9th June 2021

Energy Security Board

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Finncorn

## Submission to the Energy Security Board in response to the Post-2025 Market Design Options Consultation Paper

Please find attached a public submission for the consideration of the ESB.

Yours sincerely,

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# Post-2025 Market Design

Finncorn Consulting's response to the Options Paper

Released as a public submission



9th June 2021

# Introduction

Finncorn has been engaged by Energy Consumers Australia ('ECA') to provide independent advice to assist in ECA's assessment of the Post-2025 Market Design ('P2025') options, in relation to:

- **Workstream 1:** Resource Adequacy Mechanisms and Aging Thermal Generation;
- **Workstream 2:** Essential System Services, Scheduling and Ahead Mechanisms; and
- **Workstream 4:** Transmission & Access and Renewable Energy Zones.

## The Long-term Interests of Consumers

We have assessed the P2025 options against the long-term interests of energy consumers in the NEM. In our view, the NEM market design should support consumers' **affordability, reliability, and choice**.

Choice may relate to:

- Desire for **engagement** with the energy market through their behaviours;
- Investment in and operation of **distributed energy resources and flexible aspects of demand**; and
- **Preferences** for other characteristics of their energy supply, such as carbon intensity.

Consumers understand that there may need to be trade-offs made between these factors. In particular **we do not think consumers are well-served by a presumption that marginal improvements in reliability should be traded off against either affordability or choice.**

## There are no guarantees on jurisdictional interventions

Some proposed P2025 reforms imply new revenue streams for generators, without any suggestion (let alone evidence) these will be offset by reduced costs elsewhere.

The qualitative reasoning to support this is 'improved reliability' – although the ESB makes clear the underlying judgement about the marginal value of more and more reliability seems to be being made by jurisdictions[1] rather than the Reliability Panel or consumers.

In reality, the jurisdictional definition of 'reliability' is very broad, given it seems to encompass:

- Whether or not certain assets exit the market when the economics dictate they should, and
- Whether or not price signals should be allowed to emerge as a result, to encourage the replacement investment.

As a result, the benefit of these reforms is clearly at least partly directed at an assumption that they will be sufficient to deter jurisdictional interventions and allow the NEM to go back to some version of 'the good old days' in terms of market participants driving investment without jurisdictional distortion.

**We think this assumption is a dangerous mistake and a terrible precedent.**

Rather than a policy of appeasement – putting in place poorly-designed and weakly-supported market design because that is what one or more jurisdictions currently think they want – we think the ESB, market participants and stakeholders in general should rather appeal to their better angels: design good policy with clear evidence and support and continue to encourage jurisdictions to work with such policy and market design.

That includes accepting the durable, direct role jurisdictions have chosen to take in the transition of the NEM – that genie is well and truly out of the bottle, and it will not be returning via this process.

[1] In this paper we refer '**jurisdictions**' as a shortcut for '**the state, territory and Commonwealth governments, who are generally represented by their respective Energy Ministers in forming energy sector policy (as part of their broader concerns)**'. They are a key stakeholder alongside corporate market participants, consumers, and the regulatory (AER), rule-making (AEMC) and operational (AEMO) market bodies. Jurisdictions should represent the interests of citizens in general in this debate, which overlaps with, but is NOT the same as energy consumers' interests. Citizens' interests include social, employment, economic and environmental concerns which are broader than the National Energy Objectives and thus the (NEO-defined) interests of consumers.

## Characteristics of a market design supporting consumers' interests

Seven characteristics of a long-term energy market design which would support consumers' interests are:

1. **Designed for the system, not the politics:** We do not think any market design features will cause jurisdictions to withdraw from their influence in the market – this is pervasive in terms of state-owned assets in TAS, QLD and (via Snowy Hydro) the Commonwealth, as well as Commonwealth, NSW, VIC and QLD direct policies. Market design should focus on evidence-based reforms to support appropriate affordability, reliability and choice rather than shadowboxing with current and future energy ministers about the existence, extent or nature of their interventions.
2. **Encourages a national market (including for interventions):** Accepting the durability of jurisdictional interventions, market design should seek to accommodate these where possible, including by establishing best-practices, supporting evidence-based decisions, and seeking to encourage multi-jurisdictional approaches and consistency in policy design and application.
3. **Competition and efficiency:** The existence of competitive energy markets where appropriate, based on participants (including consumers themselves) being free and encouraged to make efficient investment decisions, supported by efficient operating costs.
4. **Transparency:** Timely and adequate information to facilitate competition and efficiency. This includes the information held by participants and other stakeholders, especially including jurisdictions (to the extent they choose to participate or influence the market).
5. **Sufficient Markets:** The existence of markets to recognise valuable services provided to the system, including new markets enabled by new technologies, and 'missing markets' to reflect services previously provided as a co-benefit of a legacy centralised synchronous generation system.
6. **Minimal barriers to entry or exit:** Neither retarding the entry of new investment or technologies, nor preventing the manageable exit of superseded assets, as the system evolves through the transition.
7. **Consistency with System Planning:** The NEM now includes a significant top-down aspect via the Integrated System Plan ('ISP'). Market design should directly support this, especially in the area of transmission and access for new and existing assets, in Renewable Energy Zones ('REZs') and more broadly. <u>We note the ISP assumes Locational Marginal Pricing applies to investment and operational behaviours in its modelling of the least system costs</u>.

We have assessed the various options against these characteristics as we formed our views. In many cases, P2025 options are consistent with these characteristics – but not all.

## Summary of our views on the P2025 proposals

Overall, we are supportive of the majority of the P2025 market design proposals, at least in their best form.

There are a significant minority of proposals which we do not support, particularly in relation to additional markets to specifically support reliability in either the investment or operational timeframe.

In the case of transmission and access reform, we are concerned the P2025 options are not ambitious enough in pursuing Locational Marginal Pricing plus Financial Transmission Rights ('LMP+FTR') in a more immediate manner – although we recognise that the most favourable proposals around REZ-specific market design in this area do take a substantial step in the right direction.

In the body of this submission, we detail our views against each proposed P2025 option.

Prior to that, we highlight some of the general concerns we have applicable to all proposals.

## Quality of the evidence base should be directly related to support

In a number of areas, the evidence base to support the need for or desirability of a P2025 option is very well-developed. Examples include the approach to **fast frequency control**, and the extensive modelling and engagement provided in relation to **LMP+FTR**. Generally, we are supportive of such proposals, partly because they have survived a relatively high degree of scrutiny to date.

There are other areas where the evidence base is emerging – such as the AEMC's modelling commissioned in relation to **operating reserves**. In this case, we think it is clear that this modelling does NOT demonstrate that the proposal is necessary or desirable. Consequently, we are not supportive of this being included in the final P2025 reforms.

Finally, there are areas where the evidence base appears to be largely hypothetical – including the proposals for a **modified RRO** or a **decentralised capacity market** (also known as the '**physical RRO**'). We do not support these, both because we do not accept the hypothetical arguments that they are necessary, nor have we seen any evidence to help change our views.

Any P2025 options which fall into the 'evidence pending' category should – in our view – only attract qualified support or opposition whether from stakeholders in this consultation process, or ultimately, the jurisdictions who will receive the ESB's recommended pathway for their consideration.

These are major proposed changes and should – at most – be further investigated via careful modelling in the context of the status quo and any other certain or likely P2025 reforms.

## The Status Quo is not the past or the present NEM

P2025 considers many potential changes to market design, with obvious overlaps and interdependencies. Not only that, they are being assessed while we are still in the early stages of implementing or assessing several other recent prior reforms.

We think there is a risk some P2025 options are being considered based on a recent history of the NEM that is no longer relevant, particularly in some qualitative arguments being advanced. When it comes to modelling and evidence, proposed reforms should be rigorously assessed in light of recent changes:

- **Five-Minute Settlement ('5MS')**
- **Wholesale Demand Response (WDR')**
- **42-month Notice of Closure** (or greater)
- The **existing Retailer Reliability Obligation ('RRO')** design

It is also critical that assessment is realistic about the genuine outlook for investment in the NEM, and the impacts this will have to support reliability and system security. These include:

- **Recent commitments to 'traditional' firming capacity** – including EnergyAustralia's Tallawarra B plant and Snowy Hydro's Kurri Kurri plant – totalling over 1GW of new dispatchable gas capacity.
- **Substantial announcements in relation to new battery storage project**s – from both existing and new market participants. These include locations on brownfield sites with strong transmission access and increasingly contemplate two to four hour of storage duration. This is consistent with

the CSIRO GenCost forecasts[2] (informing the ISP) that battery storage will relatively quickly emerge as a commercial investment in the evolving NEM.

- **Progress with ISP projects** – including Project EnergyConnect, and with continued progress on other proposals including Marinus Link. If, as the ESB has stated, the NEM is evolving faster than the 2020 ISP's 'Step Change' scenario, then it is very likely that projects like Marinus Link will be further supported and likely accelerated in the 2022 ISP. This will substantially improve the interconnectedness of the NEM and allow access to substantial new pumped hydro and wind capacity to improve the outlook for both low-cost energy supply and the necessary firming to support it.
- **Government policy**: As a good example of 'modern' jurisdictional intervention, the NSW Electricity Infrastructure Roadmap policy is explicit in its support for marginal firming capacity to be underwritten, in parallel with the large expansion of REZs in that state. This is a legislated policy with multi-party support – it is clearly now a 'fact on the ground'.

## The counterfactual must sensibly consider the P2025 package

If the status quo is represented as above, this is a good basis to start assessing P2025 options – but it is not sufficient.

P2025 is likely to propose a package of reforms. Some of these are clearly more likely than others to survive to implementation and are also therefore likely to be in place prior to other, less-mature proposals.

For example, it seems very likely to us that both **very fast frequency response** and the **structured procurement and scheduling of system strength** will feature in the final P2025 reforms, give they have been matured through the AEMC's rule change proves, supported by analysis, and generally seem to have attracted stakeholder support.

Given that is the case, any modelling and assessment of less-mature P2025 options (such as **operating reserves**, **modification to the RRO** or a **decentralised capacity market**) should acknowledge this – there is a queue, and they are NOT at the front of it.

To the extent the more mature, more certain and likely precedent reforms have impacts on (in these examples) reliability, that should be accounted for as part of the counterfactual.

## Marginal gains versus marginal costs – a consumer trade-off

Under this approach, we expect it should weaken the evidence base to support further layers of reform on top, such that proposed reforms such as **operating reserves**, **modification to the RRO** or a **decentralised capacity market** would have a relatively high bar to surmount.

Modelling should be undertaken to answer the question in relation these proposed reforms:

> *"Given the status quo in the NEM, including current and pending reforms, the current status of investments as well as any impacts of other highly-likely P2025 reforms:*
> 1. *What is the marginal improvement in reliability?*
> 2. *What is the additional cost likely to be experienced by consumers?*
> 3. *Do consumers support this trade-off?"*

While we suspect it will be very difficult to demonstrate evidence-based support for these reforms on this basis, we have already acknowledged these are relatively immature proposals. We would change our view if the evidence suggested we should.

As a result, we strongly believe that P2025 reforms in this category should either be rejected, or (at most) sent back for extensive modelling and further consultation before market bodies lend them firm support.

[2] The final CSIRO GenCost 2021 report was released on 8 June 2021, and the most notable change from only a year ago is its recognition of the rapid reduction in battery costs, with very substantial further reduction expected, which is a direct input assumption into the upcoming 2022 ISP. See: https://www.csiro.au/en/news/News-releases/2021/CSIRO-report-confirms-renewables-still-cheapest-new-build-power-in-Australia

## LMP+FTR is the counterexample – a missed opportunity?

It is ironic that LMP+FTR has not been strongly supported by stakeholders in consultations to date, even though it is a relatively mature reform proposal which does have evidence-based support.

We agree with the AEMC and ESB analysis which demonstrates very material affordability benefits to consumers through both more efficient investment, and more efficient dispatch of current and new generation capacity in regard to transmission constraints.

We acknowledge the ESB has been very clear in its Options Paper that it believes LMP+FTR is an essential and quite urgent reform despite the concerns raised – but it is a missed opportunity to kick the can down the road rather than using the P2025 process to advocate strongly for faster reform.

We think the ESB, market bodies and stakeholders should be more strongly focussed on re-prosecuting the case for immediate commitment to implementing LMP+FTR system-wide on a known date (and not just in the REZ context) including enough grandfathering / compensation to overcome resistance from incumbents, and therefore ensure delivery of the very material efficiency benefits to the system and thus, consumers.

**A critical aspect of this is the necessity of aligning reality with the assumptions in the ISP, upon which so much else relies.**

**The ISP's least-cost modelling assumes LMP in the investment and operational timescales. If we continue to knowingly model a system and drive 'central-planning' style investment based on a different and less-efficient market design to the one which exists, stakeholders would be right to lose confidence in and support for the ISP process and the additional transmission costs it asks consumers to bear.**

# 1. Resource Adequacy Mechanisms and Aging Thermal Generation

We support most of the proposed reform options in this workstream, as set out later – but we focus on our key area of concern in relation to the proposals to modify the RRO or replace it with a decentralised capacity market, creating an additional revenue stream for generators at the expense of consumers.

## 1.1 Defining "orderly exit" would help ensure "timely entry"

The thematic behind this workstream is well-stated in the P2025 Options Paper:

> *"The ESB's objective is to encourage the timely entry of required generation and storage, and the orderly exit of aging thermal generation."*

### 1.1.1 "Orderly" is not the same as "end of technical life"

"Orderly" retirement of aging thermal generation is a sensible objective, and it implies the need for careful trade-offs between affordability, reliability, system security and carbon emissions[3] over the retirement period. However, stakeholders should take care to ensure "orderly" is NOT defined rigidly as preserving coal (or other inflexible / high-cost capacity) in the system, despite its economic impairment, to some arbitrary technical end-of-life date.

Some of the proposed reforms in P2025 run the risk of encouraging this, and that would be to the detriment of consumers since ESB, AEMO and other stakeholders have been very clear: **replacement firmed renewable capacity is cheaper**.

**"Orderly" should be clearly defined to mean an exit which is undertaken with appropriate notice, allowing time for in-market (or if necessary, out-of-market) responses to accommodate the change without unacceptable impacts on reliability or security.**

We exclude price here, since a price signal is necessary to relatively rapidly attract new investment – exactly as we have seen in the period since 2017. The presumption should be that the market design (in its current form or with any supportable P2025 improvements) ensures appropriate investment in efficient new generation capacity, within a competitive market structure, which will lead to appropriate affordability in the long run as the system transitions.

### 1.1.2 "Timely" is not the same as "before needed, just in case"

"Timely" entry should be judged in light of the project pipeline (captured very thoroughly in AEMO's Generation Information page), and the related outlook provided by the Medium-Term Projected Assessment of System Adequacy ('MTPASA'), the Electricity Statement of Opportunities ('ESOO'), and the forecast reliability outlook against the Reliability Standard.

These processes are all transparent, consultative and evidence based. They recognise the uncertainty and lead-time for both committing and delivering new capacity. As far as we can see, there is no smoking gun here. Deteriorating reliability outlooks over the 10-year ESOO period have frequently been a feature, but only become a concern if the project pipeline moving forward to address it appears inadequate – and that is not what we are seeing, as we discuss next.

**Delaying, or threatening to delay, coal exits will be the overwhelming factor dissuading timely entry of new capacity. Unclear and poorly-structured government intervention (such as the Commonwealth's Underwriting New Generation Investment – or 'UNGI' policy) runs a close second.**

[3] We know this is not part of the National Energy Objectives and so is strictly speaking, out-of-scope for P2025. However, stakeholders recognise (and most support) that this is a highly relevant shadow objective from the perspective of consumers, most jurisdictions, and most market participants and other stakeholders.

## 1.2 Weak evidence for a resource adequacy problem

In our opinion, there is relatively little current evidence that reforms to support resource adequacy are needed at all, given the lack of any forecast breach of the Reliability Standard and the relatively benign outlook from the latest ESOO, when considered in light of recent commitment to both firm capacity and transmission, as well as the burgeoning level of proposals for battery storage of medium (one to four hour) duration.

### *10 reasons why not*

The P2025 Options Papers and preceding ESB materials have provided extensive partly-qualitative, partly-quantitative arguments to support the need for relatively interventionist resource adequacy reforms (while noting that more robust modelling and analysis is outstanding).

In the same spirit, we offer the same in rebuttal – with each of the following themes briefly discussed:

1. In fact, dispatchable capacity investment plans are booming.
2. Coal withdrawals are being covered by the pipeline in a reasonable outlook period.
3. Early coal closures have 'automatic stabiliser' characteristics and backstops.
4. Reforms have been and will be supportive of resource adequacy.
5. Unsubsidised battery projects are emerging quickly, and have key advantages.
6. Jurisdictions bear some responsibility for directly creating uncertainty…
7. … but they are probably a positive impact on resource adequacy
8. Renewables continue to be deployed, but in a more structured manner.
9. Demand response is a potentially large new source of reliability.
10. The government IS actually here to help!

### 1.2.1 In fact, dispatchable capacity investment plans are booming

AEMO's NEM Generation Information spreadsheet is the most reliable and transparent source regarding NEM current and future capacity, and it includes an archive to allow us to observe the evolving behaviour and intentions of generation market participants over time.

We have compared the current (May 2021) version with the situation a year ago (April 2020).[4]

In the table below, we have simplified the breakdown to:

1. **VRE:** the variable renewable energy (wind and large-scale solar PV) capacity; and
2. **non-VRE:** dispatchable coal, gas, hydro and battery capacity collectively used to provide bulk energy or (increasingly) firming of VRE.

We have also simplified the status to either **existing** capacity, or **projects** – which are any potential incoming capacity (including AEMO's categories of Upgrade/Expansion, Committed and Proposed), which represents the 'pipeline' of new capacity for the NEM[5].

[4] Retrieved from: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

[5] Small non-scheduled generation (and small-scale rooftop PV) is excluded, so this is a focus on the large-scale capacity situation relevant to the 'big picture' of resource adequacy as renewables grow and coal retires.

| Apr 20, GW | VRE | non-VRE | Total |
|---|---|---|---|
| **Existing** | 9.3 | 42.4 | 51.6 |
| **Projects** | 45.2 | 17.8 | 63.0 |

| May 21, GW | VRE | non-VRE | Total |
|---|---|---|---|
| **Existing** | 12.4 | 42.5 | 55.0 |
| **Projects** | 57.5 | 38.0 | 95.5 |

| growth, GW | VRE | non-VRE | Total |
|---|---|---|---|
| **Existing** | 3.2 | 0.1 | 3.3 |
| **Projects** | 12.3 | 20.3 | 32.6 |

Over the past year:

- 3.2GW of new variable renewable capacity has been added to the NEM, providing substantial quantities of additional bulk energy in the near term.
- The pipeline of VRE has grown very materially – up 12.3GW (or 27%) to over 57GW – confirming the ISP's message that a lot more bulk energy is available to the NEM in future, and that market participants continue to see the investment opportunity as coal retires.
- Most importantly in terms of reliability and resource adequacy, **the pipeline of dispatchable capacity** – which was already substantial at almost 18GW a year ago – **has more than doubled over the past year**, with an additional 20GW of capacity identified as participants mature their opportunities ahead of the retirement of coal and the need to firm renewables.

The growth in the dispatchable capacity pipeline has been tilted heavily toward batteries (with nearly 13GW of project capacity added in the past year, tripling the pipeline), but a diversity of technologies is responding to the opportunity, notably fast-responding gas and hydro, as shown below:

| **non-VRE Projects** | Coal | CCGT | OCGT | Gas other | Water | Battery | **Total** |
|---|---|---|---|---|---|---|---|
| Apr 20 | 0.3 | 0.8 | 1.9 | 0.8 | 7.9 | 6.2 | **17.8** |
| May 21 | 1.2 | 0.9 | 5.7 | 1.5 | 9.7 | 19.0 | **37.9** |
| **growth, GW** | **0.9** | **0.1** | **3.8** | **0.7** | **1.8** | **12.8** | **20.2** |

This is not reflective of any looming crisis of resource adequacy in our view – more the reverse.

**Note that this data precedes the 1GW Borumba pumped hydro project announced by the QLD government on 8th June 2021.**

### 1.2.2 Coal withdrawals are being covered by the pipeline in a reasonable outlook period

Coal withdrawals are currently notified as 5.5GW before 2030, with the remaining 17.7GW following in the longer-term. It isn't realistic to expect today's non-VRE project capacity to fully reflect opportunities more than a decade away – this is one reason why the ESOO is a 10-year outlook.

While the relationship between exiting coal capacity and incoming VRE plus non-VRE firming capacity is clearly not 1-to-1:

- 37.9GW of non-VRE project capacity appears to be more than adequate to cover the 5.5GW of short to medium-term withdrawals; and
- The recent, very strong growth in the pipeline is not indicative of any investment strike or lack of incentive to project developers to meet this opportunity.

### 1.2.3 Early coal closures have 'automatic stabiliser' characteristics and backstops

There are three clear reasons why we do not think stakeholders should give credence to any scenarios of completely uncoordinated and rapid collapse in coal capacity on economic grounds (and therefore should not support unnecessary P2025 reforms proposed in anticipation of this).

1. **Clear long- and medium-term signals:** Provided the situation is transparent regarding closure dates[6], we have noted the evidence that the anticipated price signal for a tighter supply / demand balance will attract both VRE and non-VRE replacement capacity. As the situation evolves (such as notice of an earlier closure date) so too will the project pipeline respond to meet the more imminent opportunity.
2. **Each coal withdrawal delays the next:** Every announced tranche of withdrawn coal capacity provides prospective (albeit temporary) relief to all remaining coal capacity, via higher expected utilisation rates and/or higher received prices in a tighter market[7]. This will tend to smooth and delay economically driven closures as remaining capacity enjoys the brief respite and defers any private early closure plans by months or years when a peer blinks first and announces its earlier exit.
3. **Government will step in, in extremis:** The key risk to the above is a non-compliant early exit, ahead of the Notice of Closure requirement, which cannot be replaced in a timely manner by new capacity and/or which is adjudged to lead to politically-unacceptable levels of pricing for a period. This is a valid risk to consider, but by no means a certainty, nor a situation the market design should seek to prevent at the expense of the wider interests of consumer and other participants. As this P2025 workstream makes clear, jurisdictions will step in if they feel they must, and bridge the capacity gap until they feel the market can respond[8].

### 1.2.4 Reforms have been and will be supportive of resource adequacy

As well as the basic expectation of an incentive price signal, the evidence of participants adding project capacity likely also reflects several recent or pending reforms which will have materially positive impacts on resource adequacy, including:

- **Five-Minute Settlement** – Encouraging fast-responding capacity investment including batteries, which are well-suited to a high-VRE system and its inherent short-term uncertainty, and rapid to deploy as projects.
- **Wholesale Demand Response** – Incentivising dispatchable "negawatts" to bid into dispatch, improving the ability of demand to meet fluctuating VRE-driven supply and adding new firming capacity.
- **Retailer Reliability Obligation** – already designed as a 'belt and braces' policy to support reliability as a counterpoint to the discarded emissions-reduction element of the National Energy Guarantee, this creates additional incentives for resource adequacy which is yet to be tested.
- **Notice of Closure** – while we acknowledge the concerns that this is not and never will be 'bulletproof', it does carry important weigh as an obligation on any participant who may wish to continue operating in the NEM beyond the withdrawal of a particular asset. It is clearly a positive development post-Hazelwood and the resulting recommendation from the Finkel Review[9].

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[6] As is increasingly the case given the enhancements to information including Notice of Closure, the AEMO-published expected closure dates for all coal capacity except Callide C in the Generation Information spreadsheet, and P2025 proposals to further this transparency.

[7] Illustrated clearly by the withdrawal of Hazelwood in 2017, which presaged a couple of 'golden years' for remaining coal capacity as they collectively increased utilisation into higher NEM wholesale prices. This is an extreme example given the short notice.

[8] It seems we have just witnessed this in action, as the VIC government turns its attention briefly from supporting renewable capacity entry, to delaying the related Yallourn capacity withdrawal.

[9] We think this improvement is apparent from the subsequent behaviour observed by AGL (with Liddell), EnergyAustralia (with Yallourn) and the general transparency around intended closure dates (including caveats about economic pressures) from almost all thermal capacity owners.

All of this has occurred within a framework that accepts the Notice of Closure framework as a genuine obligation. It has had a genuine impact via moral suasion if not a credible threat of enforcement. It seems likely to us that had the obligation been in force before the event, Engie (a major multinational with a reputation to preserve, and ongoing interests in the NEM) would have been unlikely to announce the Hazelwood closure with such inadequate notice.

The key enforceability problem is unresolved and will probably remain so, because it collides with the reality that jurisdictions cannot really force someone to lose money if they can cut their losses and retreat. But perhaps that is OK. The basic objective of providing a firmer public signal for replacement within the investment timeframe is still worthwhile as an improvement over the Hazelwood scenario.

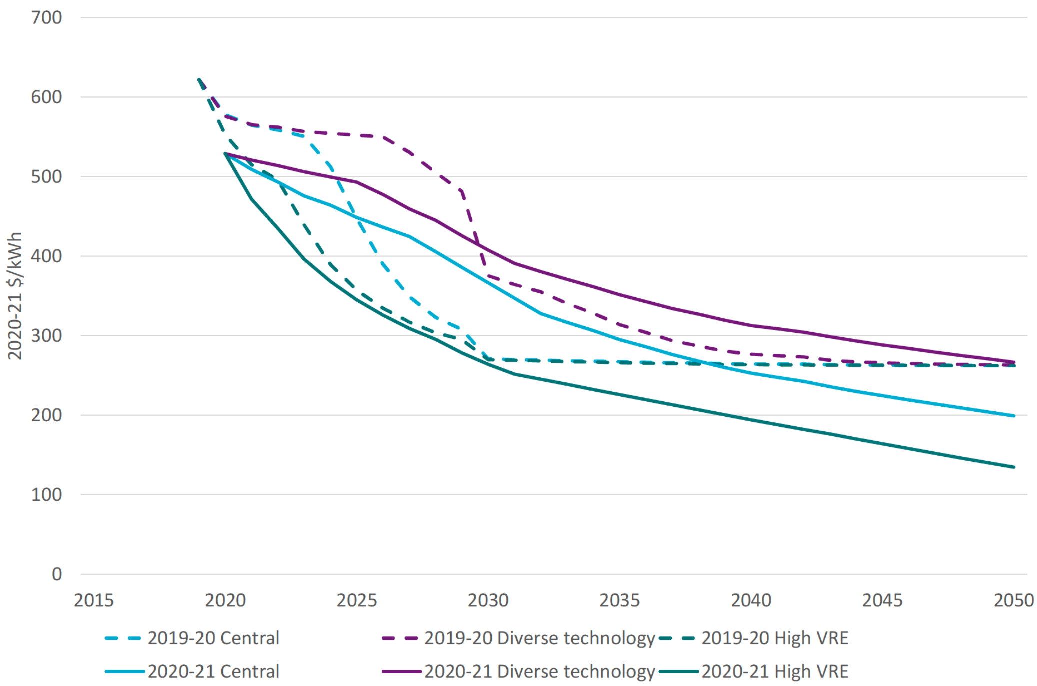
### 1.2.5 Unsubsidised battery projects are emerging quickly, and have key advantages

Initial large-scale battery investments were economically fragile at best and required substantial subsidy – but over the past year we observe many emerging unsubsidised private-sector proposals for large-scale firming and storage from batteries, to complement the least-cost MWh from renewables.

This investor behaviour is consistent with the technology cost and uptake forecasts used by AEMO's ISP, from CSIRO's GenCost report[10] – rapidly falling battery costs allow these assets to emerge as strong competitors to gas peaking, pumped hydro and demand response.

Noting the ESB's advice we appear to be following the 'High VRE' scenario, the figure below[11] shows:

- Battery costs are expected to fall rapidly; and
- Expectations about this from only 12 months ago are looking too conservative.




Other than the momentum from cost reductions, there are three other factors which support battery investments in the NEM:

1. **Speed to market:** Battery capacity can be deployed very rapidly when necessary – they are able to nimbly respond to market signals in the investment timeframe, compared with other firmed capacity such as pumped hydro or gas-fired capacity.
2. **Expansion options for duration:** Initial battery capacity can be easily enhanced with greater duration of storage added behind that connection, as costs fall and/or the market need grows, as we have just seen at the Hornsdale Power Reserve.
3. **Complementary to renewable investments:** In many cases, incremental battery investments will be easily accommodated within existing or new renewable project sites.

**We expect that any apparent hesitancy shown by private sector participants to invest in gas peaking is almost entirely explained by the rapid emergence of the battery investment as an economic alternative.**

Rather than a withdrawal of investment proposals for firm capacity, we see a sensible substitution from gas to battery capacity occurring in the pipeline.

[10] See footnote 2 and https://www.csiro.au/en/news/News-releases/2021/CSIRO-report-confirms-renewables-still-cheapest-new-build-power-in-Australia

[11] Page 47, GenCost 2020-21 as above

### 1.2.6 Jurisdictions bear some responsibility for directly creating uncertainty…

The technology shift in investment plans described above is occurring while the crowding-out risk from Snowy 2.0 and the Commonwealth's opaque UNGI programme has persisted – and has been exacerbated by the very significant potential underwriting on offer from the NSW policy… in future, not today!

### 1.2.7 … but they are probably a positive impact on resource adequacy

However, whatever we may think about it generally, this jurisdictional crowding-out is not an evident 'resource adequacy' problem.

While it persists, the risk is that jurisdictional investment is excessive relative to reliability requirements. The Commonwealth has been explicit that it expects Snowy's Kurri Kurri gas peaker to reduce prices, not (just) meet a reliability need (even though it is expected to operate within a highly concentrated portfolio of Snowy's peaking assets, in terms of the competitive structure of the market).

While this may not make much sense[12], the direction of government direct intervention is clear – excess capacity, lower prices.

### 1.2.8 Renewables continue to be deployed, but in a more structured manner

The VRE pipeline is already very large and growing. We see the ongoing addition of renewables occurring in a more structured manner, coalescing around the ISP's REZ concept, which is being enthusiastically accelerated by state governments.

Increasingly, jurisdictional policy in its better forms is taking the need for resource adequacy directly into account, as is evident in the design of the NSW policy with parallel support for firming capacity.

### 1.2.9 Demand response is a potentially large new source of reliability

The enhanced facilitation of wholesale demand response opens up a new class of (by definition) flexible capacity to the system. This is a large latent source of virtual generation which already exists.

As this is demonstrated initially at the large wholesale level, we have every reason to expect that it will pave the way for the aggregation of many sources of smaller demand flexibility, whether specifically focused on assets such as pool pumps, hot water storage, air conditioners, EVs, or more generic loads.

### 1.2.10 The government IS actually here to help!

Finally, the ESB has made much of the fact that the NEM is moving down a transition path even more aggressive than the 2020 ISP's 'Step Change' scenario.

Given that, it seems likely (and perhaps appropriate) that Snowy 2.0 will be followed by Marinus Link / Battery of the Nation, both of which will be optimised by the evolving ISP, to **add longer-duration, publicly-owned firming capacity to a more strongly interconnected system.**[13]

Development of smaller-scale pumped hydro by the private sector is clearly very challenging[14] - and certainly not helped by jurisdictional crowding-out (such as the enthusiasm to build these state-owned competing projects).

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[12] A 660MW OCGT plant costing $610m, operating at 2% utilisation as reported (e.g. https://www.afr.com/companies/energy/snowy-expects-2pc-usage-of-610m-hunter-gas-plant-20210513-p57rhb) will produce 116 GWh annually, about 0.06% of NEM demand. If operated commercially for a 10% return on capital, the plant would require $528/MWh in annual margin over operating and maintenance costs. Ignoring non-fuel costs, with a likely efficiency of around 11GJ/MWh and gas prices of perhaps $10/GJ, the plant is only likely to bid for dispatch to support average revenues of well over $600/MWh. It seems to us this not particularly likely to be a plant which drives DOWN electricity prices, especially if held within Snowy's portfolio of similar assets.

[13] QLD is joining the party – with support for the very large (1GW) Borumba pumped hydro project announced on 8 June 2021: https://statements.qld.gov.au/statements/92296

[14] Highlighted by the apparent failure or indefinite deferral of projects advanced by Origin Energy (Shoalhaven expansion), EnergyAustralia (Cultana), AGL (Kanmantoo), and the extensive support required to get Genex Energy's Kidston project over the line – tapping all of ARENA, CEFC and NAIF as reported by the AFR: https://www.afr.com/companies/energy/taxpayers-prop-up-genex-power-s-pumped-hydro-project-20210604-p57y3c

However, the fact is, certain jurisdictions ARE the owners of the largest-scale pumped hydro opportunities in the NEM, and they possess the capability and apparent appetite to press on despite the market uncertainty which might cause private investors to pause and reflect a little bit longer.

Given this, perhaps the Commonwealth, TAS and Queensland government should continue down that path with conviction, given the ISP's identified need for such "deep storage".

## 1.3 Pointless to pretend there will ever be certainty

In the past, the NEM's investment signals have NEVER really extended beyond the three years of the ASX Energy listed derivative instruments, or equivalent bilateral contracts (with the exception of some longer-term contracts to control dispatch for some gas-fired capacity, such as AGL's 10-year deal with ERM Power's Oakey).

Those signals, more recently supplemented by the growth of long-term PPAs, have served the NEM relatively well to date. Investment decisions have never been risk-free or even close to it. Nor have they typically been taken pre-emptively, or on any arbitrary schedule jurisdictions or regulators might deem convenient.

Recent enhancements (including notice of closure, RRO, WDR and 5MS) suggest that in light of the above, there is little credible risk of insufficient firmed energy capacity in future to justify costly reforms funded by consumers.

## 1.4 The market still responds, even under jurisdictional interventions

This is despite recognising (as the ESB has) the distortion of these jurisdictional schemes.

At their worst, these interventions do increase the challenges: as possibly the most misguided example the policy driving excessive variable renewables into the VIC region will depress average prices and therefore dissuade investment in intermediate gas plant, and maybe also drive out some existing thermal capacity.[15]

However, the supply volatility from force-fed VRE capacity will increase the prospective economic opportunity available to fast-responding plant such as batteries and gas peakers to respond to short-term price spikes, as well as deeper storage to respond to longer-term reliability threats such as wind droughts.

In this paradigm, government distortion does not destroy the investment signal for new capacity, it just redirects it to where the residual need is after governments have done their "worst". That modified signal is consistent with the fait accompli associated with government intervention but can still be effective (if not efficient in terms of overall system costs).

## 1.5 Consumers should be wary of gold-plated reliability here

Given there appears to be some linkage between the Interim Reliability Standard[16] and the P2025 reforms, we wonder whether a shadow objective of this workstream is to 'bake in' the more stringent 'Interim' level of expected unserved energy[17] ('USE').

If so, this should be of great concern to consumers, unless they are to be properly consulted about whether they value the **incremental 7 minutes of annual reliability** more highly than the cost of such a change.

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[15] Although to be fair, the continued unnecessary subsidy of rooftop PV via the Small-scale Renewable Energy Scheme – despite the ACCC's clearly-stated and well-evidenced recommendation #24 in their 2018 Inquiry – might be even worse. The ACCC was clear: "The small-scale renewable energy scheme should be wound down and abolished by 2021".
https://www.accc.gov.au/system/files/Retail%20Electricity%20Pricing%20Inquiry—Final%20Report%20June%202018_Exec%20summary.pdf

[16] Set at 0.0006% expected USE in any region in a year vs. the formal 0.0020% USE Reliability Standard set by the Reliability Panel process.

[17] Unserved energy is defined as demand which is unable to be met due to a lack of capacity in the **generation and transmission** system. It excludes the far-more-frequent distribution-level outages and is therefore a relatively minor component of the "blackouts" experienced by consumers.

96% of consumers' experience of outages are at the distribution level and unaffected by these proposals[18] – so a marginal improvement to the remaining 4% is not likely to be viewed as a material step forward by consumers.

## 1.6 NEM-wide information provision and financial principles

We agree with the ESB's objective of standardising the nature of jurisdictional interventions (including principles such as maintaining incentives for generation capacity to respond to the real-time price signals required for efficient dispatch, and ensuring jurisdictional contracting does least harm to contract markets) and aligning the targeting of such interventions with a NEM-wide assessment of need.

These may prove to be important reforms to benefit consumers via better-designed and better-coordinated intervention by jurisdictions. This is despite the overall concern with such interventions – arguably the ESB is exposing stakeholders to moral hazard by condoning or even facilitating this behaviour. But as we have said, the genie is out of the bottle.

We are strongly in favour of the ESB's attempt to improve and generalise jurisdictional investment or underwriting schemes, based on the NSW model. This is not because we think the NSW model is particularly excellent, or that government intervention is necessary in the first place. Rather, because the advantages of consistency in any such policy are likely to be very large, in terms of avoiding policy-related unintended consequences between states and across time, associated with uncertainty and inconsistency.

Investors tend to say, '*we don't care what the rules are, as long as we know what the rules are.*'

### 1.6.1 Enhancement to information provision on resources to be underwritten

The ESB proposes further information be targeted at jurisdictions, to guide their interventions (in addition to, but consistent with, existing information such as the ISP, ESOO and MTPASA

> **SUPPORTED:** While we are unclear why those sources alone may be insufficient, we see little harm in a more bespoke advice to jurisdictions to guide them away from harm or unintended consequences in their energy market interventions.

The ESB also seeks to extract clearer and more consistent information from jurisdictions on their support, to improve transparency for all participants.

> **SUPPORTED:** This is a sensible element of *quid pro quo* in light of the above. We agree that the market would be better served by transparency from jurisdictions on the nature of the assets they are subsidising, contracting or underwriting.

### 1.6.2 Agreed national principles for contract design

The ESB seeks to 'dovetail' jurisdictional support arrangements with the operation of the spot and contract markets, as well as the RRO (which relies on generation assets / portfolios / owners being free to sell qualifying contracts).

This is to ensure efficient dispatch based on operational conditions, and to preserve liquidity in contract markets where supported assets would be encouraged to contract commercially with other participants 'over the top of' a jurisdictional underwriting option (as opposed to a fixed-price PPA or equivalent).

> **SUPPORTED:** These are very sensible principles which should be strongly supported. They are based on well-considered aspects of the NSW Electricity Infrastructure Roadmap and the ACCC's Recommendation 4 from their 2018 Inquiry.

## 1.7 Enhanced exit mechanisms

We are generally very cautious about these euphemistically named reforms. It seems to us that to the extent they go beyond improved information transparency, they would create barriers to exit for relatively high-cost and/or inflexible thermal capacity, which is then **a barrier to entry for the lower-cost, more**

[18] Well-explained and sourced at: https://theconversation.com/sure-no-one-likes-a-blackout-but-keeping-the-lights-on-is-about-to-get-expensive-145168

**flexible plant which is needed through the transition**, and which can deliver lower system costs for consumers.

There are already several factors which mitigate against very sudden and 'disorderly' exits – including the 42-month Notice of Closure which has been more than met by both AGL and EnergyAustralia for Liddell and Yallourn.

The RRO also formalises the technology-neutral demand for the firm energy thermal assets can provide. But if that contract demand is more cheaply met by other means, then this would be a very clear market signal that the current capacity is not the optimal means to deliver both acceptable reliability and lowest energy costs.[19]

Given this, we do not see any evidence that additional measures are justified to retard coal exits, especially as these are over and above the ESB's recommendation for jurisdictional scenario planning to be prepared for the unexpected exit risk (despite the above).

In principle, it seems better to plan for the unexpected and unlikely, and to be ready to take action if needed, rather than to slow a desirable and manageable transition of the system which may well involve further early coal closures, but without any catastrophe.

Fortunately, most of the measures proposed by the ESB are quite light-touch with a focus on better information for decision making - and these are therefore supportable in our view.

The ESB are advancing three options described below, which we expect are not mutually exclusive (i.e. none, some or all may apply).

### 1.7.1 Increased information around mothballing and seasonal shutdowns

The basic information is already provided by generators into the MTPASA and ESOO processes, but the ESB believes a greater level of detail is desirable.

**SUPPORTED:** There is no doubt that we will see coal capacity responding to challenging conditions via mothballing, seasonal shutdowns or other changes to lesser utilisation in order to improve economics[20].

As a result, the underlying situation is becoming more complex. That is good reason to agree that a greater level of understanding of the status of capacity (such as its required time to return to service if needed) is desirable to improve transparency for both current and potential market participants, as well as regulators, policy-makers and concerned jurisdictions.

We note this may have real impacts on asset owners (in terms of making public what was commercially sensitive information, valuable for trading).

### 1.7.2 Expanding the notice of closure requirements to include mothballing

**SUPPORTED (TO A SENSIBLE POINT):** This is a subtle question in our view. At one extreme, there is a fairly obvious risk of a loophole in the 42-month Notice of Closure requirement, if a very deep mothballing is proposed, which may be indistinguishable from a withdrawal except that:

- other market participants may not be confident the capacity is really gone for good, dulling the investment signal; and
- it may be used as a means to delay appropriate closure activities such as site remediation, or defer the opportunity for valuable characteristics of the site (such as its grid connection) being redeployed to support lower system costs in transition.

From this perspective, we agree that some tightening of the Notice of Closure arrangements is likely to be appropriate, if clearly targeted to this extreme.

At the other extreme, genuinely temporary mothballing is a perfectly valid commercial lever for an asset owner to pull, if it seeks to preserve value during a time of particularly poor operating

[19] And noting that other characteristics relevant to system security are the subject of Workstream 3.
[20] Examples include recent investor communications from both Origin Energy and AGL in relation the outlook for their coal capacity.

conditions. Creating an onerous approval requirement to mothball seems too heavy-handed, in much the same way we believe it was entirely inappropriate for jurisdictions to attempt to 'inpropriate'[21] AGL's Liddell asset when it was announced for closure.

An unintended consequence of this might be asset owners fearing they lack the flexibility to ride out transient market conditions through such genuine, temporary mothballing… **which might prompt them to withdraw the capacity prematurely, exactly the opposite outcome desired by the ESB.**

On balance, a relatively narrow version of this reform is probably a good idea – provided it only seeks to ensure 'mothballed' capacity has a clear ability to return to service in a known and transparent timescale, including some assurance that the necessary maintenance is undertaken by the asset owner to support that return-to-service performance.

### 1.7.3 An integrated process to manage early exit

Generators can seek an exemption to the 42-month Notice of Closure requirements. The ESB seeks to improve the informational basis for decision-making by the regulator and jurisdictions in response, and to provide some high-level principles about how bespoke support arrangements may be designed and put in place to delay early exits if jurisdictions so desire.

**SUPPORTED (IN ITS BEST FORM):** We see little harm in more rapid and complete information-gathering to support assessment of the situation, and a decision (by a jurisdiction) about whether to ride to the rescue, take other mitigating action, or not. The ESB is clear about the moral hazard of such intervention for the energy market, but describes some sensible principles if a jurisdiction nevertheless decides to intervene to delay an early closure.

We note the ESB is remaining studiously neutral and not expressing any clear support for this type of approach. We also appreciate that many of the issues of early closure are not really about reliability or resource adequacy – they are related to employment, social, carbon and political impacts in a complex mix which is clearly the remit of jurisdictions, not regulators under the National Energy Objectives as they stand. These are likely to be highly political and bespoke situations, and that is recognised here.

This approach recognises that jurisdictions are best-placed to weigh up these issues against what might be 'best' for the energy market… and it is the jurisdictions who bear the responsibility for these broad issues, including energy market failure if they get it wrong.

Some additions or improvement to the principles may include:

1. **Funded by budget, not consumers:** Since the decision to support a generation asset owner with an intention to exit early is likely to have significant non-market benefits (i.e. beyond price, reliability, system security), we disagree that recovery of cost from consumers via DUOS should be presumed. If a decision is taken by a jurisdiction to support a generator, the costs of that decision should be accounted for in the jurisdiction's budget and subject to the usual appropriate scrutiny from voters, bureaucrats and other stakeholders who generally act to ensure some sensible restraint in the spending of other peoples' money.
2. **Flexibly designed to accommodate improvements in outlook:** arrangements to support a generator should not be set in stone, if the circumstances change for the better. For example, if an alternative provider of capacity is prepared to commit to invest IF the supported generator were to withdraw 'early' as originally intended, then any jurisdictional support delaying that exit should be able to be withdrawn to facilitate this. Equally if the forecast upon which the support was predicated improves, support should be ended. This is a means to mitigate the risk of erecting impermeable barriers to entry under this type of arrangement.

[21] A new word we have coined – defined as "The risk of jurisdictions forcing private investors to run assets they don't want to."

## 1.8 Modifying the RRO

While grouped together, the two proposals here are extremely different.

- One is a marginal change to the RRO via removal of the T-3 trigger. The RRO is an existing feature of the market design, making use of existing risk-management contracts and working in concert with the well-established spot and contract markets.
- The other is a very radical replacement of the RRO (before it has been given an opportunity to demonstrate its worth or otherwise) with an additional, completely separate revenue stream for generators via a decentralised capacity market.

The current RRO has been triggered by Ministerial fiat in SA for Q1 of 2022, 2023 and 2024, and for Jan-Feb 2024 in NSW under the Interim Reliability Measure. It is notable to us that:

- The RRO has never been triggered under its actual design, based on the actual Reliability Standard.
- The RRO has never been observed in operation, to judge its necessity, effectiveness or (unintended) consequences.

In other words, it is not at all clear that the RRO is required in any form, let alone any modification of its current design.

> **NOT SUPPORTED IN EITHER VERSION AT THIS POINT:** Adequate modelling (as described below) might provide a compelling reason to alter our view, based on revealing the opportunity for material marginal improvements to reliability at a cost acceptable to consumers. But we doubt it, because there has been no good evidence offered that there is a material reliability problem that needs addressing, so the opportunity for delivering benefits to consumers seems very limited.
>
> More importantly perhaps, we doubt the RRO in either its current or any sensible modified form is likely to be effective in preserving inefficient capacity in the system, provided new capacity is free to offer the functionally equivalent RRO contracts / certificates more cheaply.
>
> If the RRO cannot 'save coal', then the objective of dissuading certain jurisdictional stakeholders from continuing to stick their fingers in the dyke will not be met.
>
> In that case, changing the RRO will meet neither the market nor the political objectives the ESB appears to hope it might.
>
> If forced to choose, the incremental change to the RRO associated with a removal of the T-3 trigger would be preferable to any attempt to pursue the decentralised capacity market approach, in our view.
>
> To be clear, we are not suggesting that a capacity market is the wrong design for the NEM – just that we have not seen any credible case that it is the right design – in particular this specific version as opposed to others which might present less risk to consumers of shouldering additional costs.
>
> As a more pragmatic concern, such a material change seems likely to require extensive lead time and detailed further analysis with a relatively high risk of failure along the way. This isn't consistent with facilitating investment now and in the short-term.

### 1.8.1 Financial RRO without the current T-3 trigger

This is the current RRO design, with a relatively small change to remove the initial triggering at T-3 years (ahead of the trigger being confirmed at T-1).

The ESB suggests this may strengthen / lengthen investment signals by creating uncertainty about whether the RRO will be triggered with relatively short notice at T-1. The ESB envisages this would drive retailers / large consumers to enter into qualifying RRO contracts just in case.

This is presented as offering the benefit of some simplicity compared with the current RRO (and certainty compared with the decentralised capacity market alternative).

#### *1.8.1.1 Hard to see any evidence for this mechanism working*

We struggle to follow the logic here. Retailers and large consumers assess the outlook for reliability and take steps to manage their risk in any case and have been doing so since well before there was any RRO or T-3 trigger. We do not think fear of a sudden and unexpected T-1 trigger is likely to drive particularly different behaviour, in the same way that fear of a T-3 trigger probably hasn't.

The RRO appears to have been designed based on a premise that retailers and customers are systemically "underhedged" – despite the large risk of exposure to spot prices that entails – and that the RRO corrects their foolish behaviour. We have never seen any clear evidence (such as actual levels of unhedged exposure to spot prices at time of poor reliability) to support this hypothesis.

In any case, there seems to be something quite perverse in suggesting the threat of a sudden regulatory lightning strike is a good way to incentivise sensible risk-management behaviour.

The better approach might be to ensure the information about future reliability upon which an RRO trigger is based is clearly available to all and updated regularly, so everyone can see a trigger coming (and one would hope, capacity providers would be more confident to invest pre-emptively to respond to that clearer signal).

We have this in mind when suggesting alignment of the regular MTPASA with the RRO trigger assessment, providing a rolling three-year forecast of reliability and thus, ample warning of a potential threat to medium-term reliability, and a better opportunity to respond judiciously.

#### *1.8.1.2 The (current) financial RRO drives up consumer costs via contract supply / demand*

In common with the RRO as it stands, the risk to consumers of a modified RRO without the T-3 trigger is that it drives risk-management contracting on a regulated basis to higher levels than it would be on an unregulated basis.

The regulatory nudge from the RRO is in addition to the <u>already</u> very severe financial disincentives faced by retailers (or large consumers) if they allow themselves to be left uncontracted when reliability is questionable and therefore, spot prices are likely to be high.

The supply / demand consequence of being pushed to excessive contracting by the RRO is higher demand for contracts, thus higher contract costs, which are passed through to consumers directly as the cost of supply in tariffs.

### 1.8.2 Physical RRO – a decentralised capacity market

Note that there are a substantial number of subsidiary design questions for the Physical RRO model which are identified as options by the ESB, but which we are not assessing in detail at this stage. But we are happy to acknowledge they do a good job in highlighting the complexity of the proposal. The ESB acknowledges this would be a complex and radical change.

The design would be based on certification, with instruments created by dispatchable resources, and bought by liable RRO entities. **This is identified by the ESB as a form of decentralised capacity market.**

The apparent benefit of this design is that it might (!) reduce or remove the "need" for jurisdictions to underwrite dispatchable investment.

Firstly, we very much doubt jurisdictions will be making any meaningful commitment to step back from their new-found interventionist roles – witness the build-out of NSW public service capacity to support their Electricity Infrastructure Roadmap policy. If this idea was ever going to work, it seems clearly too late now.

Secondly, we suspect the cure might be worse than the disease – given other P2025 and external efforts to ensure government underwriting is provided in its least-distortive form.

#### *1.8.2.1 Decentralised capacity market is a new revenue stream, a new cost to consumers*

The decentralised capacity market's new certificates would create a completely new revenue stream for generators, paid for by retailers, and passed through to consumers. This is closely analogous to the cost of

Large-scale Generation Certificates ('LGCs') incurred by retailers and embedded in retail prices as a result of the Large-Scale Renewable Energy Target ('LRET').

#### *1.8.2.2 No offset to energy spot market costs*

In fact, the design of the decentralised capacity market is WORSE than the LRET in terms of cost impacts for consumers.

Since the certificates will be earned based on MW available, not MWh dispatched, their value will be fixed in the view of a generator when bidding into the spot energy market. This is revenue completely divorced from whether they are actually dispatched or not, and (exactly as is the case for fixed costs unrelated to dispatch) they will not be included in bidding strategies based on short-run marginal costs ('SRMC').

Therefore, unlike the LGC case[22], they will have no effect in lowering SRMC for generators, and so there will be no offsetting effect to lower spot energy prices.

#### *1.8.2.3 Pure, permanent regulatory revenue for no clear consumer benefit*

It is important to note that the physical certificates have no intrinsic value. They do not entitle the retailer buyer to any useful service and may not even carry any obligations on the generator sellers, other than being notionally available. The only purpose they would serve is to avoid penalties under an RRO assessment process.

As a result, if the RRO is arguably not necessary to deliver reliability, but in this design is ALWAYS applicable, it is simply creating a new form of 'regulatory revenue' which is more or less unrelated to the value of capacity (to consumers, in terms of reliability).

When assessed as a form of capacity market design this seems highly unusual.

#### *1.8.2.4 Assessment of a capacity market alternative should be thorough and broad*

At this stage, the ESB is not able to clarify whether this proposal would replace the prime energy-only market price signal, or form a modest adjunct to it (which might perhaps imply it is a type of camouflage to ward off jurisdictional interventions, rather than a policy with any real impact on the market).

In our view, at this stage of the game, this is not an acceptable degree of ambiguity. It does not sound like an adequate basis to gather stakeholder support for such a substantial change to market design, especially given the uncertainty to investment it would create in the process.

If the ESB or other stakeholders consider that a capacity market may be a more appropriate market structure, that would be a valid case to make – but we do not think this the current P2025 process and timetable is an appropriate way to move this forward. Instead, there should be a broader consultation on capacity market designs including modelling of alternatives, before settling on one such proposal.

### 1.8.3 Modelling impacts against the status quo and a sensible P2025 counterfactual

We understand the two proposed models for modifying the RRO will be assessed against the status quo of the RRO as currently designed, and in light of other P2025 reforms.

As noted earlier, we expect that other well-supported and well-advanced P2025 reforms with impacts on resource adequacy which are likely to be introduced should be recognised in the counterfactual (in addition, of course, to the impacts of relevant pending reforms, in particular 5MS and WDR).

Earlier in this section we have provided 10 general arguments why do no see a systemic resource adequacy problem demanding a significant change to the existing RRO, supported by some evidence from investors as expressed in the evolution of the AEMO Generation Information spreadsheet.

[22] All else equal, if a renewable generator is receiving (say) $30/MWh in LGC value, but only when dispatched, they will be happy to bid $30/MWh less than their SRMC in order to be dispatched. This tends to suppress bids and thus spot energy prices – although with solar and wind SRMC already at zero the impact may not be of much benefit to consumers.

### 1.8.4 Some improvements to the RRO are warranted

Improved transparency and reduced complexity are worthy opportunities to pursue in relation to the RRO. We offer two suggestions.

#### *1.8.2.1 Rolling MTPASA-based Trigger*

AEMO's existing MTPASA provides a two-year forward outlook of reliability, updated weekly. It is based on detailed three-year availability input from generator participants.

This is already quite close to a RRO Reliability Gap forecast, and we suggest AEMO consider extending it to a period consistent with the next annual Reliability Gap assessment and allowing it to play the role of a continuously updated RRO Trigger forecast.

This would reduce uncertainty by ensuring changes to the reliability outlook (and thus the likelihood of an RRO trigger event looming) are immediately apparent – particularly, new committed capacity becoming relevant to the three-year forward outlook.

#### *1.8.2.2 Assess contract coverage at T, not T-1*

We understand the advance nature of the assessment is meant to encourage earlier contracting and thus a longer-duration signal to capacity from the RRO, but in a practical sense we do not think marginal contracts being held at T-1 can do much to bring on any new capacity at T.

On the contrary, this introduces a great deal of administrative complexity given the changes in load a retailer is inevitably going to experience over a year, through winning and losing customers or other changes in customer behaviour. Risk-management portfolios are continually optimised for the retailer's latest expectation of load, and market conditions, all the way up to T.

Surely what matters is that retailers are adequately contracted when it matters – at T. Providers of capacity, knowing the overall level of demand in the system, will know this contract demand <u>will</u> eventuate, and that knowledge is the signal to invest and provide capacity (and thus RRO qualifying contracts) to meet the demand at T.

From a competitive perspective, the T-1 assessment tends to disadvantage smaller retailers – given they are likely to be facing greater proportional uncertainty in what their load will turn out to be at T. Risk-management contracting is already credit-intensive and administratively complex for small retailers and being forced to hold a full contract position at T-1 is exacerbating this challenge.

# 2. Essential System Services, Scheduling and Ahead Mechanisms

We think the proposals in this area are generally supportable in their best forms, with the exception of a new Operating Reserves ('OR') market.

A number of the proposals for this workstream, in their preferred options, are clearly technology-neutral responses to the challenges of the NEM's transition. They may support both existing and new assets, of many types, for the valuable services they currently provide (or can provide).

The proposed reforms also therefore remain flexible to accommodate the substantial technical innovation underway to solve the challenges of maintaining system security, as well as the obvious evolution in the NEM's capacity from aging thermal generation to firmed renewables backed by storage.

Concerns some stakeholders hold related to either the pace of decarbonisation on one hand, or the loss of 'baseload' coal on the other, are less-relevant here: These reforms tend to smooth and facilitate the economically driven transition of NEM capacity, rather than either accelerate or retard it.

As the system changes, we think it is better for market design to allow for incoming technology in this way, rather than the alternative of erecting barriers to exit for outgoing technology.

The P2025 reforms have provided a good example of this, by NOT recommending a new inertia spot market to preserve existing sources of inertia from thermal plant. In a sense this would have been treating the cause of the problem of deteriorating frequency-control conditions – but in this case we think it is actually better to treat the symptoms, including via the new **fast frequency response** service and **primary frequency control** arrangements.

It is important to note that these reforms look to ensure not just minimum levels of security and system strength, but optimal levels. The benefits from these reforms will therefore be realised via more efficient dispatch, in particular ensuring all relevant assets are included in the optimisation, and that the optimisation is effective over all costs seen by consumers – energy, FCAS and (new) security costs.

In this sense, these reforms promise to work well within the proven market design.

The **Unit Commitment for Security ('UCS')** structured procurement and scheduling concept makes sense, but the details are very important. In this regard, we support the option which extends the scheduling of security units most broadly – by integration with a **System Security Mechanism ('SSM')** which brings in more potential sources of real-time security into the co-optimisation and dispatch process. If implemented well, UCS+SSM has the potential to maintain security in a manner which minimises total costs of energy and security for consumers, with technology neutrality and flexibility inbuilt.

However, the alternative of a contracted UCS-only market has the potential to support current technology to the exclusion of the rest of the evolving system, and without the opportunity to optimise across all assets and avoid unintended consequences of preferentially scheduling and dispatching UCS assets, which may drive out real-time participation from lower-cost energy suppliers who otherwise could contribute to security and/or lower energy costs.

By contrast, we see no evidence to support the need for an **Operating Reserves** market, particularly given existing observable trends in the ramping characteristics of the system, and other P2025 and pre-P2025 reforms which tend to support reliability in the operational timescale (for all but the most rare and severe circumstances, where other measures such as RERT are more appropriate mechanisms).

The RRO, 5MS, reducing battery costs (and associated emergence of large-scale battery investments), and the side-effects of reforms such as P2025 system security all have the ability to support fast-ramping capacity entry, and thus improved ramping performance and the long-term provision and short-term availability of appropriate levels of operating reserve capacity.

This issue highlights the problematic nature of the many-headed beast that is P2025. We are fairly confident that if a good fast FCAS reform and a system strength reform were assumed to be part of the system, then modelling would show little if any marginal improvement in short-term reliability by layering a new OR mechanism on top. If so, OR would be an unnecessary additional cost to consumers.

## 2.1 Four services – but an odd grouping

The ESB has identified four essential system services for the purposes of this workstream:

1. Frequency Control
2. Operating Reserve
3. Inertia
4. System Strength

We think it is problematic to group all four of these together in this way.

### 2.1.1 Security-related services are closely related in both threats and remedies

Of the four, we consider **frequency control, inertia and system strength** to be closely related:

- They are all required to deliver a securely-operating system, resilient to faults and disturbances (we refer to these loosely as 'security' services).
- They are all diminished by the relatively lower levels of synchronous generation capacity being dispatched in the NEM recently and in future.
- There are some overlaps in how services can be provided – for example, synchronous condensers ('syncons'[23]) with flywheels contribute to system strength, inertia and frequency control. Batteries offer fast frequency response and may also be able to contribute via 'synthetic' inertia.

### 2.1.2 Operating Reserves is a reliability issue and should be assessed as such

We see the remaining OR service identified by the ESB as a quite different service, addressing not security, but very short-term reliability.

Unsurprisingly there are substantial overlaps between the operational-timeframe reliability considered by OR, and the investment-timeframe reliability dealt with in the Resource Adequacy workstream.

We think it very important that the OR proposal is assessed in a completely integrated manner with other Resource Adequacy proposals, including modelling costs and impacts of various proposals consistently. This applies to assessing each independently and assessing how multiple proposals might interact if more than one was to be implemented.

The most obvious examples would be the interaction of OR with any other new payments to generators under a decentralised capacity market, or under bespoke jurisdictional support schemes.

## 2.2 Operating Reserve market

Arguments in favour of an OR market presume consumers will value marginal improvements in reliability more highly than the cost of paying capacity additional revenue to stand ready as a reserve (AS WELL AS paying that capacity in the spot energy market if and when dispatched).

> **NOT SUPPORTED:** We think it is very challenging for the ESB to make the case for supporting a new OR revenue stream for generators. The spot energy price is designed to incentivise a suitable level of operating reserves, has clearly done so adequately to date, and (most importantly) seems likely to continue to meet that challenge based on the AEMC's commissioned modelling.

### 2.2.1 A new revenue stream with no clear offsetting savings

As is the case for the decentralised capacity market, the new revenues from OR payments are not likely to lead to any offsetting lower bids and dispatch prices in the energy spot market.

OR requires a commitment to be AVAILABLE to be dispatched, not to ACTUALLY dispatch in the future period. Once a generator has secured an OR payment in return for being committed in (say) 30 minutes' time, this becomes a sunk benefit – which would not impact the offer price that generator will then submit.

As such this is not just a reshuffling of revenues in the energy market to improve a reliability outcome – it is a new, additional revenue stream for generators, and thus a new, additional cost for consumers.

[23] These are large electric motors with no load, spinning freely, and synchronised with the three-phase alternating current of the transmission network. They are able to stabilise the grid in the face of disturbances in a similar manner to synchronous generators.

Consumers should be critically concerned with whether an OR market would drive any material improvement in reliability of greater value to them (at the margin) than this cost.

### 2.2.2 Operating Reserves proposal has been modelled

The OR proposal has been supported by rule change requests in late-2019 and is being assessed by the AEMC under that process.

The AEMC-commissioned modelling assessed the key issue of greater and more frequent forecast errors in supply / demand, and associated ramping requirements, associated with more weather-dependant renewable penetration.

This modelling is correctly informed by the fact that a substantial amount of the new firming and storage capacity likely to be added to the NEM has very fast ramping capabilities by its nature – batteries and pumped hydro are extremely quick to respond, as are some demand response assets. By contrast, the capacity being withdrawn is slower-responding coal and less-flexible gas.

As such, the need for particular quantities and qualities in operating reserves (or put differently, the adequacy of ramping capacity in the face of VRE uncertainty) seems to be a concern which is resolving itself thanks to the technology changes underway in the NEM's capacity. This presumes – as we believe we should – the more impactful investment signals to bring on this capacity are in place, as dealt with under the Resource Adequacy workstream.

In our view the AEMC's modelling makes fairly clear the lack of evidence to support the OR proposal.

**We include a detailed summary and assessment of the AEMC's modelling of OR reserves as Appendix 1.**

## 2.3 Security-related reforms are supportable in their best forms

P2025 reforms which focus on security – the 'nuts and bolts' of operating the system securely (as opposed to cheaply or reliably) – are easiest to support in general. They are urgent, pressing concerns, in many cases already matured through rule-change requests, and (given their main focus on the operational timeframe) they have less potential downside for consumers from their introduction[24].

### 2.3.1 Sensible degree of competitive market design for the specifics

We agree with the approach taken by the ESB here, essentially:

- **Use spot markets where that makes sense:** Where closely related market price signals are already well-established and the services can be fairly easily unbundled now for competitive purposes, this is likely to be efficient (e.g. extension of FCAS markets to fast frequency response).
- **Use an alternative market design where it might not:** Where the viability of an unbundled spot market is not clear at present (due to complexities and overlaps in the services required, or location-specific needs) it is sensible to pursue a structured approach to procuring the minimum necessary investment, coupled with a flexible, broad and technology-neutral means to access and schedule resources for system security, co-optimised with energy spot prices.

## 2.4 Frequency control – fast frequency response service

The ESB proposes a market to compensate faster response than the current 6-second ancillary service. The option with the greatest stakeholder support is the creation of a new category of FCAS (as opposed to changing the specification of an existing, slower category).

> **SUPPORTED:** We agree this is a low-risk and sensible extension of the FCAS markets, which function well. New technology (in particular, batteries) offers very fast frequency response, which has already proved to be valuable in the face of disturbances to the grid, and it is appropriate those assets be remunerated for this service which is currently unique to that technology.

[24] Even though this workstream's reforms may provide some incremental investment-timeframe signals to capacity, the main benefit is enhanced security, at the risk of somewhat higher system costs and possibly less-efficient dispatch of the system's current assets at any point. The risk to consumers in that trade-off is less significant than baking in more-substantial capital-related costs indefinitely via poor long-term investments in new capacity and transmission assets, as might occur under the investment-timeframe resource-adequacy and transmission & access workstreams.

### 2.4.1 Fast frequency control market has co-benefits

Improving the investment case for batteries has co-benefits for reliability in the short and long term.

This is because clearer access to fast frequency response value fortifies the overall investment case for a battery asset. Battery investments are likely to continue to target multiple revenue streams, including energy price arbitrage. A single battery project may have some capacity earmarked to serve FCAS markets, other capacity to address energy price arbitrage, with the ability to optimise the split dynamically based on market conditions in each market.

This new FCAS market will therefore also support the case for battery energy capacity being in place in the system (investment timeframe) and therefore more likely to be available for ramping (operational timeframe, and relevant to the OR question). This overlap is an example of why we do not see a strong case for a separate OR market once other P2025 reforms and pre-P2025 reforms are considered.

Improving the ability of the system to respond quickly to frequency disturbances also **assists in managing lower levels of inertia and system strength**[25].

This is addressing the symptoms rather than the cause, but nevertheless, it can be an effective measure. The alternative is seeking to procure excessive amounts of other security services to maintain the historical stability of frequency, at higher cost.

## 2.5 Frequency control – primary frequency control

The ESB proposes to normalise the recent 'emergency' requirements for generators to provide primary frequency control from their assets. This measure has proved to be very effective in quickly arresting recent deterioration in frequency performance of the system, without much apparent trauma for the generators subject to the requirement. Several versions of the reform remain in in play, and further evidence is being gathered by the AEMC to inform the recommended choice.

> **SUPPORTED IN GENERAL:** We think the basic case has been clearly demonstrated for primary frequency control obligations / services to be the norm in future. The remaining question is exactly how – including the possibility of a new ancillary service market rather than a mandatory obligation with a particular form of compensation. At this stage it isn't clear to us which alternative is preferred, and we think stakeholders should await the next stage of analysis, to confirm a sensible version is being favoured.

## 2.6 System Strength

These are among the P2025 reforms subject to specific rule changes being addressed by the AEMC, and so are relatively mature and well-developed.

They cover both the investment timeframe (procuring the assets required by the system) and the operational timeframe (scheduling those assets into dispatch, in light of the impact on existing energy and FCAS spot markets).

At their best, these proposals are very sensible and supportable – but the details are important to ensure the outcomes for consumers are efficient.

### 2.6.1 Structured procurement approach has trade-offs

The essence of the system strength reform is the use of a "structured procurement" model rather than introducing a full spot market or other more obviously competitive and transparent market design.

We think this is a sensible and pragmatic approach under the circumstances – but the risk of this approach is that the structured procurement may be inefficient, or (more worryingly) may not be flexible in accommodating evolution in technology that might leave earlier structured procurement deals looking dated and expensive.

As a result, we support the reforms in their best forms, which mitigate against this risk – with caveats.

[25] ESB identify the POTENTIAL for future battery assets and other inverter-based capacity to directly support system security in other ways, such as by providing 'synthetic inertia' and via the use of grid-forming (rather than grid-following) inverters.

We suggest:

1. **Use broadest possible scheduling and dispatch for security:** The ESB should recommend the System Security Mechanism (SSM) alternative, which brings in all potential system security assets to the dispatch optimisation, rather than just historically contracted resources from TNSPs under the basic Unit Commitment for Security (UCS) process; and
2. **Minimise inflexible contracting:** The details should ensure that the quantity of procurement under the (less-flexible) UCS contract process is minimised, allowing for shorter-term and more flexible participation of assets in providing the optimal (as opposed to minimum) levels of system security in real time.

### 2.6.2 Important to consider the status quo – which is unacceptable

In other aspects of the P2025 proposals we have objected to creating new revenues streams for assets, which inevitably become new costs for consumers. On the face of it, the cost of structured procurement contracts and the dispatch of assets for the purposes of system security falls under this category.

However, the ESB's proposals of a formalised approach to maintaining not just minimum, but **optimally efficient** system security is an important difference.

At one level, this is likely to be better than large-scale and frequent AEMO interventions as we are currently seeing – which already carry a cost, and one which we have no reason to think is particularly efficient.

At the next level, the ESB has made clear that co-optimising system security with energy dispatch can lead directly to lower energy dispatch prices, to the benefit of consumers.[26]

### 2.6.3 System Strength – Structured Procurement

The ESB supports the thrust of the TransGrid rule change, which would see TNSPs proactively planning for and investing in system strength assets (including via contracting) and doing so consistently with the ISP.

The reform is a wider, more systematic version of the recent situation in SA, where syncons have been put in place by the TNSP, under directions, to support security. We can see this will allow for less AEMO interventions (which are costly, keeping more expensive gas plant running) and therefore greater dispatch of lower-cost variable renewables.

> **SUPPORTED WITH QUALIFICATIONS:** We think this is a relatively simple, quick and potentially quite efficient means to maintain system strength. Importantly, it can do so without necessarily erecting barriers to exit for synchronous thermal generation assets which we suspect represent a higher cost for consumers than the alternatives of:
>
> 1. TNSP-driven investment in alternatives such as syncons and / or network enhancements; complemented by
> 2. Cheaper replacement energy capacity via firmed renewables and storage.
>
> However, we see some risks which could be addressed in more detailed design and operation of this reform.

#### *2.6.3.1 Central planning has a role, and this is consistent with that role*

Central planning of system strength (or many other things) may not be philosophically ideal, but it is pragmatic in our opinion, at this point in the transition – especially given the clear linkage to the ISP, another centrally-planned fact of life. It is relatively easy to identify where and when system strength needs to be enhanced, with reference to the ISP's pathways, and this is a reasonable extension of the ISP's tentacles in our view.

#### *2.6.3.2 Is this a positive opportunity for MORE jurisdictional intervention?*

In fact, we think this reform might suggest an opportunity for more effective government intervention in the energy system.

[26] In short, because the OPTIMAL level of system security assets being dispatched (such as an additional syncon, over and above the minimum needed purely for security purposes) may alleviate restrictions on the quantity of VRE able to be dispatched – allowing for more very low-cost energy enter the system and drive down prices.

If jurisdictions wish to stimulate a reliable and secure energy transition with less distortion and unintended consequences, investment (guided by TNSPs and the ISP) in syncons with the ability to offer both system strength and inertia (e.g. including flywheels) would be a relatively good way to do so.

Getting 'ahead of the market' on these investments – perhaps investing before the need is fully-realised from further VRE capacity build-out in REZs, for example – is relatively cheaper compared with (say) pumped hydro or gas-fired generation investments. Importantly, it is also obviously less-distortive since there is no real system strength market to distort.

Such assets could be divested into a future competitive unbundled market for these services should the market opportunity develop (as the ESB envisages it might).

### *Synchronous condensers – investment leverage for the transition*

Electranet's four syncons of 2,300 MVA were approved by the AER at a capital cost of \$166m, or \$0.07m per MVA – alleviating system strength concerns for the entire NEM region (at least for a while) and driving lower costs for consumers in the process.

The large-scale Electranet investment here is clearly more efficient than the previous project-level 'do no harm' approach: the Clean Energy Council suggested that a 50-70MVA syncon might cost \$15-20m (so, about \$0.30m per MVA), to remediate system strength issues associated with a notional 200MW VRE project.[27]

At the lower system-scale costs, investment in syncons has a capital intensity of around \$0.04m/MW of VRE facilitated, without creating any distortion to the energy-only market. To put that in context:

**\$100m of jurisdictional syncon support might facilitate nearly 3GW of VRE by alleviating the system strength concern.**

The capital intensity of Snowy 2.0 is about \$2.5m/MW excluding transmission upgrades. The Kurri Kurri gas plant budget is \$0.9m/MW. Perhaps jurisdictions could have more leverage and cause less harm by focusing on MVA instead of MW or capacity – and funding syncons.

### *2.6.3.3 Care required to avoid inflexible, outdated arrangements being baked in*

We have two areas of concern about structured procurement of system strength which we believe the ESB should carefully consider:

1. **Technology neutrality should be actively supported against TNSP paradigms:** The solutions to system strength and inertia can involve several technologies, both network (e.g. transmission enhancements, TNSP-owned syncons) and non-network assets (including contracting non-TNSP synchronous generators, syncons, or possibly grid-forming inverter-based assets). While TNSPs are well-placed to assess these against each other and in light of the wider ISP, some active design features may be needed to ensure TNSP procurement is technology-neutral and appropriately forward-looking as new, possibly more efficient solutions emerge. TNSPs may have a private incentive towards network solutions and RAB growth which may be inconsistent with a consumer view of efficient investment.
2. **Long-term contracts should be minimised in time and volume:** Structured procurement contracts may tend to be relatively long-term and inflexible and are likely to carry a fixed-cost element for consumers. An overabundance of these may work against the most flexible, low-cost optimisation of system strength costs with energy and FCAS costs in real time, especially as technology evolves. This is especially the case in light of the total system assets available to be optimised in real time (leading directly to operational-timeframe reform for optimisation of dispatch). As a result, we think structured procurement should be limited to ensuring minimum levels of system security over modest contract terms (perhaps with some forward-looking buffer), rather than seeking to procure optimal levels in this way.

[27] See: https://www.aemc.gov.au/sites/default/files/2019-05/Rule%20Change%20SubmissionEPR0070%20-%20Clean%20Energy%20Council%20-%2020190515.PDF

## 2.6.4 System Strength - Scheduling (UCS / SSM)

The ESB is considering two main proposals for dealing with the operational timeframe for system strength:

1. **Unit Commitment for Security ('UCS')-only** would only schedule assets contracted under TNSP's structured procurement, as discussed above. We refer to these as 'security assets' as opposed to assets being bid or dispatched in the spot energy or FCAS markets; or
2. **UCS with the overlay of System Security Mechanism ('SSM')** which would extend the system-strength scheduling to include procuring system strength from all relevant assets which may contribute to security at that time, not only those contracted by TNSPs.

In all cases, security assets would be paid to commit, a cost to be recovered from consumers.

> **UCS+SSM OPTION SUPPORTED:** Aligned with our views on ensuring structured procurement is done efficiently and flexibly, we consider the scheduling of system strength via the UCS, if supplemented by the SSM, is a good approach. The SSM will allow for greater competition in the provision of system strength, and less risk of distortion in the process of co-optimising and scheduling dispatch of both capacity and security assets. Optimised scheduling will be very important to minimise costs for consumers, both of the system security assets available, and across security, energy and FCAS markets for lowest overall system costs.

### *2.6.4.1 Commitment for security could increase energy market dispatch price*

**If the security assets that are committed are syncons,** they would provide security services only.

- Their contracted costs would be incurred, but the energy and FCAS dispatch would be optimised for hopefully-lower overall costs (for example, via greater dispatch of low-cost VRE which would be otherwise constrained, and/or by avoiding the need to dispatch higher-cost capacity under AEMO direction).
- Generally speaking we expect it would be fairly simple to determine whether this 'syncon case' is lower cost for consumers compared with the current circumstances of AEMO intervention[28].

**If the security assets that are committed are generators,** they will also dispatch energy, and so the situation is more complex.

- If they are NOT participating in the energy market, we presume this means they are relatively high-cost, and that would be reflected in the compensation they receive from the TNSP under contract.
- If dispatched for security purposes, they would contribute to the energy required in real time, and so would displace other generation capacity in dispatch. We expect they might sometimes displace even higher-cost marginal capacity, (such as gas peaking, hydro and / or battery), but at other times (most times?) they will displace low-cost VRE capacity.
- Therefore, the first-order effect of security-related dispatch of generators is likely to be higher spot energy prices, a prima facie concern for consumers.
- However, if the issue is minimum security for the system, the counterfactual may be similar or worse (via AEMO interventions). It is quite possible that the cost of security assets under structured procurement and dispatch may be less than would be incurred under AEMO interventions, so this first-order impact may in any case be an improvement for consumers over the current situation.
- Given the uncertainty here, the second-order effect becomes very important – the optimisation of security capacity with energy and FCAS markets for overall secure conditions which are lowest cost for consumers. Simplistically, this relies on the fact that in some cases, an optimal dispatch of security capacity (potentially including relatively high-cost synchronous generators) may allow for greater co-dispatch of low-cost VRE, effectively relieving constraints on wind and solar assets in the operational timeframe and supporting further investment in these assets in the investment timeframe (based on lower risks of security-related constraint).

In this 'syncon versus generator' dichotomy, it seems to us consumers will either face:

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[28] For example, in the manner that the AER assessed the Electranet syncon investment's net benefits, see: https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20-%20ElectraNet%20-%20SA%20system%20strength%20contingent%20project%20-%2016%20August%202019.pdf

1. The certain but relatively modest cost of new syncons, or
2. The less certain but potentially higher cost (at least sometimes) of synchronous generators being dispatched for security rather than their energy bid price.

BUT in either event, the situation appears to be better than the status quo, maybe a lot better if co-optimisation of system security draws in additional VRE to displace higher-cost generation capacity.

#### *2.6.4.2 UCS+SSM model addresses several limitations and risks of UCS-only*

The ESB have highlighted a number of concerns in relation to the UCS-only option. In our view, the arguments for the alternative UCS+SSM option include:

- **More operationally flexible:** The ability to utilise non-UCS assets in security scheduling is more flexible in the operational timeframe.
- **More competitive:** Short-term procurement of non-UCS assets can increase competition and potentially lower the costs of procuring the optimum level of system strength.
- **More technology-neutral:** Non-UCS assets are more likely to represent emerging technologies with possible contributions to system security. The SSM version of this reform lowers the barrier to entry for these assets, compared with the need to first secure a long-term TNSP contract.
- **Less distortive in short-term dispatch:** The best version of this reform would involve all assets being remunerated for the system strength they are willing to contribute (via the short-term SSM, if not via structured procurement contracts). This would see all relevant assets incentivised to participate transparently in pre-dispatch bidding and commitment for energy and security.

In our view, the final point here is very important, as the alternative may be quite unpredictable rebidding and decommitment by energy market bidders in response to security scheduling information that indicates the likelihood of a lower energy pool clearing price in the imminent dispatch – with a clear risk of undermining the co-optimisation of costs upon which the security scheduling was based.

#### *2.6.4.3 Some questions we would like to see answered in supporting UCS+SSM*

We see a number of qualitative high-level reasons to support the thrust of the UCS+SSM approach, including pragmatism in the face of urgency, consistency with the ISP, opportunity for lower co-optimised costs for consumers, and the prospect of <u>relatively</u> efficient and technology-neutral price signals in both the investment and operational timescales (in the reform's best version).

However, we would hope to see this supported by some clear evidence as the proposal progresses.

**What does the synchronous generator versus syncon trade-off look like?** Under modelling, how expensive is dispatching a contracted syncon (plus whatever the marginal energy price might be from other capacity) versus a contracted synchronous generator (which will displace marginal-cost energy in dispatch BUT is likely to be pretty expensive under the UCS contract)?

Given this, what is the expectation consumers should have: a preference for new syncons (i.e. extending the SA regional situation more broadly) or a preference for contracting with existing synchronous generators (which we note is a supportive form of payment for that technology similar in effect to a capacity payment)?

**What is the scale of potential Regulated Asset Base ('RAB') growth here?** If the preference is likely to be TNSPs building syncons, what is the scale of RAB growth, and how material is this compared with existing and other new RAB under the ISP?

**What is the opportunity for efficient inertia management at the margin?** What is the marginal cost of investing in syncons that also address inertia (e.g. by adding a flywheel)?

If this appears to make any sense, how is this being considered to ensure the issues of both system strength and inertia are being addressed most efficiently?

**What might the 'size of the prize' be under co-optimised dispatch?** Compared with the status quo (minimum system strength and AEMO directions), how material is the opportunity to allow greater volume of lower-cost energy to be dispatched, setting spot prices lower.

Will the modelling of this proposal include a clear assessment of these benefits against the costs?

# 3. Transmission & Access and Renewable Energy Zones

LMP+FTR offers very material savings to consumers through more efficient dispatch, and more efficient location of new investment in generation capacity relative to the existing and new transmission assets. This is a relatively mature reform proposal, developed carefully, supported by clear cost-benefit analysis[29].

Having said that, we do not think LMP+FTR would be sufficient. There is also a complex problem to be solved in encouraging competitive but efficient investment in generation and transmission, and we don't think a laissez-faire approach based only on LMP+FTR would magically lead to the least-cost generation and transmission system.

As such, we generally support the ISP model of a high-level plan based on REZs. One of the consequences of this is the need to manage the interface between central planning and the competitive market, at a REZ level as well as for the overall NEM system.

However, the P2025 Option Paper focus on REZ transmission and access first, to the exclusion of the overall reform, has only served to highlight the disadvantages of not taking the more general whole-of-system approach. Any attempt to create two systems, or to promote interim solutions, adds the complexity by creating major 'boundary issues' either temporally or geographically.

In particular, creating two transmission access arrangements on either side of a defined REZ is not likely to support efficient, lowest-cost investment within REZs (given the risk of being congested and constrained outside the REZ). But it IS likely to create risks of regulatory arbitrage.

In this sense we applaud the ESB's characterisation of the issues, which recognise this problem. That naturally leads to their implicit support for options which move us as close to the LMP+FTR end-game as possible, while acknowledging the resistance or disinterest of stakeholders to this point.

Some of the proposed approaches in the current menu of possibilities are indeed quite close to the original LMP+FTR model, and so these are the versions which should be strongly supported, as they will make it easiest to extend this concept to the overall network.

The issues around **'who pays'** in the first instance for transmission (within a REZ, or in general) seem far less important to us than whether the arrangements drive the most efficient investments in the first place, and the most efficient dispatch of those assets in real time. Ultimately, whether TUOS is initially paid by generators or retailers, it will find its way to consumers in the long run since revenues will tend to reflect total system costs including a hopefully-competitive return on capital.

Therefore – even taking a long-term interests of consumers viewpoint – we strongly resist the urge to reflexively support 'making generators pay' unless that happens to be the most efficient answer.

Where 'who pays' becomes important is where a generator can pay to secure access, in such a way that their cost of capital is driven down by the reduction of revenue risk from future congestion caused by later entrants – an obvious free-rider problem.

LMP+FTR clearly addresses this problem effectively – whether the FTR are secured periodically via competitive auctions or bought up-front at their expected value to guarantee access for a period (which can also be structured competitively).

## 3.1 Efficient development of capacity, load and storage is critical

While much of the debate might focus on the traditional generation and load issues, the issues raised by the ESB regarding efficient location of storage and flexible load relative to VRE capacity are more important in our view.

**The scarce asset in the future NEM is not bulk VRE or legacy coal capacity, it is the firming, storage and flexibility needed to ensure VRE output translates to least-cost consumer supply.**

The ESB's contention is that it is more efficient to locate storage and flexible load within a REZ, than to

[29] Originally under the banner of the AEMC's Coordination of Generation and Transmission Investment or 'CoGaTI' reform.

fund the incremental transmission needed if they are located elsewhere. There might be some specific exceptions (e.g. assets able to benefit from brownfield development costs and transmission network access, by locating nearby current large-scale generation capacity being withdrawn) but we agree with the premise in general, in the absence of anyone suggesting otherwise as far as we are aware.

VRE is fundamentally low-cost and economic as part of the future system, but the investment case for storage, firming and flexible demand response is less clear-cut at the moment. As a result, transmission and access arrangements for REZs must be carefully designed to ensure the investment signal is accurate.

## 3.3 Transmission cost approval and allocation must evolve with the NEM

This is clearly a difficult issue for consumers to assess. While the relatively strict RIT-T process is a tried and tested bulwark against gold-plating, that does not guarantee it remains suitable for the transition of the NEM.

The key case is Marinus Link.

We are not suggesting this project is in the long-term interest of consumers in any particular timeframe. But we are well-aware that under the current RIT-T approach, the costs appear to fall disproportionately on the VIC and TAS regions, compared with benefits which we accept are NEM-wide. In addition, the relatively fast rate of change in the NEM suggests the decision about Marinus Link timing needs to reflect this uncertainty and be flexible to change.

The ESB appears to support a fast-track process which avoids overlap between the ISP and the RIT-T, as well as a reconsideration of the cost allocation for interconnection investment.

> **SUPPORTED IN PRINCIPLE:** The ISP is a fact of life now, and the RIT-T should not be a fallback process to frustrate it. Instead stakeholders must focus on optimising the ISP process – including its assumptions and methodology. Subject to careful further assessment in regard to 'how', the RIT-T should be changed to optimally balance costs, benefits, and the parties exposed to each across the system as a whole.
>
> This includes the possibility that some benefits are outside the scope of consumers or market participants – in which case, it is appropriate for jurisdictions to contribute to costs which deliver benefits they value.

## 3.4 Actionable ISP project process must recognise consumer risks

The ESB outlines the 'chicken and egg' problem between generation commitment and transmission investment – and we agree the P2025 design of the NEM needs to recognise this.

This is essentially a problem of timing mismatch between the investment, and the ramp-up of utilisation of the investment which eventually delivers the benefits to consumers. The problem reflects the uncertainty inherent in the ISP process, which contemplates multiple future scenarios and associated least-cost investment pathways.

However, it is NOT clear to us that the risk associated with making decision under conditions of uncertainty should be shouldered by consumers alone – nor TNSPs, if they are the alternative.[30]

The ESB's options paper states:

*"…if a transmission investment associated with a REZ is classified as an actionable ISP project and passes the RIT-T, it is able to proceed on a regulated basis – that is the assets would be built, owned and operated by the local TNSP and funded by consumers."*

> **NOT SUPPORTED:** This places <u>all</u> risk of poor planning or poor execution with consumers, in a process where they have limited influence. In our view, this is another area where jurisdictions may have a valid role to play in deploying stimulus to the transition. If the ISP determines an asset

[30] The apparent need for the CEFC to step in with a subordinated debt facility to get Project EnergyConnect over the line (following the AEMC's dismissal of the rule change request to adjust financing arrangements) does suggest there is a significant issue to be addressed here. TNSPs are tightly-restricted in their ability to match (regulated) returns to risk and uncertainty.

needs to be built under conditions of uncertainty, consumers should not be taking the timing risk or utilisation, nor should the risk and associated cost be passed back to TNSPs – but it might well be the role of jurisdictions to bridge the gap. This could be either via short-term financing to TNSPs (as in the recent CEFC facility for Project EnergyConnect) or underwriting regulated asset revenues to the extent they are not justified by asset utilisation in the ramp-up period.

## 3.5 Access reforms should move as close to LMP+FTR as possible, now

This is the key reform in this workstream and in our opinion, the most important issue in the entire P2025 portfolio. The ESB's framing of the issue is very clear about the need to get this right.

### 3.5.1 Criteria are good but could be better

In assessing options, the ESB has considered four criteria:

1. **Locational signals** for generation and storage (in the investment timeframe)
2. **Congestion management** (price signals in the operational / dispatch timeframe)
3. **Enabling new technologies** (essentially, providing the right signals for storage and flexible loads to locate close to VRE and thus minimise transmission investment and/or congestion)
4. **Risk management tools** (providing a means for market participants to manage the congestion risk to which they are exposed by the signals above)

This is an excellent list as far as it goes, but we believe three other criteria need to be considered:

5. **Consistency with the ISP**
6. **Ease of migration to full LMP+FTR**
7. **Limited reliance on centrally-planned congestion cost estimates**

We describe each of these below.

#### *3.5.1.1 The ISP assumes LMP-based investment and operational signals*

The P2025 and ISP consultation processes revealed to us critical ISP assumptions we had been unaware of.

The ISP is a model which optimises for the least-cost system. In doing so, it assumes generation, storage and transmission assets are located based on optimal investment signals, and that generation and storage dispatch is based on least-cost SRMC bidding.

By contrast, the ESB's analysis of this issue makes it clear the real world – <u>if the access regime is not corrected</u> – involves:

- **Increasing disorderly 'race to the floor'** bidding leading to inefficient dispatch of generation into transmission constraints.
- **Inappropriate generation investment signals** – which reward new entrants locating behind transmission constraints given their ability to access a share of the 'race to the floor' pie.
- **Underutilisation on interconnector capacity** – due to counter-price flows between regions and clamping of interconnector capacity to minimise the unfavourable price impact of this.
- **Perverse signals for storage** (and flexible load) assets – which may charge when they should be discharging and vice-versa, due to the unrecognised impact of local transmission constraints compared with exposure to only the regional reference price.

In short, <u>the ISP assumes investment and operations based on LMP</u>. If that is not correct, the ISP modelling is invalid. There are really only two directions we can go from this point:

1. **Squib on transmission access reform**, and adjust the ISP modelling to reflect the higher costs associated with incorrect price signals; or
2. **Bring the real world into alignment** with the conditions needed to realise the ISP's least-cost system.

**In our view, opponents of LMP+FTR are implicitly suggesting we take the first path. This is a dismal outlook for market design and energy policy generally, from the point of view of consumers exposed to the inefficient costs implied by such a failure.**

The system is currently sleepwalking into circumstances the ESB and AEMC have clearly alerted us to. Any access reform under the P2025 process should be judged against how well it will push back against this.

#### *3.5.1.2 The future is LMP+FTR*

While we regret the ESB deferring the full-scale debate needed on LMP+FTR, it seems clear to ourselves and the ESB that we must move eventually to an efficient access arrangement based on LMP+FTR.

Therefore, any interim arrangements should be judged on how smoothly they can facilitate that medium-term outcome. This mitigates against partial reforms which might provide some benefits, but are not easy to unwind or fold into a full LMP+FTR reform in (we hope) the foreseeable future.

#### *3.5.1.3 No need to guess the cost of congestion*

One of the ironies of the situation is that LMPs already exist as an integral part of the operational dispatch process – in many ways, LMP is the easy, obvious path to apply an accurate real-time cost to congestion and (by extension) forecast the future cost for the purposes of investment signalling.

However, several of the options proposed involve complex, centrally-administered forecasts of future congestion in order to provide a proxy price signal for investment. At worst, these are imposed as a congestion fee. Slightly better, they are established through competitive processes (such as auctions where the pricing is at least subject to the views of the market participants affected).

The ideal is to apply LMP in the operational timeframe, and use FTR, which would be priced as the expected future value of congestion, as the investment-timeframe locational signal. Any P2025 proposal which falls short of this should be assessed favourably based on how close it can get.

### 3.5.2 Hybrid Congestion Management and Connection Fee model is preferred

Five possible models are investigated – of these, three appear to fail immediately:

- **Congestion Management model:** fails to provide the critical locational price signal for investment to minimise congestion / transmission costs.
- **Connection Fee:** fails to provide the operational price signal to eliminate disorderly bidding and to properly incentivise least-cost behaviour by storage and flexible load assets.
- **Generator TUOS:** identical failure to Connection Fee.

However, the Congestion Management model provides a very strong basis for operational price signals to optimise dispatch behaviour by generation, storage and flexible loads – and it does so by applying LMP. In that respect it also meets our extra criteria very well.

As a result, the ESB has evolved the Congestion Management model into two hybrids, combining it with locational price signals. The more extensive of these addresses locational signals adequately, providing:

- **A rebate from congestion impacts for both existing plant and foundational REZ generators**.
    - This is a strong incentive for assets to locate inside a REZ – with the potential for an access auction to recover some of this value for consumers in reduced TUOS.
    - For incumbent assets, they are fully grandfathered against the impact – fair enough given this is a question of forward-looking investment decisions, not revisiting the past.
- **A congestion fee arrangement, to allow new entrant generation capacity** outside a REZ to gain protection from congestion impacts, in return for a fee based on an estimate of those impacts.

**'OPTION 5' SUPPORTED:** While it isn't ideal, the introduction of LMP to all assets will alleviate a major element of the overall problem, by aligning bidding behaviour with least-cost system assumptions. This will benefit consumers – with AEMC modelling indicating $1bn of NPV over 2026-2040.

In addition, it provides the correct price signals to storage and flexible load. That is likely to be of material value in terms of efficiency if those assets therefore locate close to VRE assets within REZs, and thereby minimise the cost of new transmission required and the quantity of VRE spilled rather than used.

The congestion fee is a somewhat clumsy proxy for the purchase of FTR as a form of firm access, while the rebate to REZ-located generators is a very blunt signal indeed – albeit the value may be discovered and partially recovered by consumers via REZ access auctions.

**In our view, this is a viable and significant step towards full LMP+FTR.**

# Appendix 1 – Assessment of Operating Reserves modelling

Finncorn participated in the 22nd April ESB / AEMC workshop concerning the Operating Reserve ('OR') rule change requests.

## A1. Executive Summary & Conclusions

AEMC commissioned Endgame Economics to model OR, in order to investigate the conditions under which an OR mechanism might be beneficial in ensuring reliability in the operational timeframe (i.e. on a 5-minute to daily basis, in response to forecast uncertainty in supply and demand). A detailed presentation was provided to participants for review and discussion.

Our impression from the outcomes of the modelling, the feedback from workshop participants (including Finncorn) and the response from AEMC all suggest that it would be difficult for the AEMC to support the development of an OR mechanism on the basis of this modelling and analysis of the results.

The modelling and workshop assisted to clarify our view that OR is not a P2025 proposal which deserves support, because:

(a) the need is not evident – i.e. at this stage of modelling, it remains unclear if there really are any material gross benefits on offer in terms of reliability for credible OR conditions, let alone net benefits after the costs of a new market value stream to generators are considered; and

(b) where reliability is an issue, other mechanisms (including the existing energy-only market price signal, pending or recent reforms such as the RRO and 5MS, and other P2025 initiatives particularly those related to the longer-term issue of resource adequacy, operational-timescale inertia and frequency control, and improvements in forecasting) are likely to be sufficient.

## A2. Definition of Operating Reserves used

OR is defined by AEMO as '*Available, but unutilised power reserves to ensure the system is able to cope with unexpected variations in supply and demand*'.

In practice this applies to the fairly short-term operational (as opposed to planning or investment) timeframe of minutes to several days with a focus in the rule-change request and workshop on 30-minute OR – in other words, capacity which is available for dispatch in 30 minutes or less if necessary.

There is therefore a subtle distinction between OR and strategic reserves.

- **Operating reserves:** should be directed at dealing with typical uncertainty (such as 'everyday' short-term forecast errors in supply / demand).
- **Strategic reserves:** Concerned with large-scale contingency events (e.g. unexpected outage of large generation / transmission) and falls within the 'resource adequacy mechanisms' P2025 workstream.

There is a risk to consumers in confusing the two. Creating an 'everyday' value stream to generators associated with an OR mechanism is not likely to be the most efficient means to deliver strategic reserves against rare, severe events. We should not create an OR mechanism to attempt to address a strategic reserve issue

**This turned out to be a key issue raised in the AEMC modelling and workshop.**

## A3. Modelling of system reliability under forecast uncertainty

The modelling was based on VIC region in six configurations of the generation fleet:

1. its current state (F1).
2. its current state with additional rooftop PV added (F1*).
3. Future states based on 40% VRE and 80% VRE penetration (with coal exiting). Two versions of the portfolio of firming for the future states were used:
    - one with relatively more gas capacity (F2 at 40% VRE, F4 at 80% VRE)
    - the other with relatively more battery and pumped hydro capacity (F3 at 40% VRE, F5 at 80% VRE).

**The model did NOT use an OR mechanism** – rather it assumed no OR value, and therefore assessed how the current system would respond, to see whether this reveals the need for OR to improve reliability.

The model assumed a start-of-day supply / demand forecast, with generators planning ahead to dispatch into the expected demand (for example, being in a position to be ready to dispatch at certain times of the day, or not).

The model was then disturbed by some sort of forecast uncertainty that threatens reliability (i.e. higher grid demand or lower grid supply) and assessed the extent to which the generation capacity was able to respond to that unexpected change.

At the point of disturbance, any reserve capacity seeks to respond.

- There might be limited capacity for a period (e.g. some coal plant may be offline with a long response time).
- Some capacity may respond immediately but be limited by its ramp rate (e.g. gas peakers) such that the gap between supply and demand cannot be met for a short period.
- Some capacity may be fast-responding but energy-limited (such as pumped hydro and batteries), so the gap might be avoided in the short-term, but emerge again later (e.g. after. 2-hour battery has discharged, or if pumped hydro or battery assets were not fully charged at the time of the event).

Therefore, there are some circumstances where supply and demand cannot be balanced, creating a 'gap' – which implies a loss of reliability and load-shedding.

**These gaps are circumstances where an OR mechanism MIGHT have value**, if it would have caused a greater amount of capacity to be in reserve than the no-OR system was modelled to have delivered.

The question the model sought to address was when this might occur:

1. Under what types / scale of disturbances?
2. Under what generation capacity portfolios in the current and various possible future states as the supply side evolves to higher VRE penetration?

## A4. Notable limitations of the model leading to pessimistic outcomes

There are several areas where the model does not reflect the system fully, in a manner which we believe materially overestimates the likelihood of a reliability gap being shown in the model results:

1. **No update of forecasts over the course of the day.** When the disturbance is due to a weather event, short-term forecasting is likely to at least partially indicate the change in expected conditions, creating reforecasts of supply and demand (and expected dispatch prices). Unless the disturbance is a sudden, unforeseen event like a physical system outage, the 'everyday' forecast inaccuracy is likely to narrow over time and give the system some warning to respond, dulling the severity of limited ramp rates or lack of anticipation by storage assets.
2. **No interconnection is included.** In practice, interconnection of VIC with other regions is another additional form of reserve capacity – in most circumstances, one or more interconnectors will have some spare capacity to supply VIC if needed, with a rapid response time (exactly as needed to support short-term reliability in the face of disturbances).
3. **No demand-side response is included.** This is another form of capacity within VIC which is likely to increase over time, and which is designed to support reliability.
4. **No price signal is included.** The model optimises for dispatch costs but does not consider the impact of pre-dispatch forecasting of high prices evolving over the course of a day, which would cause capacity to ready itself for dispatch because of the attraction of capturing potentially high spot prices (or the need to defend contract positions). If assets can foresee the potential for very high spot price revenues, they may choose to incur costs to position themselves for that. A cost optimisation model cannot capture this incentive.
5. **Other relevant markets not included.** FCAS markets hold some capacity in reserve against frequency disturbance, and some of the contingency events would be likely to draw on these, either directly via AEMO dispatch, or indirectly by attracting capacity out of FCAS and into the energy market towards high expected spot prices.

6. **System security constraints not included.** Some of the events modelled involved very low levels of inertia, which in practice would not be allowed to occur by AEMO. Directions would ensure some level of non-VRE capacity would be in the dispatch at all times.
7. **Energy storage assumed to be empty at start-of-day**. The implication is that all batteries and pumped hydro expect to charge during middle-of-the day periods with high PV output and low prices. This obviously may not be the case if overnight prices are (also) low, but the assumption can mean that a middle-of-the-day disturbance finds only limited duration of fast-responding energy storage capacity available.

Taken together, we think these indicate **the modelling is likely to be VERY VERY pessimistic compared with the actual reliability of the system in responding to uncertainty and disturbance**.

## A5. Key outcome: system responds very well to everyday forecast errors

Despite this, the modelling suggests the system would accommodate the everyday uncertainty associated with forecasting VRE-driven supply against demand.

There was typically enough reserve capacity among coal, gas, pumped hydro or batteries to cope with the need for more supply than expected at start-of-day.

Interestingly, in some cases constrained VRE itself might be a form of reserve capacity, if the system supply is being dominated by rooftop PV and if the disturbance was a sudden drop in rooftop PV output (e.g. a cloud passes over Melbourne).

## A6. Major events needed to drive reliability gaps

Given this, the modelling moved on to examine more severe events in order to drive some interest in the results! The five event-driven cases illustrated in the results are:

1. As the evening demand ramps up, the wind dies away contrary to expectations.
2. In the middle of the day, the expected output from VRE drops away for some time (e.g. via the loss of a transmission link to a large REZ).
3. In the middle of a sunny, fairly still, low-demand day (when coal may be driven out of dispatch due to very low grid demand), all rooftop PV output is lost immediately, for some time.[31]
4. As evening demand ramps up on a still day, an expected windy evening turns out to remain still.
5. All rooftop PV output is lost in less than 15 minutes

These were assessed against the current state (F1), current state plus more rooftop PV (F1*) and four future states (F2-F5), so a total of 30 modelled situations to consider.

In our opinion, only cases 1 and 4 above are really the type of 'everyday' forecast error that an OR mechanism might usefully target.

Case 5 is too extreme, given the unlikelihood of a totally unforecast major cloud event. However, a less-severe version based on more limited unexpected drop-off in rooftop PV would be a typical case where an OR mechanism might be targeted.

As they stand, cases 2, 3 and 5 are more in the nature of sudden, rare, severe contingency events – similar to the existing risk of unexpected outage from a large coal turbine or plant, or failure of a transmission line.

## A7. Care needed in assessing OR against non-credible contingency events

There is nothing wrong with stressing the model until it shows us something interesting in terms of reliability threats. But great care is needed in interpreting what this means.

These events and their consequences are probably not the purview of an OR mechanism, as the scale of reserve capacity required is likely to be very material, but only needed on extremely rare occasions. It does

[31] We are not sure how this could happen – perhaps a very large alien ship exits hyperspace, hovering over greater Melbourne?! This is a good example of how very severe non-credible events are needed to create some apparent reliability threat.

not seem likely to be efficient to introduce a constant 'everyday' value stream to hold very large but almost always un-needed capacity at the ready.[32]

These types of events are not impossible, but should be (and are being, and will be) dealt with via mechanisms such as RERT and the general resource adequacy stream of P2025 (which seeks to ensure the required capacity to maintain reliability is at least in place, if not primed and ready to go).

## A8. Modelling results show limitations of ramp rates, storage duration

While noting again our caveat that we think the results are highly pessimistic due to model design (as noted earlier), some situations show energy gaps emerging. We have tabulated here when a reliability gap of any size is modelled.

| Unexpected event → | Evening wind falls away | REZ lost middle of day | Rooftop PV disappears middle of a sunny, still low demand day | Evening wind doesn't eventuate | All rooftop PV lost suddenly in middle of sunny day |
|---|---|---|---|---|---|
| F1 – current | No gap | No gap | No gap | GAP | Gap |
| F1* - current plus more rooftop PV | No gap | No gap | Gap | No gap | Gap |
| F2 – 40% VRE with more gas share of firming | No gap | No gap | Gap | GAP | Gap |
| F3 – 40% VRE with more battery / PH share of firming | No gap | No gap | No gap | GAP | Gap |
| F4 – 80% VRE with more gas share of firming | No gap | No gap | No gap | No gap | No gap |
| F5 – 80% VRE with more battery / PH share of firming | No gap | No gap | No gap | GAP | Gap |

*In the table above, Gap means the case is a non-credible contingency event we think is not particularly relevant to an OR mechanism. **GAP** means the case is relevant to 'everyday' OR mechanisms as a mitigant.*

From this we can observe:

- **Most situations do not present a reliability gap, regardless of the generation fleet.** This includes all cases of the 'everyday' lack of evening wind and the contingency event of losing all VRE via a REZ transmission failure.
- **The loss of rooftop PV when there is little coal on-line can be managed in most future states**, especially when HIGHER levels of (utility-scale) VRE penetration are constrained off at the time of the event and therefore acting as a form of operating reserve themselves. In any case, we have noted that this is improbable in reality given ability to at least partially anticipate rooftop PV output via cloud forecasting in the short-term.
- **The even less likely event of a complete loss of rooftop PV in the middle of a sunny day tends to create problems** (as one might expect), but these are generally short-term (and in reality, likely to be at least partially met via interconnectors and demand response).

[32] The equivalent would be a permanent state of emergency RERT contracts in place… or a capacity market!

- The concern is when firming relies more on battery and pumped hydro rather than gas, where the duration of storage can be a problem leading to longer gaps.
- We suspect this is primarily a question of resource adequacy (in the P2025 context) rather than an argument for OR – unless it can be shown that an OR mechanism causes energy storage to be in a greater state of charge in these circumstances than they otherwise would be. But given the event itself is so unlikely, we continue to suspect this is more appropriately handled under more general contingency planning (as the system always has, based on the risk of losing one or more of the largest generating units in a region).

- **Unexpected lack of a windy evening is a problem now, and in future states.** This is perhaps the most interesting case in terms of assessing the need for OR.
    - Currently, the challenge is ramp rates of gas to meet an (apparently) sudden lack of wind, once hydro capacity is fully committed.
    - Again, the model does not consider the price signal - we wonder whether it is likely that gas would not ready itself earlier than modelled, observing the hydro capacity ramping up to full commitment in the hours prior, presumably in response to high prices and likely in the face of even higher forecast prices.
    - Future states with less gas / more battery and pumped hydro appear to face a more severe gap, due to lack of energy storage duration at the time of the event. This is probably a useful conclusion, but more relevant to resource adequacy: driving the right balance of capacity investment (as opposed to short-term operational behaviour).
    - Note that the issue is not as simple as "more gas, less storage", but also about optimising the depth of storage – how much pumped hydro versus battery, how many hours of storage duration behind a given battery capacity (the model assumes two hours). We do not see how an OR mechanism specifically assists with that optimisation of investment decisions.
    - Again, model limitations (such as assuming no initial charge, no interconnection) are probably relevant to the apparent result.

# Appendix 2 – Referencing ESB's consultation questions

In this Appendix we make some cross-references back into our submission, in relation to some of the questions for consultation posed by the ESB in the Options Papers parts A and B.

## Questions for consultation – Workstream 1

1. *What types of information provision regarding jurisdictional investment schemes would benefit participants the most?*

   **Refer Sections 1.1.2, 1.6 and 1.6.1**

2. *Which financial principles are most important in establishing means to integrate jurisdictional investment schemes with market arrangements as smoothly as possible?*

   **Refer Section 1.6.2**

3. *Are there financial principles missing, or that have been included but shouldn't be?*

   We support the proposals and have not identified any serious gaps.

4. *What are some of the market-based signal challenges, if any, with mothballing/seasonal shutdown?*
5. *What additional costs or process burden may the disclosure of such information place on stakeholders?*
6. *What concerns do stakeholders have around the commercial sensitivities associated with disclosing information?*
7. *Do stakeholders perceive the disclosure of mothballing / seasonal shutdown information as limiting a participant's flexibility in operating their plant?*

   **Refer Section 1.7.1.** We acknowledge the commercial sensitivity regarding mothballing information, but in our view the benefits to all participants and stakeholders of greater transparency and confidence outweighs these concerns.

8. *Do stakeholders agree the notice of closure exemption process should be extended to include mothballed generation? If so, should it apply to all generators or just to large designated thermal generators?*
9. *What suggestion do stakeholders have for defining mothballing?*

   **Refer Section 1.7.2.** We support the thrust of the proposal but we are very cautious about this being an over-reach into necessary commercial flexibility, with potential unintended consequences of earlier withdrawal. Therefore this should be narrowly-focussed on preventing any egregious loophole between closure and deep, indefinite mothballing.

10. *How can governments, market bodies and market participants better work together to be prepared for exits?*
11. *Do stakeholders agree governments are best placed to enter into a contract with a respective participant in the event of early exit?*

    **Refer Section 1.7.3.** We are pragmatic about this and support the ESB's proposals in general – however we offer two possible additional principles for such contracts – that they should be (1) Funded by budget, not consumers and (2) Flexibly designed to accommodate improvements in outlook.

12. *Do stakeholders agree that any future contract arrangements should be kept separate to existing RERT mechanism?*

    Yes, in the absence of any argument we are aware of otherwise.

13. *Do stakeholders agree with the proposed principles and measures of success? Are there others that should be considered?*
14. *Are there any obvious priorities given current and plausible likely future market scenarios?*
15. *What options are there to encourage contractual compliance among retailers without adopting higher punitive penalties?*
16. *Would one RRO option over another better suit particular types of market conditions anticipated over the course of the transition?*
17. *[Financial RRO option] How could you strengthen the signal? Could minimising the triggers do this? What are the unforeseen consequences or implications with this?*
18. *[Financial RRO option] What are options to make the RRO simpler, while still advancing some measures of success?*
19. *[Financial RRO option] What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?*
20. *[Physical RRO option] Should it be a triggered mechanism, or be developed as a rolling one?*
21. *[Physical RRO option] How should the physical certificates be regulated?*
22. *[Physical RRO option] How would a physical RRO impact contract market liquidity?*
23. *[Physical RRO option] What other impacts on small retailers and C&I customers need to be considered? How can they be best mitigated?*

For these RRO-related questions 13-23: **Refer to Introduction, Sections 1, 1.2, 1.3, 1.4, 1.5 and 1.8** in which we lay out our opposition to modifications to the RRO.

In **Section 1.8.4** we set out two proposed improvements to the current RRO design for consideration.

## Questions for consultation – Workstream 2

24. *What are stakeholder views on what specific design issues should be considered for an operational system security mechanism (SSM) to support the objectives of providing secure operations through the transition of the power system and to support efficient dispatch outcomes?*
25. *What additional information should be considered to assess the complementarity and materiality of an operational SSM in the context of a TNSP-led solution in the investment timeframe?*

    **Refer Sections 2.3 and 2.6** in general.

    We support variations on the system strength reforms which remain flexible to new technology and full participation by system-supporting assets in the operational timeframe (**Refer Section 2.6.1**).

    We are somewhat concerned to ensure TNSP-led investment / contracting is appropriately diverse and flexible in relation to potential non-network solutions (**Refer Section 2.6.3.3**)

    We consider whether MORE jurisdictional investment / intervention would be justified in this are (**Refer Section 2.6.3.2**)

    While we support the UCS+SSM version of system strength reform, we are aware system strength may increase first-order total costs of dispatch in some circumstances. We would like to see considerably more supporting evidence about the scale of the costs, trade-offs between technologies, and benefits from co-optimised dispatch in the next stage (**Refer Section 2.6.4**).

26. *How do stakeholders view a ramping or operating reserve as fitting within the overall framework for essential system services?*

    **Refer Summary and Sections 1.2, 1.2.1, 1.2.4, 1.2.5, 1.2.6, 1.2.9, 1.4, 1.5, 2, 2.1.2, 2.2 and Appendix 1.** In very brief summary, we view it as superfluous both resource adequacy and essential system services, based on the evidence we have seen and the trends we are observing in terms of other reforms and the investment pipeline.

1. *What are stakeholder views on the interactions between the proposed investment and operational procurement mechanisms for structured procurement?*
    a. *In what other circumstances to the ones listed in the paper would having both mechanisms be complementary to one another? How should they be designed to support this complementarity?*
    b. *In what circumstances might having both a long-term and short-term procurement mechanism potentially cause unintended consequences? What should be done in the design to mitigate these risks?*
    c. *What are the potential impacts, in either or both mechanisms, for the different segments of industry, for efficient investment in transmission and generation, and efficient operation of the system?*
2. *How do stakeholders envisage contracting arrangements will work under the long-term procurement mechanism, and how may this interact with the design of the SSM or vice versa?*
3. *Do stakeholders agree that the UCS should schedule for an efficient level of the service which has been structurally procured, with the efficient level being with regards to meeting a dispatch cost minimisation objective, as defined by the terms of contract activation and pre-dispatch bids.*
    a. *If so, why? If not, why not?*

    **Refer Sections 2.6.1, 2.6.3.3, 2.6.4.2.**

No – we believe long-term structured procurement (being contractually inflexible and at risk of being superseded by other technologies available in the operational timeframe) should be contracted to minimum, not optimum system security levels. The scheduling should then bring in other assets based on short-term procurement to achieve the optimum level.

4. *Do stakeholders consider the potential for the UCS to centrally-commit contracted resources to be of material concern?*
   a. *If so, are the proposals put forward by the ESB sufficient to address this concern?*
   b. *If not, what should be done to mitigate this concern?*
5. *If the UCS commits units ahead of time, how would this interact with the existing wholesale spot and frequency markets that are real-time?*
6. *What are stakeholder views on how the UCS schedule should be reflected in pre-dispatch and dispatch (i.e., contracted resources being required to bid into dispatch to be scheduled and/or constraints applied)? Are there any possible unintended consequences of these approaches?*
7. *Do stakeholders consider the potential interactions between pre-dispatch, dispatch and the UCS to be material? I.e., that participants may change their self-commitment status following the UCS run.*
8. *What are stakeholders' views on the best way to address the potential decommitment?*
9. *How do stakeholders think that the uncertainty associated with scheduling units ahead of time in the UCS should be managed? Are there any considerations that should be taken into account in addition to those outlined above?*

We do agree this is a prima facie concern which must be carefully addressed. It seems to us that the version of the proposal which includes all assets in the benefits of system strength dispatch is most likely to avoid the risk of units decommitting when they see UCS-scheduled assets entering and disrupting the optimisation (as described in Option Paper Part B, page 30).

10. *Do stakeholders agree with the ESB's proposal that TNSPs would be responsible for providing AEMO with the required contract information for the system service contracts, where these have been agreed between the TNSP and the relevant resource?*
11. *How do stakeholders envisage the contracts for system services would be designed where these are to be scheduled by the UCS, and what information would be required to be provided to AEMO to support the scheduling mechanism?*
12. *Do stakeholders consider that all system service contracts (e.g., system strength) should be required to be scheduled through the UCS? I.e., must offer?*
    a. *If so, why? If not, why not?*
13. *Do stakeholders agree with the transparency measures proposed for the UCS implementation, or suggest other considerations exist that should contribute to transparency with regards to the UCS?*

(No comment on these questions)

14. *How do generators and demand response providers position themselves under current frameworks ahead of periods of high ramping or periods of uncertainty?*

They position themselves to maximise their risk-adjusted profitability based on their expectations of spot prices and their contract positions. The energy-only price signal offers a substantial reward for sound positioning.

15. *What challenges are envisaged in a future with higher variability and uncertainty in net demand?*

More complicated investment decision-making and operational algorithms to respond.

16. *How would a reserve service influence commitment and other operational decisions made by generators and demand response providers?*

    It may encourage them to formally commit when they otherwise would not have, if the reserve service (set via regulatory decision making, which may be too conservative) appears to be calling for more certainty than the observable market conditions indicate will be profitable.

17. *Who should pay for reserves and why?*

    Consumers already pay for reserves, in a reflection of the value of reliability they perceive, and this is appropriate.

18. *How would the fleet described in the case study have positioned itself under current frameworks in a future with higher net demand uncertainty? Would it have provided more ramping reserve?*

    This is a complicated question calling for sophisticated price-based modelling, not hypothetical answers.

19. *In what circumstances would a reserve service be beneficial for consumers?*

    **Refer Summary.** In it we state that modelling should be undertaken to answer the question in relation these proposed reforms:

    "Given the status quo in the NEM, including current and pending reforms, the current status of investments as well as any impacts of other highly-likely P2025 reforms:

    1. What is the marginal improvement in reliability?
    2. What is the additional cost likely to be experienced by consumers?
    3. Do consumers support this trade-off?"

## Questions for consultation – Workstream 3

43. *Does the proposed reform pathway for transmission and access meet the needs of the transition?*

    **Refer Section 3.** We support a move to LMP+FTR more rapidly than proposed.

44. *For each medium-term access option presented in Part B:*

- *Do you think that the model satisfactorily addresses the access reform objectives set out above?*
- *If any, what is your main criticism of the model?*
- *What additional detail do you require to understand the option?*

**Refer Section 3.5.** Any model must adequately meet the ESB's four criteria. We agree several do not.

Model should also meet three other criteria we offer, including making reality consistent with the ISP modelling assumptions, and facilitating a path to full LMP+FTR. Models which rely on administrative forecasts of future congestions are less appropriate than models based on actual revealed congestion costs, or participants expectation of those future costs.

45. *Which medium term access option is preferable?*

    **Refer Section 3.5.** The hybrid congestion management model plus connection fee.

46. *Are there alternative options that the ESB should consider?*

    Not at the expense of prosecuting the case for LMP+FTR, no.

47. *Are there potential improvements to the options that the ESB should consider?*

    **Refer Section 3.5.** Expanding on this, we would support market-based mechanisms which reveal the benefit of the congestion management rebate for foundational REZ participants (e.g. via REZ capacity auctions) and allow that value to be used as an offset to consumer TUOS costs associated with REZ transmission infrastructure.

48. *Would enhanced congestion information help to improve the coordination of transmission and generation investment? If so, what additional information would add value?*

    Yes it would, because it would socialise the LMP+FTR concept and issues for stakeholders.

    LMPs already exist as a shadow price in the dispatch process. We think it would be valuable to calculate and publish:

    - The costs of congestion associated with generators receiving RRP instead of LMP.
    - The extent of race-to-the-floor bidding
    - An estimate of the inefficiency of the resulting dispatch under those conditions.

49. *What are stakeholder views on when these arrangements should be implemented by? What should be taken into account when determining implementation timeframes?*

    Grandfathering of existing connected capacity is appropriate, as proposed via rebates of congestion costs associated with LMP. CoGaTI and these P2025 reforms have been exposed for several years now, and so these reforms should, not be delayed for the sake of opposition from stakeholders invested in the short-term VRE capacity pipeline.