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30 September 2021

Ms Anna Collyer
Chair, Australian Energy Market Commission
GPO Box 2603
SYDNEY NSW 2001

Dear Ms Collyer

AER submission to the AEMC's Transmission Planning and Investment Review consultation paper

The Australian Energy Regulator (AER) welcomes the opportunity to comment on the Australian Energy Market Commission's (AEMC) Transmission Planning and Investment Review consultation paper examining the current transmission planning and investment framework's ability to support the timely and efficient delivery of major transmission projects.

We support the AEMC's review of the frameworks related to the efficient delivery of transmission infrastructure during this period of significant planned investment in major transmission projects to support the National Electricity Market (NEM) transition and the development of Renewable Energy Zones. We consider this review is necessary in the context of a changing environment and the concerns raised by stakeholders with the AER about the increased risk of cost overruns associated with large transmission projects compared to the typical investment and augmentation that has been required in recent years.[1] The AEMC's proposal to consider whether the existing incentive-based regulatory arrangements remain 'fit for purpose' to support the timely and efficient delivery of major transmission projects is, in our view, one of the key issues the review should explore.

When examining the issues associated with the delivery of large transmission projects, we consider it important to distinguish between uncertainty and risk: Risk refers to situations where a mathematical probability can be applied to events that may occur, and uncertainty refers to events that cannot be expressed in mathematical probabilities.[2] For example, a risk may be cost overruns with large projects, whereas an uncertainty could be the potential impact of changing technology on the long term benefits of a transmission project. In

[1] AER, *Final guidance note covering letter — Regulation of large transmission projects*, 31 March 2021, p. 10.
[2] Toma, Chiriţă, and Şarpe, *Risk and Uncertainty,* Procedia Economics and Finance, Vol 3, 2012, pp. 975-980.

recognising this distinction, the review should consider who is best placed to manage or respond to the consequences of uncertainties and risks.

We also acknowledge and support the steps the AEMC is taking to engage closely with key stakeholders, including the existing Investor Reference Group, to understand the drivers of investment decisions in the current market, as well as consumer groups, such as Energy Consumers Australia.

In November 2020, the AER initiated the 'Transmission Investment Regulation' review to support the efficient delivery of 'actionable' Integrated System Plan (ISP) projects, in recognition of the challenges associated with the delivery of large transmission projects. This resulted in the publication of a guidance note in March 2021 that clarified the regulatory process and the AER's expectations of transmission network service providers in bringing forward large transmission investment proposals to the AER. It sought to improve the predictability of the AER's assessment of the costs associated with actionable ISP projects, whilst promoting flexibility, transparency and reducing uncertainty. In addition to developing the guidance note, the work program identified other areas of reform to explore, including:

- changes to the contingent project application process and regulatory investment test for transmission to allow for more reliable project cost estimates and streamlining of the process
- changes to improve incentives for the efficient delivery of actionable ISP projects
- the introduction of competitive tendering to deliver greater productive efficiencies, and reduce the need for regulatory assessment of expenditure forecasts.

The AER recognises the opportunity the AEMC's review presents to explore these issues in more detail. Attached is our detailed response to the consultation paper. In particular, we note the following:

- The current economic regulatory framework is incentive-based to encourage efficient project delivery. However, there can be significant uncertainties associated with major transmission projects, such as the actionable ISP projects. Due to their unprecedented size and complexity, there is a lack of comparable projects from which reasonable benchmarks can be drawn. This uncertainty may lead to Transmission Network Service Providers (TNSPs) over-forecasting the costs of project delivery. Such cost "buffers" could lead to consumers paying more than they need to for transmission network investment by transferring the risk of cost overruns. Generally, the AER cannot easily assess the efficiency of the buffer in a TNSP's cost forecasts due to information asymmetry. However, for major projects, there is simply a lack of information and reasonable benchmarks for both the TNSPs and the AER to consider when preparing and assessing cost forecasts, respectively, at least at this initial stage before any major projects are delivered.[3] The greater uncertainty and/or cost risk associated with major transmission projects warrants a review of whether the existing incentive-based regulatory arrangements remain appropriate for major transmission projects or if an alternative approach, such as contestability, would be more suitable.
- In our recently developed guidance for the regulation of actionable ISP projects,[4] we outlined the expectation that TNSPs will proactively manage project risks, and identify risks that are uncontrollable and/or not economic to mitigate. We consider TNSPs should

[3] In the attachment to this submission, we note that our understanding of the uncertainty of major projects will evolve as these major projects are delivered and, in turn, better information and forecasting tools are able to be developed.

[4] AER, *Guidance Note – Regulation of actionable ISP projects*, March 2021.

be exposed to project risks that they are best able to control or manage; we acknowledge there are circumstances where uncontrollable events may arise, and therefore it may be appropriate to pass efficient costs to consumers. The AER and TNSPs have dedicated significant resources to improving processes for estimating large project costs, and the AER's guidance note represents a significant step in this improvement. We consider it critical to further explore opportunities to manage uncertainty and increased cost risk associated with large transmission projects.

- Under the ISP process, large transmission projects that are identified as actionable can then proceed through the Project Assessment Draft Report and the Project Assessment Conclusions Report components of the regulatory investment test for transmission, prior to commencing the contingent project application process. These collective processes are intended to ensure a chosen investment delivers the maximum benefit to consumers. There is potential for duplication and redundancy in these combined process, and we encourage consideration of whether a more appropriate framework could streamline the economic assessment process, while maintaining scrutiny to ensure consumer interests are protected.
- In relation to the RIT-T, the AER supports, in principle, giving consideration to approaches under which broader benefits can be identified and outlined in a transparent way. However, the AER would not support an approach that would, in the absence of clear policy requirements, transfer risk and costs to NEM consumers in order to make up for a shortfall in NEM-attributed benefits. In our view, NEM consumers should only pay the costs of an investment to the point that they reflect benefits that directly accrue to the NEM, with costs beyond this point being met by governments.
- The AER considers that increased contestability in the provision of transmission services has the potential to solve a number of issues identified with both the planning and investment stages. These include driving efficient project delivery, enhancing innovation and value add in the identification and delivery of solutions, reducing information asymmetries by revealing efficient costs and addressing the perceived barriers to the equal assessment of non-network options at the planning stage. As part of our preliminary analysis of models of competition under our TIR review, the AER identified that sponsor-based competition allows for the greatest scope for market-led innovation in the identification and design of solutions to network needs. This would be expected to result in productive and dynamic efficiencies, to be passed on to the end consumer. We recommend that the AEMC's review explore the potential benefits of sponsor-based competition.

We look forward to continuing working with the AEMC to ensure the planning and investment framework is fit-for-purpose for the efficient and timely delivery of major transmission projects. To discuss any matter raised in this submission, please contact Arista Kontos on (08) 8213 3492.

Yours sincerely

Jim Cox
Deputy Chair
Australian Energy Regulator

Sent by email on: 30.09.2021

Attachment: Detailed response to the Consultation Paper

There appears to be greater uncertainty associated with the costs and benefits of large and/or complex infrastructure projects.[5] There is some evidence that these types of projects have a higher likelihood of being delivered over-budget and later than originally expected.[6] In light of this, we strongly support a review of the transmission planning and investment framework as it applies to large projects, to ensure it remains fit-for-purpose for identifying and progressing efficient investment.

This was the objective of the Australian Energy Regulator's (AER) recent Transmission Investment Regulation (TIR) review to support the efficient and timely delivery of large actionable Integrated System Plan (ISP) projects.[7] As part of that work, we identified key issues with the existing framework, which we are pleased to see have been canvassed by the Australian Energy Market Commission (AEMC) in its consultation paper, amongst others, for consideration under its review.

It is important to distinguish between uncertainty and risk when considering the framework and processes associated with the delivery of large transmission projects. A risk refers to situations where a mathematical probability can be applied to events that may occur, whereas uncertainty refers to events that cannot be expressed in mathematical probabilities.[8] For example, risks for a large transmission project may include cost overruns and/or construction delays, whereas an uncertainty for the same project could be the potential impact of changing technology on the long term benefits of the investment. Under the current framework, the risk of cost overruns are shared by Transmission Network Service Providers (TNSPs) and consumers, with the National Electricity Rules (NER) establishing the incentives for estimation and pass-through of costs to manage these risks. However, uncertainty around the long-term benefits of an investment are borne by customers, not TNSPs, and are managed through the ISP process. In recognising this distinction, the review should consider who is best placed to manage or respond to the consequences of these uncertainties and risks.

The AEMC's review is important to ensure consumers pay no more than necessary for transmission investment required to facilitate the current National Electricity Market (NEM) transition. Consumers ultimately pay the costs associated with transmission assets and they are long-lived assets that consumers will pay for a significant period of time. Below we highlight the priority issues from the AER's perspective and provide additional considerations around the framing of certain issues.

Managing cost risk under a regulatory framework

The AER's role in the existing framework

Our role under the economic regulatory framework, as set out in the existing NER, involves assessing forecast expenditure (or costs) in determining the maximum amount of revenue network businesses can earn. We assess the efficient and prudent forecast expenditure and incremental revenue a TNSP requires to deliver an identified project. The AER's assessment occurs after the investment has been identified by the Australian Energy Market Operator (AEMO) and the TNSP under the preceding planning framework – for actionable ISP projects, that planning framework comprises the ISP and regulatory investment test for transmission (RIT-T).

The existing regulatory assessment framework

We support the AEMC's proposed holistic review of the planning and investment frameworks. This includes considering whether the existing incentive-based regulatory arrangements are appropriate

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[5] Compared to more business as usual capital expenditure.

[6] PwC, *Managing capital projects through controls, processes, and procedures*, 2014, p. 4; KPMG, *Managing risk in the Australian construction industry*, May 2020; Grattan Institute, *Cost overruns in transport infrastructure*, October 2016; McKinsey & Company, *A risk-management approach to a successful infrastructure project*, 1 November 2013.

[7] See AER, *Regulation of large transmission projects* project site here.

[8] Toma, Chiriţă, and Şarpe, *Risk and Uncertainty,* Procedia Economics and Finance, Vol 3, 2012, pp. 975-980.

for major discrete projects, or whether an alternative approach such as contestability is more suitable for managing the types of risks and/or uncertainty that may be associated with such projects.

As part of the AER's TIR review, we explained that the current economic regulatory framework is incentive-based to encourage efficient project delivery without the need for direct regulatory oversight of how the TNSP spends its approved expenditure allowance day-to-day within a regulatory reset period.[9] We set a periodic ex-ante revenue 'cap' that is based on the forecast efficient costs of running a transmission business plus a commercial return on capital. If a TNSP is able to beat the forecasts while still meeting performance targets, it shares rewards with consumers (and vice versa, with penalties).[10]

These 'high powered' incentive-based frameworks encourage service providers to achieve productive efficiencies by offering the prospect of economic rent.[11] However, at the same time, these capital expenditure incentives increase the incentive on TNSPs to over-forecast the capital costs of a project, in order to minimise the possibility that the TNSP will spend more than its revenue allowance and incur a penalty. Faced with the increased risk of cost overruns that is associated with major discrete projects, the incentive for TNSPs to over-forecast is greater. As the AEMC notes, such cost "buffers" could lead to consumers paying more than they need to for transmission network investment by transferring a large share of the risk of cost overruns onto them before the risk eventuates.[12]

Generally, the AER cannot easily assess the efficiency of the buffer in a TNSP's cost forecasts due to information asymmetry – a challenge faced by any regulator. Specifically, the network business has more information available to it than the regulator and the regulator cannot observe the network business's efficient costs. This means the regulator must make a decision based on the best available information rather than the full suite of information available to the TNSP. However, for major transmission projects, there is simply a lack of information for both the AER and the TNSP to rely on in order to accurately forecast the efficient costs for delivery. This is because the unprecedented size and complexity of major projects, such as the actionable ISP projects, means that there is a lack of comparable projects from which reasonable benchmarks can be drawn.

We note that lack of information may only be a temporary challenge. As experience is gained from the delivery of major projects, TNSPs and the AER will have access to more benchmarks and improved ability to identify and assess costs.

Determining the appropriate strength of incentives for large projects

There is therefore a question as to whether the strength of the existing incentives are appropriate for TNSPs to efficiently manage the types of risks and/or increased uncertainty that are typically associated with certain large discrete projects, to ensure the most efficient outcomes for NEM consumers. As in the design of any incentive mechanism, there is a trade-off between:

- the level of productive efficiency that is attained through incentives, and

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9 See AER, Work program letter – *Regulation of large transmission projects*, 17 November 2020, available here.

10 See AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013. The framework contains an additional incentive through ex-post measures, which allow us to review and exclude certain types of outturn capital expenditure from the regulatory asset base (RAB)—for example, inefficient over-spends against the forecast.

11 By 'economic rent', we refer to profit the TNSP earns, above its economic costs (including the cost of remunerating capital); see HoustonKemp, *Regulatory treatment of large, discrete electricity transmission investments: A report for the Australian Energy Regulator*, August 2020.

12 If TNSPs fully factor expected cost overruns into their expenditure forecasts, consumers pay the financing costs for this before the risk eventuates, and TNSPs are not as strongly incentivised to proactively manage project risks and find cost efficiencies. Also, if the risk does not eventuate and the TNSP underspends, it will receive a CESS reward; see AER, Work program letter – *Regulation of large transmission projects*, 17 November 2020.

- the cost of any incentive payment (a form of economic rent) that must be made to attain greater levels of productive efficiency.[13]

'Low powered' incentives that offer less (or no) prospect of economic rent can reduce the incentive on TNSPs to include a risk buffer or premium in their project forecasts as there is less (or no) penalty for the TNSP if it overspends in delivery. However, low powered policies, in turn, offer less incentive for TNSPs to achieve productive efficiencies throughout project delivery. This would require closer monitoring by the AER to ensure efficiency in project delivery. `High powered' incentives increase the incentive on the TNSP to achieve cost savings through project delivery, but also increase the incentive on the TNSP to include a risk buffer or premium.

We must find the right balance in this rent-efficiency trade-off in all incentive mechanisms. In principle we must weigh the efficiencies achieved in the ex-ante forecast under lower powered incentives, against the efficiencies to be achieved in project delivery through higher powered incentives.

In the case of small-or-medium-sized capex projects, the risk of a cost overrun occurring above the overall expenditure allowance is relatively modest. For such projects we consider that the existing incentive mechanism promotes efficient outcomes. However, as noted earlier, large capital expenditure projects may involve a much greater risk of cost overruns, of a potentially greater magnitude. This may warrant consideration of what the appropriate balance is for the rent-efficiency trade-off (i.e. high-powered versus low-powered incentives). Any adjustment to the incentives arrangements for major projects would need to be coupled with the appropriate level of regulatory involvement to promote the greatest efficiencies for consumers. We emphasise that the objective remains to deliver needed projects at the overall lowest cost to consumers in the long-run.

Efficiency can otherwise be incentivised through competition, as an alternative to regulating these large projects. We discuss this below.

Sources of project risk

In determining the appropriate strength of efficiency incentives for major projects, we should remain cognisant that the degree of the risk of cost overruns is project specific. It is the unique characteristics of a project that inform the degree of cost risk, for example where significant greenfield assets are required and the line route is subject to community acceptance and local government approvals. We think the AEMC is right in seeking to understand from where the increased cost risk and/or uncertainty associated with major projects stems. In understanding this, we can consider whether there is the opportunity to appropriately treat certain cost components differently under the regulatory framework, in a way that reflects the level of risk of forecasting error. This may be a more pragmatic outcome that would retain the incentives for efficient spending on the rest of the project.

This would be beneficial in scenarios where a new type of cost is being considered; where there is little experience from either the proponent or the AER to draw from when assessing forecast costs associated with a major project. For example, during the assessment of Project EnergyConnect's contingent project application, there were challenges in assessing the efficient costs associated with complying with the NSW biodiversity protection regulations in a timely manner. These costs were expected to be material, but there was relatively little historical experience or benchmarks to rely upon to assess these costs. The assessment was completed following significant additional work and information provided by the proponent. However, this likely resulted in an extension to the project's assessment and subsequent investment decisions by the proponent.

Consideration of alternative treatments for a specific group of costs in scenarios where there is a high degree of associated cost risk could therefore assist in streamlining the economic assessment process, by allowing assessment of those costs later when more information is obtained. As noted

[13] Laffont and Tirole, 'Competition in Telecommunications' (Jul. 2001) 68 (1) *Southern Economic Journal 190*; HoustonKemp, *Regulatory treatment of large, discrete electricity transmission investments: A report for the Australian Energy Regulator*, August 2020.

above, as major projects are delivered, such as greenfield interconnectors or other new transmission of significant scale, the experience will provide TNSPs and the AER with benchmarks and an improved ability to identify and assess certain costs, such as the costs of land purchasing and environmental offset. Therefore, any special treatment of cost components may only need to be temporary and perhaps more appropriately left at the discretion of the AER.

As noted above, diluting the efficiency incentives in the framework, including allowing for additional provisions to pass-through specific costs, removes the incentives on the TNSP to pursue efficiencies in project delivery. This may result in worse outcomes for consumers in the long-run. A more targeted regulatory approach may also add regulatory complexity overall. The AEMC is asked to take into account these competing considerations in its review of a fit-for-purpose framework.

Managing project risks under the existing framework

Many project risks can be managed in some way by TNSPs, including for large projects.[14] As noted in the AER's recently developed guidance for the regulation of actionable ISP projects, when developing project cost forecasts, we expect TNSPs to proactively manage the project risks, and identify risks that are uncontrollable and/or not economic to mitigate.[15] We consider TNSPs should be exposed to project risks that they are best able to control or manage; in some circumstances, they should be able to pass efficient costs associated with uncontrollable events through to consumers.[16] Importantly, our contingent project determination is not intended to completely de-risk the project, as investment projects always contain risk and financing arrangements account for this.[17] We consider project risks should be held by the party best able to manage them.

Under the existing regulatory framework, the approach to quantifying risk is a key difference between business-as-usual (BAU) and major projects. As risk associated with BAU projects can generally be managed by network operators, we do not expect that risk allowances will be incorporated into forecasts. However, material project specific risks associated with large projects are also non-systematic in nature and best managed by the network. In this situation, the inclusion of project risk allowances in an expenditure allowance may provide the appropriate incentives for a TNSP to manage these risks and to mitigate the need for TNSPs to add buffers to their cost estimates.[18]

The AER and TNSPs have put a lot of work into improving the processes for estimating large project costs, including through the better estimation of project risks and the use of tender processes to estimate project specific costs. The AER's guidance note was an important step in this process, in addition to recent contingent project processes.[19] The staging of contingent project applications is also another way TNSPs can manage risks around large projects. This is because as each stage progresses, it can reveal important project information and reduce associated cost uncertainty.[20] Therefore our understanding of the "inherent uncertainty" of major projects continues to evolve as better information and forecasting tools are developed.

Through recent contingent project applications, such as those for Project EnergyConnect, we have demonstrated to TNSPs an openness to exploring other mechanisms within the existing rules and

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[14] See Deloitte, *Capital projects: Project and risk management—Leading practices*, January 2016, p. 5; McKinsey & Company, *A risk-management approach to a successful infrastructure project*, November 2013; KPMG, *Managing risk in the Australian construction industry*, May 2020. We note that risk management does not mean fully mitigating all risks. Risks can be managed through avoidance, transference, mitigation (to varying degrees) or acceptance. See Deloitte, *Capital projects: Project and risk management—Leading practices*, January 2016, p. 12.

[15] AER, *Guidance Note – Regulation of actionable ISP projects*, March 2021, pp 17-18, 20.

[16] There are mechanisms in the existing regulatory framework that allow TNSPs to pass through efficient costs associated with certain events that are beyond their reasonable control via cost pass throughs (or, in exceptional cases, the capital expenditure re-opener provision).

[17] AER, *Guidance Note – Regulation of actionable ISP projects*, March 2021, p 17.

[18] AER, *Guidance Note – Regulation of actionable ISP projects*, March 2021, p 18.

[19] See AER, Project EnergyConnect contingent project site here.

[20] AER, *Guidance Note – Regulation of actionable ISP projects*, March 2021, pp 25.

regulatory framework for more efficiently dealing with uncertainty and identifiable risks for which the forecasting error may be particularly significant.

Material change rule change request

Regarding the 'material change in network infrastructure project costs' rule change request, we agree that increasing project cost estimates are a concern. It is important that consumers have confidence that transmission investments deliver benefits to them that exceed their cost, given that they ultimately fund them.

We are of the view that this issue is best considered in reviewing the planning framework as a whole. The reason we see significant increases in project cost estimates is that once a project is identified through the RIT-T, the TNSP undertakes further design activities to improve the accuracy of the cost estimates for its contingent project application. The AEMC should therefore consider the extent to which TNSPs should improve the accuracy of the cost estimates for different options prior to selecting a preferred option. There are considerable costs associated with the activities to improve the accuracy of these cost estimates. Again, the AEMC will need to weigh up the costs of these upfront activities against the long-term efficiencies to consumers to be realised from improved options analysis and selection.

We further consider that time is needed to understand the effectiveness of the existing safeguards in the actionable ISP framework. Under the actionable ISP framework, the AER's RIT-T assessment under former clause 5.16.6 was removed to avoid duplication in light of the introduction of the ISP.[21] To ensure only beneficial investments are progressed, the NER was amended to stipulate that, before a contingent project application can be lodged with the AER, the TNSP must satisfy the actionable ISP project trigger event set out in clause 5.16A.5 of the NER. As the AEMC notes in its consultation paper, this contains a criterion that 'caps' the forecast project cost that can be included in the contingent project application to the project cost used in AEMO's feedback loop. The feedback loop, among other things, checks that the updated costs do not change the status of the actionable ISP project as being part of the optimal development path. As the actionable ISP framework has only been implemented relatively recently,[22] it has yet to be applied fully to an actionable ISP project. We consider there is merit in allowing this component within the planning framework to mature, to understand its effectiveness.

Further, we wish to reiterate that the ISP and RIT-T processes are responsible for the cost benefit analysis that allows TNSPs to select a preferred option to meet a network need, one which maximises net economic benefits. The AER does not have a role in assessing the RIT-T for actionable ISP projects. We therefore do not have full visibility of the costs and benefits contained in a RIT-T. This should be kept in mind in determining the appropriate decision-maker under the proposed rule change.

Opportunities to streamline the economic assessment process

We welcome the AEMC's examination of potential opportunities to streamline the economic assessment of major transmission projects. We consider the examination of streamlining the planning and investment processes, including the removal of duplication and/or redundancy, should be a priority issue for the review.

Streamlining the contingent project application and RIT-T processes

Under the existing framework, TNSPs must complete the RIT-T cost benefit analysis before undertaking major investments in their networks. The purpose of the RIT-T process is to undertake a

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[21] Energy Security Board, *Recommendation for National Electricity Amendment (Integrated System Planning) Rule 2020 – Decision Paper*, March 2020 p 21.

[22] The National Electricity Amendment (Integrated System Planning) Rule 2020 came into effect on 1 July 2020.

detailed examination of project costs and ensure the chosen development (from a suite of options) delivers the maximum benefit to consumers for the associated costs.

Following the changes to the NER to action the ISP, the first of the three stages of the RIT-T, the Project Specification Consultation Report, has been replaced by the ISP process for actionable projects. The remaining two elements of the RIT-T, the Project Assessment Draft Report and the Project Assessment Conclusions Report, were largely unchanged and are still required to be completed, in addition to satisfying AEMO's feedback loop. These changes for ISP projects sought to streamline the economic assessment process for ISP projects, while maintaining the detailed scrutiny of project costs to ensure any investment is in the best interests of consumers.

We agree there is potential for duplication and overlap between the RIT-T and ISP processes. In particular, the RIT-T adopts the benefits that are modelled by AEMO for the ISP. This raises the question as to whether project benefits need to be re-modelled at the subsequent RIT-T stage. The previous changes to the NER to action the ISP sought to streamline the existing process, without suggesting new or alternative processes. We encourage the AEMC to consider whether a more appropriate process should be developed that streamlines the regulatory assessment framework for ISP projects and maintains the appropriate degree of scrutiny of project benefits against costs to ensure consumers' interests are protected.

In the AER's TIR review, we identified the following potential changes to the contingent project application and RIT-T processes to allow for a more robust assessment of project benefits alongside more reliable project costs estimates, while enhancing stakeholder input and streamlining the overall process:

- the introduction of a draft decision to promote greater stakeholder input/engagement
- streamlining the overall planning and regulatory processes by integrating some elements of the RIT-T process into the CPA (and/or AEMO's ISP) process
- improving NER information disclosure requirements associated with the CPAs to improve the quality of our assessment while reducing the administrative burden of issuing and responding to information requests.[23]

These suggestions may aid the AEMC's consideration of improvements in this area. We recognise they represent significant reforms, and so reiterate the need to understand the costs and benefits of any changes to ensure the maximum benefit to consumers over the longer term.

Misalignment between ISP and feedback loop and practicality of ISP updates

We consider the AEMC has accurately articulated the impact that the pace of the changing environment has on the alignment of the ISP and RIT-T processes, as well as on the application of AEMO's feedback loop in practice.[24] Specifically, rapid changes in the sector mean that the inputs and assumptions used in the ISP quickly become out of date and raise questions as to whether it is appropriate to use these in a RIT-T. The AEMC also notes that an ISP update may not be suitable to resolve these questions due to the effort and complexity that would be involved at the same time that AEMO is preparing the next ISP.

We consider this a priority issue that should be investigated under the AEMC's review. We seek exploration of how to resolve the issues that arise when applying the processes in practice, whilst ensuring the appropriate checks and balances remain for AEMO. This is to ensure that market developments and changes are adequately captured and robustly tested in AEMO's ISP analysis, which remains the very purpose of processes like updates to the ISP and the feedback loop. We consider this needs to be urgently resolved, given the heavy reliance on these processes at present

[23] AER, *Final guidance note covering letter – Regulation of actionable ISP projects,* March 2021, pp 11.

[24] AEMC, *Consultation paper – Transmission Planning and Investment review*, 19 August 2021, pp 24-5.

to identify investments to support the NEM transition. The issue of misalignment between the ISP and feedback loop should be considered in the context of the streamlining of ISP and CPA processes outlined previously in this attachment given the highly interrelated nature of these matters.

Unequal treatment of non-network options

Another issue that the AER considers a priority that should be explored under the AEMC's review is the perceived barriers for non-network options (for example, demand side management and aggregated distributed energy solutions) under the planning framework, specifically the RIT-T stage. As referenced in the consultation paper, this was a key issue raised by stakeholders under the AER's previous TIR review to support the efficient delivery of actionable ISP projects. The regulatory framework around transmission planning and investment aims to promote competitive neutrality, to promote identification of a solution to a need that has the greatest net market benefit. This benefits consumers directly by reducing the risk that they will pay for inefficient investments. This also encourages efficient outcomes in the longer-term by supporting competitive procurement of network services and reducing the risk to consumers of long-term transmission investments that may subsequently prove to be inefficient.

The incentive to preference capital expenditure over operating expenditure has long been recognised where the regulated rate of return exceeds the actual financing costs for any regulated RAB-based network business.[25] As noted in the consultation paper, in its 2019 Economic regulatory framework review, the AEMC found that TNSPs may have an intrinsic preference for capital expenditure (over operating expenditure) where the regulatory rate of return exceeds the actual financing costs faced by the business.[26] We acknowledge the potential for such bias, whilst also noting that the AER's decision-making regarding the regulated rate of return is complex and there is the opposing risk that if the regulated rate of return is set too low, TNSPs will be dissuaded from undertaking desirable investments.[27]

As part of the AER's TIR review, HoustonKemp also identified an institutional preference within TNSPs for network solutions.[28] As the AEMC notes, the fundamental role of TNSPs is to provide transmission services, and so their knowledge and capabilities are likely to be more orientated towards supply-side, capex-focused solutions, rather than as providers of alternative non-network solutions. We also agree with the AEMC that network and non-network options are not directly comparable, and these differences will affect their consideration in the assessment process.

Our analysis of the regulatory investment tests for transmission and distribution (RIT-T and RIT-D, collectively RITs), completed to date since 2018, indicates limited consideration of non-network options in the RITs. Of the 17 RIT-Ts completed by network businesses across the NEM since 2018, only one RIT-T identified a partial non-network option as a preferred option. We identified similar issues at the distribution level, with only two RIT-Ds having identified a non-network option as a preferred option among approximately 45 RIT-Ds. Our analysis supports the perception of the risk that network solutions are likely to be favoured despite the existence of a non-network solution, or a combination of a network and non-network solution, that may provide greater net benefits to consumers.

Further, the pre-RIT processes undertaken by network businesses on non-network engagement are also important to ensure there is sufficient opportunity for all interested stakeholders to actively contribute to the development of RIT options. Currently, the NER requires distribution network

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25 H. Averch and L. Johnson, *The Behavior of the Firm Under Regulatory Constraint,* American Economic Review, December 1962.

26 AEMC, *Economic regulatory framework review | Integrating distributed energy resources for the grid of the future,* 26 September 2019, p 64.

27 HoustonKemp, *Regulatory treatment of large, discrete electricity transmission investments: A report for the Australian Energy Regulator*, August 2020, p 63.

28 HoustonKemp, *Regulatory treatment of large, discrete electricity transmission investments: A report for the Australian Energy Regulator*, August 2020, p 63.

businesses to publish a demand side engagement strategy and maintain a demand side engagement register to enable non-network participation in upcoming network planning and expansion projects. However, no such requirements exist for transmission network businesses; there is inconsistency between the requirements between the transmission and distribution frameworks. There are also additional reporting requirements as part of network businesses' annual planning reports that aim to provide key information to all stakeholders including non-network proponents enabling their participation in processes such as RITs. We consider there is a need for the AEMC to also review the effectiveness and prudency of the pre-RIT processes for TNSPs, to ensure they promote a level-playing field for all network and non-network participants and that they provide sufficient lead time for non-network businesses to meaningfully contribute to the RIT-T.

We consider that the AEMC's review provides a timely opportunity to investigate this priority issue more holistically at the transmission level by identifying key barriers to:

- non-network engagement in RIT processes, and
- the equal assessment of non-network options that do engage in RIT processes.

Any learnings may then inform consideration of this issue as it pertains to the distribution level.

The consequence of unequal treatment of non-network solutions in investment options analysis is the risk for increased network costs – a risk that mainly sits with consumers given network solutions are long-lived assets that consumers will pay for a significant period of time. This risk is significantly compounded given the size of the discrete network solutions that are needed to support the NEM transition. Further, as technology rapidly develops to meet the needs of the transmission network and the electricity system as a whole, it is even more crucial that the regulatory framework ensures that non-network options are provided with equal consideration as appropriate to promote efficient outcomes in the long term interests of consumers.

The sponsor-based competition model also has the potential to solve this issue in transmission planning, amongst its other merits, which we discuss below.

Treatment of benefits in transmission planning – broader economic impacts

In its consultation paper, the AEMC asks stakeholders whether wider economic benefits should be included in the ISP and RIT-T to justify transmission investments in the NEM, given the scale and pace of the NEM's energy transition.

In principle, the AER is supportive of giving consideration to approaches under which benefits that accrue beyond the NEM can be identified and outlined in a transparent way through a RIT-T. However, the AER would not support an approach that would, in the absence of clear policy requirements, transfer risk and costs to NEM consumers in order to make up for a shortfall in NEM-attributed benefits. In these circumstances it is appropriate for governments to meet the shortfall or gap in NEM benefits identified through the RIT-T via a contribution to funding the costs of the project. Put differently, broader social benefits could be considered in the test, but NEM consumers should only pay costs that reflect the benefits that directly accrue to the NEM; benefits that accrue outside of the NEM should be paid for by governments on behalf of their respective taxpayers.

The Rate of Return Instrument (RORI) and Financeability

The rate of return instrument (RORI) sets out how we determine the allowed rate of return on capital in regulatory determinations for energy networks. We must remake the RORI we set in 2018 by 17 Dec 2022. We are currently doing research and stakeholder consultation through a series of working papers. The more formal active phase of the review will start early next year.

Our working papers allowed us to consider technical aspects of the rate of return ahead of the active phase. The following draft and final working papers have been published in this process to date:

- Energy network debt data – debt term and extension of debt index (draft and final)[29]
- CAPM and alternative return on equity models[30]
- International regulatory approaches to rate of return[31]
- Rate of return and cash flows in a low interest rate environment[32]
- Term of rate of return[33]
- Debt[34]
- Equity[35]
- Overall rate of return (including gamma and gearing).[36]

We have received a significant number of submissions on our draft working papers. We also had a number of expert reports prepared to assist us with this work. Other than confidential submissions, this material is available on our website at the links provided in the footnotes.

The AER draft working paper, Rate of return and cash flows in a low interest rate environment, considered what impact the current relatively low interest rates may have on the networks businesses we regulate.[37] This draft paper considered a number of topics related to network financing including:

- The relationship between the risk free rate and the return on debt
- Potential relationships between the risk free rate and the return on equity
- The interaction between the risk free rate, inflation and gearing on net profit after tax
- The impact lower interest rates will have on regulated gas and electricity network service providers'(NSPs) net profit after tax and financial metrics
- The possible use of financeability metrics by the AER when making the RORI.

29 AER, *Rate of return – Energy Network Debt Data – Draft working paper*, 26 June 2020; AER, *Rate of Return – Energy Network Debt Data – Final working paper*, 18 Nov 2020. Working papers and public submissions are available here.

30 AER, *Rate of return – CAPM and alternative return on equity models – Draft working paper*, 27 Aug 2020; AER, *Rate of return – CAPM and alternative return on equity models – Final working paper*, Dec 2020. Working papers and public submissions are available here.

31 AER, *International regulatory approaches to rate of return – Draft working paper*, 27 Aug 2020; AER, *International regulatory approaches to rate of return – Final working paper*, 16 Dec 2020. Working papers and public submissions are available here.

32 AER, *Rate of return and cashflows in a low interest rate environment – Draft working paper*, May 2021; AER, *Rate of return and cashflows in a low interest rate environment – Final working paper*, Sept 2021. Working papers and public submissions are available here.

33 AER, *Rate of return – Term of the rate of return draft working paper*, May 2021; AER, *Rate of return – Term of the rate of return draft working paper*, Sept 2021. Working papers and public submissions are available here.

34 AER, *Rate of return – Debt draft working paper*, July 2021. Working paper and public submissions are available here.

35 AER, *Rate of return – Equity draft working paper*, July 2021. Working paper and public submissions are available here.

36 AER, *Rate of return – Overall rate of return draft working paper*, July 2021. Working paper and public submissions are available here.

37 AER, *Rate of return and cashflows in a low interest rate environment – Draft working paper*, May 2021.

In September we published a final combined working paper on the Term of the Rate of return and cash flows in a low interest rate environment.[38] In this paper we expressed a number of preliminary views including:

- Measures of financeability should not be directly used when setting the rate of return. However, we will consider financeability metrics as a cross check in our final overall rate of return working paper
- The regulatory framework does not require Network Service Providers (NSPs) to be able to achieve the benchmark assumptions used in making and applying the RORI at all times
- It is viable for regulated networks to adopt a capital structure different to our gearing assumptions used in the RORI because the return on capital is relatively invariant to changes in gearing
- In determining how we set the rate of return under the RORI we aim to provide all regulated businesses a reasonable opportunity to recover their efficient costs. However, this does not require a given business (or even the industry average) cost structure to exactly reflect the benchmarks we use for setting the rate of return (e.g. to have the same debt to equity ratio as we use for setting the rate of return in the RORI).
- While NSPs expressed concern about receiving an ongoing negative net profit after tax NPAT under current interest rate settings, we do not consider this an issue. The total expected return to equity including RAB indexation is positive even where NPAT is negative. Despite negative NPAT, NSPs can continue to finance their operations by borrowing against the increase in the value of the debt component of the RAB due to inflation indexation. In addition, firms can reduce gearing to increase NPAT if they choose to do so and investors should not be worse off by adopting a different gearing ratio.

As part of the RORI review we will also consider if it is appropriate to lower our assumed gearing ratio, something that would improve hypothetical financeability metrics at our benchmark-gearing ratio. Although, even if we did lower our benchmark-gearing ratio used in the RORI, NSPs can and are likely to operate at varying gearing ratios. We expect NSPs to make capital structure decisions that best suit their individual cash flow profiles and financing needs.

However, as the AEMC noted in its consultation paper, we are not intending to examine financeability broadly as part of the RORI review. We only intend to examine direct implications or uses for financeability metrics for the rate of return under the RORI. That is, we expect to limit consideration of financeability metrics to what, if anything, they may imply about the rate of return. The principle reason for this approach is the RORI review process's purpose is to develop a RORI that determines rates of return for network businesses that best promote the NEO and NGO. Financeability, while related to the rate of return, is broader as it depends on all the cash flows set by the regulator and all of the actions and costs of the regulated firm.

We note that if a contestability framework was introduced, we would expect that framework to facilitate competitive provision of new infrastructure at efficient cost. Therefore, we would expect this framework to facilitate financeable investment.

We consider that the issues of financeability and the cost of capital are interrelated and this interrelationship needs to be recognised as part of the review.

Contestability in transmission planning and investment

The AER considers that increased contestability in the provision of regulated transmission services has the potential to solve a number of issues spanning both the planning and investment stages and ensure identification of efficient investments as well as their efficient delivery. Benefits from innovation

[38] AER, *Term of the rate of return & Rate of return and cashflows in a low interest rate – Final working paper*, September 2021.

may be better realised through competition than through regulation, and are likely to be greater for large projects (because of their scale and scope).

The current transmission planning framework only introduces competitive tendering in the design and construction of an investment that has been identified under the central planning process.[39] As part of the AER's TIR review, we raised the introduction of sponsor-based competitive tendering as a potential reform to support the timely and efficient delivery of actionable ISP projects.[40] Under a sponsor-based competition model, AEMO would continue to identify a network need via the ISP process; however developers would then be invited to bid solutions to meet the identified need. Developers would bid to provide (finance, build, own and operate) their proposed solutions.[41]

Contestability in transmission planning

Sponsor-based competition could deliver greater productive and dynamic efficiencies in transmission planning by allowing the market to identify more innovative solutions.[42] Subjecting the identification and assessment of solutions to a competitive tender that is run by AEMO rather than the TNSPs would also be expected to overcome the perceived biases against non-network options (discussed above), in turn further promoting the most efficient solutions to network needs.

Expanded contestability in transmission investment

Increased competition in transmission investment can mitigate the overstatement of appropriate risk premiums and contingencies, as bidders seek to increase the value of their bids in order to win the work.[43] Further, opening procurement to a wider range of bidders and combinations of bidders will allow different lead parties with potentially different development approaches to bid in alternative (and possibly more efficient) solutions. This facilitates increased innovation and value add in the design of the solution and greater capital and operating efficiencies in construction.

In the United Kingdom (UK) jurisdiction, the energy regulator, Ofgem, reported between £600m and £1.2bn savings for consumers as a result of competitively procuring offshore transmission infrastructure. This framework is now being implemented for onshore projects in the UK.[44] Another example where competitive procurement has led to positive results can be seen through the delivery of competitive renewable energy zones in Texas ERCOT system. The competitive tendering process was used to determine who would build, operate and maintain the necessary transmission capacity. This project is considered to have been delivered in an efficient and effective way as a result of the competitive process used for the transmission augmentation.[45] In the electricity sector in Brazil, between 2000 and 2010 approximately 70 per cent of investments in transmission came from the private sector and is seen as promoting efficiency in delivery of the projects.[46]

Importantly, expanding competition beyond design and construction of a transmission project to financing and ongoing operation also provides the potential for:

- innovation in financing arrangements that can capture efficiencies

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39 Victoria is the exception to this, as it has a unique planning framework with bid-based competitive tendering. This is where AEMO would tender out for implementing, owning and operating a preferred solution it identified through the RIT-T.

40 AER, Work program letter – *Regulation of large transmission projects*, 17 November 2020, available here; HoustonKemp, *Regulatory treatment of large, discrete electricity transmission investments: A report for the Australian Energy Regulator*, August 2020, pp 67-71.

41 This is in comparison to a bid-based competitive procurement model which sets out the preferred solution to meeting the identified need and potential bidders bid on delivering the specified solution; see HoustonKemp, *Regulatory treatment of large, discrete electricity transmission investments: A report for the Australian Energy Regulator*, August 2020, pp 68-75.

42 HoustonKemp, *Regulatory treatment of large, discrete electricity transmission investments: A report for the Australian Energy Regulator*, August 2020, pp 69-71.

43 Stucke, Maurice E., *Is Competition always good?,* 4 February 2013, pp 178-179 (available here).

44 Frontier Economics, *Regulating for a net zero future*, January 2020.

45 HoustonKemp, *Regulatory treatment of large, discrete electricity transmission investments: A report for the Australian Energy Regulator*, August 2020, pp 115 - 121; Centre for Energy Studies, Rice University's Baker Institute for Public Policy, *Texas CREZ lines: how stakeholders shape major energy infrastructure projects,* November 2020.

46 HoustonKemp, *Regulatory treatment of large, discrete electricity transmission investments: A report for the Australian Energy Regulator*, August 2020, pp 132-133.

- TNSPs to adopt greater risk (where efficient and appropriate to do so) rather than contracting out risk or passing its own risk costs to consumers
- greater innovation in contractual and risk-sharing arrangements that re-allocate risks away from consumers, as non-incumbent bidders seek to differentiate, and increase the overall value of, their bids.[47]

In its analysis for the AEMC's 'Financeability of ISP projects' rule change process, CEPA noted the potential for contestability to attract financing from different classes of investors, where the current investors in a regulated network may be unwilling to contemplate the investments in question, or alternatively where the incumbent company could not support the increase in risk associated with delivery of the project.[48] For example, for the Thames Tideway Tunnel, Thames Water was able to have a large part of the work be delivered by a third party infrastructure provider via a licence.[49] A key feature of obtaining the licence was the submission of the cost of capital (BWACC) through a competitive tender process, ultimately won by Bazalgette Tunnel Limited (BTL), a consortium comprising of a group of institutional investors. The winning bid was 2.497%, less than Ofwat's 3.29%[50] and less than the 3.60% wholesale WACC from Ofwat's final determination for water and sewage companies.[51] One of the reasons BTL was able to provide this lower BWACC was a low cost of debt; though we note that it was also because BTL obtained a government liquidity support package and regulatory risk shields.[52]

Experience in international jurisdictions demonstrates that competitive procurement does promote relatively high levels of participation in the procurement process (as has been observed in the United States (US) PJM jurisdiction)[53] or different groupings of bidders submitting bids for a project (as was observed in Alberta where the five-shortlisted companies were a combination of existing network operators in Alberta and financiers and design and construction companies).[54]

As competitive tension reduces project costs, including risk premiums, it reduces the need for regulatory assessment of project expenditure forecasts. As potential bidders' seek to be the successful bidder in a competitive tender process, the efficient costs of the project are revealed. We note, however, that experience in the US CASIO jurisdiction demonstrates that competition does not always result in a convergence of bid costs to reveal a single efficient cost of the project (of the ten projects offered for competitive procurement between 2013 and 2016, individual bids for each project varied by up to 100 per cent).[55]

It is therefore important, in considering the introduction of competition in transmission in the NEM, to assess the potential competitive outcomes to the extent we can – this includes assessing whether there is sufficient depth of competition in the market for transmission services in Australia and understanding how to design any competitive tendering framework in a way that maximises engagement by bidders. This includes removing any actual or perceived advantages by the incumbent TNSP to ensure a level-playing field for non-incumbent bidders.[56]

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47 Non-conventional cost containment mechanisms such as cost caps and performance-based incentives have been common in transmission tenders in FERC Order 1000 jurisdictions in the US; see Joskow, Paul L, *Competition for Electric Transmission Projects in the USA: FERC Order 1000*, September 2020.

48 CEPA, *Financeability of ISP Projects, Report for the AEMC*, 8 January 2020, section 3.4.2.

49 CEPA, *Financeability of ISP Projects, Report for the AEMC*, 8 January 2020, section 3.4.2.

50 This was estimated from an indicative economic draft guidance.

51 Oxera, *The Thames Tideway Tunnel: returns underwater?*, 24 September 2015.

52 Oxera, *The Thames Tideway Tunnel: returns underwater?,* 24 September 2015.

53 Joskow, Paul L., *Competition for Electric Transmission Projects in the USA: FERC Order 1000*, September 2020.

54 See T&D World, *Five Companies Selected to Bid on Fort McMurray West 500-kV Transmission Project,* 24 January 2014.

55 Joskow, Paul L., *Competition for Electric Transmission Projects in the USA: FERC Order 1000*, September 2020, p 297.

56 A key reform under FERC Order 1000 in the US was the removal of the right of first refusal for the incumbent Transmission Operators; see HoustonKemp, *Regulatory treatment of large, discrete electricity transmission investments: A report for the Australian Energy Regulator*, August 2020, p 104.

Other challenges around a competitive tendering framework include, for example:

- the significant administrative burden that would be placed on the party responsible for assessing proposals, particularly under sponsor-based competition, which would result in highly varied bids that may take time to process and consider
- understanding the role and nature of regulation around competitively tendered projects, to ensure appropriate safeguards for NEM consumers.

The costs of the reform must be weighed against the benefits, but we do consider contestability – particularly sponsor-based competitive tendering – to be a potential alternative to the regulation of major projects that warrants exploration as part of the AEMC's review.