4 June 2020

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear Mr Pierce

RE: Capacity Commitment and New 30-minute FCAS Raise and Lower NEM Rule Change Requests

Delta is submitting two Rule Change requests (attached) that will address the need for new market mechanisms to deal with impact of variable renewable energy on NEM operations. These Rule Change Requests propose:

- the development of a new day ahead ex-ante market for capacity commitment to address operational reserve and system security concerns not currently addressed in any other market mechanism; and
- an extension to the current suite of FCAS Raise and Lower services to include sustained ramping.

Delta has been closely following the work being undertaken by AEMO and the Energy Security Board on the operational implications of increasing variable renewable energy in the National Electricity Market. In AEMO's Renewable Integration Study, it was concluded that "The NEM power system will continue its significant transformation to world-leading levels of renewable generation.." and "..the need for flexible market and regulatory frameworks that can adapt swiftly and effectively as the power system evolves". The Energy Security Board in its April 2020 consultation paper 'System Services and Ahead Markets' refers to 'missing markets' and that "there is a need for new market arrangements for the procurement of system services crucial to the secure and reliable operation of the system."

AEMO, has stated "Given the pace and complexity of change in the NEM, the RIS [Renewable Integration Study] highlights the need for flexible market and regulatory frameworks that can adapt swiftly and effectively as the power system evolves". Delta's NEM Rule Change Requests are readily implementable as solutions to existing system security and reliability problems in the NEM that will deliver clear net benefits for consumers and can be adapted to align with the longer-term requirements to be determined by the ESB post 2025 review.

Yours sincerely

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NEM Rule Change Request
Capacity Commitment Mechanism for Operational Reserve and Other System Security Services

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Ex-ante Capacity Commitment Mechanism for Operational Reserve and Other System Security Services

1. SYNOPSIS

Delta Electricity has identified a current and developing issue that limits AEMO's access to sufficient system stability and reliability services to ensure system operating standards are met. As stated by AEMO in its Renewable Integration Study "the system is reaching the bounds of known stability limits." Delta's proposal is for an Ex-ante Capacity Commitment Mechanism using an ahead market approach which, combined with a separate proposal for new Raise and Lower Ancillary Services, will help address the NEM operational issues identified by AEMO. Compared to the status quo of market intervention by direction, the proposed mechanism has the benefits of technology neutrality, price transparency, price discovery and competitive pressures to innovate both within the current generation fleet and for future new investment. The proposal represents a simple, relatively easy-to-implement solution. It may act as a transitional mechanism until either new generation or demand capabilities can ensure system reliability standards are maintained without the need for the proposed mechanism, or until an alternative market approach is designed and implemented.

2. THE ISSUE

The issue identified in, and the subject of, this proposal can be expressed as:

> **As conventional generators in the NEM receive stronger and more frequent energy market signals to decommit for short periods, the NEM will more frequently experience periods of shortfalls in system security and reliability services such as operational reserve capacity[1]. Whilst AEMO can intervene in the market and direct scheduled generators to recommit to address these shortfalls, the NEM will benefit from AEMO having access to a market-based alternative to its powers of direction.**

The generation mix in the NEM is changing rapidly. The market share of large-scale asynchronous generators (wind and solar) is increasing. Delta agrees with the Energy Security Board (ESB) that "the change in the generation mix is making some services that used to be abundant, now scarce at times. In a well-functioning electricity market, all services critical to the reliable and secure supply of electricity should be available whenever needed in real-time." [2]

[1] In this paper the term Operational Reserve Capacity, in MW, contributed by a generator for a trading interval means the generator's maximum generation capability (MAX_AVAIL) less its Minimum Stable Operating Level (MSOL) for that trading interval.

[2] COAG ESB 'System Services and Ahead Markets' Paper, Section 3.1.

Synchronous generators, particularly large slow-start thermal generators, provide a range of system services, referred to in this proposal as **SSRS**, including:

- operational reserve;
- frequency control (other than current FCAS market services);
- inertia;
- voltage control;
- high ramping capability*; and
- system strength.

** Note: the contribution that committed slow-start thermal generators contribute to power system security through their ramp rate capabilities are of higher value than fast start gas fired peaking plant which need to restart before ramping can be provided.*

These system services are not typically provided by asynchronous generators. The services above are broadly in line with the ESB's identification of Essential System Services including:

- "operational reserves to ensure adequate flexible dispatchable reserves are available to manage variations in the supply and demand over a number of dispatch periods";
- "additional services for frequency management, particularly synchronous inertia to resist frequency changes that would be too fast for frequency control services and protection schemes to operate"; and
- "system strength to ensure the power system can maintain and control a stable voltage waveform during normal operation and following a disturbance".[3]

When demand is low and output from asynchronous generators is high, electricity spot prices are increasingly falling below the short run marginal costs of some slow-start thermal generators (e.g. coal or gas fired units) for extended periods. These generators will be incentivised to avoid losses and remove generating units from service (de-commitment). In the case of slow-start thermal generators (especially coal fired), returning a unit to service (commitment) is a complicated process with a low degree of certainty in meeting any set return to service time (unlike open cycle gas fired generating units). Once synchronised, a coal fired generating unit can take many hours to achieve full load, particularly if that unit has been out of service for several days.

Coal fired generating units require a substantial amount of fuel oil (e.g. diesel) to restart and to bring the unit up to a minimum stable load. A generator will only commit to returning a 'standby' unit to service if the short-term forward outlook of spot prices not only covers marginal fuel cost but also the restart costs which could be a few hundred thousand dollars. Even if there is limited supply and very high prices at the daily peak, a 'standby' slow-start thermal unit may decide not to return to service until average spot prices provide a reasonable margin above short run marginal costs. Ultimately some generating units may establish a 'two-shifting' pattern whereby slow-start thermal generators will shut down each day during the periods of high asynchronous generation. The exact nature of a 'two-shifting' pattern will be dictated by the expected spot price profile.

The primary issue arising from slow-start thermal units being removed from service during periods of very low prices is that the market operator will increasingly have to resort to

[3] COAG ESB 'System Services and Ahead Markets' Paper, Executive Summary.

directing synchronous generators to recommit or to remain in service for both system security and system reliability reasons. As is regularly seen in SA, fast start gas generating units may also be subject to commitment directions. Directing fast start plant carries less risk for AEMO as this technology has very high return to service reliability and can be called to commit at a precise time. On the occasions when interventions of this nature are necessary it is self-evident that scheduled conventional generators are AEMO's providers of last resort for System Security and Reliability Services (SSRS) as all other available generation technologies will be already accounted for in AEMO's evaluation. It is for this reason that this proposal only deals with competitive sourcing of SSRS from the pool of last resort SSRS providers that would, under the status quo, be subject to direction.

The ESB consultation paper 'Energy Security Board System Services and Ahead Markets', dated April 2020, states that the "unpredictable nature of such intervention represents further distortion to the market and could cause further disruption to participants' operational planning and therefore potential costs to consumers". As expressed in the ESB paper there is a need for new market arrangements for the procurement of system services crucial to the secure and reliable operation of the system.

Delta's proposed rule change takes a pragmatic approach to dealing with this issue by proposing a process that ensures AEMO gets a least-cost access to the SSRS the system needs from all technologies capable of providing the SSRS while acknowledging the unique technological characteristics of slow-start thermal generators (minimum loading, slow starts, high ramp rates) and the important role these generators can play in providing grid-formation and critical system services. Whilst the proposal will appear to favour one technology over another, it does so to permit full participation from slow-start thermal generators in addressing the identified issue. The proposal may be seen as a simple (for ease of implementation) interim solution to facilitate the transition to lower emission technology by ensuring the power system remains secure and reliable as the volume of variable renewable energy increases.

3. CONTEXT FOR THIS RULE CHANGE REQUEST

Currently there is no market through which AEMO may procure, for example, inertia and system strength services or signal to market participants that their ramp rate capabilities may be needed at certain times. Similarly, there are no mechanisms within the spot market that would help AEMO manage reliability. As a result, reliability is managed through a framework of cascading measures, outside the spot market. As noted by the ESB[4] "..essential services required to maintain security and reliability are either:

- provided as a free by-product of the resource being committed, online and generating energy;
- provided via regulatory requirements (for example, technical standards, including connection requirements and those for building and maintaining assets);
- contracted by TNSPs or AEMO in network support and control ancillary service (NSCAS) contracts or other non-market contracts; and
- procured by out-of-market intervention by AEMO such as RERT and market directions.

[4] COAG ESB 'System Services and Ahead Markets' Paper, Section 3.1.

A. Current Market Design Is Incomplete

In absence of an adequate ongoing power system security management regime within the spot market, AEMO has been increasingly intervening in the operation of the market through the issuance of directions to synchronous generators to achieve or maintain a required level of generation output.[5] An increasing frequency of market intervention is indicative of costly[6] dysfunctionality better addressed by some change to market design.

It has become evident that the mix of the generating units that are committed at any given time affect the power system security and reliability due to the differences in the technical capabilities between generating units. The assumption of fungibility, that all units of MWh generated in a Trading Interval has the same benefit and impact on the power system, may have been a reasonable assumption in the past when only synchronous generators participated in the market. Over time the generation mix has changed and the impact from the changes in the technical capabilities of the generating unit types is left for AEMO and TNSPs to manage, outside the spot market.

Synchronous generators like coal, biomass, gas thermal and hydro operate with large spinning turbines that help maintain consistent frequency and voltage, keeping the power system stable. They inherently produce inertia – the stored energy in the rotor mass of the system's rotating synchronous and induction machines that lets the system ride through sudden disturbances and maintain its operating frequency of around 50 Hz. Non-synchronous generators like wind and solar have no or low inertia. Systems with a large proportion of non-synchronous generation are harder to control following a disturbance as frequency collapses more rapidly and blackouts may occur. Refer to Appendix 1 'The Maths of Inertia' for more detail.

System security related issues first emerged in South Australia but are now also becoming evident in other regions of the NEM. Directions result in intervention pricing and a series of compensation payments which adversely impacts spot pricing, the contract markets, and investment signals. Generators' operational and commercial decisions are overwritten by AEMO's directions in order to maintain power system security. While the market benefits from the system security provided by synchronous generators being directed to provide services, investors' confidence is undermined by the unpredictable nature of the interventions. Furthermore, customers and affected participants are required to bear the costs.

Intervention is inherently inefficient. When it occurs, generators will seek a commercial return from the directions without the presence of competitive pressure whereas in the proposed market for capacity commitment there is not only competitive pressure to drive efficient outcomes on the day but there is an incentive to innovate that will improve outcomes in the future from existing providers, as well providing price transparency to foster the potential entry in to the market of new providers and technologies qualified to provide the service.

[5] As at 31 July 2019, AEMO had issued 267 system strength directions, most of which occurred in the last two years. During 2018, directions were in place for around 30 per cent of the time in South Australia. See AEMC, Investigation into Intervention Mechanisms in the NEM, Final report, 15 August 2019, p.7

[6] AEMO Q1 2020 Quarterly Energy Dynamics Report

A key question is therefore how the market can deliver efficient price signals to deliver the optimal level of system security services and reliability while allowing for the continuation of the evolution in the generation mix in the NEM.

B. Technology Neutrality

The day-ahead market mechanism proposed in this Rule Change request is expected to achieve broadly similar physical outcomes to that occurring under the status quo mechanism of market intervention by AEMO. Where there is a SSRS shortfall, this Rule Change would substitute a market process for the selection of service providers from the same pool of providers who would otherwise be candidates for AEMO direction on a timetable that ensures that all current SSRS providers can participate. It is the timetable in the proposed day-ahead market that makes this proposal technology-neutral.

Plant that is fast-start such as gas peaking plant, hydro and battery storage systems have a natural advantage when participating in this mechanism as their low cost of commitment and reliability of restart means that they can avoid exposure to the increasing frequency of low spot energy prices by decommitment and thus can make their SSRS services available at low cost compared to slow start thermal plant. Accordingly, energy prices alone will typically, but not always, be likely to provide sufficient incentive for fast start technologies to commit and for their SSRS to be available. In regions such as Victoria, NSW and Queensland, slow start thermal units continue to be the most significant source of SSRS and it is less likely that fast start technologies will appear in the pool of candidates for AEMO direction, but when they are, their low costs of re-start should see them dispatched ahead of slow start thermal generators under the proposed Capacity Commitment mechanism.

In regions such as Victoria, NSW and Queensland, slow start thermal generators will likely be the majority of the pool of SSRS providers that under the status quo arrangements would be subject to AEMO direction – in effect the 'providers of last resort' of SSRS to the system. That is the reason why the Capacity Commitment mechanism needs to be conducted on a timetable that fully enables their participation.

C. Loss of SSRS from Decommitted Units

When slow-start thermal generators are decommitted, for example due to the above mentioned two-shifting, the SSRS associated with them are no longer immediately available to the power system. Several hours of notice is required to make these services available again by starting up and synchronising the generators. A critical point in the slow-start thermal generators' supply is the minimum stable operating level (MSOL). Slow-start thermal generators are well positioned to provide inertia, system strength, ramp rate capabilities, and other SSRS but to do so at a short notice, they must be already committed, operating at least at their MSOL.

Currently, in making operational decisions, slow-start thermal generators do not take into consideration the value of the SSRS they may provide. Their operating decisions are made by considering marginal costs and the expected spot prices in the energy and FCAS markets only. No market mechanisms exist to dynamically manage, and price, the value of the additional services that generators with different technical capabilities may provide (the SSRS). Therefore, rational decisions on the part of slow-start thermal generators to 'two-shift' may have significant consequences for system security and reliability. Ironically, these same slow-start generators are often well positioned to address these system security and reliability issues if they could be retained committed and dispatched at least at their MSOL.

The QLD, NSW and VIC regions have a configuration different to elsewhere as supply remains dominated by slow start thermal capacity. If the market is allowed to operate in its current form, the market will be left with increasingly frequent occasions of insufficient system services to maintain system security and reliability. For this reason, a solution is necessary to ensure ongoing access to sufficient system services from existing sources until alternatives (either technologies or market mechanisms) can be found.

Adopting a 'two-shift' mode of operation for slow start thermal units as a response to low spot price signals became common in the UK electricity market at a point in time when it also was in a transition phase in terms of its generation mix. Two-shifting older slow-start thermal plant will impact on plant reliability, in particular restart reliability, which can potentially lead to reduced operational reserve capacity available at time of system peak. In the UK, however, by the time two-shifting was occurring the market had solved the system security issues through more gas plant and new market mechanisms.

AEMO has primary responsibility for ensuring the power system is secure through a framework of measures that includes technical standards, guidelines, operating procedures, network design requirements, generator dispatch constraints, and the procurement of a range of ancillary services. However, AEMO does not have an ability to tap into the technical capabilities of different generators through the current spot markets to access the SSRS. This is understandable as the NEM spot market was initially designed to price the energy only, measured in MWh, at a time when generators were all synchronous and their technical capabilities very similar to one another. With the evolution towards more VRE in the generating mix, it is becoming increasingly important that the NEM dispatch process considers not only the MWh energy that may be available but the SSRS capabilities of generators that are available.

Without some new market mechanism, the ongoing transition to a high VRE NEM is likely to see increasing levels of market intervention in more regions of the NEM.

D. Ahead Market Solution

In order to address the above issues with power system security and reliability of supply, Delta Electricity is proposing that the National Electricity Rules (NER) be changed to introduce an Ex-ante Capacity Commitment Mechanism in the National Electricity Market (NEM).

The objective of the proposed rule change is to extend the existing framework of measures with a new, market-based, tool that allows AEMO to meet the ongoing operational challenges by tapping into the SSRS capabilities of decommitted (or to be decommitted) synchronous generating units when necessary.

The duration and uncertainty of the decision timeframe involved in implementing unit 'commitment' or 'decommitment' decisions for slow-start thermal generators does not lend itself to a solution via a 5-minute or half-hour market. Accordingly, Delta's proposal is framed as an ex-ante day-ahead market. Fast start generating units that participate in the ahead market will also have their commitment (at least for part of the day) determined a day ahead.

The proposed 'ex-ante capacity commitment market' would help AEMO to ensure that the system can be operated securely and reliably. The following sections provide an example of how such a market-based mechanism may operate in combination with the existing spot market. This proposed day-ahead market is in keeping with COAG's Energy Security Board's paper "A form of ahead mechanism is considered essential for improving the visibility and confidence in essential system services." [7].

It is anticipated that the same day-ahead ex-ante market can also serve to provide market access to not only operational reserve but any of the SSRS that AEMO require from eligible generating units to meet its security and reliability objectives.

Eligibility criteria are proposed that are targeted towards any scheduled generator that would be likely subject to direction under the status quo. However, as alternative technologies develop that can deliver the equivalent SSRS, it is expected AEMO would have reduced need to acquire SSRS from this capacity commitment mechanism.

The proposed rule change proposes a relatively simple day ahead market to secure access to SSRS over the entire day. Consequently, systems development and implementation are expected to be minimal in terms of IT resources compared to a project like a 5-minute or half-hourly settled co-optimised market solution. Importantly there is no change to dispatch processes or price setting in the energy or FCAS spot markets. The proposed mechanism should be seen as a market-based alternative to the non-market, mainly intervention-based approaches noted by the ESB[8] such as AEMO directions. The proposed rule change will provide greater operational certainty for market participants as well as competitive sourcing of SSRS, and will provide a price signal to promote allocative efficiency in the NEM. The proposed mechanism can be considered an interim approach to move the NEM rules in the direction outlined by the ESB's 'System Services and Ahead Markets' paper.

Delta is aware of Infigen's 18 March 2020 rule change proposal and understand that there is significant overlap between the proposals and that there are broad similarities in the issues that Delta and Infigen are attempting to address. Delta considers that its day-ahead operational reserve market proposal is more focussed on the issue of two-shifting and periodic standby outages of slow-start thermal generators and should be simpler to implement, resulting in a process in which generators guarantee to commit their units for a day (slow start) or a defined period (other) rather than via a half-hour ahead market for reserve.

The simplicity of implementing the proposed solution is in keeping with it being an interim solution, capable of enhancement over time. If more holistic and comprehensive market reforms take longer to develop and deliver, then at least AEMO will have access in the interim period to a flexible tool to supplement the existing rules to deliver appropriate standards of security and reliability for as long as may be required.

Ultimately, the quantities of operational reserve or any of the other SSRS that AEMO acquire under this proposed rule change are only the quantities that AEMO deem necessary, only on the days the service is required, sourced on a competitive basis. On most days in most regions, it is anticipated there will be no operational reserve shortfall and the operational reserve day-ahead market will clear at a zero price.

[7] COAG ESB 'System Services and Ahead Markets' Paper, Executive Summary.
[8] COAG ESB 'System Services and Ahead Markets' Paper, Section 3.1.

4. THE PROPOSED CAPACITY COMMITMENT MECHANISM RULE CHANGES

This proposed rule change provides appropriate economic incentives for scheduled generation capacity to provide any or all of the SSRS, as and when required by AEMO, to maintain a secure and reliable power system.

The proposed mechanism is a day-ahead ex-ante market for capacity commitment to address any or all of the SSRS for which AEMO forecast a shortfall.

As part of the day-ahead pre-dispatch forecasting process, AEMO shall determine the amount of operational reserve and other SSRS required to meet regional stability and reliability standards.

Separately, Delta is also submitting a separate rule change proposal to extend the current FCAS markets to respond to sustained high rates of change in VRE. That proposal recommends new raise and lower services over a 30 minute timeframe and relates to this mechanism in that the ability of decommitted slow-start thermal generators to provide the new raise and lower services on a day will require them to be recommitted in sufficient time to be in service, stable and at MSOL.

5. DAY-AHEAD EX-ANTE MARKET FOR CAPACITY COMMITMENT FOR OPERATIONAL RESERVE

This section illustrates the application of the day-ahead ex-ante market to solve the issue of potential shortfall in operational reserve. The same market can be used to address shortfalls in any of the SSRS however the eligibility criteria for generators in the provision of the other SSRS may differ. Aspects of this proposal are discussed below with sections D,E,F and G illustrating the application of the proposal to identify and address a scenario of a shortfall in operational reserve. The same process may be used to secure access to any of the SSRS to address a shortfall.

A. Scheduled Generator Eligibility

Eligible generators under this proposed rule change are those scheduled generators, irrespective of technology type, that can provide the required SSRS and are most likely (in the absence of this proposed rule change) to be subject to direction. These are more likely to be generators that cannot fast start and have a non-zero minimum load on their primary fuel source but could be any generator type.

It is recognised that in some regions this criterion will frequently apply to slow-start thermal generators in relation to providing operational reserve. That is to be expected because it is those generators who, because of their MSOL, are presently exposed to incentives to decommit during periods of very low or negative prices. Gas turbine peaking plant and hydro units do not face the same issue as they can decommit and restart without the significant restart timeframe or cost and have very high unit start reliability.

As outlined is Section 1, this proposal is intended to substitute for the status quo mechanism of intervention by AEMO direction to generators who have bid their capacity as unavailable (or subject to a recall) to the market and on those days, this category of generators are the system's last resort source of operational reserve or other SSRS, where all other categories of generation have already been accounted for in AEMO's deliberations. Accordingly, this proposal is designed to provide a market-based solution to secure the commitment of operational reserve or other SSRS from generators that would have otherwise been unavailable or scheduled to be decommitted, at least cost and irrespective of technology type.

B. Participant Registration

Operators of generators may classify one or more of their eligible generating units as a Capacity Commitment Generating Unit (CCGU).[9] A CCGU must have relevant capabilities. For example, they must be able to provide inertia, system strength, and other SSRS or they must be able to be ramp up/down at a controlled rate. At registration, the market generator must declare, and AEMO must assess, the CCGU's technical characteristics and capabilities. The relevant technical characteristics and capabilities may include:

- the generating unit's minimum stable operating level (MSOL);[10]
- the operational reserve it can provide when dispatched at MSOL (this is essentially the difference between the maximum and minimum operating levels);
- voltage and frequency control;
- inertia constant (MWs / MVA);
- ramp rate capabilities (MW/min); or
- system strength.

Registering a generating unit as an CCGU would leave the existing registrations of the generating unit unaffected. For example, the CCGU may also be an ancillary service generating unit for the purpose of providing, for example, frequency control ancillary services.

If AEMO is satisfied of their relevant technical capabilities, CCGUs would be eligible to participate under the new ahead market for capacity commitment.

C. Methodology to Forecast SSRS Requirements

As part of its day-ahead forecasting, AEMO would monitor the short term PASA, and pre-dispatch schedule outcomes to identify on a regional basis the SSRS requirements to ensure a secure operating state and power system reliability.[11]

[9] Scheduled generators may be market or non-market generators. Currently, there are no non-market scheduled generators registered in the NEM. Small generation aggregators would also be eligible to register their aggregate scheduled generating units.

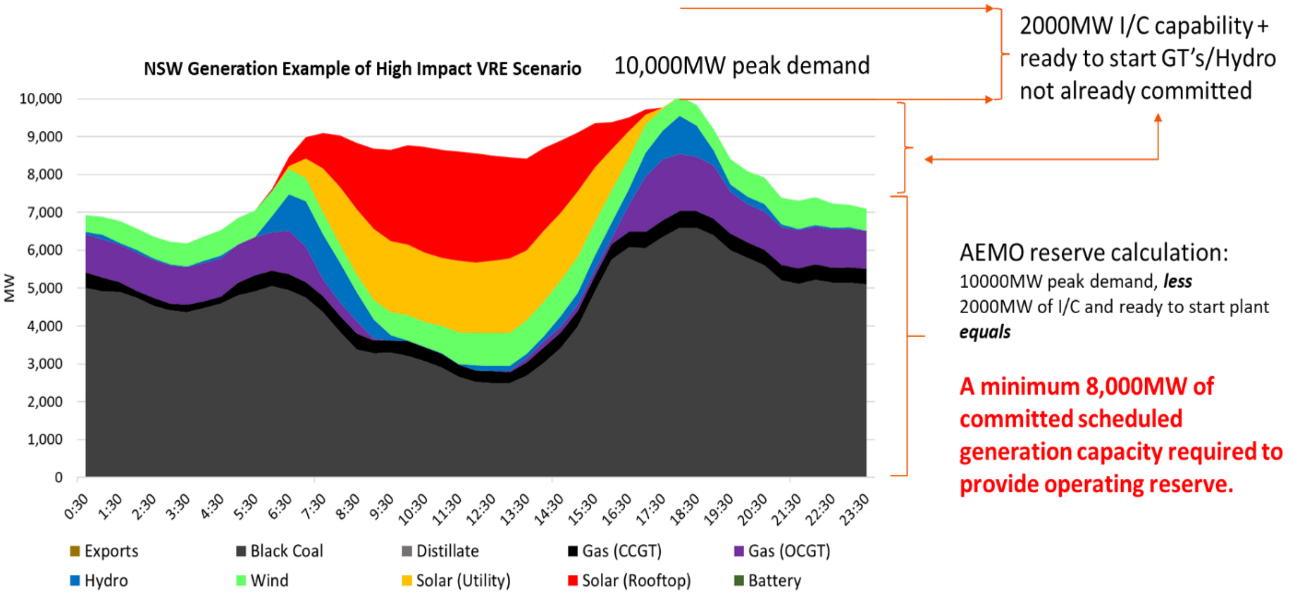
[10] A MSOL is the lowest output a generating unit can sustain without becoming unstable or requiring auxiliary fuel. This level of output would be established for each CCGU based on technical characteristics and plant safety rather than commercial considerations.

[11] Pre-dispatch procedures are 30-minute resolution, up to 40 hours ahead. Short Term PASA is published at a 30-minute resolution every 2 hours and it provides information on short-term power-system supply/demand balance prospects for six days following the next trading day.

Operational reserve (Reliability)

The principle Delta is proposing in this rule is illustrated in Figure 1 to identify a shortfall of operational reserve.

Figure 1 – operational reserve assessment



Source: Delta modelling of high impact VRE scenario

For this proposed day-ahead market, the operational reserve requirement in a region will be calculated for the day ahead as follows:

Operational reserve Requirement (for system reliability):

> = region daily maximum demand *plus* the contingency reserve relevant to the region
>
> *Less* forecast interconnection import capability at time of MD
>
> *Less* non-committed fast-start scheduled capacity within the region at time of MD
>
> *Less* aggregate MSOL of the committed scheduled capacity within the region at time of MD

The operational reserve capacity for a day is the pre-dispatch aggregate of the capacity of all committed scheduled generators at the time of the day's maximum demand less the aggregate MSOL of those generators.

If the operational reserve requirement exceeds the operational reserve capacity at any time then there is an **operational reserve shortfall** for that day.

If there is no operating shortfall for a day then the proposed day ahead capacity commitment mechanism will clear at a zero price. If there is an operational reserve shortfall for a day then the bidstack, for capacity commitment from decommitted generators, illustrated in Section G, will determine the clearing price (on a half-hourly basis) which is paid to all generators who recommit to provide this service.

In Figure 1 above, if the scheduled generator fleet were to consist of generic 660MW units with a 200MW MSOL, the scheduled generators total capacity requirement of 8,000MW would be satisfied by 13 units (rounded up to the nearest whole unit from 12.12) with an aggregate MSOL of 13*200MW = 2,600MW and aggregate Operational reserve Capacity of 13*460MW = 5,980MW.

The above simplistic illustration assumes all regional and interconnector capacity in pre-dispatch does not fail. AEMO would also need to consider the potential impact from contingency events including region contingency reserve (in accordance with its standards for security and reliability). AEMO would assess whether the technical capabilities of the generators that are likely to be required for SSRS support are sufficient to overcome a range of potential system security and reliability events including:

- the largest contingency event (loss of the largest generating unit) as it is currently the subject of the LOR assessment;
- the technical characteristics of the generator mix that is expected to be dispatched;
- the number of (and relative ratio of) the synchronous and non-synchronous generators that is expected to be dispatched;
- the demand forecasts, including peaks, troughs and rate of change in demand (incl rooftop solar PV generation);
- the uncertainties associated with the output of non-scheduled generators;
- the uncertainties associated with the output of semi-scheduled generators (unconstrained intermittent generation forecast determined by AWEFS and ASEFS);
- expected interconnector import in each region;
- frequency control ancillary service requirements; and
- network constraints.

AEMO may determine VRE should be included in the Operational reserve levels at time of Maximum Demand at level of firmness equivalent for that time to other generation categories, e.g. at the 99%POE level.

Delta considers that AEMO is best positioned to determine the details of an appropriate methodology for the assessment of regional operational reserve (and all other SSRS) requirements. AEMO would be required to publish an *operational reserve requirements guideline* that describes the considerations and detailed methodology AEMO applies in performing its operational reserve assessment and similar guidelines for all other SSRS.

In the interests of clarity, periods in pre-dispatch where AEMO has determined that there is a shortfall for any SSRS service is referred to in this paper as “low SSRS periods”.

In examples where operational reserve is used to illustrate a point the term “low operational reserve period” may be used.

<u>Non- Operational reserve SSRS</u>

A similar process to the above would apply except that the set of generators able to provide other required SSRS capability may be different to the set that may provide operational reserve. In the event that more than one SSRS is required for a day then AEMO would co-optimise the solution to meet all required SSRS at least cost.

D. Market Participants Information Provision

It is not expected that market participants would be required to provide any additional ongoing information as they already provide the necessary information to AEMO as part of the existing short term PASA, pre-dispatch PASA submissions and registration. However, MSOL may need to be subject to regular testing.

E. 'Ex-ante Capacity Commitment Market-based Mechanism'

Market participants with CCGUs would have the opportunity but not the obligation to provide operational reserve offers.

Delta views Capacity Commitment offers as falling into two fundamental categories:

- offers to commit capacity for the entire day (slow start); and
- offers to commit capacity for specific trading intervals (**TI**s) in the day (fast start).

<u>Offers To Commit Capacity For The Entire Day</u>

This category of offer would be expected from slow-start thermal CCGUs that need to commit capacity well in advance of the system's need for that CCGU's full range of SSRS. These offers allow AEMO to secure grid formation SSRS services that span the entire day, not just at time of system peak.

<u>Offers To Commit Capacity For Specific TI In The Day</u>

This category of offer would be expected from fast start plant such as hydro, gas peaking and battery CCGUs that have relatively low start costs and reliable restart. These offers could provide AEMO access to SSRS services at particular Trading Intervals when SSRS shortfalls are target needs.

The combination of the offers accepted will provide a clearing price for capacity commitment for each TI in the day ahead.
Any operational reserve offer, if accepted by AEMO, would obligate:

1. the generator to remain committed and available for dispatch for the entirety of the period to which the offer applies;
2. generators committed under this process to not rebid energy offers for the entirety of the period to which the offer applies (the energy offers are 'locked' in at those current at the time AEMO accepts the commitment offer);
3. AEMO to dispatch the generator at no less than its MSOL for all TIs in the period in the offer; and
4. AEMO to pay to the generator the TI clearing price for operational reserve capacity for all TI's in the period in the offer.

F. Operational Reserve Offers

For any trading interval each eligible scheduled generator has a MSOL and a maximum generation capability ('MAX AVAIL' in the generator bids) each of which may be impacted from time to time by operational issues.

The operational reserve capacity, in MW, offered for a trading interval is the generator's maximum generation capability less its MSOL for that trading interval.

An offer (a bid) to participate in the operational reserve market consists of the offered operational reserve capacity, the periods for which the offer applies and a price. That is, an operational reserve offer of a CCGU represents the minimum price (per MWh) that the market participant is prepared to accept to maintain the electrical output of that generating unit at the MSOL during the entire period to which the offer applies.

24 hour commitment

An illustration of how an offer price may be determined for an 'Offer To Commit Capacity For The Entire Day', based on pre-dispatch data is:

- pre-dispatch indicates an average negative spot price of -$20/MWh for a duration of 5 hours;
- AEMO determine 'low operational reserve periods' duration of 3.5 hours;
- a Marginal Cost of generation of $30/MWh;
- a Maximum generation Capability of 660MW;
- a MSOL of 200MW;
- the cost of operating at MSOL during the negative Spot Price period is ($30 + $20)/MWh*200MW = $10,000/hr; and
- the Operational reserve Capacity offered in each TI is 660MW-200MW= 460MW.

The price of the Operational reserve Capacity may be offered at a minimum of:
($10,000/h*5h)/(460MW*24h) = $4.53/MWh

The total cost for the commitment = $50,000

It is important to note that the generators that the risk that the actual prices clear a lower levels than forecast.

TI Commitment

For fast start plant an offer to provide operational reserve for the period of low reserve may be determined as:

- AEMO determine 'low operational reserve periods' duration of 3.5 hours;
- a Marginal Cost of generation of $80/MWh;
- a Maximum generation Capability of 460MW;
- no minimum MW operation (fast start plant);
- spot during 3.5hours of low reserves is $70/MWh; and
- the cost of operating during low reserve period = $80/MWh (cost) less $70/MWh (spot) = $10/MWh.

The price of Operational Reserve Capacity for the fast start gas peaker may be offered at a minimum of $10/MWh, but the total cost of the commitment is:
$10/MWh*3.5hrs*460MW = $16,100.

It is important to note that generating units that are made available as operational reserve CCGUs would not be required to be 'out of market generating units' (i.e. generators part of the RERT). In fact, the generating units that are made available as CCGU may already be synchronised and generating at the time of submitting operational reserve service bids.

All eligible CCGUs (regardless of whether they are expected to be dispatched or not and whether they would otherwise decommit or not) may participate in the day-ahead Capacity Commitment market.

G. Selecting Successful Operational Reserve CCGU

AEMO would select the CCGUs that deliver the required capacity commitment at lowest cost in the following manner:

All Day capacity commitment

Firstly, AEMO considers the timeframe of the SSRS shortfall(s). If SSRS, including grid formation services, are required for the entire day then AEMO first considers the 'All Day' offers to commit capacity, orders them in increasing cost ($/MWh of Operational reserve) and accepts sufficient offers to system security objectives are met for all TIs where no 'Offers To Commit Capacity For Specific TI In The Day' are made.

Specific TI Capacity Commitment

For all TI where SSRS shortfall(s) remain, AEMO orders commitment offers in ascending order by TI. Sufficient offers are accepted in each TI until system security objectives are met in relation to that TI.

The clearing price for capacity commitment in each TI is the offer price of the last commitment offer accepted for that TI. All successful CCGUs are paid the TI clearing price for their offer capacity in that TI.

AEMO may need to iterate between these two capacity selection processes to ensure system security objectives are met at all times for the day ahead. If acceptance of one or more all-day offers meets system security objectives at lower cost than accepting the lowest cost set of specific TI offers then those all-day offer(s) should be accepted and vice versa.

The following is an illustration of applying these Capacity Commitment principles to address a shortfall in operational reserve in a region.

Operational reserve

Table 1 provides an example of offers that may be submitted by the CCGUs in a region where has identified an Operational Reserve shortfall of 1,800MW. In this example 3.5 hours of 'low operational reserve periods' likely coincide with the time of daily Maximum Demand, say between 15:30 to 19:00.

Table 1. Offers submitted by CCGUs to AEMO to provide operating 'All Day' operational reserve service

Unit	MSOL (A) MW	Max Capability (B) MW	Operational reserve Capacity Offered (C) MW	No Units (D)	Offer Price to provide Operational reserve (E) $/MWh All Day	Cumulative Operational reserve Capacity (G) MW	Payment at Offer Price (H= D x C x E x 24)	Payment at clearing price # (H= D x C x ($4 x 20.5 +$30*3.5)) $	Dispatch Merit Order
CCGU1	200	660	460	1	$3	460	$33,120	$86,020	**3**
CCGU2	200	660	460	1	$4	920	$44,160	$86,020	**4**
CCGU3	200	660	460	1	$5	-	$55,200	$0	
CCGU4	200	660	460	1	$6	-	$66,240	$0	

20.5 is 24 hours less 3.5 hours. The period for which the all-day commitment generators receive the all-day clearing price. For the 3.5hours of shortfall the market clears at the TI price (see Table 2)

Table 2. Offers submitted by CCGUs to AEMO to provide 'Specific TI' operational reserve service

Unit	MSOL (A) MW	Max Capability (B) MW	Operational reserve Capacity Offered (C) MW	No Units (D)	Offer Price to provide Operational reserve (E) $/MWh - 15:30-19:00	Cumulative Operational reserve Capacity (G) MW	Payment at Offer Price (H= D x C x E x3.5)	Payment at clearing price (H= D x C x $30 x 3.5) $	Dispatch Merit Order
CCGU5	0	460	460	1	$15	460	$24,150	$48,300	**1**
CCGU6	0	460	460	1	$30	920	$48,300	$48,300	**2**
CCGU7	0	460	460	1	$55	-	$88,550		

In reality, generators differ not only in their costs of operating at MSOL but also in the amount of operational reserve capacity that they can make available and generators may form a different view to pre-dispatch of the risk of potential price outcomes during the day and prepare their offers accordingly.

The operational reserve capacity supply schedule is the order, from lowest to highest, of the $/MWh operational reserve that is made available by each of the CCGUs. These range from $3 to $6 per MWh of 'All-Day' operational reserve offers in Table 1 above, with Table 2 showing two offers for the specific TIs where AEMO had identified a shortfall (covering the period 15:30 to 19:00). Each Table is ordered from lowest to highest representing in aggregate the operational reserve supply schedule, which gets cleared for the day in a process similar to the process of clearing bids in the energy market for a trading interval where the objective function is to meet the identified SSRS shortfall at minimum cost to the market.

The CCGUs with the lowest cost combination of operational reserve capacities that jointly meet or exceed regional operational reserve requirements are declared successful. By inspection of the Tables 1 and 2, AEMO would consider the least cost to the system of providing the required 1,800MW of Operational reserve and the suppliers would be selected in the merit order shown. The Clearing price for the TI in the period 15:30-19:00 would be $30/MWh set by the fast-start unit CCGU6 (the marginal TI offer) and the clearing price for all other TI in the day is $4/MWh set by CCGU2 (the marginal 'All-day' offer). CCGU's 1,2,5 and 6 are the units selected to meet the SSRS shortfall in this Capacity Commitment example. The process illustrated above would be conducted down to a half-hourly resolution to minimise costs.

CCGU's 1,2,5 and 6 are obligated to commit their units for the periods of their offer and AEMO dispatches them at no less than their MSOL for the entire period relating to the offer, irrespective of the spot price. Payments made are in accordance with Figure 2 in Section H below which is equivalent to AEMO paying the successful CCGUs for the energy generated at the spot price in addition to a fixed amount determined the day prior being the operational reserve clearing price ($/MWh) for the operational reserve capacity (expressed as MWh) for the trading intervals in the generator's offer for the day-ahead market.

An important point is that it is not the entire maximum capacity of the generating unit that is dispatched at this stage. Instead it is only the MSOL which is dispatched to ensure that the remainder of the operational reserve is available to meet the need in the market.

Another important point is that for successful CCGUs their first energy band is set at MSOL, and that capacity is automatically dispatched for all trading intervals in the day, irrespective of the spot price.

Non- Operational reserve SSRS Offers

In the event that more than one SSRS is required for a day then AEMO would take the CCGU offers to commit and co-optimise a solution to meet all required SSRS at least cost. Offers by CCGUs to provide other SSRS services would reflect their cost to provide the service in the appropriate units, for example inertia is a property that is available if the generator is committed and is not available if it is not committed, it is not a property present on "per MW of capacity" basis, accordingly inertia offers would be on a $/unit basis for the period of offer.

Some important points to note:

- given that a generating unit cannot be dispatched to a lower level than the MSOL the operational reserve procurement in the example above would necessarily need to include all of the MSOL output of the successful CCGUs. That is, the operational reserve capacity requirement established by AEMO is necessarily a lower bound of what would be procured. This is due to the 'lumpy nature' of the operational reserve capacity blocks;[12]
- the operational reserve market would clear ahead of the spot market dispatch. Successful CCGUs would be automatically dispatched to at least their MSOL for the entire day;
- The example above demonstrates that storage providers with zero MSOL are less likely to participate in this market. This is in line with efficient incentives. These generators have no start-up costs, require no preparation time and they are well positioned to respond to Spot energy market prices when these signal the need for capacity.
- no 'intervention pricing' would apply. The operational reserve service price would only be applicable to the MW capacity that is successfully bid into the ex-ante operational reserve market;
- there is no requirement for generating units to be out of market, unlike RERT. However, out of market RERT generators that meet the eligibility criteria could compete with scheduled generators in the operational reserve ahead market. This would align the procedures and further improve outcomes; and
- participant generators are also available to provide inertia, FCAS and the other SSRS.

H. Interactions with the Spot Market

Current spot market operations would be largely unaffected. The operational reserve or other SSRS provided by CCGUs that are successful in the Capacity Commitment

[12] The MSOL and the subsequent lumpiness is a reflection of technical and plants safety considerations, not commercial considerations.

mechanism is not quarantined or treated in a different manner to that provided by any other generator. All generators participate in the spot markets for energy and FCAS in the usual way. The spot markets benefit from the greater level of competition for dispatch.

Generators with CCGUs whose Capacity Commitment offers were accepted would receive a payment through the 'ex-ante capacity commitment market'. The payment through the 'ex-ante capacity commitment market' is a fixed dollar amount determined by the SSRS (eg operational reserve capacity) offered, the SSRS clearing price and the period of offer. Also, regardless of whether the actual service was required on the day, CCGUs still receive the payments from the Capacity Commitment mechanism determined the day before. This is because making these services available requires these generators to make operational decisions that are costly and most of the time these generators are required to forgo other options (ie. their ability to rebid and opportunity cost).

Because the payment to a generator proposed under this mechanism is a fixed amount, it does not distort the short-run incentives for generators to bid for dispatch in the spot markets. The least-cost dispatch efficiency benefits in the NEM are not affected as all generators continue to receive the spot price for all generation.

Gaming

In recognition of the concern that generators that are successful in the Capacity Commitment mechanism may have an opportunity to use that commitment to gain an unfair advantage in the spot market it is proposed that each successful generator's energy bids for the relevant day be 'locked' at their energy bids current at the time that their offers to the Capacity Commitment mechanism are accepted, ie the successful generators may not re-bid their energy bids for the periods in their offer after their Capacity Commitment offer has been accepted (emergent plant issues excepted).

CCGUs that are not successful in the Capacity Commitment mechanism would continue to participate in the spot market, make dispatch offers and be dispatched as they currently are. They would be required to follow dispatch instructions. When CCGUs are successful in the Capacity Commitment mechanism, their decision space is restricted as they have to operate within the envelope that allows them to comply with their obligations under that mechanism. It is for this reason that the Capacity Commitment Mechanism is proposed as a voluntary market.

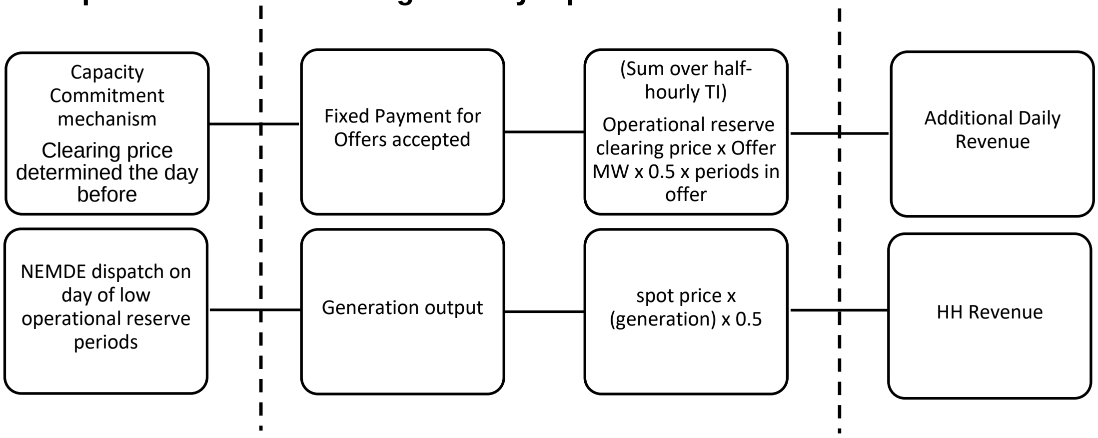
CCGUs that are unsuccessful in providing capacity under the mechanism are free to decommit their CCGUs during low spot price periods if they wish, following existing dispatch processes.[13]

Most importantly, market participants with CCGUs that are successful under the Capacity Commitment mechanism would not be shielded from spot market outcomes and still carry significant price risk. These CCGUs offered their units on the ahead market based in part on pre-dispatch prices. Should the low-price periods in pre-dispatch become, in actual dispatch, lower-priced or of greater duration than those CCGUs assumed, they remain obliged to AEMO keep their capacity committed for the entire period in their offer.

Figure 2 depicts the bidding and price relationships between ex-ante Capacity Commitment mechanism payments and the spot market.

[13] These processes are already available for generators who consider, for example, that spot prices are not expected to be high enough to cover their marginal generation costs.

Figure 2. Relationship between prices of ex-ante capacity commitment mechanism and spot market – illustrating 'All-Day' operational reserve case



CCGUs would compete with other generators in the spot market dispatch as they do now. Existing dispatch bidding procedures and obligations would remain in place. Once AEMO advises that additional committed has been procured under the proposed mechanism, all market participants are likely to adjust their bids

I. Interactions With Frequency Control Ancillary Service Markets

Market participants with CCGUs would not be prevented from bidding into the frequency control ancillary market as long as they can comply with their obligations in the ex-ante Capacity Commitment mechanism. For example, CCGUs that have been dispatched for providing ex-ante operational reserve services would not be able to provide frequency lower ancillary services while operating at MSOL during the 'low price period'. Market participants' ability to provide frequency raise services would be unaffected and it is expected that market participants would manage their ancillary service bids in line with their capabilities and system requirements.

A. Ramp Rate Capability Requirement

In a separate NEM rule change proposal, Delta proposes new 30-minute Raise and Lower services to meet the need for sustained rates of change from non-VRE committed generators.

As indicated in Section 4 above, the proposed new 'Raise and Lower 30-minute' FCAS services for sustained ramping capability (subject of a separate rule change proposal) would be dispatched as a separate market. If that service is to be sourced from slow-start thermal generators (also considered an SSRS in this paper), it would only be available from those that are in service and are dispatched to least at their MSOL. Accordingly, if not already committed, such generators would need to be committed well in advance, for example under this day-ahead Capacity Commitment mechanism.

Noting that the NER requires each thermal generating unit to provide a minimum 3MW/minute ramp rate some thermal plant is technically capable of substantially greater ramp rates, albeit at potentially greater operating costs.

B. Penalty Provisions

A penalty regime would need to be established to ensure that CCGUs are capable of providing the services they are committed to under the ex-ante Capacity Commitment mechanism. In particular, if a generating unit cannot operate at its offered MSOL when dispatched to that level, it should lose a pro-rated proportion of its commitment payment.

C. The Time Lag Between Ex-Ante Operational Reserve Dispatch And The SSRS Shortfall Period

The procurement of operational reserve services would need to balance the generators and AEMO's requirements. On the one hand, the time lag needs to provide sufficient time for generators to make operational decisions and commit (or continue to commit) their CCGUs. On the other hand, AEMO needs to have good forecasting information to ensure that the SSRS shortfall assessment is accurate and the operational reserve procurement is efficient.

It is proposed that offers by generators with CCGUs may be submitted for the identified 'low operational reserve period'(s) that are at least 12 hours, and not more than 24 hours ahead.

The structure of this proposal as a day-ahead market rather than as a half-hourly or 5-minute market improves technology neutrality as it ensures all technologies can particulate in the competition to supply SSRS, improving the competitive outcome. Shorter commitment time frames would act as an anti-competitive barrier to participation by slow start thermal generators, limit market access to fast-start generator technologies, and result in reduced competition for the service as well as increasing the likelihood that insufficient SSRS can be acquired to address any shortfall.

D. Dealing with Unanticipated Events

It is unrealistic to assume that the day-ahead ex-ante assessment will always be accurate. At times the assessment of SSRS shortfalls may be overly conservative and will lead to the procurement of capacity commitment that may not be required. Other times there may be events that are not predictable.

The optimisation engine (NEMDE) may find solutions that are more desirable (even when considering that payments to CCGUs will required to be made regardless of their dispatch). Under these circumstances, NEMDE should dispatch the more economical solution. However, CCGUs obligation to remain available should remain; their payments should be honoured and the generators should be dispatched at no less than their respective MSOL.

6. HOW THE PROPOSED RULE WOULD ADDRESS THE ISSUE

To ensure that sufficient SSRS remains available to AEMO to deal with system security and reliability scenarios in the day ahead, a new market mechanism is needed to avoid the decommitment of slow-start thermal generators during periods of low or negative prices.

The proposed rule change addresses the two components ESB identified to ensure the system will have the right mix of resources in real-time, and at lowest overall costs to consumers[14]:

- “Establishing new frameworks to value all essential system services so that they will be available to the power system when needed; and

- Incorporating a mechanism in the NEM’s pre-dispatch and dispatch process that provides visibility and enables efficient co-optimisation of the diverse set of resources ahead of time to ensure all necessary system services will be available, without costly and distortionary interventions. “

The proposed rule change is presented as a conceptually simple, relatively easily implemented market-based solution that directly addresses the issue and which has the following merits:

Minimising disorderly market outcomes
The proposed solution addresses a potential driver of premature exit from the market (under its current design) of critical plant until the SSRS that they provide can be replaced and therefore promotes more orderly market exit that assists planning for system security and reliability. The ‘ahead market’ nature of the proposed rule change provides more cash flow certainty and is therefore more sustainable compared to real-time markets (for example the Texas market) where generators may sustain losses for long periods in the hope that occasional high-demand periods will generate sufficient revenue to stay in business.

Reduced cost of market intervention
This is achieved by replacing intervention with an offer-based market mechanism that will support least cost provision and innovation such as the economic lowering minimum loads that will allow more VRE into the system.

Incentivises investment
The mechanism rewards CCGU with low MSOL and large reserve capability. Investing in reducing MSOL will reduce the displacement of lower cost generation at times when some plant needs to remain committed to provide reserve later in the day. The mechanism will incentivise investment in additional SSRS at the lowest cost with price signals from a common clearing price.

Addresses Operational uncertainties arising from market directions
Operational planning by slow-start thermal generators is compromised by the threat of directions and the uncertainty surrounding market revenues that will prevail in a market subject to interventions. In contrast, the proposed rule change provides a market solution that supports operational planning.

Efficient price-finding
By introducing a market-based solution the value of the SSRS become transparent to the market allowing both innovation by existing potential providers to increase supply (e.g. by innovating to reduce generator MSOL) as well as providing an investment signal for new technology to provide equivalent services.

[14] COAG ESB ‘System Services and Ahead Markets’ Paper, Introduction.

Technology Neutrality
Eligibility criteria to participate in the proposed ahead Capacity Commitment mechanism is determined by generator status as 'likely to be subject to AEMO's direction' and applies equally to any technology. The mechanism will capture capacity from any source, including potential demand-side products.

The structure of this proposal as a day-ahead market rather than as a half-hourly or 5-minute market improves technology neutrality as it ensures that slow-start thermal generators can participate in the competition to supply SSRS, improving the competitive outcome. Shorter commitment time frames would limit market access to fast-start generator technologies and would result in reduced competition for the service.

Simplicity and timeliness
This rule change is proposed on the understanding that there are major review processes underway that may address the same security and reliability concerns in a more holistic and comprehensive manner. However those review processes may take some time to complete and in the meantime Delta sees that the increasing role of VRE in the NEM energy supply is already creating increased frequency and duration of very low or negative spot price periods in most regions. A market-based solution that can be relatively quickly implemented is preferable to increasing the frequency of market interventions. Early implementation of the rule would provide experience and price information that may help inform the development of successor NEM rules.

The above merits move the market towards the ESB's objective of increasing visibility of resources.[15] It is enhanced by implementation of a market-based solution which will provide price signals for essential system services to promote innovation and engagement by both sides of the market and fulfils key market design elements identified by the ESB including providing competition and market signals and addressing information asymmetries and at modest regulatory and administrative costs.[16] This makes this proposal an excellent interim solution advancing the ESB's objectives in key areas while addressing imminent market needs in a timely fashion. AEMO has also highlighted the merits of a staged "transition of an essential service 'mid-flight'" [17], comments that support a simple solution with the flexibility to adapt to lessons learned.

7. HOW THE PROPOSED RULE CHANGE WILL CONTRIBUTE TO THE NEO

The National Electricity Objective (NEO) is efficient operation of, and investment in, the electricity industry for the long-term interests of end-users. Delta Electricity considers that the proposed ex-ante capacity commitment market contributes to the achievement of the NEO.

Allow generators and the market operator to make efficient operational decisions.
At times it may be inefficient for generating units to decommit and recommit. There are significant economic costs of doing so both in terms of fuel costs and costs of wear-and-tear on equipment. The rule change allows generators to consider these costs and submit

[15] COAG ESB 'Moving to a Two-Sided Market' Paper, Introduction.
[16] COAG ESB 'Moving to a Two-Sided Market' Paper, Section 1.4.
[17] AEMO 'AEMO Renewable Integration Study update" Nov 2019

their operational reserve offers accordingly. AEMO is in control of when, how much and at what price to procure operational reserve services.

Minimise the cost of operational reserve services. Only the lowest cost service providers are procured and the new Capacity Commitment Mechanism will provide an incentive for providers to innovate.

SSRS are only procured when and where they are needed. AEMO is tasked to define low SSRS conditions. The differentiation of SSRS services (e.g. reliability, inertia, ramp rate capability) allows for a targeted procurement from eligible generators that are capable of providing the right type of service. Generating units are included in dispatch using their unique DUIDs. DUIDs allow AEMO to consider the location of CCGUs and thus to ensure that only those CCGUs that can meaningfully contribute to overcome the identified low SSRS condition would be successful in the ex-ante operational reserve market.

Efficient price signals to provide operational reserve services. The ex-ante operational reserve market provides clear price signals for technology innovation and investment. Generators that can provide operational reserve service compete on equal footing with one another. The generators that can make themselves available at least cost will be dispatched for operational reserve service during 'low operational reserve period'(s). Given that the market provides ongoing, dynamic and transparent price signals, they directly promote the adoption of relevant capabilities by new and existing generators. The value of the provision or reliability, inertia, ramp rate capability are clearly priced at certain times and locations. These can be used to provide efficient price signals for investments into technology that can provide these services. The following may be longer term outcomes of the ex-ante operational reserve markets:

- generators that are currently intermittent are incentivised to adopt technology that enables them to provide one or more of the services required; and
- for currently dispatchable generators there would be an incentive to reduce their MSOL and increase the discretionary capacity.

Ensure the least distortionary effect on the operation of the market. CCGUs are guaranteed dispatch at their MSOL only. This minimises spot market impact. Successful CCGUs bids remain in the spot market and they receive the dispatch price for all energy dispatched above MSOL, subject to complying with their commitments in the ex-ante operational reserve service market.

CCGUs that were unsuccessful in providing operational reserve services may continue to bid their generating output into the spot market.

Co-optimise the provision of energy and operational reserve services. CCGUs that are successful in providing operational reserve services on a day provide all generation output to the spot market at the spot price. Sufficient operational reserve has been secured at the lowest cost and NEMDE dispatch occurs according to optimise (minimise) energy costs.

Efficient price signals to augment and invest in transmission network. Augmenting the transmission network will depend, in part, on short-term pricing and dispatch arrangements. Whether investments in, for example, synchronous condensers by transmission networks are justified may be measured against the price signals in the ex-ante operational reserve market.

Technology neutral. Participation in the Capacity Commitment mechanism is limited to scheduled fully dispatchable generators and with that proviso is agnostic as to technology. It is acknowledged the rule change proposal will likely have a differential impact across technologies. Whilst initially it is expected that slow-start thermal generators would often provide these services when required and that is consistent with the need identified. With technology improvements generators with synthetic inertia capabilities may also be able to provide similar capabilities in some SSRS, subject to satisfying AEMO that their capabilities are adequate. The proposed day-ahead market is a market to address a current need which will diminish as a range of current and future technology options develop. This will lower costs for consumers in the long term as the frequency of SSRS shortfalls diminishes.

Effective competition. Competition and market signals, where feasible, generally lead to more efficient operational and investment decisions than prescriptive rules and central planning as well as being more flexible to changing market conditions and provide consumers with the services in the most efficient manner possible. For competition to be effective, market signals must be delivered to parties best able to respond in a manner that benefits consumers. The proposed rule change establishes a competitive framework for the provision of system security and reliability services. The no-rebid element of this proposal addresses concerns that generators who participate in the proposed Capacity Commitment mechanism should not be in a position to game outcomes once commitment is assured.

Flexible and resilient market frameworks: Regulatory arrangements must be flexible to changing market conditions. They should not be implemented to address issues specific to a particular time period or jurisdiction. The proposed rule change is resilient to changing market conditions (changing generator mix).

8. COSTS AND BENEFITS OF THE PROPOSED RULE CHANGE

In terms of costs and benefits Delta notes the single-quarter cost to the NEM of $310m reported in AEMO’s Q1 2020 Quarterly Energy Dynamics Report. This cost was dominated by the effects of a major transmission line failure on 31January 2020, an event that some might wish to describe as a one-off event, however the last similar failure occurred on 28 September 2016 so the type of event is entirely foreseeable and the frequency is alarming given the duration of disruption to repair multiple transmission towers with their associated lines (18 days in the January 2020 case).

These two events are only the most significant of a series of highly disruptive events (from https://www.energycouncil.com.au/analysis/south-australias-blackouts-not-as-simple-as-it-looks/):

“South Australia experienced blackouts on 8 February 2017 (90,000 households), 20 January 2017 (55,000 households), 27 December 2016 (155,000 households), 1 December 2016 (200,000 households), a system black event on 28 September 2016 (whole state) and a blackout on 1 November 2015 (110,000 households). The 2015 blackout occurred before Northern Power station closed.

The level and frequency of these events are also unprecedented in the history of the National Electricity Market and in comparison with modern grids around the world.”

Note: Report dated 11 May 2017 and therefore does not include any events post that date, including 31 January 2020

The $229m costs associated with the 31 January event is only AEMO's costs and does not include the costs to customers from the loss of electricity supply. Using AEMO's estimate of Value of Customer Reliability (NEM average, '**VCR'**) from Its "Value Of Customer Reliability Review" Final Report dated September 2014 of $33,460/MWh and assuming the loss of load from the event was one day of SA region load (including embedded rooftop PV) of 55.6 GWh, the costs borne by the customers are estimated at **$1.86 Billion**, dwarfing the visible costs from AEMO managing the event post the transmission failure.

While it is difficult to extrapolate costs and benefits from these events to the NEM generally, they do serve to illustrate the consequences of allowing a situation to develop where insufficient signals existed to incentivise sufficient SSRS to remain in a region to permit AEMO to adequately manage system security for that region.

Delta's proposal can provide such a market signal to help provide a glide path to a high-VRE future while maintaining system security.

What is clear from this example is that in terms of the costs and benefits, the cost of failing to secure sufficient SSRS, whether by Delta's proposal or by a different mechanism is dominated by the VCR. By implementing Delta's proposal this avoided cost is the principal benefit

A. Benefits

The expected principal benefit of AEMO being able to secure sufficient SSRS (ie remaining with the status quo NEM design) is estimated as a single day in each NEM region of a single day's loss of load (including rooftop solar) at a probability of occurrence of 1 day in each 20 years where the loss of load is valued at the VCR:

NEM VCR Benefit = VCR * 198,000,000 MWhpa/365 * 5%

= $33,460/MWh * 198,000,000MWh/365 * 0.05

= **$0.91 Billion** (expected value per annum)

(using May'19-April'20 actuals as an estimate of the lost load)

Additional benefits are a reduction in NEM system costs generally, AEMO reported Q1 costs of [18] $310m, principally associated with "three major power system events, most notably the 18-day separation of the Victorian and South Australian power systems after a storm event knocked out key transmission lines on 31 January. These events contributed $229 million, or 74%, of system costs for the quarter" [19] and in particular:

1. AEMO described FCAS costs as being the main contributor to the large Q1 2020 NEM system costs. While Delta's proposal will not lead to the elimination of these

[18] In AEMO's QED reports, NEM system costs refer to the costs associated with: Frequency Control Ancillary Services, directions compensation, the Reliability and Emergency Reserve Trader function, and variable renewable energy curtailment.

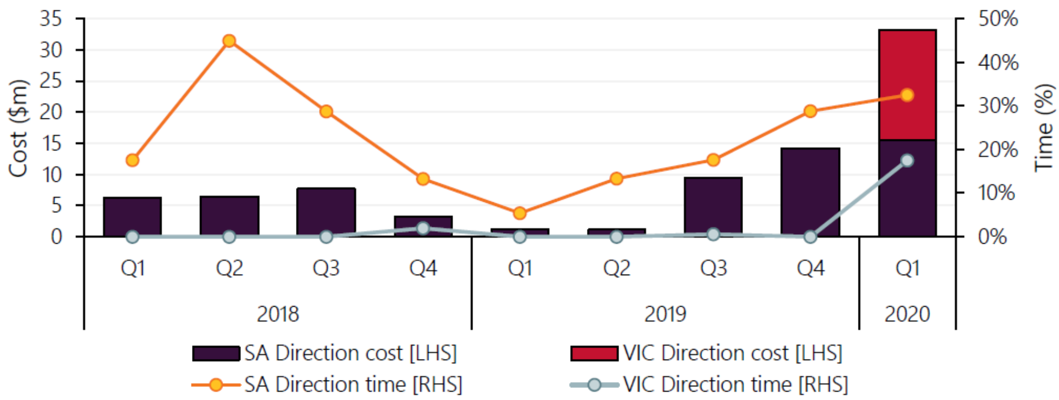
[19] IAEMO Q1 2020 Quarterly Energy Dynamics Report

costs it will lead to greater competition in their provision due to the additional commitment of large slow-start thermal generators that are well suited to FCAS provision and may be, with Delta's proposal regarding 'Ramp Rate Capacity Requirement' be able to provide well above standard rates of change;

2. The avoidance of NEM direction costs [20] using the current tools available to AEMO, refer Figure 33 from AEMO's Q1 2020 Quarterly Energy Dynamics report below:

Figure 33 Victoria drives NEM direction costs to record quarterly levels

Frequency and cost of system security directions (energy only) in South Australia and Victoria



Note: direction costs reported are preliminary estimates which are subject to revision.

Total directions costs for the most recent 12 months is **$57m** (from AEMO's Q1 2020 Quarterly Energy Dynamics reports);

3. The expected avoidance of incurring RERT costs running at **$35-52m** per annum;

There are additional qualitative benefits as follows:

4. Delta's request introduces competition to the delivery of a proposed new service that directly addresses a growing need in the NEM that is already pressing in some jurisdictions;

5. The proposed rule change is simple and directly addresses the need;

6. The visibility of a transparent price signal for operational reserve in the day-ahead market. Once this market becomes visible then the prospect of a traded market emerges and the price signal provides the opportunity for allocative efficiency in investment in technology to meet AEMO's operational reserve criteria, including for new technologies or demand side response where those services are able to meet AEMO's needs. The deployment of these new supplies will help to provide downward pressure on electricity prices as well as providing AEMO with greater choice to efficiently provide the required level of operational reserves;

[20] As at 31 July 2019, AEMO had issued 267 system strength directions, most of which were in the last two years. During 2018, directions were in place for around 30 per cent of the time in South Australia. See AEMC, Investigation into intervention mechanisms in the NEM, Final report, 15 August 2019, p.7 and Figure 33 on page 27.

7. The additional dispatchable capacity kept in service because of the operational reserve day-ahead market should contribute to more competitive energy pricing in:
    a. the NEM energy market over the entire day of their commitment; and
    b. the contract market as the propensity of generators to contract their capacity increases as the day-ahead market provides a means for generators to manage the risk of contracting for periods when they may have expected they would not be able to defend those contracts.
8. Reduced variability in the total cost of energy, benefits both generators and customers. Generators will be able to plan with greater certainty and promote a more predictable and manageable transition to a high VRE-based NEM and avoiding price shocks for customers.

B. Costs

Delta considers that while the proposed rule change is not cost-free the costs are very modest.

1. The costs of payments made to Operational Reserve suppliers. As Infigen noted[21] "*This market proposes to price a service that was previously provided for free – i.e., the provision of sufficient market Operational reserves. On face value, this represents a new cost to consumers. However, we expect that this cost will be negligible most of the time (when Operational reserves are in good supply).*

   Although Delta proposes a different market structure, Delta agrees that most of the time the cost of Operational Reserve will be zero as dispatchable capacity offered to the market is usually plentiful. Operational Reserve will acquire a value at times of very high system demand, very high VRE that may otherwise drive non-zero MSOL generators to de-commit, or at times of supply-side scarcity.

   The cost to a slow start thermal generator remaining in service is the spot losses of operating at MSOL when the Spot is below Marginal Cost (**MC**) offset by avoiding the cost of fuel oil for re-start. As low price period duration increases, in the limit this tends to just recovering ∑MAX(0,MC-Spot)*MSOL*0.5. At present, while there is usually an ample supply of synchronous generation in most regions, competitive pressures should drive Operational Reserve offers towards this limit. As Operational Reserve becomes more scarce, clearing prices are likely to be higher as more expensive offers become marginal. Other services such as increased Rate Of Change may include additional costs (such as more oil support for frequent mill changes) that a generator will take into account in its offers.

   A 660MW generator which could provide Operational reserve of 460MW with MSOL of 200MW and a marginal operating cost of $30 would face costs of $52,000 to remain committed through a low-price period of 5 hours of negative Spot at -$10.00/MWh (ignoring any offsetting re-start costs). An estimate of the annual costs if applying this proposed rule change at a future year when spot

[21] Infigen's Rule Change Proposal ERC0295 at https://www.aemc.gov.au/sites/default/files/2020-03/ERC0295%20Rule%20change%20request.pdf .

prices drive multiple generator de-commitments on a daily basis is to assume 4 generators seek to recover the costs of remaining committed every day which yields an annual cost of $52,000*365*4 = $76 million.

2. VRE providers may face some additional VRE curtailment in the short term (prior to Snowy 2.0 development and other storage initiatives), however this is offset as VRE providers, along with all participants in the NEM, also benefit from the improved security of the system.

3. AEMO would incur the costs of implementing the new ex ante day-ahead market. Delta's proposal has none of the complexity of seeking to implement 5-minute or half-hourly bidding and dispatch (which Delta believes is not well suited to the commitment and de-commitment decision timeframe for slow-start thermal generators) let alone integrating those markets into the existing energy and FCAS markets and co-optimising dispatch solutions. Accordingly the simplicity of the proposal should translate to a low cost of implementation and testing, particularly in the IT domain but also in the areas of procedures and reporting.

4. Potential Operational Reserve suppliers will need to develop systems to bid for and comply with outcomes of the new day-ahead Capacity Commitment Mechanism. Only those generators that qualify and that wish to participate will incur those costs however those generators will take those costs into account when making the deciding to participate or not. Again, the simplicity of the proposed rule change should translate to a low cost of implementation.

C. Net Benefits

As the estimated quantifiable Costs of $76 million per annum are a figure similar to the Benefits of potentially avoided system costs and RERT alone ($92 to $119million per annum) then the Net Benefits of the proposal approximates the potential avoided VCR benefit of $0.91 Billion.

D. Cost Allocation of AEMO's costs between NEM Participants

One driver for the emergence of negative price periods that are providing the incentive for conventional generators to decommit is the increasing levels of VRE generation in the middle of the day, in particular Solar PV generation. Applying a causer-pays principle, it is this class of participants that could be exposed to the costs of the proposed day-ahead operational reserve market. Such an allocation will incentivise investment in energy storage, to provide equivalent operational reserve capacity, or to curtail. For example, co-located hydrogen production combined with generation capability using the stored hydrogen fuel addresses the issue directly. Co-located battery energy storage systems help serve the same purpose.

Ultimately, AEMO's NEM average VCR of $33,460/MWh of unserved energy indicates it is customers who benefit the most from adequate system stability and reliability, accordingly there is also a case for allocation of costs to customer load. Allocating costs to consumers on a pro-rated energy basis avoids the complication of determining causer pays factors.

APPENDIX 1 – THE MATHS OF INERTIA[22]

Kinetic Energy refresher

KE is the Kinetic Energy or Stored Energy of a Rotating Mass:

$$KE = \frac{J\omega^2}{2}$$

KE is in MW-s or MJoules for transmission power system analysis
J is the Moment of Inertia of the Mass (larger mass=larger J)
ω is the rotational Speed of the Rotating Mass in radians/sec

System Inertia is defined as the stored rotating energy, KE, in the system

Inertia Constant of a Unit or System

Define an Inertia constant, H, in units of MWs/MVA as

$$H = \frac{J\omega^2}{2 \times MVA}$$

H is proportional to the kinetic energy of the unit or system.

Benefit of Inertia

For a loss of **P** MW of load or generation, the rate of change of frequency, $\frac{df}{dt}$, is given by:

$$\frac{df}{dt} = \frac{\Delta P}{2H}$$

Accordingly, following a System loss of **P** MW, the higher the System Inertia, **H** (assuming no frequency response e.g. from opening turbine throttle valves) the longer it takes to reach a new steady state operating frequency.

Where does Inertia come from?

- As the mass of the rotating system increases, the Moment of Inertia (J) increases;
- Directly connected synchronous generators, contribute directly to System Inertia. Slow-start thermal generators are typically two-pole machines, meaning that they spin at 3000RPM, with a rotating mass of around **240 tonne** comprising the generator rotor and typically the four turbine rotors of the two low pressure, the intermediate pressure and the high pressure stages together with the couplings to link all these turbo-generator rotor elements together;
- Compared to a 660MW-class steam turbo-generator, a typical 30 or 60MVA synchronous condenser can provide the spinning mass of a much smaller two-pole electrical rotor but no turbine mass;
- Modern inverter-based Generator technologies such as Solar PV or Wind Turbine generators which decouple the prime mover from the electrical generator will not necessarily contribute directly to System Inertia; and
- Under a high VRE Scenario, significant volumes of new generation are unlikely to contribute to System Inertia.

[22] Refer: Antony Johnson National Grid: "Grid Code Frequency Response Working Group - System Inertia", Sandeep Sadanandan "System Technical Performance Power System Optimization with an Inertia Study on the IEEE 30-Bus Test System"