Discussion paper: C-FCAS requirements methodology

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Introduction

The Secure System Guidelines[1] (SSG) describes the application of ancillary services for the Northern Territory Power Systems, including those used to maintain the frequency as defined by the *Frequency Control Ancillary Services* (FCAS).

Contingency FCAS (C-FCAS) is the service used to recover power system frequency to a stable level following a contingency event. These contingency events are caused by the tripping of generators, loss of transmission network elements and loss of load leading to substantial power system frequency deviations.

Presently the Power System Controller operates all Regulated Power Systems based on a spinning reserve policy. This policy requires specific generator combinations to be scheduled and dispatched to provide the necessary reserves to enable frequency response for contingencies within the power system. To support dynamic spinning reserve requirements the Power System Controller raises Risk Notices to manage generator and network constraints on a seasonal basis. The daily management of the spinning reserve policy, especially for the Darwin-Katherine Power System (DKPS) requires a time consuming and demanding highly manual process.

The Power System Controller has researched and developed a methodology that dynamically assesses the credible contingency requirements for the DKPS, and schedules sufficient C-FCAS reserves on a real-time basis to account for the dynamically assessed credible contingency level.

Fundamentally both the proposed C-FCAS methodology and spinning reserve policy operate to the following principles:

- Dispatch sufficient contingency raise to prevent an UFLS for the largest credible contingency affecting supply (for example, the loss of the largest loaded generating unit or largest loaded transmission circuit – whichever is greater) and return the frequency to a stable level (not fully to 50 Hz) until other generation can be committed and dispatched to return the system to a normal operating state.
- Dispatch sufficient contingency lower to prevent an over frequency generator trip for the loss of any load and return the frequency to a stable level (not fully to 50 Hz), until the dispatch can be changed to return the system to a normal operating state.

Methodology

The C-FCAS methodology is based on the System Frequency Response (SFR) model that has been applied across various jurisdictions including the Wholesale Electricity Market in Western Australia[2] [3]. The SFR model has been further tailored to suit the specific dynamics and operational requirements of the DKPS. The SFR models are built using empirical data from historical frequency events. The model is continuously refined and regularly updated following significant contingency events and is dependent on the power system's response. The SFR model is calibrated using empirical data from past frequency events. These

[1] Power and Water Corporation - Secure System guidelines v4.2, 30th April 2020.

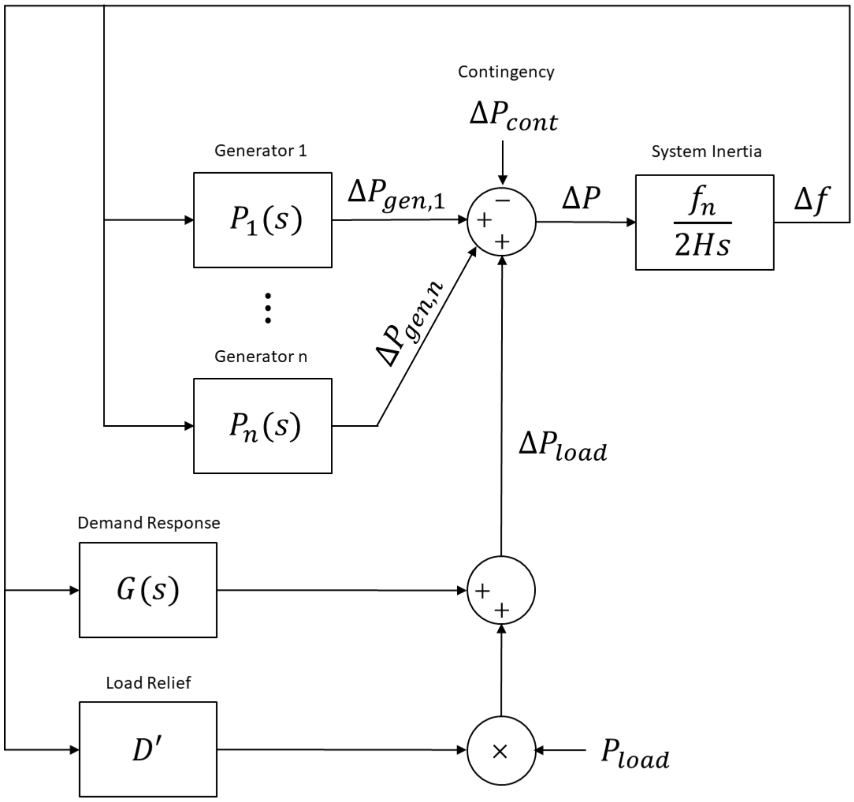
[2] A. Fereidouni, J. Susanto, P. Mancarella, N. Hong, T. Smit and D. Sharafi, "Online Security Assessment of Low-Inertia Power Systems: A Real-Time Frequency Stability Tool for the Australian South-West Interconnected System", 31st Australasian Universities Power Engineering Conference (AUPEC), Perth, Australia, 2021, pp. 1-9, doi: 10.1109/AUPEC52110.2021.9597823.

[3] R. Frost, T. Smit, A. Fereidouni and M. Dalton, "Utilisation of a Real Time Frequency Stability tool to support operating decisions in a reduced inertia power system", CIGRE Cairns Symposium, 2023

historical events provide a realistic basis for tuning the model parameters, ensuring the SFR reflects actual system behaviour during frequency disturbances.

The SFR is a simplified single mass machine model for the DKPS and incorporates parameters that reflect the system's dynamic response to frequency disturbances. The simplified SFR model is presented in Figure 1 below.

Figure 1 - Simplified SFR Model Representation



The SFR model parameters include:

- Generating unit power response to frequency changes, including:
  - Inertia, which represents the kinetic energy stored in large rotating generators and industrial motors.
  - Governor action, which represents changes in generator output as a function of frequency deviation.
- Demand response, which is not currently present across the DKPS.
- Load relief, which accounts for the natural reduction in load as frequency decreases.
- Load inertia, representing the stored kinetic energy in rotating loads that contributes to frequency stability.

The integrity of the SFR model depends on its alignment with the actual generator responses and system parameters during frequency events. SFR parameters represent how individual units and the whole system responds to sudden frequency changes. The Power System Controller is responsible for initial accreditation and the maintenance of C-FCAS generating units' accreditation, as well as ensuring that system-level parameters in the model are properly tuned.

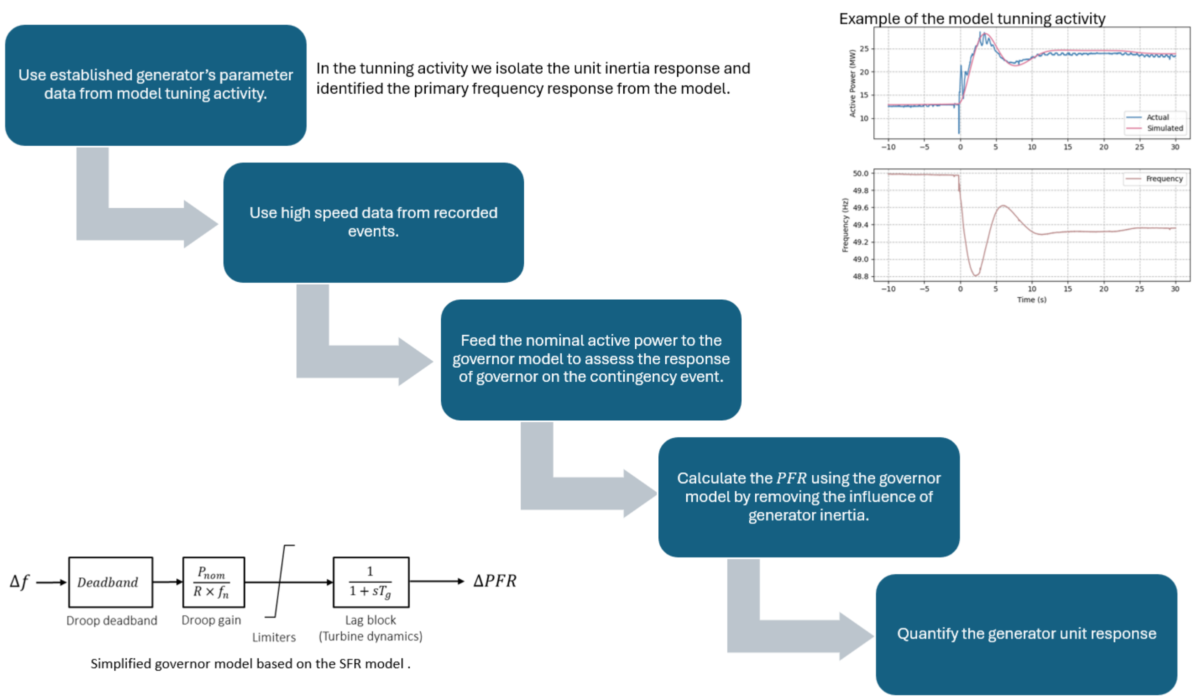
The SFR model is a key operational feature of a newly developed operational application that provides the Power System Controller with real time decision support for generator unit commitment and dispatch. The application provides real-time insights allowing assessment of sufficient C-FCAS to maintain system frequency following a credible contingency. The C-FCAS application will provide prediction of the frequency response, and the system response based on the assessment of the committed generation and system load.

If the SFR model indicates that the available C-FCAS is insufficient—namely, the predicted nadir frequency falls below the acceptable threshold or response in MW is insufficient—the Power System Controller will be prompted to take corrective action. This may include adjusting the dispatch of existing generating units or, where necessary, committing additional generators to restore sufficient contingency reserves. The determination, and subsequent scheduling and dispatch of C-FCAS system requirements will remain at the discretion of the Power System Controller.

Unit accreditation process

The C-FCAS unit accreditation process will be carried out using a governor model based on the SFR methodology. The modelling will be performed to assess the Primary Frequency Response (PFR) of each C-FCAS unit based on the empirical data (historical events). A simplified block diagram of the governor model is presented alongside the detailed assessment steps in Figure 2 below.

Figure 2 - Unit accreditation diagram



SFR model assumptions

The System Frequency Response (SFR) model is a commonly used tool for predicting frequency dynamics and it relies on several assumptions. It treats all generators and loads as being at a single node, ignoring network topology and constraints like thermal limits. This has been modelled and is not considered to be an issue for the DKPS. It assumes a single average frequency across the system, which is reasonable for a compact system like DKPS where generators are electrically close to one another.

The model also assumes voltage remains well-regulated before and after disturbances, which holds true when voltage control is adequate, and loads are not overly sensitive to voltage changes. It uses simplified models for governor and primary frequency response, making it less suitable for long-term simulations where the detailed complex dynamics of turbines may become more relevant, for example, the behaviour of gas turbines operating at low frequency over more than 5 minutes may not be sufficiently captured by the SFR.

System and load inertia estimation

Total system inertia (KE_{sys}) is estimated based on the empirical value of post contingent events using two common methods:

- the sliding window method[4]; and
- the polynomial fit method (also called the Inoue method)[5].

Inertia from online synchronous generators (KE_{gen}) is calculated using SCADA data and known generator inertia values. Load inertia (KE_{load}) is then calculated by subtracting generator inertia from total system inertia:

$$KE_{load} = KE_{sys} - KE_{gen}$$

This estimate captures any unmeasured synchronous inertia, such as from behind-the-meter generators or synchronous motors. In the DKPS, early estimates and modelling shows that load inertia contributes around 25% of total system inertia.

Load relief factor estimation

Estimates for the load relief factor (D) are based on the following simplified equation:

$$D_{est} = \frac{\Delta PFR_{qss} - P_{cont}}{\Delta f_{qss} \times P_{load}}$$

where D_{est} is the estimated load relief factor (% MW / Hz)

ΔPFR_{qss} is the aggregate PFR delivered at the quasi-steady state (MW)

P_{cont} is the contingency size (MW)

Δf_{qss} is the frequency deviation at the quasi-steady state (Hz)

P_{load} is the pre-contingent system load (MW)

Preliminary estimates in DKPS indicate a load relief factor of 2.5-4.0% MW/Hz.

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[4] P.M. Ashton, C.S. Saunders, G.A. Taylor, et al., "Inertia estimation of the GB power system using synchrophasor measurements," IEEE Transactions on Power Systems, vol. 30, no. 2, pp. 701-709, 2015

[5] T. Inoue, H. Taniguchi, Y. Ikeguchi and K. Yoshida, "Estimation of power system inertia constant and capacity of spinning-reserve support generators using measured frequency transients," in IEEE Transactions on Power Systems, vol. 12, no. 1, pp. 136-143, Feb. 1997, doi: 10.1109/59.574933.

Implementation

The methodology is proposed to be implemented in a staged manner, commencing with the DKPS, where there is likely to be the largest operational efficiencies coupled with improved power system security.

The transition from the spinning reserve policy to the FCAS methodology for each Regulated Power System will follow due process that requires the development and integration of several applications. The process for the DKPS includes:

- Research and development of the methodology and simulation thereof utilising historical data.
- Development of operational systems, tools and applications for FCAS management.
- Concurrent consultation of the methodology together with proposed amendments to the Secure System Guidelines (SSG).
- Accreditation of C-FCAS generating units.
- Trial implementation of the application of FCAS management (shadowing the application of spinning reserve limits).
- Operational readiness assessment, fine tuning followed by full operationalisation.
- Formal notification to licensed participants of final transition to FCAS management.
- Retirement of the obsolete spinning reserve limits giving effect to the revised SSG.

Notwithstanding the progress already achieved in the development, testing and trial use of the methodology, the transition into real time operations will span a considerable period ensuring that the security of the DKPS is not compromised through the implementation.

Following successful implementation across DKPS, a similar process will be followed for Alice Springs and Tennant Creek power systems to the extent necessary.

Contact

NTESMO Power System Controller
Core Operations
market.operator@powerwater.com.au
powerwater.com.au