Submission

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Subject Infigen submission to ESB Post-2025 Consultation Paper

1. Overview:

Infigen Energy (Infigen) welcomes the opportunity to make a submission to the ESB Post-2025 process. Infigen delivers reliable energy to customers through a portfolio of wind capacity across New South Wales, South Australia, Victoria and Western Australia, including both vertical integrated assets and PPAs. Infigen also owns and operates a portfolio of firming capacity, including a 123 MW open cycle gas turbine in NSW, a 25 MW / 52 MWh battery in SA, and will soon take ownership of 120 MW of dual fuel peaking capacity in SA. Our development pipeline has projects at differing stages of development covering wind, solar and batteries and we are also exploring further opportunities to purchase energy through capital light PPAs. This broad portfolio of assets has allowed us to retail electricity to over 400 metered sites to some of Australia's most iconic large energy users.

We consider that the ESB has responded positively to the feedback received to date, and presented a comprehensive discussion paper. Our overarching comments are that the NEM is more than just the market design – it is also the extensive financial and retailing markets that help participants to manage risk. These markets have delivered over $21b in investment over 2016-2020, including sufficient dispatchable capacity to ensure reliability until at *least* post-Liddell closure – and there is no reason to believe they will not continue to do so. Conversely, major disruptions to these markets would have a significant impact on investments, and so should be approached with caution.

We also note that the market is rapidly evolving, and conventional businesses models (large coal units, running at high capacity factors) no longer apply. Instead, businesses such as Infigen will deliver affordable, reliable, and low emissions supply through diverse portfolios of wind and solar, firmed by batteries, peaking gas, and pumped hydro. This approach has enabled Infigen to deliver low-cost contracts (both short and long term) to our customers. The ESB should take great care not to restrict flexibility or prevent innovation that will deliver future value.

Finally, in planning for a post-2025 world, the ESB must align take into account Australia's obligations to reduce emissions in a manner consistent with international efforts to limit anthropogenic climate change to 1.5-2 degrees Celsius above pre-industrial levels. Failure to implement policy that achieves a smooth glide path for reducing emissions to net-zero by mid-century is not in the long-term interests of consumers. Not addressing this aspect of energy policy will create a disorderly transition, as has been the case during the recent 3-4 year investment boom noted above. As such, planning for a system that has a high penetration of zero or very low-emissions generation and increased storage (either BESS or pumped hydro) is in the long-term interests of consumers. The ISP should have as its central scenario a linear transition to net zero by mid-century. Anything other than this is not consistent with Australia's international obligations and the long-term interests of consumers (as noted by the AEMC in its updated application of the NEO guideline released in 2019).

Below is a summary of our key comments on each of the workstreams, which we expand on in the subsequent sections.

Essential System Services

- The Operating Reserves framework should be implemented as soon as possible (CY21) to provide greater certainty to AEMO and Governments that physical reliability can be maintained even in response to unexpected real-time conditions.
- The Fast Frequency Response (FFR) market proposed by Infigen has broad support across industry, will reduce costs to consumers, and will enhance reliability and resilience. It should be implemented as soon as possible (CY21).
- The ESB should progress a structured procurement of system strength and inertia. Specifically, Infigen supports TNSPs being obligated to procure sufficient system strength, voltage control, and inertia to enable the future grid. To minimise project delays, appropriate system strength standards should be developed across the NEM, driven by project Development Approval applications (similar to how TNSPs might currently plan for future transmission).
- Spot markets for inertia merit further consideration (co-optimised with FFR), but should be progressed subsequent to the immediate package of reforms.
- AEMO and TNSPs should work to identify future needs for system services (e.g., in the ESOO) so that efficient co-optimisation can be undertaken. For example, the ISP/ESOO should identify where additional inertia/synthetic inertia is likely to be required so that private investors can identify opportunities to develop and contract services to TNSPs (such as adding flywheels to synchronous condensors, or appropriate capabilities to future inverters).

Ahead markets

- Infigen supports the basic principles of a more formalised approach to interventions, with transparency through pre-dispatch, and a structured process for committing resources for services without a real-time spot market. The proposed "unit commitment for security" (UCS) framework is a reasonable starting point.
- However, the AEMC should work with AEMO and industry to develop a more detailed issues paper on the UCS, more clearly highlighting the design options and the advantages and disadvantages before final designs are developed or decisions made.

- Particular attention should be given to understanding what unintended consequences may arise from implementing new frameworks, especially the impact of multiple changes occurring coincidentally (depending on implementation timing)
- Infigen expects *most* resources to be contracted ahead of time (against the real-time price). Therefore, day-ahead markets for energy will not have a material impact on unit-commitment decisions for aging coal generators – instead, they would just be about short-run profit maximising decisions. Alternatively, if coal generators are *not* contracting, there may be an opportunity for more targeted obligations on these generators to support contract liquidity.
- Given the lack of benefits identified at this time, further work on ahead markets for system services or energy should be deferred until the Essential System Services workstream is completed.

Reliability Adequacy Mechanisms

- The existing energy only market has been highly effective at delivering energy to meet expected peak demand, and seems likely to continue to do so. However, the risk of new modes of failure and extreme events such as unexpected generator closures, increased forced outage rates from aging thermal units, and extreme weather events due to climate change mean the focus should be on managing reliability for low probability, high impact events.
- Procuring new supply for these events makes little sense, while demand response will enable a more efficient system.
- An Operating Reserves should be implemented in 2021, with a staged start to allow time for additional capacity and contracted resources (including demand response) to be brought into the market (driving additional investment and hence reducing unserved energy). This will help manage the risk of unexpected coal closures.
- In addition, retailers could be required to procure demand response options contracts that could be exercised under extreme conditions – effectively allowing some customers to choose a lower level of reliability and be compensated for it.
- Given very high levels of reliability projected by AEMO *plus* the proposed Operating Reserves mechanism or development of a demand response target, there may be no need for the RRO in the future, and the RERT should apply only as an emergency measure. In the near-term, the RRO should continue as a backstop measure but with no further changes.
- Physical capacity markets are not consistent with the NEM evolution (diverse portfolios of wind and solar firmed by energy storage and peaking gas) or the extensive consultation on the RRO Firmness Guidelines which reject a centralised definition of "firmness".
- The ESB should explore additional incentives for aging thermal generators to maintain their units to an acceptable reliability level and avoid unexpected closures. The coal

bonds proposed by Grattan Institute would provide clear financial incentives for generators to avoid closures with short notice.

Two-sided markets

- Additional demand response could be procured through a retailer certificate scheme, requiring retailers to procure a minimum level of demand response while allowing third party aggregators to drive competition. This would allow some customers to choose a lower level of reliability and be compensated for it.
- Network tariffs should be made cost reflective where possible, such as the "solar sponge" tariffs developed by SAPN. This will help drive the efficient uptake of DER (batteries).
- Incentives should be created for customers to increase demand during low demand periods, which may represent a critical constraint in the future.
- Retail competition is critical for consumer outcomes. Residential customers on standing offer tariffs that have not engaged with their retailer within 2 years could be auctioned off, to ensure that consumers continue to receive the best prices and incumbent retailers do not simply take advantage of time-poor customers.

COGATI and transmission reform

- While the original intent of COGATI was to coordinate generation and transmission, the proposed framework does not achieve this. Instead, it is an overly complicated scheme that delivers no benefits to investors; rather, in our view it will harm investment at a critical time. As such, Infigen does not support the proposed COGATI reforms.
- Coordinating future generation and transmission can be assisted through clear, national frameworks for developing renewable energy zones, as well as leveraging the ISP to deliver transmission where needed.

1.1 Future investment trends

Infigen has undertaken detailed modelling of future investment under a range of scenarios (see attached slide deck). Infigen's modelling considers detailed half-hourly modelling with strategic bidding of generator portfolios, with iterative scenarios to meet both reliability and revenue adequacy requirements. Infigen's model builds on the ISP assumptions, but with additional commercial information (fuel costs, portfolios and contracting levels, etc.) and is not simply a least-cost planning model.

Even under a scenario where the electricity sector does its fair share of emissions reduction (40-60% emissions reduction by 2030), all new capacity is renewables, batteries, or pumped hydro capacity (with existing peaking gas capacity continuing to firm the system). This is consistent with the outcomes of the ISP.

Therefore, when considering revenue adequacy and future investment, it is critical the ESB recognises how reliability will be delivered: from diverse portfolios of VRE, firmed with energy storage. Simplistic "physical capacity" approaches are not fit-for-purpose for VRE, while energy storage – particularly batteries – are ideally placed to respond to strong, real-time price signals (i.e., the energy-only market).

Importantly, our modelling also shows the significant costs and disruption associated with delaying the development of a nationally consistent mechanism for reducing emissions in a manner consistent with Australia's international obligations. Delaying the development of a mechanism will result in significant disruption to the electricity sector from the late 2020s onwards. The capital injection/withdrawal is likely to become too rapid and result in significant additional cost and potential breaches of system technical limits.

2. Resource Adequacy

As demonstrated in Simshauser & Gilmore (2020), the NEM's energy only market *plus* the associated financial markets and hedging strategies have successfully delivered investment in the NEM. We do not find there has been underinvestment in the NEM to date, and furthermore no future shortfall in investment is projected in the near-term. In particular:

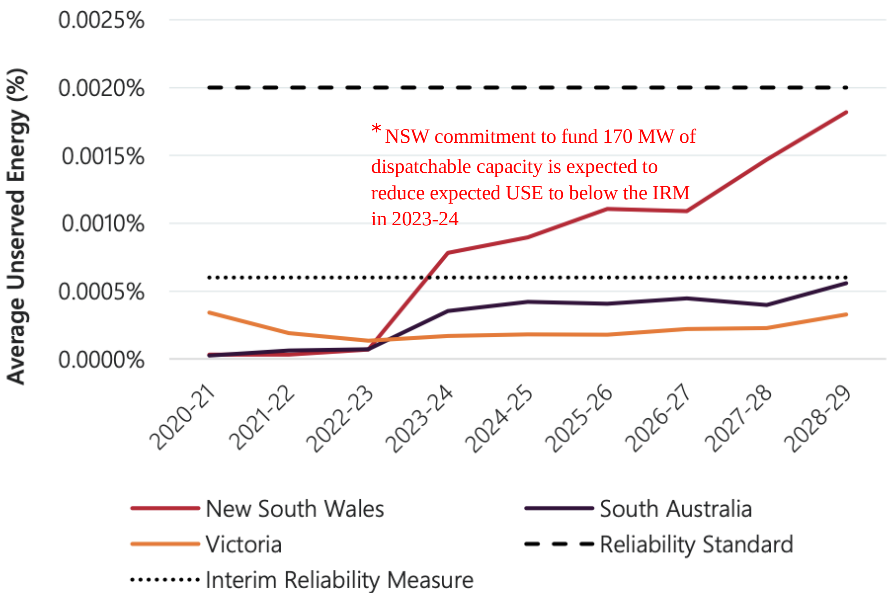
— Reliability projections by AEMO indicate expected reliability below even the 0.0006% Interim Reliability Measure in all regions even after the closure of Liddell (once funding commitments are taken into account).

— AEMO notes in its 2020 ESOO that additional renewable generation has also contributed to reliability. Future reliability will not be simply about peak demand, but rather about variability

— Investment in dispatchable capacity, while lower than renewables, has reflected system need. Cap prices, which act as proxy capacity prices in the NEM, are not trading above historical levels, and are in fact consistent with Infigen's projection of the long-term cost of physically backing a cap contract from a gas peaker.

— We note that reliability has been delivered *despite* continued Government intervention.

Figure 1 Expected unserved energy (AEMO 2020 ESOO)



The NEM remains investable

Flexible and evolving businesses such as Infigen have continued to invest in both dispatchable and VRE capacity in the NEM. Infigen has recently invested in, or is investigating, the full spectrum of technologies making up the future mix: variable renewables (wind and solar), batteries, peaking gas capacity, and pumped hydro projects, as well as demand response resources.

Even where these investments have been supported through out of market schemes (e.g., the LRET, correcting for a missing carbon externality in the NEM), Infigen accepts the balance of the investment and associated market risks (including of multiple revenue streams, in the case of LGCs).

Infigen has also signed PPAs (such as with Collector wind farm), providing a path to market for independent developers.

The financial contracts market already provides long-term hedges

The ESB has suggested that the financial contracts market has "never evolved to be longer than two to three years duration". This is not strictly accurate – financial contracts are regularly struck on longer timeframes, including run of plant PPAs (5-25 years), long-term firming contracts (~10 years), and retail contracts (2-15 years). Vertical integration is also used by businesses to deliver even longer-term generation certainty.

Infigen is a both a buyer and seller of long-term contracts such as these. In fact, Infigen has just recently negotiated a seven-year retail agreement with a major industrial customer.

The operation of these financial markets is an essential part of the NEM, and the ESB should be highly cautious of disrupting this market. Policy and regulatory uncertainty (e.g., the introduction of new capacity markets) would certainly result in an investment freeze at a critical time; while this should not preclude market changes, the benefits should be clearly articulated.

The ESB should focus on managing extreme reliability events through demand response

As noted, the existing energy only market (with associated market price cap settings and financial markets) will deliver capacity to meet a credible set of scenarios. However, it is unlikely that investors will commit new capacity to respond to extreme events, such as less than 1 in 10-year weather events, significant generator outages, bushfires, etc.

In our view, the costs to individual participants of hedging these “unexpected” may outweigh the penalties of unserved energy. This is recognised in the setting of the reliability standard, which realises that there are limits to what level of firmness can (and should) be hedged to.

Furthermore, even if participants were incentivised to do so, supply side solutions are unlikely to be economic for managing extreme peak events (e.g., less than 1 in 10-year events).

Instead, higher reliability is likely to be best met through demand response driven by price transparency or incentives: with customers effectively being able to choose their level of reliability and being paid to reduce consumption during peak times.

The ESB should focus on schemes that will hedge these extreme risks, initially through an Operating Reserve framework (which we expect will drive additional demand response as well as incentivise dispatchable capacity) and over time through enabling the two-sided market. Infigen has proposed options in Section 6 to assist with this, including through the mandatory procurement of additional demand response through a certificate scheme (similar to energy efficiency white certificates) to manage the gap between desired reliability and an economically rational supply side response.

In parallel, the Reliability Panel should continue to review the market settings, including the Market Price Cap and Cumulative Price Threshold, to ensure they are consistent with the market reliability standard.

Infigen has provided responses to the specific questions raised by the ESB below.

2.1 Operating Reserves

Infigen considers that an Operating Reserves framework would address many of the issues raised by policy makers and stakeholders.

Infigen supports a framework that will deliver *additional* reserves beyond what participants would naturally deliver in response to the market signals, similar to Infigen’s rule change proposal.

In particular, they would:

- Bring forward investment by delivering price signals *before* there is a critical risk of load shedding. By "carving out" reserves from the energy market, the incentives for hedging and investment would be maintained – including sharp real-time performance signals led by the market price cap.
- In practice, operating reserves would effectively allow for a market based wholesale demand response mechanism (where demand response is effectively priced above the market price cap) and effectively allow customers to choose their own level of reliability at varying price levels above the market price cap (links to Two-Sided Markets).
- Ensure AEMO always has sufficient[1] reserves to deliver a reliable grid when unanticipated events occur. This includes near real-time events (such as the unplanned outages of aging coal units, thermal derating of renewable projects, or higher than expected demand) as well as events on planning timeframes such as unknown system constraints (such as the system strength constraints emerging across the NEM requiring curtailment of capacity or another unanticipated coal closure).
- Provide Governments with confidence that existing economic signals will continue to function, *but* the physical market will not skate close to delivering unserved energy. Governments could also in principle use the Operating Reserve mechanism to procure (and fund) additional reserves (beyond the Reliability Panel's settings) for their regions, rather than seeking out of market procurement - for example, sufficient reserves could be procured at all times to ensure N-2 reliability (if the Reliability Panel and AEMO determine a lower procurement level).

Infigen does not support frameworks (so-called "ramping reserves") that would simply pay generators for what they would prudently do anyway – this would simply result in a wealth transfer from consumers to generators.

- Paying generators for withholding headroom for the *credible* ramping requirements conflicts with the market price cap, which already provides real-time signals for ensuring sufficient supply. (E.g., if generators are paid to offer energy, this will implicitly increase the market price cap – generators will be paid once to bid, and again when they generate – resulting in higher costs to consumers.)
- A service that procures the "entire" ramping requirement would require centralised forecast of both the expected and unexpected ramping requirements, creating a single point of failure. In contrast, an explicit Operating Reserve market would allow participants to manage credible ramps
- Creates new risks of gaming, through withdrawing capacity in order to offer into the reserves market

[1] Infigen recommends that level of reserves to be procured be determined by the Reliability Panel based on advice from AEMO

- The ESB's consultant FTI recommended an Operating Reserves (or price adder) framework more similar to Infigen's proposal
- A ramping reserves market does not provide clear investment signals for new capacity

A distinct Operating Reserves service will drive new capacity

Provided that clear guidelines of procurement volumes (including any demand curves) are published in advance, investment will be brought forward to meet expected peak supply-demand periods *plus* the Operating Reserves quantity. Critically, the resources required for Operating Reserves cannot be used by retailers to hedge prices[2] (as the reserves are only called for reliability); therefore, *additional* capacity or demand response must be brought into the market.

Infigen's proposed Operating Reserve framework would deliver investment exactly the same as the existing FCAS markets: while resources switch between the FCAS and energy markets, the total quantity of resources required is higher than the energy market alone. Similarly, while Operating Reserves are a real-time spot market, so too are the energy and FCAS markets – and they have successfully underpinned investment. Introducing an Operating Reserves service will necessarily require additional physical capacity *or* demand response, providing another reliability lever.

With Operating Reserves and a stronger two-sided market, we expect RERT will not be required. Effectively, Operating Reserves would take the role of the "standing reserves" framework originally suggested by AEMO, but with market drivers. Importantly, the risks of stranded assets would sit with the electricity industry, not consumers. If RERT is retained, it should be rarely exercised.

Quantity of reserves

As discussed in Section 4.1, the quantity of reserves should be linked primarily to the real-time variability in the market. The ESB should link this rule change to the AEMO PASA review we understand is currently underway. In particular, how reserves are procured and shared geographically under various conditions. This requires consideration of the risk of coincident peak demand/low supply, interregional transfers, etc.

The quantity of reserves procured could also reflect the risk of major or protracted outages (e.g., of aging coal units), or tighter jurisdictional reliability targets.

Cost recovery

We expect that Operating Reserves will be a relatively low-cost service. Given that it plays a similar role to RERT, it would be most reasonable to recover costs from consumers on a simple consumption basis in each dispatch interval. This would also provide further incentives to minimise consumption during extreme periods. Over time, additional

[2] In Infigen's proposal, the specific resources used to deliver Operating Reserves can vary across the day, allowing for the most efficient use of limited resources such as demand response. However, the total resources required at peak times will drive investment.

financial products may emerge to hedge these risks, but we expect that it will generally be captured under an all-in price or simple pass through by retailers (similar to other comparatively low-cost items).

It may also be possible for jurisdictions to procure additional reserves through this framework if desired; in this case, the cost of those reserves should be directly recovered from the respective Government.

2.2 Capacity markets and an expanded RRO

The RRO was developed and implemented to provide greater certainty to governments and policy makers that reliability would be maintained throughout the transition to a net-zero grid. The RRO provides certainty that when a shortfall in reliability is identified, participants would have an additional incentive to contract capacity, or be liable for additional costs – effectively providing an increase to the market price cap. Additional measures deliver contract liquidity and help match buyers and sellers of contracts.

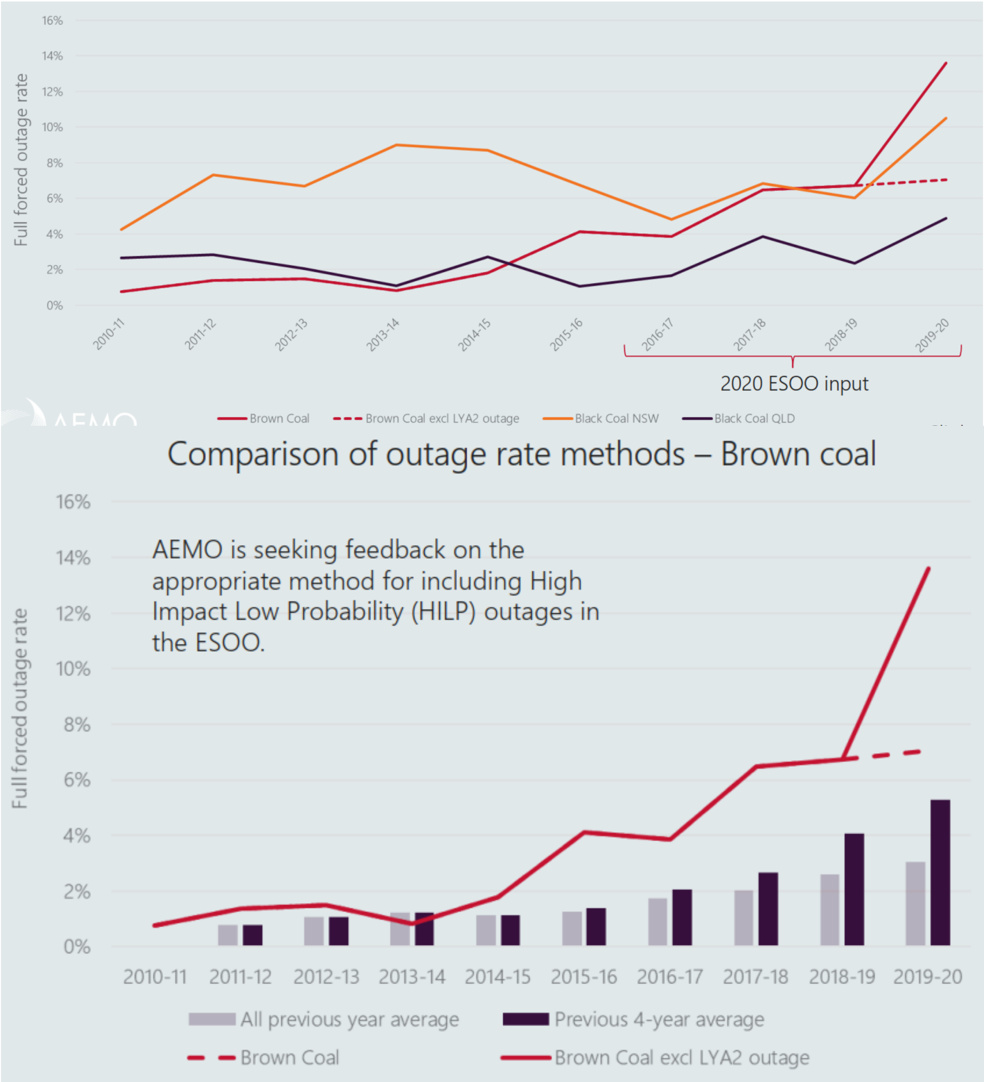
The RRO has not yet had an opportunity to be tested, despite being the result of an extensive, 18-month consultation process. It therefore seems unwise to further stress investment markets by introducing yet further schemes that distort existing contract markets.

The history of the RRO shows that capacity markets will not work for Australia

In considering the development of alternative capacity markets, it is helpful to consider the RRO's history:

— The original design proposal involved physical "certificates" that would be stapled to financial contracts. This was resoundingly rejected as it undermines the futures markets, would increase complexity and reduce flexibility, and is not consistent with delivering firm capacity from portfolios of resources.
— The RRO Interim Contracts and Firmness Guidelines recognise that "capacity" is no longer as simple as nameplate megawatts. For example, the forced outage rate of coal generation has been steadily increasing (Figure 2Figure 1), as aging units suffer poor reliability, meaning firmness factors must be declining. Conversely, portfolios of wind and solar projects with flexibly firming capacity can deliver very high levels of reliability – and even higher when gains from exchange from the NEM spot market are included.
— The development of the RRO recognised that forcing a centralised definition of "capacity" will reduce innovation and flexibility in both contracting and the delivery of physical capacity.

Figure 2 Coal forced outage rates (AEMO June 2020 Forecasting Reference Group)



It is therefore clear that there is no longer a simple definition of "capacity" that can be defined centrally and backed by single, physical, assets. Rather, the firmness of portfolios (even if divided across individual assets, as under the RRO) must be considered. Reliability is a property of the system as a whole, not a trait of individual generators.

While more decentralised capacity markets exist (e.g., France), Iberdrola's experience has highlighted the complexity, tendency to drive capacity oversupply, counterparty risks (including liquidity problems, force majeure clauses, etc.), and the "recentralisation" of the exchange of certificates via organised auctions. This market complexity also creates challenges for smaller players, requiring the design of additional measures – as has been the case for the RRO in Australia, even gives its narrow capacity.

Value stacking is critical for future investments, further reducing the value of "capacity" markets

Assets such as batteries (the primary source of firming in AEMO's ISP) use significant value stacking to deliver capacity. Given the expected growth in requirements for Regulation, inertia, FFR, system strength, and Operating Reserves, this suggests that only a small fraction of the future revenue stream will be covered by "capacity" markets. No single definition of "capacity" could capture all these roles.

While this does not preclude decentralised capacity markets, it would not provide "revenue certainty" for the new investments that are most valuable for the NEM.

Table 1 Lake Bonney BESS projected revenues at time of financial investment decision

Energy Arbitrage	Regulation FCAS	Contingency FCAS
30%	50%	20%

Markets should reward flexibility, not inflexibility

Implementing a capacity market with centrally determined, tradeable products would conflict with the existing spot, retail, and financial markets, and create considerable uncertainty for investors. It would also not be consistent with the new norm of delivering reliable capacity from diverse portfolios of VRE firmed by energy storage and peaking gas. In fact, the required behaviour from future resources is one of maximum flexibility – which is best incentivised through strong, real-time signals (i.e., the energy only market with a sufficiently high market price cap).

In contrast, capacity payments will tend to reward inflexible resources – the opposite of what is indicated in AEMO's ISP. Non-performance penalties must be enforced, but are invariably weaker than the energy only market's high MPC signal – resulting in generators being paid regardless of availability, with consumers (rather than generators) bearing those costs.

Higher reliability standards should be achieved through demand response

Using capacity markets to force very high reliability standards (e.g., 0.0006% USE) will be inefficient if it involves new supply; any future long-term availability payments should be focused only on demand response. Infigen has proposed a demand response target scheme (similar to energy efficiency targets with tradeable products) that could be used to provide longer-term certainty to demand response providers and hence Governments (Section 6).

Capacity markets will tend to force in more capacity than is efficient, risking "gold plating" the grid and leaving future consumers (rather than the electricity industry) to bear the risk of overbuilding and the associated costs of this.

Conclusions

- Infigen supports the ESB's decision not to pursue a centralised capacity market.
- Capacity schemes backed by individual physical assets is not consistent with emerging businesses, and would materially impact competition, flexibility, and affordability.

- Longer-duration financial decentralised capacity markets do not have identified benefits for Australia, and have been demonstrated not to be a prerequisite of future investment.
- With the development of an Operating Reserve framework and a demand response target, there is no need for any form of capacity market.

2.3 Impact on RERT and reliability measures

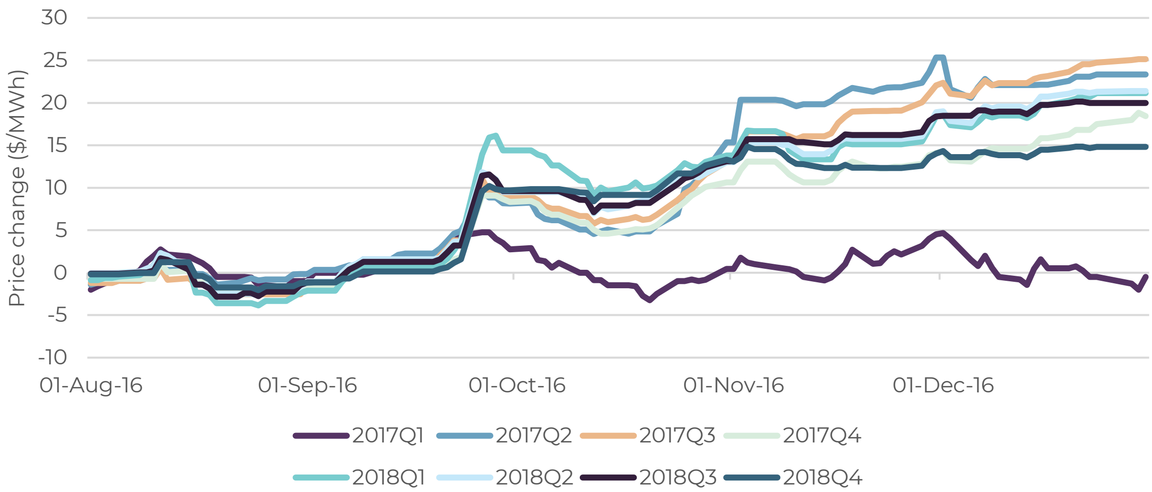
Infigen expects that if the Infigen Operating Reserves proposal is implemented, RERT will no longer be required to be procured annually, as has been done by AEMO recently at significant cost. We support preserving the RERT framework, as a safety net in the future, but expect that it should be reduced to its original intended role of an *emergency* service only.

3. Managing risks from coal closures

The most critical missing market in the NEM is the lack of an emissions reduction policy. This increases the risk of *unexpected* coal closures, which have directly led to increased consumer costs. *Unexpected* coal closures represent a material cost to consumers: the closure of Hazelwood drove forward price increases of $10-25/MWh (noting that most retailers and hence consumers would not be exposed to this full price increase due to prudent hedging arrangements). The figure below shows the increase in forward prices for Q2 2016 to Q4 2017, driven by speculation, media reports (Sep 2016) and the formal closure announcement (Nov 2016); note that in contrast, forwards for Q1 2016 (pre-closure) were relatively unchanged.

Figure 3 Change in Victorian forward prices due to Hazelwood closure

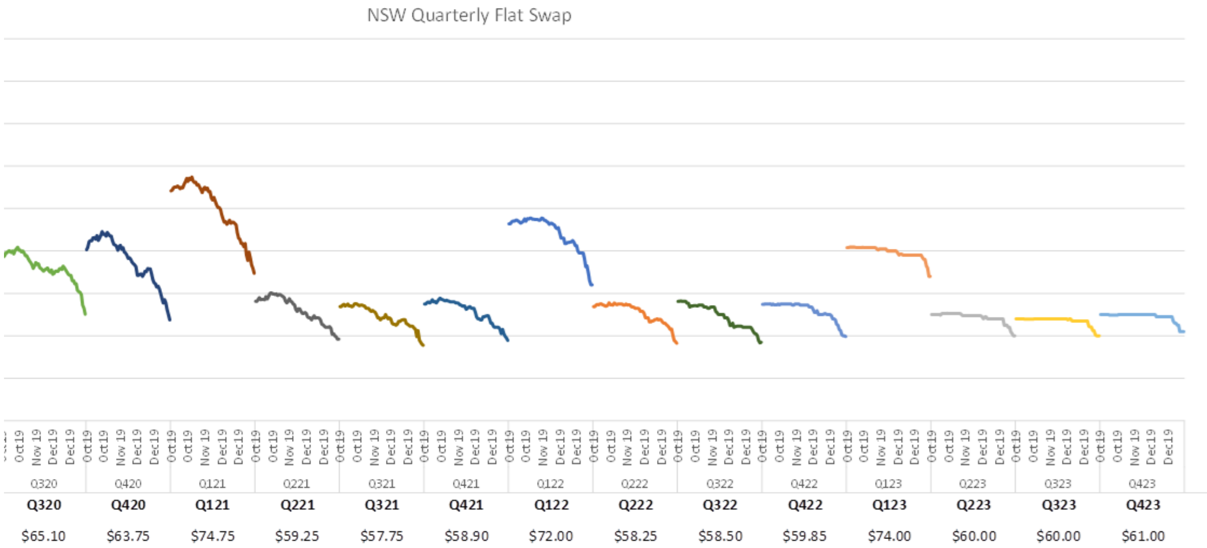
Prices normalised to average traded price in July 2016; all eight quarters prices move in tandem until closure reported in September 2016 – when quarters post closure rise by $10-25/MWh. Source: ASX forward prices



In contrast, the well telegraphed closure of Liddell has not led to a material change in futures prices over the 2021 to 2023 period. The figure below shows a snapshot from January

2020 (pre-COVID impacts), showing similar forward market expectations over time even as Liddell units are expected to close.

Figure 4 NSW forward prices as of January 2020 showing no impact of Liddell closure[3]



The pace of change has been underestimated historically

Despite the closure of ten coal power stations over the past decade, AEMO's Electricity State of Opportunities did not identify any potential closures ahead of time, nor did the market anticipate any closures. Various ESOO scenarios included demand, economic growth, and carbon sensitivities, but have not generally included material closures. The 2016 ESOO included the closure of a generic 1600 MW over four years, but did not consider the possibility of a major closure within 12 months. In short, all ESOO reports appear to be very reactive rather than proactive or anticipative.

Table 2 Historical coal closures and reporting in ESOO

	Announcement date	Closure date	AEMO ESOO positions
Swanbank B	26-Mar-2010	27-Mar-2012	2009 ESOO – No projected closure 2010 ESOO – Announced closure included
Playford (mothballing)	Apr-2012 (mothball) 07-Oct-2015 (closure)	08-May-2016	2011 ESOO – No mothballing assumed[4] 2012 ESOO – Announced mothballing included 2015 ESOO – Announced closure included[5]
Collinsville	01-Jun-2012	01-Dec-2012	2012 ESOO – No mention of closure 2013 ESOO – Announced closure included
Munmorah	03-Jul-2012	03-Jul-2012	2010 ESOO – Available until 2014 2011 ESOO – Available until 2014 2012 ESOO – Announced closure included
Morwell	29-Jul-2014	30-Aug-2014	2012 SOO – Downgraded capacity 2014 ESOO – Possibly further capacity downgrade

[3] Snapshot from January2020
[4] Reduction in available capacity to 200 MW
[5] Despite full re

			2015 ESOO – Announced closure included
Wallerawang	01-Nov-2014	01-Nov-2014	2013 ESOO – No closure considered 2014 ESOO – Announced withdrawals included
Redbank	31-Oct-2014	31-Oct-2014	2014 ESOO – No closure considered 2015 ESOO – Announced closure included
Anglesea	12-May-2015	31-Aug-2015	2014 ESOO – No closure considered 2015 ESOO – Announced closure included
Northern	07-Oct-2015	08-May-2016	2012 SOO – Announced winter mothballing 2013,2014 ESOO – No change 2015 ESOO – Announced closure included
Hazelwood	03-Nov-2016	01-Apr-2017	2016 ESOO – 400 MW brown coal closure in FY18 (1600 MW by FY21 in Weak outlook) 2016 ESOO Update – Announced closure included

An Operating Reserves framework is ideally suited to managing this risk: ensuring that there is additional capacity available to cope with unexpected events. It would reduce the risk of reliability impacts until either a clearer decarbonisation path is established, or a mechanism to encourage greater transparency and confidence in closure dates (such as Grattan's coal closure model[6]) is implemented, as discussed below.

3.1 Coal bonds

"Coal bonds", such as the framework proposed by Grattan Institute, would facilitate an economic framework for an orderly transition away from ageing generators to new investment. Ageing generators above a certain size (e.g more than 5% of jurisdictional registered dispatchable capacity) could be required to put funds aside, managed by an independent third party, to be held as security. Generators would be allowed to nominate their own closure window, but would only get their funds back only if they closed within this window. This would provide a strong incentive for predictable and orderly closure.

To balance flexibility and certainty, younger generators would be allowed to nominate relatively long windows, but they would need to tighten these windows as they age. Limited exemptions would be available if early closure did not harm the reliability of the market, or conversely if continued operation of the coal plant in question was absolutely necessary to maintain reliability.

4. Essential System Services

Infigen strongly supports the ESB's focus on establishing clear services (not necessarily organised spot markets) for procuring the NEM's missing markets. Infigen agrees that column 1 (Directed ESS/self-provision) is not a sustainable approach, and supports:

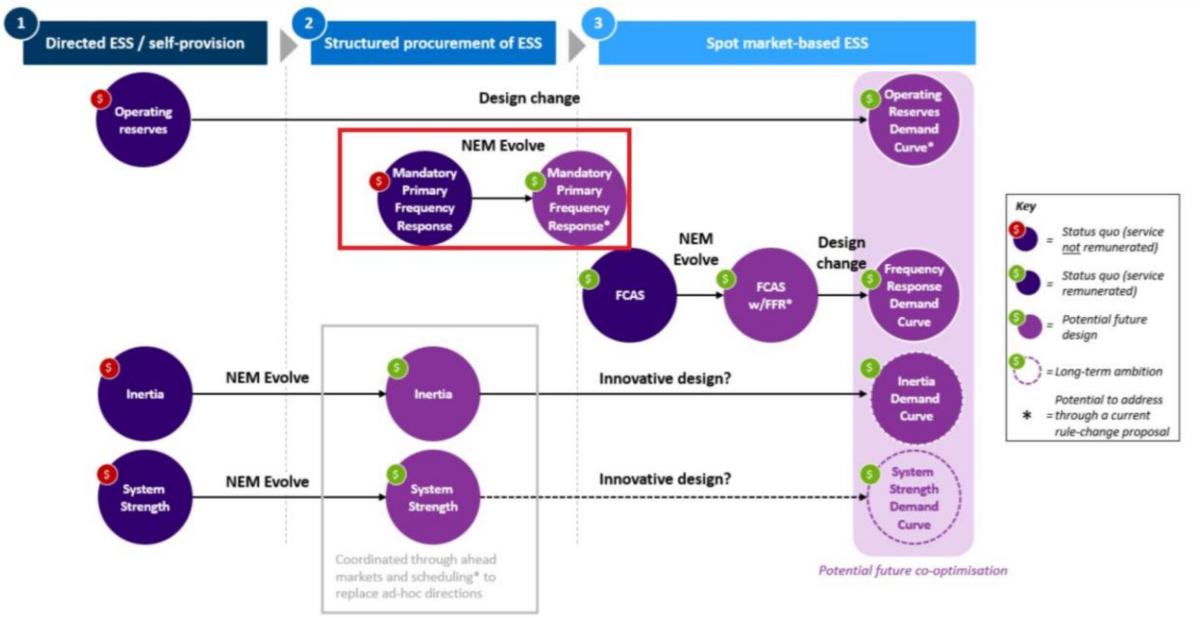
- transitioning Operating Reserves to a spot market-based ESS (column 3)
- Implementation of a FFR market (column 3)

[6] https://grattan.edu.au/report/power-play/

- Moving to structured procurement of inertia and system strength, with investigation of a future inertia market.
  - We note that structured procurement does not preclude the use of an inertia or system strength demand curve on *operational* timeframes if there are non-zero resource operating costs
  - We do not see a spot market for system strength as viable, given the lack of locational competition and information and forecasting asymmetry
- transitioning from mandatory primary frequency control procurement to a clearly defined service, similar to the existing FCAS markets, where AEMO would have certainty of the volume of narrow deadband primary response available to the system (and therefore avoid future shortages)

These issues are explored further below.

Figure 5 ESB ESS pathways



4.1 Operating reserves

As discussed above, Infigen strongly supports the rapid implementation of Operating Reserves to support resources on both investment and operational timeframes. Operating Reserves will provide certainty for AEMO that sufficient reserves will be available in real-time, while not distorting the operational and price-hedging decisions of market participants.

While market participants have delivered sufficient reserves in response to all *forecasted* extreme events, responding to increased risk of aging asset outages or climate-change driven extreme weather may create new modes of failure – “unknown unknowns” that are difficult to manage.

Quantity of reserves to procure

Determining the quantity of reserves to procure will be a critical input, supported by AEMO and the Reliability Panel. In our view, the Reliability Panel should be tasked with

There is some merit in the concept of a demand curve approach, with additional reserves being procured when cost effective. However, we note that, if reserves are low-cost there are likely to be reserves readily available even without an Operating Reserve target; care would need to be taken not to increase the scheme cost unnecessarily or inflating energy prices.

Implementation and timing

If an Operating Reserve (to, say, N-2) were implemented immediately, there is a risk that it would lead to higher prices to consumers, due to dispatchable capacity being withdrawn from the energy market unless it is balanced by either RERT resources being moved into Operating Reserves or the development of new dispatchable capacity. It may therefore be prudent to have a "slow start" where the volume of reserves to be procured is increased over several years – allowing participants to gain confidence in scheme operation and to contract new demand response and/or develop new capacity.

On this basis, Infigen supports the implementation of Operating Reserves as a priority, which will ensure that a full service can be delivered by 2025.

4.2 Fast Frequency Response

Infigen strongly supports the establishment of a new FFR FCAS market.

Given the key role that FFR will play in trading off inertia, contingency size (including transmission flows), and contingency FCAS procurement, it seems most sensible to establish a new, explicit FFR FCAS market as proposed by Infigen. In principle, one of the existing Contingency FCAS services could be repurposed (for example, instead of R6/60/5min, there could be R2/R60/5min); further analysis should be undertaken on current and future likely providers to minimise the risk of low-cost assets being excluded in the near-term.

In addition to Infigen's rule change proposal, we note the following in response to the AEMC's questions:

- We recommend seeking further advice from AEMO and the Reliability Panel on the benefits and hence volume and location of FFR to be procured, including any minimum procurement level and its motivations. While existing Raise contingency services are recovered from generators, depending on the motivation for the procurement quantities, it may be appropriate in this case to recover the costs of FFR Raise from both generators and loads if some level of FFR is for system security rather than specific contingencies like other FCAS services.

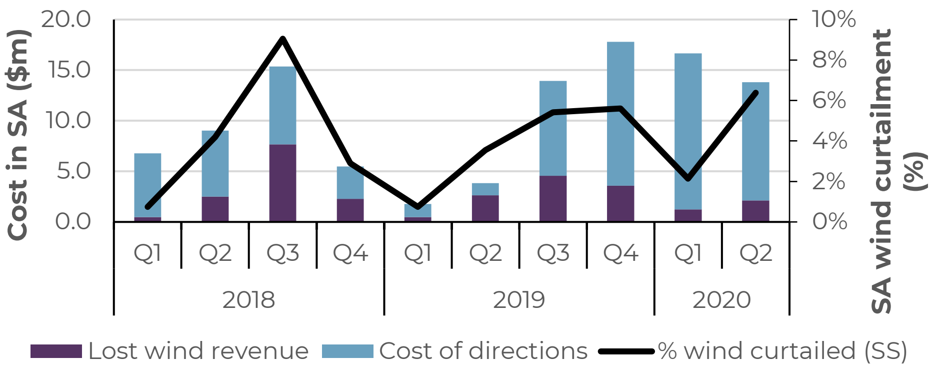
– It is possible that an FFR service could be used a proxy inertia market, valuing the delivery of any initial inertial response that is excluded from the Fast Raise FCAS service. Synchronous inertia and some virtual inertia services[7] deliver additional value to the grid, and it would seem preferable to establish a separate inertia market/service (e.g., an inertia standard for TNSPs or potentially a spot market for inertia in the longer-term), but the FFR service may be appropriate as an interim measure to reward inertia provision depending on the specific timescale and response durations considered. Alternatively, inertia delivery could be considered when recovering the costs of the FFR service.

4.3 Structured procurement of system services

4.3.1 System strength

Addressing system strength should be a priority project for the ESB. The "do no harm" framework has failed to deliver effective outcomes, and resulted in significant costs to the energy sector. Currently, in South Australia alone, system strength results in $11m pa of curtailed wind power plus $30m+ in directions, plus the less quantifiable cost of project delays and higher future costs.

Figure 6 Cost of system strength in South Australia



Source: Infigen analysis of AEMO data, AEMO QED publications

In our view, system strength is ultimately best described as a network service: it is locational, requires coordination between multiple projects, and requires sophisticated modelling that is not generally available to participants. Like transmission, it is an essential service, and is a fundamental requirement for managing the transition to a clean energy future.

Critically, the costs and benefits of these risks are asymmetric. Insufficient system strength will result in project delays and/or the curtailment of resources, which will ultimately result in higher costs to consumers through both higher project hurdle rates (in the long-run) and

[7] Virtual inertia is distinct from Fast Frequency Response, for example: http://www.wattclarity.com.au/articles/2020/04/do-you-know-the-difference-between-virtual-inertia-and-fast-frequency-response/

use of more expensive resources (in the short-run). These directly affect energy costs, which is the primary driver of consumer bills. In contrast, over-procurement will increase the cost of that service but also deliver additional value through improved system "resilience".

Infigen therefore supports the basic principles of a structured procurement by TNSPs:

- Removal of the generator do no harm regime, while still requiring generators to meet connection standards.
- AEMO would be required to set minimum fault level requirements for various "nodes" or "sub-regions" of the NEM based on power system modelling (see below). We suggest that this could expanded to other system strength metrics as AEMO modelling capabilities expand.
- TNSPs would then be required to maintain fault levels sufficiently to meet a standard set by the Reliability Panel.
- TNSPs would invest or contract for system strength with a forward-looking investment plan that considers developments in the ISP (or other likely investments). We consider this is appropriate, reflects the similarities between transmission and system strength services, and would address the challenges of timing new developments. Importantly, it would also allow TNSPs to plan network development in a manner consistent with Australia's international climate change commitments and obligations.
- TNSPs would be required to demonstrate to the AER that they had considered non-network solutions (either directly, such as through requests for tenders, or indirectly through market modelling) in order to address any planning gaps before a network solution (e.g., transmission or syncons) was implemented.
- Drive efficiency of investment in system strength by addressing key points in the network and gaining scale benefits from colocation of technology delivering the service.
- Likely better utilisation of services as they are managed centrally and can service more of the network while ensuring risk of interaction between devices is minimised.
- Any costs associated with connection must be transparently determined upfront.

Nodes need to be sufficient to allow a least-cost generation mix

In the AEMO-defined nodes framework, participants will have confidence that the TNSP will develop and maintain sufficient system strength to enable connection and ongoing operation of the units (based on AEMO's announced minimum levels). However, these nodes need to be defined with sufficient granularity to reflect network limitations but also to avoid central planning.

For example, the ISP is essentially a "greedy" mechanical model, where if a resource is even $0.01/MWh cheaper[8] than another, then that entire resource will be built out. The resolution of this modelling is also very coarse, and does not reflect real-world projects. In practice, therefore, high value projects will be more distributed.

Given the significant uncertainties and risk asymmetry, it would be prudent to err on establishing *more* nodes than fewer. This should map to at least the REZ regions in AEMO's ISP, but further sub-nodes will likely be required to capture the majority of projects. Nodes could be developed in response to both ISP projections and project connection applications.

This would not force TNSPs to necessarily overbuild system strength – rather, as with transmission, TNSPs would take a probabilistic approach, where low-probability or low-capacity development regions will require minimal (or no) investment to meet the "standard", while high investment regions will require more.

Furthermore, any "overbuild" will continue to deliver system resilience, *and* will very likely be required in the future, given the net-zero commitments of every state and territory of Australia. If additional syncons/batteries/etc. are eventually required to reach 100% renewables, it is no more costly to develop them in remote locations (with good renewable resource) than in centralised locations. Similarly, a location may currently have higher system strength, but only because a coal power station has not yet retired but will do so in the near future.

Charging will be challenging

A key question is how system strength costs will be allocated. In our view, system strength is a network service similar to transmission that ultimately delivers for the long-term interest of consumers. Efficiently estimating future system strength costs are already challenging, and as such it may be difficult to accurately estimate long-run marginal costs. These pricing risks were a significant factor in the rejection of Optional Firm Access and, more recently, the initial COGATI proposal where generators would pay TNSPs for transmission access.

The AEMC should consider whether it is in the long-term interest of consumers for system strength costs to simply be rolled into the Regulated Asset Base rather than passed on to consumers through higher electricity prices (reflecting higher build costs for new technologies).

The ESOO needs to identify future requirements, to maximise value stacking of investments

A risk of any centralised procurement process is that private investors will not have sufficient signals to develop or adjust investment plans. For example, new synchronous units could be upgraded to allow a synchronous condenser mode, batteries and inverters could be installed with grid forming hardware and software capabilities, etc. Therefore, it will be critical that potential needs for synchronous services (or synthetic alternatives) are

[8] Actually, the cost of serving load – that is, a wind farm might cost $5/MWh more, but deliver $10/MWh of additional value to the system.

identified as quickly as possible, along with associated modelling. These opportunities could be published in the ESOO alongside capacity requirements.

TNSPs would be required to feed into these projections, and to consider non-network solutions (including contracting with existing assets).

Reactive power also needs to be considered

Infigen notes that fault levels are not necessarily sufficient on their own to ensure power system security. Effective voltage control will also require sufficient reactive power, which is also a localised service. For example, the Infigen understands that the Victorian Maximum Supportable Demand is underpinned by the reactive power availability and was reduced following the retirement of Hazelwood PS.

The ESB should consult with AEMO on insights to be shared from their Voltage Dispatch System (VDS) that automates instructions for units to deliver voltage control. This could then feed into the TNSP procurement process (including being projected in the ESOO, and a longer-term evaluation of whether an organised spot market is appropriate.

4.3.2 Inertia

Infigen supports the ESB's approach to further investigate the viability of an organised spot market for inertia. However, if EnergyConnect is developed, there may be *relatively* little urgency for the development of a formal inertia market.

Unlike system strength, inertia is likely to relatively fungible between assets and geographical locations. Even without a spot market, it may therefore be appropriate to develop a framework that rewards all inertia providers, whether contracted or not. In the near-term, this could potentially leverage the FFR framework (rewarding rapid response).

A key question is whether, under the structured procurement framework, non-contracted providers of inertia should be renumerated. This is most consistent with Infigen's view on market-based services. This would provide additional incentives to existing generators to deliver the service (and potentially reduce the need for directions) but a market-based price may be challenging to implement.

5. Ahead markets

As Infigen's previous submissions to the ESB and the AEMC have demonstrated, there appears little need for ahead markets to manage unit commitment. Voluntary financial ahead markets days to week ahead may be useful for adjusting net positions, but are low priority at this time.

5.1 UCS development

AEMO has proposed the "unit commitment for security" (UCS) design as an alternative framework for interventions, where AEMO would use a clearly defined process to determining the costs and benefits of intervention, including publishing intended interventions in the pre-dispatch process.

Infigen in principle supports a more structured approach to directions as well as a clear framework for how non-energy (or energy-coincident) contracts for ESS should be activated. However, it is critical to define exactly what is meant by UCS, which is somewhat confused in the ESB's paper: is it intended to simply replace the existing directions framework (and so rarely used), or to be the framework where ESS without a real-time organised spot market are committed when required?

There is significant problem definition work still to be done before design work is undertaken:

- What is being optimised by the UCS? Is the UCS intended to only manage costs of directions, or will it be used to activate ESS contracts?
  - Will the UCS be used only to correct "gaps", or will it also be used to activate ESS resources for "market benefits"? If the former, how will contracts for system strength, inertia, or other non-market ancillary services be activated?
- The Reliability Panel should develop clear guidelines for how AEMO should use the UCS to intervene in the market, potentially including reviewing the LOR and PASA frameworks or any other "gap" definitions
  - For services where a spot market exists (energy, FCAS, etc.), UCS interventions should only be for reliability (to an agreed reserve level/probabilistic standard).
- What timeframe should the UCS optimise over? How will AEMO balance lower-cost but potentially unnecessary interventions in advance against high-cost interventions once certainty is reached?
  - What "discount rate" should be applied in the UCS decision making – how should low costs to manage low probability events "now" be traded off against high costs "later" only if the event actually occur?
  - We suggest that while AEMO operators should have final discretion, there needs to be a clear structure around this, leveraging quantitative modelling where possible, for the UCS to deliver value
- How will gaming be prevented? For example, could coal generators manufacture a shortfall in services order to get startup costs covered?
  - Could be managed by any units that are committed through the UCS only being eligible to recover their costs for all their output? For example, any unit that does not self-commit and is instead committed by the UCS, could then be forced to bid at its SRMC or be contracted to AEMO for its entire output at its standing data costs.
  - Units could also provide a "last time to commit", and if not either self-committed or committed by the UCS by this time would be prevented from self-committing later (under bidding in good faith rules)
  - If a unit was intending to self-commit at 4pm, but was committed by the UCS at 11am, would it be eligible to recover its start costs?
- Is UCS commitment financial or physical commitment?

  - While Infigen does not support physical ahead markets, the UCS's role in committing location specific capacity and the proposed reliance on physical plant standing data lends itself to *physical* commitments – similar to current directions.
- When will intervention pricing apply?
  - We suggest that commitment of resources where an organised spot market does not exist should not trigger intervention pricing, similar to recent changes to the intervention frameworks.

We note that these questions may not be particularly relevant in practice: we expect that the majority of essential system services will be procured from fast-start units (particularly syncons and grid forming batteries), with slow start thermal units being uncompetitive given their significant fuel and carbon costs. Further modelling should be undertaken to test this.

5.2 Ahead markets for system services and energy

Through the Technical Working Groups, AEMO has primarily focused on ahead markets for energy and, more recently, the Delta rule change proposal for procuring services day-ahead from slow-start coal generators.

However, there has been relatively little work done to date on identifying the problems to be solved by ahead markets for energy or system services, or quantifying how ahead markets deliver value compared to alternatives (including the real-time market, existing long-term contacting, and the proposed structured procurement of ESS). AEMO advised through the TWG that there are no identified instances historically or in the ISP where centralized ahead scheduling would have avoided unserved energy; this is consistent with Infigen's previous submissions to the ESB.

Essential system services must be defined first

In our view, the ESB cannot make an informed decision on ahead markets for system services *until* those services, and requirements, have been defined. For example, if most missing system services (particularly inertia and system strength) are to be procured through a structured procurement process (e.g., TNSP procurement), then there will be little value in an expensive and complex organised ahead market for "topping up" and instead frameworks should ensure that TNSPs can contract efficiently.

We note that in South Australia, procuring system strength from existing generators was far more expensive than building syncons; it seems likely this will be true in other regions (particularly given market power). Furthermore, batteries are increasingly capable of delivering Fast Frequency Response, virtual inertia, and system strength – and are able to be activated even more quickly than syncons. There seems little need or value in developing new "ahead" frameworks specifically for aging coal assets.

New ahead markets for energy would be highly disruptive

Currently, all of the NEM's contracted energy references the real-time price. Generators that are contracted to the real-time price (e.g., through contracting to customers or selling futures) cannot then *also* sell into a day-ahead market (as they would then be contracted twice).

It would be incredibly challenging and disruptive to rewrite existing contracts or to establish new forward markets to the day-ahead price. Infigen expects that contracts would continue to reference the real-time price.

Therefore, it seems most likely that ahead markets for energy would be used only as a "balancing market", by either uncontracted generators selling capacity, uncontracted loads buying capacity, and contracted generators/loads "unwinding" their contract positions by buying/selling (respectively) capacity. Therefore, a day-ahead market would not be consistent with the RRO that *encourages* all participants to be contracted ahead of time.

Infigen therefore supports the ESB's decision not to proceed with compulsory ahead markets, and no clear benefits have been identified for a co-optimised system services and (balancing) ahead market. A voluntary Short-Term Forward Market trading days- to week-ahead futures market to allow portfolios to rebalance closer to real-time could be re-considered in the future.

Demand response will be most valuable if contracted

While some demand response resources may seek day-ahead certainty of activation, if these resources have high marginal costs (e.g., $1000+/MWh), it is unclear what counterparties would seek to buy energy at that price a day-ahead spot market for energy (given the difficulty in forecasting such high prices day-ahead). Conversely, demand response can deliver greater overall value if integrated into the contract market; it is then unlikely to participate in an ahead market. Retailers such as Infigen already work with customers to enable demand response and to share the value this brings to the market.

Recommendations

We recommend that further work on ahead markets, beyond a clearly defined UCS, be deferred until after the ESS workstream has been completed and the necessary services defined.

6. Two-sided markets and DER integration

An active two-sided market can fulfill two key roles:

- Improving affordability by providing in-market firming services that can be contracted to retailers as alternatives to new physical supply; and
- Improving reliability and reducing load shedding events by allowing consumers to choose their desired level of reliability and being paid to reduce consumption at critical times.

Infigen supports the activities identified in the ESB workstreams, including the short-term, intermediate and long-term approaches. Where possible, the Rules should specify services to be delivered rather than specific permitted technologies – this will maximise participation from future, non-conventional resources (such as aggregated loads and DER).

Infigen supports frameworks that will drive significant demand side participation, with engagement from a broad range of load and DER resources. This could include:

Efficient tariffs

Cost reflective network (and energy) tariffs will help to increase value for consumers and make efficient use of the network. For example, the SA “solar sponge” tariffs[9] allow for network prices during the middle of the day that are 25% of the single rate price. This provides efficient price signals to consumers to angle solar panels to maximise morning/afternoon production, as well as increasing incentives for distributed batteries (shifting energy away from the daytime solar peak) that will improve overall system resilience and value stacking opportunities if embedded in the distribution network.

Given that individual consumers have no ability to choose where embedded generation is developed, Infigen also supports investigating efficient export tariffs for consumers, to ensure that consumers see efficient price signals for developing responsive DER such as battery energy storage.

Retailer demand response target

The recent Demand Response Mechanism rule change is intended to increase the uptake of demand response, including by facilitating third party aggregators where retailers are unwilling. However, to deliver maximum value, demand response should be incorporated into retailers’ hedge books, reducing the need for costly physical peaking capacity.

An alternative approach would be to require retailers to procure a certain capacity of demand response, with obligations tracked through a retailer scheme with tradeable products. This could be managed by:

- A central body (e.g., AEMO or the Clean Energy Regulator) identifies the gap between an *expected* peak demand and *extreme* (e.g. POE10) peak demand
- Retailers are allocated this gap on the basis of market share
- Standardised contracts developed by industry to allow trading of demand response.
- Contracts would be with individual customers and have unique prices and quantities but the same conditions, however third party aggregators could manage and on-sell these contracts for multiple customers.
- When aggregate system peak demand exceeds the *average*, the contract is ‘triggered’
- Customer agrees to reduce demand by a certain quantity for a certain price
- Retailers must hold a certain number of these contracts, based upon their market share, or face a penalty

Further consideration would need to be given to how price-triggered demand response contracts would interact, performance obligations, and how metering and baselines would be treated. Unlike the DRM, given that these contracts would be (for the purposes of peak

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[9] https://www.sapowernetworks.com.au/public/download.jsp?id=9508

demand) rarely triggered, baseline methodologies could be defined more conservatively, acknowledging that reviews could be undertaken later.

Positive demand response

Infigen noted in the development of the Demand Response Mechanism that incentives might be needed to encourage customers to *increase* demand at critical times. This was not taken up by the AEMC, but recent experiences in South Australia have highlighted that mechanisms for exposing customers to *negative* prices will also be valuable.

Auctioning unengaged residential customers

An active two-sided market requires either that customers are engaged, or that their retailers are engaged on their behalf (with customers not experiencing any loss of quality). Furthermore, customers that are not engaged risk being stranded on higher-cost tariffs.

Governments have sought to address this through implementing default market offers; however, while this reduces costs for unengaged customers, it tends to reduce overall competition and increase prices for engaged customers[10].

An alternative would be for residential customers on standing offer tariffs that have not engaged with their retailer in a 24 month window to be "auctioned off" – whereby retailers make competitive offers to secure the customer. This would help ensure that retailers have incentives to engage with customers, and that customers were always on competitive offers.

7. Transmission access reform and REZs

Infigen has responded to these questions primarily through our submission to the AEMC on COGATI.

We note, however, with $21 billion of investment (2017-2020) and wholesale prices at the lowest level they've been in 25 years in real terms, what problem are we solving, or economic gain are we anticipating? The three reasons for introducing the reforms are said to be:

- Reducing generator risks: yet an AEMC survey revealed 100% of investors said it will do the opposite.
- Improving locational decision making: Existing problems were caused by the rate of change due to policy discontinuity of the Renewable Energy Target. Existing MLF framework *plus* congestion signals provides more than enough locational incentives (no projects are committed on the assumption of future local transmission upgrades)
- Efficient pricing: Efficient pricing will only occur if CoGATI reforms are applied to both generators and loads. This is likely to be unacceptable to policymakers as it would present significant equity impacts

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[10] https://www.sciencedirect.com/science/article/pii/S0301421520305462

Pressing ahead with COGATI and the most significant elements of the market design alterations has a high risk of being counterproductive. The problem that needs addressing is to ensure sufficient network capacity and system strength exists to enable a seamless transition.

Notably, coordination of generation and transmission is not a major issue for the NEM: AEMO projects that REZ transmission infrastructure will be only ~1% of total NEM costs over the next 20 years[11], suggesting limited coordination risks.

Instead of the latest iteration of COGATI, the ESB should focus on enabling REZs and actioning the ISP. This means:

- Actioning the ISP to ensure that major transmission projects are delivered in a *timely* fashion, and helping to coordinate national action
- Renewable Energy Zones providing a straightforward approach to coordinating Generation and Transmission without upending every participant in the National Electricity Market, and the Capital Markets which provide the capital to invest
- Clearly establishing net-zero emissions as being in the long-term interest of consumers and so a starting point for all investment and policy decisions
- Delivering an ISP with a credible Central scenario

8. Conclusion:

We look forward to the opportunity to continue to engage with the ESB. If you would like to discuss this submission, please contact Dr Joel Gilmore (Regulator Affairs Manager) on joel.gilmore@infigenenergy.com or 0411 267 044.

Yours sincerely

Ross Rolfe
Managing Director

[11] Infigen analysis of AEMO 2020 ISP costs