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Dear Commissioners

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Transmission Planning and Investment Review Stage 3 (EPR0087) — Draft Report — 21 September 2022

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 4,500MW of generation capacity.

We share the concerns of various stakeholders around the risks of delayed investment in new infrastructure which is necessary to accelerate the transition. A combination of political, commercial and technical issues is resulting in large volumes of coal-fired generation exiting the electricity system much faster than has been anticipated. The scale of replacement generation and storage needed to maintain system reliability is enormous, and strategic transmission investments will ensure the system evolves in a least cost manner. This is already a challenging task that is now being compounded by the need to gain social licence, contain cost increases, and overcome global supply chain constraints.

The acceleration of transmission investment as a low or no regret element of the transition should be placed in proper context. Comments from the Commission[1] and others reflect a general perception that the consequences of overinvestment are less severe than that of underinvestment from the customers' perspective. The costs of transmission currently make up only a small part of customer bills, and modelling exercises indicate that the consequences of not commissioning certain projects, in terms of foregone benefits, are significant. On the cost side, the $21 billion[2] of capex on Actionable and future projects compares to the current electricity network regulatory asset base of $105 billion[3]. In rough terms, and assuming no further increase in estimated costs, these projects would result in an increase to retail electricity bills of 10

[1] AEMC, *Transmission Planning and Investment Review Stage 3 Draft Report*, September 2022, p. 10
[2] AEMC, p. 13. Note this estimate excludes projects such Central West Orana REZ and EnergyConnect, which would add another $3 billion
[3] AER, *State of the Energy Market 2022*, September 2022, page 81.

per cent.[4] The quantification and discussion of expected project benefits tends to presume that they are as certain as cost estimates. These benefits, however, reflect a very large number of disputable assumptions that form part of complex long-term scenario modelling. Benefits are also calculated with respect to counterfactual 'no transmission' cases where decarbonisation of the energy sector would still take place, and this is poorly understood. Hence while approved project costs will be incurred up front and fully recovered from customers, there is far less certainty that the expected benefits of these projects, which may take decades to accrue, will ever materialise. Finally, the Integrated System Plan's (ISP) high-level development pathways include some projects that are marginal in terms of their contribution to net benefits. Such projects will and should attract more scrutiny when subjected to actual detailed assessment. These are important considerations for the Commission when examining possible changes to project approval frameworks, and in setting incentives and risk-sharing for out-turn costs and benefits.

We do not believe there is evidence to justify amending the application of the Regulatory Investment Test for Transmission (RIT-T). Overall, regulatory approvals do not reflect a material source of project delay relative to project-specific factors. Amendments to the RIT-T and Actionable ISP framework were given effect in 2020, specifically with the aim of streamlining cost-benefit assessments. As we have suggested previously, efforts to ensure timely transmission investment would be better targeted at improving cost estimates and in community engagement. We therefore support the Commission's work in progressing other refinements in its 'stage two' issues determination, alongside ongoing efforts to improve transmission cost estimation. This work, combined with the work of jurisdictional planning entities and project proponents, will help in gaining social licence and in addressing many other planning issues that feed into cost benefit assessments. Once addressed, this will enable projects to progress more quickly through regulatory approval stages.

The most pressing issue raised by the Commission as part of its stage three issues is the need for the rules to accommodate concessional finance. This requires a near-term solution given the recent funding announcements for Marinus Link and others under Rewiring the Nation. We understand that government officials are expecting to submit a rule change proposal on this shortly.

We do not consider that TNSPs require any additional or ad hoc incentives to invest. We support the Commission exploring means within incentive frameworks to better balance the risk of uncertainties in out-turn costs. The practicalities of monitoring and addressing situations where benefits do not materialise should be explored further.

Our detailed considerations on each of these points is presented below.

Changes to the RIT-T and Actionable ISP framework are not (yet) justified

As per our prior submission, we do not consider there is a strong case to amend the regulatory framework around RIT-T and ISP assessments.

Section 2.3 of the Commission's draft report explains how there is insufficient experience with the current Actionable ISP framework. It would be useful to draw more insights from this analysis, particularly the factors listed on pages 34 and 35, in any estimates of

[4] Assuming network costs contribute around half of retail bills, with a 20% expansion in asset base having a proportionate impact on operating expenditures and other building blocks.

project approval timings under counterfactual and strawperson proposals of alternative models. A further examination of approval times for recent projects would also be useful in illuminating any stakeholder concerns that RIT-T requirements are a source of delay. In particular, the Commission calculates that it took around 17 months for QNI to complete its economic assessments (and without the benefit of the more streamlined, current regulatory framework) contrasting with the experience of EnergyConnect and HumeLink. Clearly, project-specific issues rather than regulatory requirements explain these differences. The lessons from these and other project delays are being fed back into future project development and planning. For example, the final 2022 ISP lists earliest practical delivery times for Actionable projects, which in some cases is beyond optimal timing.[5] We also understand that dimensions around social licence are being incorporated into AEMO's scenario designs. The Commission's analysis would generally be useful in cultivating more realistic expectations of lead times for large, complex projects. Jurisdictional governments would benefit from this analysis given some have instituted alternatives to the RIT-T and ISP framework in the hope it will expedite project delivery.

The Commission's strawperson proposals all highlight the critical stage of conducting thorough early works in order to meaningfully engage with affected stakeholders and properly cost options (particularly line routes and landowner compensation) for detailed assessment. Shifting these or other RIT-T elements onto AEMO would not meaningfully reduce the effort, time or cost involved. For example, we disagree with the Commission's assessment that there would be material time savings where AEMO is tasked in conducting project-specific cost and/ or benefits calculations. The Commission's considerations around rigour[6] illustrate this, noting that the ISP does not currently reflect granular network modelling, or project-specific stakeholder engagement. That is, an estimated time savings of 2 years by removing the RIT-T ignores the lead times and resourcing that would still be required to engage stakeholders on multiple actionable projects in the lead up to each ISP. AEMO is not currently resourced to deal with targeted community engagement and, if poorly executed, taking on these functions would risk much longer project delays than seen under the current TNSP-led approach. Increasing the frequency of ISP assessments under strawperson three also seems infeasible, with unwieldly overlapping consultations on different ISP editions. The changes from the 2020 to the 2022 ISP were significant. It would be imprudent to assume AEMO has now reached a 'steady state' in terms of data and methods such that future ISPs could be quick updates of prior versions.

As some early works are intended to better inform cost benefit assessments, the Commission's suggestions that they can be done concurrently with RIT-Ts (e.g. in strawperson one) may need to be reconsidered in finer detail. The suggestion that TNSPs could seek regulatory approval to fund early works without an associated RIT-T otherwise has merit.

Assuming the Commission concludes that refinements are justified from its current analysis, we recommend they be deferred and considered holistically in the upcoming ISP Review. We also understand that government officials intend to influence the development of (i.e. supercharge[7]) the 2024 ISP and potentially future ISPs, which will affect the Commission's work in this area. In conjunction with concessional financing,

[5] AEMO, *2022 Integrated System Plan*, June 2022, pp. 12-13.
[6] AEMC, pp. 52, 53, 58.
[7] Energy Ministers, *Meeting Communique*, 28 October 2022, p. 2.

designating projects as nationally significant and jurisdictions implementing their own variations, there is a risk of reform fatigue in this area. Continual and uncertain changes affecting transmission will tend to undermine private investment decisions for generation and storage.

Rule amendments are required to accommodate concessional finance

The recent ministerial agreement on concessional financing for Marinus Link and VNI West[8] cannot be processed under the current rule framework. Whereas the AER is currently bound to apply benchmark financing assumptions, concessional finance arrangements would presumably require "actual" values for the cost of debt, gearing and equity returns, and potentially tax/ dividend imputation.

Overall, we agree with the Commission's proposed approach in terms of reflecting the intention of relevant jurisdictions and their financing entities. Jurisdictional intent should be explicit rather than left to the AER's discretion. That is, the formal notification of government intent to the AER should be a pre-requisite for recognising any concessional finance, otherwise benchmark parameters should apply. We do not consider this to be an unreasonable or onerous requirement on governments, given they will be making well-considered decisions to support projects on behalf of taxpayers. Such a requirement would also ensure transparency of government policy, and of the specifics of concessional finance terms. Government estimates of the impact of their concessional financing, in terms of reductions in total project costs or prices paid by customers, could also be compared to what is ultimately given effect in the AER's revenue determinations.

Incentives should be geared towards benefits realisation not delivery dates

The premise of a timely delivery incentive seems to rest heavily on the absence of obligations on TNSPs to invest in specific projects, but also an overstatement of how important this is. We do not consider there should be an obligation or incentive to execute Actionable projects for several reasons, some already noted by the Commission:

- Having identified a project as actionable in the ISP or during RIT-T stages, there would be considerable momentum and pressure on TNSPs (particularly from policy makers) to follow through with investment.

- Benchmark costs of capital are almost certainly higher than TNSPs' actual costs of capital, providing a strong and ongoing incentive to invest and increase asset bases. The AER's performance reporting[9] shows that NSPs consistently outperform their benchmark rates of return. While this is attributable to many factors, we consider that conservatism in rate of return parameters is a material factor.

- We believe there is currently no credible risk of the AER disallowing the recovery of project capex in an ex post review, which might otherwise be a deterrent to committing large amounts of capital expenditure. While the Commission does propose refinements to ex post reviews, this would only be a deterrent where there are prospects of optimisation or adjustments based on information arising after investment decisions are made.

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[8] https://www.pm.gov.au/media/rewiring-nation-supercharge-victorian-renewables

[9] https://www.aer.gov.au/system/files/2022%20Electricity%20network%20performance%20report%20-%20July%202022.pdf, see section 4.4.

- Actionable projects bring potentially large cashflow impacts. However, the Commission has already considered this is more adequately dealt with in setting depreciation allowances, and its stage two final recommendations will provide the AER explicit powers in this area.

If the Commission intends to progress with additional project specific incentives, they should be geared towards net benefit maximisation.

The general ex ante framework provides for TNSPs to minimise expenditures subject to compliance obligations as well as targeted output incentives like the service target performance incentive scheme. The issue arising for Actionable projects is effectively a lack of corresponding 'output' for which incentives can be geared towards, which would be the delivery of market or customer benefits e.g. lower wholesale prices associated with a more efficient resource mix. The Commission should explore whether it is feasible to monitor or provide some qualitative discussion on out-turn project impacts in return for the billions of dollars of funding that customers will pay.

Incentives to simply bring forward project delivery could compromise the safety or quality of projects that are delivered. TNSPs could also have some ability to influence the timing or scope of projects that better suits changing market circumstances. In other words, it may be too simplistic to reward TNSPs for meeting or beating target commissioning dates, particularly where transmission projects are timed to coincide with large generation or storage projects that also have variable timing (e.g. Snowy 2.0).

Other considerations in setting incentives include:

- whether the TNSP has a fine degree of influence over delivery timing, relative to the time windows used for incentive payments e.g. target delivery would presumably be within a particular regulatory year.

- how uncontrollable factors are accounted for e.g. unforeseeable resource constraints, including for discrete events like flooding.

- how the quantum of incentive payments or penalties will be determined. For example, whether these are set by reference to expected market benefits in certain scenarios, and how uncertainty in forecasting is accounted for.

- how incentive payments flow through to transmission prices in different jurisdictions. For example, whether the allocation of incentives mirrors cost allocation agreements, or whether they reflect the proportion of expected or realised benefits.

We support more targeted incentives and risk sharing on project costs

As per our prior submission we support the AER having the ability to conduct ex post reviews of large Actionable projects separately to the total out-turn capex amount.

There is a higher likelihood and consequence of large complex projects being subject to uncontrollable cost variations, which requires careful consideration of how risks are shared between the TNSP and customers. If these are not reflected in associated incentive frameworks (including any 'timely delivery' incentive) it would also result in large windfall gains and losses. As noted above, a greater concern is likely to be that expected benefits do not materialise and this risk should be shared between customers and TNSPs. We do accept, however, that it may not be practical to measure out-turn benefits in a way that can be robustly attributed to individual projects. Some ex post reporting of asset utilisation may still provide insights on whether projects are delivering their full expected value or playing their intended role in a future NEM.

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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