System Control Operational Document – Policy

System Knowledge – Power System Knowledge

Secure System Guidelines – Version 4.2

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1 Scope

This policy applies to Secure System Guidelines.

This Reference Document details Guidelines setting out the principles for determining whether a Power System operated under Licence from the NT Utilities Commission is in a Secure Operating State.

This Document is produced under the auspices of the System Control Technical Code. Should any conflict arise between this document and the System Control Technical Code, the Code shall prevail.

For further understanding or resolution of issues relating to this document, please refer all matters to the Power System Controller.

Where potentially commercial-in-confidence information is necessary to ensure the Guidelines are sufficiently clear, the relevant information will be detailed in Participant-specific attachments and are negotiated separately.

2 Definitions

AGC	Automatic Generator Control
AS	Ancillary Service
BA	Bachelor (Zone Substation)
Base Capacity	As defined in Section 4 (Determining Base Capacity)
CI	Channel Island (Zone Substation)
CIPS	Channel Island Power Station
Contingency Frequency Control Ancillary Service (C-FCAS)	Services to correct the generation / demand balance following a major contingency event such as the loss of a generation unit, major industrial load, or a large transmission element, as further described in Section 8.
Contingency Raise or Lower, Contingency Reserve	As defined in Section 8 (Contingency Frequency Control Ancillary Services (C-FCAS) / Spinning Reserve))
Credible Contingency	As defined in Section 3 (Adoption of Reliability Criteria for networks)
DKTL	Darwin – Katherine Transmission Line
Embedded Generator	As defined in the SCTC
Frequency Control Ancillary Service	The suite of services used by the Power System Controller to maintain the frequency on the electrical system, at any point in time, close to fifty cycles per second as required by the NT frequency standards, as further described in Section 5 (Determining adequate frequency levels)
Gould AR PLC	A programmable logic circuit installed at MT, PK and KA for the DKTS signalling Scheme.
HRSG	Heat Recovery Steam Generator
HV	High Voltage

Inertia Frequency Control Ancillary Service (I-FCAS)	Services that contribute to the capability of the power system to resist changes in frequency by means of an inertial response from a generating unit, network element or other equipment that is electro-magnetically coupled with the power system and synchronised to the frequency of the power system, as further described in Section 7 (Inertia Frequency Control Ancillary Service)
Isochronous (Isoch)	Governor in speed (or Frequency) control mode.
KA	Katherine (Zone Substation)
KPS	Katherine Power Station
kW	Kilo Watt (1000 W)
Lack of Standby Generation (LOS)	As defined in the SCTC and Section 10 (Determining Standby Reserve)
LDC	Line Drop Compensation
LORR	Lack of Reactive Reserve
Material load	Load of a sufficient size such that sudden disconnection may result in a measurable frequency disruption.
MT	Manton (Zone Substation)
MW	Mega Watt (1000 kW)
N Criteria	Equipment operated without redundancy.
N-1 Criteria	Equipment operated with a single level of redundancy.
NTC	Network Technical Code
Network Operator	As defined in the SCTC
OFGS	Over Frequency Generator Shedding
OLTC	On Load Tap Change
PC	Pine Creek 66kV (Zone Substation)
PCPS	Pine Creek Power Station
PK	Pine Creek 132kV (Zone Substation)
Power System Controller (PSC)	As defined in the SCTC

Protected Event	As defined in Section 3 (Adoption of Reliability Criteria for networks)
PWC	Power and Water Corporation
Reactive Power Reserve	As defined in the SCTC and Section 13 (Determining adequate Reactive Power Reserve for the System)
Regulating Frequency Control Ancillary Service (R-FCAS)	Service to correct the generation / demand balance in response to minor deviations in load or generation, as further described in Section 6 (Regulating Frequency Control Ancillary Service (R-FCAS))
Regulating Reserve	The capability of a Generator or Generators to provide the marginal increase or decrease of power system demand.
SCTC	System Control Technical Code
Shall, will	Mandatory
Should, may	Recommended
Spinning Reserve	As defined in the SCTC and Section 8 (Contingency Frequency Control Ancillary Service (C-FCAS) / Spinning Reserve)
SSG	Secure System Guidelines
Technical Envelope	The *technical envelope* means the technical boundary limits of the *power system* for achieving and maintaining the *secure operating state* of the *power system* for a given demand and *power system* scenario.
UFLS	Under Frequency Load Shedding
WD	Weddell (Zone Substation)
WPS	Weddell Power Station
ZSS	Zone Substation

3 Adoption of Reliability Criteria for networks

The Power System Controller adopts the following reliability criterion for network primary plant. Such criterion will be employed for maintenance planning and coordination:

Equipment that cannot be operated to 'N-1 Criteria' due to means of connection, are operated to 'N Criteria'. E.g. distribution feeders.

Equipment that could be operated according to N-1 Criteria is classified into 3 groups:

- Non-Credible (Operated to 'N Criteria')
- Protected (Operated to prevent system black)
- Credible (Operated to 'N-1 Criteria')

Under normal conditions the following are deemed to be non-credible contingencies:

- Bus faults
- Three phase faults

Under normal conditions, the following contingencies are classified as protected:

- Loss of the 132kV Transmission line south of Channel Island – Only to the extent that the southern region may go black, impact to the remainder of the Darwin-Katherine System is managed as a credible contingency and should not result in UFLS.
- 132kV Channel Island Nodes are operated as protected events. Outage planning and dispatch is managed to prevent System Black, however UFLS may occur.
- Loss of multiple transmission lines due to shared towers.

Fuel Supply contingencies are handled under Section 9 (Determining adequate energy for the System).

The remainder of contingency events are considered credible.

Under planned or forced outage contingencies, the Power System Controller may reclassify contingencies.

Protected events and credible contingencies:

The Power System is operated under the principle that credible contingencies wherever possible shall not result in involuntary load shedding. There are exceptions for planned outages where risk of involuntary load shedding is unavoidable, however in these cases risk analysis and mitigation is undertaken. This requires system constraints in place and scheduling of planned generation and network outages to ensure reliability criteria are at acceptable levels.

There are single contingency events that are plausible to occur, however the impact of enforcing constraints to prevent involuntary load shedding for these contingencies is impractical to apply on a permanent basis. These contingency events are classified as protected events such that constraints and scheduling of planned generation and network outages will only be enforced to ensure Power System Security is maintained to the extent required to avoid System Black. These events may be reclassified as credible if the Power System Controller deems necessary due to an identified increase in risk.

For the contingency of a radial line, the resultant impact to the wider system is considered and treated as credible (constraints are enforced to prevent UFLS/OFGS). The local impact (Loads/generation) on the radial is managed under 'N criteria' for reliability, unless determined otherwise by the Power System Controller.

4 Determining Base Capacity

Base capacity of generating units shall not take into account use of facilities that might provide short term (defined as 4 hours or less) capacity gains.

Base Capacity is defined as the maximum sustainable output in a generation unit under the worst seasonal ambient conditions.

For a generating unit with a staged output capability (such as water injection) the unit will have a variable base capacity. This base capacity of such unit will consider the availability of the staged output, whether it is currently online and the intended utilization of this capacity. I.e. if a staged output is available but offline, it may count towards planning criteria for maintenance outages, but not to spinning reserve/C-FCAS.

Base Capacity will be according to advice from the System Participant to the Power System Controller. System Participants shall provide the Power System Controller with advice of any variation to the Base Capacity of a unit promptly in writing. The Power System Controller is responsible for accrediting these Base Capacities provided by the System Participants and may amend the figure as required.

The Power System Controller will take a conservative approach in accrediting Base Capacity of a generating unit. An untested increase in Base Capacity may be accredited at a lower value than the Participants' advice until there is an appropriate opportunity to test under the worst expected seasonal ambient conditions.

The Power System Controller is cognisant of the business requirements involved with tests and will endeavour to undertake these tests where they minimise impact to System Participants (e.g. following a machine start where there is a surplus of Spinning Reserve/C-FCAS).

Application

Refer to document "Secure System Guidelines Generation Specifics".

5 Determining adequate frequency levels

For the removal of doubt Frequency Control Ancillary Service (FCAS) is comprised of the following three services:

- Regulating Frequency Control Ancillary Service (R-FCAS)
- Inertia Frequency Control Ancillary Service (I-FCAS)
- Contingency Frequency Control Ancillary Service (C-FCAS)

The specification of frequency levels is to ensure frequency is held within adequate levels prior to and following a single contingent event. This principle is set out to establish a baseline frequency range for the coordination of frequency control measures such that the inertia, contingency FCAS /Spinning Reserve respond to sudden supply/demand imbalance before frequency protection schemes (UFLS/OFGS) operate.

Normal Operating Frequency Band is the band system frequency is to be maintained within for normal load variation. This frequency control service is managed by regulating reserve specified in Section 6 (Regulating Frequency Control Ancillary Service (R-FCAS)).

Under abnormal operating conditions, the network frequency may vary between 47 Hz and 52 Hz. However the longest time allowable for the frequency of the power system to remain outside the normal operating frequency band for a region, for any condition (including an "island" condition) is 10 minutes.

Governor Deadband is the maximum frequency deviation before governor action is required to start. Governor action can start within the deadband, but governor action must start if the frequency is outside the specified deadband.

Active Frequency Control Deadband is the maximum frequency deviation required before the frequency is actively controlled by the generator dispatch control system. The generator dispatch control system must control frequency deviations outside the Active Frequency Control Deadband.

Cumulative frequency induced Time Error must be within +/- 15 seconds at all times, with no time correction action required if the error is within +/- 2 seconds.

The Power System Controller may exercise frequency reduction strategies outside of the frequency levels specified above as and when required to ensure supply is maintained. A circumstance that may require such action would be due to an imminent shortfall in fuel supply.

Normal Operating Frequency Band is:	DEFINED BY REGION.
Governor Deadband is:	50.00 +/- 0.025 hz.
Active Frequency Control Deadband is:	50.00 +/- 0.05 hz.
Emergency Operating Frequency Band is:	50.00 +/- 0.5 hz.

Regional Application

Darwin/Katherine

Normal Operating Frequency Band is:	50.00 +/- 0.2 hz.

Tennant Creek

Normal Operating Frequency Band is:	50.00 +/- 0.4 hz.

Alice Springs

Normal Operating Frequency Band is:	50.00 +/- 0.2 hz.

6 Regulating Frequency Control Ancillary Service (R-FCAS)

For the removal of doubt, Regulating Frequency Control Ancillary Service (R-FCAS) is a subset of Frequency Control Ancillary Service (FCAS).

R-FCAS and Regulating Reserve are used interchangeably in this context.

Regulating Reserve is that capacity of a generating unit or units available to regulate frequency to within the defined normal operating limits including time error correction. Regulating Reserve is only the amount required to follow the normal load changes and output variation in unregulated generation (embedded or registered), not the loss of load or load restoration following loss of load; this is covered by Contingency Reserve – refer to Section 8 (Contingency Frequency Control Ancillary Service (C-FCAS) / Spinning Reserve).

The minimum amount of Regulating Reserve will be a dynamic requirement based as per the following:

$$\mathrm{MinimumRegulatingReserve} = \mathrm{Greaterof}\begin{cases} \mathrm{MinimumRegionalFigure} \\ \mathrm{SystemLoadRateofChange} \end{cases}$$

System Load Rate of Change is a dynamic figure determined by the change (or anticipated change) in the summation of all online machine MW output over the region specific duration. The region specific duration is defined as two times the Average Regulating Unit Start Time. This allows for a single failure to start a regulating unit without breaching the Minimum Regulating Reserve requirement.

System Load Rate of Change will require to take into account anticipated load changes such as rain storms approaching populated areas.

Where this is not practical, the Power System Controller will determine the appropriate course of action.

The Power System Controller will appoint the regulating units which operate to regulate frequency, and determine the control mode for all regulating units.

Regulating Reserve will be altered as required under planned/forced outages (e.g. Islanding) on a case by case basis; expectations are that the minimum requirements will increase in these circumstances.

The Power System Controller will ensure regulating reserves are such that normal load changes and output variation in unregulated generation (embedded or registered) do not result in frequency deviations outside the normal operating frequency band.

Regional Application

Darwin/Katherine

Minimum Regional Figure of 5 MW

System Load Rate of Change defined as change in system load over 30 minutes.

Tennant Creek

Minimum Regional Figure of 0.5 MW

System Load Rate of Change defined as change in system load over 10 minutes.

Alice Springs

Minimum Regional Figure of 2 MW

System Load Rate of Change defined as change in system load over 10 minutes.

7 Inertia Frequency Control Ancillary Service (I-FCAS)

For the removal of doubt, Inertia Frequency Control Ancillary Service (I-FCAS) is a subset of Frequency Control Ancillary Service (FCAS).

The amount of inertia online determines the rate at which frequency changes immediately following a sudden imbalance between the supply (generation) and demand (load) which results from:

- an unexpected disconnection of generating units,
- an unexpected disconnection of transmission equipment, or
- sudden loss of load or fault on the system.

The less inertia online the greater the rate of frequency change immediately following such an event.

For a protected contingency event, there is a large demand/supply mismatch and the post-contingent inertia online is a determining factor for the Rate of Change of Frequency (RoCoF). Frequency control ancillary services are not intended to prevent loss of supply in such situations; the under frequency load shedding (UFLS) scheme is designed to operate to prevent a cascading failure leading to system black.

For protected contingency events a minimum amount of post contingent inertia is required to limit the initial RoCoF. This is required to ensure RoCoF is sufficiently low such that:

- Orderly UFLS or OFGS occurs and;
- RoCoF remains within the capabilities of the dispatched generation to prevent pole slipping (leading to cascading failure).

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

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

For single contingency generator events, the Contingency Frequency Control Ancillary Services (C-FCAS) are dispatched to prevent an operation of the UFLS. The amount of frequency control raise service dispatched is dependent upon the post-contingent inertia online.

This I-FCAS places a requirement for the Power System to maintain a minimum amount of inertia online following a single contingent event.

I-FCAS Principle:

I-FCAS is specified as a minimum required amount of post single contingency online inertia. This:

- Ensures that the rate of frequency change for single contingency events can be managed by the Contingency Frequency Control Ancillary Service (C-FCAS) raise/lower
- Provides a degree of consideration for multiple contingency events regarding settings for the UFLS and generator over-frequency protection.

For determination of I-FCAS, inertia connected to the power system is categorised in two groups.

- Inertia with post-contingent frequency disruption (Group 1)
- Inertia without post-contingent frequency disruption (Group 2)

Specifically, any inertia lost by a single credible contingency that does not also result in a frequency disruption is considered as "Inertia without post-contingent frequency disruption". An example of this would be loss of a synchronous condenser connected at an interconnected section of the grid.

However, if an inertia source is connected with material load, it may disconnect with load resulting in a post-contingent frequency disruption. Similarly, generators providing inertia and supplying real power if tripped would result in a frequency disturbance due to the loss of MW output.

I-FCAS is determined by:

$$Post \quad ontingent\ Inertia = \left(\sum Inertia_{G2} + \sum Inertia_{G1}\right) - \max\{Inertia_{G1}\}$$

It is noted that Synchronous and Non-Synchronous (emulated) inertia sources have different operational performance. Synchronous Inertia is to be independently tested and the determined inertia provided to the Power System Controller for assessment. Emulated Inertia will be assessed on additional factors of operational performance including, but not limited to the following:

- Measurement time
- Signalling time
- Activation time
- Ramping time

Based on the assessment of an emulated inertia or engineering technology, the technology may be accredited with an inertia contribution, a C-FCAS raise/lower contribution or another determination as deemed appropriate by the Power System Controller.

All inertia contributions (whether synchronous or emulated) towards the I-FCAS are only accredited by the Power System Controller.

Regional Application

Darwin/Katherine

Implementation Date:	TBD.
Minimum I-FCAS:	TBD.
Material load defined as:	1 MW or greater

Tennant Creek

Implementation Date:	TBD.
Minimum I-FCAS:	TBD.
Material load defined as:	30 kW or greater

Alice Springs

Implementation Date:	TBD.
Minimum I-FCAS:	TBD.
Material load defined as:	200 kW or greater

8 Contingency Frequency Control Ancillary Service (C-FCAS) / Spinning Reserve

For the removal of doubt, Contingency Frequency Control Ancillary Service (C-FCAS) is a subset of Frequency Control Ancillary Service (FCAS).

C-FCAS and Contingency Reserve are used interchangeably in this context.

Implementation Plan

The three regulated power systems in the Northern Territory; Darwin-Katherine, Alice Springs and Tennant Creek are to have their existing spinning reserve policies replaced with the Contingency Frequency Control Ancillary Service (C-FCAS). Until further notice the Spinning Reserve requirements outlined in this document will be in effect for each regulated system.

The algorithms for C-FCAS provision and system C-FCAS requirement will be implemented in a consistent manner across all regulated power systems. However, prior to announcement of a changeover date, specific requirements of the C-FCAS policy will be established with system participants such as the accreditation of machine C-FCAS provision or reference times for C-FCAS services.

When all systems are in place to implement C-FCAS policy within a regulated system, System Control will provide all system participants with formal advice of a changeover date by updating the Secure System Guidelines. The changeover date will be updated in the Secure System Guidelines a minimum of two weeks in advance. From the changeover date the regulated system will operate with C-FCAS requirements in place of Spinning Reserve requirements.

Contingency Frequency Control Ancillary Service (C-FCAS)

C-FCAS provides a means for the Power System to respond to some disruption resulting from an unexpected disconnection of generating units, items of transmission equipment or sudden loss of load. The C-FCAS policy will also account for the UFLS scheme in place at the time in determining the system requirements.

The principle of C-FCAS is as follows:

- Dispatch sufficient contingency raise (fast, slow and delayed) to prevent an under frequency load shed for the loss of any single machine (allow for impact of combined cycle) and return the frequency to a stable level (not fully to 50Hz) and maintain until other generation can be dispatched to return the system to a normal operating state.
- Dispatch sufficient contingency lower (fast, slow and delayed) to prevent an over frequency generator trip (full speed no load) for the loss of any load and return the frequency to a stable level (not fully to 50Hz) and maintain until the dispatch can be changed to return the system to a normal operating state.

C-FCAS is broken down into 3 different services: Fast, Slow and Delayed, each covering a different section of time following the event.

The reference times for each service are tabulated below. Currently this only applies to the Darwin-Katherine System. Alice Springs and Tennant Creek will require extensive review and analysis to generate similar requirements.

	Fast Reference Times	Slow Reference Times	Delayed Reference Times
Time A	0 – 2 Seconds	2 – 60 Seconds	60 – 300 Seconds
Time B	2 – 60 Seconds	60 – 300 Seconds	300 – 900 Seconds

C-FCAS provision is based on the following:

$$F_{fast} = \min \begin{cases} \dfrac{2}{t_{ref_{fast}}} \displaystyle\int_{t_m}^{t_m + t_{ref_{fast}}} \Delta P_g \, dt \\ \dfrac{2}{\left(t_{ref_{slow}} - t_{ref_{fast}}\right)} \displaystyle\int_{t_m + t_{ref_{fast}}}^{t_m + t_{ref_{slow}}} \Delta P_g \, dt \end{cases}$$

$$F_{slow} = \min \begin{cases} \dfrac{2}{\left(t_{ref_{slow}} - t_{ref_{fast}}\right)} \displaystyle\int_{t_m + t_{ref_{fast}}}^{t_m + t_{ref_{slow}}} \Delta P_g \, dt \\ \dfrac{2}{\left(t_{ref_{delayed}} - t_{ref_{slow}}\right)} \displaystyle\int_{t_m + t_{ref_{slow}}}^{t_m + t_{ref_{delayed}}} \Delta P_e \, dt \end{cases}$$

$$F_{delayed} = \min \begin{cases} \dfrac{2}{\left(t_{ref_{delayed}} - t_{ref_{slow}}\right)} \displaystyle\int_{t_m + t_{ref_{slow}}}^{t_m + t_{ref_{delayed}}} \Delta P_e \, dt \\ \dfrac{1}{\left(t_{ref_{delayed}}\right)} \displaystyle\int_{t_m + t_{ref_{slow}}}^{t_m + 3t_{ref_{delayed}}} \Delta P_e \, dt \end{cases}$$

ΔPg and ΔPe are the C-FCAS providers' responses ignoring any inertial response.

The system requirements are calculated based on the following process and equations. Note the amount of delayed raise is similar to the requirement for slow raise.

Identify and Calculate Post Contingent System MVA and H:

$\text{SystemMVA} – \sum \text{RemainingOnlineMVA}$

$\text{SystemH} – (\sum \text{RemainingOnlineMVAs}) / \text{SystemMVA}$

Define:

ΔPm (Contingency Size);

fmin and nmin (Lowest Frequency/Speed Change – Based on UFLS Scheme);

tref (Fast Reference Time – 2 Seconds); &

tg (Time assumed for all governor actions – Declared at 4 Seconds)

Calculate:

ΔPg (Calculated Governor Response); &

$$P_g = -\frac{\Delta P_m{}^2 t_g}{4Hn_{min}}$$

tmin (Time of Minimum Frequency)

$$t_{min} = \frac{\Delta P_m t_g}{\Delta P_g} + t_m$$

tm is event time, and is assumed to be 0 Seconds unless stated otherwise.

Check tmin against tref and determine C-FCAS Fast and Slow requirements:

Case 1: $\mathrm{t_{min}} < \mathrm{t_{ref}}$

$$F_{fast} = \frac{2\Delta P_m}{t_{ref}}\left[t_{ref} - \frac{t_{min} - t_m}{2}\right]$$
$$F_{slow} = 2\Delta P_m$$

Case 2: $\mathrm{t_{min}} > \mathrm{t_{ref}}$

$$F_{fast} = -\frac{{\Delta P_m}^2 t_{ref}}{4Hn_{min}}$$
$$F_{slow} = \Delta P_m\left(1 - \frac{\Delta P_m t_{ref}}{4Hn_{min}}\right)$$

The provision of C-FCAS and determination of C-FCAS system requirement will be assessed by and approved at the discretion of the Power System Controller.

Based on the assessment of an engineering technology, the technology may be accredited with an inertia contribution, a C-FCAS raise/lower contribution or another determination as deemed appropriate by the Power System Controller. Refer to Section 7 (Inertia Frequency Control Ancillary Service) for Inertia accreditation and requirements.

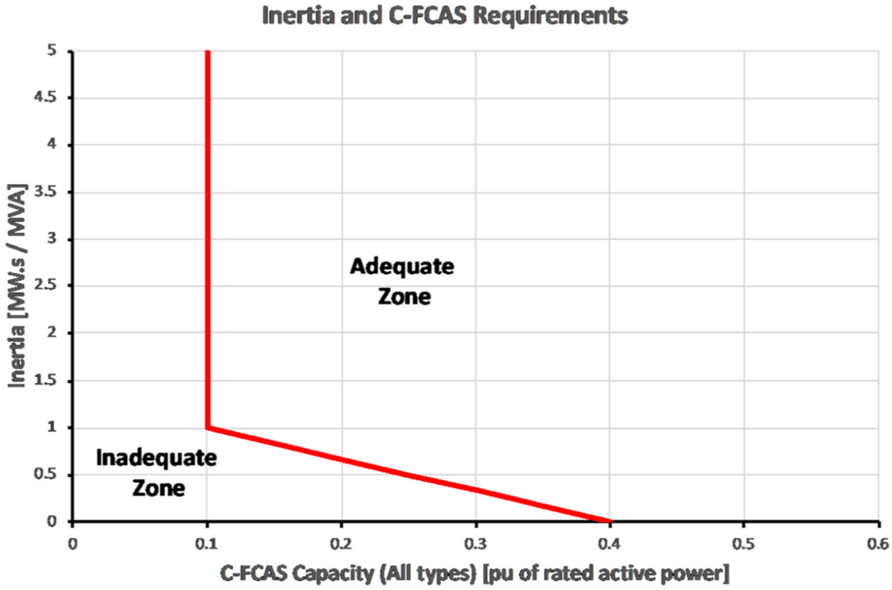
At a minimum the combined amount of machine provided C-FCAS must be greater than the system requirement. By the nature of the calculations/requirements this will be spread across multiple machines.

The Power System Controller may vary the minimum amount of C-FCAS required to accommodate the perceived risk level to the power system or sub-system at the time. This may include specific machine/island and or region requirements.

C-FCAS accreditation to meet the requirements of NTC 3.3.5.15 "Inertia and Contingency FCAS"

The Network Technical Code 3.3.5.15 requires a generator to demonstrate capability against the following inertia and C-FCAS trade off requirements.

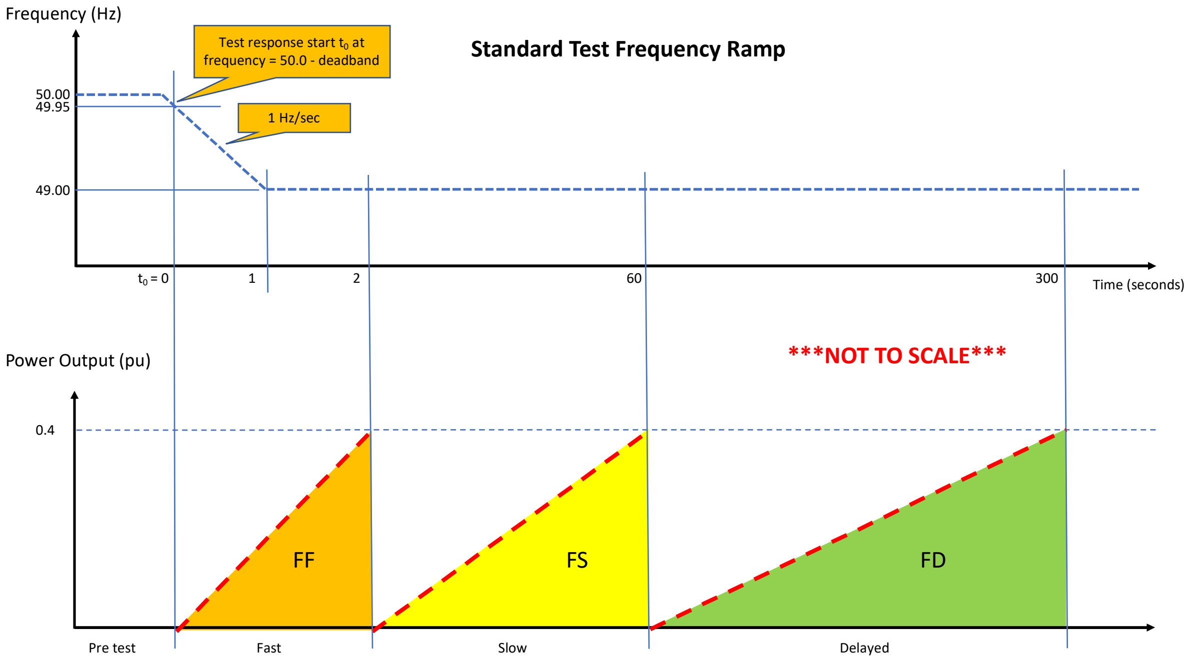
Figure 9 – Inertia vs C-FCAS Trade Off Requirements for New Generators



The per unit (pu – ie % of rated power output divided by 100) rated active power on the horizontal axis of NTC 3.3.5.15 is the rated active power output a generator is to achieve between the start and finish of each type of C-FCAS in response to a 1 Hz/second frequency test ramp over a 1 second period commencing from the Governor Deadband setting.

Example 1 –Base Case - Generic Minimum Response required for a 20MW Solar generator providing no inertia

For a generating system that provides no inertia (i.e. required to provide 0.4 rated power output), the generic minimum response capability would be as illustrated below for a C-FCAS raise (i.e. low system frequency) scenario.



Minimum Required C-FCAS Response by Type

The requirement for each type of C-FCAS is for the generator to provide 0.4pu (= 8MW in this example) rated power by the end of the particular C-FCAS time period.[1] The required energy capability for each type of C-FCAS in this scenario is the area enclosed by the Power Output vs time curves :

FF = Fast = 0.4 x 2 seconds ÷ 2 = 0.4 pu seconds

FS = Slow = 0.4 x 58 seconds ÷ 2 = 11.6 pu seconds

FD = Delayed = 0.4 x 240 ÷ 2 = 48 pu seconds.

The C-FCAS accreditation works by converting the energy provided back to pu power to be attained by the end of the respective C-FCAS time period by applying the formula in section 8 as follows :

Fast Raise = $\frac{2}{(2-0)}\int_0^2 (Power\ Output)dt = \frac{2}{2}$ x FF = 0.4 pu

Slow Raise = $\frac{2}{(60-2)}\int_2^{60} (Power\ Output)dt = \frac{2}{58}$ x FS = 0.4 pu

Delayed Raise = $\frac{2}{(300-60)}\int_{60}^{300} (Power\ Output)dt = \frac{2}{240}$ x FD = 0.4 pu

Further, the accreditation for C-FCAS requires the generator to sustain a level of performance to ensure smooth transition between C-FCAS time periods provided across the generation fleet and therefore the C-FCAS capability accreditation by type is assessed as follows:

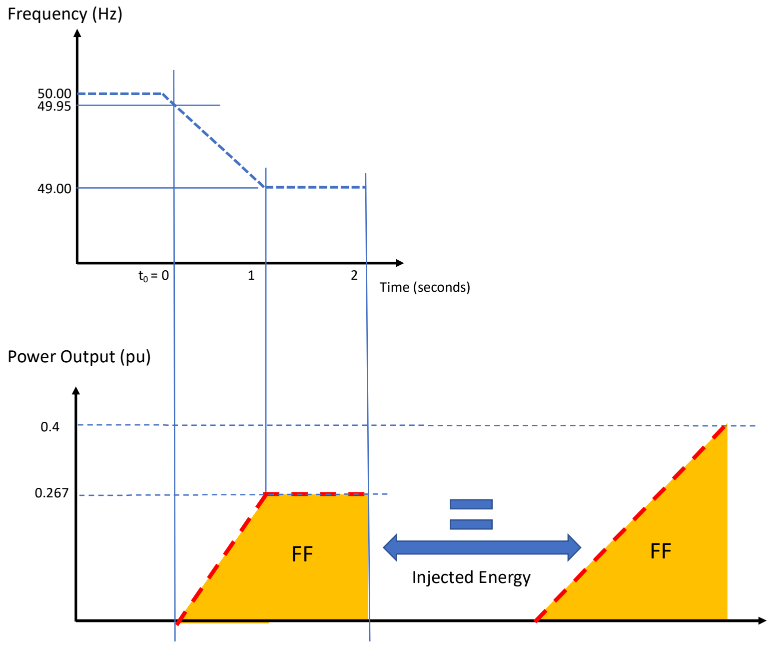
Fast	Lesser pu value of performance for Fast response during the 0 – 2 second period and continued through the 2 – 60 second period.
Slow	Lesser pu value of performance for Slow response (ie commencing after 2 seconds) during the 2 – 60 second period and continued through the 60 – 300 second period.
Delayed	Lesser pu value of performance for Delayed response (ie commencing after 60 seconds) during the 60 – 300 second period and continued through the 300 - 900 period.

In recognising that different generator technologies may be capable of providing faster responses, the accreditation works by determining the equivalent energy provided in each of the C-FCAS types. In simple terms, provided the generator can provide the equivalent energy FF, FS and FD for each C-FCAS type then it will meet the equivalent rated pu power requirements of NTC 3.3.5.15. This is illustrated by the following example.

Example 2 – 20MW Solar Farm providing no inertia with fast response – assessment of C-FCAS fast raise

In this example, the generator is required to meet the equivalent of reaching 0.4 pu rated power output by two seconds after crossing the frequency deadband. For the fast raise this equates to 0.4 pu seconds energy injection. In this case the generator is capable of injecting power at twice the rate of the base case curve. To meet the C-FCAS requirement it therefore only needs to provide 0.267 pu of rated power (ie 5.34 MW) as illustrated below to provide the same injected energy. Ie (0.267 x 1 ÷ 2) + (2.67 x 1) = 0.4 x 2 ÷ 2 = 0.4 pu seconds.

[1] Note for a high system frequency event there would be the equivalent requirement to reduce output.



C-FCAS Response

In this case the generator meets the requirements of NTC 3.3.5.15 by providing the equivalent of 0.4 pu rated power against the standard C-FCAS fast response. It is evident that the faster that a generator can respond within a C-FCAS type time period, the lower the value of power it needs to achieve for the same energy injection over the same C-FCAS type time period.

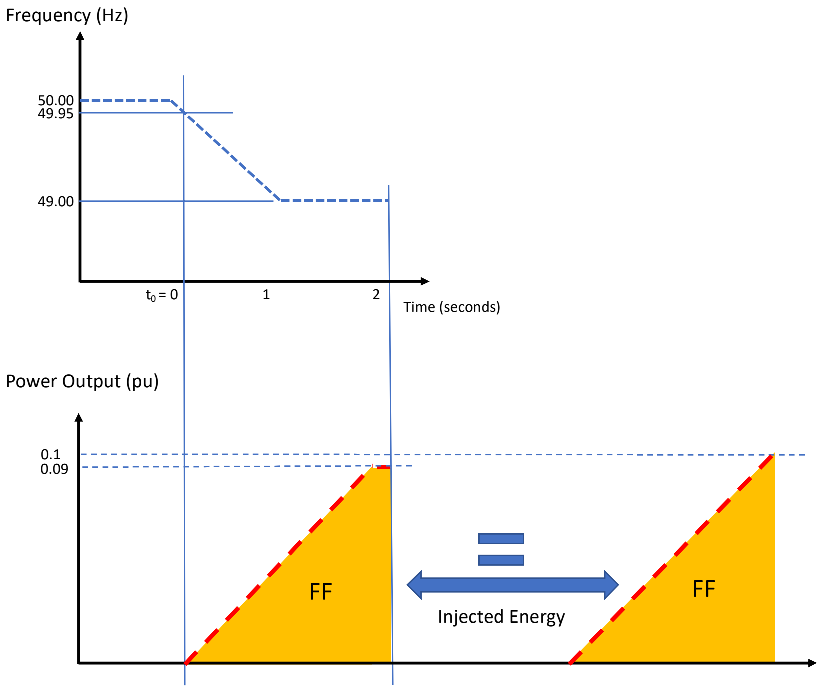
On the assumption that the same generator sustained 0.267 pu power output between 2 – 60 seconds (ie 15.49 pu seconds) it would also easily meet the C-FCAS slow requirement of 11.6 pu seconds.

Note all other C-FCAS types would be evaluated as per the requirements to meet the equivalent 0.4pu power by the end of each C-FCAS time interval.

Example 3 – 40MW Synchronous generator that can provide 1.5MW.s/MVA Inertia

In this example, to meet the requirements of NTC 3.3.5.15 the generator would need to be capable of providing the equivalent 0.1pu of rated power (4MW) of C-FCAS against the base case C-FCAS curves illustrated in Example 1.

The response of the generator to the test ramp for fast raise is as follows.



C-FCAS Response

As the energy injection area bounded by FF equals the minimum requirement then the generator would meet the C-FCAS fast raise requirement under NTC 3.3.5.15 provided the slow raise requirement was also met or exceeded. For example if this generator could sustain 0.09 pu for the 2 – 60 second period it would inject 5.22 pu seconds of C-FCAS slow energy exceeding the equivalent 2.9 pu seconds of energy required for the slow raise C-FCAS period.

Note all other C-FCAS types would be evaluated as per the requirements to meet the equivalent 0.1 pu power by the end of each C-FCAS time interval.

Spinning Reserve

Spinning Reserve provides a means for the Power System to ensure that the power system can respond to some disruption resulting from an unexpected disconnection of generating units or items of transmission equipment.

At a generating unit level, Spinning Reserve is calculated as the difference between the current load and Base Capacity of a generator. The Power System Controller will assess non-generator sources of Spinning Reserve and accredit, to the extent appropriate, in accordance with the principles outlined in this document.

At a system level, Spinning Reserve is the sum of all individual generating unit Spinning Reserve amounts. Spinning Reserve must be dispatched across two or more generating machines and a minimum amount of Spinning Reserve must be maintained at all times.

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

Regional Application

Darwin/Katherine

Minimum Spinning Reserve:

25 MW of Spinning Reserve at all times.

A contribution to contingency response must be provided by a minimum of two Frame 6 machines:

The two Frame 6 machines must be on different nodes (i.e. [C4/C5 Node], [C2/C3 Node], [C1/C7 Node]).

The two Frame 6 machines must be loaded at 26 MW or below.

The two Frame 6 machines must not be otherwise restricted in their capacity or response.

Changeover to C-FCAS:	Date to be determined.
Minimum C-FCAS:	As detailed in the equations above.

Tennant Creek

Minimum Spinning Reserve:	0.800 MW of Spinning Reserve at all times.
Changeover to C-FCAS:	Date to be determined.
Minimum C-FCAS:	This will undergo review to determine the application of the principles applied to the Darwin-Katherine System

Alice Springs

Minimum Spinning Reserve:

the greater of:

- 8 MW (Day)
- 5 MW (Night)
- Largest Machine MW Output

During daytime hours Spinning Reserve may violate the requirement for:

- no longer than 30 minutes and;
- by no more than 3 MW at any instance.

There shall be 5 regulating (controllable variable load) machines online when possible[2].

This is to be done in the following manner where possible:

- When online, the larger generating units (R9, O1, O2 & O3) should have load distributed approximately equally on each unit.
- If one of the gas turbines (OA or R9) is available at least one is required to be online.

[2] The principle of increasing the number of regulating units is to ensure there are a number of machines (with sufficient spinning reserve contribution) that can respond for the loss of a generator. To meet these requirements, units with tight regulating bands (R1-8 and OA) may need to be switched for a unit with a larger regulating range (R9, O1, O2, or O3).

- A minimum of two generating units are required online at Owen Springs Power Station.[3]
- Any machine undertaking test is not classified as a regulating unit to meet the above requirements.

Contingency Down is defined as additional load on units above their minimum stable loads and caters for sudden loss of load such as feeder trips. In contrast to Regulation, it is deemed acceptable that units may fall back to diesel operation for a sudden loss of load event. Contingency Down should be maintained on the system at all times with consideration to the highest plausible contingent load loss at any time.

Where Regulation (refer to Section 6 Regulating Frequency Control Ancillary Service (R-FCAS)) or Contingency Down cannot be met the following actions can be taken (in order of priority):

- Units with higher minimum stable loadings to be swapped for units with a lower minimum stable load.
- Uterne output to be restricted as required

The requirement for 5 regulating units can be reduced provided:

- The unit brought offline is not OA or R9 (unless both are online).
- Regulating machines are brought online to meet the requirement in Section 2 at the earliest opportunity.

Changeover to C-FCAS:	Date to be determined.
Minimum C-FCAS:	This will undergo review to determine the application of the principles applied to the Darwin-Katherine System

[3] In case of multiple forced outages at OSPS where the minimum of two machines online at OSPS requirement can't be met, frequency control is to be taken over locally by RGPS.

9 Determining adequate energy for the System

Energy supply adequacy is generally measured by the quantity and quality of fuel available for use at each power station.

An Alert level is defined as a case where available fuel supply falls below that quantity or quality required for operation at forecast load levels for the next 8 hours.

Due to the complexity of arrangements required to deal with shortfalls in fuel supply, or departures from quality standards, it is necessary that there be a Preliminary Alert level where any contingency in the delivery and or storage systems for fuel supply has the potential to result in an Alert level being reached in the next 18 hours.

Generators shall immediately notify the Power System Controller when a Preliminary Alert or Alert level is reached.

Where more than one fuel source and/or fuel type is available each source/type should be monitored and subject to the Alert level process.

When the PSC has been notified of a fuel adequacy alert the PSC may then deem that the partial or complete loss of the power station is a credible contingency. The PSC will communicate with relevant parties and may take measures to mitigate this risk; these measures may include making Directions as provided for by the SCTC.

Application

Refer to document "Secure System Guidelines Generation Specifics".

10 Determining Standby Reserve

The Power System Controller will determine the required generation capacity of a power system according to the summation of:

- the actual or forecasted load of the power system,
- the required spinning reserve or C-FCAS raise of the power system, and
- the capacity at risk from a credible or protected contingency event.

The Power System Controller will declare a Lack of Standby Generation (LOS) condition when the available generation plant capacity is below the calculated required generation capacity. LOS Conditions will be classified according to the considered actual or expected severity of generation shortfall.

Breach of the *technical envelope* as indicated in the LOS conditions below, would include insufficient post contingent inertia to meet the requirements set out in Section 7 (Inertia Frequency Control Ancillary Service). The Power System Controller will assess LOS levels with regards to inertia in addition to generation base capacity as outlined above (when the Inertia Frequency Control Ancillary Service is implemented on a regional basis).

LOS1 Condition

LOS1 is declared when the occurrence of a protected contingency event involving the loss of the largest available generation node in the power system will result in the power system operating outside the *technical envelope*.

LOS2 Condition

LOS2 is declared when the occurrence of a single credible contingency event involving the loss of the largest generation unit available in the power system, will result in the power system operating outside the *technical envelope*.

In determining the largest available generation unit, the effective load of an online combined cycle unit is deemed to be the load of the open cycle unit plus the inferred load derived from its associated HRSG.

LOS3 Condition

LOS3 is declared when the power system is operating outside of the *technical envelope*, the minimum spinning reserve or C-FCAS raise has been breached and/or the Power System Controller is implementing measures to maintain system security.

LOS Margins

LOS Margins set the boundaries for determining and declaring when the power system is in any of the three LOS Conditions. The following figure provides the formulae the Power System Controller will utilise to calculate the three LOS margins, and illustrates the application of the LOS Margins to determine LOS Conditions.

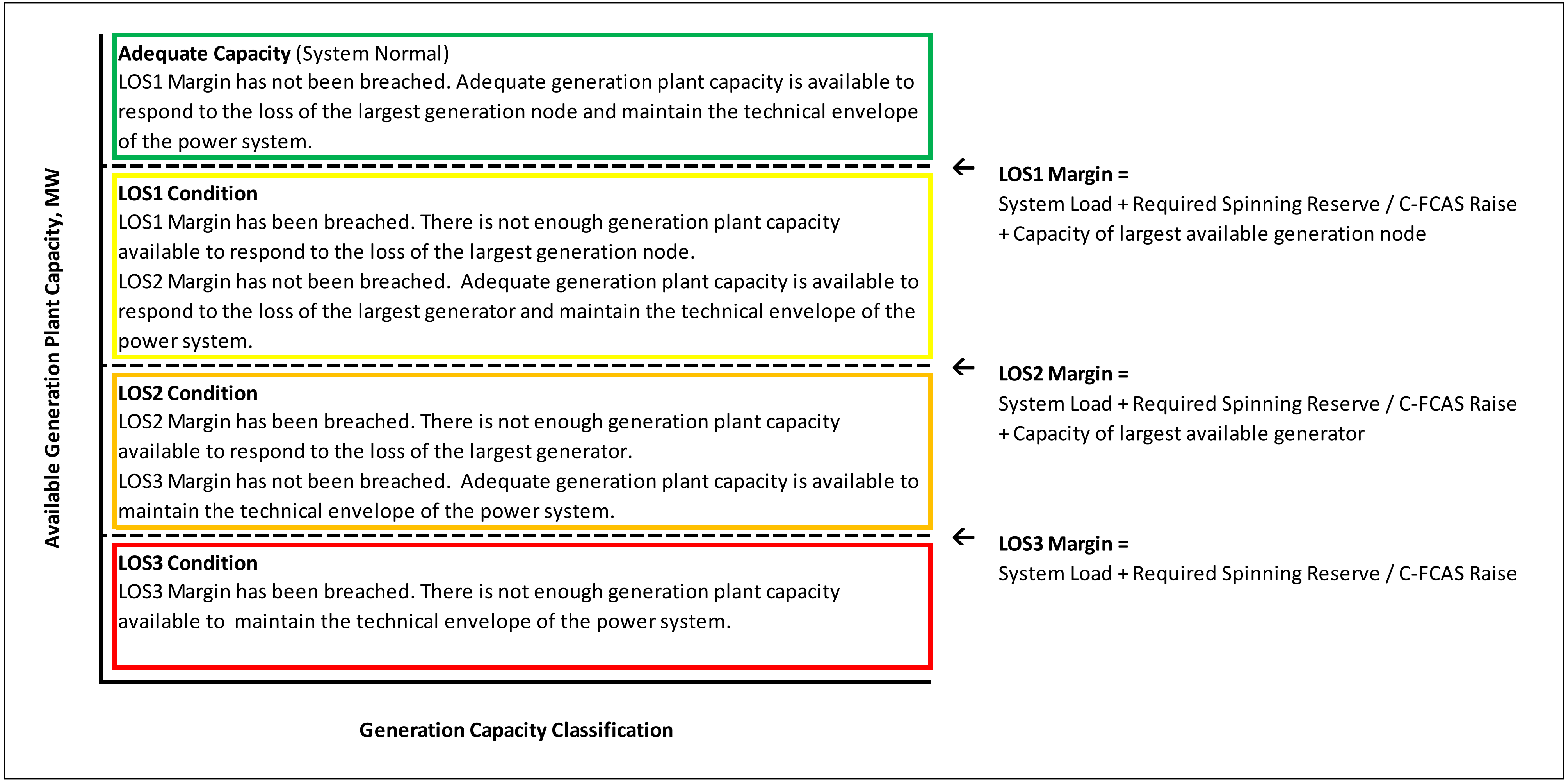


Figure 1: LOS Classification

11 System stability

Any equipment identified as causing Voltage instability or Frequency instability event may be disconnected as directed by the Power System Controller or directed to undertake rectification actions to ensure such an event is not caused in future.

Definition:

The AEMO Power System Stability Guidelines definitions of stability as quoted below are used by the Power System Controller to assess system stability.

AEMO POWER SYSTEM STABILITY GUIDELINES V1.0 Stability Definitions

1.4 *Voltage* stability

Voltage stability is the ability of the *power system* to maintain or recover *voltage* magnitudes to acceptable levels following a *contingency event*.

Instability would result in *voltage* magnitudes in part of the *power system* exhibiting an uncontrolled sustained increase or decrease over time (a “run-away” condition) or sustained or undamped oscillatory behaviour. *Voltage* instability can occur rapidly (over seconds) or slowly (over minutes).

1.5 *Frequency* stability

Frequency stability is the ability of a *power system* to maintain acceptable *frequency* following a *contingency event.* Typically, that *contingency event* causes an unbalance between *generation* and *load* in the *power system*. It depends on the ability of the *power system* to maintain or restore equilibrium between *generation* and *load* and recover the *power system frequency* to acceptable levels.

Instability results in an uncontrolled sustained increase or decrease over time (a “run-away” condition) or sustained undamped oscillatory behaviour.

Determination:

System Stability will be determined based on the specific requirements obtained from Section 16 of the Network Technical Code (Version 3.1 – December 2013).

Refer to Section 5 (Determining adequate frequency levels) of this document for acceptable levels.

12 Determining adequate voltage levels for the System

System Voltage is a distributed phenomenon, and its limits are defined in various Acts, Regulations, Codes and Standards.

The Network Technical Code requires that all plant be designed to operate with minimum and maximum steady state voltages to 90% and 110% of nominal design voltage respectively, unless specifically designed and approved. Generally, contestable customers are expected to design their plant to accept voltage levels of +/- 5% of nominal voltage.

The Network Technical Code also defines:

- Maximum voltage perturbation for a routine switching step (excluding de-energising) +/- 3.7% nominal voltage before reactive control responses and
- Maximum voltage perturbation for an infrequent switching step (excluding de-energising) +/- 6% nominal voltage before reactive control responses.

System Voltage Reduction is a credible means of reducing load under emergency conditions, but has the impact that customers at feeder extremities may suffer out-of-standard limit voltages. Only the Power System Controller approves Voltage Reduction strategies.

Regional Application

Normal voltage control limits for all regulated voltage nodes regulated by OLTC transformers shall be +/-1.5% of a specifically defined nodal voltage value.

LDC (Line Drop Compensation) usually provides benefits for very long feeders with relatively large loads at the ends of the feeders. Typically, fixed value (no LDC) regulated voltage set-points are set slightly higher than nominal to allow for voltage drop at the ends of the feeders. The latter type is in most common use in PWC.

Control balance points are as follows:

Nominal voltage	Typical Voltage Setpoint	Tolerance
132kV	Not controlled by OLTC	+/- 10% nominal
66kV	67.6kV	+/- 10% nominal
22kV	22.5kV	+/-5% nominal
11kV	11.1kV	+/-5% nominal

13 Determining adequate Reactive Power Reserve for the System

There are nominal design voltage levels and tolerances defined within these SSG. The system voltage at each node and, corresponding reactive power requirements, are determined by power system local loading demands and the reactive impedance of the various sections of the power system.

Measures of adequate reactive power reserve include:

- voltage levels for the System meet Adequacy limits
- there is no ZSS OLTC transformer that has reached maximum or minimum tap and regulated voltage is within normal control deadbands
- voltage collapse situations are not imminent
- no generator is operating close to maximum or minimum excitation level and under automatic control
- Power Factor on ZSS Bus's are within normal ranges

Power System Controller will issue advice to all affected System Participants when:

(LORR1):

- Any OLTC transformer is operating at Top or Bottom tap and regulated voltage remaining outside normal control deadbands OR,
- any scheduled generation unit is operating within 5% of maximum or minimum excitation level and under automatic control OR,
- 2 scheduled generating units are operating under manual voltage control

(LORR2):

- Any system voltage controlled node operating outside of statutory voltage limits OR
- any system node operating outside of stable voltage control limits OR
- any generation unit operating at maximum or minimum excitation level and under automatic control OR
- 3 or more scheduled generating units operating under manual voltage control.

Power System Controller may initiate commensurate actions including Directions, load shedding, load transfer, or generation plant adjustments at any of these stages.

Regional Application

Darwin/Katherine

In addition to above, LORR1 will also be issued if the sum of in service reactive power from Capacitor Banks in the system is below 25 MVAR.

Tennant Creek

As described above

Alice Springs

As described above

14 Determining fault level requirements

The Network Operator shall advise the Power System Controller of:

- the fault level rating of all transmission equipment down to feeder circuit breaker equipment at zone substations. This may include the fault level rating of distribution equipment as seen at the zone substation.
- any system configuration that may result in prospective fault levels above fault level rating of transmission, or distribution equipment.
- any system configuration that may result in prospective fault levels below the requirement for protection to operate as designed.

The determination of whether equipment or configuration which may breach fault level requirements shall include (but is not limited to) an assessment of the following:

- Possible configuration of distribution equipment.
- Possible network configurations (including during system restart).
- Possible generation dispatches (including dispatch for minimum/maximum demand or other worst case).
- Any other factor likely to contribute or detract from the fault level rating or minimum required fault level of switchgear.

The Network Operator will work in conjunction with the Power System Controller to develop operational configurations to mitigate risk of prospective fault levels exceeding ratings or below the requirement for protection to operate as designed.

The Network Operator shall assess fault levels for any relevant change to distribution or transmission equipment. This may include (but is not limited to) the following:

- Commissioning of equipment
- De-commissioning of equipment
- Protection setting modification
- Significant change in network or distribution configuration.

Specific requirements for fault level capacity are outlined in the Network Technical Code.

15 Determining adequate protection integrity

When a planned outage of a protection scheme for a transmission element is requested, the Power System Controller will assess the risk to system security and make a determination on the most appropriate action, be it to leave the transmission element in service for a limited duration, to take the transmission element out of service, and/or to put temporary protection equipment or measures in place.

When a planned outage is scheduled for one of two independent protection schemes on a transmission element, the duration shall be kept to a minimum, and not exceed eight hours, unless the Power System Controller has granted prior approval.

Protection schemes will only be considered independent if appropriate redundancy and separation of equipment exists, each protection system is capable of performing the same fault detection / isolation functionality, and each protection system has the facility to alert the Power System Controller via SCADA in the event of equipment failure. The requirement for separation of protection equipment extends to secondary equipment including, but not limited to, CT and VT secondaries, auxiliary supplies, cabling and wiring, circuit breaker trip coils, and battery and intertripping arrangements.

In accordance with the SCTC, a System Participant must advise the Power System Controller immediately whenever the System Participant becomes aware that any protection scheme equipment is not operating correctly. The System Participant is responsible for ensuring that the Power System Controller is kept informed while any such scheme is promptly and diligently repaired or replaced. The Power System Controller shall make a determination regarding the continued serviceability of affected HV equipment, and initiate any additional operational actions to mitigate the perceived risks.

16 Determining capacity of transmission assets

The Network Operator is responsible for determining ratings of the transmission assets. The Network Operator shall advise the Power System Controller of these ratings. The Network Operator shall provide ratings for transmission equipment in the manner specified by the Power System Controller:

- A minimum of 2 weeks prior to commissioning of any transmission equipment,
- immediately upon any assessed change to the rating of an asset
- whenever requested by the Power System Controller within an agreed timeframe

The Power System Controller shall utilise any limit provided by the Network Operator for a given asset as required for normal operation, planned maintenance or otherwise.

The Network Operator shall provide ratings according to the following terms which are used to determine the capacity of transmission assets:

Transformer Rating: The Continuous and Emergency Rating provided by Power Network (Asset Management) associated with the transformer.

Line Rating: The Continuous and Emergency Rating provided by Power Network (Asset Management) associated with the Transmission Line.

Bay Rating: The Continuous and Emergency Rating provided by Power Network associated with the related assets in the bay.

Relay Load Limit: The Continuous and Emergency Rating provided by Power Network (Test and Protection).

Normal Continuous Ratings: Continuous Rating with no time restrictions.

Emergency Rating: Emergency Rating with an associated time restriction provided.

Short Term Relay Load Limit 1 & 2: The exceedance of the MVA/Amps Limits provided for the specified time duration will trip the plant.

Effective Continuous Rating: The most conservative Continuous Rating between the Transformer Rating, Bay Rating and the Relay Load Limit.

If there is a rating or restriction on plant that does not fit in the terminology provided above, the Network Operator is still obligated to advise the Power System Controller.

Application

Refer to document "Secure System Guidelines Network Specifics".

17 Power system outage planning

In approving the disconnection of power system elements for scheduled and planned, generation or transmission outages, the Power System Controller will determine the specific requirements necessary to maintain the security and reliability of the power system for the duration of the outage. The requirements to maintain security and reliability will extend to cover the occurrence of credible contingency events that have been identified or reclassified as part of the assessment.

Generation outage approval

Planned generation outages, or planned transmission outages which place a constraint on generation, will be assessed based on reliability of the power system under a credible or protected contingency event. The Lack of Standby Generation criteria defined in Section 10 (Determining Standby Reserve) of the Secure System Guidelines will apply. Planned outages which trigger a breach of the LORR1 or LOS2 margin will not be granted approval. Planned outages which trigger a breach of the LOS1 margin will be assessed on a case by case basis and may be approved under the majority of circumstances, however a LOS1 condition will be declared.

When generation units are undergoing online testing, the Power System Controller will define the required spinning reserve or FCAS requirements (Contingency and Inertia FCAS may be specified) necessary to facilitate the testing while maintaining power system security and reliability.

Network outage approval

At all times, the power system must operate within its defined *technical envelope* and maintain system reliability. The ratings of power system elements supplied by the System Participant will be utilised to determine the *technical envelope* of the power system. Planned outages which trigger a breach of the LORR1 margin will not be granted approval.

In circumstances where planned network outages pose heightened risk to system reliability due to extended recall time, the System Controller may require a System Participant to submit an appropriate emergency restoration plan. Approval of such planned outages will be conditional on the acceptance of the emergency restoration plan.

Timeframe for Outage Planning

Refer to the SCTC for specific details associated with Annual Plant Maintenance Forecasts and Application for Plant Outages.

Any Application for Plant Outage less than the duration specified in the SCTC must provide sufficient justification for the lack of notice and requires approval by the Power System Controller.

18 Black Start and System Black Restart procedures

The SCTC requires that each Generation site capable of Black Start shall submit to the Power System Controller a procedure to start generation plant and prepare to take load when connected to the power system. To maintain the effectiveness of Black Start procedures they must be regularly audited, updated and resubmitted. The Power System Controller shall from time to time require that Black Start procedures be tested in a manner that will be agreed by the parties.

The SCTC requires that the Power System Controller develop a Black System Restart procedure. The guiding principles of the Black System Restart are:

1. Safety of public and personnel.
2. Integrity of Power System Plant and Equipment
3. Restoration of normal supply whilst maintaining conformance with the provisions of relevant Technical Codes and Secure System Guidelines.

In determining the priority for restoration of normal supply the guiding principles of the Black System Restart are:

1. Essential to any System Black Restart is the early identification of the cause of the System Black, in order that any causal condition is avoided in the process of Black System Restart.
2. The connection of a generation site that has completed its' Black Start to an appropriate type of load.
3. The interconnection of generation sites and the restarting of generation sites without black start capability.
4. The continued connection of load to the power system with priority given to Hospitals and facilities necessary to maintain the health and security of the public. Priorities may also be set as part of Disaster response processes of PWC and/or the NT Government.

Refer to document "Regulated Power System – Black System Procedures", or station specific black start procedures.

19 Generator and Load Registration Thresholds

The Power System Controller must be aware of any material step change in load or change in output of embedded generation to ensure supply to all customers is within the *technical envelope* and appropriate generation dispatched. As such thresholds for registration of generation (embedded or otherwise) and switchable loads are specified by region.

As part of the Network Connection process, a generator or load exceeding the region specific threshold shall be registered with the Power System Controller prior to connection.

The System Controller may impose various connection requirements for a registered generator or load including, but not limited to:

- High speed data recording
- Remote control capabilities
- Inter-trip or other protection schemes
- Operational communication requirements
- Ramp rates

These connection requirements will be determined on a case by case basis.

The Power System Controller may require a registered generator or load to exercise any of the following actions (the list is not exhaustive) for system security:

- Adjust output/load
- Voltage Control
- Frequency Control
- Disconnect

Regional Application

Darwin/Katherine

Registration Threshold: Connection in possible radial islands at Katherine, Pine Creek, Batchelor, or Manton Zone Substations:

200 kW

Connection in possible radial islands at Archer, Humpty Doo, Marrakai, Mary River, Palmerston, Strangways, Weddell or Wishart Zone Substations:

500 kW

Elsewhere within Darwin/Katherine System:

1000 kW

Tennant Creek

Registration Threshold: 30 kW

Alice Springs

Registration Threshold: 200 kW

20 Special Control and Protection Requirements or Schemes

The Power System Controller has oversight of the following control and protection schemes to cater for credible system security contingencies such that supply is maintained or returned to within the *technical envelope*:

DKTS System Status Signalling Scheme.

The Darwin Katherine Transmission System (DKTS) has connections to generation facilities at Pine Creek Power Station (PCPS) and Katherine Power Station (KPS).

In normal circumstances, if these facilities are on-line, PCPS and/or KPS will be under AGC control and their governors in Droop mode.

However, if any of the Lines, Busbars or Transformers become isolated under protection action or deliberate switching it is necessary to have governor and excitation modes switch to Isochronous (Isoch) and voltage control within a matter of seconds in order that frequency and voltage control be maintained. Table 1 shows Scheme responses to potential events:

DKTS element isolated	PCPS on-line	PCPS control mode	KPS control mode (if on-line)
CI-MT	Y	Isoch/Voltage	No change
CI-MT	N	No Change	Isoch/Voltage
MT-BA-PK	Y	Isoch/Voltage	No change
MT-BA-PK	N	No Change	Isoch/Voltage
PK-KA	Y	No Change	Isoch/Voltage
PK-KA	N	No Change	Isoch/Voltage

Further detail:

Connectivity is based on circuit breaker status, taken from the Gould AR PLC at MT, PK and KA. Circuit breaker status at CI is taken from the 132CI210 Circuit Breaker C60 relay. So a circuit breaker isolated for maintenance, and closed as part of the work, will cause a status change. The scheme was designed to deal with faults; if the outage is planned then part of the planning should be to manually select Isoch at the appropriate site for the duration of the work after the initial switching.

Signalling is carried out by microwave communications which are duplicated and pilot wire communications between PK and PC, which are not.

Both PCPS and KPS have separate and independent "Local Isoch" functions whereby circuit elements local to the power stations are monitored and also cause a change to Isoch mode.

Power Station Anti-Islanding Requirements

A Power Station that is not capable of maintaining appropriate Frequency and Voltage Limits while not operating in parallel with one or more other Power Stations connected to the Power System, shall have control/protection systems in place to immediately disconnect from the Power System at the relevant Connection Point, if that parallel connection is interrupted.

Under-Frequency Load Shedding Scheme.

Under the terms of the SCTC a UFLS scheme shall be implemented to ensure that where other provisions of the Secure System Guidelines fail to maintain frequency within the appropriate Limits appropriate Circuits/Load will be disconnected to the extent, and within the time required, that will return the Power System to a Satisfactory State.

Under normal operating conditions at least 75% of all load in each region is to be selected for UFLS.

Refer to document "Under Frequency Load Shed Schedule".

Over-Frequency Generator Shedding Requirements.

Over-Frequency Generator Shedding (OFGS) may be in place where other provisions of the Secure System Guidelines fail to maintain frequency within the appropriate limits appropriate generators will be disconnected to the extent, and within the time required, that will return the Power System to a Satisfactory State.

There are no current or planned OFGS schemes in place as the configuration and operation of the three regulated systems is such that the above requirements are met by generator protection. Within each region the generator over frequency protection settings shall be unique and provided to the Power System Controller. The System Controller may require changes made to over frequency protection settings of any generating unit and the participant will ensure these settings are changed promptly.

Refer to document "Secure System Guidelines Generation Specifics".

Embedded Generation Anti-Islanding requirements.

All Embedded Generation Plant (of any type/technology) that is permanently or occasionally connected in parallel with the Power System, shall have control/protection systems in place to prevent the possibility of exporting power into the Power System, unless that export is:

- in parallel with Power System source(s), and,
- explicitly permitted by a Connection Agreement, and, on each and every occasion of such export, by explicit permission from System Control.

Embedded Generation Anti-Paralleling requirements.

Where an Embedded Generation plant has multiple Connection Points to the Power System, control/protection systems shall be in place that prevent a parallel connection between one or more Connection Points, unless explicitly permitted by a Connection Agreement, and, on each and every occasion of such parallel, by explicit permission from System Control.

Power System Islanding Requirements

Depending on the topology and configuration of a Power System there may exist points at which connections may be opened in order that autonomous generation and load areas are formed, usually consequent to a major system wide disturbance, with the aim being to facilitate preventing a System Black event. While not implemented as of 2016 this is a provision that may in future be implemented if feasible.

21 Records

This policy is to be stored in:

- The System Control Operational Document Facility accessed through the intranet web site for System Control.
- Power and Water's Records Management System (RM8) in accordance with the Corporate Document and Record Control Procedure.
- Records are to be retrievable through Power and Water's Record Management System.

Upon specific request to the Power System Controller a record may be made available in part or full where appropriate.

References

References			
No.	**Document**	**Date**	**Location/HPE No.**
1	System Control Technical Code	May 2015	Published Online
2	Network Technical Code and Network Planning Criteria	Dec 2013	Published Online
3	Secure System Guidelines Generation Specifics		
4	Secure System Guidelines Network Specifics		
5	Alice Springs System Security Dispatch Constraints	05/08/2016	D2016/316637
6	Under Frequency Load Shedding Schedule	29/11/2016	BDOC2015/135
7	Regulated Power System – Black System Procedures	03/06/2014	BDOC2013/405
8	Channel Island Power Station Black Start	10/03/2017	TGEN DOC
9	Weddell Power Station Black Start	08-03-2017	TGEN DOC
10	Katherine Power Station Automated Black Start Procedure	13/03/2017	TGEN DOC
11	Ron Goodin Power Station Black Start		TGEN DOC
12	Owen Springs Power Station Black Start		TGEN DOC
13	Tennant Creek Power Station Black Start		TGEN DOC

22 Document History

As indicated in the cover page, the nominal review period of the Secure System Guidelines is one year, however it shall be reviewed earlier if a substantial change or addition is required.

Document History				
Revision	**Date**	**Status/Change**	**Updated by**	**Remarks**
2.6	Aug 2008	Issued	Ken Lewis	Issued
Draft 3	Dec 2016	Reviewed for consultation	Power System Controller	Reviewed. Substantive changes throughout. Ready for consultation.
Draft 3.1	May 2017	Consultation Preliminary Review changes	Power System Controller	Darwin-Katherine Spinning Reserve and C4/C5 Node contingency Short Term Advices included. Other minor changes.
Draft 3.2	June 2017	Consultation Review Changes	Power System Controller	Clarification on Frequency Control Ancillary Service usage/definitions. Alice Springs Short Term Advice included.
Version 4	July 2017	Issued as final	Power System Controller	Sections re-ordered. No other change from Draft 3.2 In effect from Wednesday 12/07/2017 at 12:00 hours
Draft 4.1	Dec 2018	Preliminary Consultation Draft	Power System Controller	Draft changes required by introduction of Generation Performance Standards
Version 4.2	Apr 2020	Issued as final	Power System Controller	Changes required by introduction of Generation Performance Standards