Energy Security Board
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Submission
Post 2025 Market Design Options – A paper for consultation

Delta appreciates the opportunity to contribute to the Energy Security Board's work on post 2025 market design options for the National Electricity Market (NEM). Delta's generation portfolio includes the 1,320MW Vales Point power station on the NSW Central Coast and a 150MW off-take from the Darlington Point Solar Farm. In addition to its wholesaling activities, Delta retails to large commercial and industrial customers. Delta has operated in the NEM since its inception in 1998 and has developed renewable and gas fired generation capacity.

The Australian Energy Market Operator's (AEMO) recent Quarterly Energy Dynamics Q4 2020 and Q1 2021 reports note the impact that the rapidly increasing amounts of Variable Renewable Energy (VRE) is already having on the market:

- changing demand patterns;
- changing market price signals with more frequent and longer lasting negative prices (generators pay to dispatch their energy);
- increasing intervention in the market (at this stage primarily South Australia) by AEMO to maintain power system security; and
- significant displacement of conventional generation by VRE sources.

While the landscape across the NEM is changing far faster than expected when the Post-2025 NEM Market Design work was initiated, Delta maintains that the principles of competition, market-based solutions and technology neutrality should continue to be prioritised in the development of the detailed market design for the 'new' market dynamics. The rapid pace of change, boosted by State based energy policy such as NSW's Electricity Infrastructure Roadmap, risks the early closures of conventional thermal plant (Chart 1) that will be needed to maintain power system reliability and security as the NEM transitions to lower carbon emissions.

A greater urgency in implementing changes in the NEM ahead of 2025 is now warranted and some of the identified next reforms, like operating reserve, ramping and inertia mechanisms should be considered for immediate and initial reforms.

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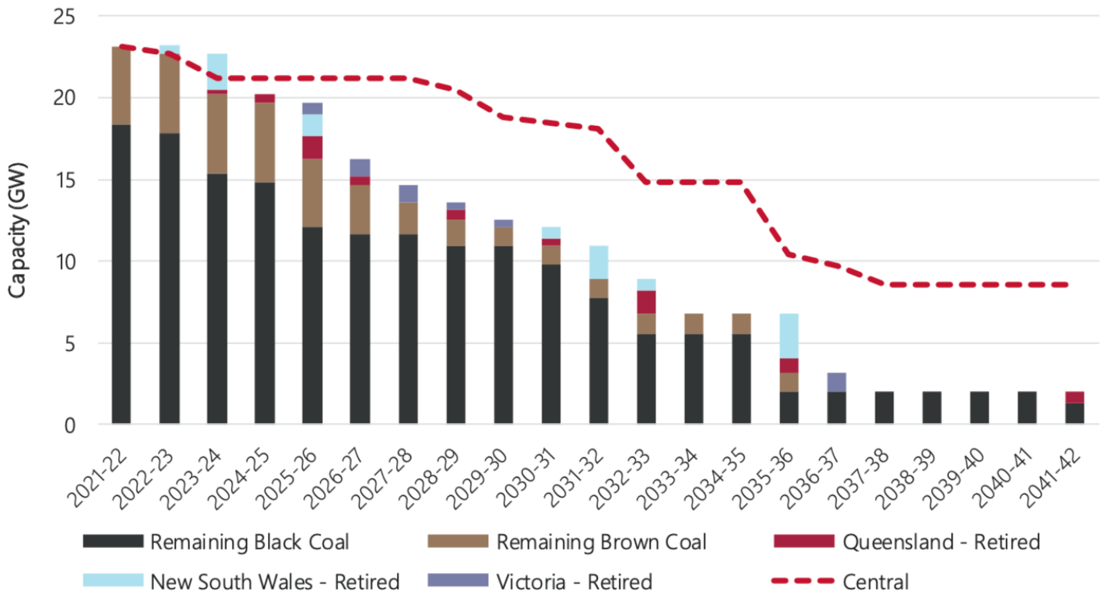
Chart 1 – Forecast coal-plant retirement under AEMO's ISP 'Step Change' scenario



Note: Chart 1: The step down in remaining plant in FY24 (Liddell) occurs in FY23.

The priority for reform should therefore be to ensure that shorter term system security mechanisms are put in place by mid to late 2022 and that medium to longer term resource adequacy mechanism are completed by end 2024. Short term measures are critical to ensure the continued operation of dispatchable generators to the extent they are required to meet demand for essential system services (e.g. frequency control, voltage control, inertia and ramping). Both short term and medium to longer term measures are needed to incentivise innovation and new investment and provide time for delivery of the lowest cost technology solutions to meet future NEM needs.

The ESB has noted[1] that "*Governments have indicated a preference to drive investment through the transition*" and that support schemes often represent broader policy objectives instead of prioritising the maintenance of reliability. The ESB has proposed options that embed Government involvement in the market, these include:

- involvement in early plant retirement reviews with a view to providing financial support;
- the design of Government long duration contract schemes for new investment; and
- potentially including economic and social benefits in the RIT-T to facilitate investment in renewable energy zones.

If implemented these options potentially lead to investments only occurring if underwritten by Government, and risk that is better managed by the private sector transfers to consumers and taxpayers. The lessons of the past are being ignored. The NEM was established to address over investment and bureaucratic decision making. The pathway that better supports energy consumers is one that prioritises the enhancement of NEM arrangements to provide a market reward for existing and new dispatchable generation capacity, storage and

[1] ESB Post 2025 Market Design Options, 30 April 2021.

system services in response to a market need. This is also a pathway that removes Government interventions except as an absolute last resort and only allows network investment that passes economic net benefit tests and where investment costs are rigorously tested in order to ensure that they meet the requirements under the National Electricity Law and the associated National Electricity Objective. Ironically, by undermining the current market reward-based system, Government interventions may well create the need for more intervention as private investment evaporates.

Market Reform Categories

The post 2025 market design options paper is the next stage in the process of design changes to the NEM to support the changing generation mix. Delta makes the following observations about the details of the proposed framework.

Resource adequacy and aging thermal generator retirement

Notice of closure – increasing information requirements reduces operational innovation – for what purpose and at what risk of unintended consequences?

Increasing information requirements on coal fired power stations is not going to provide additional generation resources or solve the problem of managing coal fired power station exits. Since Hazelwood's sudden closure, the notice of closure obligations on coal fired power stations (Liddell and Yallourn) have sent early signals about closure dates without the need for regulation.

Involving the jurisdiction in an early closure request will further entrench market interventions, mute new resource signals and reduce the efficient operation of the NEM. If the proposed market reforms are implemented in a timely manner, then closures will be dealt with by the market.

Changes to the Retailer Reliability Obligation (RRO)

A physical RRO is an important reform that will provide a necessary stronger signal for medium to longer term capacity needs. As with any capacity mechanism there is a risk that a capacity surplus could be delivered which will unnecessarily increase electricity prices to consumers. As discussed in detail in Attachments 1 and 2, getting the design right will be critical.

As mentioned above, long term resource adequacy measures need to be complemented by shorter term arrangements recognising the dynamic nature of electricity market operations driven by weather patterns and technical operating parameters. An ahead operating reserve market, of a form proposed by Delta Electricity[2], should still be implemented as it deals with the important issue of the necessary lead time for slow start unit commitment for short notice reserve needs. A short-term ahead operating reserve/system services mechanism will deal with the increasing real time variability and uncertainty of market conditions and will address the increasing costs of AEMO's directions.

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[2] NEM Rule Change Request Capacity Commitment Mechanism for Operational Reserve and Other System Security Services (AEMC website)

Essential System Services

If the new market design is to be technology neutral, it needs to recognise the different operating characteristics of electricity generators and that no single generation (or demand response) type provides all required services.

Ramping services have not been given the priority warranted given the forecasts by AEMO[3]. By 2025, there could be up to 75%[4] penetration of renewable energy (instantaneous generation) without the necessary operating reserves to manage uncertain changes in net demand. As VRE grows so too does the need for ramping. Conventional coal-fired power stations limit ramping to avoid over-stressing plant and peaking gas plant has start time delays. Ramping requirements are not related to price signals and within a few years there is likely to be shortfalls in its availability. Ramping is a service aligned with operating reserve and it warrants further assessment by the ESB with a view to establishing a separate service.

The immediate frequency control reform to implement a Fast Frequency Response (FFR) is an acknowledgment of the importance of covering the full range timeframes for reserves. Inertia is inseparable from frequency control and ensures the rate of change of frequency following credible contingences can be managed by frequency response sources. It is therefore critical that an inertia service market be established in lock step with the fast frequency response market. Otherwise, fast frequency response solutions will drive inertia requirements and optimum least cost service provision will be lost. It is worth noting that:

1. a structured procurement approach to inertia is not adopting a technology neutral position as it is taking for granted a service that is provided by existing technologies; and
2. inertia procured by a TNSP under contract may well lead to a high-cost single solution like synchronous condensers that will lock in costs for consumers over decades with no guarantee of continuing net benefits, as well as “crowding out” new technological developments that could provide a lower cost solution. Additionally, there would be no incentive for existing synchronous generation to continue to provide low cost inertia.

While allowing TNSPs to provide inertia and system strength is a short-term band aid to rapid changes in the NEM, long term it is an inferior solution that will diminish competition and innovation. System strength does not naturally lend itself to a market-based mechanism, but a body like AEMO will be better placed to ensure holistic solutions across the entire NEM that can be better integrated other essential services.

Integration of Distributed Energy Resources

The application of competition and market-based principles is particularly important to the development of future reforms in this area to support good customer outcomes. Delta supports the proposed approach that uses an iterative Maturity Plan to develop regulatory and market design changes particularly given the dynamic environment for developing new

[3] AEMO 2020 ISP Appendix C
4 Energy Security Board (2021) Post 2025 Electricity Market Design, Infographics paper, p.3

retail products and services. The primary role of networks (transmission and distribution) should be as a facilitator and balancer between retailers and their customers, not a player in the market. Customer focused network pricing which meets customer product preferences is critical to underpinning this arrangement.

Transmission and Access

The future NEM should not assume that new transmission is a pre-requisite. Cost remains a critical factor in deciding the optimal path for the energy market transition underway. Policy objectives (benefits) beyond the NEM Objective cannot be included in the RIT-T. In particular, consideration of economic benefits to regional communities would allow the politicisation of decisions and risk investment in major transmission projects that ultimately become 'white elephants'. Including any other benefits in the RIT-T, than already allowed, will discourage more economic generation investment decisions in different locations. It would also be inconsistent with the NEL/NEO and could easily undermine the confidence of consumers (who ultimately pay for this infrastructure) in the RIT-T process.

The ESB has proposed several transmission access options. At the very least, there should be a realistic locational signal to generators looking to locate within a renewable energy zone. The creation of a financial transmission access rights could be a barrier to entry and present high transaction costs. A simpler access fee regime that is linked to a share of the planned transmission upgrade costs would equitably expose new generators to the cost of their locational decision.

Priorities for Reform

As an immediate priority, existing proven technologies should be financially incentivised to remain operational as required while new system service technologies emerge and are tested. This approach would de-risk the current electricity market transition underway. This can be achieved with the implementation of new market mechanisms that incentivise supply. This places value on the provision of essential power system services that are currently provided as by-products by synchronous (traditional) generators and, therefore, are not valued even though they are critical to maintaining a secure and reliable electricity supply. The ESB[5] notes that the lack of markets or other means of valuing essential system services means AEMO is increasingly, and regularly, intervening in the market. This intervention, largely resulting from directing conventional synchronous units into service, has cost consumers up to $30m in a single quarter[6] in just one State (SA), and AEMO clearly identified in its Renewable Integration Study that the risk of market intervention will extend to other States through to 2025. There are also significant "unseen costs" from AEMO intervening to protect system security by constraining off large scale renewables.
Delta contends that to avoid losing the benefits delivered by a properly functioning NEM, the next stage of reform must include priorities for:

1. a physical RRO that will incentivise existing dispatchable capacity to be available as required over a longer period and not lead to an oversupply of new capacity (refer Attachment 1). Design parameters (Attachment 2) should ensure capacity is incentivised to be available on a typical 'worst day' of supply shortfall/high demand.

[5] ESB Post 2025 Market Design Options – A paper for consultation Part A, April 2021
[6] AEMO Quarterly Energy Dynamics Q1 2021.

To ensure technology neutrality, the PRRO should be established as a trading platform and the retailer obligations to acquire certificates must be aligned with AEMO's assumptions when determining a reliability gap, and any trigger of the RERT;

2. the establishment of an ahead operating reserve mechanism[7], complementary to a PRRO, that provides short and medium term investment signals to incentivise the availability of dispatchable capacity, as needed, for times of low VRE output and particularly in the context of an increasing daily dispatchable generation ramping requirement when solar generators come on and off at around the same time across the NEM;

3. the establishment of market-based arrangements for system security services that adequately respond to the increase of VRE underwritten by Governments. This will include fast frequency response, inertia and ramping services to incentivise the availability of the right type of dispatch generation whether it be existing conventional plant, new dispatchable generation sources or storage; and

4. exposing new VRE generation to the cost of their locational decisions within the network and, where efficient, to the costs of system services directly attributable to their operation. Such exposure will support more efficient investment decisions and innovation.

As stated earlier, the rapid pace of change requires key reforms to be given priority so that they can be implemented in a timeframe that avoids Government intervention and costly AEMO market directions. There are considerable risks for consumers if reforms are unnecessarily delayed:

1. a reliance on network solutions via regulated monopoly businesses will deliver very long-lived network assets with relatively high costs that are locked-in for the life of the asset regardless of whether real benefits for consumers are achieved and regardless of whether there are new technological developments in the pipeline that could potentially deliver lower cost outcomes within a reasonable timeframe;

2. the loss of low-cost system services from conventional generators that are forced into early retirement due to low energy prices and limited dispatch opportunities, with these services replaced with expensive non-market options;

3. Government intervention is creating a highly uncertain investment future which could ultimately result in investment only delivered if underwritten by Government; and

4. the return of problems that led to the establishment of the NEM in the first place. These include wasteful over-investment, poor centralised decision making and taxpayers and consumers bearing the financial risk of investment.

[7] NEM Rule Change Request Capacity Commitment Mechanism for Operational Reserve and Other System Security Services (AEMC website)

Longer term, it is important to continue the market design work to support the electricity market of 2030 and beyond. It should be noted that conventional generation can be life extended to continue to provide essential system services should they be required by the market. This plant could be operating at low output factors that reduce greenhouse gas emission but be online ready to respond to changes in VRE or power system events. Substantial work will need to be undertaken to find solutions to the technical challenges that will result from far higher levels of weather-dependent VRE entering the NEM.

Information and analysis that supports Delta's views can be found in Attachment 1. A discussion on the PRRO and the proposed UCS/SSM mechanisms is included as Attachment 2. Delta's answers to the questions posed in the option papers are included as Attachment 3.

Yours sincerely

Anthony Callan
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ATTACHMENT 1

Supporting Information

1 Overview

Attachment 1 provides the context and supporting information for Delta's comments on the options papers.

The draft determination for Delta's rule change proposal (Capacity Mechanism for System Security and Reliability Services) is due 24 June. This rule change proposal is inextricably linked to the market design options proposed by the ESB, particularly the unit commitment for security (UCS), discussed in detail in part B of the options paper. It is worth highlighting that the UCS/SSM proposal does not adequately deal with unit commitment as the UCS will only schedule services procured under contract by a TNSP. Generators with uncertain futures will be hesitant to commit to providing security services under a longer term contract, where the provision of those services requires the generator to be in service, regardless of the energy price. Delta's rule change addresses this issue by giving AEMO a mechanism to commit the least cost plant for either reliability or security a day ahead.

1.1 Context – Uncertainty and Risk

There are two factors – commercial pressures and government funded investment - driving risk and uncertainty for thermal generators which, if not addressed, will accelerate exit strategy decisions. It is these factors which should inform decisions around market design. They underscore the need for a quick response and decision from the Energy National Cabinet Reform Committee (ENCRC) on the next stage of NEM market design proposed by the ESB mid-2021:

1. Existing commercial challenges. Actual revenue is falling, reflecting lower wholesale prices and declining volume, and potential revenue for system services is not forthcoming, despite a widely recognised need. While the theoretical technical life of these power stations may be 50 years, commercial factors will drive retirement and life extension decisions.

2. Post 2023, composition of generation in the NEM and its impact on wholesale prices is highly uncertain. This is being driven by a series of Government funded investments which are making investment decisions difficult and are likely to continue to dampen prices:
    - new gas peaking plant. EnergyAustralia's Tallawarra B (350MW) is scheduled to commence operations in the summer of 2023/24 and Snowy Hydro is constructing a 660MW gas fired peaking station at Kurri Kurri;
    - results of the first tender for the NSW long term energy service agreements is likely during 2022; and
    - scheduled commencement of Snowy 2.0 in 2025.

These factors require market design decisions which recognise:

- technology neutrality and support the different operating characteristics of generators given that no generator provides all required electricity market services;
- Government investment is impacting price signals;
- the dynamic operating environment including regulatory risk;
- a complete transformation in the NEM wholesale generation and storage mix is underway supported by an expanded and geographically altered transmission network, distributed energy resources and active demand management; and
- the practical reality is that, apart from the Government-owned generators in Queensland, coal fired power stations across the NEM could be forced into early retirement due to financial pressures, with significant disruption to the NEM.

In this context, a two-pronged approach may be preferable:

1. adopting a precautionary approach to the current rapid, and faster than expected, transition of the NEM by keeping the system securely operating with existing proven technology until there is certainty about system operability at 50%+ levels of instantaneous renewable penetration; and
2. continuing to develop a market design over the three pathways proposed by the ESB, albeit Delta considers the ESB needs to revisit the prioritisation particularly around the establishment of long term resource adequacy and short term operating reserve mechanisms (including a ramping service).

It is particularly noted here that the ESB Options Paper (Part A, page 16) stated:

> "The levels of wind and solar energy that can operate on the system at any time varies depending on system conditions. Increasing levels of penetration means more curtailment of those resources because of network congestion and insufficient services like frequency control system strength, voltage control, or flexibility (ramping). Without further action, the maximum instantaneous penetration of renewable resources would be limited to between 50 and 60 percent."

The ESB has included the development of measures such as operating reserves (ahead markets) and changes to the RRO in its initial reform steps however they require clear deliverable timetables to ensure their implementation. Design work and supporting rule changes should be completed by the end of 2022 to provide the clarity of direction and market signals needed to manage the environment post 2023. Without this clarity, the risk of early power station retirement increases due to the commercial challenges.

The inter-related questions that need to be answered are:

1. How long will large conventional thermal plant need to operate to ensure system security and reliability?
2. What is the most competitive mechanism required to encourage them to do so?

1.2 Market Design Focus and Pathways

The current market design reform approach, while not explicitly stating so, appears to assume that it can accommodate different generator technical operating parameters and different capital and operating cost models. However, this may not be possible given the rapid change underway, government regulatory and financial intervention, and the financial pressures on the existing thermal fleet.

Existing dispatchable generation is needed to provide essential system security services necessary for maintaining a safe, secure electricity system and successfully manage the acceleration in uptake of weather dependent variable renewable energy (VRE) across the NEM. By 2025, there could be up to 75%[8] penetration of renewable energy (instantaneous generation) without the necessary operating reserves to manage uncertain changes in net demand.

The priority therefor needs to be on what measures can be taken now to manage what the ESB Chair is reported to have described as 'messy' transition over the next ten years as AEMO deals with high levels of non-synchronous generation and the introduction of new technologies. Both the ability to operate such a system and the timeframes for new technologies to emerge on a cost competitive basis that can operate at grid scale are uncertain and unproven.

Given the urgency to provide back-up capacity and de-risk the changes in the composition of generation in the NEM, Delta's submission considers the immediate proposed reform pathway. As an immediate priority, existing proven technologies should be financially incentivised to remain operational through the explicit recognition and valuation of the services they provide (including ramping) while new system service technologies emerge and are tested, and AEMO is confident that the NEM can be securely operated with a new technology mix. This approach would provide time for a long term market design not reliant on large scale synchronous thermal generation to develop and provide the necessary investment signals.

1.3 Dispatchable Generation

Flexibility from dispatchable generation is critical to de-risk the near term NEM transition to high variable renewable generation penetration.

In a 2020 report the IEA stated that the 'cornerstone' of electricity market security in a modern market is flexibility[9]. Flexibility allows for sudden changes in net demand to be managed seamlessly through backup capacity which has the ability to ramp up or decrease generation output as net demand changes. It is provided by a variety of services across timescales ranging from seconds, hours, days to seasons. These services are provided by a variety of sources such as thermal and hydro power stations, demand management, networks and storage. Each source has a particular strength with regards to the amount of flexibility it can provide, the speed it provides the service and the timescale it delivers against. No one source satisfies all needs - diversity is therefore critical.

The rapid and unprecedented change occurring in the NEM and other markets globally, particularly as a result of increased solar, means that greater and unprecedented levels of flexibility are required to maintain security because of the increased variability and uncertainty that becomes prevalent as the grid becomes more reliant on weather related

[8] Energy Security Board (2021) Post 2025 Electricity Market Design, Infographics paper, p.3
[9] International Energy Agency (2020) *Electricity Security in Tomorrow's Power Systems* https://www.iea.org/articles/electricity-security-in-tomorrow-s-power-systems

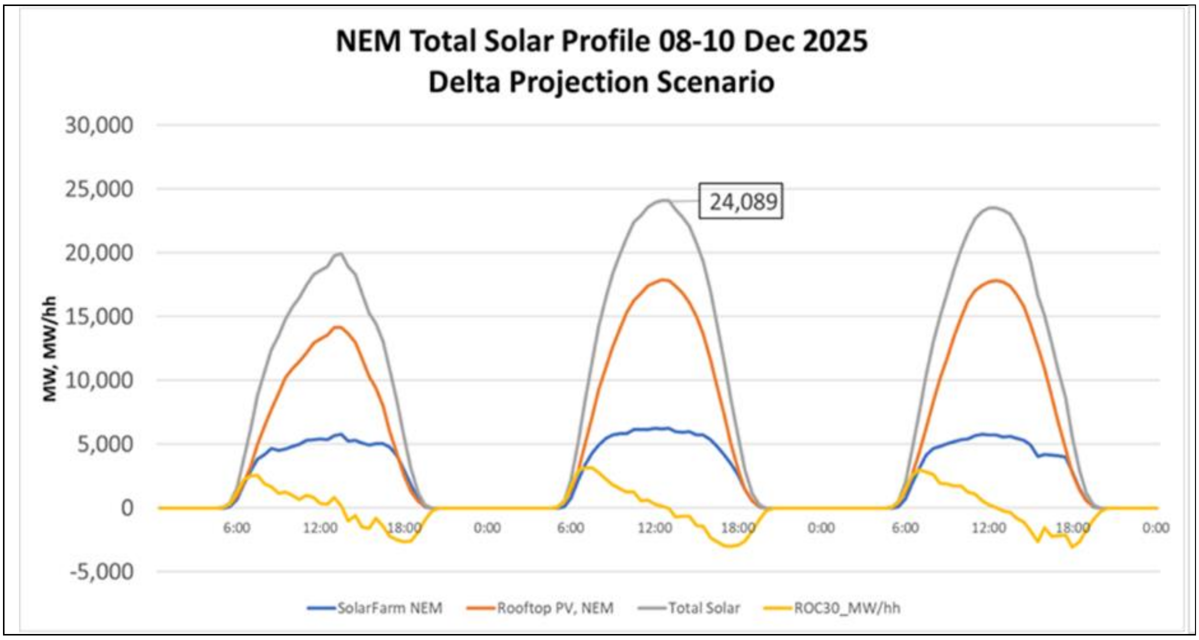
VRE. Although these systems are transitioning, there is still no gigawatt scale power system that does not rely on dispatchable, synchronous resources for grid stability and resilience.

Delta estimates that ramping capacity needs could be as much as 24,000 MW or approximately 68% of current NEM maximum demand in only a matter of a few years. This increased need for substantial backup capacity is consistent with IEA analysis in other markets (see Electricity Security in Tomorrow's Power Systems) although it will be a smaller amount of maximum demand in these markets.

Delta's analysis (see diagram 1) demonstrates that managing the solar profile (let alone the added variability in wind), especially the morning and evening solar ramping, will be a dominant feature in the operation of the NEM in the near term.

The chart shows daily ramping-in and ramping-out of up to nearly 24,000MW by 2025. To balance supply with demand, potentially AEMO needs to ramp-out, and then ramp-back in, up to 24,000 MW of capacity from synchronous generators, principally hydro and conventional thermal generators. And this could be sustained for periods of days or weeks. For comparison, the 2020 NEM average and maximum demands were 21,408MW and 35,440MW respectively - so 24,000MW represents more than NEM average demand and 68% of NEM maximum demand.

Diagram 1 - Wind and solar projections based on Delta Projection scenario



Source: Delta Electricity. The analysis assumes levels of solar generation (both rooftop and grid-scale solar farms) consistent with recent projections by the Clean Energy Regulator (Quarterly Carbon Market report, September 2020, page 4) and AEMO's ISP "Step Change" scenario.

Note: Charts are extrapolations of current dispatch profiles, and these profiles may not be operationally feasible. They illustrate the potential implications for NEM operations under state and territory government targets for new wind and solar. The analysis may change depending on variations in wind and demand patterns. However, while it may change, the magnitude of operational backup and capability required to manage sudden shifts in solar output will still be substantial.

The AEMO Renewable Integration Study (p.56) report underscored the importance of flexibility and the role of dispatchable generation with the report stating:

“To effectively integrate higher levels of Variable Renewable Energy (VRE). While maintaining a secure and reliable grid, the system needs access to adequate sources of flexibility that can respond to the constantly varying supply-demand balance, as well as headroom to cover uncertainty. Where there is an increasing need for system flexibility under higher penetrations of VRE, there may be less flexibility available when required in some regions of the NEM, due, for example, to synchronous generation retirements, or displacement of online synchronous generation during high VRE periods”

There is no question that ramping services are required to support the energy market transition. Existing conventional plants provides these services cost effectively as part of their energy dispatch operations. Premature closure of these plants would compromise the ability for the power system to accommodate increasing levels of weather dependent VRE and the resultant increase in variability and uncertainty in the supply of energy into the grid. As conventional plant does retire, however, there remains a need for replacement technology that can deliver comparable levels of dispatch flexibility.

This position was reinforced in the *Post 2025 NEM Market Design Options paper* (Part A, page 50):

“The expected increase in net demand variability and forecast uncertainty as the power system transforms raises concerns that participants providing reserves based on the risks they see in the energy market may not be the most efficient approach to meeting the system need for reserves over the long term.

Addressing the challenge of providing reserves in the most efficient way requires actions across multiple fronts, including continual improvements to forecasting and resource visibility……………This would reduce the rate at which forecast uncertainty will grow (which contributes to the need for reserves), as well as ensuring that a mix of flexible resources is operationally available when needed to meet unexpected ramping requirements (which contributes to the supply of reserves). These requirements will vary across different timescales and increase in magnitude as the penetration of VRE increases (particularly solar PV without significant storage) and the flexibility of the scheduled capacity on the NEM changes.

“Consistent with these principles and the increasing value of flexible, responsive resources, the ESB is considering establishing an explicit price signal for reserves that would reflect their real value at any point in time. The ESB is principally considering reserve services as an essential system service…………… “

Against this background, the questions that need to be answered are:

1. What is needed now to keep existing proven technology operating in order to maintain a safe, secure and reliable supply of electricity to households and business?
2. When will AEMO be confident that the next round of large thermal plant retirements can occur without interruptions to supply?

In short, what is the minimum amount of time the system requires conventional dispatchable capacity to be in place to derisk transition?

2 Resource Adequacy and Ageing Thermal Generator Retirement

Notice of closure and the retailer reliability obligation are the two tools to support long term resource adequacy. They focus on managing generator exit and targeting technology neutral investment signals for generators (or demand side options) who provide firming capacity.

In practice there is a disconnect between these tools and day-to-day financial and operating decisions of an ageing thermal generator, limiting the effectiveness of these tools. Firstly, the notice of closure and proposed changes inhibits flexibility and may undermine the commercial incentives of the physical RRO. The Australian Energy Council in its submission highlights the restrictions of this requirement. Delta would like the ESB to explain what these requirements will achieve and to justify why government and regulator intervention in business operations is necessary.

2.1 Notice of Closure

The proposed information tool may support AEMO reliability planning and could assist governments to understand pricing (affordability) and outage risks. However, it effectively becomes a tool for micromanagement of generator operational decisions.

Mandating increased information from generators on forward operational plans will not provide any greater certainty around the retirement of coal fired plant as the National Electricity Rules already place obligations on generators to advise availability at granular levels. Generators already know that changing their operating plans in a beneficial manner will involve a regulatory burden of explanation and justification, such as is already being seen in the present 42-month notice of closure arrangements.

Involving the jurisdiction in an early closure request will further entrench government market interventions, mute new resources signals and reduce the efficient operation of the NEM. If the proposed market reforms are implemented in a timely timeframe, then an early closure will be dealt with by the market.

The ESB proposed changes that require more details on mothballing and seasonal maintenance will add to the restrictive nature of existing reporting requirements. The changes will increase operational risk and complexity as they reduce flexibility in operations in what is an increasingly dynamic market with rapidly changing conditions.

As highlighted in the ESB's workshop on the *Post 2025 Market Design Options - A Paper for Consultation*, the generation mix in the NEM is now approaching AEMO's Integrated System Plan 'Step Change' scenario. What was the outer boundary in 2025 is now in existence by mid-2021. Change is happening at a very fast pace and lessons are being learnt in real time. A dynamic environment where ageing thermal generators lack flexibility to make business decisions to respond is not sustainable.

Ageing thermal generators committing to seasonal maintenance and mothballing with potential penalties resulting from changing tack and/or inability to reduce/stop operating losses quickly does not work. Increasing operating constraints on ageing thermal generators and building in rules to support flexible decision making is complicated in a regulatory framework.

2.2 Current Approaches

Following the short notice period for the 2017 closure of Victoria's Hazelwood coal fired power station, the evidence to date suggests that government preference is to work with generators to confirm the closure date and prepare for it. These timeframes are longer than three years, as governments also seek to manage local economic and job impacts. The ESB options paper acknowledges that there are a range of government policy objectives at play in the energy transition beyond energy markets.

EnergyAustralia (EA) has given seven years notice of closure for Yallourn power station and is bringing forward retirement by four years. It reached an agreement with the Victorian Government to deliver an orderly retirement of the power station. "Under the agreement, EnergyAustralia will retire Yallourn in mid-2028 and build new storage capacity through a 350 MW, four-hour, utility-scale battery project that will be completed by 2026."[10] There are reports that the Victorian Government entered into an arrangement with EA to prevent an even earlier closure.

Preparations for the closure of the Liddell power station have been extensive. The notice given for this power station closure was also around seven years. The Commonwealth established a taskforce and set a dispatchable investment target "for the private sector to commit investment, by the end of April 2021, to deliver 1000 MW of dispatchable capacity to come online in time for the summer."

The NSW and Commonwealth Governments are providing $83 million support for EnergyAustralia's new 300MW gas fired power station at Tallawarra. The Commonwealth Government will provide Snowy Hydro funding to develop a 660MW gas peaking plant at Kurri Kurri in NSW. Their reasons for providing this support are that there has been a lack of private sector investment. This would appear to suggest that the RRO is not functioning as intended.

The combined capacity of the remaining Victorian and NSW coal fired generators is around 13,000MW. The bulk (65%) is due to reach the end of its technical life by the early 2030s if it does not exit earlier due to financial pressures.

It would seem that notice of closure is not the management tool for a transition of this size over the next 10 years especially where further rules restrict the dynamic operating envelope of these power stations and would therefore increase financial risks.

2.3 Current RRO Design

Current RRO design is not sufficient to support long term investment signals. The RRO is seeking to ensure that there is sufficient capacity in place to meet expected system peak demand.[11] While this is useful for meeting system peaks, it limits demand for contracts to

[10] https://www.energyaustralia.com.au/about-us/energy-generation/yallourn-power-station/energy-transition
[11] Commonwealth Government Retailer Reliability Obligation Fact Sheet
https://www.energy.gov.au/publications/retailer-reliability-obligation-

those periods where demand is at its highest. As a result it has limited benefit in supporting baseload plant maintain operations through the year.

To date, the RRO has only provided support for short periods, around a month, making it a high risk and low return mechanism for ageing thermal generators to rely on.

Therefore, the current RRO does not drive the required investment nor is it encouraging ageing thermal generators to remain in the market if needed for reliability. This is exacerbated by low contracting requirements as the RRO only requires retailers to enter qualifying contracts to meet their share of forecast one-in-two year peak demand during the gap. This is considered to represent the minimum risk management contracting strategy for a prudent retailer. Furthermore, this is not in line with the Reliability Standard, used by the Reliability Panel to underpin the market settings, or the Interim Reliability Measure used by AEMO to determine the reliability gap for the RRO.

A physical RRO, designed along the lines suggested in Attachment 1 and 2, will better signal and incentivise new dispatchable generation.

2.4 Options to Enhance the RRO

The ESB's proposed minor amendments to the existing RRO are unlikely to ensure an ongoing demand for contracts for the reasons discussed above. Without a change to the quantum of contracting, the current RRO and the proposed changes will have little impact.

The current approach relies on an assumption that minimal contracts are provided on a speculative basis i.e. supply in the financial market mirrors that in the physical market.

2.5 Physical RRO

For the reasons discussed above, Delta's preference is for a physical RRO. This section discusses the rationale behind the design parameters summarised in Attachments 1 and 2.

2.5.1 Trigger Point

If the T-3 trigger is removed the RRO becomes a permanent requirement on retailers. This would mean the demand for certificates would be maintained by retailers regardless of any potential Reliability Gap. The removal of both triggers would allow the market to deliver capacity up to the point of a Reliability Gap.

A T-1 Trigger will push new capacity into the market earlier than required and/or leave new capacity unable to earn a return for meeting the supply shortfall. Consequently, the removal of both triggers would be optimal.

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factsheet#:~:text=The%20Retailer%20Reliability%20Obligation%20(RRO,National%20Electricity%20Market%20(NEM).

2.5.2 Contract Assessment

The ESB is considering moving the contract assessment point for the retailers to T rather than T-1. As per removing the T-1 Trigger, this would allow newly installed dispatchable capacity to meet a retailer's liability. This would be the preferred option as it gives notice for retailers to act. It also allows new capacity to enter the market between T-1 and T and earn a return on investment.

2.5.3 Assessment

Under the current RRO a retailer's position is assessed on any day that exceeds the 50% POE demand during the compliance period. Under the Physical RRO, the ESB is proposing that the compliance period be changed to "annual peak period", nominally Summer.

It would be useful to understand the reasoning for this change. Under the existing approach a compliance day could be any day in the year. If dispatchable resources need to demonstrate their capability to meet their allocated capacity this would assist in limiting the period over which this would need to be evidenced.

2.5.4 Issuing Certificates

Certificates would be issued in advance on a forecast basis. The main comments made in the paper are that certificates would be issued to "dispatchable resources" and that "Methodologies for assessing and certifying dispatchable capacity should be consistent with those used by AEMO in the ESOO and ISP".

It is sensible that certificates are issued in line with the methodology for developing the Electricity Statement of Opportunities (ESOO). It will be critical that the ESOO process is rigorous, robust and clear.

A robust allocation method will reduce the requirement/risk of compliance penalties. However, it will be critical to address the issues with different technologies that are discussed in detail below. There should be opportunities to issue certificates to assess dispatchable generators in line with their provision of availability through the AEMO systems.

2.5.5 Trading of Certificates

A trading platform will facilitate trading up to T and ensure technology neutral as all certificates will be considered equal.

As with any trading platform, the determination of the prudential requirements of participants will be a material issue. The level of detail provided in the Option papers does not allow for a consideration of how best to minimise prudential requirements and this will be one area requiring further work.

2.5.6 Uncertainties in Supply

The value of certificates will be impacted by which assets receive certificates and what quantum of certificates an asset receives.

It is expected that demand management will be treated as a "dispatchable resource". This will require significant work to ensure the robustness of any capacity calculation.

Other areas of uncertainty will be:

- Allocation to wind and solar resources**.** Currently the ESOO uses a 10% capacity factor for wind and 0% for solar. In the case of wind, would each asset be allocated 10% of their capacity or would they be allocated based on historic performance?
- Allocation to interconnectors. The ESOO also accounts for interconnector supply. Would interconnector carry physical certificates, and would they be allocated to SRA holders?
- Allocation to batteries. Would a two-hour battery receive a certificate, and would it receive the same quantum of certificates as a four-hour batter?
- Constrained Dispatchable Resources. If an asset is built behind a network constraint or becomes subject to networks constraints will that assets allocations be impacted? This could be a very significant issue of Snowy 2.0 is completed without HumeLink being developed.

A move to a physical RRO will need to address these issues and more.

Through a process of consultation, AEMO should provide a detailed methodology for each technology type for the allocation of certificates. The methodology should align with the treatment of that technology in the calculations of a Reliability Gap. AEMO should ensure the development of new methodologies for new technologies is timely and robust.

2.5.7 Penalties & Compliance for the Supply of Contracts

Certificates will be issued in advance on a forecast basis. The ESB's options paper then considers the two book ends to manage compliance:

- there is no review of actual delivery of capacity, or;
- alternatively, actual compliance is measured on the day with any non-compliance met with enforcement action from the AER.

Under the current energy only arrangements of the NEM, there is no commercial incentive to overestimate the capacity of an asset. This is because capacity earns no revenue.

It would be highly unusual, and a breach of the market rules, for a participant not to reflect their capacity position in the AEMO PASA. AEMO relies on companies own estimates of capacity to develop the ESOO and ISP. With the introduction of a value on capacity, through a certificate scheme, there will be increased commercial pressures for organisations to be more optimistic with their forecasting of capacity. This could be particularly true of the delivery of new capacity to the market and/or demand management schemes. A new capacity project coming to market could drop the price of certificates without delivering any capacity to the market.

The other bookend of making penalties punitive on actual capacity during an event potentially creates an incentive for generators to hoard certificates. Faced with an exposure to penalties for unforced outages, generators will tend to not fully sell their issued certificates.

Since the aim of the rule change is to ensure the overall reliability of the system, punitive penalties could lead to an overly conservative outcome and force certificate prices higher than they should naturally be.

Therefore, any penalty scheme should focus on an asset's performance over a sustained period of time rather than an individual event. This would mean a penalty would only apply where an assets capacity was materially different over time from that used to issue certificates. This would remove exposure to short duration unplanned outages.

Where an asset suffers a long-term downgrading or outage an entity should be required to return issued certificates and/or buy back any shortfall in certificates.

For the scheme to be robust a penalty regime should be in place that seeks to prevent:

- the deliberate withholding of capacity by an entity that has been issued physical certificates and benefited from the sale of those certificates[12]; and
- the deliberate over statement of the physical capability of a "dispatchable" resource.

3 Essential System Services and Ahead Scheduling

Delta considers that developing markets for essential system services is of the greatest urgency and needs a clear timeframe for delivery.

Ramping services have not been given the priority warranted given the forecasts by AEMO[13]. By 2025, there could be up to 75%[14] penetration of renewable energy (instantaneous generation) without the necessary operating reserves to manage uncertain changes in net demand. As VRE grows so too does the need for ramping. Conventional coal fired power stations limit ramping to avoid over-stressing plant and peaking gas plant has start time delays. Ramping requirements is not related to price signals and within a few years there is likely to be shortfalls in its availability. Ramping is a service aligned with operating reserve and they warrant further assessment by the ESB with a view to establishing a separate service.

The immediate frequency control reform to implement a fast frequency response (FFR) is an acknowledgment of the importance of covering the full range of timeframes for reserves. FFR deals with the sub 1 second period, but the need for the longer term standby or back up reserves (Operating Reserves) have not been given the priority required. As conventional synchronous plant is displaced from the market this could be in the form of two-shifting, standby reserves and seasonal shutdowns. Out of the market, but available for shorter term reserves, deserves due consideration in the reform options.

[12] A unit being mothballed would need to buy back certificates for the period of mothballing
[13] AEMO 2020 ISP Appendix C
14 Energy Security Board (2021) Post 2025 Electricity Market Design, Infographics paper, p.3

3.1 Short Term fixes for Inertia and System Strength

While allowing TNSPs to provide inertia and system strength is a short term 'band aid' to rapid changes in the NEM, long term it is a second best solution that will diminish competition and innovation. System strength does not naturally lend itself to a market-based mechanism, but a body like AEMO would be better placed to ensure holistic solutions across the entire NEM that can be better integrated with other essential services.

Giving monopoly transmission operators responsibility for procuring inertia and system strength services either directly (i.e., through the installation of network assets such as synchronous condensers) or under long term contracts may appear to be a panacea by addressing immediate issues in part, but it will add to long term transition challenges.

The TNSPs have no risk as they are rewarded via guaranteed regulated returns over the life of their assets transmission companies and will naturally tend to technology that fits with their standards and expertise. This may bias certain types of technologies over others, and particularly favour a network asset approach as this affords them a guaranteed return over the life of the asset and therefore, effectively shields them from any stranded asset risk.

The implications of this are:

- conventional synchronous plant may be locked out of the procurement process proposed as they cannot supply these services separately to committing generating units to service. They will be very hesitant to enter into a service contract when there is no certainty the market will support unit commitment;
- such a procurement approach could support expensive and very long-lived equipment such as synchronous condensers with flywheels which may not benefit consumers over their full life as network and market conditions will continue to change and evolve;
- a long term procurement contract by its very nature will limit development over time of new innovative technologies that could provide the same services at a lower cost; and
- a procurement approach will deliver the least cost solution to what is asked for at a point in time, whereas a properly functioning market promotes competition to deliver least cost and innovative solutions at alltimes (which would be more in line with the NEL/NEO).

Some of these risks were highlighted in the recent International Energy Agency (IEA) report "Conditions and requirements for the technical feasibility of a power system with a high share of renewables in France towards 2050" in which it particularly stated (emphasis added)[15]:

> *"While synchronous condenser technology solutions have been proven in specific situations, <u>a generalised roll out in the context of large-scale system strength has yet to be evaluated</u>. In particular, because synchronous condensers are assets with relatively long lifetimes requiring longer term contracts and the system needs may evolve dynamically, their roll-out as the*

[15] Link to IEA report: https://www.iea.org/reports/conditions-and-requirements-for-the-technical-feasibility-of-a-power-system-with-a-high-share-of-renewables-in-france-towards-2050; page 89.

preferred strategy to deal with concerns of system inertia, still needs to be compared to other technical solutions that may be more flexible in terms of their implementation or more cost-effective once they reach market maturity."

Therefore, it is crucial that work is prioritised on an inertia market. Delta supports the AEC's work in this space and agrees with the AEC that it would be preferable to have the solution developed via the ESB's package of reforms. Given the linkages between workstreams, a combined approach would lead to better outcomes.

ATTACHMENT 2

Discussion on PRRO and UCS/SSM Mechanisms

This attachment provides additional information on Delta's consideration of:

1. physical RRO;
2. UCS and SSM mechanisms;

Physical Retailer Reliability Obligation (PRRO)

The PRRO is a form of capacity market. As with any capacity market arrangement there is a risk that Government and market regulator's concern for reliability will lead to settings and assessments that drive an oversupply of capacity. As the PRRO requires retailers to secure sufficient capacity certificates, the cost of compliance will ultimately be borne by consumers. Any over-supply will be an unnecessary cost on consumers.

The energy only design of the NEM was designed to incentivise capacity through high prices at times of limited supply. A mechanism like an PRRO has become necessary because the recent increase in prices, that is a feature of the NEM to signal reducing supply and incentivise new investment, has resulted in Government intervention. The NEM's price signal for new capacity is further muted by the quantity of subsidised VRE and storage that is placing downward pressure on average prices. A PRRO would provide signals for private investment before a Government decides to intervene.

As stated in the covering letter, the best way to ensure a PRRO provides incentives for the provision of dispatchable capacity at the right time is to ensure alignment in settings of the following calculations:

1. the determination of any reliability gap against the reliability standard:
2. AEMO determination of a lack of reserve;
3. AEMO's trigger criteria for RERT; and
4. the quantity of capacity certificates retailers will be obliged to secure for compliance.

This alignment of settings means dispatchable capacity will be incentivised to be available on a typical worst day for any capacity shortfall.

To achieve the objective for modifying the RRO, as set out on Page 32, of Options Paper Part A, the following list of PRRO parameters is provided for consideration.

1. Always 'on', with all triggers removed will ensure the mechanism will cover what could be worst supply/demand that will not necessarily occur on a very high demand day in summer. Periods of multiple generating unit planned outages, or extended unplanned outages, can give rise to a forecast reliability gap.

2. A single certificate definition (i.e. 1 MW of dispatchable capacity for a period) is critical to keep the scheme as simple as possible, and to ensure all technologies/suppliers are treated equally. For example, a gas turbine unit with a firm dispatchable capacity of 100MW (as gen) would be issued with 100 certificates whenever it is declared available in the AEMO systems. Season ratings and planned outages could easily be taken from the MTPASA data.

3. To minimise administrative overheads, the obligation on retailers to acquire certificates should continue to be limited to periods where a reliability gap exist.

4. The establishment of a trading platform will:
    a. act as a register of the holder of certificates;
    b. support liquidity in the certificate market up to T; and
    c. ensure technology neutrality of certificates.

5. Trading/registration functions should be determined based on how it meets the criteria of least cost, time to implement, supporting flexibility in trading, and contributing to transparency and oversight.

6. Bilateral trading of certificates should not be precluded, with transactions required to be registered on the platform.

7. An assessment of options to manage and minimise prudential requirements will assist with minimising costs and ensuring there are no undue barriers to participating in the market.

8. The penalty for non-compliance on retailers does not need to change as it is linked to potential cost which will be quantified by the triggering of the RERT. However, if the penalty regime needs to be strengthened then some portion of the cost of interruption could be considered but capped based on the size of the retailer's load.

9. It is sensible that certificates are issued in line with the methodology for developing the Electricity Statement of Opportunities (ESOO). It will be critical that the ESOO process is rigorous, robust and clear to maintain the credibility and robustness of the scheme.

10. A robust allocation method that clearly specifies dispatchable capacity will reduce the requirement/risk of compliance penalties.

11. Treatment of technologies will have a critical impact on scheme design and will need to align with reliability gap calculations:
    a. capacity certificates must be supported by technology that can meet extended LOR1 durations (e.g. 8 hours); and
    b. the likelihood of interconnector transmission capacity constraints should be included in the reliability gap assessment.

12. Compliance and penalties will need to be carefully constructed so as not to incentivise:
    a. deliberate withholding of capacity;
    b. overstatement of capacity; or
    c. gaming.

13. The penalty regime for generators should not be any more onerous than on retailers with appropriate caps based on size. The penalty regime does not need to extend to actual availability during a reliability gap period as system reserves already take account of generating unit reliability.

The addition of physical certificates will create a material increase in administration and compliance cost for participants. If a PRRO is recommended, then considerable work will be necessary to ensure complexity and costs to participants are minimised. There should be opportunities to link a market participant's availability declarations to AEMO with the PRRO to avoid duplicating existing processes.

Essential System Services – UCS/SSM Mechanism

The unit commitment for security mechanism (UCS) has been proposed by the ESB as an option for AEMO to schedule resources contracted through structured procurement well ahead of time.

A UCS aligned only with contracted services is not technology neutral and will specifically preclude low cost services available but not contracted.

Security services such as inertia and system strength are predominantly provided by conventional dispatchable plant – coal, gas, hydro. This plant needs to be committed to provide these services. Hydro will have commitment costs related to the value of their water resource, whereas coal and gas fired plant use fuel to start and load to their minimum load. Conventional plant commitment is currently driven by spot market prices and hedge contracts.

If a TNSP is seeking offers for say inertia for a three-year period, conventional plant can only offer their services if they are sure the plant will be operational for the period of contract. The only generation that would likely contract essential services will be the lowest cost baseload plant. An example of this issue occurred in SA when Electranet was assessing options for system strength. It is understood that gas turbine plant could not offer competitive prices as they needed to factor in the uncertainty over future market prices and their likely operation. Electranet proceeded to arrange for the installation of synchronous condensers.

Therefore, the UCS will only be dispatching the technology under contract that has a very low cost of commitment and operation. Uncontracted conventional plant will continue to provide the services for free. Other conventional plant that would operate if the spot market plus essential service value justified commitment would stay out of the market.

The system security mechanism (SSM) has the potential to provide some essential system service value to conventional plant but in practice this mechanism may never be used. It is assumed that the contracted resources will be sufficient to meet AEMO's requirements and the need for additional resources would be limited to extreme circumstances like multiple equipment failures.

One of the key priorities of reform is to ensure the conventional plant that provides essential system services remain available until replaced with alternate lower cost technologies. Locking these types of generators out of essential system services market is counter to this objective. Delta proposed its unit commitment for operating reserve and ramping to ensure the lowest cost services would be available to the market. As it stands, consumers will be likely paying for new resources whilst existing resources continue to provide a large portion of the services for free, which is neither equitable nor sustainable.

Delta proposes:

1. inertia, operating reserve and ramping market based mechanism are established to allow a value to be placed on these critical services;

2. inertia and operating reserve are best suited to an ahead market in which participants offer their services in advance of commitment decisions. Inertia could be an ancillary services market to align with the recommendations for FFR;
3. the proposed SSM is used to procure inertia, operating reserve and other essential system services that are not established as real time markets or long-term contract markets (system strength); and
4. UCS is the unit commitment and dispatch mechanism.

ATTACHMENT 3

Delta Response to ESB Consultation Questions

Part A and Part B

Delta notes that the Australian Energy Council has put in a response to the ESB questions. Delta is responding to only those questions where it has additional information to add based on its expertise and/or where Delta's approach differs to that of the Australian Energy Council.

A1	*What types of information provision regarding jurisdictional investment schemes would benefit participants the most?* Government involvement in market related processes undermines private investment and the benefits derived from competition and innovation. The underwriting of new investments shift risk from the private sector to consumers and taxpayers. The NEM was established in response to costly over-investment in electricity infrastructure by Governments and to drive productivity improvements, which it has done. Should the proposal for structured jurisdictional investment be recommended then the following information would be useful: • a clear framework around the start dates for the scheme; • size of the scheme in terms of financial support and MW capacity; and • a quantification of the liabilities and risk to be assumed by the State. To the extend possible, such a scheme must be clear structured as a last resort intervention.
A2	*Which financial principles are most important in establishing means to integrate jurisdictional investment schemes with market arrangements as smoothly as possible?* Both principles proposed by the ESB are important. The efficient operation of the NEM should not be compromised so as to retain the benefits of competition.
A3	*Are there financial principles missing, or that have been included but shouldn't be?* Maintaining a competitive, technology neutral market is critical, therefore when clarifying the financial principles it is important to note that: • retaining exposure to the wholesale market should include user pays for ancillary services costs; and • these mechanisms should not be used to subsidise essential system services thereby crowding out other providers.

A4	*What are some of the market-based signal challenges, if any, with mothballing / seasonal shutdown?* Information provision should be based on a clear need and benefit and not limit operational flexibility. Increased requirements effectively become another form of government intervention in how the market operates. Given the rapid and unpredicted changes in the market, highlighted by both ESB and AEMC, incentives should be developed that support mothballing and/or seasonal shutdowns of coal plant where generation service are not required but may still be needed as backup until AEMO is comfortable that new technologies can replace existing large thermal capacity. Plants should retain maximum flexibility to enter or exit mothballed status quickly as conditions change. The existing MTPASA, STPASA and EAAP arrangements satisfactorily publish generator intentions in these regards. The discussion should focus on risk minimisation during the transition, i.e., how do we minimise unnecessary costs but still have the capacity when required? The role of mothballing is misunderstood. The ability to restart a generator when conditions require it, is all that matters with respect to closure. To retain registration, generators must remain technically compliant, this means they must be capable of operating, and will do so if conditions improve. Considering how commercial incentives (e.g., market design changes) could be integrated with the existing notice of closure requirements could lead to better outcomes.
A5	*What additional costs or process burden may the disclosure of such information place on stakeholders?* The cost and risk in this process comes from restrictions on how a generator can operate, rather than compliance costs per se. The financial implications of the operational risks are far greater than the compliance costs, albeit these will increase. A generator is potentially exposed to lost revenue and/or financial losses, where it cannot respond quickly to changing market conditions by turning on and off.
A6	*What concerns do stakeholders have around the commercial sensitivities associated with disclosing information?* The ESB will need to consider how these requirements align with other corporate and financial disclosure requirements and mitigate any risks on directors.
A7	*Do stakeholders perceive the disclosure of mothballing / seasonal shutdown information as limiting a participant's flexibility in operating their plant?* Absolutely.
A8	*Do stakeholders agree the notice of closure exemption process should be extended to include mothballed generation? If so, should it apply to all generators or just to large designated thermal generators?* No. Treating generator operations differently reduces competitive and technology neutrality. If the issue that needs to be managed is having sufficient thermal capacity until there is confidence that alternative technologies are in place at the

	required scale, then the focus should be on incentives for thermal technology to remain in place. This is a strong argument for expediting market design work rather than putting in place additional regulatory requirements.
A9	*What suggestion do stakeholders have for defining mothballing?* The focus should be on maximising plant availability at certain times (e.g., extreme weather, sudden loss of generation) rather than restricting operations. Again, this is a strong argument for expediting market design work rather than putting in place additional regulatory requirements.
A10	*How can governments, market bodies and market participants better work together to be prepared for exits?* It would appear that aside from the sudden closure of Hazelwood, governments and generators are working together to prepare for exits well in advance of the three year notice of closure. For governments there is substantial interest in planning for a range of policy reasons including local area economic and jobs impacts. The Liddell and Yallourn power station closures were notified well in advance. The critical component is ensuring that market intervention does not occur.
A11	*Do stakeholders agree governments are best placed to enter into a contract with a respective participant in the event of early exit?* Changes to essential system services and the RRO should preclude the need for any government intervention. Where government's do intervene, competition and technology neutrality should be important considerations and any Government support should not affect the relevant entity's bidding behaviour or otherwise distort its pricing/contract behaviour.
A12	*Do stakeholders agree that any future contract arrangements should be kept separate to existing RERT mechanism?* If governments enter contracts, this should be quarantined from other market operations to reduce duplication, cost and unintended consequences. If governments intervene in coal fired power station closures, the objective should be keeping the lights on until AEMO is confidence that new technology with the required capabilities and investment is adequate to replace the capacity and services of the coal fired power stations.
A13	*Do stakeholders agree with the proposed principles and measures of success? Are there others that should be considered?* Yes. No others proposed. An independent audit process should be introduced to ensure the stated principles are being appropriately applied and to measure outcomes against the agreed benchmarks. The Commonwealth Productivity Commission would appear to be the appropriate body to perform this audit function.
A14	*Are there any obvious priorities given current and plausible likely future market scenarios?* For Delta, the priorities are establishing long and short term financial incentives to provide resource adequacy and essential system services.

A15	*What options are there to encourage contractual compliance among retailers without adopting higher punitive penalties?* See comments in Delta's submission.
A16	*Would one RRO option over another better suit particular types of market conditions anticipated over the course of the transition?* See comments in Delta's submission.
A17	*How could you strengthen the signal? Could minimising the triggers do this? What are the unforeseen consequences or implications with this?* Delta's preference is for physical RRO. If a financial RRO is introduced, at a minimum the contract target needs to be increased. See Attachments 1 and 2.
A18	*What are options to make the RRO simpler, while still advancing some measures of success?* For a PRRO: 1. establish a registration/trading platform developed by the market for the market 2. link existing mechanisms around AEMO capacity declarations and bids to the availability of certificates 3. have one clearly defined certificate 4. only assess compliance when a reliability gap occurs 5. no triggers 6. minimise prudential obligations where there is opportunities for some sort of contract 'reallocation' as is available for AEMO spot and financial contracts.
A19	*What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?* Flexibility in regard to assessing T-1 compliance. Focus on compliance at T if the RERT is triggered.
A20	*Should it be a triggered mechanism, or be developed as a rolling one?* See Delta's comments in the submission
A21	*How should the physical certificates be regulated?* See Delta's comments in the submission
A22	*How would a physical RRO impact contract market liquidity?* The PRRO will not impact electricity contract market liquidity if established as a separate market. There may be opportunities to align PRRO and the contract market to allow bilateral certificate trading.
A23	*What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?*

	The biggest concern is if the PRRO creates a barrier for small retailers to operate in the electricity market. Consideration needs to be given on how to minimise prudential requirements, trading overheads and compliance.
A24	*What are stakeholder views on what specific design issues should be considered for an operational system security mechanism (SSM) to support the objectives of providing secure operations through the transition of the power system and to support efficient dispatch outcomes?* See Attachment 2. Given the proposal for a FFR market and TNSPs to procure system strength and inertia, the supply of system services should be adequate. It is not clear what additional value an SSM provide given it is unlike to be used except in exceptional circumstances. Delta has put forward two rule change proposals to inform the design of essential system services. These rule change proposals should inform the design an operational SSM. See 1. Introduction of ramping services (ERC0307); and 2. Capacity commitment mechanism for system security and reliability services (ERC0306) It is critical that essential system services provide competitive price signals and are technology neutral. TNSP led investment is not technology neutral and will lead to significant over-investment in network friendly technology (syn cons) as some existing conventional generation will not be willing to commit to a long term contract given so much uncertainty over early exists and operational profiles.
A25	*What additional information should be considered to assess the complementarity and materiality of an operational SSM in the context of a TNSP-led solution in the investment timeframe?* See A24 TNSP-led solution is not supported. See Attachment 1.
A26	*How do stakeholders view a ramping or operating reserve as fitting within the overall framework for essential system services?* Delta views this as critical and a service that needs to be given the utmost priority. This is evidenced by the two rule change requests submitted by Delta to the AEMC, which are being considered in parallel to the work of the ESB. Refer Delta's submission the AEMC Directions Paper on operating reserve and AEMO's RIS Appendix C. Analysis of future ramping assumes standby hydro and gas plant will be incentivised to start purely to provide ramping but NEM price may simply be too fleeting to warrant a start. Secondly, it is assumed coal fired plant ramp at 10MW/min or better. These levels of ramping can be achieved but at material cost to plant wear and tear. Unless the is an additional financial incentive to provide ramping, there will be shortfall in capability as early as 2023 if current trends in solar built continue.

A27 to A49	Delta directs the ESB to consider the AEC's response to these questions.
B1	*What are stakeholder views on the interaction between the proposed investment and operation procurement mechanisms for structured procurement?* The objectives for procurement should be to support competition and innovation. Transmission companies provide system services as a last resort. There should be a transparent process for overseeing and testing transmission network planning assumptions. The procurement of essential system services for security through long term contracts is reasonable when the service does not lend itself to a recall time or ahead type market. The procurement should be by a market body that does not have any vested interests or technology bias. Inertia, however, is so closely linked to FFR that the two must be market based to allow co-optimisation at the very least. Ideally there could be a single FFR/Interia market. Inertia can be substituted for FFR and vice-a-versa. All that is required is a frequency standard that is enhanced to include 'rates of change' boundaries. The market operator should be the procurement entity, not TNSPs, for the reasons set out in Delta's submission.
B2	*How do stakeholders envisage contracting arrangements will work under the long-term procurement mechanism, and how may this interact with the design of the SSM or vice versa?* See comments for Part A
B3	*Do stakeholders agree the UCS should schedule for an efficient level of the service which has been structurally procured, with the efficient level being with regards to meet a dispatch cost minimisation objective, as defined by the terms of contract activation and pre-dispatch bids. If so, why? If not, why not?* Delta does not support services being structurally procured by TNSPs for the reasons set out in Delta's submission. Delta has put forward two rule change proposals to inform the design of essential system services. These rule change proposals should inform the design a UCS. See 1. Introduction of ramping services (ERC0307); and 2. Capacity commitment mechanism for system security and reliability services (ERC0306) It is critical that these services provide competitive price signals and are technology neutral.
B4	*Do stakeholders consider the potential for the UCS to centrally-commit contracted resources to be of material concern?* • *If so, are the proposals put forward by the ESB sufficient to address this concern?*

	• *If not, what should be done to mitigate this concern?* Yes, it is a material concern. As a noted above the TNSP led investment will not capture all of the low-cost essential services. Inertia, operating reserve and ramping are services the UCS mechanism could be used to manage commitment in a timeframe that matches the technology e.g. some plant may take 24 hours to return to service. The SSM could be used to procure these services where a spot market is not applicable. Refer Attachment 2.
B5	*If the UCS commits units ahead of time, how would this interact with the existing wholesale spot and frequency markets that are real-time?* Ahead of time commitment is essential where a low cost essential service provider is slow start. The decision to commit must be co-optimised as generation not incentivised by the spot market will displace lower cost plant.
B6	*What are stakeholder views on how the UCS schedule should be reflected in pre-dispatch and dispatch (i.e., contracted resources being required to bid into dispatch to be scheduled and/or constraints applied)? Are there any possible unintended consequences of these approaches?* Contracted resources and other essential service resources (see Attachment 2) must be required to bid. Where a contractual obligation to provide the service exists that generator will bid zero $ to ensure dispatch.
B7	*Do stakeholders consider the potential interactions between pre-dispatch, dispatch and the UCS to be material? i.e., that participants may change their self-commitment status following the UCS run.* A principle could be applied whereby system security is prioritised on the basis that if the system is not secure then interruption to supply could occur. This effectively gives system security a value of the market cap. So long as the lowest cost services are dispatched to meet a security standard then energy market and its participants should be unconstrainted to be dispatched according to bids, offers and any network limitations. That is, participants can change their self -committed status. If system security is compromised, AEMO will direct the operations of that participant.
B8	*What are stakeholders' views on the best way to address the potential decommitment?* To the extent possible restriction or obligations on commitment/de-commitment should be minimal or non-existent. Where a self-commitment decision occurs contrary to the UCS, then AEMO could direct and that participant could be disallowed form claiming any direction related costs.
B14	*How do generators and demand response providers position themselves under current frameworks ahead of periods of high ramping or periods of uncertainty?*

	Delta has made considerable progress in increasing the operating flexibility of Vales Point power station. However, there are limits on its capability and there is an increasing need for financial incentives to provide this service especially in the short term. Most conventional thermal generation limits ramping to a level that does not cause undue plant and equipment wear and tear. NEM price signals <u>will not</u> incentivise ramping capability where higher ramping could compromise generating unit security. i.e at times of high price volatility there could be large cost if the unit trips. Delta contends that as the ramping requirement on thermal plant increases, the availability of ramping capability will be withdrawn. The AEMC's initial assessment is that variability and flexibility will increase before the required flexible resources are in place. Therefore, it will be important to ensure existing, proven dispatchable resources remain in place until the new technology and resources are in place.
B15	*What challenges are envisaged in a future with higher variability and uncertainty in net demand?* More flexible resources will be required over time but they will only be delivered if there is a value placed on that flexibility.
B16	*How would a reserve service influence commitment and other operational decisions made by generators and demand response providers?* Refer Attachment 1.
B17	*Who should pay for reserves and why?* Consumers are the primary beneficiaries of a reliable power system.
B18	*Would the fleet described in the case study have provided more ramping reserves under current frameworks if there was higher net demand uncertainty?* Yes.
B19	*In what circumstances would a reserve service be beneficial for consumers?* A reserve service would derisk reliability and security challenges being caused by the energy market transition as they supported the operation of existing, proven dispatchable resources until new technologies and investments were in place.