and then included indicative asynchronous solar production (including solar forecasts) for the asynchronous generators that have applied to connect—totalling about 120MW in capacity.
- We have then looked at the number of daylight 30 minute periods where the SSG would have been breached[10] due to the error between the forecast and actual production for these asynchronous generators, at different levels of assumed forecast accuracy.
- It should be noted that this modelling provides 'best case' outcomes as it does not assume any relationship between the forecasting errors of different generators. The modelling outcomes further trend towards 'best case' outcomes by assuming that the additional spinning reserve above

[9] As opposed to managing network outages or the islanding of the system due to the 132 kV line, which are significant causes of customer events, but are not relevant events for the purpose of considering the SSG and new solar generation, given that such a network event will affect all generation in a similar manner.
[10] A breach in this case simply means that we had less than 25MW of remaining spinning reserve.

the minimum that was available in 2017 as a result of the size and merit order of dispatch of the existing generators continues.

- We have set out the results in Table 1.1.

Table 1.1: Percentage of Daylight Periods with SSG breach

| | | Percent of periods accurately forecasted | | | |
|---|---|---|---|---|---|
| | | 95% | 90% | 80% | 50% |
| Maximum Error Rate modelled | 5% | 0.76% | 1.52% | 3.42% | 6.84% |
| | 10% | 0.76% | 3.04% | 3.80% | 6.84% |
| | 20% | 1.52% | 3.04% | 4.18% | 13.31% |
| | 50% | 4.18% | 7.22% | 16.35% | 41.44% |

*Implications*

The above 'do nothing' analysis is simply illustrative because clearly Power and Water would not allow the increase in load shedding to occur from coincident forecasting errors and generator contingencies. It illustrates that relying on the current Spinning Reserve arrangements is not sufficient and we need to act now to ensure we have the levers to maintain power system security. The questions is: what should we do?

The fundamental issue is that we require high levels of predictability and dispatchability from all generators:

- To achieve high levels of predictability and dispatchability, we propose short term forecasting requirements on all materially large generators.
- We will aim over time to move to a C-FCAS based security management regime, which Power and Water has already foreshadowed in the SSG.
- We will require all generators to be capable of participating in the FCAS arrangements – this is already a requirement included in the proposed NTC 3.3.5.11 (generators need to demonstrate capability for all forms of FCAS).

## 1.6 Principles for GPS review

The code amendments that give effect to the generator performance standards must be approved by the NT independent regulator, the Commission. This process is outlined in section 2.1.

The Commission will consider our amendments under the *Utilities Commission Act*. Relevantly, section 6(2) of the Act states:

> *'In performing the Utilities Commission's functions, the Utilities Commission must have regard to the need:*
>
> *(a) to promote competitive and fair market conduct;*
>
> *(b) to prevent misuse of monopoly or market power;*
>
> *(c) to facilitate entry into relevant markets;*

*(d) to promote economic efficiency;*

*(e) to ensure consumers benefit from competition and efficiency;*

*(f) to protect the interests of consumers with respect to reliability and quality of services and supply in regulated industries;*

*(g) to facilitate maintenance of the financial viability of regulated industries; and*

*(h) to ensure an appropriate rate of return on regulated infrastructure assets.'*

The Commission has also relevantly foreshadowed in its 2016-17 Power System Review that it will:

> *'consider the cost trade-offs between GPS, ancillary services and network investment as part of its assessment of System Control's proposed GPS'.*[11]

In developing, consulting on and refining our proposed amendments we have considered these requirements and guidance, and pursued an approach that we consider will best achieve them. Indeed, several of these considerations are of key importance to the GPS we are developing and to how we have considered evidence and feedback in arriving at the proposed approach and remaining consultation options outlined in this paper. The table below explains what we consider to be the implications of these threshold provisions for our approach to this review.

Table 1.2: Complying with the regime that governs our code amendments

| Utilities Commission Act requirement | Implications and resulting principles for how we approach the GPS review[12] |
|---|---|
| Promote competitive and fair market conduct | The GPS should:<br>• Be technology agnostic as far as practicable and thereby not create market power for one generator over another based on technology<br>• Not raise the costs of subsequent renewable generators based on the treatment of first entrants i.e. not create market power based on the order in which proponents connect to the NT grid (i.e. beyond the competitive advantage that first movers may gain in a competitive market) |
| Prevent misuse of monopoly or market power | Poorly designed grandfathering for inflight renewable proponents could become a source of market power |
| Facilitate entry into relevant markets | Notwithstanding the necessary timing of this review, PWC is seeking to establish GPS that provide certainty to potential investors by taking a long term / "no regrets" view to establish a "Framework for the Future", through being<br>• Clear about obligations<br>• Forward-looking to support GPS that can be stable over the foreseeable future<br>• Transparent about the technical challenges in the NT system and the relative cost/viability of alternative options considered<br>• Intent on having standards in place prior to the connection of first mover renewable proponents |

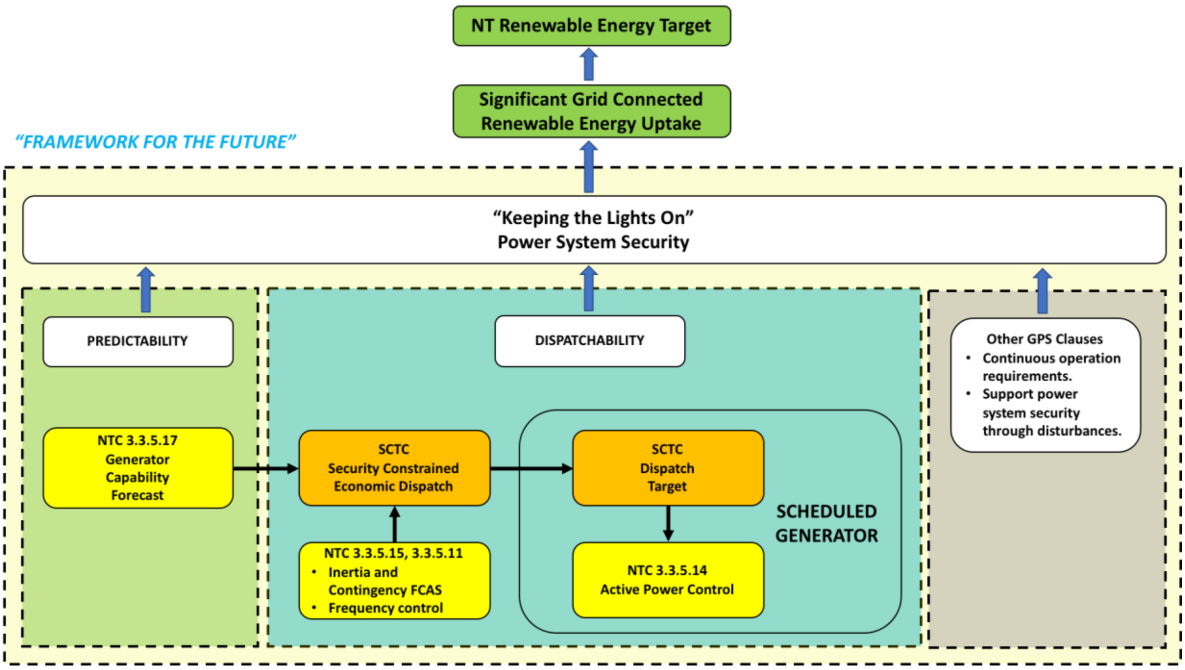
[11] Commission, Power System Review 2016-17, p. iv.
[12] These elaborate on the principles that have previously been presented in our public consultation.

| | |
|---|---|
| Promote economic efficiency | The GPS should support the lowest total cost of reliably providing energy whilst facilitating the connection of asynchronous renewable energy technologies<br>The total costs should be considered having regard to cost trade-offs between GPS, ancillary services and network investment<br>Risk should be placed with those best able to manage it |
| Ensure consumers benefit from competition and efficiency | Our Framework for the Future means we are facilitating renewable generation entry in a manner that minimises the total cost of reliably providing energy whilst facilitating a greater share of renewable generation |
| Protect the interests of consumers with respect to reliability and quality of services and supply in regulated industries | Our primary focus is keeping the lights on while facilitating increased connection of asynchronous renewable energy and storage technologies |

## 1.7 GPS framework for the future

The considerations in the preceding sections, their interrelationship with this GPS review and the instruments we are amending (including the specific clauses that relate to key issues covered in sections 3, 4 and 0 of this paper) are illustrated in the following figure. This framework for the future was the focus of our March 2019 Supplementary Consultation Papers and remains relevant to the content of this paper.

Figure 1.1: Framework for the future overview



# 2. What is the GPS review process and governance?

## 2.1 Framework for approving code changes

The framework for developing and approving changes to the instruments affected by the GPS is set out in the instruments listed in the table below.

Table 2.1: Powers and processes to amend GPS-related instruments

| Instrument | Source of power to amend | By whom? In what capacity? | Process required |
|---|---|---|---|
| Network Technical Code<br><br>NTC | Section 66A of the *Electricity Reform Act 2000*<br><br>NTC content stipulated in Schedule 2 of that Act | Power and Water in its capacity as **network provider**<br><br>Commission as regulator must approve | Network provider must: consult with Commission[13]; make publicly available details of the proposed amendments; and allow a reasonable time for persons affected to comment on the proposed amendments[14]<br><br>Network provider must change the proposed amendments if required by the Commission or regulator under the *Electricity Networks (Third Party Access) Act 2000*[15] |
| System Control Technical Code<br><br>SCTC | Section 38(1) of the *Electricity Reform Act 2000* - power to make SCTC<br><br>Content is set out in regulation 5A, *Electricity Reform (Administration) Regulations 2000* , also Commission ability to amend<br><br>Content and power to amend are also set out in Clause 15 of the PWC System Control Licence<br><br>Clause 1.8.2 in the SCTC sets out amendment process | Power and Water in its capacity as **system controller** (licensee)<br><br>Commission as regulator must approve<br><br>Commission may require amendment | Licensee *may* amend at any time, with the prior written approval of the Commission[16]<br><br>Licensee *must* amend if requested to do so by the Commission[17]<br><br>Licensee must consult with all electricity entities holding a generation licence, network licence or retail licence (or current market licence) when establishing and amending the Code[18]<br><br>Commission must not approve unless satisfied that the system controller has consulted with all electricity entities that are engaged in the operation of, contribute electricity to, or take electricity from, the power system[19]<br><br>System controller must publish consultation submissions when Code is approved[20] |

[13] Section 66A(4)(a)(i) of the *Electricity Reform Act 2000*.
[14] Section 66A(5) of the *Electricity Reform Act 2000*.
[15] Section 66A(4)(b) of the *Electricity Reform Act 2000*.
[16] Regulation 5A, *Electricity Reform (Administration) Regulations 2000*; clause 15.3 System Control Licence
[17] Clause 15.4, System Control Licence issued by Commission to Power and Water
[18] Clause 15.5, System Control Licence; clause 1.8(f) of the SCTC
[19] Regulation 5A(3) *Electricity Reform (Administration) Regulations 2000*
[20] Clause 1.8.2(g) of the SCTC

| Instrument | Source of power to amend | By whom? In what capacity? | Process required |
|---|---|---|---|
| Secure System Guidelines<br><br>SSG | Clause 3.5 of the SCTC | Power and Water in its capacity as Power System Controller | Can amend, vary or replace at any time, provided:<br>- Must consult first with System Participants[21]<br>- Must take into account government policy, system controller's statutory obligations, historic levels of reliability, and costs & benefits[22] |

Power and Water has met the content, procedural and consultation requirements specified above.

Consultation is summarised below and Appendix A.

## 2.2 Our consultation process so far

The consultation process to date for incorporating the GPS in the NTC and SCTC (the codes) has included:

- 18 December 2018 – Release of the proposed changes to the codes and overarching consultation paper;
- 18 February 2019 – Public information session held for stakeholders on proposed code changes;
- 22 February 2019 – Extension of consultation period to 8 March 2019;
- 6 March 2019 – Extension of consultation period to 29 March 2019;
- 12 March 2019 – Release of a supplementary consultation on removal of semi-scheduled generator classification and capacity forecasting; and
- 20 March 2019 – Release of a supplementary consultation on contingency FCAS (C-FCAS) / Inertia proposed standard.

Power and Water acknowledges and appreciates the effort of stakeholders in making submissions to the proposed Code changes. Power and Water has reviewed each issue raised and has structured this document to systematically respond to those issues. We have attempted to group like issues raised by stakeholders and respond accordingly wherever possible.

## 2.3 Feedback received

We have received 13 submissions from ten stakeholders since we commenced consultation in December 2018. These are available on our website, except for those which a stakeholder has claimed contain confidential information.

[21] SCTC clause 3.5.3
[22] SCTC clause 3.5.4 (a) to (d)

There are four main amendments that have raised significant stakeholder interest which this paper addresses:

- Capacity forecasting – section 3
- Removal of the semi scheduled generator classification – section 4
- C-FCAS – capability vs provision – section 0
- Grandfathering – existing connected generators and generators under construction – section 6.

There were also a range of further items raised which we have prepared Appendix A to address. This appendix discusses:

- Issues associated with our proposed code changes that have now been addressed
- Issues that are not within the scope of this review but where we have accepted the code change
- Issues that have been deferred for consideration in a future review of the Code requirements
- Issues that stakeholder have raised which relate to policy matters and which we have shared with the relevant NT Government agencies.

## 2.4 How we have considered stakeholders' feedback

Our consultation to date has provided a wealth of feedback and helped to target our further work on stress testing and refining the options we've considered and our proposed standards. In this section we explain how we have assessed the key issues.

In preparing for this round of consultation we have sought to take stakeholder feedback and our further research and analysis and adopt a common assessment framework for considering the remaining key issues. The framework examines for each issue:

- *What problem the GPS must address* | We explain what the GPS are seeking to address so that stakeholders can understand the risk, cost and materiality of the issue that the proposed generator obligation (or other solution) responds to and how commensurate the response is
- *Our current proposed solution* | We outline our current view of the optimal solution based on feedback and analysis to date
- *Feedback received* | We provide an issue-based summary of stakeholder views and our responses to these
- *Engagement questions* | We outline the questions we seek further submissions on and hope to discuss at the workshop.

Where relevant we present in our problem statement, solution or response to feedback the further analysis we have undertaken, including:

- options considered
- clarifying questions we have sought to answer
- evidence prepared and reviewed

- assessment against the principles set out in section 1.6
- assessment against for future proofing, by looking at the options and their implications under the I-NTEM and our current understanding of the future NTEM.

## 2.5 Purpose of this further round of consultation

Our consultation to date and further analysis has moved our thinking. This further round of consultation seeks to provide a standalone record of what we are now proposing for the GPS and why.

We have listened and refined our proposals, and we now need to finalise the NTC and SCTC amendments and submit them to the Commission for approval to ensure they remain timely for investors. This means this further round of consultation has two key purposes. We are seeking to:

1. Test whether the proposed GPS obligations are understood, and
2. Test if there is relevant evidence we have not considered, particularly in terms of the things the Commission must assess when approving any code changes as outlined in Table 1.2.

Test whether the proposed GPS obligations are understood, we will host a workshop for all interested stakeholders on 26 June from 10am to 4pm at the Darwin Innovation Hub (Level 1/48-50 Smith St, Darwin). You can register for this workshop by emailing market.operator@powerwater.com.au.

The workshop will walk stakeholders through the current context of this review, key issues arising from stakeholder feedback and our amended proposals for the GPS. We will present for discussion case studies and technical examples that illustrate the key concepts that underpin the GPS requirements and which address our stakeholders' feedback.

To enable stakeholders to present any further relevant evidence that we have not yet considered, we invite submissions by **19 July 2019**. These should be emailed to market.operator@powerwater.com.au.

Where the workshop and submissions reveal areas where the obligations remain unclear or misunderstood, we will provide further explanation in our public code change proposal to the Commission.

## 2.6 Summary of engagement questions

The overarching engagement questions are:

**1. Are the requirements arising from the propose code amendments understood?**

**2. Having regard to the framework that will govern the Commission's approval of the code amendments (see Table 1.2), do stakeholders think there are any other viable options that Power and Water hasn't yet considered? If so, what is the option and what evidence can you provide to show that this is viable?**

The issue-specific engagement questions are:

**3. Do you understand the difference between an energy and a capacity forecast?**

**3. Do you believe that providing a dispatchable offer at 30 minutes ahead and a firm offer at dispatch time would make your project non-commercial? Where do you believe the costs of securely managing commercial scale asynchronous generation uncertainty should be borne?**

4. **Does the forecasting obligation as drafted in the proposed code, provide sufficient clarity on the obligation? If not, please provide suggested amendments.**

5. **Do you understand the factors that differentiate the feasibility of having a semi-scheduled generator classification from those present in the NEM and WEM?**

6. **Do you understand the terminology used to describe the capability, enablement, provision and delivery of C-FCAS?**

7. **Do you believe the droop characteristic will introduce additional cost to your project? How material is this?**

8. **Do you believe all generators should contribute to providing a C-FCAS/Inertia safety net for customers?**

9. **Would you be interested in providing and delivering C-FCAS services if a market/competitive mechanism were introduced?**

10. **Have the revised code amendments provided sufficient clarity on the grandfathering arrangements?**

## 2.7 Timeline to implementation

Power and Water is working to have standards in place in time for first mover renewable proponents' connections to the power system. The next steps are:

- Receive stakeholder submissions – 19 July
- Review and update NTC and SCTC amendments – July-August
- Submit proposal for code amendments to the Commission – September
- Commission performs its review – October
- Updated codes take effect – subject to Commission approval.

# Part B | Statement of approach to key issues

We identified four key issues from the previous consultation process requiring detailed response, namely:

- Forecasting requirements
- Removing the semi-scheduled generator classification
- Treatment of C-FCAS capability
- Grandfathering provisions.

In this part we discuss each of these matters in depth.

## 3. Capacity forecasting requirements

### 3.1 Problem the GPS must address

The DKIS has a relatively old existing generation mix, with 42.7% of the electricity generated in the DKIS coming from gas generation plant that is in excess of 30 years old.[23] Unlike in the NEM, where there is a significant diversity of energy forms (hydro, natural gas, solar, wind, coal, and others), in the NT power systems only natural gas and solar present near-term viable options, and within a relatively narrow geographic range.

Whilst in the NEM there is a wide diversification by location and renewable generation type between wind and solar (and hydro), that is largely lacking in the NT regulated power systems, including the DKIS. There is no significant wind resource, and whilst the climate is at certain times of the year conducive to solar (with long periods of relatively uninterrupted sunlight), at other times the production from solar is highly variable, due to both localised and widespread weather patterns (such as clouds and rain). Other forms of renewables (for example, tidal or geothermal) appear to have significant resource, but face issues of economic and technical viability in the near term.

We must plan for managing our power systems where a significant component of the generation is asynchronous solar. Indeed, to meet the 50% renewable energy target, we must plan for managing our power systems where potentially more than 100% of the system demand is being delivered by asynchronous energy at points of the day, with surplus being stored for later use.

Under this assumption, asynchronous renewables are no longer the “new technology”, but are in fact for significant periods of the time the backbone and dominant energy source for operating our power systems. Within this paradigm it makes little sense to create the “default” rules for “traditional” (gas) generation, and to then depart from those requirements as required to enable asynchronous “new entrants”. This for example was the original thinking in the NEM behind the creation of “semi-scheduled” generators as a separate class from “scheduled” generators – being that this represented a small departure from “the norm” of scheduled fossil fuel generators that was reasonable given the marginal and then relatively immaterial role of renewables at that time. In this new environment, renewables will now be the dominant form of generation at many times.

[23] Commission, Northern Territory Power System Performance Review 2017-18, (June, 2019), p.11.

The GPS must therefore allow System Control the ability to manage our power systems where a large majority of energy is coming from asynchronous generators, and under this circumstance managing the inherent operational variability of solar energy production becomes critical.

This management of the inherent operational variability is a different issue to the management of contingencies, which concerns how to plan for the inevitable unexpected events that occur–for example, a generator (solar or gas) "tripping" off-line unexpectedly due to equipment failure.

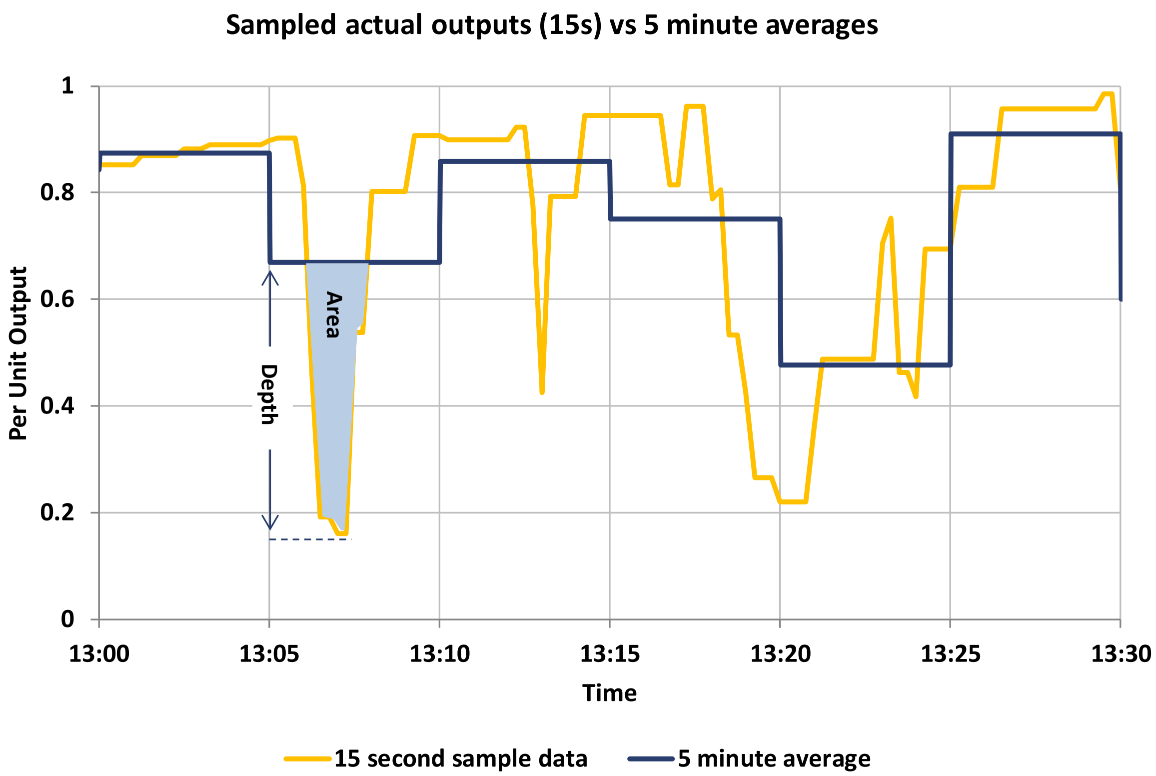
There are two forms of operational power output volatility we are seeking to manage:

- *Short term output volatility* | Power swings within a 5 minute period, which must be managed by arrangements that are already in-place and operational (such as spinning reserves, battery storage, or other firming arrangements), since this timeframe is too short for additional generating plant to be brought on line.
- *Medium term output volatility* | Changes slow enough to be included in a pre-dispatch/dispatch process – meaning on a time scale in the order of 30 minutes

### 3.1.1 Managing short term power output volatility

For example, Figure 3.1 shows the instantaneous (on a 15 second basis) power output (blue line) from an **actual** solar generation facility (in per-unit or 'PU' terms – meaning "1" represents 100% of possible output), compared to the 5 minute average power output (the orrange line).

Figure 3.1: Solar output comparison




It can be seen for example that between 1:05pm and 1:10pm the average power generated was around 0.67PU, however after starting at a PU output of 0.9, subsequently for a period of around 2 minutes the instantaneous power was as low as 0.18PU.

To put this in numerical terms, if this were a 100MW rated solar farm, the power output would have started at 90MW, and then dropped by about 80MW (to about 20MW) over a period of 1 minute, before recovering to around 90MW by the end of the 5 minute period. This scale of short term power swing (moving from 90% rated output to 20% rated output and back) must be considered in the context of there being around 120MW of asynchronous solar farms applying for application in the DKIS, and with an expectation of further solar farms making applications.

In addition to large stand-alone solar farms, there is also currently in the order of 50MW of "behind the meter" roof-top solar that has already been installed in the DKIS area, with residential roof-top solar installations expected to continue to increase.

Whilst we do not have detailed production metering for these roof-top panels (and so cannot clearly identify the exact aggregated scale of the power production swings), it is clear from the wholesale demand observed on the system that similar swings in production are occurring. These kinds of sudden changes have on occasion already challenged the System Controller's ability to maintain the stability of the DKIS, because we see significant demand "drop" on or off the system as clouds move through the Darwin area in a period of minutes.

System Control is itself now procuring solar forecasting services to provide information on a real time basis about this. However, with no requirement for firming on these roof-top units in the short term, they will present a growing challenge from an overall system control perspective.

The nature of the challenge is further complicated due to the relatively small number of existing gas generators in the DKIS which, for a range of reasons, are experiencing a large number of trip events where a generator has dropped off-line unexpectedly. The Commission reported 98 separate generation trip events during 2017-18.[24] These issues are separately being addressed, but remain an operational reality.

Accordingly, to ensure that consumers are not exposed to load-shedding, System Control plans on the basis of meeting a contingency event where:

1. not only has solar production momentarily dipped (not itself a contingency event),

2. but that at that same moment a generator trip event (a contingency event) occurs.

This can be particularly important in the circumstances where we are running gas generators specifically to provide support services to the solar production. At these times, if a generator trip occurs there can be relatively little other "spinning reserve" immediately in the system.

This is currently done by way of the SSG's spinning reserve requirements. Although as we have noted in this document, these spinning reserve arrangements will rapidly become inadequate as asynchronous solar penetration increases. Hence over time we are proposing to move to a more sophisticated C-FCAS arrangement. This change in arrangements is not part of the current GPS arrangements, but has been previously flagged and will be progress by Power and Water.

Under the proposed GPS arrangements managing the short term power volatility will involve requiring all generators to provide System Control a firm 5 minute **capacity** offer at dispatch time, which is the

[24] Commission, Northern Territory Power System Performance Review 2017-18, (June, 2019), p.8.

minimum level of power output that the generator can supply **continuously**[25] during the coming 5 minutes.

### 3.1.2 Managing medium term power output volatility

System Control can manage power output changes that occur on the timescale of 30 minutes by starting additional generation plant. The existing generation mix in the DKIS is primarily gas turbine based. Whilst there is some variation, it generally takes approximately 30 minutes to start an NT gas turbine and have it available to contribute to meeting demand. This is the practical minimum when allowing for the time required for human decision making as well as resolving any immediate issues that may occur as a given turbine is started.

In operational terms, System Control must observe multiple timeframes – considering a week ahead any known maintenance or other plant outages, and then a day ahead having a proposed set of dispatch arrangements to meet forecast load. The current system operation – and the possible need to start or stop plant - is then closely observed about an hour ahead, with final dispatch instructions being made 30 minutes ahead, and any "starting" issues being finally resolved during that last 30 minutes.

The proposed GPS arrangements are thus intended to be consistent with, and support this timeline, having a requirement for capacity forecasts from all generators on a weekly and daily basis, and in particular a rolling-5-minute capacity forecast, with an accuracy requirement being applied for the last 30 minutes ahead of dispatch.

### 3.1.3 Modelling work to inform decision making

System Control has been conducting a range of forward looking economic dispatch modelling of the DKIS under scenarios where there are high levels of asynchronous solar penetration. These models are informing the proposed arrangements in this consultation paper.

In particular we have obtained solar forecast information for the approximate 10 locations where there are proposals to construct solar farms, and using that information estimated half-hourly production data for each site. We have then run a security constrained economic dispatch model of the system across a simulated year on a half-hourly basis using the actual 2017-18 electricity demand, and the actual availabilities and offer behaviours of the existing generation plant during that year. This enabled us to explore how the system would be dispatched in a manner that is secure when having various levels of solar farms in the generation mix.

We have then modelled how various levels of forecasting accuracy from solar farms affects how the system is likely to perform and needs to be dispatched. This modelling informs the proposed forecasting accuracy requirements.

[25] This is discussed further in the next section, but in summary, "continuous" here means "at the measuring resolution of the Power and Water systems, nominally SCADA", which is about 15 seconds. So a firm offer of "10MW" given at dispatch time really means "I can generate at least 10MW for every 15 second period over the next 5 minutes". Additionally, high speed data recordings may be used on an ad hoc basis where sampling frequency of SCADA is insufficient.

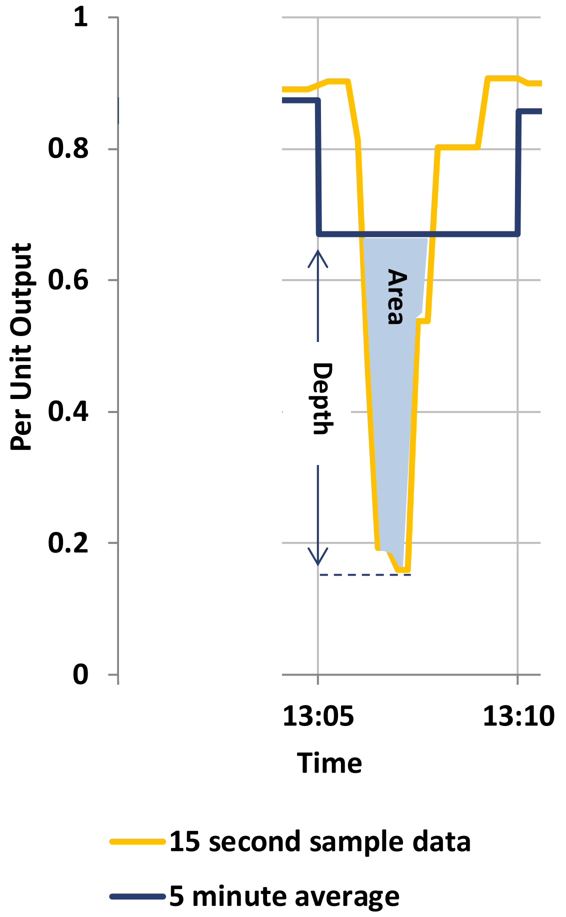
## 3.2 GPS forecasting requirements

### 3.2.1 Capacity or energy forecasts

The proposed requirement is for **all** generators to provide a **capacity** forecast, on a rolling 5 minute basis for 24 hours ahead. We are also requiring a one week ahead forecast on a 30 minute basis. The forecast is proposed as a **capacity** forecast.

Figure 3.2 provides an extract from Figure 3.1 shown previously which gives illustrates instantaneous power compared to the 5 minute average.

Figure 3.2: Solar output comparison




**A capacity forecast means forecasting a level (for example the orange line[26]) to which the generator is prepared to manage their output for the 5 minute period, continuously supplying this level within the period.** That is, a level at which the blue line will **never** fall below the orange line.

For solar generators, this implies that they need to have some form of smoothing for dealing with the short term power swings (the "depth"). In the example, a battery that charged when the blue line is above the orange line, and discharged when it is below. In energy terms, smoothing required is represented by "the area" as shaded in Figure 3.2.

[26] This was the average energy production in Figure 3.1, but here it is used to illustrate a minimum capacity forecast

We are requiring that all generators manage (either themselves on-site, or in some other manner) the short term power swings such that the instantaneous power does not drop below the 5 minute forecast provided at dispatch time.

We anticipate that for a solar farm providing this generation capacity forecast is likely to involve a mix of inputs including:

- A solar forecast – possibly obtained by the generator from a 3rd party - which forecasts the level of solar energy being received
- A risk management model for that farm – presumably specifically developed by the farm itself – which takes into account the historical performance and known maintenance and other factors of that farm
- Some form of energy storage or smoothing to enable the short term power flows to be managed to the 5 minute forecast level.

### 3.2.2 Why do we need PV capacity forecasting?

The large instantaneous variations in production need to be balanced somewhere in the system, and cannot be solved using solar forecasts with a 5 minute resolution.

There are two separate but related issues that need to be managed:

- Short term (within 5 minute) stability due to instantaneous power variation.
- Medium term (within 30 minute) stability issues due to forecast generation (being used to commit to starting machines on a 20-30 minute lead time) not matching actual generation when dispatch occurs.

For a level of solar penetration up to around 50MW our modelling suggests this is mostly of issue in managing a contingency (eg: a generator trip) that occurs at the same time that a forecast proves to be inaccurate.

For example, a solar forecast proving inaccurate and a fast start-turbine failing to start in the same 15 minute period.

We also aim to minimise the amount of generation running at minimum load to provide spinning reserves, since this does impose a significant cost on the system.

As the amount of asynchronous solar generation on the system increases, in the absence of output smoothing providing a capacity forecasts, we will face larger and larger short term power variations on the system. This presents issues for:

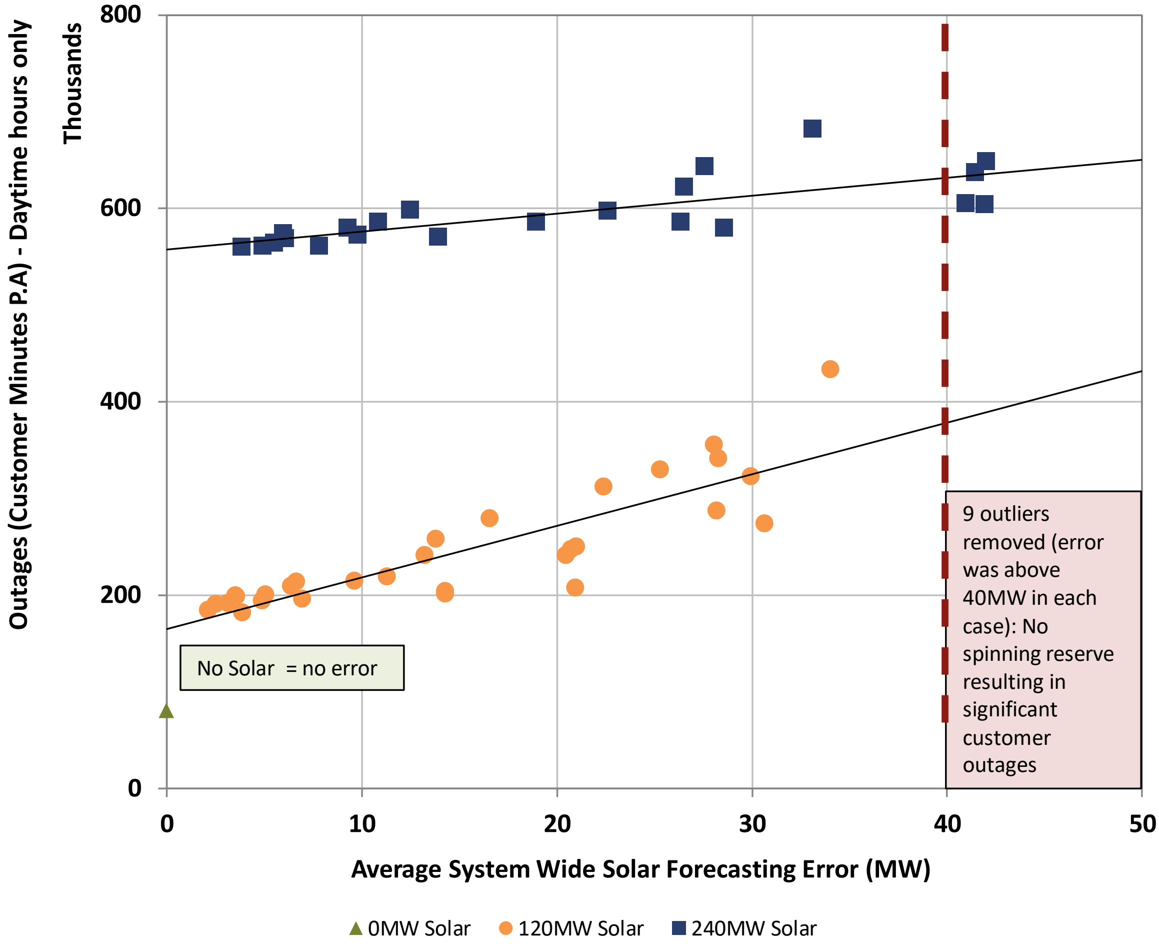
- Contingency management.
- Voltage control and frequency control
- Network capacity/operation

The existing modelling work shows clearly that as the level of asynchronous generation on the system increases, using the existing SSG requirements becomes more and more unworkable.

Modelling that **assumes** using the existing SSG requirements to manage the system (shown in Figure 3.3) shows clearly that as the level of asynchronous generation increases, the level of customer outages increases by multiple times, and also becomes worse as the level of forecasting inaccuracy increases.

This is not to say that relying on the existing SSG is the anticipated position. It does say that the manner in which the system is managed must be fundamentally changed from the current arrangements as higher levels of asynchronous solar generation are achieved.

Figure 3.3: Solar forecasting error versus customer outages – from single contingency events




## 3.3 Our current proposed solution

### 3.3.1 Requiring capacity forecasting

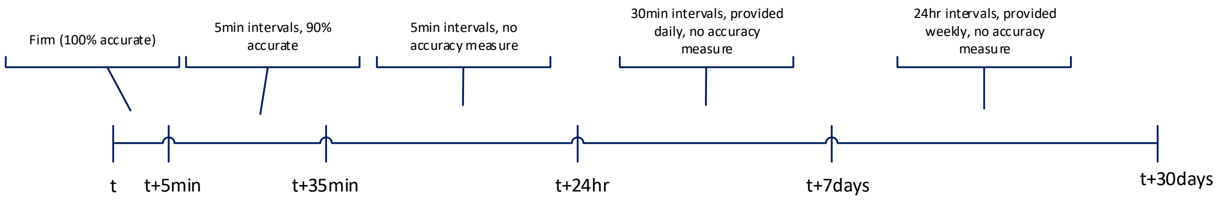
Our proposed forecasting requirements – which would apply to all generators – and the interactions with the dispatch process are summarised below and illustrated in **Error! Reference source not found.**.[27] All generators are to provide

- A rolling 5 minute ahead capacity forecast for 24 hours in 5 minute intervals

[27] In the following the term “t” means “the time at which physical dispatch instructions for the next 5 minutes occurs”.

- A rolling 7 day ahead forecast for capacity in 30 minute intervals, updated daily
- A rolling 30 day ahead forecast for capacity in daily intervals, updated daily.

Figure 3.4: Timeline of forecasting requirements

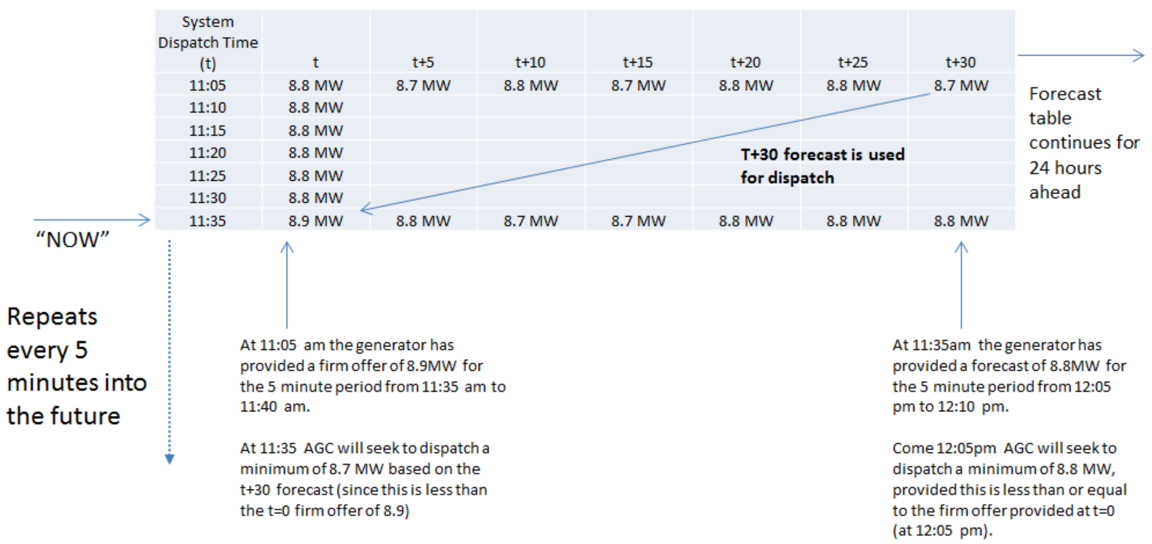



Notice that the forecast provided at t+30 is used in the pre-dispatch decisions, and is the basis on which decisions about the mix of generation to be started and operated are made. It is this quantity that will (potentially) be dispatched at t=0.

In our example below, at 11:05 am the generator forecast provided a 30 minute ahead forecast of 8.7MW for the 5 minutes from 11:35 am to 11:40 am.

However at 11:35 am the generator now indicated that their capacity was in fact 8.9MW. In this case they would (normally) be dispatched to 8.7MW.

Figure 3.5: Forecasting example




The t=0 forecast provided is treated as a **firm offer** of capacity. This means that the plant may be dispatched up to this level, although under normal arrangements it would only be dispatched to the level provided in the t+30 forecast which was used in the pre-dispatch process.

Any additional capacity offered at t=0 may be applied by the system controllers to meet contingency events.

Once a dispatch instruction is sent (at t=0), the plant is expected to meet the dispatched level for every 15 second period within the 5 minute period.

Failure to achieve this means that in future periods dispatch may be de-rated compared to the t+30 forecast and t=0 offers provided by the generator.

### 3.3.2 Relevant code provisions

NTC 3.3.5.17 – capacity forecasting. SCTC 3.11.1.

## 3.4 Is it technically feasible and cost effective for PV generators to provide capacity forecasts?

For a solar generator, providing a capacity forecast is not simply on-providing to System Control a solar (insolation) forecast obtained from a 3rd party (possibly from using satellite imagery and sky cams).

It is instead the combination of such an insolation forecast with knowledge about the actual exact performance of that solar farm, any maintenance or other outage issues, and the capabilities of either on-site firming or firming provided by commercial partners. There is considerable scope for technical and commercial innovation around how to improve the accuracy of forecasting of all these aspects, and both because of the information asymmetry (individual owners will always know the capabilities of their plant and their arrangements better than outsiders), and to structurally promote innovation, it is our view that these requirements best sit with the individual generation operators.

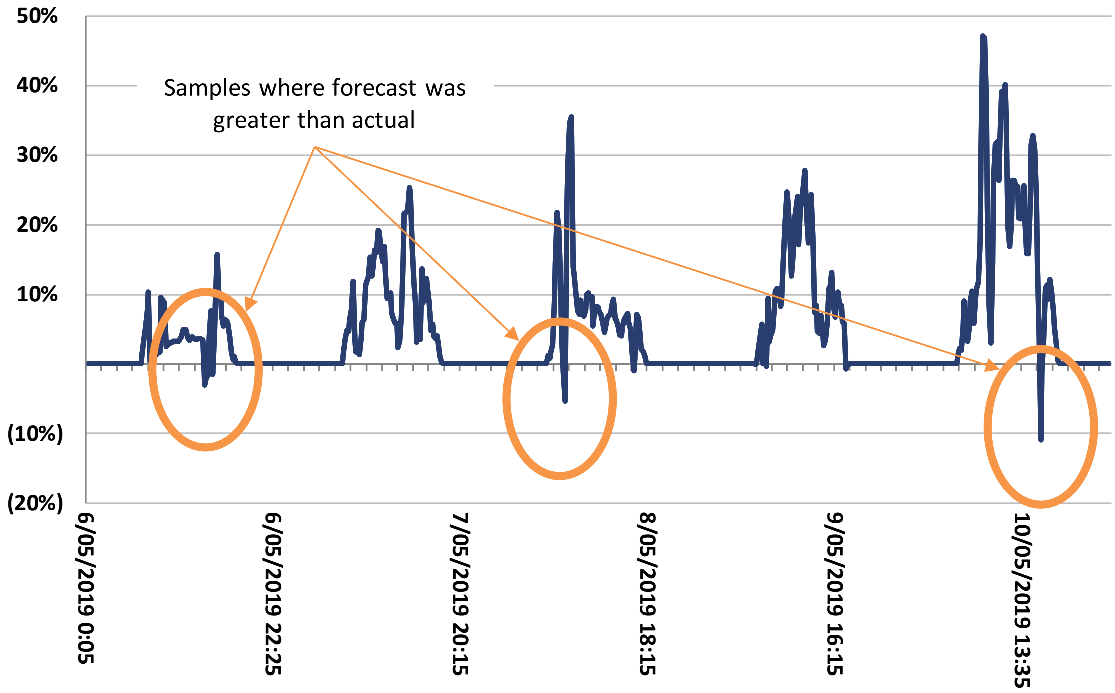
There is clearly no informational barrier about a generator knowing the internal capabilities of their own plant, and of any commercial arrangements that may have been put in place, and so there is no doubt about the ability to meet the proposed accuracy forecast in respect of this component of the capacity forecast.

There is a question about the ability of the insolation part of the capacity forecast to meet the required accuracy.

In considering this we have reviewed solar (insolation) forecasts prepared by two third party providers for multiple sites in the DKIS. Some of our analysis is shown in Figure 3.6, where we have compared the size of the forecast insolation error. In this graph the data included 5 typical wet season days and 5 typical dry season days. On a 30 minute ahead basis only in a very small number of forecast point was the forecast greater than the actual output (which on this sample size represented 5% of the samples).

In the other 95% of cases the 30 minute insolation forecast was less than or equal to the actual production.

Figure 3.6: 30 minute forecasting error




At this time we are proposing to only place an accuracy requirement on the performance of the sub-30 minute ahead forecasts, being that 90% of rolling 5 minute forecasts provided in the 30 minutes before dispatch must be less than or equal to the actual capacity at dispatch time.

On the basis of our review of the data, we believe that there is no technical barrier to forecasting to the required level of accurate 90% of intervals, and within 5% of power production for the remaining 10% of intervals. We note that within the sample sets we reviewed there was 1 period that exceeded the error threshold.

To manage the transformation from a solar forecast to a capacity forecast is likely to involve using smoothing services from a small amount of battery storage or generation. To verify that this requirement is not overly onerous we have conducted some analysis of the amount of energy storage required to achieve this short term smoothing. Our desktop analysis suggests that on reasonable assumptions such a smoothing requirement could be achieved with in the order of 0.2MWh of storage capacity for each 1MW of installed solar capacity (on an assumption of the battery being oversized somewhat to allow for the relatively high instantaneous power flows). This is a relatively small battery, and we anticipate on the basis of our desktop research into pricing would not increase the capital cost of the farm beyond the point of economic viability.

An independent consultant's review of the proposed standard supports this analysis:

> "Forecasting requirements proposed by PWC have been assessed by Entura for their implications on solar PV generators. Entura supports the view that mature technical solutions are available to meet these requirements. Likely cost (or revenue) implications for generators is estimated in the order of about $320-480/kWac of PV installed or 20-30% of

the cost of the solar PV plant, plus a similar ratio of ongoing operations and maintenance cost."[28]

## 3.5 Why this level of forecasting accuracy?

System Control has conducted a series of simulations including from 50MW up to 250MW of solar generation into the generation mix, and examining the resulting system wide impacts on the levels of spinning reserve required and probabilities of forecasting inaccuracies leading to customer outage events.

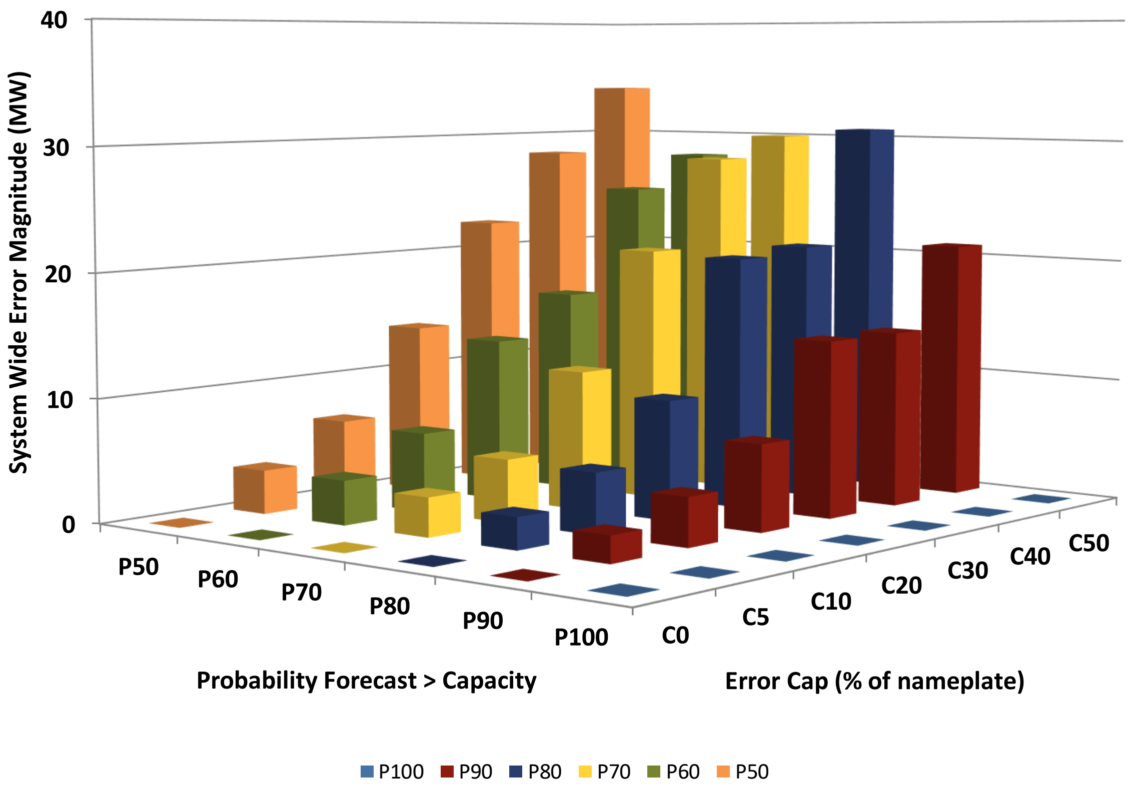
Taking the case considering the current solar farm applications (totalling around 120MW), we found the relationship between the number of daylight 30 minute dispatch periods where the SSG were breached, and the accuracy requirement on the solar capacity forecasts to be as shown in Table 1.1: Percentage of Daylight Periods with SSG breach on page 15 above.

The coloured cell in Table 1.1: Percentage of Daylight Periods with SSG breach represents the proposed accuracy standard. It is observed that the number of periods where the SSG are breached due to inaccuracy in provided forecasts increases rapidly as the accuracy requirements are decreased.

A similar message can also be seen from looking at the largest estimated MW error in forecasting that is propagated onto the network at different levels of forecasting accuracy requirement on individual generators. This is presented graphically in Figure 3.7 – where again the proposed accuracy standard is coloured green, and is based on the case of all currently proposed solar farms proceeding (totalling about 120MW of installed solar capacity)

[28] See Appendix C, section 4, p.7.

Figure 3.7: Forecasting accuracy, worst error




## 3.6 Why is this standard different to the NEM?

The NEM is a much larger electricity market than the NT market, and has a much larger diversity of fuel sources, generation types, and geographical distribution. Even so, with increasing penetration of renewables the GPS in the NEM are now evolving in directions consistent with those adopted in these proposed standards.

## 3.7 Must the required smoothing be provided at each generator?

No. We intend to set a technical standard for the firmness of offers provided to the market, and not to constrain the manner in which any required smoothing is achieved.

For example, a group of generators could engage an outside party to provide firming capability, be that via a centralised battery or providing additional spinning reserve generation, or in some other manner. The proposed solutions would need to be demonstrated through the negotiated connection process.

However our analysis of the following options suggests that the most likely economic response will be at (or near to) the individual asynchronous generation sites:

### 3.7.1 Option – have onsite (or near-onsite) firming

Under this option a solar farm has small on-site batteries for providing firming within 5 minute periods, or other local firming arrangements (possibly shared with other local generators).

This on-site option allows for a relatively small capacity battery on the DC side of the plant, before the existing inverter.

- Based on public information, we estimate this firming capacity would require around 0.2MWh of battery for each MW of installed solar.
- No additional network augmentations are required
- No additional inverter is required

Accordingly we consider (using public information) that this is likely to be the least cost option.

### 3.7.2 Option – firming from existing gas turbines

Under this option a solar farm would contract for an existing generator to cover any these short term variations

We note however that:

- Existing synchronous generators are not designed to accommodate ramps of 10-20MW over ~1 minute as a regular event, and that is probably the required scale of operation as we move to having 100MW + of solar in the DKIS.
- Network stability and transfer limits mean that additional network augmentation is likely to be required, and this will need to be paid for by someone.
- Generation capacity used for this purpose cannot also be counted for C-FCAS or spinning reserve purposes.

However as long as their effectiveness can be demonstrated, there are no barriers to individual parties negotiating these arrangements under NTC 3.3.5 should they wish to do so.

### 3.7.3 Option – Centralised battery

Under this option a solar farm arranges for a centralised battery owner to inject/absorb from the grid the instantaneous unders/overs of production within the 5 minute period from owners to cover any of these short term variations, in a manner that satisfies System Control.

We note however that:

- A centralised battery for managing these short term variations requires a relatively large inverter (and a relatively small battery), which will be a significant cost due to relative size of storage required for short term variation management.
- Using public data we estimate the additional costs of doing this service using a centralised battery to be in the order of a 20% premium compared to the "on site" firming. This additional cost is mostly in the need for a dedicated high-capacity inverter.
- As with using turbines, the centralised approach raises issues of network stability and transfer limits (with the likely result that additional network augmentation would be required).

However as long as their effectiveness can be demonstrated, there are no barriers to individual parties negotiating these arrangements under NTC 3.3.5 should they wish to do so.

## 3.8 Responding to specific feedback received

The requirement for capacity forecasting appears to be one of the biggest concerns for stakeholders. Based on feedback we understand that this is likely to be due to the key differences in approach to the NEM being that we require a capacity forecast rather than an energy forecast and that the obligation has been placed onto the generator rather than sitting predominantly with the market operator.

### 3.8.1 Capacity forecasting vs solar forecasting

We observed that a number of stakeholder submissions were centred around solar forecasting capability. Having read the feedback in a number of cases we are of the view that we may not have adequately explained that our requirement for capacity forecasts are driven by managing power system security in the context of the NT power systems (and hence relate to forecasting generator capacity) rather than the limitations of solar forecasting technologies.

> *"Short term (1 - 20 minutes) forecasting can be provided by on-site cameras and satellite forecasting. This can be fairly accurate as per the document. However, beyond that timeframe the accuracy possible to provide to PWC reduces drastically ……. notes that the required forecasts and accuracy within this section may be difficult to meet, even with advanced forecasting methods."*[29]

We also acknowledge following discussions with AEMO and solar forecasting companies that the requirement of a capacity forecast (rather than a 5 min resolution insolation based forecast that is effectively an energy forecast) is a new concept.

> *"Requirements are too onerous"*[30]

As a corollary to the solar vs capacity forecasting issue, stakeholders expressed concerns about the cost effectiveness of achieving the requirements through solar forecasting technology alone or having to supplement solar forecasting equipment with energy storage technology.

> *"…..requirements as currently proposed are too demanding."*[31]

Following discussions with AEMO and a number of solar forecasting companies (and having independently obtained solar forecasting data for a number of sites in the NT and statistically examined it), we have concluded that there are significant issues accurately forecasting insolation beyond about 30 minutes. Accordingly, Power and Water has taken the approach of applying the accuracy requirements on forecasts provided only for the period 30 minutes ahead of dispatch.

Given the time required for making dispatch decisions and for equipment to be started and brought on line (being not much less than 30 minutes), having reliance only at the 30 minute mark on forecasts provided by solar farms will place significant operational challenges on the dispatching and system control processes.

Based on our modelling, and the practical issues involved, we consider having a 90% reliable forecast of available generation at 30 minutes ahead to be the lower workable limit.

[29] Epuron submission 29 March 2019

[30] Multiple submissions gave this feedback, including: Epuron, NT Airports, confidential submission, Tetris, T-Gen, NT Solar Futures.

[31] Multiple submissions gave this feedback, including: Epuron, NT Airports, confidential submission, Tetris, T-Gen, NT Solar Futures.

We are however also still requiring that a 24 hour ahead 5 minutely forecast be provided, and we will be closely observing the information this gives us.

Noting the close relationship found in the modelling work between the amount of intermittent generation in the system, the allowed size/frequency of forecasting errors, and the need to make dispatch decisions, it may well be that as the level of solar in the DKIS rises that accuracy requirements may need to be applied further ahead. However, no decision or plans to do this currently exists, and it will be assessed as part of a future refinement.

### 3.8.2 Who is best placed to provide capacity forecasts?

T-Gen raised the prospect of placing the forecasting obligation on System Control as per the NER 3.7B which requires AEMO to develop unconstrained intermittent generation forecast (UIGF) for each semi scheduled generator.

> *"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."*[32]

Comparisons were also provided by Tetris and Epuron regarding the nature of the forecasts in the NEM.

> *"Reference to NEM forecast: Whilst we agree that a forward-looking forecast is required, we note that MT PASA and ST PASA do not enforce accuracy requirements on proponents. Rather, ST PASA takes the 50% POE forecast from AEMO's Australian Solar Energy Forecasting System (ASEFS), and MT PASA develops a profile based on historical weather patterns."*[33]

> *"On page 7, Table 1 of the Supplementary Consultation Paper compares forecasting requirements of this document to the NEM. In general, the forecast terms of 3.3.5.17 (b) matches the NEM, but the accuracy and resolution requirement of the 60-minute ahead (1-minute resolution) forecast is vastly more difficult to comply with. In comparison, the NEM requires a 5-minute dispatch forecast out to two hours."*[34]

As discussed elsewhere in this paper we consider there are a number of significant differences between the NT and the NEM, as well as a number of relevant policy matters, including that:

- The NT is a very small system which will rapidly reach a point where asynchronous renewable generation is the dominant form of energy generation for significant periods.

[32] T-Gen submission 29 March 2019
[33] Tetris submission 29 March 2019
[34] Epuron submission 29 March 2019

- We are accordingly not proposing to adopt the existing NEM style arrangements, which were put in place in the past when renewable generation was only a marginal contributor to the energy sector.
- We also note that there is considerable debate in the NEM about whether the "semi-scheduled" category should be retained, the nature of forecasting, and the appropriate role of the market operator.
- We observe that NEM policy debate as the role of renewables matures in the NEM and comes to play a more critical role in the energy mix is suggesting that the direction of NEM regulatory change is most likely towards what we propose for the NT.

- As discussed in section 3.2.1 the forecasts being sought are not "average energy" insolation forecasts, but are instead capacity forecasts with a dispatch offer being provided at t+30 (i.e.: 30 minutes out) and a firm offer being provided at t=0 (i.e.: at the start of the dispatch period).
  - Creating such a firm capacity offer requires mixing the insolation forecast with site specific knowledge about the operation of that solar generator, the risk management processes they apply, and the firming capabilities (both technical and commercial) available.
  - This information will always be better known by the generator than by the system controller.

It is also not the role of a market operator to be making decisions about the levels of production that market participants choose to offer.

Placing the requirement with the individual generators thus not only puts the obligation upon those best informed to make the required decisions, but also places competitive pressure to innovate and improve the forecasting and management of the generation assets, which is consistent with the policy objective of driving least cost outcomes as well as technological innovation.

### 3.8.3 Using spinning reserve / FCAS to manage renewable production volatility

Suggestions were provided by NT Solar Futures and Epuron that regulating FCAS (R-FCAS) should be used to manage uncertainties and errors associated with capacity forecasting on the basis that these errors should be treated at a system wide level similar to load demand variations.

> *"Addressing system wide capacity forecasting errors is part of what R-FACS should be for, in our view. Just like we do not know when a GT is going to have a fuel supply issue, we cannot forecast the solar resource with 100% accuracy. R-FCAS should be allowed for in this scenario (and the NTEM should deal with who pays for this service)."*[35]

> *"Due to the way that the DKIS has been run historically with thermal generation this makes sense. Epuron agrees that generators must not cause C-FCAS events; that clouds are considered normal operation; and understands PWC's desire to treat all generation as scheduled. However, the relatively minor changes in load that are handled by R-FCAS have an equivalent on the generation side. There is no functional difference in R-FCAS for load or R-FCAS for generation and it should be treated the same. The imbalance between load and generation will always be matched by governor action. Epuron understands that PWC is concerned about the predictability of required R-FCAS levels, however it appears that load and generator side requirements can be treated in a similar manner. In some instances, they*

[35] NT Solar Futures submission 28 March 2019

*will cancel each other out. This may result in an ability to relax the specifications in the 1-minute resolution 95% accurate forecast to a level more easily achieved via forecasting providers."*[36]

We have modelled solar forecast data provided by external parties, and reviewed the actual energy performance of solar facilities in the NT. This work suggests to System Control that with 120MW of new solar farms on the system, the size of insolation forecasting error that may need to be dealt with will at times be significant, and that this will increase as more asynchronous solar generation is placed into the system.

Note here the important point that this error is in the insolation forecast (which is the only forecast that System Control could obtain), not in the risk adjusted capacity forecast which is what we proposing to be provided by the connecting generators, where we would anticipate the errors would be much smaller.

The concern here is not about the statistical cases where errors "cancel out" – but about the inevitable cases where they are instead compounding.

As discussed previously we also note that our proposed approach does not preclude a solar farm owner from engaging with any party – including T-Gen – to provide the required firming capacity.

- We note that such an arrangement with a provider that is not co-located at the site of generation may involve additional network investments to manage the resulting power flows. The nature of these costs and any related network stability requirements can only be quantified when a specific proposal is put forward for detailed consideration.
- Should proponents believe this is the least cost manner to meet all the requirements in NTC 3.3.5, there is no barrier to proposing such an arrangement under a negotiated connection arrangement.

### 3.8.4 Capacity forecast process

Stakeholders have sought further detail regarding the specifics of forecast information and associated processes as these details have not been included in any of the proposed code changes or published guidelines.

*"SCTC Clause 3.11 – forecasts – Is very light on for detail in terms of what forecasts are required from generators. Can this be specified in more detail for generators what is required?"*[37]

*"The modification to 3.11 of the SCTC appears to be a placeholder for a requirement on generators to provide forecasts of generation active power capability. The details are indicated to be contained in the Secure System Guidelines, but there does not appear to be any details contained in the SSG's. Provide a description of the proposed forecast requirements and advise when these details will be finalised. Advise what System Control is proposing to do with the forecast information provided from generators."*[38]

We believe our previous commentary in this chapter should provide the answers sought.

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[36] Epuron submission 29 March 2019
[37] NT Solar Futures submission 15 February 2019
[38] T-Gen submission 13 February 2019

### 3.8.5 What will happen if a generator is non-compliant?

Stakeholders sought details regarding how capacity forecast accuracy would be measured and if errors exceeded the capacity forecast accuracy requirement how they would be "penalised".

> *"Is there a listing of non-compliances and the cost of the penalties associated with these excursions? I.e. how does an investor include these likelihoods into their financial calculations?"*[39]
>
> *"Capacity Forecasting – 3.3.5.17, point (d) - leaves compliance totally up to the System Controller as to the format and frequency of compliance assessment. This needs to be specified as annually (any less would be too onerous) and the format needs to be specified (e.g. comparative assessment of actual vs forecast of for all trading intervals for the year). Also, the consequence of failing to comply needs to be specified."*[40]

Should a generator's forecasts not meet the required accuracy standard, System Control will de-rate that generator's dispatch to manage the inaccuracy to within acceptable limits.

The derating would be adjusted with the objective of keeping the error observed between their provided forecasts and their t=0 firm offer within the stated limits.

We do not consider it appropriate at this point to further specify the exact nature of the derating process that will be applied since the number of potential scenarios is considerable. However, noting the objective is to manage information accuracy being received by System Control to within stated limits, this should provide some guide on the manner of application.

The effect is that inaccurate forecasting on the part of a market participant will lead to a lowering of the energy dispatched from that participant, and conversely, participants that forecast accurately will tend to be dispatched closer to their 30 minute offer quantity.

We are not proposing any specific "penalty" regime.

## 3.9 Engagement questions

| Capacity forecasting requirements \| engagement questions |
|---|
| Do you understand the difference between an energy and a capacity forecast? |
| Do you believe that providing a dispatchable offer at 30 minutes ahead and a firm offer at dispatch time would make your project non-commercial? Where do you believe the costs of securely managing commercial scale asynchronous generation uncertainty should be borne? |
| Does the forecasting obligation as drafted in the proposed code, provide sufficient clarity on the obligation? If not, please provide suggested amendments. |

[39] NT Airports submission 29 March 2019

[40] NT Solar Futures submission 28 March 2019

# 4. Generator classifications

The consultation process delivered considerable discussion around the potential classifications within the NT electricity sector, with some evidence of an expectation that NER arrangements as applied in the NEM would be applied automatically in the NT. This section examines the issue of fit-for-purpose generator classifications in the NT.

## 4.1 Problem the GPS must address

It has always been the approach that the application of the NER to the NT would be tailored to the specific conditions that are found here. In the matter of generator classification, this has required recognition that the NEM is a much larger electricity market than the NT market, with a larger diversity of fuel sources, generation types, and geographical distribution.

The NT's extremely small power systems will rapidly move to the point where renewable generators represent a majority of the generation producing at certain times. The "semi-scheduled" status in the NEM reflected the historically "new entrant" and marginal nature of NEM renewables.[41]

With the maturing of the renewable industry, and the central role it is being called on to play in meeting the energy demands of the NT power systems, it is not appropriate to maintain this distinction. The distinction only works when asynchronous renewables are not a material share of the generation pool. In effect the "semi-scheduled" status pushes the risk of generation not performing in the manner forecast to the power system as a whole. This outcome would lead the costs of addressing this to be borne by those who are not causing it, whereas our analysis suggests that generators have access to the least cost ways of addressing it and our proposal places the responsibility with them to do so.

## 4.2 Our current proposed solution

As per the materiality threshold outlined in 3.3.1 of the NTC, the intent is that all generators 2MW or larger will be classified as scheduled. Those generators who are smaller than 2MW will be assessed on a case by case basis and may still be classified as scheduled. As a principle we are seeking to allow for technological innovation and competition to drive the transformation of the NT power systems, in particular by providing for a consistent set of requirements for major generation plant within the NT industry.

Consistent with the principles set out in section 1.6 that the Commission will apply, we consider that this approach:

- Ensures that there is a consistent incentive across all forms of generation and thereby promotes competitive and fair market conduct
- Promotes economic efficiency by supporting the lowest total cost of reliably and securely providing energy whilst facilitating the connection of asynchronous renewable energy technologies because it ensures the system security risk associated with increasing levels of asynchronous generation is placed with those best able to manage it

[41] Even so, we note that with the increasing penetration of renewables policy discussions in the NEM are now evolving in directions consistent with the principles underpinning the proposed application here – namely that renewables are moving from the margins into the centre of energy generation, and will be performing the role of the dominant form of energy generation at some time.

- Protect the interests of consumers with respect to reliability and quality of services and supply by:
  - maintaining the system security levers of predictability and dispatchability that System Control needs to perform its function, and
  - learning from the lessons currently being experienced in the NEM.

#### 4.2.1 Relevant code provisions

NTC 3.3.5.14. NTC 3.3.5.17, SCTC 3.2.3 (b).

### 4.3 Responding to specific feedback received

In this section we answer clarifying questions arising from our consultation to date and respond to specific feedback in stakeholder submissions.

#### 4.3.1 Clarifying questions

*How can PV generators that are inherently intermittent be classified as scheduled?*

Capacity forecasting (that is, with a small amount of firming capacity) to the proposed accuracy level 30 minutes ahead provides a sufficient level of predictability for a generator to be classified as dispatchable, based on our current modelling.

*If the capacity forecasting capability is relaxed where errors are accepted – doesn't that also mean that ability to follow a dispatch target is compromised? If so, why isn't the classification also not being relaxed?*

The capacity forecasting error will be designed on the basis of the ability of the online generators to manage supply / demand mismatch at an acceptable level of risk to system security. This means a tolerance around a dispatch setpoint rather than less than or equal to a constraint signal.

Please consider the sections of this paper where the probabilistic impact of forecasting errors on breaches of the SSG is discussed.

*Is there or should there be a materiality threshold?*

It is proposed that the GPS will apply to all generators that are 2MW or greater. For those generators below 2MW we will consider applying a moderated set of technical standards which may give effect to performance that is more akin to semi or non-scheduled. However, this will depend on the relative size of the generator to the system demand in the regulated power system where they are connected.

#### 4.3.2 Feedback received

*Increased cost and adverse impact on NTRET*

Concerns were raised by stakeholders that requiring new generators to be scheduled would increase entry barriers to renewable energy and was not consistent with the NEM and West Australian Energy Market (WEM) arrangements. Some also speculated that the requirement would have an adverse effect on achieving the NT Roadmap to Renewables.

> *"The proposed change places onerous obligations on renewable generation that may significantly increase the costs of these generators and cause decreased viability. There is not a sound basis to deviate from the NER on this matter now. Such a move would be at odds with the National Electricity Market, the Western Australian Energy Market and NT Government Policy. Renewable energy power generation is inherently intermittent. Cloud forecasting, ramp-rate control and battery support all mitigate against adverse behaviour of*

*the renewable energy generator on the grid. System stability and reliability does not necessarily require dispatchable active power by all generators."*[42]

*"Tetris' main concern is the removal of the semi-scheduled generators concept, which results in a requirement that variable renewable generators behave in a fully dispatchable manner will result in the process of integrating variable renewable generators being unnecessarily complex and costly. As such, Tetris believes that this approach will significantly impede the path to 50% renewable energy generation in the Territory."*

*"The semi-scheduled generator classification must be retained to facilitate early entrant intermittent renewable energy generation. Proposed removal of this classification places an unnecessary cost burden on new intermittent generators entering the market. In both the National Electricity Market (NEM) and the Wholesale Electricity Market (WA) (WEM) there are semi-scheduled and non-scheduled classifications that work well to enable intermittent generation. The removal of the semi-scheduled generator classification will make the NT unattractive for investment due to complexity and cost. The balancing requirement for intermittent generation is better and more economically provided centrally at a system level (and therefore provided as a market ancillary service), once the aggregate output of all various intermittent RE generators is considered."*[43]

#### *Alternate definition of semi-scheduled generator*

Some stakeholders recognised that there needs to be certain outcomes in regard to predictability and dispatchability to maintain power system security. There were suggestions that this could be achieved by reviewing the definition of semi scheduled generators in the NT and placing other obligations on renewable generators.

*"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'."*[44]

*"Tetris appreciates the additional clarification, however, maintain that there is clear value in having a "semi-scheduled" category (albeit with a different definition and application to the NEM, thereby enabling PWC to account for forecasted generation into its forward dispatch). As solar does not behave like gas, the dispatch needs to be tailored in order to maximise the performance of both. Tetris suggests creating a new category (that does not need to be called "semi-scheduled"), that requires a forecast within a minimum and maximum bound."*[45]

### 4.3.3 Power and Water response

We note that our proposed approach of requiring all generators to provide forecasts, but allowing an error band on the forecast, is close in definition to what Tetris suggests in the last comment above.

[42] Alan Langworthy submission 30 January 2019
[43] NT Solar Futures submission 6 March 2019
[44] T-Gen submission 29 March 2019
[45] Tetris submission 29 March 2019

The proposed error bands are based on statistical modelling of the DKIS with the current applications for solar farms all proceeding (adding approximately 120MW of solar capacity), and the resulting frequency of occasions where adverse system events have a higher probability.

Although it is true that the operation characteristic of a solar generator is different to a gas turbine, we suggest this argument is a rather generator centric view of the purpose of an electricity market. The market exists to provide reliable power at least cost to the consumers, and it is deliberately the case that it is setup to allow all generation types to compete to supply on an equivalent footing.

This is particularly the case given that under the current policy settings solar energy will become the dominant form of generation for considerable parts of the day. The inherent costs of dealing with intermittency must be dealt with, and we are deliberately seeking to establish a framework that allows those costs to be borne where it is most efficient to do so.

The idea that specific generator types (for example, large steam plant with a large construction cost and low run costs) should have offer arrangements that are different to other types (for example, gas, with low construction costs and high run costs) seems to be inherently picking winners and not driving innovation and good consumer outcomes, and is not an approach that we consider is aligned with the principles that the Commission will have regard to when assessing the proposed amendments.

In amending these codes Power and Water is bound by the NT policy settings, its System Control accountabilities and the factors the Commission must consider when approved code amendments (see Table 1.2). Together these support an approach that puts risk and cost with those best placed to minimise it, and confirm that the achievement of the Roadmap to Renewables is not to be 'at any cost', but rather should prudently seek to minimise cost.

This was reflected in the NT Government's response to the recommendations of the Roadmap to Renewables, wherein on the recommendation of policy alignment the NT Government stated:

> *"While government will seek to utilise renewable energy, subject to its availability and ability to deliver secure, reliable and least-cost electricity, policy initiatives will need to be carefully managed to avoid unintended consequence such as price increases for other electricity consumers."*[46]

## 4.4 Engagement question

| Generator classifications \| engagement question |
|---|
| Do you understand the factors that differentiate the feasibility of classifying a generator as semi-scheduled from those present in the NEM and WEM? |

[46] https://roadmaptorenewables.nt.gov.au/roadmap-to-renewables-expert-panel-report/government-response.

## 5. Requiring the ability to provide C-FCAS

The feedback received on the proposed C-FCAS requirements suggested to us further clarification was required about the intended difference between all generators:

1. having the technical capability of providing C-FCAS, as compared to

2. being called upon to actually provide this service.

Under the current commercial arrangements in the NT (the I-NTEM) there is no mechanism to facilitate ancillary service payments to generators other than T-Gen.

The I-NTEM is designed on the principle of T-Gen being the primary provider of ancillary services. System Control have managed the system utilising these principles for the past four years, and accordingly it would be an unusual situation where System Control actually constrained down a non-TGen generator to provide C-FCAS raise. The two principles for use of C-FCAS from non-TGen generators is that it occurs either as a last resort, or if it is in the commercial favour of the generators – that is - providing C-FAS results in higher dispatched energy for that generator.

However as discussed earlier in this consultation paper, the level of new generation coming into the NT power system means that over coming years asynchronous solar generation will at certain times be the dominant form of generation. Clearly as the NT sector evolves so will the manner in which FCAS is provided.

We have for example discussed in previous sections that the SSG, which currently work mostly on the basis of minimum spinning reserve requirements at Channel Island, will need to be replaced by an FCAS based contingency regime, and having the dominant generators operating at that time as participants will clearly be required.

The requirements outlined in the GPS are intended to:

- "Future proof" the equipment installed by ensuring that the underlying capabilities to (at least potentially) participate in future (as yet unspecified) commercial arrangements exists.

- Ensure that the system is capable of being operated safely even in circumstances where T-Gen's ability to provide FCAS has been constrained in some manner.

- Ensure that new entrants are not required to be constrained down pre-emptively in order to ensure that T-Gen plant is operational. We consider on a practical basis that this is the major factor that should actually be encouraging all participants to ensure they are FCAS capable.

It is our expectation that the proposed connection requirement can be met with minimal cost, since most inverters on the market have the required capabilities

Under normal circumstances, non T-Gen generators will not have their output constrained to provide C-FCAS, but will operate in a frequency droop mode (C-FCAS enabled) to provide C-FCAS lower to avoid displacement (curtailment/constrained off) for T-Gen plant to perform this service.

Only under abnormal circumstances, such as islanding where T-Gen are unable to provide adequate C-FCAS raise is it expected that non T-Gen generators may be dispatched at a level such that they provide C-FCAS raise, the less desirable alternative is to not dispatch these (or significantly constrain) asynchronous generation sources. We are not able to provide guidance at this time as to the likely frequency of these events, since it is at least in part determined by the exact location and timing of connections of new generation to the grid. We will be conducting further modelling on this question of the likely practical number of events as asynchronous generation rises.

## 5.1 Clarifying our terminology

To ensure adequate distinction between connection requirements and operational requirements such that the matters discussed in this document are clear and unambiguous, the following terms relating to C-FCAS are defined:

- *Capability* | Connection requirement (NTC): Connecting parties are to demonstrate that plant can supply FCAS services if the generator is in the appropriate control mode to do this and with appropriate headroom/floorroom. It does not specify a generator will be obligated to operate in this mode or curtailed to ensure provision.

- *Enablement* | Operational requirement (SCTC): If the System Controller requires a generator to be enabled for FCAS it will only supply it if it has the headroom (for raise) or floorroom (for lower) to do so. A generator operating at maximum output can be enabled for FCAS, but be unable to supply FCAS raise as it has no headroom. In regards to lower service, a generator can provide FCAS lower if it is enabled and it is dispatched above its minimum stable load.

- *Provision* | Operational requirement (SCTC): If the System Controller requires a generator to be enabled for FCAS services AND its dispatch level has the headroom or floorroom to supply the FCAS service it is providing FCAS. For example, a generator dispatched below maximum capability that is enabled for FCAS is able to provide an FCAS raise service. This service is the quantity referred to in any market payment arrangements.

- *Delivery* | Operation is the result of provision when a service is used. For instance if a generator tripped, other generators providing C-FCAS raise would then deliver this service by increasing their output in response to the low system frequency.

## 5.2 Problem the GPS must address

### 5.2.1 Why do we need generators to be C-FCAS capable?

The principle behind the proposed GPS clause on C-FCAS is to 'do no harm' in regards to reducing the power system's technical capability to maintain power system frequency.

To ensure ongoing system security, new generators (including renewables) need to provide the equivalent capability in supporting the management of frequency as the generators that they displace. Otherwise the circumstance will quickly be reached where additional renewable investment will be constrained off the system.[47]

Renewable plant having the technical capability for to provide FCAS is a required step to enable the system to support a significant penetration of renewable energy.

[47] Note that depending on the means by which generators achieve this requirement, there is a potential for an inertial floor to be reached, thus limiting penetration of PV with only C-FCAS capability until this can be provided as a network service by synchronous condensers.

## 5.3 Our current proposed solution

### 5.3.1 Requiring C-FCAS capability

Proponents of new generating systems will be required to connect in accordance with the proposed NTC clause 3.3.5.15 "Inertia and Contingency FCAS". Although the GPS specifies that to meet the automatic standard the performance is to be achieved at the point of connection, it does not prohibit that the proponent may negotiate for the standard to apply across more than one connection point if it benefits the system.

This would be through the process outlined in the proposed NTC clause 3.3.5 on the basis that the connecting generator retains responsibility at all times.

The NTC clause 3.3.5.15 requires that a generator is **Capable** of supplying C-FCAS (subject to control mode and dispatch level), the NTC contains no obligations with regards to **Enablement, Provision** or **Delivery** of C-FCAS.

However, during the connection process, the various performance requirements (including C-FCAS) would require testing to demonstrate capability by actually delivering the service; this does not influence the normal mode of operation for the generating system following the connection process.

**Although batteries and other technical solutions may be used, an inverter with a droop frequency control could meet this capability requirement. The incremental cost for an inverter based generator to obtain this capability by droop frequency control is minor.**

An independent consultant's review of the proposed standard supports this analysis:

> *"This definition is consistent with Entura's view of the capability of typical inverter based solar PV plant. System Control could only call on raise capacity from systems with no storage if they were known to already be curtailed. A requirement for 'enablement' of automatic frequency control is expected to add no significant additional cost to a typical inverter solution in the market now."* [48]

### 5.3.2 The AEMC ruled against similar requirements proposed for the NER, what is different here?

The expected rapid high penetration of asynchronous generation in the NT, and the sizing of NT generators being extremely large relative to the system demand (compared with their counterparts in the NEM), mean we face both large contingency sizes and lower inertial frequency response.

Thus these provisions for C-FCAS capability are of critical importance in the NT power systems, which due to generation characteristics already operate with low levels of frequency control.

The large size of units compared to the system means that if significant generation is dispatched without frequency control enabled, in the event of a contingency it would not respond to the frequency and would maintain existing loading levels. This significant quantity of energy would be held by these generators until a dispatch signal is received, which takes minutes to manage loading levels on generators, far too slow in an emergency event.

In this case it is possible (and has occurred in the past) that following a contingency event and under frequency load shedding (UFLS), the remaining T-Gen units online would not have sufficient loading

[48] See Appendix C, section 3.1, Page 6.

levels to operate in a stable manner. They would thus try to increase their loading level by pushing the system frequency up. With the generators operating with C-FCAS disabled, the frequency could go out of bounds in the high range which would likely result in cascading failure and complete loss of supply to all customers (i.e. a System Black event). This is a much more credible scenario in the NT than it is in the NEM, which necessitates a different approach.

In the scenario described above, the normal C-FCAS arrangements were insufficient to accommodate the contingency event. The desirable outcome from new generators is that they have C-FCAS capability and operate with C-FCAS enabled to provide C-FCAS lower when operated at maximum output, such that they can share loading with the synchronous generators following operation of UFLS to dampen the unstable frequency oscillations, that could otherwise cause a system black.

## 5.4 C-FCAS operating availability and payment in Darwin-Katherine power system

How has Power and Water's position on C-FCAS changed during the consultation?

In the first round of consultation Power and Water initially presented that generators would be obligated to provide all forms of C-FCAS at all times as part of dispatch arrangements based on the expected timeframe for NTEM commencement and the proposed NTEM design at that point in time. Both of these have changed.

As a result PWC clarified in a supplementary paper that the operation under the I-NTEM does not mandate any obligation for a new generator connecting to continually provide C-FCAS raise. The requirements introduced in the GPS are only to have C-FCAS capability. The operation of this capability is unchanged and remains consistent with the existing I-NTEM arrangements which require enablement of C-FCAS capability. Provision of C-FCAS raise from non-T-Gen generators is only to occur either as a last resort, or if it is in their favour (providing C-FAS results in higher energy dispatch quantity).The details of this are also outlined in the following part of this chapter.

For asynchronous generators currently working through the connection process requirements would find that the refined position on C-FCAS operation results in potentially less capex. This would be the case if their initial solution was a large battery or greater potential annual production if they were considering curtailment.

### 5.4.1 The proposed operating requirements in Darwin-Katherine

In the I-NTEM, T-Gen is the primary provider of all ancillary services including C-FCAS. Other generators are only called upon for system security purposes where T-Gen is unable to do so or if not providing these services would reduce dispatch level. Should it be called upon, there is no mechanism in the I-NTEM for payments to other generators providing C-FCAS. T-Gen is paid a rate to compensate it for operating away from its most efficient operating points. This rate is embedded in the SCTC and will be reviewed in the near future.

As T-Gen is the primary provider of ancillary services, other generators are required to pay T-Gen for providing ancillary services at the rate in the SCTC proportional to the demand these generators serve. The regulated price covers voltage control, reactive power control, regulating frequency control, contingency frequency control and black start capability.

All generators dispatched are expected to be operated in frequency response ("droop") mode (C-FCAS **enabled**). In practice if a low cost generator is economically dispatched and unconstrained it will likely operate at maximum capacity with the possibility of reducing output in response to a sudden rise in frequency, but not be curtailed to provide a raise service.

### 5.4.2 Why is enabling this mode in a generator's self-interest anyway?

Although it will result in the normal **provision** of C-FCAS lower from non-T-Gen generators, it allows greater dispatch levels for these generators when **not delivering** C-FCAS lower.

Under normal circumstances, the only impact to energy production for these generators is following a load contingency; these generators will have **delivered** C-FCAS lower by temporarily (typically less than 15 minutes) reducing their output, but overall have been dispatched at a greater quantity for a longer period of time.[49] The reliance on new generators to **provide** contingency lower service will increase significantly as the share of energy available to T-Gen reduces due to this service requiring the generators have a share of energy reduce on demand.

During stormy periods, the contingency lower requirement is approximately 30% of system demand,[50] so constraint levels could be significant if C-FCAS is **not enabled** and **provided**.

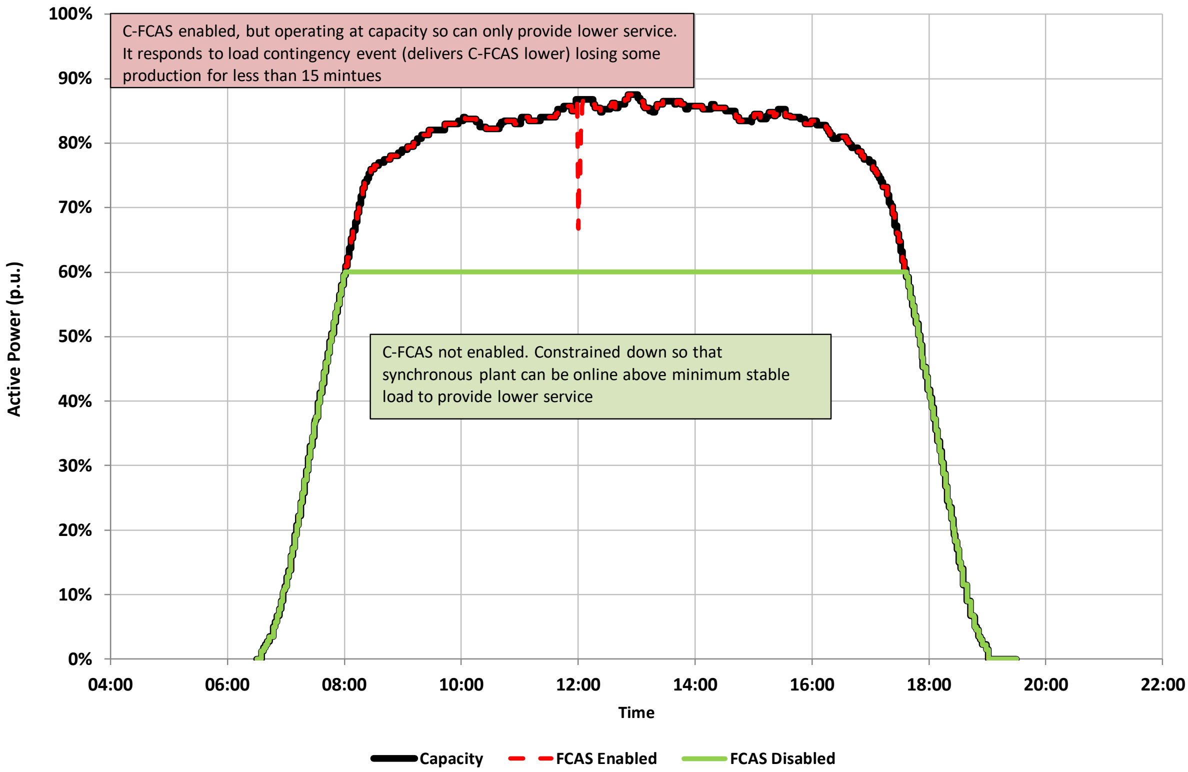
If this service is **not provided** by these generators, they will frequently be constrained down to allow a T-Gen unit online (with sufficient floorroom) to **provide** FCAS lower services.

Figure 5.1 below shows an example of the difference between a generator **enabled** and **providing** C-FCAS lower or not, in the circumstance where it would be constrained to allow another unit to perform this service.

[49] The greater quantity of dispatch is due to the likelihood of being constrained down or offline to facilitate energy dispatch on T-Gen units to have those units providing C-FCAS lower

[50] This is due to load relief following a lightning caused voltage surge. The load relief is understood to be from power electronic devices 'protecting' themselves from unstable voltages.

Figure 5.1: Comparison of dispatch options




An emergency scenario raised in the previous section that requires C-FCAS lower provision for all generators is during an UFLS event generators must share load to stabilise the system. The outcome of not providing C-FCAS lower is high risk of a system black event due to cascading failure with insufficient stabilising load on synchronous plant. The primary benefactor of this is the customers' continued supply, although another benefit is the temporary reduction in load from providing C-FCAS lower would naturally be less impactful to these generators than the impact to production when restoring from a system black.

## 5.5 Responding to specific feedback received

### 5.5.1 Provision of C-FCAS

We acknowledge there may be some residual confusion regarding the requirements of the proposed NTC 3.3.5.15 which requires demonstration of **capability** of providing either inertia or C-FCAS or a combination of both as distinct from the **provision** of C-FCAS (i.e. how it would be called upon and effects on generator dispatch).

> *"During the information session held on the 18th February 2019, it was stated that it was the intent of the System Controller that ancillary services "shall be available from generators". This is contrary to the current wording. In addition, the current wording needs to be modified based on the proposed NTEM arrangements. The requirement to provide ancillary services should be optional and be procured as per the NTEM."*[51]

[51] NT Solar Futures submission 6 March 2019

*"...This is due to the understanding that new generators need to provide similar characteristics to the generators they are replacing.."*[52]

*PWC response*

We have sought to better define the terminology we are using in section 5.1 above.

### 5.5.2 Payment for C-FCAS

T-Gen, Epuron and NT Airports raised concerns about the mechanism and nature of compensation for generators providing frequency control services.

> "The introduction of an FCAS market may more easily allow new entrants that could receive payment for providing ancillary services. Alternatively, new entrants could contract for these services with another provider."[53]

*PWC response*

As discussed above, there is no mechanism in the I-NTEM to facilitate ancillary service payments to generators other than T-Gen. The issues raised regarding market structure and payment mechanisms for FCAS have been passed onto the Department of Treasury and Finance for consideration as they continue to finalise the design of the NTEM.

## 5.6 Engagement questions

| Requiring ability to provide C-FCAS \| engagement questions |
| --- |
| Do you understand the terminology used to describe the capability, enablement, provision and delivery of C-FCAS?<br><br>Do you believe the droop characteristic will introduce additional cost to your project? How material is this?<br><br>Do you believe all generators should contribute to providing a C-FCAS/Inertia safety net for customers?<br><br>Would you be interested in providing and delivering C-FCAS services if a market/competitive mechanism were introduced? |

# 6. Grandfathering

Feedback we received in relation to grandfathering sought to clarify the application of grandfathering regarding the requirements to meet the new GPS for generators currently connected to the power system as well as generators that are currently under construction. This section explains the feedback and our proposed approach for these two types of generators.

## 6.1 Problem the GPS must address

The problems that the GPS and any transitional or grandfathering arrangements must address are:

[52] Epuron submission 29 March 2019
[53] Epuron submission 29 March 2019

- Legacy generators need clarity on how upgrades to their assets will interact with the GPS grandfathering provisions
- The new GPS have been developed in order to facilitate the transition to renewables, so it is logical to confirm the capabilities of existing generators against the GPS and therefore System Control would need compliance data measured against the new standards
- The conditions that have given rise to the need to adopt these new GPS are equally applicable to the new generation currently under construction.

## 6.2 Our current proposed solution

Our updated GPS grandfathering arrangements mean:

- Existing generators will to the extent they are able (without requiring modification, alteration or enhancement) to comply with the automatic access standards and their performance updated in their connection agreement.
- Generators that modify any part of their generating system will need to comply with the relevant NT NER requirements.
- Generators that were not physically connected prior to 1 April 2019 will need to comply with the proposed GPS obligations.

### 6.2.1 Relevant code provisions

NTC 12 Grandfathering, NT NER 5.3.9.

## 6.3 Existing connected generators

Generators that are currently connected raised concerns about the potential costs of compliance with the new GPS arising out of the compliance assessment process and changes to generating systems.

### 6.3.1 Process to demonstrate compliance of legacy assets

*Feedback*

T-Gen were concerned that there have been no guidelines published to inform generators of the process for demonstrating compliance to the new performance standards.

> *"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."*[54]

[54] T-Gen submission 29 March 2019

*PWC response*

We do not consider the compliance demonstration obligations are materially different from those already applicable to existing generators, and will work with these generators to agree the method and timeframes for compliance monitoring under the updated GPS.

The existing NTC and SCTC place obligations on existing generators to demonstrate capability performance against the respective connection agreement. For example:

- NTC 5.4 (d) requires…. "*Each User shall negotiate in good faith with the Network Operator to agree on a compliance monitoring program, including an agreed method, for each of its Generation Units to confirm ongoing compliance with the applicable technical requirements of clause 3.3 3.3.2 and the relevant Access Agreement*."
- SCTC 6.24 also provides an existing requirement for generators to perform periodic tests to confirm performance capability.

We intend to apply the principles of negotiating in good faith with existing generators to develop an agreed methodology and timeframe. If these negotiations fail, arbitration by the Commission is also available through the existing dispute resolution clause in NTC 1.6.

We have updated NTC 12 to provide greater clarity on grandfathering.

### 6.3.2 Use of derogations

*Feedback*

EDL suggested we should use a derogation mechanism to achieve the effect of grandfathering of existing connected generators.

> *"An alternative approach may be to continue to derogate existing conventional generation plant from some or all of the changes, a position that we would be willing to support. The proposed revisions to clause 12 appear to be trying to address this. However, we are concerned that that wording doesn't achieve the desired outcome and may actually deliver the reverse by binding currently derogated generators to a higher standard. We also note that, under the current version of the Electricity Networks (Third Party Access) Act 2011, there may in fact be no ability to either revoke an existing derogation or to make a new one. Accordingly, we strongly submit that this aspect of the changes requires further consideration and consultation."*[55]

*PWC response*

Our intention for existing generators is to assess their capability against the proposed GPS and then bind them to that assessed performance level. It does not mean that the generators necessarily have to achieve each of the automatic standards but they cannot perform below the requirements of version 3.1 of the NTC. We have sought to provide further clarification with amendments to NTC 12.2.

Use of a derogation would seem contrary in achieving this intended outcome. It is also our understanding that under the NT regulations a derogation is only possible during the application for access process or in the event of significant changes to the connection agreement.

[55] EDL submission 29 March 2019

### 6.3.3 Modifying existing plant

*Feedback*

T-Gen were concerned that modification of part of one of its generating systems would trigger an automatic requirement to meet all of the new GPS and effectively annul their grandfathered arrangements.

> *"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."*

*PWC response*

This was not our intent of the application of grandfathering in regard to modifications to generating systems.

If an existing generator is to modify its generating system the NT NER 5.3.9 (that we understand will take effect from 1 July 2019) places an obligation on generators to formally advise the Network Operator in the event of any modifications to prescribed elements of its generating system and how they impact on the agreed performance standards. This process is designed to prevent a modification that resulted in the generator being unable to meet performance standards as required in its connection agreement. Conversely, if the modification resulted in the generator being able to meet a higher standard (or an automatic standard) for a particular GPS, then that new performance would be recorded and acknowledged in a revision to the connection agreement.

## 6.4 Generators currently under construction

*Feedback*

Concerns were raised by particular stakeholders of generators currently under construction regarding certain GPS requirements being placed on them.[56]

*PWC response*

We have considered these concerns having regard to:

1. the need to provide certainty to investors
2. the materiality of the net effects of these changes on projects that are currently under construction
3. the principles set out in section 1.6 that will govern regulatory approval of these code amendments.

Because the system security issues that have driven these GPS changes apply equally to in-flight projects, we have tried to take a 'no surprises' approach to developing the GPS. This was on the expectation (communicated prior to licences being issued and during the connection process) that the new standards would need to apply to projects under construction.

Throughout the consultation process, we have been mindful of striking the right balance between:

[56] Confidential submission 29 March 2019

- providing certainty to generator applicants that are in the connection process, and
- the need to undertake appropriate consultation on the updated GPS that are needed to support power system security.

The impacted generators have been aware from the outset that the GPS were being developed and that they would need to meet those requirements once finalised. In considering the revised position as a result of stakeholder feedback, Power and Water is of the view that subject to derogations, the NTC and SCTC changes approved by the Commission will apply to all generators that were not connected at 1 April 2019.

We have updated the wording of NTC 12.2 to provide a clearer proposed position.

The GPS have been evolving in response to feedback from stakeholders. Our analysis suggests the net cost impost of the current proposed GPS relative to the first GPS amendments proposed in December 2018 is significantly lower. For example, whereas the initial obligation taken to consultation would have required a large battery for C-FCAS provision, we are now only requiring C-FCAS capability and capacity forecasting which could be achieved through inverter droop controls and a smaller battery.

Power and Water has applied a "no regrets" philosophy and holds the view that it is essential to set the "Framework for the Future" such that the outcomes are consistent with the NT objectives insofar as:

- promoting a competitive and fair market
- preventing misuse of monopoly or market power
- facilitating entry into relevant markets.

In this context, the treatment of generators that are under construction and commenced amid this current review should not face an outcome that creates market power for them, or raises barriers to entry for subsequent generators. Early mover renewable generators should not get an unfair advantage of lower access standards that result in higher entry barriers to subsequent generator developments and higher costs to consumers. Further, our approach will maximise the chances of the available renewables actually being used rather than constrained off-to enable synchronous stabilisation.

## 6.5 Engagement question

| Requiring ability to provide C-FCAS \| engagement questions |
|---|
| Have the revised code amendments provided sufficient clarity on the grandfathering arrangements? |