SW Advisory

29 July 2022

AEMC
Ben Hiron / Clare Stark
Sydney 2000

Dear Ben and Clare,

Re: Submission on frequency control options in the NEM using a market approach

Further to our discussion on the 20 July 2022 about a unified market in frequency control, considering both frequency based and inertial response, we would like to submit our ideas to the AEMC to allow a more formal consideration of the approach. The submission comprises:

- A presentation by SW Advisory describing the mathematical equations defining the approach
- A high-level presentation by Tim George providing and overview of the approach and indicating the relative merits of a market as opposed to a mandated approach
- A short summary of the approach in Appendix A of this letter.

Please note that this effort in defining this novel approach to frequency control is of an academic nature and is totally ***unfunded***. It represents the outcomes of discussions and sense of frustration at the apparent move away from market solutions, and market development generally, and a drift back to a 'system control' approach with little regard to the cost of mandating services.

Both companies – SW Advisory and DIgSILENT Pacific – have supported the work by Messrs Wallace and George but do not necessarily support the outcomes or findings. The views expressed in this submission do not represent official company positions.

We would also take this opportunity to apologise for the delay in this submission and we hope that it can nevertheless be included in your considerations.

Yours sincerely,

Tim George
For Tim George and Stephen Wallace

Melbourne (Head Office)
Level 13, 484 St Kilda Rd
Melbourne
VIC 3004
+61 3 8582 0200

Perth
Suite 11, Level 2,
189 St Georges Terrace
Perth, WA 6000
+61 8 6220 6700

Brisbane
Level 5, 82 Eagle Street
Brisbane
QLD 4000
+61 7 3144 6400

Sydney
Suite 28.03, 31 Market Street,
Sydney
NSW 2000
+61 400 339 416

@digsilent-pacific
info@digsilent.com.au
digsilent.com.au

Appendix A Submission on unified frequency control market

A.1 Background

Frequency control in an environment of reducing inertia requires different resources and a revised approach if frequency is to be consistent with the frequency operating standards (FOS). The prospect of a net zero environment in 2050 and significant emissions reductions by 2030 makes these considerations urgent. There is a temptation to apply minimum change to existing arrangements to solve the incremental transition to a lower inertia environment. There is a further temptation to mandate solutions to manage a perception of risk, without a serious cost-benefit assessment that is required in the National Electricity Law, specifically the national energy objective (NEO).

In this submission we argue that the adoption of incremental and mandated solutions is unlikely to meet the NEO as there are alternative solutions that can be shown to have better efficiency, increased practicality, and longevity as they are not technology specific.

A.2 Fundamental requirements of any frequency control strategy

The frequency operating standards (FOS) define the frequency control requirements to deliver both a secure operating condition and the required quality of frequency control. Of these, the requirement for power system security dominates.

A.2.1 Frequency control quality

The quality of frequency control, perhaps measured as the closeness of the control to the nominal 50 Hz value, is not that critical. There are few processes on the demand side that a highly dependent on good frequency control and problems are only likely to emerge when frequency control is extremely poor, say outside of a 0.5 Hz band. We believe there have been few complaints from consumers about frequency control quality in the past and the development of power electronic equipment with converters at the front end will tend to further isolate consumer processes from frequency control quality issues. Assigning a value to the quality of frequency control is thus challenging.

A.2.2 Frequency control and power system security

Frequency is a measure of the supply-demand balance and large excursions represent large imbalances that may affect the ability of the power system to reman in a secure operating state. The FOS defines (or should define) the acceptable operating envelopes for frequency required to deliver secure operation of the power system. The frequency control arrangements should thus target compliance with the FOS. Should the frequency move outside of these envelopes, more extreme actions to address the supply-demand imbalance may be required, such as load shedding or generator output reduction, including tripping [1].

A.2.3 Frequency control objective

The starting point in defining a frequency control strategy should logically be the FOS. It is the output that the frequency control strategy is required to achieve.

A.3 Swing equation

The swing equation defines the frequency response of the power system and includes the dependencies on:

- The size of the disturbance in the supply-demand balance (ie the size of a generator or load contingency)
- The inertia of the power system, which is readily calculated from the synchronous machines connected to the power system, plus any synthetic inertia available from inverter-based resources.

The swing equation can be used to estimate what sort of frequency response must be provided to deliver a frequency outcome that complies with the FOS.

It is highly relevant that this swing equation includes inertia – it is integral to the management of frequency within a power system and cannot efficiently be removed or partitioned from the arrangements being put in place to manage frequency, at least note when the quantity of inertia in the power system is significantly reduced.

A.4 Controlling frequency

Having defined the require frequency control outputs in the FOS, and the frequency dynamics in the swing equation, there remains the consideration of sources of frequency control. In essence, any resource that can affect the supply-demand balance can influence frequency and can therefore be recruited to control frequency. Each of these resources will have a cost associated with their application to the control of frequency.

A key challenge for the control of frequency is to understand how the available resources respond and then to recruit those resources that are best suited to meeting the requirements of the FOS ***at the lowest cost***.

The ideal outcome would be to:

- Understand what the frequency requirements are at a given time:
  - Inertia on the power system
  - Largest credible contingency
- Select from the available frequency control resources sufficient quantities to maintain frequency within the FOS
  - As many resources are possible
  - The most efficient resources to meet the objective
- Manage non-credible contingencies with overarching requirements on all participants
  - These are rare and inefficiencies in a generic requirement are likely to be small
  - Load shedding is an example of a generic requirement for control of under-frequency events

Since many resources that are able to provide frequency control services are also energy resources (loads or generators), an efficient solution should be co-optimised with the energy market.

A.5 Procurement of frequency control services

The frequency control problem is well understood and enables the required services to be specified with some degree of confidence. Challenges in procuring these services include:

- The requirement changes with time – different generation profiles will affect inertia and the size of the largest credible contingency
- Required response times preclude the use of SCADA-based controls and necessitate autonomous response, historically referred to as primary frequency control
- There are at least two fundamental services required:
  - Control in the normal operating frequency band (as defined in the FOS), which will typically have an objective a requirement to consider:
    - Frequency itself
    - Tie line flows between control areas (the NEM Mainland currently is operated as one control area)
  - Control to manage contingencies

Procurement of services can be by means of:

- Markets
- Competitive and transparent contracting by the system operator (here AEMO) or some other body Mandated service provision.

In our view the order of preference is as given, with the least efficient solution being mandated provision.

A.6 Conceptual approach for a unified frequency control market

The control of frequency, as indicated by the swing equation, includes consideration of:

- Inertia
- Contingency size

- Frequency control services, offered by equipment that can vary its generations or consumption in proportion to the change in frequency

Using the swing equation and the FOS, the authors have developed a solution (it is unlikely to be unique) that incorporates both frequency control services and inertia in a unified approach that makes it possible have:

- One market for frequency control, which incorporates inertia
- Co-optimisation with the energy market
- The FOS as an objective function
- The swing equation to define the nature of the services required to meet the objective function
- A clearing price for both frequency control services and inertia

Details of the formulation of the approach are outlined in [2] [3]and [4].

Taking this approach would be a significant rationalisation of the NEM but would also provide a long-term rather than an interim solution. It would also provide a 'light on the hill' to guide interim solutions, which should remain consistent with this view.

Furthermore, as a market solution, it should be preferred over non-market solutions, which typically are opaque and have unquantified costs and no market signals to encourage investment or incentivise innovation. The authors have a view that the predilection for mandated solutions is driven by unquantified threats of consequences and comparisons with power systems that may be quite dissimilar to the NEM. Given the objectives in the NER and the NEO, it should be necessary to prove that a market solution will not deliver efficient outcomes before any of the less efficient approaches are justified.

A.7 Sources of costs and benefits

Taking the position that a market-based solution is preferred, the authors suggest that benefits are likely to arise in the following areas:

- Providing the required (ie necessary) amount of the service in order to meet the FOS
  - A mandated solution is likely to over-provide the required services
  - A contracted solution would likely be based on conservative assumptions for requirements but would likely be better than a mandated solution
- The complexities of different services for different operating conditions (eg inertia, contingency size) will be challenging for procurements that are not based on assessments of system conditions, leading to conservative assumptions on quantities and therefore cost
- Some providers would prefer not to provide frequency control services because their plant is more efficient operating at a steady output (example include super-critical fossil plant, variable renewable energy plant)
- At least at a conceptual stage, it would seem better for efficient providers to control frequency while inefficient providers can avoid costs associated with providing a low value service.
- Investment signals will encourage innovative solutions to improve frequency control
- Investment signals will encourage alternative sources of services to offer frequency control services, including loads.
- Service providers can assess the true costs of service provision and take these into account when offering a service, improving the efficiency of the market overall
- Service providers are rewarded for the value of their services, including synchronous machine inertia, which is paid at the clearing price for inertia.

A.8 Conclusion

The authors present the conceptual approach in this submission as an alternative approach, rather than a ready to go solution. A great deal more work will be required to deliver an operational solution. However, the challenge is no more difficult than those faced when the NEM was first established, including the need to bring those with less conviction of market solutions to a point where they can be satisfied that security will be maintained.

The leverage of market solutions can be significant. In a large market, a small efficiency gain can deliver significant benefits to end users.

Further, a key objective of markets is to encourage investment (from sources other than governments). Solutions providing transparency and fair value for services provided should be encouraged. The drift towards a NEM with characteristics familiar to the bad old days of ‘system controllers’ rather than markets should be discouraged. Frustration with recent developments was a driver for the authors to spend unfunded time exploring options that may provide a more robust and efficient outcome and still be robust to technology changes that we expect in the energy transition currently running its course.

Our findings are that there is a high probability that there are market options available that will meet the requirements of the frequency operating standards (FOS) and provide a far more efficient outcome than other approaches, including a mandated approach or the introduction of a stop-gap measure such as an inertia market. Our perception is that market-based solutions have not received the attention they deserve and that this raises a question in relation to the application of the NEO.

This submission is unfunded and does not represent the views of the authors’ companies.

A.9 References

[1] P. Denholm, T. Mai, R. W. Kenyon, B. Kroposki and M. O’Malley, “Inertia and the Power Grid: A Guide Without the Spin,” National Renewable Energy Laboratory. NREL/TP-6120-73856, Golden, CO, 2020.

[2] T. George, S. Wallace, J. Crisp, L. Mardira and J. Leung, “Exploring options for new frequency control ancillary service markets in the Australian National Electricity Market,” IEEE 10.1109/ISGTAsia49270.2021.9715660, New York, 2021.

[3] S. Wallace, “Presentation: SWA DIgSILENT presentation to the AEC on 'Spot market for inertia and FCAS 20th July 2022',” SW Advisory, Sydney, 2022.

[4] T. George, “Presentation: FCAS markets,” Digsilent Pacific, Brisbane, 2022.

Integrated Spot Market for Inertia and FCAS

Slides for discussion with the AEMC
on 20th July 2022

Stephen Wallace   SW Advisory
Tim George   DIgSILENT

SW Advisory and **DIgSILENT**

The challenge

- Can we develop a ***new*** approach to frequency control that:
  - Meets the Frequency Operating Standard defined for the power system
  - Takes advantage of new technologies (rather than putting a band-aid on legacy systems)
  - Rewards the service providers that are good at providing efficient frequency control
  - Encourages innovative solutions to meet the Frequency Operating Standard and
  - Recognises the likely trajectory for the energy transition currently under way in Australia?

Principles of an inertia and FCAS market

- Should be:
  - Based on the Frequency Operating Standard
  - Recognise the value of response speed
  - Consider inertia and synthetic inertia
  - Be co-optimised with the energy market
  - Flexible enough to respond to changing mixes of generation technologies
  - Able to manage a range of islanding or potential islanding situations

Table A.3: Summary of mainland system frequency outcomes for an interconnected system

CONDITION	CONTAINMENT BAND (HZ)	STABILISATION BAND (HZ)	RECOVERY BAND (HZ)
No *contingency event* or **load event**	49.75 – 50.25 49.85 – 50.15[1]	49.85 – 50.15 within 5 minutes	
Generation event or **load event**	49.5 – 50.5	49.85 – 50.15 within 5 minutes	
Network event	49.0 – 51.0	49.5 – 50.5 within 1 minute	49.85 – 50.15 within 5 minutes
Separation event	49.0 – 51.0	49.5 – 50.5 within 2 minutes	49.85 – 50.15 within 10 minutes
Protected event	47.0 – 52.0	49.5 – 50.5 within 2 minutes	49.85 – 50.15 within 10 minutes
Multiple contingency event	47.0 – 52.0 (reasonable endeavours)	49.5 – 50.5 within 2 minutes (reasonable endeavours)	49.85 – 50.15 within 10 minutes (reasonable endeavours)

Note: 1. 99% of the time.

Source: AEMC Reliability Panel

Outline of proposed co-optimised FCAS and inertia market

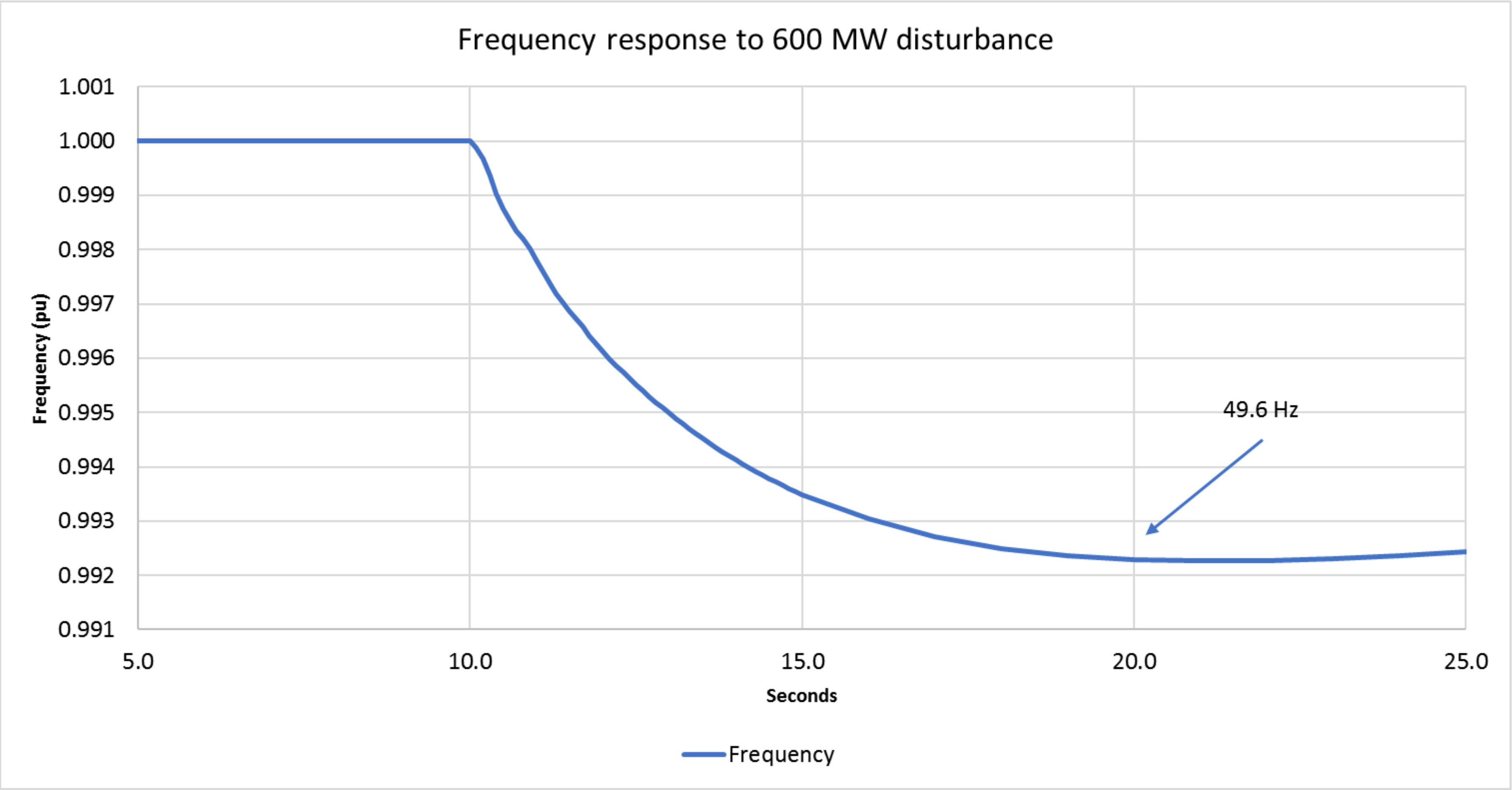
- Uses the Australian Frequency Standard
  - For a generation/load contingency – permissible frequency deviation is =/- 0.5 Hz
- Calculates requirements using the swing equation

$$\frac{df(t)}{dt} = \frac{\omega_o}{2H}\,(P_m - P_e) \text{ where } \omega_o = 1 \qquad [1]$$

$$Rate\ of\ change\ in\ frequency(t) = \omega_o \frac{generation(t)\ - load(t)}{2\ \times System\ inertia}$$

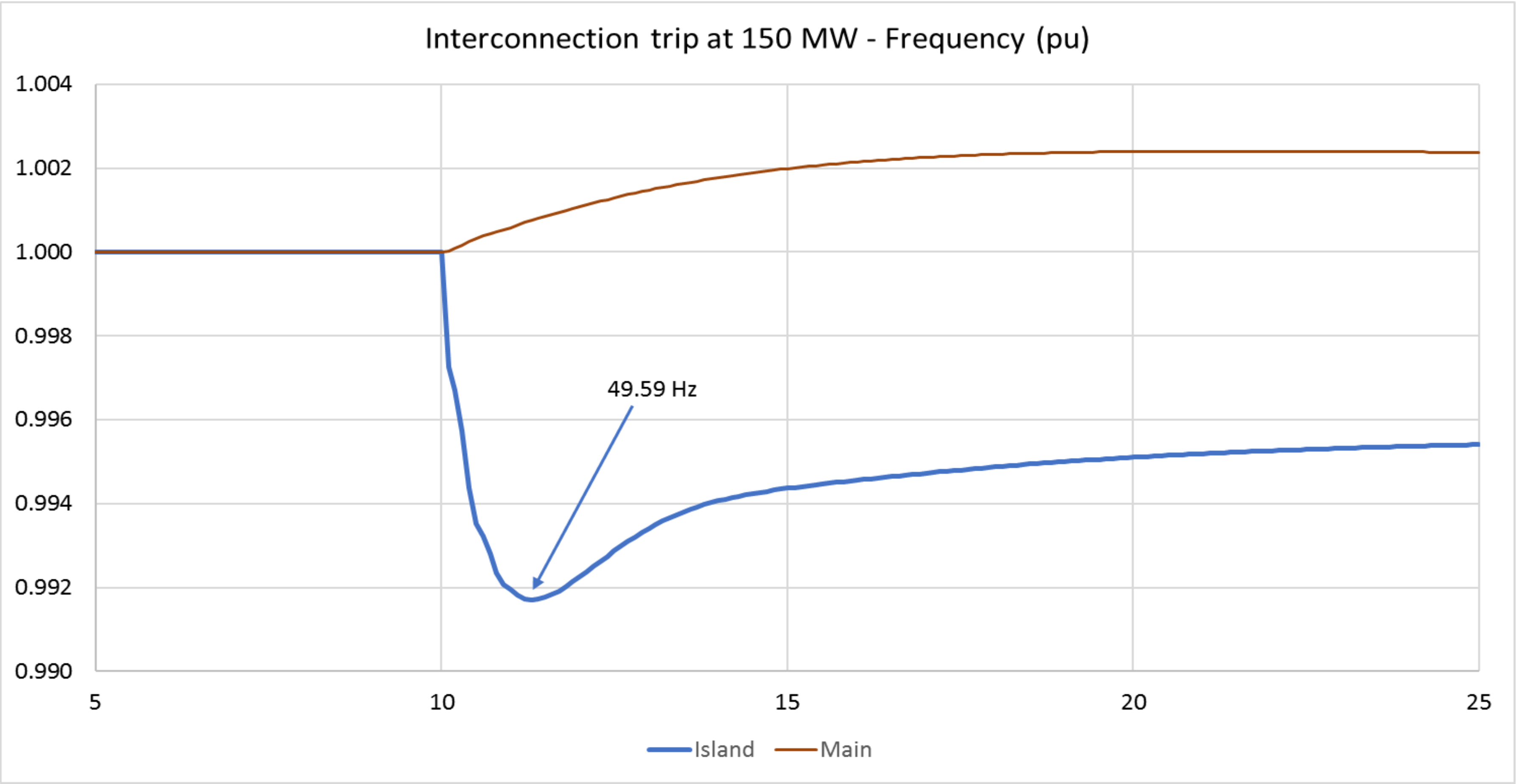
- Considers the response profile available from generators offering the service
- Yields linear constraint equations that can be co-optimised with the energy market
- Includes inertia (as in equation 1)
- Provides market clearing prices (shadow prices) for:
  - Inertia
  - Primary frequency responses

Frequency following a 600 MW contingency in a high inertia environment



Frequency nadir occurs after 10 seconds from the time of the contingency

Frequency following a 150 MW islanding contingency with a lower inertia island



Frequency nadir occurs around 2 seconds after the time of the contingency
In an even lower inertia environment the frequency nadir could occur in less than 1 second

Low inertia environment

- In a lower inertia power system compared to a high inertia one:
  - The rate of change of frequency (RoCoF) is much higher
  - The frequency nadir following a contingency occurs in a much shorter time
  - To manage frequency within the Frequency Operating Standard requires more fast response
  - The speed of response required to manage frequency will change as inertia decreases
  - Hardwiring FCAS contingency categories does not make sense while system and potential island inertias rapidly change

Modelling inertia and FCAS

- Two key points:
  - Swing equation is the basis of the proposed formulation of a co-optimised dispatch of FCAS and inertia
    - It links frequency, FCAS provision, a contingency event and inertia
  - The frequency Standard sets the upper and lower bounds for frequency
    - Linear constraints for an optimisation can be determined by combining the frequency Standard with the swing equation

- The following slides present key elements of the equations in the our IEEE presentation

Modelling inertia and FCAS

- The swing equation can be re-written as the frequency at time T given the frequency at time 0

$$f(T) - f(0) = \int_0^T \frac{1}{2H}\left(P_m(t) - P_e(t)\right) dt \quad [2]$$

$$= \frac{energy\ in - energy\ out}{2H}$$

- The impact of a contingency event occurring at time 0 and its mitigation through the total amount of contingency FCAS provided at time t by all providers is

$$\left(P_m(t) - P_e(t)\right) = FCAS(t) + load\ relief(t) - contingency(t) \qquad [3]$$

- The frequency Standard requires that the frequency $f(T)$ is between the Standard's upper and lower bounds:

$$F_{lb}(T) \leq f(T) \leq F_{ub}(T) \quad [4]$$

Modelling inertia and FCAS

- The upper and lower frequency standards can be converted into constraints, for the lower bound

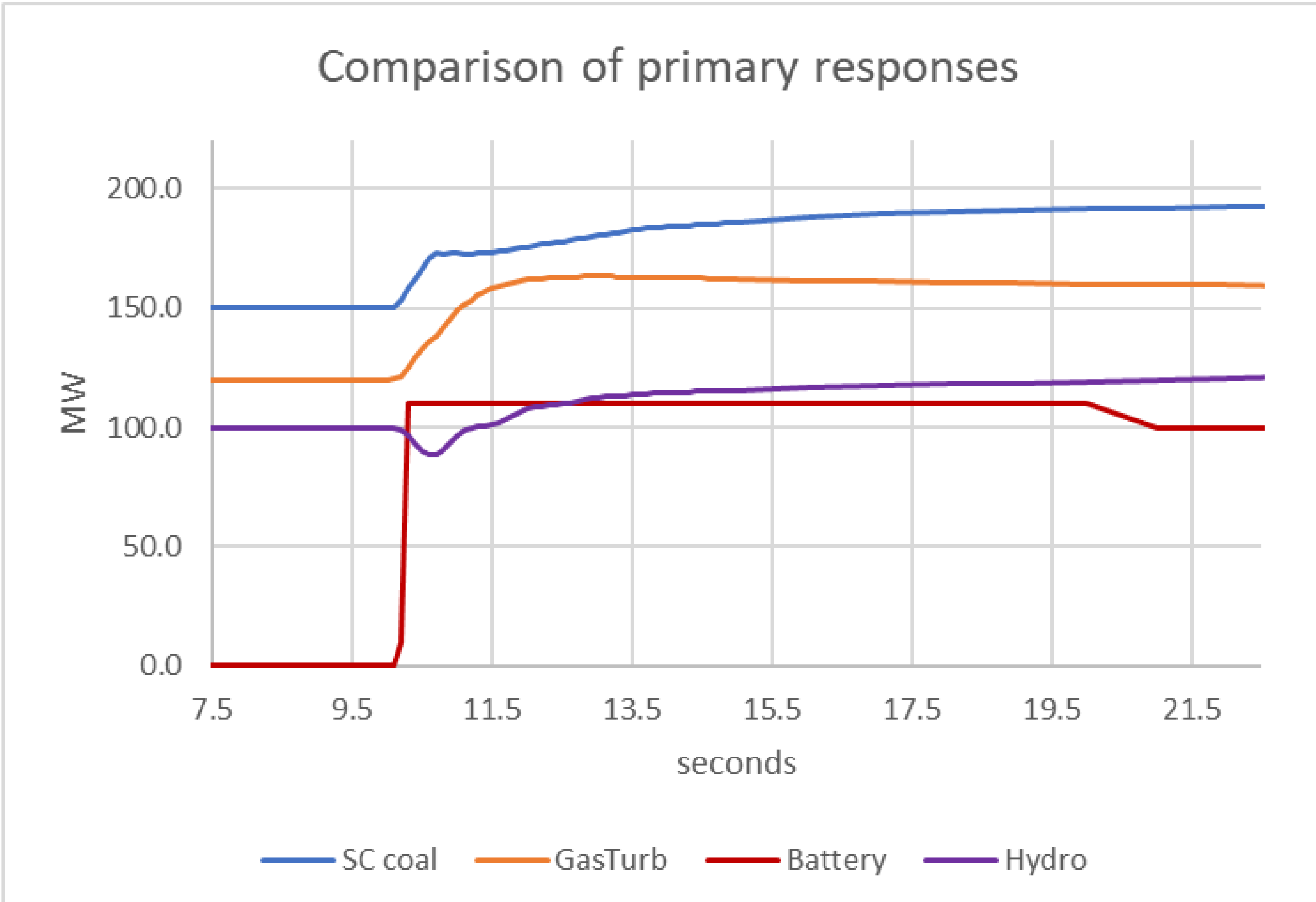
$$F_{lb}(T) - f(0) \ \leq \ f(T) - \ f(0) = \int_0^T \frac{1}{2H}\left(P_m(t) - \ P_e(t)\right) dt$$

$$2H\left(F_{lb}(T) - f(0)\right) \leq \int_0^T FCAS(t) + load\ relief(t) - contingency(t)\ dt$$ [8]

- In order to manage frequency, given the system inertia H, it is the FCAS profile that matters

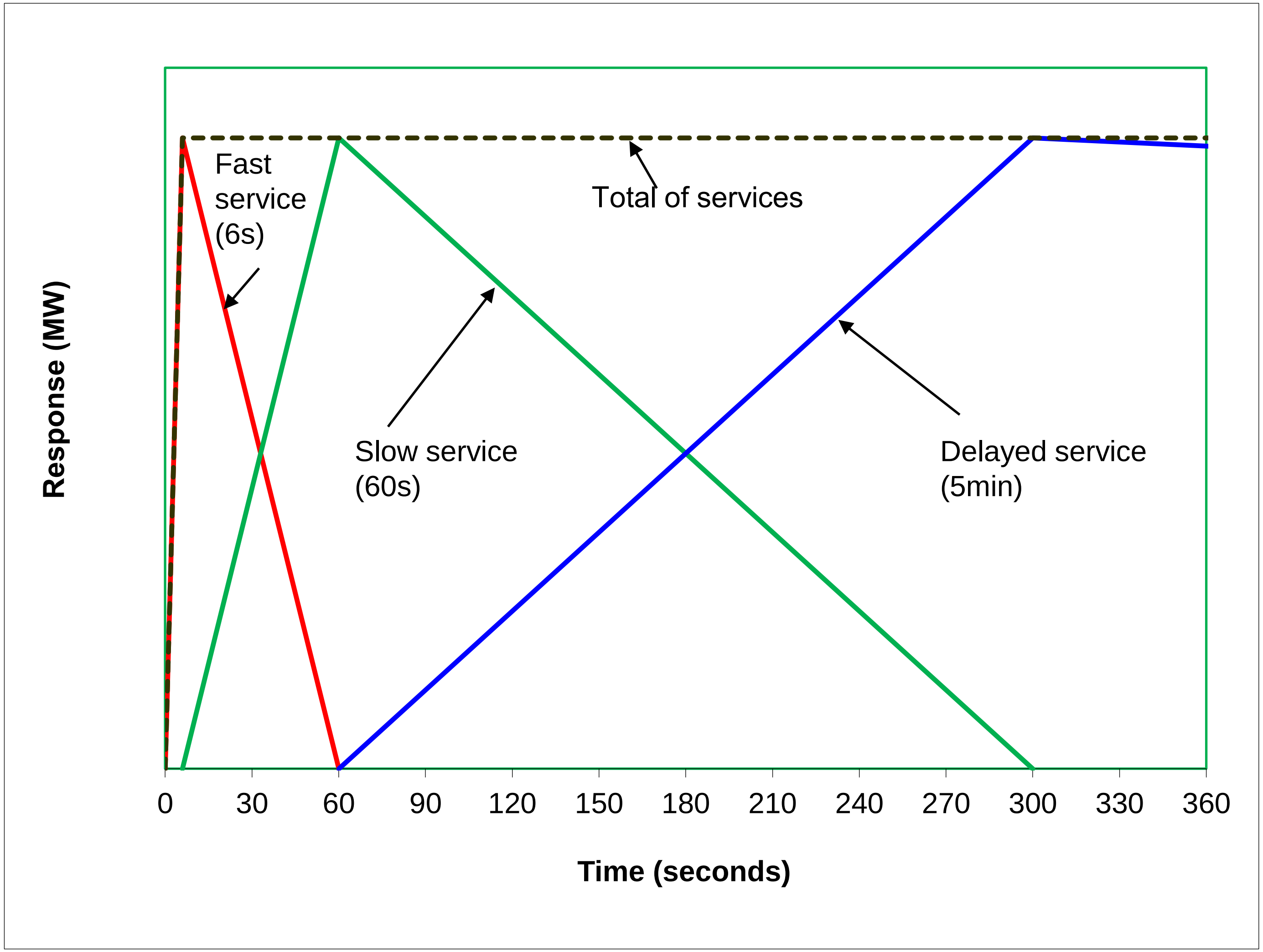
$$\int_0^T FCAS(t)dt$$

Different technologies can provide different FCAS response profiles



Responses of different generation technologies to a drop in frequency at 10s

The NEM uses a model of 3 basic FCAS profiles



Modelling primary frequency response (FCAS)

- Assume that each contingency FCAS provider can deliver a profile of additional MWs over time, t, following a contingency
- Create a standardized profile $fcas(j,t)$ at time t for provider j by dividing its profile by its maximum output over the FCAS provision period
- The FCAS co-optimization can be set up such that the amount of the FCAS profile from provider j that is enabled is a decision variable, $X(j)$.
- The total amount of FCAS enabled at time t is

$$FCAS(t) = \sum_{j \; in \; providers} X(j) \times fcas(j,t) \qquad [5]$$

- The integral of FCAS(t) over the period 0 to T is:

$$\int_0^T FCAS(t)\, dt = \int_0^T \sum_{j \; in \; providers} X(j) \times fcas(j,t) \; dt$$

$$= \sum_{j \; in \; providers} X(j) \times \int_0^T fcas(j,t)\, dt \qquad [6]$$

Modelling Inertia and FCAS

- If inertia is dispatched like energy and $Y(k)$ is a decision variable that determines whether provider k is selected, then

$$H = \sum_{k\ in\ providers} Y(k) \times H(k)\ [7]$$

where H(k) is the inertia of unit k and $0 \leq Y(k) \leq 1$

- The upper and lower frequency standards can be converted into constraints. For the lower frequency bound

$$F_{lb}(T) - f(0)\ \leq\ f(T) -\ f(0) = \int_0^T \frac{1}{2H}\left(P_m(t) -\ P_e(t)\right) dt$$

$$2H\left(F_{lb}(T) - f(0)\right) \leq\ \int_0^T FCAS(t) + load\ relief(t) - contingency(t)\ dt\ \ [8]$$

- If the equation above is rearranged and the decision variables are put on the left-hand side, it becomes

$$\int_0^T FCAS(t)\ dt\ \ - 2H\left(F_{lb}(T) - f(0)\right) \geq\ \int_0^T contingency(t) - load\ relief(t)\ dt \qquad [9]$$

- Note that:
  - Dispatch variables are on left hand side of the equation
  - Equation is solved each Tm, where {Tm} is a set of predetermined time points following a contingency

Turning the FCAS and inertia model into constraints

- $Y(k)$If equation [6] and [7] are substituted into equation [9] then the result is a linear equation in the decision variables $X(j)$ and $Y(k)$

$$\sum_{j\ in\ FCAS\ providers} X(j) \times \int_0^T fcas(j,t)\ dt - 2\left(\sum_{k\ in\ inertia\ providers} Y(k) \times H(k)\right)\left(F_{lb}(T) - f(0)\right)$$
$$\geq\ T \times contingency - \int_0^T load\ relief(t)\ dt \qquad [10]$$

- To operationalise equation [10] in a linear programming optimisation a number of discrete time points, Tm, must be chosen to ensure that the post contingency frequencies always remain within the Frequency Standard. (the set {Tm} is just input data)
- One point that is worth mentioning is that for inertia the commitment variable $Y(k)$ would be a real variable on the interval [0,1], i.e. 0<= $Y(k)$<= 1 rather than a binary variable. The reason for doing this is to get marginal cost prices for inertia and FCAS. If binary variables are used this generally can't be done. Units with a partial commitment (0< $Y(k)$ <1) would be required to commit.

Outcomes from the FCAS constraint

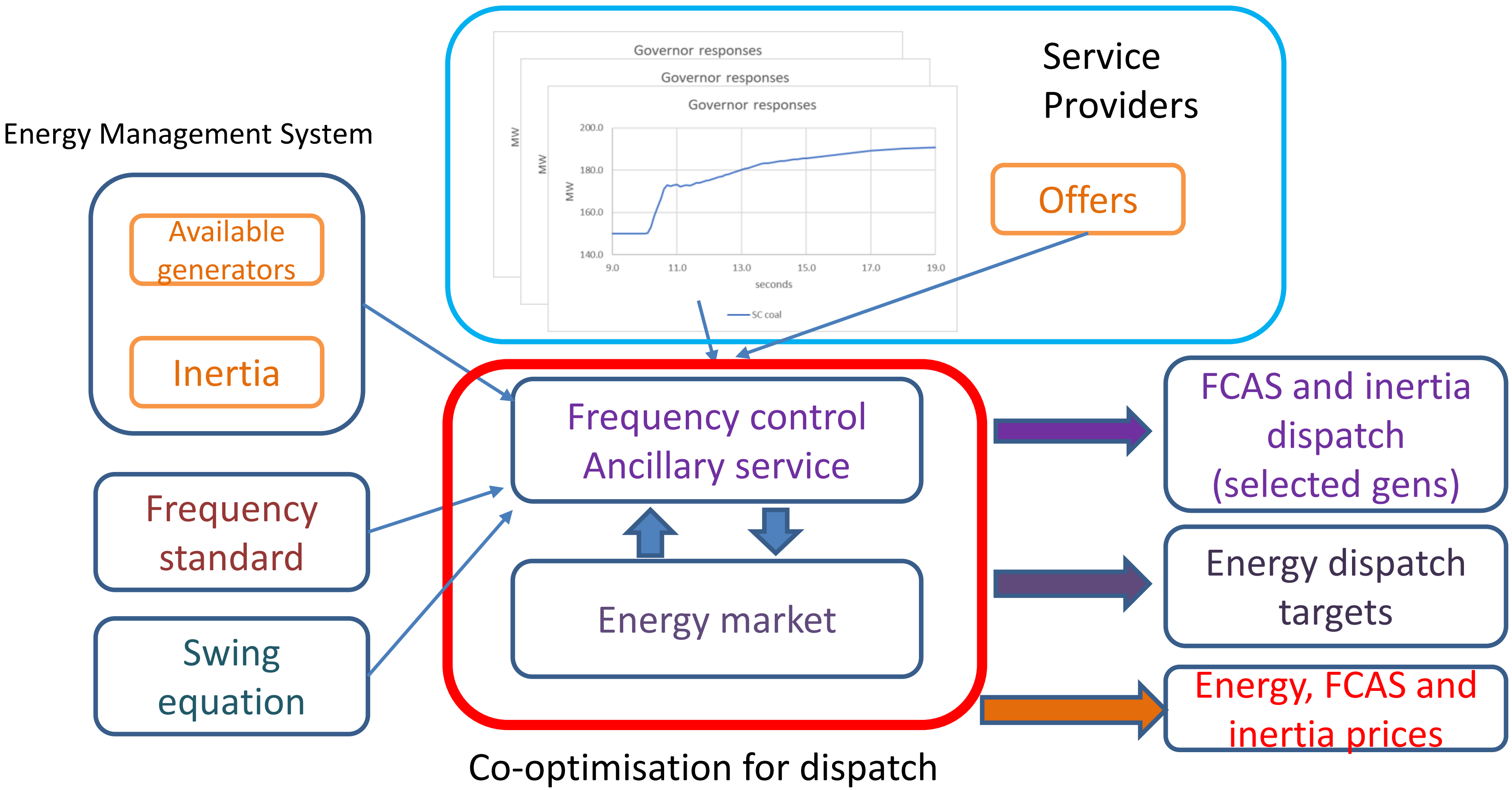
- The response is made up of two elements:
  - An inertial component (proportional to -dF/dt)
  - A contribution from FCAS provider
- In the early stages of the response, the FCAS contribution is zero and inertia is the only response
- In the later stages of the response, dF/dt is positive and the inertia increases the required FCAS response
- For each time Tm modelled in the optimisation as a constraint there will be a corresponding shadow price (marginal cost) which is the market clearing price for the services and each service provider will get paid the shadow price x their coefficient in the constraint
- A provider of an FCAS service will get paid for all of the time periods they provide a service:

$$\sum_{Tm\ in\ T} shadow\ price(Tm) \times X(j) \times \int_0^{Tm} fcas(j,t)\ dt \qquad [11]$$

- A provider of an inertia service will get paid

$$\sum_{Tm\ in\ T} shadow\ price(Tm) \times 2 \times H(k) \times (F(0) - F_{lb}(Tm)) \text{ if } Y(k) > 0 \quad [12]$$

Overview of solution



Practical implementation

- Incorporating inertia into a co-optimised inertia, FCAS and energy formulation means:
  - Pricing signals for both real and synthetic inertia
    - Technology like super-capacitors may see a reason for investing
    - Providers of synthetic inertia can compete with synchronous machine (SM) inertia providers
    - SM providers may have a reason to turn on
    - Synchronous Condenser investors will have a reason to add inertia
  - Optimal trade-offs between inertia and FCAS can be made
    - More units may be committed to provide inertia if very high speed FCAS is expensive and vice versa
  - Configurable implementation
    - The response is based on the time steps chosen which in turn generate the linear programming constraints. These time steps are just input data and hence selectable
    - Need close spacing of time steps immediately after a contingency, then longer time steps as the time following the contingency increases. The NEM FCAS service has effectively just used 3 time steps: 6s, 60s and 5min

Contacts

- Stephen Wallace: 02 6452 3501, 0419 23 43 53, stephen.swadvisory@gmail.com or swallace@snowy.net.au
- Tim George: 07 3236 3416, 0409 799 105 or Tim.george@digsilent.com.au

Frequency control markets

How to efficiently manage frequency control, including inertia

Tim George
FCAS Markets discussion - AEMC
20 July 2022

POWER SYSTEM ENGINEERING AND SOFTWARE

DIgSILENT

What is so special about inertia?

Inertia has similar characteristics to fast frequency control

Synchronous machines provide inertial response

- Proportional to df/dt (known as ROCOF in US)
  - More inertia means lower df/dt
    - SM provide slower inertial response
  - Less inertia means higher df/dt
    - SM provides rapid inertial response
- Inertial energy must be provided back to the SM as the frequency recovers
  - Zero sum gain

Need for inertia

A power system can operate with no inertia

Inertia and fast response from inverter based generators can make up for a lack of, or low, inertia

In the NEM we are likely to have inertia for the foreseeable future – Hydro generation, synch cons, biofuel plant, Hydrogen plant

- Need to have something that works for low (but not zero) inertia
- This implies frequency will remain an indicator of supply-demand unbalance

As inverter-based generation reduces inertia, there are many ways that frequency control can still be managed.

Challenge is to make sure that the ‘right stuff’ is there to provide frequency control

NREL report – 2020

Denholm, Paul, Trieu Mai, Rick Wallace Kenyon, Ben Kroposki, and Mark O'Malley. 2020. *Inertia and the Power Grid: A Guide Without the Spin*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6120-73856. https://www.nrel.gov/docs/fy20osti/73856.pdf.

"Intended to educate policymakers and other interested stakeholders, this report provides an overview of inertia's role in maintaining a reliable power system, why inertia may decrease with increasing deployment of wind and solar generation, and how system reliability can be maintained in the evolving grid. "

Using power electronics, inverter-based resources including wind, solar, and storage can quickly detect frequency deviations and respond to system imbalances. Tapping into electronic-based resources for this "fast frequency response" can enable response rates many times faster than traditional mechanical response from conventional generators, thereby reducing the need for inertia.

Replacing conventional generators with inverter-based resources, including wind, solar, and certain types of energy storage, has two counterbalancing effects. First, these resources decrease the amount of inertia available. But second, these resources can reduce the amount of inertia actually needed—and thus address the first effect. In combination, this represents a paradigm shift in how we think about providing frequency response.

Frequency response (droop) and inertia can be substitutes

High inertia system

Control	High inertia	Low inertia
Slow frequency control	more	less
Fast frequency control	some	more
Very fast frequency control	less	lots

Low inertia

Table 1. Summary of Factors That Drive Frequency Stability

Factor	Impact of Greater Amount[a]
Generator inertia	Slows down frequency decline
Load inertia and load damping	Slows down frequency decline
Contingency size	Increases frequency decline
Underfrequency limits (UFLS settings)	Lower UFLS settings provides more time for overall response
Frequency response speed	Responds faster to a decline in frequency

[a] Assumes no other factors change

NREL 2020

Characteristics of the power system

Characteristic	Variability	Observability	Controllability
Inertia	Changes as plant switches on or off	Easy – the AEMO EMS can see all plant on line	Poor. Intrinsic characteristic of plant
Primary frequency response	1. Changes with load 2. Changes with tech	Poor – used autonomously	Vague Currently mandated
Frequency control	Changes with inertia and PFR	Excellent – anywhere in the NEM	Well understood
Synthetic inertia	Depends on plant enabled	High – can be dispatched, visible in EMS	Very good - programmable

FCAS and inertia are related

Mandate or market

AEMC, AEMO

Feature	Mandate	Market
Quantity	All	What is required for the delivery of the frequency operating standard (FOS)
Quality	Variable – all types from low value to high value	What you need for FOS
Type of 'service'	All types, conservative assumptions to cover every conceivable case	Depends on needs. Still conservative but nothing like the mandate
Homogenous	No – separate PFR / Inertia	Yes – trade-off of PFR and inertia takes place
Incentives	No – penalties, Some incentive from CP	Yes – good providers earn more All service providers paid for service. Not mandated
Innovation	No – opposite?	Yes – attracts efficient providers
Resilience	Yes – at unquantified cost	Can be made so

Vision – long term view of frequency control

1. Output driven
   - Frequency operating standard (FOS)
2. Inertia and frequency response
   - Unified market including inertia and frequency response
3. Data driven
   - Actual plant response/inertia are part of the offer (no bins eg 1s, 6s etc)
4. Three markets
   - Raise/Lower contingency services
   - Normal operating frequency band : +/- 0.15Hz, AGC
5. Resilience
   - Mandatory response outside +/- 0.5 Hz (symmetrical to load shedding)

Implementation

1. Feasible
   - Formulation of co-optimisation is possible in NEMDE (but more complicated)
   - NOFB market similar to current co-optimisation
2. Data
   - Provider response capability – based on standard tests
   - EMS calculation of online inertia
   - If required, rate of change of frequency (df/dt) constraint assessment
3. Communication
   - FCAS data as part of 5 min bid data – selection of profiles
   - Autonomous response for contingency services – dispatched units are armed

Sources of benefits

1. Technology neutral
   - Enables any potential source of inertia/freq response to participate – improves competition
   - Reduces need to re-regulate as new technology or tariff structures appear
2. Co-optimised with energy market
   - Need for freq response services continuously variable
   - Cost of providing freq response generally depends on energy prices
   - Efficiency benefits – uses lowest cost providers for current conditions
   - Reduces eight markets to five (contingency R/L, Regulation R/L, NOFB response) and avoids a separate inertia market
3. Matching required services and time frames (Inertia and Freq resp) to calculated need
   - Avoids oversupply and associated costs
   - Encourages efficient providers
   - Reduces need for conservative ‘rules of thumb’ and enhances transparency
4. Provides signals for efficient investment
   - Inertia price and frequency response price give clear signals – clearing price for both inertia and freq resp
   - Encourages other providers, including loads, to participate
5. No mandates – Generation can choose to offer if economic
   - Allows plant like supercritical coal, VRE to run without PFR
   - Reduces spill from VRE
   - Encourages VRE participation if prices are low or negative
6. Power system resilience maintained as all generation provides a response at +/- 0.5 Hz

Melbourne (Head Office)

Level 13,
484 St Kilda Rd
Melbourne VIC 3004

+61 3 8582 0200

Perth

Suite 11, Level 2,
189 St Georges Terrace
Perth, WA 6000

+61 8 6220 6700

Brisbane

Level 5, 82 Eagle Street
Brisbane
QLD 4000

+61 7 3144 6400

Sydney

Level 28, Market Street
Sydney
NSW 2000

@digsilent-pacific
info@digsilent.com.au
digsilent.com.au

Exploring options for new frequency control ancillary service markets in the Australian National Electricity Market

Tim George
DIgSILENT Pacific
Brisbane, QLD, Australia
tim.george@digsilent.com.au

Stephen Wallace
SW Advisory
Cooma, NSW, Australia
stephen.swadvisory@gmail.com

Dr Jennifer Crisp
DIgSILENT Pacific
Brisbane, QLD, Australia
jennifer.crisp@digsilent.com.au

Levin Mardira
DIgSILENT Pacific
Brisbane, QLD, Australia
levin.mardira@digsilent.com.au

Dr Joseph Leung
DIgSILENT Pacific
Melbourne, VIC, Australia
joseph.leung@digsilent.com.au

***Abstract* — The energy transition in Australia is creating challenges and opportunities for frequency control. Reducing inertia introduces challenges, while the high-speed response available from inverter-based generators and storage systems create opportunities that have the potential to offset the downsides. A formulation of the swing equation shows how frequency control and inertia can be considered in a market-based frequency control framework. The benefits include pricing signals for both frequency response and inertia as well as avoidance of the opportunity and maintenance costs of mandated frequency response solutions.**

I. Background

Inverter-based generation (IBG), including battery storage, is forecast to continue at high levels in Australia's National Electricity Market (NEM). A key outcome is that the system inertia is likely to decrease to a floor set by synchronous renewable energies (hydro and pumped storage) and synchronous condensers which are installed for system strength [1] purposes. The resulting increases in the rate of change of frequency can create problems for all generation and increase the challenge in managing power system frequency within the specified limits.

II. Frequency dynamics

The power system frequency is governed by the swing equation, which takes account of the supply-demand balance and the inertia of all the generators in the power system.

$$2H/\omega_o \frac{d^2\delta}{dt^2} = P_{mech} - P_{elec} \qquad (1)$$

where:

- H is the system inertia (MWs), considering all connected synchronous and other rotating machines
- δ is the voltage angle with first derivative being frequency and second derivative being acceleration
- P_{mech} is the combined generation – actually a misnomer as some generation (solar, batteries) have no mechanical input
- P_{elec} is the combined load
- ω_o is the nominal speed in pu (equal to unity)

The frequency operating standard typically specifies acceptable frequency deviations for credible and non-credible contingencies as well as recovery times following a disturbance [3].

All of the data in (1) are readily accessible in near real time, with the exception of the load relief [2]. This is a probabilistic value that is selected to be conservative and typically applied as a constant. Excellent documentation of existing frequency control approaches is provided in several documents published by the North American Reliability Council (NERC) [2] [4] [5].

III. Maintaining nominal frequency

Frequency must be controlled over several timeframes. Traditionally, these timeframes are as shown in Fig.1 below, reproduced from [4]:

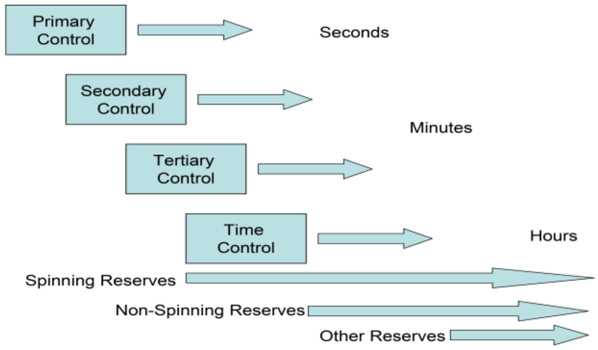


Fig 1. Traditional frequency control response categorisation (NERC)

Of particular interest in Fig. 1 are the first two categories, which control frequency in the short term 0-20 seconds, say) and then the longer-term average frequency 20 seconds to five minutes, say).

A. *What is changing?*

Many key variables in frequency control are changing:

- Inertia is falling as synchronous generation is replaced by IBG
- IBG is able to respond and inject/absorb active power much faster that turbine-driven machines
- Load damping is reducing as more motor loads are controlled by power electronic converters
- Traditional automatic under-frequency load shedding (AUFLS) may not work properly as inertia drops and frequency changes become more rapid

- Ramp rates will likely increase significantly with large solar penetration (morning and evening) for uncompensated plant
- Generation is becoming more dispersed with many smaller units
- Communication systems are significantly improved, offering realistic options for the deployment of fast acting wide area controls

Of these changes, one of the more significant positives is the rapid response available from inverter-based systems like battery energy storage systems, supercapacitor storage systems and even doubly fed induction hydro generators. Of the negatives, the need to re-think AUFLS is likely to become urgent as the inertia drops, even modestly, and the logical evolution means that response times need to be shorter.

B. *Apects of frequency control*

In [3] there are three main areas of interest:

- The normal operating frequency band (NOFB) spanning +/- 0.15Hz around nominal 50 Hz;
- The contingency band, representing frequency control for credible generation, load contingencies and network contingency events, including credible separation events; and
- The multiple contingency band where a single or multiple event is severe and rare, that it is not typically planned for in terms of provision of primary response.

Mandating primary frequency response from every generator is an attractive solution in that it improves all three of these bands of interest. However, the approach ignores the very real costs incurred in providing the response: the impact on, for example, battery cycling and the provision of pricing signals to encourage innovation and more appropriate frequency control from market participants.

Market-based solutions are unlikely to be effective in the case of very severe, and rare, contingencies. In these cases, requiring all generating systems to contribute to the restoration of frequency is reasonable and aligned with the demand-side contribution through AUFLS.

However, the first two bands of interest lend themselves well to market solutions and regulators are encouraged to look at more innovative approaches that deal with both primary response and inertia.

C. *How good is frequency control since mandated frequency response was introduced?*

In 2020 primary frequency response (PFR) was mandated in the NEM. Generally, all generating systems must provide PFR unless operating at technical limits. There is no limitation of the response.

Prior to this mandated requirement, there was very little primary frequency response in the NOFB as generators disengaged frequency influence on governors for a number of reasons. This makes it possible to broadly compare the performance of frequency control before and after the mandatory PFR change. Interestingly, the comparison will also provide an indication of how much primary frequency control is actually required to control small frequency excursions in the NOFB, highlighting that the 'all generator' mandate is likely delivering significantly more control effort than is needed.

For economic efficiency, it will be desirable to dispatch the required services and recruit those generators best able to provide these services through a market arrangement. The quantum of frequency control required to manage frequency in the NOFB can be estimated by looking at the period when governors with frequency influence were largely inactive.

The frequency of the power system is a reflection of the supply-demand balance together with any control systems that are acting to restore the frequency to the setpoint (nominal frequency). In a power system with no (or very little) primary response, the frequency can be analyzed to estimate the size of the unbalance on the right hand side of equation (1). The following approach was discussed in [6].

Using equation (1) and taking account of the load frequency dependency K_f as follows:

$$P'_{elec} = P_{elec_0} * \left(1 + K_f * \Delta f\right) \tag{2}$$

Equation (1) can be re-arranged as:

$$P_{acc} = 2\, H_{sys} \frac{df_{pu}}{dt} * S_{sys} + P_{sys} * \frac{K_f(f - 50)}{50} \tag{3}$$

where:

- P_{acc} is the accelerating power or the unbalance between the supply and demand (RHS of eq(1))
- S is the total load (or generation) in *MVA*
- *sys* subscript refers to the whole power system
- *pu* refers to per unit

In a power system with little primary frequency response, equation (3) gives an indication of the required frequency control response in order to restore the supply-demand balance. In a power system with active governors delivering primary frequency response, equation (3) gives an indication of the residual supply demand imbalance but requires also an estimation of the frequency control effort being delivered.

Having an estimate of the supply-demand unbalance on the power system allows the *sensitivity* to factors such as inertia or load damping factor K_f to be assessed through simulation studies. In [6] and [7], this approach is used to apply a 'disturbing load', which is calculated from measured frequency using equation (3), in simulation studies that could then be used to estimate future performance.

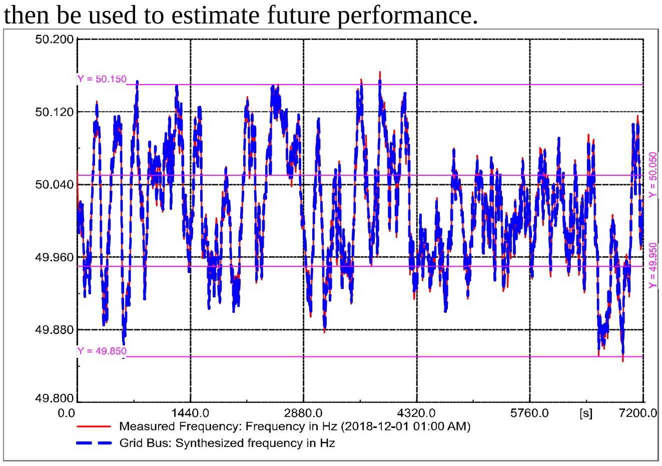


Fig 2. Measured and synthesized frequency – pre-mandate period

Fig. 2 compares the "synthesized frequency" which is the calculated from the disturbing load and the corresponding governor actions against the actual measured frequency measured in the pre-PFR mandate period. The plot illustrates accuracy of the simulation model and the loosely controlled frequency during the period. Based on the simulation model, the corresponding accelerating power required to stabilize the system frequency is presented in Fig. 3. This pre-PFR response shows that the actual level of unbalance is less than 200 MW peak to peak. That is, if there was a PFR source in the NEM that could provide that range of MW injection/absorption with a sufficiently high bandwidth, it would, conceptually, address the supply-demand unbalance and correct the frequency. In the mandated PFR case, the frequency control is of course improved but the source is now from some 20-30 GW of generation, which is many times the calculated range.

Comparison of the actual measured frequencies between the pre- and post- mandate periods is shown in Fig. 4. What this comparison shows is that for the periods considered, the extent of the supply-demand imbalance is greatly attenuated when every NEM generator is providing PFR.

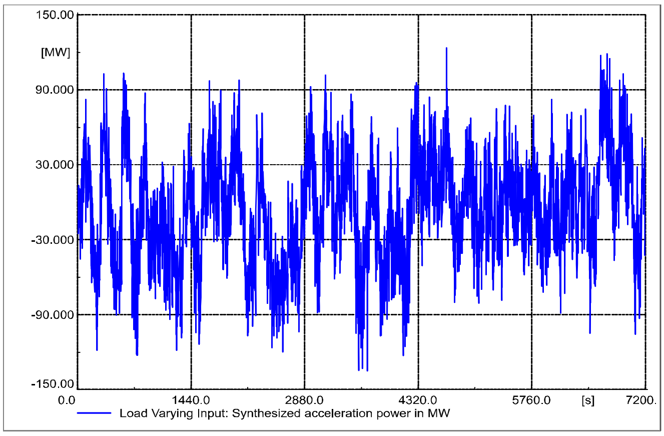


Fig 3. Calculated acceleration power (Pacc) – pre-mandate period

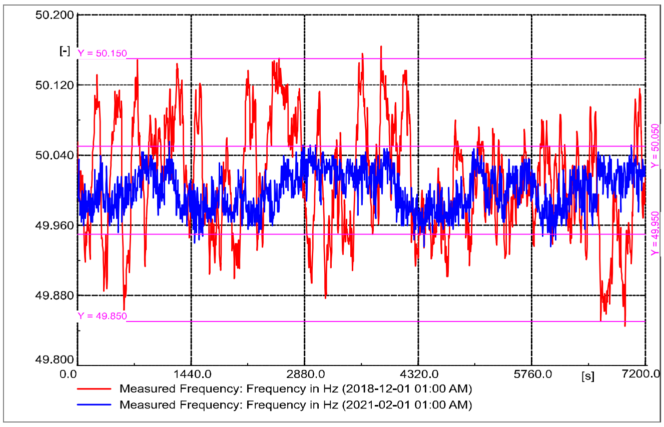


Fig 4. Measured frequency, pre- and post-mandate period

Comparisons based on two hours of data are not realistic or meaningful other than to illustrate the possibility that, perhaps, the same level of frequency control might be possible from fewer providers, particularly if those providers are specialists with fast responding controllers.

This raises a question then as to whether it is feasible and practical to deliver the required NOFB frequency control services via market mechanisms rather than a mandated service.

D. Frequency response following a contingency

Control effort required for frequency outside the NOFB for more common contingencies can be calculated based on:

- Size of the permissible frequency excursion (e.g. 0.5Hz), from the frequency standard [3]
- Total system load (from the energy management system (EMS))
- Actual system inertia (from EMS)
- Load frequency dependency K_f based on a probabilistic analysis of system frequency performance over a period of time
- Largest contingency to be considered (from EMS)

In the NEM, this control of frequency for contingencies has been achieved through six frequency control ancillary service (FCAS) markets. These markets are co-optimized with the energy market and performance is periodically audited to ensure offered services are delivered. The mandated PFR effectively adds a significant 'free' component to this service. While the performance for contingency frequency control significantly benefits from this added response, the cost of service provision is not weighed against the benefit provided and some providers incur cost in providing the 'free' service. In fact, the need for the contingency FCAS is likely significantly reduced and the need for a market in lower services appears superfluous and potentially also for raise services as well.

IV. FREQUENCY CONTROL IN A MARKET

Assuming that markets deliver more efficient outcomes than regulated requirements, interest then turns to whether an FCAS market is still warranted, given the performance (but not cost) of the mandated regime. In the case of the NEM, such markets have existed for the contingency and regulation (secondary control) bands for over 20 years.

While solving the identified problems, the mandated solution is not market-based, nor does it take into consideration the costs and inefficiencies of making all plants respond at all times to the frequency excursions. Wind and PV solar generation suffer material opportunity costs in terms of lost generation. Battery systems incur opportunity costs for having their batteries charging or discharging continuously, which can rapidly consume their contracted annual number of charge and discharge cycles. Coal-fired generators, particularly super-criticals, are most efficient when providing steady output and all turbine-driven generators suffer wear when continuously regulating.

Similar mandated operating requirements are widely used in North America and Europe, where system inertias are high and frequency deviations are small because the relative size of a contingency is small. Consequently, variations from generating systems are smaller and costs consequently lower.

The appropriateness of these mandated settings for a much smaller power system is being trialed over a three-year period, when the PFR requirement will be reviewed. It is hoped that any evaluation will include not only the technical outcomes but also the costs incurred by all generators.

For the trend in declining inertia, proposals are expected whereby minimum levels of inertia may be imposed.

The following sections outline a market-based approach to deliver both NOFB and contingency frequency control ancillary services in a market-based framework.

Resilience, the philosophy of trying to make the power system less susceptible to major outages, can be managed in a similar approach to AUFLS, using broader deadbands and requiring less intensive active power variations when frequency is being adequately controlled.

A. *The market-based approach for NOFB control– an overview*

Within the NOFB the frequency control problem is related to changes that occur in the supply-demand balance as a result of imperfect forecasting and dispatch as well as variations in load and generation, including daily load cycles and sun-up, sun-down ramping.

In a five-minute dispatch interval, it is reasonable to expect that responses of service providers will be reset every five minutes through the dispatch process. The magnitude of the response required can be determined through analysis of historic records (similar to Fig. 2) and the assessment of ramps can be assessed in simulation studies, similar to [7].

With the IBG response capabilities, there is an opportunity to incorporate fast responding (in hundreds of msec) service providers in addition to slower providers (in tens of seconds) as well as the secondary control provided by the EMS via AGC. The latter has a bandwidth which limits its response times to around 30s, so any NOFB service providers with the ability to respond faster than this can be expected to improve the quality of control.

From a market perspective, it is foreshadowed that NOFB service providers would have zero deadband and would offer volume and response time services based on system operator requirements. The dispatch of this service would be based on a supply-demand intersection and co-optimization with the energy market would be relatively straight forward.

NOFB FCAS service providers would limit their responses to the upper and lower limits of the NOFB.

B. *The market-based approach for contingency band control– an overview*

Co-optimizing energy, frequency control services and inertia recognizes that the swing equation links frequency and inertia in a way that can be incorporated as linear constraints in an optimization. The other component of the approach is to recognize that each contingency FCAS provider can deliver a defined profile of additional MWs over time following a contingency.

In the market systems, the optimization would model the swing equation and thus directly model frequency following a contingency event. Specifically, the swing equation (1) can be rewritten as:

$$\frac{df(t)}{dt} = \frac{\omega_o}{2H}\,(P_m - P_e) \text{ where } \omega_o = 1$$

$$f(T) - f(0) = \int_0^T \frac{1}{2H}\big(P_m(t) - P_e(t)\big)\,dt \qquad (4)$$

A power system's frequency standards require frequency f(T) to between a lower bound $F_{lb}(T)$ and an upper bound $F_{ub}(T)$ after T following a credible contingency, that is:

$$F_{lb}(T) \le f(T) \le F_{ub}(T)$$

The system frequency can be rewritten in terms of the starting frequency at the time of the contingency or the frequency at which the contingency services are meant to kick in *f*(0), the size of the contingency, the profile of FCAS being provided and any load relief:

$$f(T) - f(0) = \frac{1}{2H}\int_0^T [FCAS(t) + load\,relief(t) - contingency(t)]\,dt \qquad (5)$$

For the lower bound on frequency, it can be written as:

$$2H\left(F_{lb}(T) - F(0)\right) \le \int_0^T [FCAS(t) + load\,relief(t) - contingency(t)]\,dt \qquad (6)$$

For the upper bound it can be written as:

$$\int_0^T [FCAS(t) + load\,relief(t) - contingency(t)]dt \le 2H\left(F_{ub}(T) - F(0)\right) \qquad (7)$$

Each contingency FCAS provider can deliver a profile of additional MWs over time, t, following a contingency. If we create a standardized profile $fcas(j,t)$ at time t for provider j by dividing its profile by it maximum output over the FCAS provision period, then the FCAS co-optimization can be set up such that the amount of the FCAS profile from provider j that is enabled is a decision variable, $X(j)$. The profile itself can change with provider offers to reflect the capability of the plant for the time offered.

Now the total FCAS enabled at time t, FCAS(t), is composed of a linear sum of the profiles of the selected FCAS provider responses weighted by the enabled quantities, $X(j)$.

$$FCAS(t) = \sum_{j\ in\ providers} X(j) \times fcas(j,t) \qquad (8)$$

Now the integral of FCAS(t) over the period 0 to T is:

$$\int_0^T FCAS(t)\,dt = \int_0^T \sum_{j\ in\ providers} X(j) \times fcas(j,t)\ dt$$

$$= \sum_{j\ in\ providers} X(j) \times \int_0^T fcas(j,t)\,dt \qquad (9)$$

where $0 \le X(j) \le$ maximum FCAS from provider *j*

Similarly, if inertia is dispatched like energy and $Y(k)$ is a decision variable that determines whether provider k is selected then:

$$H = \sum_{k\ in\ providers} Y(k) \times H(k) \qquad (10)$$

where *H(k)* is the inertia of unit *k* and

$$0 \le Y(k) \le 1$$

Note that strictly $Y(k)$ is a binary variable but it can be modelled as a continuous variable and each generator can manage partial dispatches just like generators manage minimum loading levels in the energy market.

For the lower bound on frequency:

$$\sum_{j\ in\ FCAS\ providers} X(j) \times \int_0^T fcas(j,t)\,dt + \int_0^T [load\,relief(t) - contingency(t)]dt \ge 2\left(\sum_{k\ in\ inertia\ providers} Y(k) \times H(k)\right)\left(F_{lb}(T) - f(0)\right) \qquad (11)$$

Normally for the co-optimization, $contingency(t)$ would be assumed to be constant in *t* and just be equal to the size of the largest contingency.

$$\int_0^T contingency(t)dt = T \times contingency$$

Now for a set of time points {T_1, T_2, T_3, … T_m … T_n} which represent key time points for the management of frequency, the lower bound frequency equation above can be written as a linear constraint for each T_m with dispatchable (decision) variables moved to the left hand side of the inequality:

$$\sum_{j\ in\ FCAS\ providers} X(j) \times \int_0^{Tm} fcas(j,t)\,dt - 2\left(\sum_{k\ in\ inertia\ providers} Y(k) \times H(k)\right)\left(F_{lb}(Tm) - f(0)\right) \ge T_m \times contingency - \int_0^{Tm} load\,relief(t)\,dt \qquad (12)$$

Note that for the initial time periods following a contingency that the lower bound $F_{lb}(Tm) - f(0) \leq 0$, so increased inertia is a substitute for FCAS. If, at later time periods, frequency is required to be returned to the nominal frequency, then at this stage $F_{lb}(Tm) - f(0)$ could be positive and the inertia increases the requirement for FCAS.

For each point in time, T_m, the shadow prices of the above constraint can be determined from the linear programming optimization. These shadow prices can then be used to price both FCAS and inertia.

The payment that an FCAS provider, j, will receive is:

$$\sum_{Tm\ in\ T} shadow\ price(Tm) \times X(j) \times \int_0^{Tm} fcas(j,t)\, dt \qquad (13)$$

The payment that an inertia provider, k, will receive is:

$$\sum_{Tm\ in\ T} shadow\ price(Tm) \times Y(k) \times 2 \times H(k) \times (F(0) - F_{lb}(Tm)) \qquad (14)$$

Note that the FCAS payments are essentially payments for energy delivered, or the equivalent via inertia, following the contingency until time T_m.

V. Practical implementation and implications of a market-based frequency control ancillary service

An important outcome of formulating the co-optimization equations is the expected equivalencing for frequency and inertial responses in the initial time periods of the response.

Conceptually, the pricing of inertia provides a signal for both 'real' inertia and synthetic inertia, which may be available from sources such as super- or ultra-capacitors, battery systems etc. The impact of the two inertial types should be indistinguishable on the resulting frequency dynamics. In fact, equation (12) shows that:

- if H tends high, less FCAS is required immediately after a contingency, though some FCAS will be required in later times to return frequency to nominal;
- if the FCAS fully satisfies the requirement, there is no need for additional inertial response;

both of which are logical outcomes.

While the approach suggested is more complicated than the current eight FCAS markets, it is no more complicated than many of the constraints that have been used in the dispatch engine for many years. Further, the selection of time points which determine the frequency constraints is just a data input and thus can be quickly and easily changed as required.

The benefits of an integrated FCAS and inertia market regime include:

- Recognition of the actual speed of response available
- The ability to co-optimise fast but short duration responses with slower but more durable responses.
- Encouraging efficient providers to deliver the service while providers with higher costs can elect not to provide frequency responsiveness.
- Providing price signals that encourage investment and innovation to deliver market needs, meeting the requirements of the National Electricity Objective.
- Providing a price for inertia and avoiding arbitrary inertia requirements, improving transparency and signalling requirements for new service providers, including synthetic inertia services.

VI. Conclusions

Frequency control in a power system with many inverter based generators is quite different to traditional systems and control frameworks will need to change significantly to maximize the benefits available from faster responses.

Market based frequency control is expected to deliver significant efficiencies over a mandated response regime, where costs of over-provision need to be accounted.

A market-based framework that values both frequency response and inertia will deliver economic efficiencies, encourage innovation and signal appropriate investment.

For the NEM, a three-tiered approach is suggested:

- In the normal operating frequency band, regulation services would continue to be supplied via the energy management system and automatic generation control. These regulation services would be supplemented by paid primary response services (volume and response speed) dedicated to addressing short-term variations in supply-demand outside the AGC bandwidth.
- For contingency control of frequency, a market-based ancillary service co-optimized with the energy market and recognising the value of both generator response and inertia is proposed. Recognition of response speed and duration can be taken into consideration in selecting, pricing and dispatching services.
- For severe contingencies, including multiple contingencies, all generating systems would be obliged (mandated) to respond when frequency exceeds a frequency threshold, offering a supply-side equivalent to automatic under-frequency load shedding.

The ability to price both frequency response and inertia is a significant step in that no special arrangements are required for inertia as price signals are generated for synthetic inertia.

Acknowledgements

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