Energy Security Board
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30 September 2019

Submission to Energy Security Board: Post 2025 Market Design Issues Paper

Delta appreciates the opportunity to contribute to the Energy Security Board's work on developing advice for COAG Energy Council on a long term, fit-for-purpose market framework to support reliability that could apply from the mid 2020s as the market transitions (the post 2025 market design project).

The post 2025 market design project is one amongst a substantial suite of reform projects under the COAG Energy Council remit being undertaken through the Energy Security Board, rule change processes (AEMC) and technical/system operation enhancements (AEMO). The common objectives of this package of reforms are affordability and securing new investment to support a reliable and secure electricity system. The transition to a low carbon electricity sector is occurring as coal fired power stations retire and renewables penetration increases.

The period post 2025 will see unprecedented changes in the National Electricity Market, as coal fired power stations exit. Around 11,140 MW is projected to exit the market over a decade, although some may be life extended to maintain an affordable and reliable electricity supply. However, a more pressing concern is the strain new renewables is placing on current market operations.

In preparing for the longer-term transition, the challenge is twofold:

- managing a step change to a dynamic and flexible wholesale electricity market (i.e. greater intraday variability in wholesale market demand and pricing points). This step change is happening now and needs to be immediately addressed by new mechanisms such as operating reserves to ensure power system reliability as synchronous plant is being displaced; and
- cost competitive investment in dispatchable generation prior to coal fired power station retirements, in order to avoid the price spikes and reliability risks that have occurred in South Australia and Victoria.

We've learnt a lot from the first round of coal fired power station retirements and COAG Energy Council has implemented and continues to oversee reforms to improve outcomes for customers. At this stage, Delta's view is that the case has not been made for further structural shifts in how the wholesale electricity market operates. However, there are still areas where immediate incremental changes are required to support existing synchronous plant that provides critical system services. The immediate impacts of increased intraday electricity market variability are accelerating financial and technical pressure on coal fired power stations and this should be the next area of focus in preparing for the future. Delta is currently preparing a proposal for an operating reserve mechanism, which will be shared with the Board in the coming weeks.

Technical pressures, combined with potentially lower average wholesale prices, is likely to trigger a reduction in the operating capacity and technical life of the coal fired power stations (in their current state). Decisions about operating life will also be influenced by developments in other regulatory areas and the potential impacts of rule changes, such as the frequency response rule change, which will further impact operating and financial decisions.

Delta requests that the Board consider building on the AEMC/AEMO existing system security work program and Renewables Integrated Study to provide a path forward to supporting a technology neutral, flexible wholesale market of the future. This will mean examining a broadening of the system services work program to consider the overlap with reliability services, for example through availability payments (spinning reserves), and keeping low cost synchronous generation capacity in the market to ensure electricity prices remain affordable. This would provide a durable, competitive mechanism to support existing proven technology whilst allowing new investment to come forward which may ultimately supply these services at a lower cost. This submission highlights a range of examples from overseas markets where such products are available (or being examined) to meet similar challenges to those being experience by the National Electricity Market.

Delta would also appreciate the Board setting out in more detail how the 2025 market design aligns with other energy market workstreams. This should include AEMO's Renewable Integration Study. The AEMO Study, which is looking at the technical barriers for operating the National Electricity Market with high penetrations of renewables, is likely to inform the technical opportunities and parameters for the operation of the grid of the future. This work is not due until the first quarter of 2020 and is expected to make recommendations to facilitate the transition to a secure and sustainable electricity system. The setting of technical parameters and market design are inseparable.

If this means adjusting timing and/or scope of the post 2025 market design project, for example by prioritising measures, such as availability payments to address immediate issues and staggering work on market design, then Delta would encourage the Board to do so.

Policy parameters which Delta considers are core to the market design include:

- income streams should be available which support all energy services whilst providing incentives for suppliers to minimise cost and improve performance;
- minimal (preferably no) directions from the market operator to power stations unless under emergency situations;
- technology neutrality and recognition that a combination of generation types are required to meet the needs of the physical power system. That is physical operating capabilities of generation vary (e.g. wind/solar is intermittent, coal power stations have different ages and designs meaning that ramping/ability to run two shifts will vary, battery storage will only meet short term energy needs and can supply a range of system services);
- clear separation of the competitive and regulated segments of the wholesale market;
- minimising the risks of long-term overinvestment in new transmission assets and or large-scale generation assets by allowing time to see to what extent distributed energy resources can supply the market; and
- responsiveness to changing market dynamics, such as the intraday day operational changes.

Finally, COAG Energy Council's approach to addressing the recommendations in the AEMC's Coordination of Generation and Transmission Investment report and the AEMC's final recommendations in the Demand Response Mechanism Rule Change will be central to what, if any, further structural long-term market design change is required.

Further information on the matters discussed in this letter as well as responses to each of the questions in the Board's issues paper can be in found in Attachment 1.

Yours sincerely

Anthony Callan
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ATTACHMENT 1

1 Framework for Delta's submission

This submission sets out:

- the context, expected future challenges and potential gaps in the current market reform program; and
- responses to each of the questions in the Issues Paper.

The context is important for considering what a future market design may need to deliver and what, if any, further changes are required to the existing market design to deliver this future vision. The current market reform program under the remit of COAG Energy Council is extensive and if fully implemented, extends well into the early 2020s. It is clearly prioritising affordability and investment in dispatchable generation, amongst a range of objectives.

Responses to the individual questions asked in the Board's Issues Paper are high level given the need to define the outcomes that a future market design is expected to deliver and then determine the possible market design changes to achieve these outcomes. To adequately assess market design changes and inform the modelling approach, a significant amount of detail is required on the character for the future market design and any consequential proposed market designs.

This submission particularly focuses on the opportunities and challenges raised by the Board to underpin:

- investment signals to ensure reliability;
- system security services and resilience; and
- integration of variable renewable energy into the power system.

The opportunities and challenges of integrating distributed energy resources (often referred to as DER) into the electricity market and driving innovation to benefit the consumer are important priorities. Delta will continue to monitor reform work in this area for implications for the wholesale electricity market but at this time will not be commenting directly on these matters.

Customer preferences and implementation of distributed energy resources will be key drivers of demand trends in the wholesale electricity market as they determine how much households and business meet their electricity supply needs locally compared with the wholesale electricity market. The integration of distributed energy resources will also inform and influence the role of the wholesale market in providing a reliable supply of electricity.

2 Context, future challenges and potential gaps in current market reform program

2.1 Delta and the role of Vales Point power station in supporting electricity market operations

Delta has been operating in the National Electricity Market (NEM) since its start in 1998 and is well acquainted with the challenges associated with operating coal fired generation and developing new utility-scale generation and the need for sustainable resources that support affordable electricity for NSW businesses and households.

Delta holds a unique position in the NSW electricity market as the only major merchant generator that competes with the large integrated generator/retailer businesses. Delta also holds an energy retail licence to allow direct supply to a small number of large customers across the National Electricity Market. This gives Delta insights into the pressures facing this segment of the market. Delta is diversifying its generation portfolio with a major solar generation offtake to commence early in 2020.

In addition to energy, Vales Point can provide a range of system support services at a relatively low cost, notably frequency, voltage, inertia and spinning reserves.

Revenue streams are available for some but not all these services. These include:

- (i) frequency control to manage:
  - a. small supply/demand imbalance and variable renewable energy output changes – regulation ancillary service spot market;
  - b. loss of a power system element – contingency ancillary service spot market;
- (ii) voltage control to manage:
  - a. voltage profiles across the networks (no market currently available);
  - b. low system voltages at time of high rooftop solar PV to avoid having to switch out transmission lines or install new static reactive plant (no market current available);
- (iii) inertia to ensure rate of change of frequency does not exceed limits (transmission network owners have an obligation to provide inertia to satisfy AEMO's requirements but this could be opened to competitive provision);
- (iv) ramp rate high flexible dispatch that responds to very large changes in variable renewable energy output over relatively short timeframes (no market currently);
- (v) spinning (operating reserves) to:
  - a. provide insurance for credible loss of generation or load (no market currently available);
  - b. to cover extended periods of low wind and solar generation output (no market currently available); and
- (vi) system restart to restart the electricity system after system black (competitive procurement)

Delta's Vales Point power station is approaching its 50 year operating milestone (2029) – the rule of thumb for the end of life of a coal fired power station. There are two possible futures for Vales Point power station. Vales Point could retire in 2029, or earlier depending on technical and financial considerations, noting the three year notice of closure requirement. However, it is possible to extend Vales Point for a further fifteen to twenty years with significant new investment commitments should there be role on the market to provide affordable and reliable electricity.

Assuming a 50-year life, Vales Point will be the first of seven coal fired power stations to retire from the late 2020s into the 2030s seeing a combined reduction in capacity of 11,140 MW across the NEM. Vales Point's closure will see the withdrawal of 1,320 MW (3.8%) of NEM dispatchable capacity and energy contribution of 4.1%.

TransGrid advises[1] that the removal of the inertia services provided by Vales Point increases the risks that the rate of change of frequency (RoCoF) will be greater than 3 hertz per second, the current standard. While TransGrid expects this to be manageable, this risk is likely to increase if frequency bands are tightened under current proposals to amend the national electricity rules and will also be influenced by the timing of coal fired power station retirement decisions in other states.

Vales Point is connected to the high voltage (330kV) transmission network and therefore is also an important contributor to the maintenance of transmission network voltage.

2.2 NSW will be the next jurisdiction experiencing the step change to dynamic and flexible intraday electricity market operations

Delta considers the key challenge for policy makers remains aligning coal plant operations and their ultimate retirement with the entry of new generation, whilst ensuring the physical electricity system accesses the services it requires. This timing challenge is being intensified by the increasingly dynamic way in which the electricity market operates.

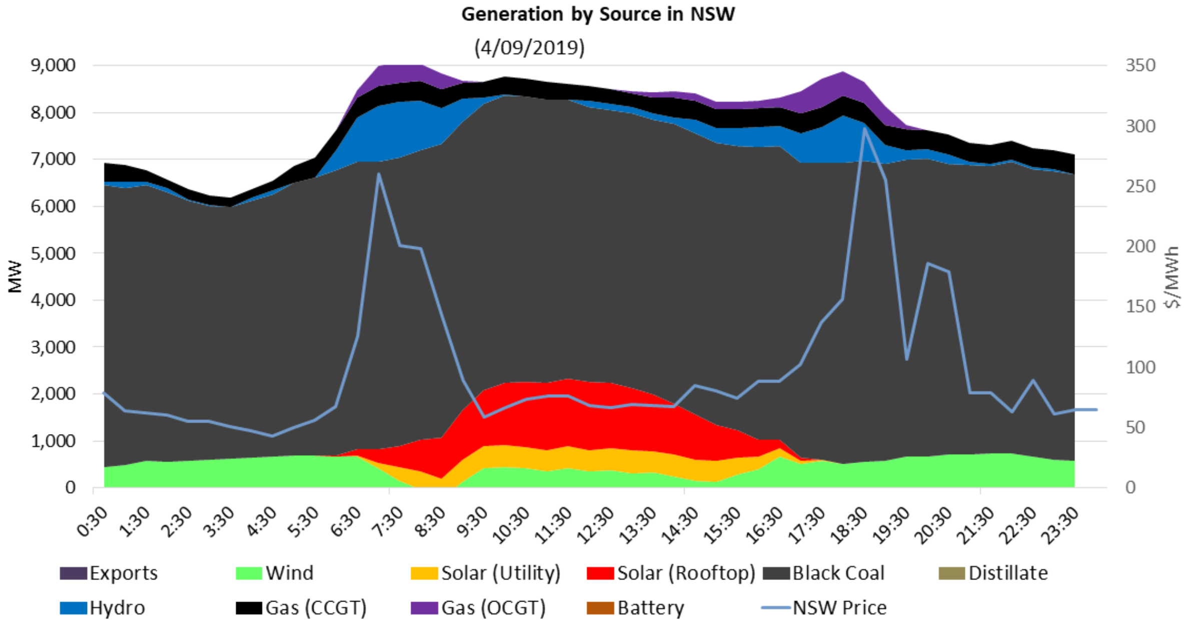
Firstly, there is a rapid hollowing out of intraday demand for electricity from the wholesale market as small scale solar and battery penetration increases. As highlighted by Aurora[2], the coal fleet is not designed for this type of cycling and this will put operational (technical limitations) and financial (higher operating costs) pressures on coal fired power stations. Secondly, the move to negative intraday wholesale pricing, as large-scale solar sets the marginal price, has the potential to undermine financial viability of existing generators.

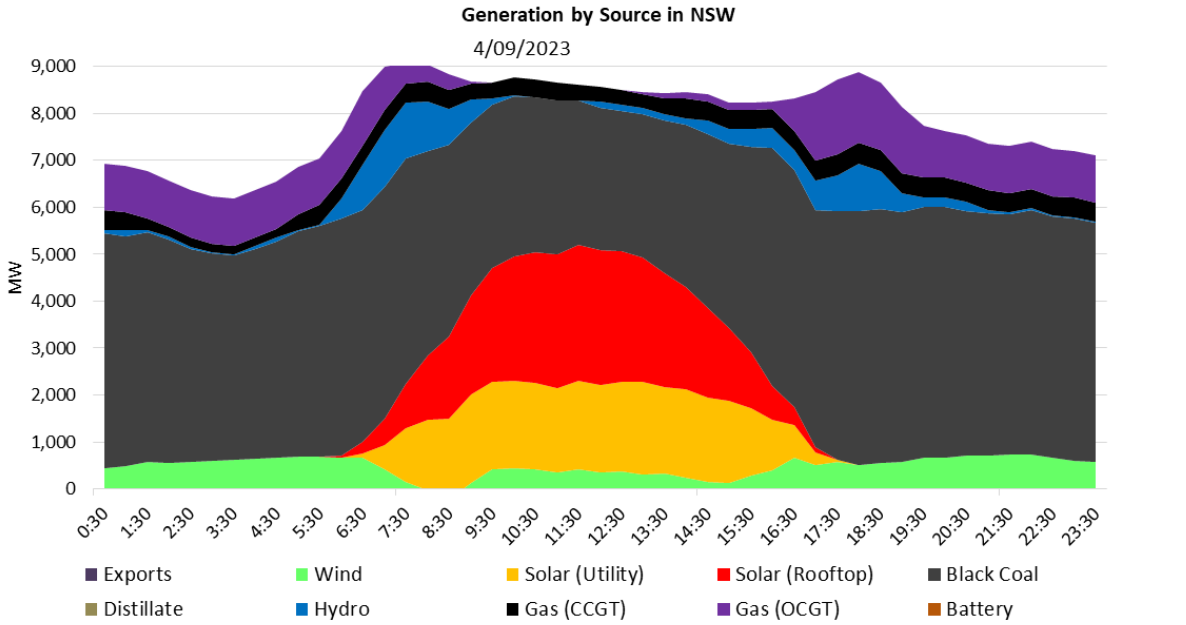
Charts 1 and 2 provide an example of how these challenges will intensify in NSW. The top chart shows NSW generation by source for 4 September 2019, a day Queensland experienced negative prices as solar set the price for generation during the day. For similar conditions as experienced on 4 September 2019, the bottom chart shows the situation in NSW on the same day in 2023 and following Liddell's closure. The price dip seen in 2019 will be significantly heightened as low marginal cost solar sets prices.

As can be seen from Chart 1 and Chart 2 generation from solar renewables (small and large scale) approximately doubles, materially displacing supply from coal fired generators. While this is for one day, this increasingly flexible mode of wholesale electricity supply will increase, requiring the necessary system support and reliability resources to manage.

[1] TransGrid 2019 Annual Planning Report https://www.powerlink.com.au/reports/transmission-annual-planning-report-2019
[2] Aurora Energy Research analysis of AEMO's ISP Part 2: economics of coal closures

Chart 1 and 2 – By 2023, in NSW higher rooftop solar production and large scale renewables could supply around 50 per cent of NSW electricity demand[3]





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[3] The projections for generation by source in NSW in 2023 are based on:

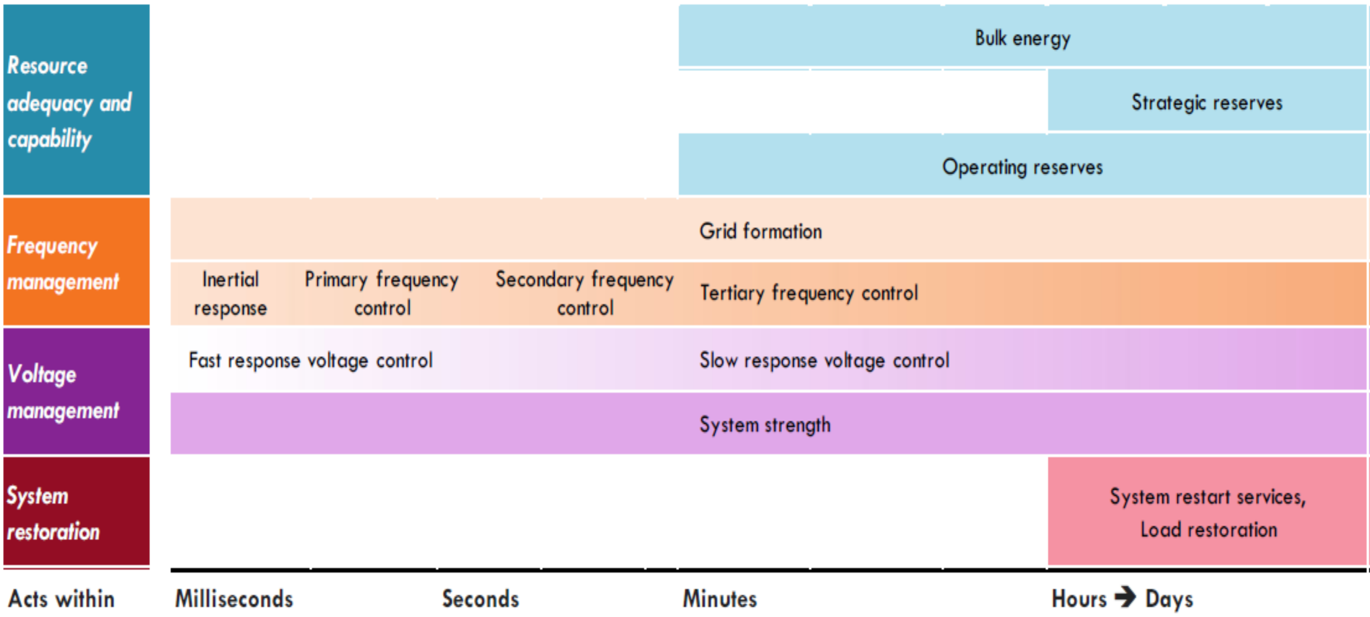
- a doubling in installed small scale PV which is in line with the forecasts from Bloomberg New Energy Finance where Australian installed small scale PV capacity will roughly double between 2019 and 2024
- a quadrupling in NSW utility PV from 500MW now to 2,000MW in 2023 based on NSW solar farms under construction (based on analysis from canstar blue)
- a 1,000MW net reduction in NSW coal generation with Liddell closing offset by Mt Piper being fully operational

The key implications of these changes are that to support the existing power system technical operating envelope and maintain reliability (resource adequacy and capability), the future electricity system will need:

- flexible system services to support stable system operation; and
- available reserves that can provide low cost, quick and flexible backup to support flexible intraday generation.

These services need to be available over a range of time scales (see Diagram 1) and are often interrelated, that is a generator can provide more than one concurrently and there can be overlap between system security and reliability services. Each generation technology, storage and demand response can provide different combinations of services with varying degrees of flexibility (see Diagram 2). However, no single resource, generation or demand response, can provide all the required services without any constraints. The transition will need to manage not only replacing the electricity output (dispatchable MW) from retiring power stations but also the services provided by these power stations. As highlighted above, Vales Point is a large contributor of system services and dispatchable power as are the other large coal fired power stations

Diagram 1 – Operation timescale for services needed[4]



[4] AEMO (2018) Power System Requirements http://www.ncsl.org/Portals/1/Documents/energy/Energy_Policy_P_Hibbard_31589.pdf

Diagram 2 – A portfolio approach will be required to the provision of system services as each resource type provides a different combination of services and has different operating parameters[5]

Services / requirements — Resource Type	Essential Reliability Services (Frequency, Voltage, Ramp Capability)					Fuel Assurance		Flexibility			Other		
			Ramp										
	Frequency Response (Intertia & Primary)	Voltage Control	Regulation	Contingency Reserve	Load Following	Not Fuel Limited (>12 hours at Eco. Max Output	On-site fuel inventory	Cycle	Short Min Run Time (<2 hrs)/Multiple starts per day	Startup / Notification time < 30 minutes	Black Start capable	No environmental restrictions (that would limit run hours)	Equivalent availability factor
Hydro	●	●	●	●	●	○	◓	●	●	●	●	◓	●
Natural Gas – combustion turbine	●	●	◓	●	◓	●	○	●	●	●	●	◓	◓
Coal	●	●	●	●	●	●	●	◓	○	○	○	◓	◓
Natural Gas – Steam	●	●	●	●	●	●	○	●	○	○	●	◓	◓
Battery/storage	◓	◓	●	●	○	○	○	●	●	●	◓	●	●
Demand Response	○	○	◓	◓	◓	◓	◓	●	●	◓	○	●	●
Solar	◓	◓	○	○	◓	○	○	●	●	●	○	●	●
Wind	◓	◓	○	○	◓	○	○	●	●	●	○	◓	●

2.3 Extensive existing national energy market reform work program already underway

KPMG in a report for the Australian Energy Council has highlighted the substantial amount of COAG Energy Council reform in progress or currently being considered which will impact market design and the need for congruency between reforms.[6] This work shows 21 projects potentially or already substantially impacting Delta across the wholesale market, generation investment and contracting. This work does not include major market design reforms being considered under the Coordination of Generation and Transmission Investment project, the AEMC's Demand Response Mechanism Rule Change and the Board's work on integrating distributed energy resources.

The KPMG report also highlights the importance of ensuring that policy measures are congruent and minimise the risk of unintended consequences and/or conflicting signals.

[5] Adapted from work by PJM and only including technologies relevant to NEM. See PJM Interconnection (2017) p. 20 *PJMs Revolving Resource Mix and System Reliability* https://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx
[6] KPMG (2019) *Coordinating Electricity Market Reform*. This report is being submitted to the ESB by the Australian Energy Council as part of its commentary on the 2025 market design project and is scheduled to be published on the Australian Energy Council's website on Thursday 3 October 2019, which is after the due date for submissions (30 September 2019).

KPMG notes that:[7]

> *While the definition is broad, Congruent reforms typically:*
> ** Reinforce signals to market participants*
> ** Allocate risks efficiently and consistently to parties best placed to manage them*
> ** Deliver unique and complementary benefits to the market and its participants*
>
> *Congruent reforms require careful thought by decision-makers and a holistic view on the impacts on consumers. Reforms lacking congruency may create unforeseen changes to incentives that result in perverse outcomes, conflicting market signals that deter investment, and unnecessary costs and complexities that can erode the benefits of the reforms.*

The work by KPMG focuses on national energy market reforms and does not include policy development in other regulatory areas, such as the National Environment Protection Council's review of the National Environmental Policy (Ambient Air Quality) Measures. The Vales Point power station complies with strict environmental requirements under its NSW Environmental Protection Licence which is independently regulated by the NSW Environment Protection Authority.

The Board's consideration of the future national energy market environment, in particular achieving a smooth energy market transition through aligning coal fired power station operations with new investment in generation, will need to be cognisant of major policy developments in other areas. It is the combined reform agenda which impacts business operating and financial decisions.

In this context, Delta requests the Board sets out the future market design characteristics by the mid-2020s, if there is a gap between this vision and the existing work program in achieving the vision, develop an evidence base demonstrating the need to address the gap and why the proposed market design changes will address this gap.

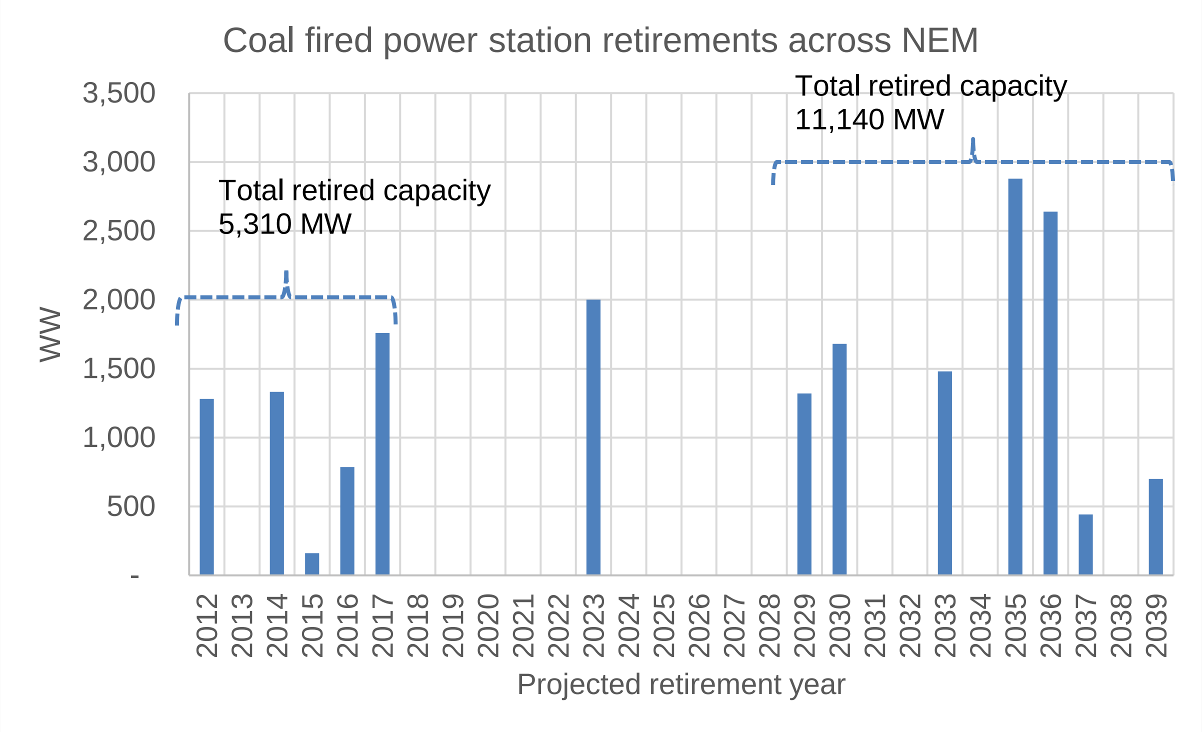
The policy challenge will be minimising the risks (and costs) of a mismatch in timing, especially early coal fired power station exits without replacement generation and services. There are many unknowns in this area including:

- a number of plausible scenarios for future demand (which will depend on the extent of uptake and integration of distributed energy resources);
- uncertainty as to the timing of entry of pumped hydro;
- availability and cost of gas for gas fired power stations;
- the timeframes for the viable entry of technologies such as hydrogen fired power stations; and
- the operating and financial performance of an ageing cold fired power station fleet which will be impacted by current rule changes and the step change being experienced in intraday electricity market oeprations.

[7] Executive Summary KPMG (2019) *Coordinating Electricity Market Reform*. See Australian Energy Council's submission to the Board's Issues Paper on the 2025 market design project.

By the late 2020s, the expected rate of coal fired power station exits (based on a nominal 50 year life) will be unprecedented. Chart 3 shows that from the late 2020s/early 2030s coal fired power station retirement challenge is more than double the retirements for the period 2012-2017.

Chart 3 – Coal fired power station retirements in late 2020s and early 2030s are unprecedented



Source: Data extrapolated from AEMO's 2018 Integrated System Plan and Section 2 and Senate Environment and Communications References Committee - Retirement of coal fired power stations: Final Report

We've learnt a lot from the 2012 to 2017 period and much work is being done on replacing MW and focusing on dispatchability.

Policy responses include: interconnection investment (SA-NSW interconnector); retailer reliability obligation; development of renewable energy zones; Snowy 2.0; and government programs such as the Commonwealth underwriting of new generation investment (UNGI) and the NSW Government's Emerging Energy Fund. These interventionist responses are occurring because of shortcomings in market design and an uncontrolled roll-out of subsidised renewable generation that has not been exposed to the full cost of deployment.

The three-year notice of closure will assist provide certainty and security around investment needs but this is on an individual power station basis. The Australian Energy Market Operator's Electricity Statement of Opportunities and Integrated System Plan (ISP) provide signals for investment needs on the impacts of retirements across the electricity system. However, using the ISP as an actionable plan is a worrying development that could lead to a 'central planning 'approach to transmission development based on very long term forecasts and uneconomic assessment criteria that could result in consumers wearing the cost of under-utilised and very long lived assets.

In this context, the post 2025 market design will need to consider whether any additional tools are required to support systemic management of coal fired power station retirements.

While many of the projects that currently underway will support reliability, Delta considers there may be gaps in the ability of new resources to act flexibly and provide the required system services and operating reserves for managing intraday fluctuations. Table 1 takes the key major and potential changes to market designs and sets out how they contribute to long term reliability, critical peaks, system services and intraday fluctuations.

Table 1 - Contribution to reliability/operating reserves (max benefit = ✓✓✓✓✓)

Primary objective Market design change	Underlying / long term reliability (MW and dispatchability)	Critical peaks (MW)	Intraday fluctuations (operating reserves)	Technical system services
Retailer reliability obligation (only short lead time capacity)	✓✓	✓✓✓✓	✓	Indirectly
Five minute settlement rule (very high cost/little benefit)	✓ (only some technologies)	✓	✓ (adverse impact on some peaking capacity)	Indirectly
Wholesale demand response (unclear if this reform will deliver substantial and firm response)	✓	✓✓	✓ (May be limited if customers do not want frequent interruptions)	Indirectly
Transmission investment • Coordination of generation and transmission investment	✓✓ (potentially improves locational signals but will adversely impact hedge contracting)	✓✓	✓	✓

Delta understands that the AEMC has a work program underway considering the future NEM system service needs and interactions with the wholesale market/reliability as the electricity market transitions. This work program includes existing rule changes focused on frequency and system restart service needs. The AEMC plans to bring this work together through the release of a paper on system security services in late 2019. Delta would encourage the AEMC to look at the overlap with reliability and need for operating reserves as part of this work program.

The technical requirements for the future operation of the grid including its needs for managing flexible generation and system services will also be informed by AEMO's renewable integration study. This work and its potential recommendations will be important for informing consideration of the long-term future national electricity market design. Delta requests that the Board give consideration to aligning the timetable of the post 2025 market design project with the technical work being undertaken by AEMO.

Overall the future market design requires integration and coordination with:

- new market mechanisms required now to deal with the current system reliability and security issues;
- planning for late 2020s and early 2030s coal fired power station retirements;
- AEMO's work on the technical integration of renewable resources;
- existing work program under COAG Energy Council remit; and
- major reforms in other policy areas which have implications for the electricity market

This may well be an iterative process, starting with incremental enhancement to NEM design required to ensure there is sufficient inter- and intra-day dispatchable capacity available to respond to large changes in wind and solar output.

2.4 What could the future market design look like?

As part of the next phase of consideration of the post 2025 market design, Delta asks the Board to give consideration to releasing guidance on what it proposes are the policy parameters for the high level market design in order to guide work on detailing market design options and informing modelling. This is different from the how to get there, i.e. a capacity market, the existing energy only market or a variation on the existing design (e.g. some form of capacity payment).

Policy parameters which Delta considers are core to the market design include:

- income streams should be available which support all energy services whilst providing incentives for suppliers to minimise cost and improve performance;
- minimal (preferably no) directions from the market operator to power stations unless under emergency situations;
- technology neutrality and recognition that a combination of generation types are required to meet the needs of the physical power system. That is physical operating capabilities of generation vary (e.g. wind/solar is intermittent, coal power stations have different ages and parts meaning that ramping/ability to run two shifts will vary, battery storage will only meet short term energy needs and can supply a range of system services);
- clear separation of the competitive and regulated segments of the wholesale market;
- minimising the risks of long-term overinvestment in new transmission assets and or large scale generation assets by allowing time to see to what extent distributed energy resources can supply the market; and
- responsiveness to changing market dynamics, such as the intraday day operational changes.

These parameters are in line with the *Electricity Market Design Principles* identified by KPMG in a report for the Australian Energy Council.[8]

[8] KPMG (2019) *Electricity Market Design Principles*
at https://www.energycouncil.com.au/media/12077/market-design-principles-final-report-180419.pdf

With the projected retirements of coal fired power stations contributing to substantial reductions in emissions, the priority is ensuring this will happen at least cost and without risks to reliability. Understanding what reliability challenge the future market design may seek to resolve needs to be clear. The level of reliability and how it's managed is directly related to market design and costs for consumers.

The current market design seeks to support reliability for the majority of situations through market mechanisms incentivising investment, with the Australian Energy Market Operator able to intervene, through the reliability and emergency reserve trader (RERT) and directions powers during low reserve periods. AEMO intervention is usually at critical peaks triggered by extreme weather and one or more large generators/interconnectors unavailable. The objective of this approach is to minimise costs (i.e. not have overinvestment) and to have a range of extra tools to manage the critical peaks.

Although AEMO has increasingly been intervening in the South Australian market to support the power systems technical operations.

The vision for a post 2025 market design should explain how it will deliver an efficient system to support reliability for underlying demand, critical peaks and manage intraday flexible operations. There is already a range of tools in place, which meet different needs, but there is ongoing debate as to what level of reliability is required and whether there are increased risks with transition.

Finally, the design will need to be developed in the context of whether only a temporary solution is required to manage the late 2020s/early 2030s exit of coal fired power stations or a permanent solution is required to support long term dispatchable generation which can support all electricity market services.

Until a new suite of technologies emerges that can provide all the required services over short and long durations then there will be a role for thermal generation to complement renewables. Battery storage and demand response are clearly emerging as technologies which can deliver a range of short term energy system services. Larger storage options, such as pumped hydro, are under development and will be able to meet energy service needs over periods of a few days. At this stage gas and coal fired generation remain the only technologies which can supply energy services for sustained periods. Potential technologies, such as hydrogen, are still under development and whilst a portfolio approach of technologies may provide long duration reliability/security, the optimal mix is not yet known and would need to be demonstrated that it is physically operating.

2.5 Ongoing engagement with the Energy Security Board

Delta appreciates the consultative approach that the Board has taken on this project to date, including the establishment of technical working groups.

In considering the next round of engagement, Delta requests the Board give consideration to engaging with stakeholders on development of a framework which sets out the:

- market design policy parameters for the long-term future of the National Electricity Market;
- evidence for gaps which need to be addressed in the current market design and reform program in order to deliver COAG Energy Council's energy affordability and security objectives and why further reforms are required to address these gaps;
- proposed market designs to address the gaps. If more than two designs emerge that warrant testing, Delta would encourage the Board to test all relevant designs. This may require a two-stage process in consultation with industry of qualitative and then quantitative assessment;
- approach to assessing the market designs including the assessment criteria and what will be assessed quantitatively and qualitatively; and
- modelling approach to assessing the market designs including the scenarios which will be used to test the market design. Delta is interested in participating in discussions on assumptions that would inform the modelling but appreciates this is a level of detail which may be more appropriately discussed at a later stage in the project.

3 RESPONSES TO QUESTIONS RAISED IN THE ISSUES PAPER

3.1 What scenarios and shocks should be used? How should these be used to test market design?

The Integrated System Plan scenarios provide a range of potential futures and an existing context in which to model market design options. However, whether all these scenarios are required for modelling and the final form each scenario ultimately takes will depend on the market design outcomes the Board seeks to achieve and the options to be modelled to deliver these outcomes.

Some shocks that could be considered to test the market design include:

- early closure of coal fired power stations as they are unable to meet flexible operating requirements needed to meet increased intraday electricity system variability and/or regulatory policy developments in other policy areas mean it is uneconomical to continue operations;
- demand side shocks where there is a sudden decrease or increase in a large industrial flat demand load. This could be a closure of an aluminium smelter or substantial further growth in the gas supply industry, through new coal seam gas developments and/or LNG import facilities; and
- a substantial increase in the cost of capital making it less attractive for investment in new generation.

These proposed shocks are designed to test the market design for its resilience in adjusting to structural changes and in particular whether there are any timing risks for new entrant generation which can provide the required mix of dispatchability and system services. Given the range of possible futures, it might be informative to look at what milestones are important for triggering change or monitoring to see if change is required.

3.2 How can market and economic modelling best be used to evaluate individual components of market design or the end-to-end market design?

Modelling is a tool for informing policy decisions by providing a quantitative lens on the impact of various options. In the post 2025 market design work program, it will be closely informed by the outcomes of stakeholder feedback on the assessment framework to ensure that where possible the desired outcomes can be measured.

At a high level, the modelling should demonstrate to what extent any proposed changes to market design will contribute to:

- a reliable (generation investment) and secure (system services) energy system; and
- affordable energy (as per the COAG Energy Council Strategic Energy Plan outcome)

The scope of the modelling exercise could be substantive and should be informed by stakeholders throughout the journey. A pragmatic approach might be required with firstly the development of a suite of design options, some of which could be ruled out through qualitative assessment and then a narrower bunch modelled in detail. If there are more than two plausible design options that could progress to modelling, Delta would encourage the Board to assess more than two.

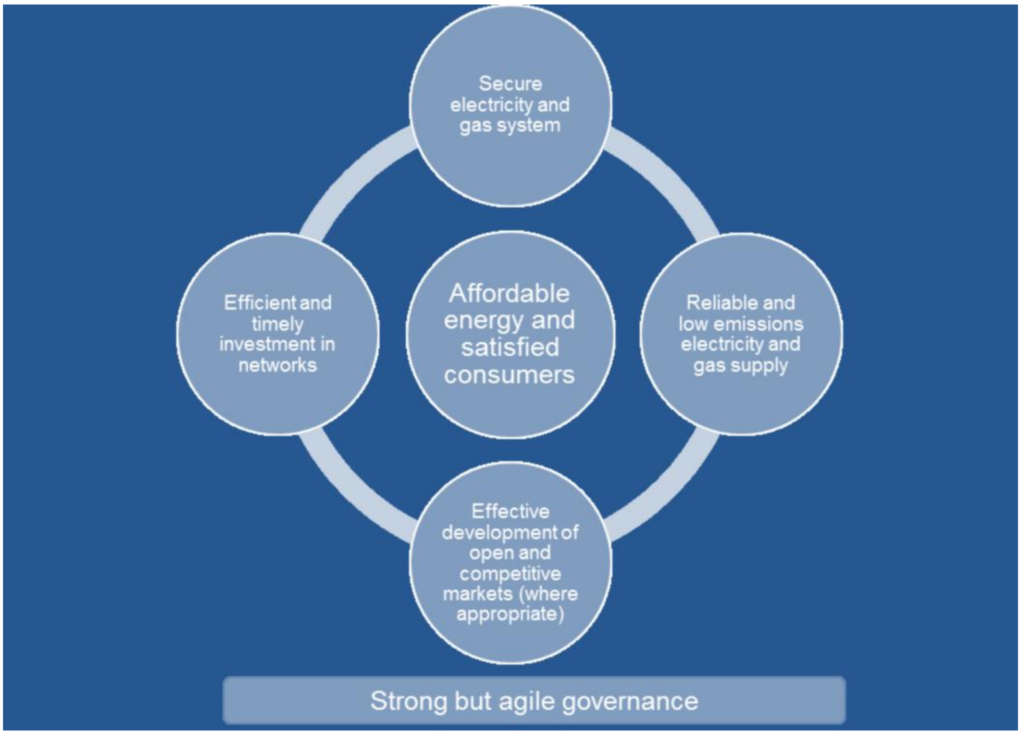
With so much reform already underway, an important consideration will be the costs and benefits of implementing each option and complementarity with existing reforms. This is discussed further in Section 3.3.

A range of approaches may be appropriate depending on the design options to be modelled. If different approaches are used, then consideration will need to be given as to how to compare outcomes.

3.3 Is the assessment framework appropriate to evaluate the effectiveness of future market designs? What else should be considered for inclusion in the assessment framework?

In 2018, COAG Energy Council approved in-principle outcomes and objectives for the energy system. These are set out in Diagram 3 and provide a sound and simplified framework for assessing the value of future market designs. The assessment criteria highlighted in Annex A of the Energy Security Board's *Post 2025 Market Design: Issues Paper* are subsets of these outcomes and objectives.

Diagram 3 - COAG Energy Council approved in-principle outcomes and objectives for the energy system



Source: Energy Security Board Consultation Paper: Strategic Energy Plan Draft Metrics, February 2019

In developing the modelling and economic assessment framework, it will be important to link this work with the assessment criteria and determine what can be quantified, compared with criteria where analysis will be qualitative.

Given the substantial reforms underway, one key area for assessment of various options will be implementation costs and impacts. Practical, simple and low-cost implementation is considered a high priority. For Delta, the five-minute settlement change will contribute to implementation and administration costs in excess of $1m. When multiplied across all market participants and multiple rule changes, the costs of recent reforms could be in the hundreds of millions of dollars. AEMO is projecting 12% per annum increases in NEM indicative fees over the four years commencing 2019/20 and finishing in 2022/23. In 2019/20, this will add around $11 million in additional charges to NEM participants 20 and even more in the later years.

3.4 Have we identified all the potential challenges and risks to the current market? If not, what would you add?

The energy market transition revolves around timing issues – exit of coal fired generators and the entry of replacement generation (small and large scale) that provides the required level of dispatchable and system security services. The key question for the Board is what are the risks of coal existing before equivalent replacement capability generation has entered as this threatens both affordability and reliability? Then what, if anything further, needs to be done to minimise this risk.

There does not appear to be a particular driver for choosing 2025 as a pivotal date for market design, aside from suggesting what a desirable future looks like. If the Board considers there is a need to bring forward any design changes then Delta would encourage the Board to do so.

Regulatory change, not just in national energy market policy, remains a key risk as this can have significant impacts on business sustainability. The risks of regulatory change will have varying degrees of impact depending on the technology type.

3.5 Which of these challenges and risks will be most material when considering future market designs and why?

For a power station such as Vales Point, where the nominal 50-year operating life milestone is 2029, the timing of investment/exit decisions will be influenced by revenue sustainability. This will be driven by three interrelated factors:

1. policy decisions (market design, environmental standards, carbon policy);
2. commercial factors notably coal prices, wholesale prices and retail contracts; and
3. the speed at which new renewable generation increases the demands on Vales Point to operate at high levels of flexibility.

Coal fired generation has limited capability to ramp production up and down to meet the increasing needs of flexible generation and adjust to low intraday prices. This plant also has minimum loading on coal firing before expensive diesel fuel is required or the unit has to be taken out of service. Minimum down times are typically a couple of hours but the return to service time increases the long a unit is out of service. There is also a risk of restart failures or delays. This means that the risk in the mismatch between exit of the existing fleet and entry of new compatible generation will be a challenge.

3.6 Which (if any) overseas electricity markets offer useful examples of how to, or how not to, respond to the challenges outlined in this paper?

Overseas electricity market designs can be reviewed as a way of responding to the challenges and opportunities arising from electricity market transition. There are some common themes across all electricity markets - market design is not static and policy makers are regularly changing/adjusting market design as everyone seeks to manage the challenges arising from a changing generation mix and integration of renewables.

Regardless of the market, evolutions in electricity market designs over recent years have sought common objectives, that is to:
- send investment signals to ensure reliability;
- provide system security services and resilience; and
- integrate variable renewable energy into the power system.

Often the design changes concurrently seek to address a combination of these objectives.

Markets globally are seeking to better manage changes in thermal generation capacity (generally exits of coal) with integration of renewables.[9] The International Energy Agency (IEA) highlights that electricity markets of the future may need to provide revenues for a range of services, not just energy, to sustain the existing fleet (e.g. manage the timing of retirements) and to provide adequate signals for timely and efficient new investment.

The IEA's analysis is driven by investment concerns triggered by low wholesale prices in some overseas markets, a consequence of renewables and low cost gas generation. This is not currently a feature of the National Electricity Market although negative pricing during the middle of the day is starting to pose a challenge. Despite the difference in generation costs for gas, there are common challenges globally notably the need to attract new investment and maintain system security. A common theme across all markets are projects and proposals to develop revenue streams to support the reliability of supply and quality of power delivered.

Table 2 highlights some observations on current and recent design changes from overseas markets for the Board's consideration. These markets have been selected as they have some features similar to the National Electricity Market. Alberta and ERCOT are energy only markets with Alberta also transitioning from a high coal fired generation base. Table 2 also contains observations on Ireland, Great Britain and PJM, given the variety of approaches to managing integration of renewables and valuing system services, particularly reserves.

Delta is continuing to undertake work on oversees markets and can share this with the Board when completed.

Singapore and New Zealand, although energy only markets, have not been included in this analysis given the characteristics of these markets. Singapore's electricity is supplied almost solely (95%) by gas generation and is at a different stage of renewables integration.

New Zealand has a very high level of renewables penetration, predominantly hydro, where the key challenge is managing water availability risks (drought). The projected exit of coal

[9] https://www.iea.org/newsroom/news/2018/december/how-will-the-electricity-market-of-the-future-work.html

fired generation in 2030 (less than 5% of supply) will be about ensuring there is an equivalent support resources when dams are low.

These examples have been translated into high level theoretical design options for the Board's consideration (Table 3). Delta is not proposing one design over another and will reserve its position on a preferred market design option. More detail is required on proposed designs for Delta to be able to evaluate the impacts both on the electricity market as a whole and the financial viability of Vales Point power station.

Application to the National Electricity Market
Examples from other jurisdictions can be useful. However, if they are to be applied to the National Electricity Market differences in the macro and micro factors influencing each market will need to be taken into consideration.

A key factor in considering the application of a market design element from another jurisdictions is how it would interact with NEM reliability and system security frameworks

Table 2 - Examples of market design features in other jurisdictions which provide lessons in how to respond to key challenge of hollowing out

Existing market	Income mechanisms for adequacy / operating reserve services	Comments
Ireland (I-SEM)	Capacity payment mechanism (contract for difference)	• Significant obligation if only looking to address intraday weather variations/system security issues • May not be appropriate in market with flat/declining demand
Ireland (I-SEM)	System services markets with an increase in the annual budget and hybrid regulated tariff/auction procurement	• Fourteen system service products meaning that market design caters for diversified mix of generation operating characteristics (e.g. variable ramping rates, intermittency, maintenance of system frequency/voltage) • May be too many products and consideration should be given for the optimal number of products noting the trade off between simplicity and diversity of product offerings to meeting each system need • Competitive provision of services may need to be achieved through variety of mechanisms (e.g. tenders, trading/market mechanisms) to ensure pragmatic outcomes and those fit for purpose with the characteristics of the market for each system service
Alberta	Maintaining an energy only market after extensive development of a capacity only market. Considering changes to market floor and price caps as well as shortage pricing. Shortage pricing links projected shortages in *operating reserves* to the probability of load shedding and then applies a "penalty factor" to the wholesale electricity price when operating reserve requirements cannot be met as determined by reliability criteria.	• Generation mix has parallels with the NEM. In Alberta, coal fired generation contributes around 50% to the electricity generation mix • In NEM context, need to consider affordability impacts on customers of changing price cap • Requires understanding of value customers place on reliability • Alberta yet to develop shortage pricing mechanisms

Existing market	Income mechanisms for adequacy / operating reserve services	Comments
ERCOT	Economic operating reserves demand curves (spinning and non-spinning). Provides an adder to electricity prices (volume of lost load – electricity price)*(loss of load probability). Alternative to capacity market (e.g. northeast US) for improving reliability.	• Implemented by ERCOT in 2014 and analysis of experience to date suggests that this may not have brought forward the required investment and may have increased pricing uncertainty • Development of loss of load probability measure is complex and likely to be contested • Integration with NEM reliability standard and existing resource adequacy mechanisms to support complementarity • In NEM context, need to consider price impacts on customers and whether this is the most cost effective • Other US capacity markets also have mechanisms with similar principles
Great Britain	National grid maintains backup power to cater for sudden loss of generation. Range of reserve services, notably short term operating reserve and Super SEL. GB also introduced supplemental balancing reserve with plants held in reserve outside the market ready to respond if needed	• Substantially different market design to NEM – network operators through license requirements procure backup generation and wholesale market is a balancing market. • Capacity payments and ancillary services been critical for determining the extent and pace of coal fired power station closures. Broad agreement that balanced approach required for transition i.e. need for all technologies to play a role. • Key difference with NEM is that Great Britain had access to gas fired generation to support the transition. • Following electricity supply disruption in Great Britain on 9 August, national grid operator (ESO) recommended a review of the security standards (SQSS) to determine whether it would be appropriate to provide for higher levels of resilience in the electricity system. ESO noted that this has cost implications which will need to be managed to balance risks and costs.

Existing market	Income mechanisms for adequacy / operating reserve services	Comments
PJM	Ancillary service *reserve* products which can be generation or demand side and quickly available in the event of the loss of a major generator. The five products are: **Operating Reserve**– The amount of power that can be received within 30 minutes. **Primary Reserve** – The amount of power that can be received within 10 minutes. **Synchronized Reserve** – The amount of power (connected to the grid) that can be received within 10 minutes. Participating generators must be synchronised to the grid. **Quick Start Reserve** – The amount of power that can be received within 10 minutes from generators that are offline **Supplemental Reserve** – The amount of power that can be received within 10 to 30 minutes.	• Capacity market design is different to that of the NEM • Able to access low cost gas fired generation to support transition

Table 3 - What does this mean for post 2025 market design?

Theoretical market design	Features for further exploration	Comments on theoretical market design which if progressed to more detailed design and development stage would need to be evaluated in more detail
Capacity style market	Capacity payments to underpin reliability	• Recognises different operating characteristics of generation • Requires greater regulatory intervention and judgement as to the amount and type of capacity required • May require changes to the market price cap • Significant further reform and would need clear demonstration of costs and benefits • May lead to oversupply (high costs for consumers) given AEMO's flat demand projections
Energy only (with variations)		• Potentially minimises changes to existing market design and considers current reform program
1. Higher reliability standard	Lifting market price cap	• May require substantial increase in market price cap making it an option which is not compatible with affordability • Implications for increased price volatility and margins, may increase uncertainty and costs to business • Not address different operating characteristics and issues of middle of day
2. Ancillary services (e.g. availability/spinning reserves)	Additional ancillary services markets which could be procured through competitive tender and/or traded markets depending on	• Spot, contract, direct payments will depend on objectives and depth of market • Trade off may be required between number of services and minimising complexity

Theoretical market design	**Features for further exploration**	**Comments on theoretical market design which if progressed to more detailed design and development stage would need to be evaluated in more detail**
	market characteristics (e.g. size, depth of market)	• Would need to be designed in such a way that is technology neutral and supports ongoing provision of services post retirement of coal fired power stations • Would need to complement RERT and consider NEM reliability framework
3. Shortage payment (e.g. ERCOT)	Additional payment on top of the electricity price if reserves fall below a pre determined level for a period	• Affordability impacts through adding payments on top of existing high wholesale electricity prices • Evidence as to whether this market design is effective is limited. Potential issues with this mechanism identified in ERCOT would need to be closely examined to ensure they were not replicated in the National Electricity Market. • May not provide revenue certainty/sustainable revenue flows. • Would need to confirm this is appropriate for managing intraday issues.
4. Direct payment for limited time period to support transition	Time limited payment to competitive suppliers of reliability services	• Would need to be developed in such a way as to support competitive outcomes. • Assessment required that new technologies will provide required system support services