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Orderly Exit Management Framework — Consultation Paper — 15 December 2023

EnergyAustralia is one of Australia's largest energy companies with around 2.4 million electricity and gas accounts across eastern Australia. We also own, operate and contract a diversified energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 5,000MW of generation capacity.

We appreciate the opportunity to comment on the need for and design of an Orderly Exit Management (OEM) framework for thermal generators. The former NSW Office of Energy and Climate Change (OECC) has been progressing the OEM framework on behalf of energy ministers. This work was initiated several years ago by the Energy Security Board (ESB) under its Resource Adequacy workstream. As per this workstream, an OEM framework needs to operate as part of an integrated package of policy and market settings that is primarily intended to maintain reliability in the National Electricity Market (NEM).

The OECC's proposed framework is intended to accommodate accelerated thermal generator retirement while maintaining reliable electricity supply. It favours negotiated closure agreements that are facilitated by mandatory information disclosures, and the threat of heavy-handed regulation (a new 'Notice of Mandatory Operation' under the National Electricity Law), which can be imposed by the relevant jurisdictional minister within 30 months of the announced closure date. The need for a managed exit would be based on independent assessments against the NEM's Reliability Standard, reflecting what customers are willing to pay to address risks to the energy system. Importantly, the framework provides a means to fund alternative, new and cleaner investment where this is feasible and preferable on a cost-benefit basis. Negotiated or regulated closure arrangements can restrict plant operation, which could provide a further avenue to address emissions impacts and preserve market signals for other participants. Closure arrangements would contain operating incentives to achieve reliability and value for money objectives, with varied approaches to deal with outage risk and cost uncertainties.

Our key observations on the framework are:

- **We support the general intent of the framework** as a way to minimise price and reliability disruptions for customers that can stem from disorderly exits, and doing so in a way that is transparent and least cost.

- **The framework can be refined to better achieve several core objectives,** namely providing more certainty on closure timings, explicitly accounting for emissions, preserving contract market liquidity, and integration with other market interventions around reliability.
- As an asset owner, we would **strongly oppose being forced into a regulated swap or cap arrangement that has very high levels of price risk relative to the underlying asset's capabilities**. This element of the proposal overstates the ability to forecast performance risk of aging assets, and of plant owners to manage and accept compensation for this risk.
- Some of the framework's stages appear to be unnecessarily **cumbersome and may not accommodate the lead times for plant owners to undertake necessary works** that would enable continued operation.

These points are expanded in the attachment. Our associated recommendations for the OECC and energy ministers in refining this framework are:

- Reconsider the timing applicable to each stage of the framework, including whether this can be feasibly prescribed for all situations. This should be done after speaking directly with different asset owners to **understand the timing and underlying factors that affect decisions around maintenance regimes and major refurbishments** for assets approaching end of life. The expected impact of these actions on asset performance, and hence achievement of the framework's reliability objectives, also need to be better understood, including in the context of other risks that are beyond the control of the asset owner such as fuel supply chains, availability of parts, specialised workforce requirements etc.
- The framework should be designed to reinforce the credibility of closure announcements and **minimise the time during which closure dates remain subject to jurisdictional confirmation. Some stages of the framework could be brought forward and combined.** For example, system needs shortfalls and a desktop identification of alternative solutions from the existing project pipeline can be done in the same assessment. Calls for bids from alternatives and submission of cost information by the exiting generator could be conducted simultaneously.
- The framework could also be supported by **enhanced planning and forecasting information** to the extent the closure framework might only be applicable to a few critical power stations. For example, AEMO's Electricity Statement of Opportunities (ESOO) could identify earliest feasible closure dates for critical power stations in line with committed and anticipated investments, with sensitivity analysis of potential closure dates informed by scenarios from its Integrated System Plan (ISP). Such analysis could inform which power stations or jurisdictions would be subject to the framework, **removing uncertainties about whether and when jurisdictions may 'opt in'.**
- Workshop with participants **how system needs assessments would translate into obligations or expectations on plant owners**, via operating modes and other performance obligations, and how this relates to contracting incentives.
- any backstop **regulated arrangement should better accommodate poor or deteriorating plant performance** and sharing of outage risk. This can be done by relying more on operational oversight and use of ex post adjustments, rather than high-powered ex ante incentives.

If you would like to discuss this submission, please contact me on 03 9060 0612 or Lawrence.irlam@energyaustralia.com.au.

Regards

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We need a formal closure framework to manage price, emissions and reliability

The NEM is characterised by a range of incentives for the entry of new and clean forms of generation and storage. Significant investment programs like the NSW Electricity Infrastructure Roadmap and the Capacity Investment Scheme (CIS) involve a high degree of prescription on the type and timing of new investments, based on emission reduction targets and other policy considerations. AEMO's ISP designates the optimal timing of 'Actionable' transmission projects, and is supported by a range of government planning interventions that will coordinate network, generation and storage investment. **This degree of control around the entry of new investment now justifies a similarly controlled approach to dealing with the exit of large thermal generators**.

Proper coordination of entry as well as exit will enable us to accelerate the transition while managing reliability and price stability for customers. That is, offering some degree of policy support for exiting generators that are critical for system reliability would not be at the expense of new investment or the pace of the transition more broadly.

Our summary statement on these policy and market design issues has been that we must build the new system before the old one closes. As pointed out by AEMO and others, the alternative "just in time" approach to replacing old with new capacity does not mitigate the risk of early and disorderly exit, nor the potential delays in getting new investment online. Taking a risk-averse approach to managing exits reflects the asymmetry in the consequences of supply shortfalls, relative to the cost of excess supply for the time that new investments and exiting emissions-intensive plant overlap.

The benefits of controlled exits are apparent in the agreements that governments have reached already, including for our Yallourn power station which is scheduled to close in 2028. **These agreements provide certainty for all stakeholders**. They allow workers and local communities that service power stations to plan ahead and transition into other economic activities. They allow discussions and planning to take place regarding site rehabilitation and meeting environmental obligations. They provide clarity on the asset owner's commitments to net zero pathways which is critical for financing and other reputational reasons. Other market participants can schedule replacement generation in line with closure dates, thereby minimising their exposure to periods of excess supply and associated low prices. As noted above it is increasingly the case that new investment will involve government financial support. Providing certainty on generator closure dates, by lowering development risk, therefore reduces the need for subsidies that are ultimately paid by consumers or taxpayers.

The framework can be refined against key objectives — certainty of exit timings, emissions, contract liquidity and integration with other reliability interventions

We support the OEM's design principles, which are listed in section 5.3 of the consultation paper. They include supporting reliability and system needs, transparency, value for money, minimising market distortions and minimising regulatory complexity. Refinements to the framework should focus on achieving the benefits of having more certainty on closure timings, and consider related policy issues of emissions reduction, reliability and contract market liquidity.

More certainty on generator closure dates

As noted above, there is a need to provide more control and certainty around the timing of large generator exits, and this should be a key objective that guides how the framework is refined. The OECC states that exit certainty is provided whereby a Notice of Mandatory Operation expires, at which point the generator will "retire permanently"[1] although this could be subject to extensions on the basis of 'adjustment events' at the discretion of the jurisdictional minister.[2] The framework involves necessary but potentially lengthy steps in assessing risks to the system of an announced closure, and the search for alternative solutions if risks do arise. Any closure dates announced to the market would not be taken as confirmed until the framework's stages are concluded, namely:

- a system needs assessment is published and finds the closure is manageable given the pipeline of new projects and other infrastructure
- there is a system needs shortfall, and an alternative solution is financially secured. Note the framework does not contemplate this level of certainty, which would be required by market participants, rather it contemplates a desktop assessment by AEMO and potential market sounding by the relevant minister
- revised closure dates and operating regimes are disclosed at the completion of a negotiated or regulated closure agreement.

The framework would apply to all notices made up to 7 years from an intended closure date, with the regulatory backstop invoked as late as 2.5 years to the closure date. This provides a maximum of 4.5 years during which the market, plant workers, local communities and the general public would be unable to plan towards a 'real' closure date. The experience with Eraring suggests that even in the presence of independent system needs assessments (and policy responses), there will be ongoing speculation[3] about whether life extension for the retiring generator is necessary. The framework's decision gates could reduce some of this speculation, for example by signalling a clear 'no return' government commitment to pursue a negotiated or regulated closure arrangement. This would need to accommodate the changing needs of the system and pipeline of new investment. In some cases, system needs assessments would be completed several years ahead of announced closure dates and their findings would eventually diverge from subsequent ESOO assessments.

The opt-in nature of the framework also creates uncertainties for market participants and other stakeholders. Furthermore, the OECC's paper suggests that jurisdictions can opt-out. We recognise the need to accommodate jurisdictional preferences however the law provisions that establish the framework should contain non-exhaustive criteria and timelines regarding decisions to opt in or out. For example, the ability to opt in should only be allowed for a limited time, say one year from amendments taking effect, and the framework should only apply on a prospective basis. The framework is proposed to apply to any generator that has brought forward its closure date since January 2021, rather than from the commencement of the framework. The OECC does not explain why January 2021 is relevant. The OECC suggests transitional arrangements would allow for ministers to opt in and deem generators to be within the framework without stage one having to apply.[4] There is a risk that a government may seek to negotiate with an exiting generator outside

[1] NSW Office of Energy and Climate Change, *Orderly Exit Management Framework – consultation paper*, December 2023, p. 23.

[2] ibid., p. 42.

[3] See for example climateenergyfinance.org/wp-content/uploads/2024/01/CEF-NSW-Electricity-report-19-January-2024.docx.pdf

[4] OECC, p. 56.

of the framework, then decide to opt in to take advantage of mandatory information disclosures or to invoke a regulated arrangement. The framework should operate prospectively and therefore not provide a mechanism to re-open any pre-existing closure agreements.

The framework applies ad hoc and contrasts with market-wide mechanisms used in Germany and others proposed in Australia, including as part of the ESB's consultations on resource adequacy.[5] Such broader mechanisms may not be needed in the NEM and seem unlikely in any case given the divergent preferences of jurisdictional governments, some of which have direct ownership of prospective generators. The OECC raises the prospect of further narrowing down the framework by suggesting criteria to **define eligible generating units**, which we would support. Periodic reliability and planning assessments already identify risks arising from the closure of specific generators, and without prejudicing government actions under the proposed framework. For example, both the latest ESOO and Energy Security Target Monitor report in NSW identify reliability gaps arising with Eraring's scheduled closure, and consider the effects of delaying the closure of two generating units by two years.[6] Potential closure timings for these type of risk assessments could be drawn from scenario projections in the ISP. These assessments could also identify critical in-service dates and necessary lead times for incoming generation, storage or transmission investments that would address any arising system risks.

The need to preserve the legitimacy of announced closure dates is also important when considering any moral hazard concerns with compensated exit arrangements. An outworking of moral hazard would be where a plant owner intends to close at a later date, however announces an earlier date with the intent of seeking windfall compensation to stay open until its 'true' closure date. Concerns at the prospect of this situation overlook the various benefits to the plant owner, and its internal and external stakeholders, of being able to plan towards a firm closure date as noted above. These benefits outweigh any upside gains that would be offered by 'gaming' a closure agreement, and by several orders of magnitude. The compensation models explored by the OECC and Frontier all approximate cost recovery with a regulated margin, and even then we recommend arrangements that involve lower risk and associated risk-adjusted margins.

Explicit assessment of emissions impacts

The OEM framework, by affecting the closure dates and operating regimes of fossil fuel generators, needs to explicitly account for emissions impacts. A key point of contention regarding the ESB's earlier work on resource adequacy and its design of a capacity mechanism was that it would have resulted in payments to fossil fuel generators, at the expense of cleaner new technologies, with higher emissions as a result.[7] Rather than engaging directly on this topic, the OECC appears to have diverted accountability to individual jurisdictions via the ability to opt into the framework. The only substantive mention of carbon emissions in the consultation paper is an example reason for placing operational limits on exiting generators.[8] This type of consideration should be explicitly instituted in cost benefit assessments under the framework. In addition to reflecting best practice and sustainable policy design, **a holistic approach that explicitly values**

[5] Brown Coal Exit: A Market Mechanism for Regulated Closure of Highly Emissions Intensive Power Stations by Frank Jotzo, Salim Mazouz :: SSRN, Phasing down gracefully: Halving electricity emissions this decade - Blueprint Institute, There's a better way to manage coal closures in Australia than paying to delay them | IEEFA

[6] energy.nsw.gov.au/sites/default/files/2023-12/2023_ESTM_Report_v2.pdf – see section 4.2.7. 2023 Electricity Statement of Opportunities (aemo.com.au) – see section 7.4.

[7] Victoria joins NSW in saying no to "Coalkeeper," wants focus on battery storage | RenewEconomy

[8] OECC, p. 39.

emissions alongside reliability and price impacts for customers is now required under the amended energy law objectives. Legislative amendments that enable the framework could provide for jurisdictional 'carve outs' from considering emissions impacts, however this would be highly contentious and therefore unlikely.

Emissions considerations arise in several elements of the framework, primarily in setting obligations or restrictions on operating modes (as already noted by the OECC) but also in the search for alternative solutions. The time constraints and deliverability barriers in bringing on new replacement generation at short notice, particularly where system needs identify risk of longer duration outages, may lend support for peaking gas or liquid (diesel) generation. The framework is silent on technology types, which would be decided by the relevant jurisdiction. It is worth noting that AEMO's ISP modelling demonstrates that some amount of peaking gas generation forms part of the least cost technology mix, alongside renewables and energy-limited storage, and can play this role while staying withing long term carbon budgets.[9] To the extent jurisdictions have in-principle concerns with gas generation on the basis of emissions, this should be explored through explicit and transparent cost benefit assessments of all prospective solutions, including those that might have operational constraints imposed.

The desire to reduce greenhouse gas emissions is likely to be a key factor in bringing forward a generator's closure date. Negotiated or mandatory closure agreements will therefore need to consider how any life extensions and associated emissions will negatively affect the owner, in terms of social, financial and legal dimensions. We recommend that responsibility for emissions under any closure arrangement transfer to the relevant jurisdictional government and be reported in state-wide carbon accounting, rather than against the facility in National Greenhouse and Energy Reporting.

Alignment with NEM reliability settings and other interventions

The framework needs to be consistent with the **reliability and risk thresholds used in existing system needs assessments and investment schemes**. We strongly recommend the framework's system needs assessments be based on the Reliability Standard. This accords with the framework's objectives of transparency and value for money, noting that the Reliability Standard is explicitly calibrated against customers' willingness to pay. Decisions relating to the procurement of services from new and exiting generation should reflect a consistent approach to system needs. Any misalignment will result in excessive procurement and higher costs for customers, or under-procurement and risks to reliable electricity supply.

AEMO has obligations to identify forecast reliability gaps across all NEM jurisdictions in the ESOO. Investment schemes across NEM jurisdictions are, however, based on several reliability and risk settings. These divergences distort investment signals. It is unclear how specific investment targets and timings under the CIS will be determined. In aggregate these appear to be limited by Commonwealth budget allocations rather than set to address any arising reliability gaps or emission reduction targets in all applicable jurisdictions. CIS investment targets across jurisdictions will also be contingent on Renewable Energy Transformation Agreements, which involve some consideration of reliability impacts.[10] The technology mix and tendering schedules under the NSW Electricity Infrastructure Investment Roadmap are driven in part by a summer N-2 reserve margin in the NSW Energy Security Target, as well as general analysis of renewable

[9] AEMO, *Draft 2024 Integrated System Plan*, December 2023, pp. 3, 65-6.

[10] Information for proponents - DCCEEW

energy 'lulls'.[11] The OECC suggests system needs assessments under the OEM framework could also accommodate similar 'tail risks'.[12]

We note the NSW Energy Security Target was examined in the recent NSW 'Check Up' review, which suggested it be brought into line with national settings, pending the current review of the Reliability Standard.[13] The Reliability Panel is currently considering the need to accommodate tail risks within the Reliability Standard. We recommend the OEM framework adopt NEM-wide settings, including any changes arising out of the Panel's review, rather than provide for jurisdictions to continue to opt for bespoke reliability thresholds.

Preserving contract market liquidity and retail competition

Our specific comments on risk and contract design for exiting generators are outlined below. In general, any **government contracting with generation and storage needs to accommodate liquidity in forward markets**. We recommend the OECC examine Frontier's recent report, prepared for the ACCC's Electricity Inquiry, which explores the implications of government underwriting and impacts on retail markets.[14] Closure arrangements under the OEM framework should incentivise plant owners to seek market revenue by selling contracts directly. Otherwise the government, as counterparty, should onsell their negotiated or regulated purchases to retailers and other market participants. While we oppose any regulated swap and cap arrangements, the value of these contracts will reflect some amount of subsidy paid by the government which would not be valued by the market hence not recoverable via such onselling.

Any regulated backstop arrangement must reflect real-life performance risk

Each power station will have different characteristics but generally there will be significant challenges in predicting the end-of-life performance of thermal generators. The proposed financial swap or cap arrangement follows Frontier's first principles assessment of efficient risk allocation, and in doing so overlooks some of these real-world complexities. The proposal for such a high-powered incentive regime indicates that governments might have unrealistic expectations of the extent to which aging generators can uphold the reliability and security of the energy system.

The prescription of the Notice of Mandatory Operation's risk sharing arrangements will have implications on how a preferred negotiated arrangement may be struck, so will be important to define ahead of time. However we are concerned about the threat of being forced into an unworkable and uncommercial arrangement, particularly at short notice and at the minister's discretion. We recommend the OECC work through how a swap or cap arrangement would operate alongside performance obligations, compliance, penalties and uncertainty mechanisms. Our view is that **alternative risk sharing models would be more appropriate and would still provide sufficient incentives on plant owners to act in line with consumers' interests.**

[11] See section 12(1) of the NSW Electricity Infrastructure Investment Act 2020, and clauses 13 and 24(2)(e) of the Electricity Infrastructure Investment Regulation 2021.

[12] OECC, p. 29.

[13] NSW Electricity Supply and Reliability Check Up - Marsden Jacob Associates Report

[14] appendix-d-future-financial-risk-management-nem-frontier-economics-inquiry-national-electricity-market-december-2023-report.pdf (accc.gov.au)

A theoretical approach to efficient risk allocation

Frontier's assessment is founded on the sound economic principle that the asset owner would be best informed of performance risk and able to take actions to mitigate this. It is assumed that asset owners, as perfectly rational and informed economic agents, would be able to value outage risk and be accepting of compensation through a regulated price.

We recognise the reliability and value for money objectives that underpin the framework. To this end it appears to make asset owners accountable for out-turn performance and reliability outcomes, in ways that would typically be expected of new dispatchable plant when responding to spot price incentives. In consultations on recent government investment schemes, EnergyAustralia has consistently argued that plant operators should indeed be exposed to high degrees of price risk, which incentivises performance in line with system objectives.

The proposed framework applies this same logic but to aging and relatively inflexible power stations. **Owners of these assets would face significant challenges in risk assessment towards end of life, and be unwilling to accept risk at any price.** This is likely to be the key driver for closure decisions in the first place. The framework's mandatory disclosures would contain a range of technical information across a plant's different risks and failure modes. Market bodies and governments, with the assistance of independent expert advice, may be comfortable in defining broad operational parameters such as average availability over seasonal or annual timeframes. More granular quantification, as it relates to seasonal operating modes, forecast periods of reliability gaps, or effectively to dispatch intervals under a swap or cap, becomes progressively infeasible.

A theoretical approach to incentive regulation more broadly

Frontier's analysis draws heavily from standard approaches to monopoly infrastructure regulation. In the energy context, high powered incentives and investigations of prudent and efficient costs apply to network assets worth many billions of dollars and whose revenues contribute to around 40 per cent of customer bills. These approaches would be excessive and disproportionate to the customer impacts of setting efficient costs for likely a handful of exiting generators, with contract terms of only a few years.

A key area arising with respect to exiting thermal generators that is not dealt with under standard regulatory arrangements is detailed assessments of performance outcomes. The AER's approach to electricity networks, for example, involves a somewhat light-handed approach which seeks to maintain trend outage performance, measured over long time periods and large geographical areas given the scale and diversity of underlying assets. The incentives attached to network performance including unplanned outages amount to 5 percent of annual revenues.[15] Frontier's approach to efficient risk allocation appears to lead it to side-step the need to define performance incentives in any regulated arrangement. Section 10.7 of the OECCs paper also defers the definition of performance obligations to the relevant jurisdictional minister. Any exit arrangement will need to reflect quite detailed and direct effects of spending and asset works on outage and other performance measures, and within a relatively short period of time i.e. one or two years ahead.

[15] AER - Service Target Performance Incentive Scheme v 2.0 - 14 November 2018 (updated 13 December 2018).pdf

Frontier and the OECC make general provisions for these challenges however still attempt to accommodate them in a standard ex ante incentive framework in the following various ways:

- ‘margins’ in the strike price — as noted above, quantifying risks will be challenging. Owners will therefore tend to be conservative in their estimates, which could be taken as merely a negotiating strategy, and so face the prospect of more aggressive assumptions being imposed via regulation. The AER will need to retain appropriate technical expertise, with assessments likely to be disproportionately contentious and burdensome.

- Insurance — the OECC states that asset owners will need a prudent level of insurance. Insurers will require prudent levels of maintenance, which will “increase confidence that the generator will be in a position to provide the required services”[16]. The OECC should explore what this insurance is intended to cover and if it will be offered, again noting difficulties in quantifying various asset and operational risks.

- Force majeure — this is only mentioned in the context of terminating a regulated arrangement, not in the context of performance obligations.

- reopening a regulatory determination for unforeseen events — this applies to costs only. The proposed swap and cap arrangement would expose asset owners to very large difference payments, up to the market price cap. The expectation is that these losses would be covered by insurance or in the strike price.

<u>Incentives and penalties associated with performance obligations</u>

Performance obligations would be defined subject to plant specific factors and system needs assessments. The OECC lists an example obligation for periods where system needs are likely to arise e.g. afternoons and evenings of peak summer periods and other specific obligations like fuel stocks. In contrast to cost pass throughs, performance obligations would not be subject to generally defined unforeseen or uncontrollable events, but explicitly limited to ‘serious technical faults’ and ‘safety issues’:

> The System Significant Generator will be exempt from the performance obligations if it is unable to meet the performance obligations because of a serious technical fault or for safety reasons for the period needed to address the technical fault or safety issue…
>
> The AER will assess the System Significant Generator’s compliance with its performance obligations at the end of each financial year. The AER may request information from the System Significant Generator and, if required, source information from AEMO in order to assess compliance... Given that the Notice for Mandatory Operation is intended to address the cost to electricity consumers of a systems needs shortfall, the AER will have access to its full suite of enforcement tools to ensure compliance. Failure to comply will be classified as a Tier 1 civil penalty under the NEL.

We have several concerns with this arrangement:

- ‘serious technical fault’ implies some form of asset failure rather than issues relating to fuel supply, or the availability of specialist engineers (for example)

[16] OECC, p. 40.

- the ability to undertake appropriate maintenance ahead of time to minimise technical faults depends on sufficient lead times being given under the broader OEM framework. Pending the AER's level of expertise and recognition of these time limitations, there is also a risk it will deem a particular outage or delayed return to service to be within the control of the plant owner

- plant owners would face tier one penalties, in addition to different payments under the swap or cap arrangement. This seems excessively punitive and the OECC should consider whether continued operation under these provisions might compromise director duties under corporations law

- failure to 'show up' under a closure arrangement could be politicised or publicised, resulting in reputational risk for the plant owner in addition to financial penalties.

We emphasise again that these negative outcomes for the plant owner all arise in a situation where it has been forced to extend plant operation at the behest of the relevant minister, and under a regulated compensation arrangement.

<u>Any regulated arrangement should be less intrusive and provide for balanced risk-sharing</u>

The OECC seeks feedback on a 'shielded loss and gain' alternative to the financial swap and cap arrangement. The core feature of this approach is ex post assessments of profits or losses, such that the generator is 'made whole' with respect to its prudent costs including a risk-adjusted margin. Positive or negative cash earnings would also be subject to sharing ratios e.g. 25 percent of upside earnings would be paid to the generator, 75 per cent of losses would be retained by the generator, with the remainder paid to or borne by the government counterparty.

The approach involves contractual obligations to limit generation when prices fall below short run marginal cost as well as general performance obligations, which we presume would still involve limited exemptions and tier one penalties for non-compliance. We would still have reservations regarding the extent of compliance penalties and attempts to provide incentives around spot market prices.

Otherwise this is a superior approach to the cap and swap arrangement for several reasons:

- Frontier's assessment is that the 'shielded loss and gain' model involves similar administrative burden to a swap or cap arrangement, which we disagree with. As noted above the quantification and pricing of risk into the swap or cap strike price would be highly contentious.

- It allows outage risk to be better reflected in performance obligations as well as in explicit risk sharing parameters. This contrasts to the swap and cap arrangement which by default fully exposes the generator to 100 percent of downside risk (except for serious technical faults), in addition to civil penalties.

- The sharing ratios could be calibrated in line with the degree of outage risk for different generators. Any ex post repayments could also be subject to profitability 'deadbands', that is only where revenue exceeds (falls below) a pre-defined cap (floor) as will be applied under CIS agreements. These risk sharing approaches should provide for a commensurately lower margin than under the swap and cap arrangement.

- Generally the reliance on ex ante forecasts in combination with a cap and swap arrangement would create incentives for cost minimisation, but the benefits of this over a contract lasting a few years appear to be minimal. Short term forecasting would rely heavily on observed spending in recent years, as well as for more discrete near-term works, likely drawn from contract information.

- A light-handed approach that relies on annual budgeting, subject to independent review before and after the event, rather than detailed bottom-up assessments by the AER, appears to be more commensurate with broader customer impacts. Any AER involvement would likely be outsourced to technical specialists in any case.

- Regulatory oversight regarding the extent to which operators act in good faith regarding spot price outcomes and minimising incentive payments form part of CIS contracts. This seems preferable to approaches that set ex ante price benchmarks including as strike prices in a flat swap or cap arrangement.

The framework needs to provide sufficient lead times and can be streamlined

The main steps in the proposed framework are designed to allow enough time for system needs assessments, identification of solutions and negotiations with exiting generators if necessary. The framework would be initiated for notices given to within 7 years of the closure date. Each generator will be different however we expect owners would need to start making decisions from around the 7 year mark on significant capital and maintenance cycles to that could prolong asset life. Sufficient lead times are also necessary to assist workforce, environmental and community stakeholders make and execute transition plans. The proposed mandatory disclosures should identify such 'drop dead' dates for decisions that would enable life extension. **These critical decisions are likely to clash with the timeframes set under the framework.**

The framework may wish to enable jurisdictions to purchase a real option for life extension, for example an up-front payment for particular maintenance or to secure fuel supplies, which would enable the generator to be called upon if found to be need in later framework stages. A real option might accommodate a regulated arrangement being imposed with less than 2.5 years to scheduled closure, which would almost certainly be infeasible unless necessary works had already been undertaken ahead of time.

Other refinements to the framework seem possible that may accommodate timing challenges.

Stage one of the framework is proposed to take approximately one year from a generator issuing its notice of closure to when the relevant minister triggers the search for solutions under stage two, that is:

- once a notice of closure is issued, the minister has within 60 business days to request a system needs assessment from AEMO

- AEMO must complete an assessment as soon as practicable. AEMO took around two months to complete an ESOO update following Origin's announcement for Eraring's closure in February 2022

- within 60 business days of receiving a system needs assessment, the minister can trigger stage two by making a request to AEMO to search for alternative solutions.

The proposed timings for stage two are less specific and in some cases we expect would involve more time than anticipated by the OECC:

- AEMO has 60 business days to advise on alternative solutions, and can seek extensions to this

- the minister has the option to seek additional information, consider policy solutions or undertake a market sounding process

- once or after stage two is triggered, the minister can request the AER to provide an indicative cost estimate of life extension within 60 business days

- other steps in the process have unspecified timeframes, namely the ability to request more information from the closing generator, a consumer benefits assessment of addressing a gap in system needs, and due diligence reports by the generator.

One of the key outcomes of stage two appears to be that the jurisdictional minister can conduct a robust cost-benefit comparison of available options, including against the value of addressing the risks to system needs. For this to occur, we consider that the search for alternative solutions must involve market sounding and the receipt of a bankable development proposal.

Noting this objective, some framework stages could be condensed and supported by existing reliability reporting, thus providing additional time to identify alternatives as well as reduce administrative burden:

- AEMO already has obligations to publish an ESOO update in the wake of a significant closure announcement. The ESOO currently specifies reliability gap periods up to 5 years out which could be taken as or extended into a system needs assessment. The ESOO's examination of prospective projects and sensitivities also seems to constitute a desktop assessment of whether alternative solutions are forthcoming.

- The market sounding for alternatives should be enhanced to seeking binding bids for solutions that address the system need as identified by AEMO. This step can coincide with the exiting generator also providing a cost bid and other information specifically tailored to that need, thus allowing direct comparison and competitive tension with new entrants. It would supplant any AER cost estimate for life extension, as well as form a robust basis on which negotiations could take place.

- The proposed framework envisages the exiting generator furnishing multiple government entities with substantial information at the time of a closure notice. This is burdensome and ultimately unnecessary if a system risk is not subsequently identified. It is also poorly targeted i.e. the "incremental" costs for life extension to the previously notified closure date would be irrelevant, and would need to be revised once the system needs assessment is completed. Exiting generators would need to reconsider costs associated with any plant operating modes or performance obligations.