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Orderly Exit Management Framework Exposure Draft Bill and Rules

AGL Energy (**AGL**) welcomes the opportunity to comment on the Orderly Exit Management Framework (**OEMF**) Exposure Draft Bill (**Draft Bill**) and Rules (**Draft Rules**).

About AGL

Proudly Australian for more than 186 years, AGL supplies around 4.3 million energy and telecommunications customer services. AGL is committed to providing our customers simple, fair, and accessible essential services as they decarbonise and electrify the way they live, work, and move.

AGL operates Australia's largest private electricity generation portfolio within the National Electricity Market (**NEM**), comprising coal and gas-fired generation, renewable energy sources such as wind, hydro and solar, batteries and other firming technology, and gas production and storage assets. We are building on our history as one of Australia's leading private investors in renewable energy to now lead the business of transition to a lower emissions, affordable and smart energy future in line with the goals of our Climate Transition Action Plan.

Overview

In September 2022, AGL released its Climate Transition Action Plan (**CTAP**). The CTAP outlines AGL's commitment to working constructively with our stakeholders, including governments, our people and the communities in which we operate, to lead a responsible and orderly transition towards a low-emissions economy.

AGL has already been in discussions or entered into agreements with governments in various jurisdictions relating to the operation of our generation assets, to provide certainty for both government and AGL in relation to the future plans for those assets and which takes into account the specific nature of the assets and needs of the jurisdiction.

We acknowledge that amendments have been made to the OEMF in response to stakeholder feedback. However, AGL continues to have significant concerns about aspects of the framework.

Our key concern regarding the OEMF is that it provides no certainty that generators will be wholly compensated for the costs they incur in continuing to operate and maintain the generation assets that are subject to the framework beyond their proposed closure date. While this concern primarily relates to the Mandatory Operating Direction (**MOD**), we acknowledge that this risk may also be present under a voluntary agreement.

Based on our review of the Draft Bill and Rules, it seems that the OEMF may require generators to bear unfunded costs and unmanageable risks when directed by the Minister to remain in operation. This outcome would represent a serious deficiency in the framework, and we ask that amendments be made to address these problems as a priority. The framework must recognise that it is very likely that any generator to which it is applied will be at the end of its technical life and will need to manage a range of unpredictable and complex operational, safety and reliability risks. There are serious asymmetric risks and exposure to outages presented under the financial component that are inappropriate for a generator directed to operate beyond its technical life.

Generators subject to the OEMF should be made whole

Both the consultation paper and the Frontier Economics report clearly state that a generator should be 'made whole'. This intent is reiterated in the recently published response to stakeholder submissions.

However, this principle is not reflected clearly or consistently in the Draft Bill or Rules.

AGL considers it is essential that ensuring generators are 'made whole' under the OEMF should be clearly stated as an overarching principle of the OEMF in the National Electricity Law (**NEL**). We consider that this may go some way in addressing some of the problems described below.

Uncertainty around the recovery of MOD generators' costs – generator payments

The Draft Rules provide that a MOD generator will be entitled to receive two types of payments (**generator payments**) under the OEMF – fixed payment amounts, and generator payment instrument (**GPI**) payment amounts.

The types of costs generator payments are designed to compensate a MOD generator for are defined in the Draft Rules. That said, there is significant uncertainty around how the definition of these costs will be interpreted by the AER – which is responsible for of making generator payments determinations which determine the total amount and components of the generator payments. When a cost type is not mentioned in the Draft Rules, or it is unclear whether it is captured under another cost, there is no certainty whether a particular cost type will be recoverable by a MOD generator.

For example, the fixed payment amount includes 'fixed operations and maintenance costs'. However, it is unclear whether the fixed labour costs incurred by a MOD generator will be included as part of the fixed payment amount.

The same issue arises for the GPI payment amounts. For example, the Draft Rules set out a prescriptive process for determining fuel costs – one of the components of the GPI payment amount. However, there is no such process for costs relating to the transport of fuel incurred by a MOD generator.

Separately, even when there is certainty that a particular cost is intended to be recovered through the generator payments, there is uncertainty around the magnitude of the cost the MOD generator can recover.

For the fixed payment amount, the AER is required to calculate the amount by determining a forecast of the prudent, efficient and reasonable expenditure likely to be required by the MOD generator.

Assessing whether actual costs incurred are prudent, efficient and reasonable will likely present significant difficulties when applied to a thermal generator that has reached the end of its technical life, and where supply chain costs and expenditure can increase significantly in dynamic market conditions.

For the GPI payment amount, the Draft Rules set out a process for determining the magnitude of the costs. For example, in determining fuel costs, the AER may take into account a range of matters, including current market prices and the forward price of fuel and research produced by suitably qualified analysts on coal or other fuel costs, stockpile and storage levels, current fuel contracting arrangements and pricing, as well as future fuel supply options.

The issues described above create uncertainty for a MOD generator about which costs can be recovered, and the magnitude of these costs. There is a very real risk that the costs recovered by a MOD generator are significantly lower than the costs they incur. This is completely at odds with the principle of ensuring generators are made whole.

Uncertainty around the recovery of MOD generators costs – GPI financial transaction mechanisms

The Draft Rules provide that the Minister can issue a GPI which may be in the form of any one or more of the following financial transactions:

- a financial swap payments transaction in respect of quantities of electricity (in MWh)
- a financial cap payments transaction in respect of quantities of electricity (in MWh), where the financial cap must be set at the administered price cap
- any other form of financial transaction relating to quantities of electricity that may be bid for dispatch in the wholesale exchange operated by AEMO under the NEL

While the intent of these GPI financial transaction mechanisms may be to compensate a MOD generator for its short run marginal costs incurred during the mandatory operation period and recoverable margin, we are concerned that the use of a derivative style product may expose the MOD generator to additional costs. Depending on the details of the arrangements put in place by the Minister which are largely unclear, the magnitude of these costs could potentially be larger than the short run marginal costs incurred during the mandatory operation period and recoverable margin, and in effect act against the intent of the GPI.

The financial contract model was recommended in the Frontier Economics OEMF analysis as it locked in prices for consumers and generators and gave a strong incentive for generators to minimise outage risk. This analysis is flawed as it presumes that outage risk can be forecast and managed with hedges and/or insurance products. This is not the case for generators that are at the end of their technical life, which experience high forced outage rates and require significant capital programmes – with long lead times – to improve their reliability.

For these aging generators wear and tear, weather extremes, ramping challenges, or other entirely unpredictable factors may result in an outage at any time. These generators are not capable of physically backing a firm financial commitment with any reasonable degree of confidence, potentially exposing the MOD generator to material loss events in the market. That is, requiring a soon to be exiting generator to enter a financial swap or cap arrangement would expose that generator to asymmetric risks, with potential price exposure up to the $17,500/MWh market price cap, which could be financially ruinous and impossible to mitigate.

While the financial swap and cap arrangements appear to have been designed as derivative contracts, we do not consider them to be comparable to the caps and swaps commonly used to manage risks in the electricity market. While under a swap there would be determined strike price, the price received by the generator is not completely certain under the Draft Rules, due to the limitations regarding payments through the financial vehicle. This means that generators carry all the risk of plant outages and no incentive to operate below the swap strike price.

Regardless, we note that the potential upside of running generators that are at the end of technical life does not outweigh the cost of running the unit without unacceptable outage risk and cost, which is generally why these generators are exiting in the first place.

We consider that a more flexible approach to mandate generator operation and compensation would be more equitable and suggest that ensuring the OEMF is equitable should be a key objective since the OEMF is a mechanism that only applies to generators that have otherwise decided that there is no commercial reason to continue to participate in the market.

Uncertainty around the recovery of MOD generator costs relating to unforeseen adverse events

We note that the Draft Rules include provisions for MOD generators to apply to recover costs relating to unforeseen adverse events.

However, in the case of capital or repair expenditure, the Draft Rules apply a materiality threshold to these costs. For example, in relation to material unforeseen capital or major repair expenditure, one of the threshold requirements is that the total capital expenditure or unplanned major repair expenditure required to rectify the adverse consequences will exceed $50 million or another amount notified by the Minister to the AER of the value of the total capital expenditure forecast for the remaining mandatory operation period. This is a significant risk that should not be placed on a MOD generator.

In relation to material unforeseen short run marginal costs, one of the threshold requirements is the total short run marginal costs required to rectify the adverse consequences will exceed 10% of the value of the short run marginal costs forecast for the remaining mandatory operation period.

Even if the costs incurred by a MOD generator met these thresholds, recovery of the costs would be subject to the AER's assessment.

Again, these provisions are at odds with the principle that a MOD generator be made whole.

Uncertainty around a MOD generators' insurance requirements – and potential interaction with recovering cost arising from force majeure events

We have significant concerns regarding the MOD insurance requirements. The Draft Rules state that the Minister may specify in a mandatory operation direction the insurance requirements that must be maintained by the MOD generator during the mandatory operation period. The Draft Rules also state that if the Minister does not impose insurance requirements in a MOD, the MOD generator must maintain insurance that reflects prudent and commercial risk management consistent with good electricity industry practice.

It is not clear how this requirement can feasibly be applied to thermal generators that have reached the end of their technical and economic life. The types of insurance products available are likely to be significantly limited, and if insurance is available, the cost could be substantial. We are concerned that a MOD generator risks non-compliance with a MOD by not obtaining insurance that is not available.

We note that a generator payment instrument issued by the Minister may include a provision which relates to force majeure events which affect the ability of the MOD generating unit to generate electricity and allowances for the MOD generator to reflect the actual amount of electricity capable of being generated for the duration of that force majeure event. However, the reference to force majeure event in this context means a force majeure event for which the MOD generator, acting prudently, has not been able to obtain insurance on reasonable commercial terms.

It is unclear how these insurance obligations are intended to work alongside the MOD insurance obligations clause 4B.E.5 and the consequences on whether MOD generators are appropriately protected from force majeure events which affect their ability to generate electricity. If you would like to discuss this submission further, we would be happy to arrange a meeting.

Yours sincerely,

Anton King

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