Rupert Doney
Australian Energy Market Commission
Level 6, 201 Elizabeth Street
Sydney NSW 2000

Lodged through online portal

14 July 2022

Dear Mr Doney,

Transmission Planning and Investment Review Stage 2 draft report (EPR0087)

ENGIE Australia & New Zealand (ENGIE) appreciates the opportunity to respond to the Australian Energy Market Commission ("the Commission") in response to the Transmission Planning and Investment Review Stage 2 draft report ("the draft report").

The ENGIE Group is a global energy operator in the businesses of electricity, natural gas and energy services. In Australia, ENGIE has interests in generation, renewable energy development, and energy services. ENGIE also owns Simply Energy which provides electricity and gas to more than 740,000 retail customer accounts across Victoria, South Australia, New South Wales, Queensland, and Western Australia.

ENGIE advises caution in implementing new rules to address purported financeability concerns arising from the delivery of large-scale ISP projects. Financeability is a relatively nebulous concept to apply in a regulatory context, and the AER does not have a track record of making detailed ex ante financeability assessments (likely because there has been no need to do so to date). Nonetheless if the Commission does decide to make changes, the focus on affording the AER greater discretion to vary depreciation profiles is preferable to other alternatives, given it is an NPV neutral approach.

ENGIE does not see any need for rule changes with respect to recovery of costs relating to obtaining social licence for projects and other stakeholder engagement. Existing cost recovery mechanisms appear adequate and impose an appropriate discipline on network project proponents to manage such costs efficiently. ENGIE notes that the underlying driver for much of the new transmission is government policy and costs incurred by network providers could be kept lower if governments did more to support social licence for individual projects.

Our detailed comments to the specific questions raised in the draft report are set out in the attached submission template.

Should you have any queries in relation to this submission please do not hesitate to contact me on (03) 9617 8415.

Yours sincerely,

Jamie Lowe
Head of Regulation,
Compliance and Sustainability

SUBMISSION TO THE DRAFT REPORT-TRANSMISSION PLANNING AND INVESTMENT REVIEW
STAKEHOLDER FEEDBACK TEMPLATE

The template below has been developed to enable stakeholders to provide their feedback on the issues the Commission is seeking feedback on in the draft report and any other issues that they would like to provide feedback on. The AEMC encourages stakeholders to use this template to provide feedback on issues raised. This template is not exhaustive and therefore stakeholders are encouraged to comment on any additional issues or suggest additional solutions. Stakeholders should not feel obliged to answer each question, but rather address those issues of particular interest or concern. Further context for the questions can be found in the draft report.

SUBMITTER DETAILS

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DATE	14 July 2022

PROJECT DETAILS

NAME OF RULE CHANGE:	Transmission Planning and Investment Review
PROJECT CODE:	EPR0087
PROPONENT:	AEMC
SUBMISSION DUE DATE:	14 July 2022

CHAPTER 2 - THE REVENUE FRAMEWORK SHOULD HAVE SUFFICIENT FLEXIBILITY TO ADDRESS ANY FUTURE FINANCEABILITY CONCERNS

The current revenue framework is not flexible enough to address the financeability challenges that may arise in the future	
1. We welcome stakeholder views on this finding that financeability challenges could arise in the future under realistic future ISP development plans and that it is appropriate for the AER to have sufficient flexibility to address this issue.	ENGIE cautions against drawing definitive judgments around the financeability of transmission network service providers (TNSPs) or of individual projects. Financeability is a challenging concept to define. In principle the regulatory asset base (RAB) mechanism should serve as a sufficient guarantee of cashflows to allow any project to be financed, providing the TNSP receives its cost of capital. ENGIE recognises that practical realities may differ, and a TNSP's ability to obtain finance may depend on its credit rating as assigned by one or more of the ratings agencies. While the ratings agencies use financial ratios to assess credit ratings, they also make qualitative judgments about the overall regulatory regime and the quality of the individual business. Accordingly, while financial ratios can be replicated, they do not fully represent the creditworthiness of a business or a project. Contestability, which the Commission is consulting on separately, also offers an alternate route to managing financeability concerns. One consideration is that there is currently no clearly established basis for testing financeability in the NEM rules or in the AER's application for them. For example, in the current Rate of Return Instrument review, the AER's approach to financeability is an ex-post review of the existing instrument, rather than an ex-ante analysis of the proposed new instrument. ENGIE offers no view on this approach, expect to note that what may be appropriate for an ex-post review of a rate of return decision may not be appropriate for an ex-ante review of an individual business. Of course, this consideration could be addressed by requiring the AER to develop and consult on a guideline for how it would evaluate forward-looking financeability challenges and use depreciation variation to address any identified issues, noting that this would add to the already heavy burden of consultation on stakeholders.
Providing more flexibility to adjust the rate of depreciation is an appropriate and proportionate approach to addressing the issue	
2. We welcome stakeholder views on whether this draft recommendation to increase the AER's discretion to vary depreciation profiles for actionable ISP projects is an appropriate response to financeability challenges that may arise. We also welcome views on alternative approaches that stakeholders consider would better promote the NEO.	If the AEMC does decide to change the rules to allow the AER more flexibility to address financeability concerns, depreciation variation is the most appropriate option for the AER to have discretion over, given it is an NPV neutral adjustment to revenues. There is no case for a higher cost of capital for TNSPs or for ISP projects, so consumers should not be exposed to the risk of having to pay higher charges than necessary, especially as a higher cost of capital would also apply to the existing sunk RAB.

Implementation challenges appear to be manageable	
3. We welcome stakeholder views on whether these are practical and workable approaches to implementation and whether there are any further challenges that we have not highlighted in this report.	ENGIE is not aware of any, beyond the points made above.

CHAPTER 3 - THE NATIONAL FRAMEWORK SUPPORTS SOCIAL LICENCE ACTIVITIES AIMED AT BUILDING AND MAINTAINING COMMUNITY ACCEPTANCE

The national framework allows TNSPs to recover the costs of activities that contribute to building community acceptance in several ways	
4. We welcome stakeholder feedback on the Commission's view that the current cost recovery mechanisms are appropriate and allow TNSPs to recover the costs associated with landowner compensation payments, stakeholder engagement, and other social licence activities associated with major transmission projects.	ENGIE is not aware of any barrier to TNSPs recovering efficient costs that are necessary to deliver a project under the national framework. This includes compensation, engagement and other social licence activities to the extent they meet the benchmark of efficient costs. Certainly, the onus is on TNSPs to demonstrate that there are specific types of costs that are demonstrably efficient, but that they are unable to obtain cost recovery for. If TNSPs have been unsuccessful in seeking recovery of particular costs in the past, this may be because they were not required for past projects, or because the TNSP failed to make a robust business case to the AER, rather than any deficiency in the framework. Accordingly, ENGIE expects that if there were genuine exceptions that were not allowable costs under the current framework, the AER would also agree that a rule change was necessary to enable them to allow cost recovery.
5. We also welcome stakeholder feedback on whether there are any other activities undertaken to support building and maintaining social licence that are not captured under the existing cost recovery mechanisms.	ENGIE is not aware of any such activities.

Further opportunities for TNSPs to improve stakeholder engagement outcomes	
6. We welcome stakeholder feedback on whether the current stakeholder engagement requirements in the NER provide sufficient flexibility for TNSPs to develop and implement appropriate stakeholder engagement plans for major transmission projects.	ENGIE is not aware of any constraints on the TNSPs stakeholder engagement arising from the NER. IF earlier engagement is beneficial to a project, then TNSPs can and should carry out such engagement. ENGIE notes that a revenue determination - or a contingent project application (CPA) - is not prescriptive of what spending should take place. Rather, it's a process to robustly estimate total revenue requirements. The TNSP's job is to manage its costs within the overall total. If social licence or other stakeholder engagement activity is more expensive than expected, then TNSP has to find savings elsewhere.
7. We welcome stakeholder feedback on whether there are any barriers to TNSPs bringing stakeholder engagement activities forward into the RIT-T stage.	A decision by a TNSP not to incur *any* costs on the development of a project (other than running a RIT-T or CPA application process) because they don't yet have guarantee of cost recovery is not a "barrier". It's a choice by TNSPs to be more risk averse than is warranted, noting that they receive a risk-adjusted rate of return. Generation proponents typically incur expenditure on early engagement with communities near a proposed project before the project reaches FID, and so before there is any confidence that such costs can be recovered. Part of the purpose of monopoly network regulation is to mimic the cost pressures competitive market participants face and so there is no reason why TNSPs should be guaranteed recovery of early engagement costs (though efficient costs should of course be recoverable if a project goes ahead), given competitive market participants have no such guarantee either. It is clear from commentary round the sales processes for TNSPs that have occurred in recent years that investors value a pipeline of potential projects that will allow an TNSP to grow its RAB. Given investors value this opportunity, it's reasonable that they be prepared to spend modest amounts on early engagement to maximise their opportunities to build such projects. ISP projects are hardly speculative, even if one or two may never go ahead as circumstances change and they cease to be part of the optimal development path.

CHAPTER 4 – COST RECOVERY OF PLANNING ACTIVITIES

Project planning activities can be clearly distinguished based on whether they relate to the selection or delivery of a preferred option	
8. We welcome stakeholder views on whether this draft recommendation to distinguish planning activities based on their purpose improves clarity in how costs related to project identification and/or delivery are appropriately recovered.	n/a
9. We are interested in views on whether amending the definition of preparatory activities and removing references to 'early works' in regulatory documents is appropriate.	n/a
10. We are also interested in stakeholder views on whether anything further is needed to achieve an appropriate balance between the cost and quality of preparatory activities. We also welcome alternative approaches that stakeholders consider would better promote the NEO.	n/a
Preparatory activities may be nominated as a cost pass through event under existing arrangements	
11. We welcome stakeholder feedback on the Commission's recommended approach including examples where there has been unforeseeable expenditure on preparatory activities, as well as any rationale for potential changes to the existing cost pass-through arrangements that may be required to accommodate those specific circumstances.	The basic framework of monopoly network regulation in the NEM is an incentive-based framework. Under this framework, TNSPs are awarded the right to recover an amount of revenue that the AER deems sufficient to allow them to operate and maintain the network efficiently and to replace or upgrade assets as required. This incentivises the TNSP to minimise its costs. There are special arrangements, such as contingent project applications, for important projects that were not anticipated (or not confirmed as necessary) at the time the revenue was determined. By contrast, a pass-through arrangement carries no incentives to carry out an activity efficiently and as such, should be reserved for those rare occurrences where costs are both unavoidable and uncontrollable (and hence unforecastable). It is not clear that preparatory activities fall into this category. Given the ISP is now well established and AEMO consults transparently on it, the likelihood of preparatory activities on actionable projects being unforeseeable is low.
The staged CPA process appropriately manages cost recovery uncertainty and will be more effective as the process matures	

12. We welcome stakeholder feedback on whether the staged CPA process appropriately manages cost recovery uncertainty for expenditure that occurs before full CPA approval. We welcome views on alternative arrangements to manage this uncertainty.	Staging appears a more appropriate approach to such expenditure than a pass-through, as it allows for appropriate scrutiny of the costs by the AER and other stakeholders, and for TNSPs to be subject to the incentive impacts of an ex-ante allowance.

CHAPTER 5 - IMPROVING THE WORKABILITY OF THE FEEDBACK LOOP WILL ENABLE IT TO OPERATE AS A TIMELY AND EFFECTIVE CONSUMER SAFEGUARD

The draft recommendation aligns the feedback loop with a draft or final ISP through an exclusion window	
13. We welcome stakeholder views on whether the draft recommendation to implement a feedback loop and PACR exclusion window between the final IASR and draft ISP is an appropriate solution. We also welcome views on alternative approaches that stakeholders consider would better promote the NEO.	ENGIE's understanding of the proposal is that it will ensure each PACR is based on the most up-to-date set of input assumptions that AEMO has available. Against this must be weighed any consequences of imposing a PACR exclusion window. In principle, a known exclusion window should be relatively straightforward for TNSPs to plan their PACR processes around, especially as the ISP iterations do not appear to be throwing up completely new actionable projects every two years. Similarly, the AER can also plan its resourcing around the likelihood of a "bunching" of PACRs following the publication of each draft ISP. It is other stakeholders who are likely to be less well placed to manage this cycle, albeit they will individually not need the level of resources of the AER or the proponent. Based on the 2022 ISP timetable, the exclusion window would run for around 4 ½ months every two years. This appears eminently manageable. By contrast, aligning with the final ISP would result in an exclusion window of almost a year, or around half an ISP cycle. This is more likely to lead to delays in project assessment.
The Commission is seeking stakeholder input on two elements of our draft recommendation	
14. We welcome stakeholder views on whether aligning the feedback loop with the draft ISP or final ISP best balances the timely and efficient delivery of major transmission projects.	See above

15. We welcome stakeholder views on whether the potential for delay due to the bunching of feedback loop assessments will have a material effect on timely delivery and, if so, is allowing the CPA and feedback loop to run concurrently the appropriate means of managing this delay?	See above
16. We welcome stakeholder views on whether amendments to the AER's CBA Guidelines to give effect to aligning the feedback loop assessment with a draft ISP is suitable.	See above

OTHER COMMENTS

17. Please provide any further comments on this report.	N/a