Submitted online: energy.consult@dpie.nsw.gov.au

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Orderly Exit Management Framework: Consultation Paper

The Australian Energy Council (AEC) welcomes the opportunity to make a submission in response to the NSW Department of Climate Change, Energy, Environment and Water's (NSW DCCEEW) Orderly Exit Management (OEM) Framework: Consultation Paper (Consultation Paper).

The AEC is the peak industry body for electricity and downstream natural gas businesses operating in the competitive wholesale and retail energy markets. AEC members generate and sell energy to over 10 million homes and businesses and are major investors in renewable energy generation. The AEC supports reaching Net-zero by 2050 as well as a 55 per cent emissions reduction target by 2035 and is committed to delivering the energy transition for the benefit of consumers.

Overall framework observations

The OEM Framework objective is to ensure the energy market transition progresses in an orderly manner, minimising risks to reliability or the security of the electricity system. The OEM Framework creates an additional set of regulatory tools for Government to seek to control the pace and extent of thermal exit.

There are practical challenges associated with regulating the ongoing operation of generators with bespoke operating requirements. It is therefore crucial that the OEM Framework, if implemented, acts only as a last resort measure and that due regard is given to existing regulatory arrangements supporting an orderly transition. This includes the RRO, RERT, notice of closure requirements, and proposed energy transition rule change that would give AEMO the power to contract services. In the absence of such an approach an OEM Framework would significantly increase the likelihood of inefficient interventions that are inconsistent with actions taken under other market mechanisms.

The AEC notes that under the "improving security frameworks for the energy transition" rule change, the AEMC is proposing to grant AEMO broad powers to contract for services during the transition which may include contracts to extend the life of thermal generators. This proposal has very broad support from industry and is likely to proceed. Broadening AEMO's powers in such a manner is also more efficient from a governance perspective since AEMO is responsible for managing power system security both in the operational timeframe as well as from a long-term reliability perspective via related mechanisms such as the RERT and performing the reliability forecasting that would identify threats associated with retirement of plant.

Under the OEM Framework, and specifically the Notice for Mandatory Operation (NMO), a generator can be forced into a complex and expensive asset life extension which neither the generator, nor the market prefers. This extension has implications for the generators ability to meet emissions reductions. This carries reputational/ESG risk and could run the risk that investors with a clean energy mandate need to reassess their position. There are also potential impacts to environmental licences – as regulations become more stringent, the investment required in end-of-life plant to meet those standards becomes costly, increasing costs to consumers.

The OEM Framework exacerbates uncertainty in the investment horizon. A generator announcing a closure date provides certainty to the market, allowing potential investors in new dispatchable generation to forecast market conditions. The OEM Framework will add significant uncertainty and risk to this equation and is likely

Level 14, 50 Market Street
Melbourne 3000
GPO Box 1823 Melbourne Victoria 3001

P +61 3 9205 3100
E info@energycouncil.com.au
W energycouncil.com.au

ABN 92 608 495 307

to have a depressive impact on investment at this critical point in the energy transition which undermines initiatives such as the Capacity Investment Scheme.

To date, where a generator signals an intent to close its plant, jurisdictions with a requirement for those generators to continue operating have entered into voluntary negotiations. The OEM Framework briefly references voluntary agreements but seems primarily designed to address information asymmetry in those negotiations through the imposition of Prescribed Information at Stage One of the OEM Framework, and through a backstop arrangement, whereby the Minister can issue an NMO. Once a generator is under this Notice for Mandatory Operation, its revenues become regulated by the AER.

The AEC does not think that the OEM Framework stages are sufficiently structured around the negotiate / arbitrate model. While the Consultation Paper notes a jurisdiction will enter voluntary negotiations, the early provision of a wide range of Prescribed Information before those negotiations commence will, in the AEC's view, drive those negotiations towards the AER determined outcome. In addition, a key concern is that the Prescribed Information would have to be provided before a system need has even been identified – this creates an onerous obligation on market participants.

The Consultation Paper sets out broad Ministerial discretion to proceed to issuing a NMO. In particular, a NMO can be issued if, "in the Minister's opinion", it is needed to avoid a system needs shortfall and it is unlikely that a voluntary negotiated agreement will be reached, or the generators proposed closure date is within 30 months. As the relevant jurisdiction will also be the counterparty to any voluntary negotiations with a generator, it is not appropriate for the Minister to have such a significant level of discretion to proceed to a mandatory notice, including an ability to effectively bypass Stage 2 (and therefore bilateral discussions entirely) if the proposed closure is within 30 months.

The AEC recommends establishing the following to introduce a more balanced approach with appropriate governance:

- A clear set of criteria / pre-conditions on which the Minister's decision must be based (including a requirement that both parties negotiate in good faith) and removing any overarching power to bypass voluntary negotiations and proceed straight to a NMO.
- A right of appeal process for the generator if there is a view the preconditions haven't been adequately satisfied.
- A minimum notice period for issuing a mandatory notice in the order of at least 12 months for plant that brings forward its closure date between 1 January 2021 and scheme start, and 18 months for all other plant. This is to ensure a generator can adequately manage its plant requirements (e.g. maintenance, people, fuel, ash dam requirements (in the case of coal plant)), hedging requirements, emissions impacts etc. As currently proposed, there is no constraint on the timing of when a generator could be issued a NMO, which creates significant uncertainty / risk for the operator.

A regulated swap or cap arrangement is not supported. It is based on a theoretical and first principles approach to risk allocation that does not reflect the realities in managing an aging power station. Risks for these assets will be difficult to assess and quantify, particularly in a regulated setting, meaning owners will not be compensated appropriately. Asset owners that cannot produce when required due to various end-of-life issues would be exposed to large difference payments up to the Market Price Cap (MPC).

If the level of support proposed by the Government under a proposed voluntary agreement is insufficient to bridge the commercial viability gap that led to the planned closure, it should be a clear signal to all parties that the plant is not viable on an ongoing basis. The AEC recommends reconsideration of the need for the NMO in the framework.

Level 14, 50 Market Street
Melbourne 3000
GPO Box 1823 Melbourne Victoria 3001

P +61 3 9205 3100
E info@energycouncil.com.au
W energycouncil.com.au

The Consultation Paper describes the OEM Framework as an opt-in framework that is intended to give government the tools necessary to manage the transition to renewables. The AEC would appreciate some clarity about which jurisdictions intend to adopt the framework, as the NEM is an interconnected system and decisions about generation in any given region will have an impact on other regions. Additionally, clarity about whether the OEM is intended to be limited to the transition period or if the Energy & Climate Change Ministerial Council intends it to be an ongoing feature of the NEM.

AEC views on the Consultation Paper questions are listed below.

Consultation Paper questions

One of the issues raised is how to activate the OEM Framework if an OEM Generator were to mothball a unit(s). Consideration is being made to include a mechanism to capture generating units that are mothballed. The proposed text for inclusion in the criteria above to trigger the OEM Framework is "when an OEM Generator notifies AEMO that an OEM Generating Unit is not available under the NER clause 3.7.2 for a period covering 75% of the period from 12-36 months, with a recall time greater than 3 days or no recall time reported".

1. *Is this mothballing precondition appropriate?*

The AEC does not agree that the OEM framework needs to include scenarios where generating plant may be mothballed. A decision to mothball will often be driven by poor generator economics / commercial issues, not necessarily an end-of-life decision. Inclusion in the OEM would be regulatory overreach, with voluntary negotiation a better mechanism to the extent a jurisdiction would prefer mothballed plant to be made available.

Further, efficient seasonal mothballing of plant has the potential to extend the economic life of generating units and the AEC considers that mothballing is unlikely during an assessed reliability gap period where retailer reliability obligations would promote contracting to underwrite operation of generating units.

It is also worth noting that AEMO can direct offline plant (including mothballed plant) to generate if deemed necessary to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state. Given this, there doesn't appear to be a demonstrated need to capture mothballed plant in the OEM Framework.

2. Do you have a view on the timings in the mothballing precondition?

The AEC does not have a view, as it does not agree that the OEM needs to cover mothballing.

3. Are there concerns with requiring the Prescribed Information to be provided when the OEM Generator notifies of a change to its closure date (or applies to the AER for an exemption from the notice of closure requirements)? If yes, please provide details.

The AEC is concerned with both the timing and scope of the Prescribed Information set out in the Consultation Paper. The AEC suggests that for clarity the introduction of an additional stage. Stage 2 should be limited to a needs assessment and identification of alternatives. A new Stage 3 would involve the voluntary negotiations if these are required. Stage 4 would then become the NMO.

The scope of Prescribed Information proposed is very broad, covering both technical and economic information. Generators would need to provide extensive technical and economic information relating to their plant prior to AEMO and the relevant jurisdiction undertaking a Systems Need Assessment (SNA) to

Level 14, 50 Market Street
Melbourne 3000
GPO Box 1823 Melbourne Victoria 3001

P +61 3 9205 3100
E info@energycouncil.com.au
W energycouncil.com.au

demonstrate that the plant may be required beyond its closure date. The technical information is not required until the SNA has been completed. The economic information is not required until a decision is made to issue a Notice of Mandatory Operation. The AEC recommends that Prescribed Information is provided when the underlying information is required.

The AEC also recommends that the Prescribed Information distribution should be limited to the relevant jurisdiction and the AER with strict controls on who within those organisations require access given the commercially sensitive nature of that information. AEMO's role is limited to undertaking the SNA and considering alternatives, not to examine the technical capabilities and economics of the existing plant, and therefore it does not need access to the Prescribed Information.

The Consultation Paper argues that the information asymmetry between negotiating parties needs to be overcome as a rationale for the scope and timing of the provision of the Prescribed Information. However, for the OEM Framework to be a true negotiate / arbitrate model, Stage 3 voluntary negotiation does not need to proceed with both parties having full information. The nature of voluntary negotiation requires incomplete information to come to a mutually beneficial agreement. A Generator should not know exactly how much a jurisdiction would be willing to pay to keep that unit open for an additional period of time, and equally a jurisdiction should not know exactly what a Generator would be willing to accept to remain open if a negotiation is voluntary. It follows that the provision of all Prescribed Information to the AER in Stage 1 dulls the incentive for genuine voluntary negotiations and approaches a direct regulation model.

Table 1 provides an overview of the Prescribed Information categories and proposes the sequencing of the information.

Level 14, 50 Market Street
Melbourne 3000
GPO Box 1823 Melbourne Victoria 3001

P +61 3 9205 3100
E info@energycouncil.com.au
W energycouncil.com.au

ABN 92 608 495 307

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Table 1: Proposed sequencing of Prescribed Information to be provided to the AER

Prescribed Information	Stage 1 – Closure date brought forward	Stage 2: Needs Assessment and search for alternative solutions	Stage 3: Voluntary negotiated agreement	Stage 4: Notice for Mandatory Operation
Generating units proposed closure date	✓			
All annual costs (fuel, maintenance, other annual capital and operating costs)				✓
Any regulatory approvals (eg. Environmental licences and renewal dates)			✓	
Technical condition of the plant, including the current condition of the Generating Unit and supporting on-site infrastructure			✓	
Revenues, including breakdown of revenue source				NA*
Risk management contracts and arrangements relating to electricity price risk and fuel supply and price				✓
Any supply contracts with related/third parties and any other related entity agreements / existing contractual obligations				✓
Corporate structure of the entity owning the Generator, including related entities providing services to the Generator				✓

*Revenue information not required for AER to set a swap strike price or to facilitate voluntary negotiations.

4. Noting that generators may operate under complex corporate structures, what are the best means for addressing related entities that provide services that are required for the operation of the System Significant Generator?

There are a range of things required to be in place to support the operation of a System Significant Generator. Key items include:

- Appropriate approvals to operate, including environmental approvals.
- A workforce with requisite technical and operational expertise. This workforce could be directly engaged or provided by related corporate entities.
- Fuel contracts for the Notice for Mandatory Operation period (these fuel contracts may need to be extended or renegotiated to the extent a generator had an expectation the plant would be closed sooner absent the Notice for Mandatory Operation).

The AEC's view is that the Prescribed Information provided should include information in relation to related entities, and the services they provide that are required for the ongoing operation of the plant. We expect the arrangements will vary across different generators, so further codification ex ante will likely prove difficult.

5. Are there other specific insurances that should be maintained?

The Consultation Paper contemplates that a System Significant Generator subject to a Notice for Mandatory Operation will be required to maintain a prudent level of insurance consistent with good industry practice. The AEC notes that the level and type of insurance held may differ as an asset reaches the end of its technical and / or economic life. In practice, the AER will presumably have a role in determining what it believes is prudent, and we expect those costs to be passed through via the FOM. To the extent that the AER prescribes a lower than recommended level of insurance, it would follow that the liability that may arise would also be recouped.

The AEC also notes in the Frontier Report that the "outage risk margin" could be priced from a hedge or insurance product in the market. The implicit assumption is the generators with end-of-life assets can do a probabilistic forecast of outages, and price that risk with perfect foresight. In practice, a reason for closing in the first place will likely be these risks cannot be accurately quantified or are not commercially viable to mitigate at any price. There are also issues with extending the asset life that cannot be priced, and therefore will not be compensated – additional uncertainty for workers and impacted communities, and reputational / ESG impacts with prolonged emissions.

6. What information should be published to the market regarding AER decisions?

The information published in relation to the AER's Determination of the Commercial Component (10.10) should not include commercially sensitive information.

7. What are your views on the appropriateness of the proposed commercial component outlined in section 10.10?

The AEC observes that the OEM framework could at times be impractical, depending on the individual circumstances of the relevant generating plant. Given the OEM Framework is only triggered when a generator closure is brought forward, it can be assumed that the relevant generator will likely be subject to technical and operational constraints that have led to the closure date being brought forward.

If a NMO is issued, and a generating plant cannot meet its obligations due to technical or operational issues, the liability for that risk should rest with the relevant jurisdiction. The AEC is concerned with the detail around performance obligations and how the AER will assess compliance in the event a technical or an operational issue arises which impacts the compliance with those obligations. Commercially negotiated service level agreements would typically include various carve outs for events outside the reasonable control of a supplier, and the NMO performance obligations should be closely modelled on a commercial basis, tailored to the circumstances of the generating unit etc.

The proposed commercial component is for a financial swap, with the AER responsible for setting the strike price. This construct also includes a separate payment for capex and FOM, also determined by the AER. This construct puts the risk of outages onto the generator. Unfortunately, the end-of-life context, coupled with the generators stated intention to close the plant, means this outage risk cannot reasonably be borne by the generator alone.

Level 14, 50 Market Street
Melbourne 3000
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E info@energycouncil.com.au
W energycouncil.com.au

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As the energy market transitions, the decline in dispatchable generation has led to a reduction in the number of generators suitable for selling firm financial contracts.[1] Thermal generators are currently some of the main suppliers of swap and cap cover, so a potential extension of their life should increase the availability of financial hedges. There is an opportunity for the OEM to be designed to support liquidity in the financial market by ensuring that all swaps and caps bought by the relevant jurisdiction under the OEM are subsequently offered to the market.

8. Is an alternative commercial component approach preferred and, if so, why?

The AEC notes that jurisdictions who opt into the OEM framework should still be free to pursue voluntary negotiations with generators. Jurisdictions may find it beneficial to strike voluntary agreements well ahead of any closure date to create optionality for both them and the generator. These upfront agreements could involve jurisdictions paying for an option to extend the operation of plant, triggered only if required for reliability or system security reasons which may or may not arise. Upfront voluntary agreements with this optionality agreed between both parties on a commercial basis would mean there is not any requirement for the Minister to proceed with a NMO.

9. Are there other key issues that need to be considered as part of the commercial component?

When a NMO is issued, the Minister can decide to restrict the operation of a generator so that it will only be allowed to operate certain capacity during specific times of the year or specific events. There is a risk that restricting a generators operating mode could limit its use in hedging a vertically integrated retailers load, undermining the utility of extending operations; and / or potentially result in the generator having to operate in a way that is not suitable for the plant type.

If an NMO is issued on a restricted operation basis, it follows that the commercial compensation appropriate to restricted operation would need to be structured to keep the generator whole and allow for recovery of a margin commensurate with both the risks of ongoing operation, and the cost of operating only on a restricted basis.

The paper contemplates imposing performance requirements on system significant generators and imposing penalties for failure to meet these requirements beyond the financial consequences of failing to generate to support financial contracts. Given the age of the generating units involved, performance criteria may be challenging to support in a cost-effective way. It is highly likely that generating plants will be in end-of-life condition with low reliability and extending their operation may be either extremely expensive or practically impossible. Once the operator has decided to close a plant, they will put together a detailed plan about how and when to close the plant. From this point, maintenance and investment will be designed to be the minimum necessary to safely operate the plant until the planned closure date. The consequence of this is that the operator will generally need to accept increasingly poor reliability from the plant as it nears closure and investment will not be made in work to preserve the longevity of the assets beyond the planned retirement date. For these reasons, imposing performance requirements could be impractical and expensive to support.

Performance obligations would also need to be carefully designed to ensure adequate regard is given to the many factors that can impact a plants availability (e.g. short-term plant issues, equipment failures, environmental licensing limits etc). To assist with mitigating this the Minister should be required to issue a Draft Notice to the impacted generator for comment prior to finalising and consult in good faith on its content.

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[1] https://www.frontier-economics.com.au/the-future-of-financial-risk-management-in-the-national-electricity-market/

Level 14, 50 Market Street
Melbourne 3000
GPO Box 1823 Melbourne Victoria 3001

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E info@energycouncil.com.au
W energycouncil.com.au

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10. Should the financial model include an additional incentive component, even if small, so that the generator has some incentive to contain costs?

The AEC does not believe a relatively small incentive component is required, as it will further complicate an already complex set of arrangements which should only be used for a limited time. A financial swap already has a sharp incentive for efficient operation, as generators are exposed to difference payments even when not operating. This is starkly different to the network businesses the AER typically regulates, with small incentive schemes designed to provide an incentive to contain costs relative to a pass-through arrangement.

11. How should services provided by related entities be treated?

The costs of services provided by related entities will need to be recouped just as direct costs would. To the extent there are common costs across multiple generators, the AER will need to advise on a cost allocation methodology or rely on pre-existing internal cost allocations already in place.

If the concern relates to the risk that related entities inflating the internal transfer pricing to game the compensation arrangement, the AER could examine the historical contracts with related parties. The historic contracts with related parties have been struck under competitive market settings, with no incentive to inflate transfer prices.

12. Should the AER have the ability to "look through" the billing arrangements of services provided by related entities to see the actual costs without mark ups?

The OEM Framework describes a broad role for the AER in relation to receiving detailed Prescribed Information, setting swap prices in the event an NMO is issued, and assessing compliance with performance obligations each financial year of operation. These responsibilities are extensive, and distinct from the AERs typical responsibilities. In particular, the AER is not well placed to understand the risks involved in running a power station, especially at end of life, and what would be fair compensation for this when setting the strike price for caps and swaps. Care should be taken to ensure the AER has the requisite skills and expertise to discharge these new responsibilities – in practice, this would likely take time and could not be easily contracted in.

The Consultation Paper outlines an exemption framework from the performance obligations where there is a “serious technical fault”, with the AER to check compliance. All other events appear to be deemed within the control of the asset owner and their risk reflected in the cap or swap strike price. In theory the asset owner would request and accept this compensation, then take actions to optimise performance. However, in practice such a strict approach would likely lead to protracted arguments when setting and assessing compliance with performance obligations, including whether the compensation arrangements provided enough funding or enough lead times to do so required maintenance and other supporting activities. The AER will also need to take a view on whether generators negotiated fuel supply or other contracts efficiently – in effect needing to micromanage the commercial operation of the relevant generator. This approach is more information intensive and intrusive than the AER’s typical ex ante regulation of monopoly network businesses. However, the context here is very different – the framework will likely apply to a few thermal plants for relatively short contract terms e.g. two years, and so the degree of regulatory involvement and administrative burden should be proportional to consequences for the market and end use customers. In the event the AER is tasked with a detailed analysis of the costs of operating the generator, we think it is important to have clear information reporting requirements that are appropriately targeted.

13. How should the return to the generator be calculated in the case of a swap?

Level 14, 50 Market Street
Melbourne 3000
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P +61 3 9205 3100
E info@energycouncil.com.au
W energycouncil.com.au

The proposed methodology to base the swap price on the short run marginal cost (SRMC) of the NMO generator has the potential to result in distortion of efficient market dispatch if the AER sets the SRMC inappropriately at a low price. In considering the SRMC all marginal costs, not simply fuel costs, must be considered and allowance must be made for the expected operational efficiency of the NMO generator where operational output is expected at less than maximum generation efficiency. Settlement of the swap or cap should align with the normal NEM weekly settlements framework.

Given there is likely to be some subjectivity in determining costs / strike prices, we recommend establishing:

- a 'true-up' settlement process to account for circumstances where actual generator costs materially differ from the ex-ante determination; and
- a merits review process, to appeal determination made by the AER where considered appropriate / necessary.

14. Should there be a 'true-up' settlement in the event that actual capital expenditure and FOM expenses (fixed costs in the case of gas fired generators) differ materially from the ex-ante determination on which payments to the OEM Generator were based?

A true up settlement approach seems a sensible way to manage the risk that the actual capital expenditure and FOM expenses may differ materially from the estimates the AER relies on its ex ante determinations. This true up would need to be done on a reciprocal basis – so that consumers are protected should costs be materially lower, and generators are protected should those costs be materially higher.

15. *How should the strike price for a cap for a gas-fired generator be determined (e.g., set at a fixed price, linked to the price of gas, or an alternative method)?*

The Consultation Paper sets out a cap contract model as the preferred method for gas peaking generation, on the basis gas peakers will not generate where regional reference prices are below their short run marginal cost. Whilst the suggested strike price is $300/MWh we consider this should be determined via negotiation with the relevant generator considering potential fuel costs under market stress conditions. As there are relatively liquid markets for cap contracts, in the first instance market-based pricing should form the initial starting point for the calculation of option premium to be paid to the generator.

16. *What do you think of using the proposed new transmission cost recovery mechanism compared to the existing distribution network cost recovery mechanism contained in the national electricity rules ("Jurisdictional Scheme")?*

The costs to consumer should be as transparent as possible. On that basis, we suggest that the cost recovery process through TNSP's via TUOS charges must be undertaken as a separate and transparent additional charge levied by TNSP's and not simply rolled in as an inclusive TUOS amount.

17. *Noting the aim of a cost recovery estimate is to even out impact to energy consumers, should the estimation be averaged out over the entire period or allocated as expected by year with a re-estimation every year to correct for any variations?*

The estimation should be performed annually, as the AER can vary the swap price annually.

Level 14, 50 Market Street
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E info@energycouncil.com.au
W energycouncil.com.au

ABN 92 608 495 307

18. *Would the shielded loss and gain option be a more suitable commercial component approach for the Notice for Mandatory Operation compared to the financial swap approach detailed in the body of the consultation paper?*

The shielded loss and gain (SLG) option establishes clear performance requirements that could be directly linked to facilitating the operation of the generating plant at high-risk periods (eg. lack of reserve conditions, potentially during defined periods). It also provides a relatively simple financial framework to support the ongoing operation of the System Significant Generator.

It is important that the OEM process supports the provision of Retailer Reliability Obligations compliant contracts for retailers.

Questions can be addressed by e-mail to David.Feeney@energycouncil.com.au or by telephone on 0427 778 621.

Yours sincerely,

David Feeney
General Manager, Wholesale and Environment
Australian Energy Council