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Thursday, 30 September 2021

Ms Anna Collyer
Chair
Australian Energy Market Commission
Level 15, 60 Castlereagh Street
SYDNEY NSW 2000

Lodged online: www.aemc.gov.au

Dear Ms Collyer

Submission to AEMC Transmission Investment Review Consultation Paper

Transgrid welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC) Transmission Planning and Investment Review consultation paper.

We understand that the purpose of the AEMC's review is to identify and test issues associated with the frameworks for planning, funding and delivering major transmission projects and to develop solutions to address these issues, including whether transmission projects should be contestable.

The AEMC is also seeking stakeholder views on a rule change request from the Energy Users Association Australia, Major Energy Users, Delta Electricity, AGL and ERM Power on material changes in network infrastructure costs in the consultation paper.

Given the unprecedented speed of the energy transition, the AEMC's review is timely, and we hope it will result in transmission projects being able to be delivered in a faster and more efficient manner than is currently possible. The delivery of major transmission projects is critical to ensuring that Australia's energy system can safely, reliably and securely transition to renewable energy. These projects will also importantly facilitate the delivery of lower electricity prices to consumers within the National Electricity Market.

In our role as jurisdictional planner and operator for the New South Wales and the Australian Capital Territory electricity system, we are acutely aware of the stress that the system is, and will continue to be under, until these and other grid augmentation projects are completed.

If you require any further information or clarification, please feel free to contact either me or Eva Hanly, Executive Manager, Strategy, Innovation and Technology at eva.hanly@transgrid.com.au.

Yours sincerely

Brian Salter
Acting Chief Executive Officer

AEMC Transmission Planning and Investment Review

Transgrid submission to consultation paper

1. Summary

Context

Transgrid welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC) Transmission Planning and Investment Review consultation paper.

We understand that the purpose of the AEMC's review is to identify and test issues associated with the frameworks for planning, funding and delivering major transmission projects and to develop solutions to address these issues, including whether transmission projects should be contestable.

The AEMC is also seeking stakeholder views on a rule change request from the Energy Users Association Australia, Major Energy Users, Delta Electricity, AGL and ERM Power on material changes in network infrastructure costs in the consultation paper.

The efficient delivery of major transmission projects is critical to ensuring that Australia's energy system can safely, reliably and securely transition to renewable energy. These projects will also importantly facilitate the delivery of lower electricity prices to consumers within the National Electricity Market (NEM).

In our role as the transmission planner and operator for NSW and the ACT for over 40 years, Transgrid has developed unique expertise and capability in managing one of the key parts of the Australian energy system. Our primary responsibility is to ensure the ongoing security and reliability of the system for the benefit of all energy users. We are not only legally obliged to meet this responsibility under the National Electricity Rules (NER) but we are also subject to a set of comprehensive obligations under our lease and licence with the NSW Government.

In this period of unprecedented change in the energy system, we are acutely aware of the stress that the system is, and will continue to be under, until the major transmission projects are completed.

In developing our views in this submission, Transgrid has drawn on analysis commissioned from Frontier Economics (Frontier), FTI Consulting (FTI) and Ernst & Young (EY). Their expert reports are attached to this submission as appendices.

Transgrid's positions

- Transgrid agrees with the AEMC's assessment framework but suggests two criteria be added:
  - The extent to which reform options are likely to lead to more timely and efficient investment in projects that are in the long term interests of consumers; and
  - Whether the reforms increase the risk to the security and reliability of the energy system.
- The existing ex-ante incentive-based framework is appropriate for the development and delivery of large transmission projects and should be retained, subject to some refinements that would improve outcomes for consumers and stakeholders.

- Any ex-post review triggered by a major transmission project should be confined to that project. It should not extend to the whole of a transmission network service provider's (TNSP) capital expenditure portfolio.
- The revenue determination process should clearly separate the costs that the TNSP has limited control over, (such as the cost and extent of biodiversity offsets and other land use management decisions by governments that impact on route alignments), from costs that the TNSPs do have control over.
- The staged contingent project application (CPA) process should enable key inputs into the revenue determination to be agreed at an earlier stage, to ensure that the basis for the Engineering Procurement and Construction (EPC) contract is considered appropriate by the Australian Energy Regulator (AER) before a market procurement process is undertaken.
- The AER should accept the competitively tendered EPC contract cost unless there is an identifiable and material defect in the market procurement processes.

- The economic assessment process is a rigorous and transparent process which should be retained, however, some of the time periods in the process could be reduced, such as the Australian Energy Market Operator (AEMO) feedback loop.
- The regulatory investment test (RIT-T) should be broadened to include other relevant quantifiable economic and environmental benefits to enable the full value of the Integrated System Plan (ISP) projects to be identified and included as part of their assessment.
- The regulatory framework should be adapted to provide TNSPs with specific incentives to develop expertise in new and emerging technologies so that non-network solutions can more effectively be considered as a viable option. We would be pleased to work with the AEMC to develop these incentives as part of its review.
- Transgrid does not agree with the AEMC that an issue with the current regulatory framework is a TNSP's exclusive right to invest with no corresponding obligation as the development of the NSW Electricity Infrastructure Roadmap demonstrates. If a project provides the return that is stipulated by the AER for a benchmark efficient entity, and the rate of return instrument (RORI) and other arrangements appropriately deal with risk then, all things else being equal, TNSPs will invest in it.
- Contestability in construction is an important way to ensure that the costs of large transmission projects are the lowest cost possible for consumers – typically, over 85% of Transgrid's costs in transmission projects are subject to competitive market processes.[1] However, contestability in transmission ownership and operation carries with it significant risks to the security and reliability of the whole energy system.
- Global precedent demonstrates that having multiple owners and operators of transmission infrastructure in a meshed energy system results in a significantly increased risk of system failures.
- The inability of a benchmark efficient entity to maintain an investment grade credit rating metric when investing in major transmission projects, is a significant shortcoming of the current regulatory framework and should be addressed as a matter of priority so that transmission projects can proceed for the benefits of consumers.
- Under the current regulatory framework, the AER is not able to address the issue of financeability of transmission projects. We propose the AEMC makes a change to the NER to provide a positive obligation on the AER to ensure that a benchmark efficient entity can finance transmission projects at the benchmark grade credit rating. This should take the form of a clear and objective commercial

[1] This excludes the calculation of biodiversity costs required by governments which would vary, including by route length and selection.

viability test or a financeability test. The test would be applied whenever revenues are determined or adjusted, such as when a CPA is approved.

- Contestability will not address the financeability issue faced by investors in large scale transmission infrastructure under the existing regulatory framework as any entity will encounter the same issue (assuming an entity can satisfy the same national security requirements as existing TNSPs). Utilising alternative mechanisms such as special purpose vehicles (SPVs) would have the disadvantage of nationally critical infrastructure being owned by investors with sub investment credit grade metrics as well as limited recourse options for governments to those SPVs should the system fail.
- We do not support the material change in network costs rule change request as it will unnecessarily further increase timeframes for delivery of transmission infrastructure. The checks and balances under the current regulatory framework are appropriate to ensure that the most prudent and efficient option is implemented. The AER already has the ability to determine whether the final costs of a project are prudent and efficient in its final determination on a TNSP's revenue.

Submission structure

This submission is structured as follows:

- Section 2 covers our views on the AEMC's approach to assessing the issues covered by the review.
- Section 3 sets out our views on whether the current ex-ante incentive based approach to regulation is appropriate for major transmission projects.
- Section 4 relates to the transmission planning process, in particular the actionable ISP process and the RIT-T.
- Section 5 sets out our views on ensuring efficient transmission investment proceeds, including the issues of commercial viability and the contestability of transmission projects.
- Section 6 covers specific issues in the planning and delivery of transmission projects.
- Section 7 sets out our views on the material change in network costs rule change request.
- Appendix A provides our response to the AEMC's questions in its consultation paper.
- Appendix B includes the following reports:
  - Frontier Economics – The commercial viability of major electricity transmission projects.
  - FTI – Financeability duty for transmission assets – Evidence from other jurisdictions.
  - Ernst & Young – Contestability in electricity transmission.

2. AEMC's approach to assessing the issues

The AEMC proposes an assessment framework to guide its decision making in the review process and its prioritisation of the issues. Transgrid supports the AEMC's proposed assessment framework, including its prioritisation approach, subject to an additional two assessment criteria being added.

Transgrid suggests that the AEMC adds the following two assessment criteria to the assessment framework:

- **The extent to which reform options are likely to lead to more timely and efficient investment in projects that are in the long term interests of consumers.** In its ISP, AEMO has identified transmission investments over the next decade that will support the energy market transition to renewables and deliver net benefits to consumers. It is important that these investments are delivered in a timely and efficient manner.

- **Whether the reforms increase the risk to the security and reliability of the energy system as a whole.** For example, global precedent demonstrates that having multiple owners and operators of infrastructure in a meshed energy system results in a significantly increased risk of system failures. This is explored in the EY report in the appendices to this submission. The east coast of Australia is a meshed energy system. Rather than having independent arterial links, the ISP projects connect into the existing energy system at multiple points. The result of this design is that, if there is a system failure on one of the components of the meshed system, it can affect energy supply throughout the entire energy system including NSW, the ACT, Queensland, Victoria, South Australia and Tasmania. Any reform must be carefully be assessed to ensure that system failure is not an unintended consequence.

3. Ex-ante incentive based approach to regulation

3.1. The AEMC's consultation paper

The AEMC is concerned that the existing ex-ante incentive-based approach to regulation may not be appropriate in light of the significant intrinsic uncertainty associated with the costs and benefits of major discrete transmission investments. In particular, the AEMC is concerned the current framework assumes that uncertainty relating to project benefits and costs reduces as a project progresses through the regulatory process and that this may not be occurring for major transmission projects.

The AEMC suggests the issue of intrinsic uncertainty may be addressed as part of significant changes to the regulatory framework, such as introducing increased contestability, or through incremental reforms to the existing framework.

3.2. Our view

Our view is that the existing ex-ante incentive-based framework is appropriate for the development and delivery of large transmission projects and should be retained, subject to some refinements that would improve outcomes for consumers and stakeholders.

Our reasons are:

- The recently introduced staged CPA process offers TNSPs greater certainty that they will recover the substantial amounts required to be invested in major transmission projects ahead of regulatory approvals.
- The staged CPA process also provides regulators, stakeholders and consumers with a number of opportunities at which the benefits and costs of the project can be considered and assessed. This allows for risks to be identified and mitigated in a transparent way.
- A contestable model as contemplated by the AEMC would not solve the issue of cost uncertainty. In fact, the issue of cost uncertainty would likely be exacerbated under a contestable model, as discussed further in the Frontier report attached to this submission. We discuss the issue of contestability in section 5.2.3 of this submission.

Project Energy Connect (PEC) was the first large transmission project to proceed through the regulatory framework and it has provided some key learnings which can be used to make some refinements to the current framework. Drawing on our experience of PEC, we propose that the following refinements to the ex-ante framework be made to enable a more transparent process and lower costs for consumers:

- Any ex-post review triggered by a major transmission project should be confined to that project. It should not extend to the whole of a TNSP's capital expenditure portfolio. Due to the sheer scale of these projects, expenditure above the allowance for these projects cannot be managed within the TNSP's business as usual capital expenditure portfolio, which in comparison is small. Likewise, expenditure above the allowance on business as usual capital expenditure should not benefit from under expenditure on large standalone projects under the current regulatory framework. We support the AER's recent consultation to provide guidance on how it may apply ex-post review measures for actionable ISP projects.
- The revenue determination process should clearly separate the costs that the TNSP has limited control over, from the ones they do. For example, the following items are included in the TNSP's application to the AER which are largely outside of the TNSP's control:
  - Biodiversity offsets, which are determined primarily through the application and processes of Commonwealth and State environmental law.
  - Corridor and other land acquisitions, which are largely determined by state land acquisition laws.
  - Costs associated with social licence issues, such as changes to route alignment required by planning processes.

  These costs can be significant and are largely outside of a TNSP's control. They should be subject to cost-pass through arrangements with appropriate third-party verification. This would, not only also ensure consumers pay no more than necessary for these costs, but also reduce both risk and cost in project development.
- The staged CPA process should enable key inputs into the revenue determination to be agreed at an earlier stage. For example, determining the EPC contract risk allocation and contingency at 'CPA 1 stage', prior to going to the market for the EPC contract, will ensure that the basis for the EPC contract is considered appropriate by the AER before a procurement process is undertaken. There are trade-offs between cost and risk in setting risk allocation and contingency which should be fully explored and agreed prior to going to the market.
- The AER should accept the competitively tendered EPC contract cost unless there is an identifiable and material defect in the market procurement process. The EPC cost typically encompasses over 85% of the cost of a large scale transmission project.[2] Where these costs have been determined through a pre-defined open competitive tender market process, with the terms (including risk allocation and contingency) agreed to upfront by the AER and stakeholders, then the best market price should be accepted as the most prudent and efficient. We note that the AER was able to engage in the tendering process for PEC. As part of this process, we transparently provided information to the AER on the competitive tenders.

4. The transmission planning framework

4.1. The AEMC's consultation paper

The AEMC raises issues relating to the transmission planning framework namely:

- Whether the economic assessment process is too complex and impacting the timely delivery of projects.

[2] This excludes the calculation of biodiversity costs required by governments which would vary, including by route length and selection.

- Treatment of benefits in the transmission planning process, in terms of:
  - Whether the benefits included in current planning processes (the ISP and RIT-T) are sufficiently broad to capture the drivers of major transmission investment.
  - Whether there is a disconnect between what is required under the NER and feasible in practice and whether this disconnect warrants guidance on how to monetise benefits.
  - Whether changes have occurred in the energy sector that warrant reconsidering the merits of a market versus consumer benefits test.
- Whether there are barriers that prevent the equal treatment of non-network options under the RIT-T.

4.2. Our view

Our view is:

- There are opportunities to reduce the timeframe for the planning process for ISP projects by reducing the amount of time it takes AEMO to conduct the feedback loop.
- The RIT-T should be broadened to include other relevant quantifiable economic and environmental benefits to enable the full benefits of the ISP projects to be identified and included as part of the assessment.
- The regulatory framework should be refined to encourage TNSPs to invest in new and emerging technologies so that non-network solutions can be implemented as a viable option.

4.2.1. The timing of the process

The costs and benefits test undertaken by a TNSP as part of the actionable ISP process is an important way of validating whether a project should be undertaken. Our issue with the actionable ISP rules process to date, has not been with the process in the rules itself, but with the time it takes AEMO to conduct the feedback loop, which can take up to six months.

It was never envisaged, when the actionable ISP rules process was developed, that this step in the process would take that long. It is our view that AEMO could significantly reduce the time it takes to complete the feedback loop while still maintaining the robustness of its application of the mechanism. To the extent that there are barriers to AEMO performing the feedback loop, the AEMC should look to make recommendations as part of its review to resolve these issues.

4.2.2. Treatment of benefits in the planning process

It is our view that the RIT-T should be broadened to include other relevant quantifiable economic and environmental benefits. ISP projects are transformative in terms of their impact on the NEM, national economy, climate and environment. Whilst it might be appropriate to apply a relatively narrow test for small scale augmentations or asset replacement, this is not appropriate for projects such as those in the ISP. Using the same test for large projects does not allow for the full quantifiable benefits of these projects to be identified and included as part of the assessment.

In particular, the widely recognised costs to the Australian economy of climate change are not included in the current cost-benefit analysis in the RIT-T. This means that under the current RIT-T, the economic benefits for ISP projects such as PEC (which is facilitating large amounts of renewable generation into the system) and HumeLink (in terms of both Snowy 2 as renewable power source as well as providing a pathway to market for renewable energy from Snowy and other generation in the area) are undervalued.

We note there are practical issues with including wider economic benefits in the assessment of the RIT-T as there is currently no agreed method for estimating these benefits, as set out by the Productivity Commission in 2014.[3] Nevertheless, our view is that the AEMC's review needs to address this substantial shortcoming of the current approach as a priority. Inclusion of positive and negative externalities is a well-accepted principle of cost benefit analysis, where these are robustly quantifiable. In respect of environmental impacts, we note there is extensive guidance provided to project assessments in other infrastructure sectors.[4]

Transgrid also takes the view that the current RIT-T does not adequately capture the efficiencies arising from increased competition in the wholesale market as a result of transmission investment.

More broadly and by way of example, we note that FTI identified the following additional benefits from PEC that could not be taken into account in the RIT-T due to its strict criteria:

- Additional gross benefits of $0.8 billion to $1.0 billion by taking into account the benefits expected to accrue from the project beyond the 2040 horizon of the current RIT-T assessment period.
- An increase in gross benefits to $2.1 billion for the 2020-2040 period, where a lower societal discount rate of 3.5 per cent is adopted for the net present value (NPV) analysis.
- Net consumer benefits of $7.1 billion to $11.9 billion, arising from the material reduction in wholesale prices in all NEM regions driven by improved access to cheaper sources of generation from neighbouring regions and increased generator competition.
- Additional 'non-monetised' benefits reflecting the strategic importance of the project to future NEM development.

4.2.3. The consideration of non-network options in the planning process

Transgrid is committed to delivering cost-effective solutions such as non-network options. For example, we are currently delivering one of Australia's largest network capital deferral programs using demand management (as part of the Powering Sydney's Future project) and we continue to develop innovation projects to help build an understanding of the capability and value that demand management can deliver to the future energy system.

One of the barriers to the adoption of non-network options is that it is not clear how the regulatory framework encourages TNSPs to develop expertise in new and emerging technologies. For example, large scale storage is one of the new technology developments to address system strength issues. However, this type of technology needs to be tested and refined in a pilot environment before it is able to be considered a reliable and viable solution for the broader energy system. The regulatory framework should provide appropriate incentives for TNSPs to test and develop emerging technologies before there is a 'need' identified under the regulatory framework. We would be pleased to work with the AEMC to develop these incentives as part of its review.

[3] Productivity Commission, 2014, Public Infrastructure, Inquiry Report No. 71, p. 103.
[4] See for example: https://www.atap.gov.au/sites/default/files/documents/pv5-multi-modal-update.pdf

5. Ensuring efficient transmission investment proceeds

5.1. The AEMC's consultation paper

The AEMC is concerned that the local TNSP's exclusive right to invest with no corresponding obligation gives rise to a risk that major transmission projects may not proceed in a timely manner due to commercial considerations. It states that incumbent TNSPs have raised a number of commercial concerns that may lead to projects not proceeding, namely the financeability of the investments and the level of compensation relative to the risk profile of these investments given their scale.

To address this concern, the AEMC seeks stakeholder feedback on whether third parties should be able to invest in transmission projects under the national framework, either as a backstop when the local TNSP decides not to invest, or more generally.

5.2. Our view

5.2.1. Obligation to invest

Transgrid does not agree with the AEMC that an issue with the current regulatory framework is a TNSP's exclusive right to invest with no corresponding obligation.

Transgrid understands that, given the critical nature of major transmission projects, it is imperative that they are built in a timely and efficient manner. However, it is our view that there is no reason that TNSPs would not invest in major transmission projects, as long as the revenue allowance determined by the AER, having appropriate regard to the risks associated with delivering the project, enables the project to be delivered with a pre-determined, risk-reflective rate of return and that the benchmark efficient entity is able to maintain the benchmark grade credit rating (currently determined by the AER to be BBB+).

If a project meets these criteria and is in the long term interests of consumers, then the TNSP will invest in it. TNSPs also have strong social licence and contractual incentives to invest, which they take very seriously. We recently demonstrated this in extensively exploring all potential options to deliver PEC, which resulted in us obtaining Government funding from the Clean Energy Finance Corporation (CEFC) to secure the financeability of this important project.

5.2.2. Maintaining investment grade credit metrics

The inability of a benchmark efficient entity to maintain the benchmark grade credit rating metric when investing in major transmission projects, is a significant shortcoming of the current regulatory framework and should be addressed as a matter of priority. Resolving this impediment will enable efficient transmission projects to proceed for the benefits of consumers in a timely manner.

Importantly, Transgrid does not agree that the rate of return is the appropriate means to address financeability concerns as suggested by the AEMC. The two issues are unrelated - one being an issue of return, the other being an issue of maintaining a benchmark grade credit rating, which relates to balance sheet and cash flow issues.

Our view is that the AER is not able to effectively or appropriately ensure the financeability of the benchmark efficient entity under the NER currently and that the AEMC should make changes to the NER (discussed in section 5.3 below) to address this issue.

In its current rate of return instrument (RORI) review process the AER states:

> *"The regulatory framework does not require NSPs to be able to achieve the benchmark assumptions used in making and applying the RORI at all times. We consider sector benchmarks rather than firm specific details in making the RORI and that the NSPs have flexibility in their capital structure decisions and employ this accordingly. However, NSPs' actual practice will help us inform the characteristics of the benchmark firm.*
>
> *Therefore we remain of the view that we should not use measures of financeability directly when setting the rate of return. For example, we should not adjust the return on equity or the parameters that inform our return on equity in proportion to movements in financeability measures. Further, at this time we do not consider that changes to our usual approach to estimating depreciation are warranted in order to address financeability issues."*[5]

In our view, it should be the role of the AER to allow the benchmark efficient entity to achieve the benchmark equity and debt returns and benchmark credit rating when setting a TNSP's revenues, having specific regard to project specific risks. The need for this requirement is heightened at times of significant investment, as is currently required in order to meet the needs of Australia's changing energy system. This is the primary reason we are recommending the AER be required, under the NER, to undertake a commercial viability or financeability test as set out in section 5.3 below.

In support of our view, Frontier states that:

- PEC was made commercially viable by a tranche of subordinated debt funding supplied by the CEFC.[6]
- The AER will not, and cannot, address commercial viability issues as part of its rate of return RORI review.[7]
- The AEMC must address the commercial viability issue as part of this review – because it will not be addressed anywhere else.[8]

More detailed reasons on why the financeability issue cannot be addressed under the current regulatory framework is provided in the FTI and Frontier expert consultant reports provided as appendices to this submission.

5.2.3. Project finance SPVs will not solve the issue

The AEMC suggests in its consultation paper that project finance SPVs could solve the 'financeability issue', as an alternative to TNSPs financing the projects under the regulatory framework. However, our view is that this concept will have unintended consequences:

- Large portions of Australia's critical national infrastructure could be owned by investors with sub credit grade metrics, assuming there are suitable investors from a security perspective.
- Due to the complex interconnectivity of the electricity grid, the potential implications of a system failure could extend well beyond the size of the balance sheet for a SPV. In fact, SPVs themselves are specifically designed to have limited liability. They are carefully calibrated and sized to have exposure to risks on a project specific, stand-alone basis. This arrangement is inconsistent with the risks and liabilities associated with owning and operating an interconnected transmission grid. In addition, it is our

[5] AER, May 2021, Rate of return and cashflows in a low interest rate environment: Draft Working Paper, p. 47.
[6] Frontier Economics – The commercial viability of major electricity transmission projects, 27 September p. 3.
[7] Ibid, p. 4.
[8] Ibid.

view that the ownership and operation of critical transmission infrastructure by SPVs would create significant contractual complexity including indemnification requirements. It would also impact on risk exposure for other TNSPs under the interoperability framework in the NEM. Addressing these issues may ultimately result in the SPV needing to be unwound unless a government is willing to step in and be the contractual intermediary.

Our view is that the current model provides significant protections to Australia's energy system and a proven track record of providing reliable and efficient outcomes for consumers.

5.2.4. Contestability

Contestability in construction is an important way to ensure that the costs of large scale transmission are the least cost possible. However, contestability in transmission ownership and operation carries with it significant risks to the security and reliability of the energy system.

Transgrid supports competitive processes in design and construction for major transmission projects and this is already undertaken in the existing framework by the relevant TNSP. Transgrid already undertakes leading market competitive tender processes for all professional services, construction, equipment and materials provision for ISP projects. For example on PEC, approximately 85% of the total cost of the project has been procured under a competitive market process. The remainder of the costs are made up of property acquisition, environmental costs and Transgrid's internal costs to manage the delivery and operation of the assets. These costs are all assessed as to whether they are prudent and efficient by the AER under the current framework.

Our view is that introducing further contestability into transmission investment during the energy transition carries with it significant risks to the system and for consumers:

- There are significant benefits of the current single point of accountability for TNSPs that will be lost under a contestable model where multiple parties could own, maintain and / or operate significant transmission assets that form the backbone of the energy system. The benefits of a single point of accountability include avoiding unintended reliability and security concerns due to the added complexity associated with having multiple parties involved, and having an experienced operator in times of crisis or emergency.
- Transgrid's returns are independently and transparently set by the regulator at a level which is in the long term interests of consumers. Costs would be less transparent under a contestable model for transmission investment due to the commercial in confidence requirements of those bidding for projects.
- TNSPs, as the owners and operators of national critical infrastructure, are subject to rigorous and complex security, cyber, data and technical standards and regulations. These requirements would not be understood by, and will need to apply equally to, any new or emerging market entrant.
- If the ownership and operation of assets are to be separated, but there will continue to be a single system operator in a given jurisdiction, that operator will need to be empowered to: specify design standards; obtain evidence that transmission assets have been built in accordance with design standards and are maintained appropriately; and have access to the assets to operate them. Also, the liability regime will need to be amended to ensure that the system operator is not held responsible for any losses as a result of the failure of the assets of others. These matters are covered by State licensing requirements and any introduction of contestability under the NER will need to be co-ordinated with changes at the State level.
- A contestable model has the potential to significantly delay the transmission infrastructure required during the energy transition by adding an additional step into the process and requiring a new framework to be developed and bedded down.

- Non-network solutions are an important part of any assessment process to ensure the lowest possible cost to consumers is obtained. A contestable model would make it more complex for non-network proponents to provide solutions, due to the increasing number of parties they would have to engage with.
- Efficient upgrades to the transmission network would become more complex where there are multiple transmission providers, which could result in the inefficient design of the transmission system. By way of example, the Australian Government has recently announced it is supporting Transgrid examining an upgrade to PEC at Dinawan from 330kV to 500kV transmission lines.[9] This upgrade would provide 50 percent more capacity and avoid consumers paying $600 million to build a new connection in the future under the current regulatory framework. This type of innovation and use of synergies, as a result of having a single TNSP, provides efficiencies for consumers. which would not be possible under a contestable model.
- There are synergies from having one provider of the supply chain of services (including planning and design, asset ownership and operation, and emergency supply management) rather than breaking these components up into separate segments provided by different parties. Synergies from having one provider include economies of scale, lower overhead costs and better use of operational resources. The cost savings from these synergies are, and will continue to be, passed on to consumers under the current model.

Transgrid's view is that introducing a new and untested economic framework for the construction and ownership of new transmission assets at this point in time (in the absence of a rigorous assessment of costs and benefits) has the significant potential to delay, and put at risk, the critical energy transition that Australia must embark on. It would expose the electricity system and consumers to serious reliability and security risks, as well as increased costs. The existing system is well known, has been settled over a long period of time and has delivered to date. It is much more preferable to address the well identified challenges of the existing system rather than develop an entirely new framework.

Drawing on examples from the UK and US, EY finds no clear examples for cost efficiency achieved in the delivery of transmission assets in a meshed network.[10] EY comments that system operations risk increases as contestable assets are located in more integrated areas of the meshed network.[11] It also states that part of the reason why Federal Energy Regulatory Commission (FERC) Order 1000 has not been more successful is because of the difficulty for bidders to accurately price and allocate risk to different parties.[12]

5.3. Proposed solution

We propose the AEMC make a change to the NER to require the AER to ensure a benchmark efficient entity can meet the benchmark credit rating when setting allowed revenues for transmission projects. This should be a positive obligation on the AER that would be applied whenever revenues are determined (or adjusted, such as when a CPA is approved).

The form of the obligation should be clear and objective. FTI and Frontier have identified two possible methods, each of which is described below. We would be pleased to engage with the AEMC further on which of these tests is more appropriate and how they can be implemented in the NER.

[9] https://www.minister.industry.gov.au/ministers/taylor/media-releases/government-supporting-delivery-critical-transmission-infrastructure-southwest-nsw
[10] EY, Contestability in electricity transmission, 29 September 2021.
[11] Ibid. p. 25.
[12] Ibid.

Financeability test

FTI set out why adopting a financeability test as part of the Australian regulatory framework could be beneficial for both consumers and companies, stating that the benefits include minimising consumer bills and ensuring companies can attract the required capital to finance their activities.[13]

FTI also describes how regulators in Great Britain performed their financeability duty and recommend it appropriate for the AEMC to implement a similar framework for the Australian regulatory system.[14] It suggests this would involve using the Moody's framework for estimating credit ratings with the addition of equity metrics such as dividend yield to ensure sufficient return for equity investors.[15] FTI states "this would ensure the Australian regulatory system follows regulatory best practice."[16]

Commercial viability test

Frontier recommends the development of a 'commercial viability' test to ensure that major transmission projects that are identified as being in the long-run interests of consumers are commercially viable and will therefore proceed.[17] It considers any proposed test of 'financeability' runs the risk of being misconstrued as there are a number of different interpretations of the concept of 'financeability' that have been proposed and considered by various stakeholders and regulators.[18]

Under this test, 'commercial viability' is defined explicitly to mean that the timing of the allowed cash flows in relation to the new project must be sufficient to support the credit rating and gearing parameters that are assumed when setting the allowed return. This test would be applied to the benchmark efficient entity for a project. That is, the benchmark efficient entity would need to be able to maintain the credit rating and gearing that are assumed when setting the regulatory allowed return.

This test would require an amendment to the NER to require the regulator to set a series of allowed cash flows such that the proposed new investment would be 'commercially viable' according to the above definition.

This test would be implemented as follows:

- The default allowance would be based on the standard allowed return on capital and the standard arrangements in relation to depreciation and regulatory asset base (RAB) indexation.
- If the AER established that this allowance would fail the 'commercial viability' test (as defined above), it would accelerate the cash flow allowance in an NPV-neutral manner – just to the extent required to satisfy the commercial viability test.
- The test would be evaluated at the initiation of the project and at the time of each determination.

[13] FTI, Financeability duty for transmission assets – Evidence from other jurisdictions, 30 September 2021, p. 25.
[14] Ibid.
[15] Ibid.
[16] Ibid.
[17] Frontier Economics – The commercial viability of major electricity transmission projects, 27 September p. 4.
[18] Ibid. p. 6.

6. Specific issues in project planning and delivery

6.1. The AEMC’s consultation paper

The AEMC seeks stakeholder views on specific issues that may impact on the project planning and delivery phase of transmission projects, in particular:

- Whether clarification on the treatment of 'preparatory activities' and 'early works' is required.
- The impact of jurisdictional environmental and planning approval processes on the timely and efficient delivery of transmission investment and whether any changes necessary.

6.2. Our view

6.2.1. Early works and preparatory activities

We support further clarity in distinguishing the concepts of ‘preparatory activities’ and’ early works’, and the related cost recovery provisions.

Preparatory activities

The extent of required preparatory activities can be difficult to forecast, as they are dependent on activities required as part of future ISPs. It may be more appropriate for the costs of preparatory activities to be treated as a cost pass-through, triggered by publication of the final ISP, and not subject to a materiality threshold.

Early works

Early works include more material planning activities related to specific ISP projects (including actionable ISP projects) and would generally be capitalised and recovered via the first stage of a staged CPA process. This could involve costs associated with pre-ordering of infrastructure components which have long delivery timeframes for example.

The new staged CPA arrangement should better enable cost recovery for early works activities for major transmission projects. However, where early works are undertaken ahead of the CPA process, either in order to shorten the overall investment timeframe or to adequately estimate the costs of the option in the RIT-T, then recovery of the costs associated with these works are uncertain because it is possible that the option does not proceed to the CPA stage. To address this concern, the NER should be changed to allow a TNSP to lodge a CPA for undertaking early works ahead of completion of a RIT-T, where this is recommended by the ISP.

6.2.2. Environmental and planning approval processes

Environmental planning issues are a key source of cost and route uncertainty that impacts the regulatory approval process. The relative timing of these two processes – with the environmental approvals inevitably lagging behind the regulatory processes in the NER, but potentially impacting the cost outcomes – needs to be recognised and considered within the overall investment framework.

Community engagement and acceptance (including with, and by, traditional owners of land) are key to ensuring the timely delivery of major projects, and play a major role in obtaining environmental and planning approvals. Transgrid would like to see a greater emphasis on the inclusion of community and landowner inputs and concerns into the economic assessment process, which will improve the delivery timeframes of the infrastructure.

7. The material change in network infrastructure costs rule change request

7.1. The rule change request

Transgrid understands that the rule change proponents are concerned that project costs can increase between completion of the RIT-T and the CPA. They use the example of PEC stating that this project increased approximately 60 per cent between RIT-T and CPA; and the Eyre Peninsula Upgrade, stating that this project experienced a 21 per cent cost increase between RIT and CPA.

To address this, the rule change proposes the following changes:

- A proponent must reapply the RIT-T if, following completion of the regulatory process its project's costs have increased by 10 per cent (for larger transmission and distribution projects: i.e. where project cost is greater than $500m and $200m respectively) or 15 per cent (for smaller transmission and distribution projects: i.e. where project cost is less than $500m and $200m respectively), unless an exemption is granted by the AER.
- The AER may determine that a proponent is not required to reapply the RIT -T (or is only required to repeat part of the RIT-T). The AER would have 30 days from the date of publication of the revised project cost estimate to make and publish its determination.
- PEC should be required to update its final RIT-T report to take account of material cost increases that have occurred.
- AER guidelines should be amended to require proponents to develop more rigorous cost estimates for the final RIT-T report, thereby reducing the risk that the RIT-T will need to be reapplied as a result of material cost increases.

The rule change proponents also seek a delay to PEC to enable further assessment of the project.

7.2. Our view

We do not support the rule change as it will unnecessarily further increase timeframes for the delivery of efficient transmission infrastructure. For example, PEC would have been delayed under the proposed rule change as it would have needed to go through the RIT-T process again, which could have taken up to six months. The RIT-T process is already extensive and taking longer than stakeholders' expect, which we note is the subject of the AEMC's review discussed in section 4 of this submission.

The checks and balances under the current regulatory framework are appropriate to ensure that the efficient option is implemented. The AER also determines whether the final costs of a project are prudent and efficient in its final determination.

Transgrid agrees with the proponents of the rule change request that consumers need to have confidence in the economic assessment process for transmission projects. However, their solution does not address the core issue.

The core issue from our perspective is that stakeholders understandably find it challenging to reconcile the early high level desktop cost estimate of a capital project with the resulting competitive market procured cost. A change in capital costs over this period however is part of the normal evolution of large capital projects as more information becomes available. This is not a unique issue to transmission infrastructure and is experienced frequently on other major infrastructure projects.

A refinement to the regulatory process could reduce the misunderstandings around cost estimating of large capital projects. The current regulatory process requires TNSPs to provide cost estimates at a number of stages, often when there is little or no information to base the costs on, such as the early initial desktop estimate. An early desktop cost estimate is made without any detailed technical, geotechnical, land, heritage or constructability information being available, which inevitably makes this estimate of limited use.

We propose the costs of a large scale project should be provided by the TNSP after route selection, studies and detailed design and a market sounding process is undertaken, rather than earlier in the planning process. This would ensure that the published costs are more in line with what would be expected after a competitive market process. Whilst this may delay the start of the RIT-T process, it will give stakeholders more confidence in the cost estimates and enable the project to proceed through the approval process in a timelier manner.

Appendix A: Response to AEMC questions

Question	Response
1. Do you agree with the Commission's proposed assessment framework for this Review?	See section 2 of this submission.
2. Are there any additional criteria the Commission should consider as a part of its assessment framework?	
3. Do you agree with that the identified factors contribute to an increase to the uncertainty surrounding major transmission projects, relative to BAU projects? Are there other factors that should be taken into account?	See section 3 of this submission.
4. Do you consider that the current ex-ante incentive-based approach to regulation is appropriate for major transmission projects? Why? Are there opportunities to drive more efficient expenditure and operational outcomes?	See section 3 of this submission.
5. Do you agree that the Review should take forward this issue as a priority issue? If not, why?	The refinements to the current framework, which we have identified in section 3 of this submission, should be made as a matter of priority, given the significant benefits that would flow from these to consumers.

6. Are there opportunities to streamline the economic assessments of ISP and non-ISP projects without compromising their rigour? If so, how could the framework be streamlined?	See section 4 of this submission. Updating of inputs and assumptions is a consequence of uncertainty, and is driven by changes in government policies, the current pace of the energy transition, as well as market conditions. • This uncertainty means that there will be changes between ISPs. • The scenarios adopted in the ISP and RIT-Ts are one means of managing this uncertainty. • The framework is likely to work best for RIT-Ts that are able to be progressed quickly following the ISP, or where the feedback loop aligns with the timing of a new ISP. This 'bunching' of assessments may be inevitable. • An improvement to the current process is for RIT-T assessments to be able to use the latest available information e.g. AEMO's draft Input Assumptions and Scenarios Report. We support the actionable ISP process, including the RIT-T, subject to the modifications we propose in section 4 of this submission. This process was only put in place in August 2020 and no major transmission project has been through the new framework from start to finish. In addition, the costs and benefits test undertaken by a TNSP as part of the actionable ISP process is an important way of validating whether a project should be undertaken. In particular, the RIT-T: • Provides a much greater degree of transparency and rigour in the analysis than the ISP, because it is focused on a particular project. • Provides a discipline on AEMO and the ISP process, helping to ensure the robustness of the investment and costs incurred by consumers. • Provides a greater level of community engagement than is possible through the ISP, providing a greater level of community trust. • Is able to consider competition benefits, option value and canvas NNO in more detail than is feasible at the ISP level which is optimising across all investments. • Includes detailed NPV analysis in comparison to the ISP. A modification to the regulatory process could reduce the misunderstandings around cost estimating of large capital projects. We discuss this further in our response to the material change in network costs rule change request in section 7 of this submission.

Question	Response
7. Do you agree that the RIT-T has a clearer value-add in relation to non-ISP projects? If not, why?	No – the RIT-T has clear value add in both processes.
8. Do you agree that the Review should take forward this issue as a priority issue? If not, why?	No. The refinements identified above and in this submission could be made to the current arrangements to address issues arising to date. The actionable ISP rules introduced in August 2020, which were subject to extensive consultation, should be given time to work.
9. Are the benefits included in current planning processes sufficiently broad to capture the drivers of major transmission investment? Does the scale and pace of the NEM's energy transition necessitate inclusion of other classes of market benefits or wider economic benefits? If so, what kind of other classes of market benefits or wider economic benefits should be included?	Refer to section 4 of this submission.
10. Are major transmission projects failing to satisfy economic assessments because certain benefits (market or non-market) are not permitted to be quantified?	There is a risk that major transmission projects, that are in the long term interests of consumers, would not satisfy the RIT-T because the RIT-T undervalues benefits (see section 4 of submission).
11. Are changes warranted to the manner in which carbon emissions inform transmission planning and regulatory processes?	Yes - carbon emissions reductions are not fully captured under the existing regulatory framework (see section 4 of this submission).
12. Do you agree that the Review should take forward this issue as a priority issue? If not, why?	Yes. Any review of the framework should include the calculation of carbon emission reduction benefits (see section 4 of this submission).
13. What classes of market benefits are hard to monetise? Is there a way that these benefits could be made easier to quantify?	Ancillary service benefits have not been material to date but are likely to become more material with new technologies and the new regulatory frameworks for these services. Uncertainty in relation to these frameworks has been the main difficulty to date. Quantification would likely be based on an expansion of the existing wholesale market modelling. Guidance on option value modelling exists already, as it is an established economic assessment technique. Also see section 4 of this submission.
14. Would guidance on hard to monetise benefits improve the timeliness at which projects proceed through the regulatory process?	

Question	Response
15. Do you agree that the Review should take forward this issue as a priority issue? If not, why?	Yes.
16. Do you consider that there are certain changes that have occurred in the energy sector that warrant reconsidering the merits of a market versus consumer benefits test? If yes, what are these changes and why do they require revisiting this issue?	No comment at this stage of the review.
17. Do you agree that the Review should take forward this issue as a priority issue? If not, why?	Not a priority at this stage.
18. Do you agree that there are barriers for non-network options in economic assessments? If so, do you agree with the barriers identified? Are there any further barriers? How should these barriers be addressed?	Refer to section 4 of this submission.
19. Do you agree that the Review should take forward this issue as a priority issue? If not, why?	Yes.
20. Are there features of financing infrastructure projects used in other sectors that should be considered in the context of the efficient and timely delivery of major transmission projects?	Refer to section 5 of this submission.
21. Should the delivery of transmission projects be made contestable? If not, why?	No. Refer to section 5 of this submission, including the expert reports attached to this submission.
22. What options, other than changes to the right of TNSPs to provide regulated transmission assets, could be considered to ensure timely investment and delivery of major transmission projects?	Refer to section 5 of this submission.
23. Do you agree that the Review should take forward this issue as a priority issue? If not, why?	Refer to section 5 of this submission.

Question	Response
24. Do stakeholders seek further clarity on the meaning of preparatory activities and early works?	Refer to section 6 of this submission.
25. Should the Commission consider how the costs of early works can be recovered?	Refer to section 6 of this submission.
26. Do you agree that the Review should take forward this issue as a priority issue? If not, why?	Yes.
27. Would additional clarity on cost recovery arrangements for preparatory activities or early work improve a TNSP's ability to meet jurisdictional requirements in a timely manner?	TransGrid agrees that additional clarity is required, the detail of which could be consulted on with stakeholders in stage 2 of the AEMC's review.
28. Do jurisdictional planning and environmental requirement intersect with the national transmission planning and investment frameworks in ways that are not discussed above and may require further consideration?	Refer to section 6 of this submission.
29. Do you agree that the Review should take forward this issue as a priority issue? If not, why?	Yes. Agree that it is a priority issue as it can affect investment timeframes.
30. Please provide any further comment relating to issues discussed in the chapters 1-4 of the consultation paper.	Refer to sections 2-6 of this submission.
31. Please discuss any further issues the Commission should take forward in this review in relation to topics covered in chapters 1-4 of the consultation paper.	Refer to sections 2-6 of this submission.
32. Should this decision remain the responsibility of the proponent or should it be a matter for the AER? Why?	It should remain primarily the responsibility of the proponent. The TNSP is the party that is best placed to judge when a change in circumstance may lead to a different ranking in the RIT-T. Refer section 7 of this submission.

Question	Response
33. If the decision remains with the proponent, should the AER have the right to test that opinion?	TransGrid agrees with the proponents of the rule change request that consumers need to have confidence in the economic assessment process for transmission projects. Refer to section 7 of this submission.
34. Should the NER include a requirement to reapply the RIT, or update analysis, when costs increase above specified thresholds? If so, do you have a view as to what those thresholds should be?	No. Cost increases are already picked up through the CPA process, and so this would be an additional and duplicative step.
35. Do you consider this requirement should apply to all RIT projects or only those above a particular cost threshold/s? If so, do you have a view as to what the threshold/s should be?	The cost thresholds proposed in the Rule change request are too low, and do not reflect the nature of the cost estimates at the RIT-T (or even CPA) stage.
36. Do you have any views regarding the suggested alternative “decision rule” approach?	Refer to section 7 of this submission.
37. Should updated project cost data be provided to AEMO to help improve the accuracy of the ISP?	Yes. TransGrid supports the AEMO cost database process in that would require up to date costs to be provided
38. Do you have any other suggestions regarding alternative ways to manage cost increases?	Yes. Refer to section 7 of this submission.
39. Should the requirement to reapply the RIT be more targeted?	Refer to section 7 of this submission.
40. Should any additional analysis and modelling that is required to be undertaken be published and subject to public consultation?	Refer to section 7 of this submission.

Question	Response
41. Do you have any views as to how the requirement to reapply the RIT should be given effect, including for contingent and non-contingent projects?	The requirement to reapply a RIT-T should not be applied to non-contingent projects. These projects are included in the regulatory proposal, and the efficiency of the expenditure and justification is assessed by the AER at that time. TNSP's are required to manage total costs within their approved allowances and are subject to ex-post review of capital expenditure if they over spend their total allowance.
42. Should there be a cut-off point (e.g. once the AER approves the CPA, or once construction commences) beyond which any requirement to update analysis cannot be triggered? If so, what would be an appropriate cut-off point?	Once major contracts have been agreed to the project should be allowed to proceed. TransGrid notes that major contracts have now been agreed to for PEC and accordingly the RIT-T should not be reapplied for this project. This will delay the project further and significantly increase costs as contractors are stood down or delayed.
43. Should there be a limit on how many times RIT analysis must be updated?	Refer to section 7 of this submission.
44. Do you consider that the current level of rigour used for RIT cost estimates is suitable? If not, what level of rigour is appropriate? In particular, would it be appropriate to require an AACE 2 estimate (i.e. a detailed feasibility study) for each credible option?	The current regulatory process dictates that TNSPs and AEMO are obliged to provide cost estimates at a number of stages, often when there is little or no information to base the costs on. (Refer to section 7 of this submission).
45. If more detailed cost estimates are required at the RIT stage, should this apply to all RIT projects, or only to larger projects? If so, which projects should be subject to this requirement?	Refer to section 7 of this submission.
46. Do you have any other suggestions to address the issues raised in the rule change request?	Refer to section 7 of this submission.
47. Please provide any further comments on this chapter.	Refer to section 7 of this submission.

Contestability in electricity transmission

TransGrid

29 September 2021

Building a better working world

Building a better working world

RELEASE NOTICE

Ernst & Young ("EY") was engaged on the instructions of NSW Electricity Network Operations Pty Ltd ("TransGrid") to document the current status of contestability in electricity transmission where it is being applied in mature electricity markets and draw out any lessons from that experience.

The key inputs, assumptions, methodology, scenarios and qualifications made in preparing this information are set out in EY's report dated 29 September 2021 ("**Report**"). You should read the Report in its entirety including any disclaimers and attachments. A reference to the Report includes any part of the Report. No further work has been undertaken by EY since the date of the Report to update it.

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1. Executive summary

Ernst & Young (EY) was engaged by TransGrid to examine the current status of contestability in electricity transmission where it is being applied in mature electricity markets globally and to draw out any lessons from that experience.

Experience with the application of contestability

- Contestability in electricity transmission is applied in mature electricity markets both at the:
  - Policy level (i.e. frameworks that facilitate it); and
  - Asset level (i.e. projects that have been procured through contestable processes).
- For major transmission assets, the vast majority of examples of contestability are either for:
  - Interconnectors between otherwise separate and independently operated electricity systems (e.g. international, interstate, inter-regional); or
  - Radial lines from an existing transmission system to a major new source of generation (e.g. new areas of renewable supply) or demand (e.g. a remote mine).
- Contestability for these types of major transmission assets creates some interface issues and risks (e.g. for system operations), that need to be well understood and managed. Given the life of major transmission assets, however, some assets that commence operations as radial lines or interconnection assets, may over time become part of much more complex systems.
- Contestability becomes significantly more complex for major new transmission assets that are part of an existing system or 'meshed' network such as a new transmission line which creates a new loop in an existing system (e.g. picking up new renewable generation in a region).
- The experience with contestability shows that the following issues are critical:
  - System operations - In the absence of an independent system operator, there are complexities in appropriately allocating risks which may reduce the efficiency of and increase the risks associated with system operations;
  - Interface management – During the operational period there is some interface risk between the operator and owner of the transmission line (if they are separate entities). Poor management of interfaces are found to result in suboptimal management of capacity, system operation, outage panning and maintenance programs; and
  - Costs - Overruns are likely to occur where parties do not have experience in managing and executing submissions for development and regulatory approvals.
- Those issues may in part explain why despite a broad mandate for contestability in the USA, activity has been modest. The incumbent's market position and first right of refusal are also likely to be important. There is some evidence of contestability delivering cost efficiencies, but on a small sample size.
- Those complexities are largely a function of the indivisibility of system operations risk (i.e. the difficulty in subdividing and therefore efficiently allocating system operations risk between different parties). For example, how system operation issues and risks might be managed when you have third parties which potentially:
  - Plan, specify and develop asset solutions (e.g. set design standards);
  - Own and maintain those assets once developed; and / or
  - Might 'operate' the asset within a broader system that is operated by another party, but have limited responsibility or accountability for that system's operation.
- Examples of contestability for these assets are relatively rare. For example, in the United Kingdom, which has considerable contestability for some transmission assets, it has not yet

been to more complex transmission assets.   The United Kingdom has a private primary transmission business who is also the system operator.

- The examples that do exist are underpinned by having an independent system operator which is typically a non-for-profit and / or government owned entity that has specific responsibilities for system operation. This includes powers to influence:
  - Planning and investment decisions;
  - Asset solution design and specification standards;
  - Construction and maintenance standards and processes; and
  - Direct control over asset operations, or indirect ability to control asset operations.
- Those independent system operators also typically have less onerous accountabilities than do privately owned transmission businesses that are also system operators (e.g. they do not have a licence that can be revoked in the event of poor performance). In other words, they have a lower degree of accountability for system operation risks.
- Independent third-party system operations can therefore enable increased contestability, albeit at the 'cost' of increased involvement of that operator in some of the key decisions along the transmission asset value chain (see below).
- The complexities of managing system operations is heightened if a private incumbent transmission operator is responsible for those operations but is also obliged to assume risks over third-party developed, owned and maintained assets. The alternatives might be that the private transmission:
  - Operator has powers to direct other private transmission businesses' key decisions, but this also creates challenges, including for contestability itself; and / or
  - Third-party business has to assume some of the same responsibilities and accountabilities as the incumbent (e.g. be a licensed entity) to ensure system operations are not compromised, and to create a level playing field from a contestability perspective.
- It is open to question, however, whether system operation risks could be managed efficiently in those circumstances.   Consistent with this, our research did not identify any examples of third parties developing, owning, and maintaining major transmission assets that are part of an existing system, operated by a private, for-profit transmission business.

Issues affecting the potential scope of contestability and the value it can provide

- There are several broader issues that emerge from the evidence, which impact the potential value contestability can provide. Those issues are that, to the extent that there is considered to be value in greater contestability, that value is:
  - Likely to be largest when contestability covers as much of the transmission asset value chain as possible. In other words, contestability is used to:
    - Reveal investment needs;
    - Determine the optimal asset solutions that might address those needs;
    - Determine the optimal way and who should deliver that assets solution; and
    - Determine who is best placed to own and maintain the asset.
  - Impacted by the nature of the underlying markets and the type of contestability that emerges.
- Transmission asset delivery (i.e. design and construction) has always been highly contested, as most transmission service providers already contract out the vast majority of that work. Moreover, the delivery of new transmission typically accounts for the vast majority of the costs (circa 85-90% for the largest projects) incurred over the transmission asset value chain.

- Transmission asset delivery, however, is only part of the transmission asset value chain and, while it accounts for a substantial proportion of the costs incurred across the value chain, it is not necessarily where the most value can be generated. As with most mature infrastructure, the delivery of which is routinely procured in highly contested markets, improved identification of investment needs and determination of the optimal asset solutions to address those needs can deliver substantial value at relatively low cost. Delivering the same value through improved delivery will often, by contrast, be relatively challenging.
- The experience with contestability shows, however, that there are some practical issues in fully utilising contestability in the early parts of the transmission asset value chain. Those issues:
  - Constrain the market's ability to assume key risks associated with transmission asset planning and approvals, even if it were 'free' to make the investment decision; and
  - Impact on the complexity of the commercial arrangements (and the time it takes to deliver them) that achieve an efficient allocation of risk, given those constraints.
- Those practical issues and underlying structure of the market are also likely to mean that, if parties were to assume a greater role in the early parts of the transmission asset value chain, they would only seek to do so if it enabled them to win the rest of the value chain (i.e. win the downstream functions – design and construction, ownership and maintenance).
- Contestability that incorporates early involvement in the value chain would likely have implications both for the nature of the:
  - Tender for that early involvement (e.g. any tender will likely involve a complex risk sharing and partnership arrangement, such as a strategic alliance); and
  - Competition in the downstream parts of the value chain (i.e. it might involve competition 'for' the downstream market, as opposed to 'in' it).
- This means there are some key trade-offs to be made when determining the scope for contestability to add value across the transmission asset value chain (e.g. in net terms, how it can provide the greatest value and how to enable that value to be contested).
- Putting those issues aside, however, the market evidence demonstrates a trend toward much greater government involvement in, and central planning of, key electricity industry investment decisions. For example, in Australia, this is true both in:
  - Generation (e.g. Snowy 2.0, state based schemes to encourage more renewable generation, such as the NSW Roadmap); and
  - Transmission (e.g. in NSW Roadmap, Victoria, the Integrated System Plan).
- This would appear to reduce the potential scope to apply contestability across the transmission asset value chain and thus its ability to generate value.

2. Introduction

EY was engaged by TransGrid to examine the current status of contestability in electricity transmission where it is being applied in mature electricity markets and to draw out any lessons from that experience.

2.1 Scope of work

To complete this work EY has sought to:

- Identify key examples of contestability in transmission in mature markets globally, including the key policy objectives that underpinned its introduction;
- Identify the models of contestability (i.e. how it is enabled and implemented);
- Identify the scope of contestability (i.e. the type of assets and parts of the transmission asset value chain to which it is applied), with a focus on major new transmission assets that are part of existing systems;
- Summarise the impacts of those contestable arrangements on transmission developments (e.g. what contestability is occurring in practice);
- Highlight any lessons learned from the available evidence and experience with contestability to date including the:
  - Benefits it may have delivered, with particular regard to its intended policy objectives; and
  - Costs and / or risks it may be revealing, particularly in regard to the implications for operating the transmission system within which those contestable assets might exist.

2.2 Approach

To address this scope of work, EY has primarily relied on desktop research. In particular, we have:

- Reviewed existing work undertaken recently on contestability (see Section 6);
- Liaised with our global Power & Utilities network to identify examples of contestability;
- Examined the examples identified through our desktop research; and
- Outlined the evidence and lessons, based on the above work, in this Report.

2.3 Limitations

EY notes that:

- Our work was undertaken in a compressed timeframe to enable submission of this report to the Australian Energy Market Commission's (AEMC's) Consultation Paper: Transmission Planning and Investment Review (the Consultation Paper)[1];
- There is relatively little information in the public domain on some of the examples;
- Some of the examples are relatively new, so some lessons may be just emerging; and
- There is considerable complexity in some of the examples in respect of roles, responsibilities and risk allocation between the parties involved.

EY cannot guarantee therefore that it has identified the full scope of examples of contestability in electricity transmission. Any conclusions drawn are a function of the sample of examples EY has

[1] AEMC, Consultation Paper: Transmission Planning and Investment Review, 19 August 2021. Submissions are due to the Consultation Paper on the 30 September 2021.

been able to identify as part of this work. That said, it appears that the sample reviewed appears to provide a decent representation of all the examples identified.

2.4 Report structure

This Report is structured as follows:

- Section 3 provides background on the issue of contestability in electricity transmission in Australia;
- Section 4 identifies what is meant by contestability and the commercial models that can give effect to it;
- Section 5 identifies the parts of the transmission asset value chain and assets that might be contestable;
- Section 6 summarises the current status of contestability in mature electricity markets and the key lessons that can be drawn from that experience to date; and
- Appendix A provides further detail on the experience with contestability.

3. Background

This section provides some relevant background in Australia to the issue of contestability in electricity transmission.

There have been a number of recent developments that are relevant to contestability in Australia, including:

- The AEMC's Consultation Paper;
- Renewable Energy Zones (REZs);
- Victorian developments; and
- Other recent developments (including CopperString and Integrated System Plan (ISP)).

Those recent developments show that:

- There is a substantial pipeline for major transmission investment;
- Governments, or their agencies, are increasingly getting involved in either directing or influencing those investment decisions;
- There is a push to increase the speed at which investment occurs; and
- There is increased interest in contestability to deliver the investment.

3.1 The AEMC's Consultation Paper

The Consultation Paper is an AEMC initiated review to:

- Identify issues with the existing regulatory framework in relation to the timely and efficient delivery of major transmission projects;
- Explore options for reform of, or improvement to, the existing regulatory frameworks; and
- Recommend possible changes to the National Electricity Rules (NER) and other regulatory instruments (if required) to support frameworks that are fit-for-purpose and promote the timely and efficient delivery of transmission services.

The AEMC identifies for consultation two key issues with the existing regulatory frameworks:

- The Transmission Planning Framework: Is the existing ex-ante incentive-based framework 'fit-for-purpose' to support the efficient and timely delivery of major transmission projects?
- The framework for transmission investment and delivery: Is TNSPs' existing exclusive right to build and own transmission projects but no corresponding obligation to invest and deliver these projects leading to uncertainty regarding such major projects proceeding? The Consultation Paper specifically considers:
    - The potential for financing challenges in the delivery of major transmission projects; and
    - Whether the delivery of major transmission projects should be made contestable.

The Consultation Paper goes on to ask whether, in respect of contestability:

- Are changes to the exclusive right of TNSPs to provide regulated transmission assets required?
- What other options could be considered to ensure timely investment and delivery of major transmission projects?

EY observes that:

- Contestability is one of a large number of issues raised in the Consultation Paper;
- The focus of the AEMC's interest in contestability appears to be less on its merits *per se*. It appears to be more on the merits of contestability insofar as it might address a possible imbalance in the incentives of TNSPs to invest in and deliver major transmission investments in a timely way (i.e. the exclusive right, but no obligation, to invest in and deliver these projects); and
- The Consultation Paper notes that there may be other options to address this imbalance. For example, by increasing the obligation on, or perhaps incentive for, TNSPs to invest in and deliver these projects in a timely way.

3.2 Renewable Energy Zones

The development of REZs raises questions regarding how to plan, approve and procure in a timely way the transmission investment necessary to both:

- Develop the transmission capacity within the REZ to which the new renewable generation can connect; and
- Connect the REZ to the existing transmission system in a way that enables the energy from the expected generation investment to get to key demand centres (with relative certainty on the risks of curtailment and reductions in MLFs).

The primary objective of REZs is to encourage renewables to increasingly be developed in particular geographic areas and to provide the transmission and related infrastructure to ensure that the overall costs of the transition to renewables in minimised.

The proposed investment in transmission to support the REZs raises questions regarding:

- Who should have the right to plan the REZs, determine the appropriate asset solutions, and to design and construct, own, maintain and operate transmission assets?
- Whether those rights should be contestable, given the size and timing of the investment need?
- Who should fund the associated costs, including whether rights to the transmission capacity created can and should be developed and monetised?

3.2.1 Developments in NSW

NSW plans in respect of REZs appear to be the most advanced of all the states in Australia.

In 2020, the NSW Government accelerated its ambition for investment in renewable generation. The NSW Electricity Infrastructure Roadmap (the NSW Roadmap) aims to increase renewable capacity by 12GW and incentivise ~$32bn in private sector generation and transmission investment by 2030.

As a critical enabler of the infrastructure investment, the planned REZs will require significant investment in network infrastructure that will enable new renewable generation connection.

In 2020, the NSW Government passed the *Electricity Infrastructure Investment Act 2020 No 44* (the EII Act) to declare five REZs in NSW and provide a framework for the delivery of:

- 3 gigawatts of network capacity for the Central West Orana REZ
- 8 gigawatts of network capacity in the New England REZ
- 1 gigawatt of additional capacity[2]

In respect of transmission, the EII Act:

[2] Electricity Infrastructure Investment Act 2020 no 44 sections 23(1), 44(3)(a)(ii); 44(3)(a)(i) and 44(3)(a)(iii).

- Creates an Infrastructure Planner role with powers to establish a planning function[3]; and
- Provides the option of implementing contestability in both the ownership and operation of new shared assets within the REZ, as well as for priority transmission infrastructure projects.[4]

3.3 Victorian developments

The Victorian region of the NEM has, since the NEM's inception, had bespoke system operations arrangements including the scope for contestability for certain intra-state transmission investments. In Victoria, AEMO operates the transmission system and has an obligation to acquire qualifying transmission assets through a contestable process. Most recently, those arrangements enabled the contestable procurement of the Western Victorian Transmission Network Project (WVTNP), by far the largest competitively procured transmission asset AEMO has procured (see Appendix A.4.1).

The Victorian Government has:

- Introduced the *National Electricity (Victoria) Act 2005* which allows the Minister to intervene in planning and development by replacing or displacing the Regulatory Investment Test for Transmission (RiT-T). Appendix A.4.1 provides that AEMO is conferred functions to contract for augmentations and specified non-network services, and to conduct competitive tenders;
- Established the REZ Fund as part of the 2020-21 State Budget. $540 million has been made available over four years for the Victorian Government to invest in electricity network infrastructure to support the development of Victoria's REZs;
- Released for market feedback an initial REZ Development Plan (RDP) Directions Paper (February 2021), which identifies potential network investments under immediate Stage One projects (to be delivered prior by 2025 among other criteria) and Stage Two projects ('medium term' projects);
- Requested AEMO to progress six Stage One projects under Ministerial Order via two procurement streams. This involves a call for expressions of interest and tender (contestable) process for services to strengthen the system across three REZs, as well as a non-contestable RFP process with the incumbent network service provider (i.e. AusNet Services) for minor network augmentation works to relieve thermal constraints in the network[5]; and
- Established VicGrid in July 2021, a new Division within the Department of Environment, Land, Water and Planning, which will oversee investment decisions related to the $540m REZ Fund. The Victorian Government continues to consult with stakeholders on the development of the framework for determining future transmission investment in REZs, VicGrid's proposed role in that framework, and the Government's broader approach to developing Victorian REZs.[6]

3.4 Other relevant developments

There have been and are a variety of other developments in respect of contestability for transmission assets in Australia. Appendix A.4.1 outlines some of the key developments. These include, for example:

- The Copperstring Project in Queensland, an asset proposed by a third party other than the incumbent TNSP (see Appendix A.4.1 for further detail); and

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[3] Electricity Infrastructure Investment Act 2020 no 44 section 30(1)

[4] Electricity Infrastructure Investment Act 2020 no 44 section 36; 32(1)(b). The Act introduces the concept of a network operator who may or may not be the incumbent Transmission Network Service Provider (TNSP) in NSW. The EII Act does not define the exact functions of 'operations' that may be envisaged to be contestable.

[5] Victorian Government Gazette, No. S 417, First REZ Stage 1 Projects Ministerial Order, 2021

[6] Victorian Government, DELWP, Renewable Energy Zones Stage One projects Fact sheet, 2021

- Priority transmission projects in the ISP, although it is less clear at this stage whether these projects might be, and the extent to which they might be, contestable.[7] Approximately $16bn of transmission investment is in the development pipeline (ISP and REZ projects) between now and 2030, 55% of which is planned to be built in NSW. It appears that $7bn to $9bn of this investment might be contestable. Some of these projects include HumeLink, VNI West and the Central West Orana REZ.

[7] AEMO, Integrated System Plan, 2020

4. What does contestability mean?

Below we briefly outline:

- What is typically meant by contestability;
- The forms contestability can take; and
- The benefits contestability can provide.

The analysis shows that:

- Contestability can and does take a variety of forms or commercial models;
- The benefits contestability can provide are largely a function of the:
  - Commercial model of contestability adopted; and
  - Extent to which it covers the project development value chain for the asset (i.e. from the planning and investment decision, through to how it is constructed).
- The benefits of contestability are likely to be largest when it covers the full project development value chain.

4.1 What is contestability

Contestability typically means introducing mechanisms, including the removal of existing barriers, to promote competition in the provision of particular functions and determine the most efficient way of designing and delivering the services those functions provide.[8]

Contestability typically creates the scope for competition to be introduced and the benefits it can realise to be delivered. It may or may not result in highly transparent competition emerging in particular circumstances (e.g. open, competitive tender).

4.2 The forms of contestability

Contestability can take a number of forms or adopt a range of commercial models. These range from the mere threat of competition to full, open, competitive tender.

A myriad of commercial models exist between these extremes and are widely used in the procurement of large infrastructure, including transmission infrastructure. Depending on the circumstances (i.e. the competitive dynamics of the relevant market), particular commercial models are likely to be more fit-for-purpose. For example, in certain circumstances, the threat of competition can be sufficient to extract most of the benefits that more formal competition can provide and can be more efficient (e.g. where the costs of open, competitive tender might be relatively high).

[8] Contestability in the Public Sector | Department of Finance

Figure 1 Types of commercial models and degree of competition

Degree of competition	Threat of competition	Bid Benchmarking	Competitive tender
Impact on competition dynamics	► Right but no obligation to go to market (e.g. contract renegotiations, periodic reviews of long term contracts, additional services) ► Can extract many of the benefits of competitive tender (e.g. if risks to the incumbent and the costs to tender are high)	► Bid benchmarking to aid bilateral negotiation ► May include the option to go to market and may provide incumbent with the first right of refusal to match price ► Can deliver similar outcomes to the above	► Can be used for a wide range of projects particularly those with well defined parameters ► Becomes more complex for projects that are less well defined and require more relationship based contracting arrangements (e.g. strategic alliances)
Applicable models	► The EII Act retains the flexibility to determine what assets become contestable ► AEMO is obliged to go to competitive tender for certain assets in Victoria above a threshold value. It has some flexibility to determine which parts of the asset is contestable	► Informal market testing ► Formal independent review ► Open book costings (e.g. additional services) ► Unsolicited proposal	► Partial or full scope (services being tendered) ► Variable degree of solution specification ► Closed tender ► Open tender

4.3 The benefits contestability can provide

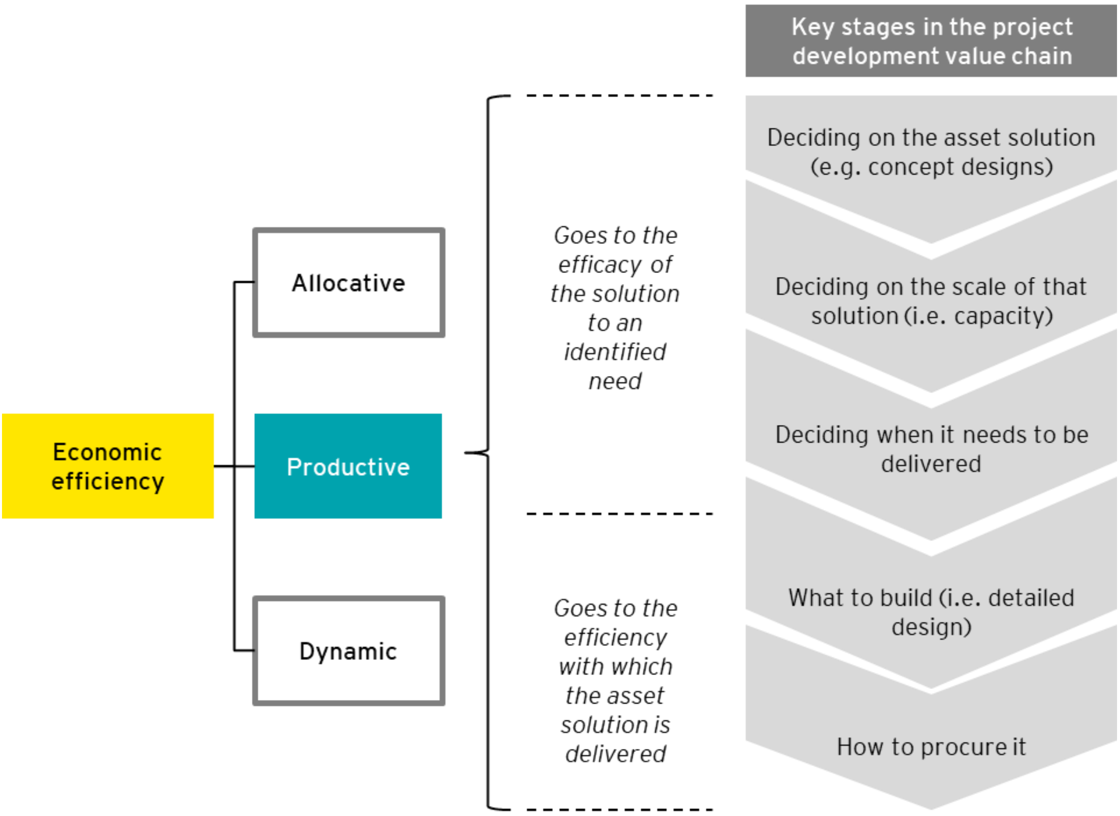
The benefits of contestability (and competition) for large infrastructure investments, including major transmission assets, are largely driven by the potential to unlock productive efficiency improvements in the investment decision, asset solution selection and project development process. Productive efficiency is essentially concerned with maximising the outputs for any given level of inputs.

Figure 2 provides a simple illustration of the typical key sources of productive efficiency in context of the development of major infrastructure projects and where they might arise across the project development value chain.

The key sources for efficiency improvements are broadly a function of:

- Correctly identifying an investment need;
- Identifying the most efficacious solution to that need (i.e. the asset solution or what to build);
- Developing that solution at the right scale and with the right timing (i.e. how big and when to build it); and
- Executing the development in the most efficient way possible (i.e. how and who builds it).

Figure 2 Likely key drivers of productive efficiency in delivering major infrastructure projects



The benefits contestability can provide are therefore largely a function of the:

- Commercial model of contestability adopted (as Section 4.2 discusses); and
- Extent to which it covers the project development value chain for the asset (i.e. from the planning and investment decision, through to how it is constructed).

In many workably competitive markets, all the decisions along the value chain are made by private sector parties and therefore the scope for contestability to generate productive efficiency gains is typically the greatest. The private sector bears the consequences of poor investment decisions and / or delivery. It is possible therefore that contestability might not always deliver the desired outcome, but that is less of an issue where it does not have material third party impacts. In the case of electricity transmission, however, the outcome will often have material third party impacts which places a premium on ensuring that any contestable process is well-designed and the incentives on project developers are appropriate.

In large infrastructure markets, including for major transmission assets, the decisions on:

- What to build, when and at what scale are often not made by the private sector, but instead made by governments or their agencies. This means that this potential source of productive efficiency is a function of the efficacy of those government investment decisions; and
- The design and construction, and how (and who) to build it is usually contested via some form of competitive tender process. This means that this potential source of efficiency is a function of the market that process is accessing. The vast majority of large-scale infrastructure is procured through a competitive process even if the decision on what to procure, at least at a high level, is made separately by government. In the case of major transmission assets in Australia and elsewhere, the relevant transmission service provider typically contracts out the vast majority of the design and construction work to specialist third parties.

To the extent that key components of the value chain are not subject to contestability, then the opportunity for it to deliver productive efficiency improvements is inevitably constrained. Given the nature of large-scale infrastructure, the scope for marginal improvements in productive efficiency are often:

- The largest in the investment decision phase of the process (deciding what to build, at what scale and when). Small changes in these decisions can have a large impact on outturn costs; and
- Comparatively small in the project development phase, given the technology to build much large-scale infrastructure is well developed and mature, and the market is already highly contested.

For example, delivering a 10-20% cost reduction through efficiency in delivering a particular asset solution may be challenging. By contrast, innovation in the identification of investment needs and determination of the optimal asset solution may often deliver material improvements in outcomes at relatively low cost. In other words, the benefits of getting the investment decision 'right' may be relatively large compared to the cost savings associated with delivering that solution more efficiently.

These issues are particularly relevant to contestability in electricity transmission, given some of the developments outlined in Section 3. This is discussed further in Section 5.

5. The scope of contestability for transmission assets

Below we outline:

- The transmission asset value chain;
- The key types of transmission assets;
- The existing degree of contestability for transmission assets;
- The scope for increased contestability for major transmission investments; and
- Implications for contestability across the value chain.

The evidence shows that:

- There are key parts of the transmission value chain that are already routinely contestable;
- There is considerable contestability currently for key types of transmission assets;
- For major transmission assets, the vast majority of the costs are incurred in the asset delivery part of the value chain (i.e. design and construct phase), and this is routinely contested now, as is the maintenance phase;
- For major transmission assets the scope for greater contestability is a function of how much of the transmission asset value chain is allowed to be contestable. This is particularly relevant in the early stages of the value chain; in particular, the extent to which asset specification and option assessment are contestable; and
- There are, in practice, boundaries around the models of contestability that are likely to work given the:
  - Degree of government involvement in making the key investment decisions;
  - Challenges of sharing responsibility for those investment decisions and associated risks; and
  - Nature of the underlying market that might bid for the associated rights.

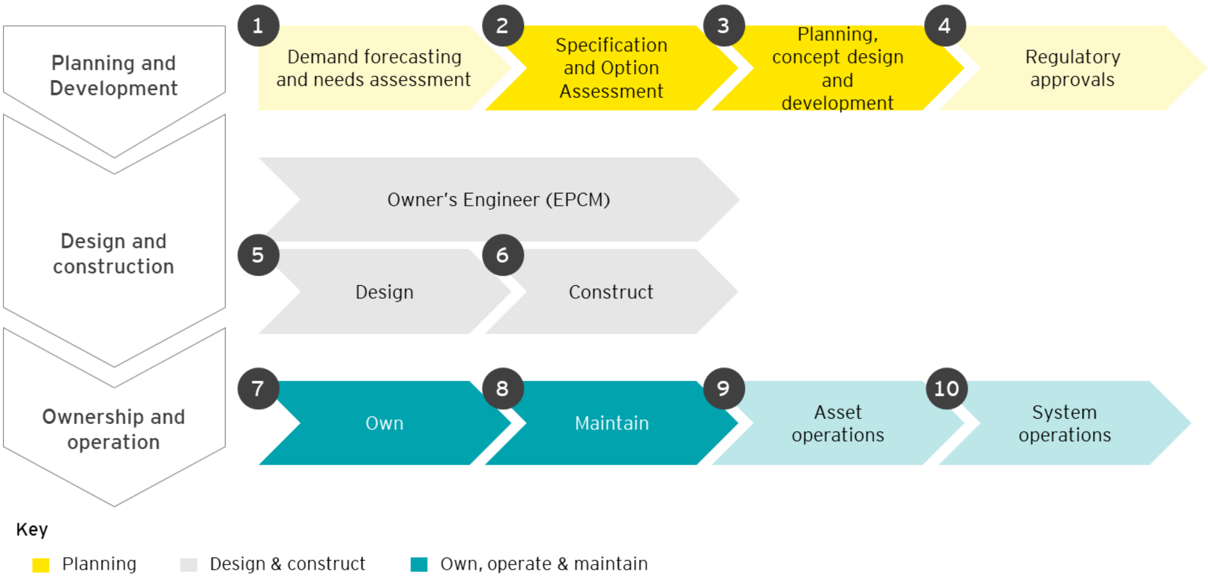
5.1 The transmission asset value chain

To identify the potential scope of contestability for transmission assets, it is helpful to map the transmission asset value chain. This presents the potential scope for contestability, or what is within the transaction perimeter of it.

Figure 3 below provides a representation of the transmission asset value chain and highlights the key steps in it, with a focus on major transmission infrastructure.[9]

[9] This description is not meant to be definitive because alternative delineations of the key stages are possible depending on the purpose for which the delineation is required.

Figure 3 Transmission asset value chain



The six functional steps that may be or are contestable for transmission investment are highlighted in the key. The four functional steps that are either unlikely to be, or may or may not be in a particular circumstance (i.e. 1, 4, 9 and 10), are separately highlighted.

5.2 Key types of transmission assets

Table 1 below highlights five key types of transmission assets.[10]

Table 1 Key types of transmission assets

Asset Type	Description
1. **Shared network assets**	▶ Augmentations to shared-use transmission system assets are classified as prescribed services, which are non-contestable ▶ Third parties need to be registered with AEMO under the national framework to provide these services
2. **Connection Assets**	▶ Connection assets are classified as Identified User Shared Assets (IUSA) and Dedicated Connections Assets (DCA), both of which are specified as contestable assets in the NEL and NER ▶ The AEMC has proposed a draft rule change to connection assets that would make large (>30km) DCAs now part of the shared transmission network as 'Designated Network Assets'. Small DCAs would remain as contestable connection assets[11]
3. **Interconnectors**	▶ Transmission lines with nodes in separate NEM regions ▶ Interconnectors are classified as market network services under the NEL and NER and are delivered under a contestable framework. The assets are generally used to pursue arbitrage opportunities in other NEM jurisdictions
4. **Non-network assets**	▶ Defined in the NER as ancillary services that are essential to the management of power system security, facilitate orderly trading in electricity, and ensure that electricity supplies are of an acceptable quality ▶ These assets can be made contestable if incumbent TNSPs do not fill gaps identified by AEMO

[10] EY analysis. The focus of this typology is functional in nature. The typology is not meant to be definitive because there are a variety of other ways those assets could be mapped both functionally and by other criteria (e.g. technical), depending on the specific purpose for which the typology is required.

[11] AEMC National electricity amendment (connection to dedicated connection assets) draft rule determination, 2020.

Asset Type	Description
5. Renewable Energy Zones	▶ The rules for contestability of REZ transmission infrastructure are still being defined across the jurisdictions of the NEM ▶ In NSW the EII Act has made REZ transmission infrastructure contestable due to the power to authorise new network operators to own, control and operate REZ transmission infrastructure[12] ▶ The framework established by the EII Act extends to priority transmission projects identified in AEMO's ISP that may be located outside declared REZs[13]

5.3 The existing degree of contestability for transmission assets

There is already a considerable degree of contestability applied in the provision of these key types of transmission assets in Australia; in particular, in the National Electricity Market (NEM).

Table 2 below highlights the degree of contestability typically applied for these key types of transmission assets based on EY's research, noting there is some variation by region.

Table 2 Degree of contestability for existing key types of transmission assets

	Planning and Development	Design	Construct	Own	Maintain	Operate
1. Shared network assets (Prescribed services)	TNSP	Competitive via TNSP tender		TNSP		TNSP
2. Connection assets	Contestable with input from TNSP	Competitive via proponent tender		Contestable		TNSP
3. Interconnectors	Contestable (Often TNSPs in practice)	Competitive via proponent tender		Contestable		TNSP Third parties in some instances
4. Non-network assets	Contestable with input from TNSP	Competitive via proponent tender		Contestable		TNSP
5. REZs	Infrastructure Planner (Contestability in development)	(Contestability in development)		(Contestability in development)		(Contestability in development)

5.4 Increased contestability for major transmission assets

This section focuses on the scope for greater contestability for major transmission assets. For the purposes of this exercise, 'major transmission assets', are defined to be:

- Large shared network upgrades;
- New lines that are connecting new sources of generation or demand (these could either be radial lines or the infrastructure connecting REZs which may also be transmission loops); and
- Interconnection assets, although in the Australian context, they are at least in theory contestable across the entire transmission asset value chain.

[12] Electricity Infrastructure Investment Act 2020 no 44 section 36
[13] Electricity Infrastructure Investment Act 2020 no 44 section 32(1)(b)

Given the life of major transmission assets, it is worth noting that some assets that commence their life as radial lines or interconnection assets between two systems that otherwise are not very integrated (e.g. are operated separately), may end their lives as part of much more complex systems.

5.4.1 The cost of delivering major transmission infrastructure

Table 3 shows the costs of delivering major transmission infrastructure across the value chain. It shows that for the largest transmission projects, the majority of costs (circa 85%-90%) are incurred in the design and construction phase.

Table 3 Capex profile[14]

Stage	Sub-stage	Proportion of total capex
Planning	Stakeholder and cultural heritage engagement	2%
	Definition and Approvals Phase	5%
Sub-Total (Planning)		**7%**
Design	Land and easement acquisition[15]	3%
	Design	1%
Sub-Total (Design)		**4%**
Construct	Transmission lines (construction)	49%
	Substation works	23%
	Internal costs (project delivery costs)	9%
	Contingency	4%
	Other	2%
Sub-Total (Construction + Other)		**88%**
Total		100%

5.4.2 Scope for contestability of major transmission assets

The scope for greater contestability for major transmission assets is a function of how much of the transmission asset value chain is allowed to be contestable. This is particularly relevant in the early and final stages of the value chain, in particular, the extent to which asset specification and option assessment are contestable.

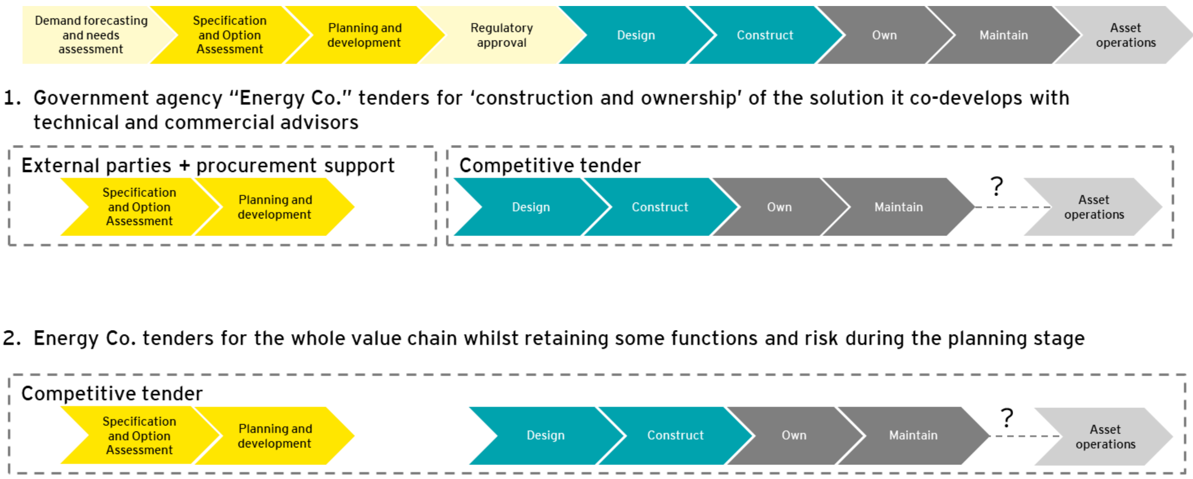
[14] EY analysis. Capital costs are sourced from the Victorian REZ Development Plan 2020, AEMO 2019 TAPR and ISP 2020. The cost components across the project lifecycle were estimated from publicly available information on Project EnergyConnect, MarinusLink, VNI Minor and Eyre Peninsula Reinforcement.

[15] Environmental offset costs will vary depending on the circumstances of each project and have not been factored into this analysis.

Figure 4 outlines the likely potential ‘book ends’ for contestability across the major transmission asset value chain.[16] In particular, at:

- ► One end of the spectrum, a government agency or similar might be responsible for:
    - ► Making the key asset specification and option assessment decisions;
    - ► Undertaking the planning and development process that feeds into the necessary regulatory approvals (e.g. economic, environmental, cultural heritage, social, technical); and
    - ► Tendering out the detailed design and construction, ownership, and maintenance (and potentially asset operations).
- ► The other end of the spectrum, a party may be responsible for the initial demand forecasting or needs assessment, or at least making that information available to the market, and then tender out the rest of the transmission asset value chain.

Figure 4 Scope for increased contestability



Both book ends imply that asset operations could in theory at least be contestable (i.e. that the asset in question could be ‘operated’ independent of the system in which it sits). This is likely to depend on the type of major transmission asset in question.

Section 6 describes these system operation issues in further detail.

5.4.3 Practical experience with the application of contestability

The experience reviewed in this report shows that there are some practical issues in fully utilising contestability in the early parts of the transmission asset value chain. Those issues:

- ► Constrain the market’s ability to assume key risks associated with transmission asset planning and approvals processes (even if it were ‘free’ to make the investment decision). For example, the key planning decisions are often controlled by government and it is challenging for the market to take planning approvals risks (both the approval itself and the timing) when they have limited ability to control the outcome; and
- ► Impact on the complexity of the commercial arrangements (and the time it takes to deliver them) that achieve an efficient allocation of risk, given those constraints.

[16] There is a myriad of options within these two extremes.

Both of these factors may impact on the returns required by the market or costs incurred to deliver this outcome (i.e. they might be higher than they otherwise could be), because they impact on the extent of development risk being taken. Where the returns are set by regulation (i.e. the new asset would be subject to economic regulation), there may be an impact on the risks the market is prepared to bear for that return. In other words, if the regulated rate of return is considered by the market to be 'too low', they will likely respond by reducing the risks to which they are exposed and / or increasing their estimates of the cost of delivering the project.

Those practical issues and underlying structure of the market also likely means that, if parties were to assume a greater role in the early parts of the transmission asset value chain, they would only seek to do so if it enabled them to win the entire value chain (i.e. get involved early to win all the downstream functions – design and construction, ownership and maintenance).

Contestability that incorporates early involvement in the value chain, would likely have implications for the nature of both the:

- Tender for that early involvement (e.g. it will not involve a simple fixed price tender, but will instead likely involve a complex risk sharing and partnership arrangement, such as a strategic alliance); and
- Competition in the downstream parts of the value chain (i.e. it might involve competition 'for' the downstream market, as opposed to 'in' it). For example, currently, the ownership and maintenance functions are largely a subset of the decision on who controls the design and construction phase, although maintenance is routinely contracted out in any case. This still involves competition in the ownership function of the value chain, but primarily indirectly via the capital markets (e.g. as demonstrated by recent activity in respect of Spark Infrastructure, Ausgrid and AusNet).

The key alternative would be not to have contestability in the early parts of the value chain, but have broader contestability for the later stages; where open, competitive tendering is substantially less complex. In other words, contract out the design and construction (as is done currently albeit usually via the incumbent transmission business), as well as the ownership and maintenance functions.

In these circumstances it seems likely that prospective bidders would want to bid for the whole of the remaining value chain (i.e. whoever won the rights to design and construct would automatically win the right to own and maintain). This is because that is where most of the value is for the proponent and for risk management purposes.[17]

If this were the case, the net increase in contestability for ownership may be more apparent than real.

Section 6 describes the experience in this regard in further detail.

[17] Otherwise the investor may bear asset ownership risks over a new asset it had no part in specifying or developing.

6. Lessons from contestability in mature electricity markets

Below we outline:

- The approach used to identify and analyse key examples of contestability; and
- Key findings with respect to lessons learned from the available evidence and experience with contestability to date, including the:
    - Benefits it may have delivered, with particular regard to its intended policy objectives; and
    - Costs and / or risks it may be revealing, particularly in regard to the implications for operating the transmission system within which those contestable assets might exist.

6.1 Approach

EY undertook desktop research to review the current status of contestability in mature electricity markets, particularly in relation to major transmission assets and how system operations are managed.

For the purposes of this exercise major transmission assets are defined to be:

- Interconnectors between otherwise separate and independently operated electricity systems (e.g. international, interstate, inter-regional);
- Radial lines from an existing transmission system to major new sources of generation (e.g. new areas of renewable supply) or demand (e.g. a remote mine); and
- Major new transmission assets that are part of an existing system or meshed network. These could be a new transmission line which creates a new loop within an existing system (e.g. to pick up new renewable generation in a region), or major shared network upgrades.[18]

EY notes that:

- There is a very large number of potential examples that could be covered;
- There is relatively little information in the public domain on some of the examples;
- Some of the examples are relatively new, so some lessons may be just emerging; and
- There is considerable complexity in some of the examples in respect of roles, responsibilities and risk allocation between the parties involved.

Given the nature of the task, EY has focussed on:

- The key examples of contestability in the major markets, both at a policy level and at the asset level; and
- Developed particular case studies in those major markets and endeavoured to cover as wide a range of examples as possible for the three key types of major transmission infrastructure identified for the purposes of this report.

In particular, it focuses on examples in:

- North America;
- South America;

[18] It is acknowledged that at the margin, it may be difficult to definitively categorise some developments into one of these three categories.

- Europe; and
- Asia Pacific.

6.2 Key findings

6.2.1 Overview of contestability in transmission in international markets

- Contestability in electricity transmission is applied in mature electricity markets both at the:
  - Policy level (i.e. frameworks that facilitate it); and
  - Asset level (i.e. projects that have been procured through contestable processes).
- Most examples are relatively recent, but there are some notable older examples, including in Australia.
- The disruption that is occurring in the industry driven by government policies to reduce carbon emissions and technological change is creating both:
  - Increased interest amongst policy makers in contestability; and
  - More opportunities for contestability (e.g. different types of assets, new entrants).

  This can be expected to continue and increase the degree of contestability in transmission.

For major transmission assets, the vast majority of examples of contestability are either for (see Table 5 below):

- Interconnectors between otherwise separate and independently operated electricity systems (e.g. international, interstate, inter-regional); or
- Radial lines from an existing transmission system to major a new source of generation (e.g. new areas of renewable supply) or demand (e.g. a remote mine).

There are fewer cases of contestability in meshed assets that are part of an existing electricity transmission network.

Contestability in electricity transmission is a mechanism used by governments to attempt to: [19]

- Attract private finance and capital markets to transmission assets. Competitors may have access to alternative funding sources and additional equity which supports the provision of services;[20]
- Alleviate budget constraints in the delivery of transmission assets through smoothing of spending via long term availability payments (in comparison to where the incumbent is government-owned);
- Accelerate delivery timeframes (potentially at the expense of procurement timeframes) and expand the transmission network to better respond to demand;
- Achieve greater efficiency in the construction, operation and maintenance of transmission assets; and

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[19] AESO and NERC indicate that the Competitive Process was developed to achieve the following objectives:
- Minimise life-cycle costs through competitive pricing;
- Create opportunity for maximum innovation throughout the lifecycle of facilities;
- Allocate risk most efficiently and effectively mitigate those risks;
- Foster efficient investment, operation and maintenance of assets across the life cycle of the facilities;
- Ensure facilities are designed to meet standards for performance, and to ensure reliable operation of the interconnected electric system;
- Facilitate timely completion of projects.

[20] Ofgem, Competition in electricity transmission, 2015.

- Encourage innovation and idea generation, improving delivery and long-term efficiency at the initial point of investment.[21]

The available case studies for transmission procurement contestability are based on a model underpinned by an independent system operator; typically, a non-for-profit and / or government owned entity that has specific responsibilities for system operation, including:

- Planning and investment decisions;
- Asset solution design and specification standards;
- Construction and maintenance standards and processes; and
- Direct control over asset operations, or indirect ability to control asset operations.

Those independent system operators also typically have less onerous accountabilities than do privately owned transmission businesses that are also system operators (e.g. they do not have a licence that can be revoked in the event of poor performance). In other words, they have a lower degree of accountability for system operation risks.

This is found in America, Canada, Brazil and Mexico (see Appendix A.1 and A.2). In the UK, contestability has been reserved for offshore transmission assets which has less risk from a system operations perspective and therefore do not require an independent system operator (see Appendix A.3.1). In New Zealand, Germany and Sweden, there does not appear to be cases of contestability.

While the common procurement approach is contestable under the models studied, a high level of regulatory and governance arrangements is typically imposed on contestable Transmission Service Providers (TSPs) in the form of a regulatory framework governing cost recovery and performance obligations over the life of the asset.

The relative success of the transmission investment arrangements in these regions and countries have been underpinned by the stability and transparency of the revenue streams and performance-based incentives under the arrangement.

Increasingly, we observe more contestability in complex parts of the network and thus more risks associated with the management of system operations. This is because some assets that commence their life as radial lines or interconnection assets between two systems that otherwise are not very integrated, may end their lives as part of much more complex systems.

Radial lines have traditionally been contested over assets in the meshed network. This is because risks can be more easily managed, and roles and responsibilities more clearly defined.

Our research did not identify any examples of third parties developing, owning, and maintaining major transmission assets that are part of an existing system, operated by a private, for-profit transmission business.

On balance, the experience shows that system operations risk increases as contestable assets are located in more integrated areas of the meshed network. For example, in the UK, competition has been introduced in the development of offshore transmission assets, which connect floating offshore wind farms to the onshore network. However, introducing competition into the onshore regime has proven more challenging due to increased complexity and risks associated with the meshed network and onshore regimes (see Appendix A.3.1 for further detail).

The UK has a privately owned electricity transmission business (National Grid) which is also responsible for system operations.[22] This is analogous to the situation that exists in NSW and South Australia (but not Victoria) in the Australian context.

[21] Ofgem, Competition in electricity transmission, 2015.
[22] National Grid is required, as part of its licence, to plan, develop and operate the National Electricity Transmission System.

Table 4 summarises the risks experienced in contestable processes globally.

Table 4 Summary of risks experienced in contestable transmission

Risk	Description
System operation risk	▶ In the absence of an independent system operator, there are complexities in appropriately allocating risks which may reduce the efficiency of and increase the risks associated with system operations. In these circumstances, the investor may bear asset ownership risks over a new asset it had no part in specifying or developing. Increased risks to the incumbent operator include breaches of the host transmission operator's license obligations. ▶ Ofgem (UK) found cases where lack of definition in role and responsibilities resulted in reduced accountability. For example, an outage can be claimed to result from poor line maintenance by the transmission operator (TO) or from imprudent dispatching by the system operator (SO).[23] ▶ The inability to effectively allocate and define roles and responsibilities can lead to sub-optimal performance and more costly outcomes. If risks are not clearly articulated, they could be priced in by both parties (incumbent and third-party), resulting in increased cost for consumers. ▶ Increased risk to the owner and/or operator is likely to increase the cost of finance and reduce the bankability of the project. ▶ To the extent contestability creates a disaggregated network, issues can emerge associated with inability to effectively deal with extreme weather events – evident in Texas where it has resulted in significant blackouts. Refer to section 0 for further details on the CREZ case study. ▶ There is system operation and coordination risk during emergency events such as system-wide blackouts. This risk is heightened when there are multiple parties accountable and responsible for responding to and managing extreme events.
Interface risks	▶ Contracts are typically packaged as either: detailed design, finance, build, operate and transfer (DFBOT); or detailed design, build, operate and maintain (DBOM). This allows for interface risk to be transferred to the consortium during construction. During the concession period, there is some interface risk between the operator and owner of the transmission line (if they are separate entities). ▶ Poor management of interfaces are found to result in suboptimal management of capacity, system operation, outage panning and maintenance programs. These costs are typically borne by TOs, SO, suppliers and generators through network charges. ▶ Contestability in complex assets creates additional interfaces.
Costs	▶ Cost overruns are likely to occur where parties do not have experience in managing and executing submissions for development and regulatory approvals.

Table 5 shows the Australian and international case studies explored as part of this research. Most examples of contestability are found in radial transmission lines. There are fewer examples of contestability in the meshed network. In all cases where there is contestability for such assets, there is an independent system operator responsible for system operations in that respective region.

The contracts are typically packaged as either DFBOT or DBOM. In some cases, ISOs requested solutions with broader design specifications. For example, PJM received 26 proposals for its Artificial Island project, which varied in solution (e.g. route, number of substations, transmission line length). This was found to stimulate innovation. See Appendix A.1.1 for further detail.

Table 5 International case studies

Case study	Jurisdiction	Asset classification / type	Party awarded	Role of delivery party	System operations
Texas CREZ	Texas, United States	▶ REZ (multiple transmission lines)	▶ Incumbent TSP (7); Third party	Build, own, operate	▶ ERCOT is the ISP for the region. Under the protocols, the TSP must abide by direct orders from ERCOT and report to the ERCOT

[23] NationalGrid, Competition in electricity transmission, 2015.

Case study	Jurisdiction	Asset classification / type	Party awarded	Role of delivery party	System operations
		▶ Radial lines and transmission lines part of the meshed network	new entrant (8) ▶ Various winners (incl. Bandera, Brazos, Lone Star, Oncor, Sharyland)		
Hartburg-Sabine Junction	Texas, United States	▶ Transmission line ▶ Substation ▶ Part of the meshed network	▶ Third party new entrant, NextEra Energy Transmission	Build, own, operate	▶ MISO is the regional transmission operator (RTO) / ISO for Eastern Texas ▶ Requires a Local Balancing Authority agreement with Entergy as the interconnecting utility (that owns the existing substation and transmission lines the project will connect to)
Duff-Coleman Transmission Project	Texas, United States	▶ Transmission line ▶ Radial line	▶ Third party new entrant, Republic Transmission / LS Power	Build, own, operate	▶ MISO is the RTO / ISO for Eastern Texas ▶ Required coordination with existing substation owner to incorporate the project into the existing Local Balancing Authority operations
Empire State Line, New York	New York, United States	▶ Transmission line ▶ Radial line	▶ Third party TNSP, NextEra Energy Transmission	Develop, build, own and operate	▶ NYSIO is the ISO for New York
Artificial Island, Delaware	Delaware, America	▶ Transmission line ▶ Two substations ▶ Proposals involved radial solutions and assets part of the meshed network. ▶ The radial solution was the preferred.	▶ Third party TNSP, LS Power over PSE&G (incumbent)	Develop, build, own and operate	▶ PJM Interconnection is a regional transmission organisation (RTO). It is part of the Eastern Interconnection grid operating an electric transmission system. It is responsible for operating the transmission network. ▶ Solicited under FERC 1000
East-West Tie Transmission Line	Ontario, Canada	▶ Transmission line ▶ Part of the meshed network	▶ Third part TNSP, ▶ NextBridge: NextEra Energy Transmission, Borealis and Enbridge	Develop, finance, construct, operate and maintain	▶ Ontario Independent Electricity Operator (OIEO) is responsible for operating and monitoring the transmission network in Ontario. ▶ The OIEO also schedules imports and exports, interconnects with other transmission grids and coordinates with other ISOs.
Alberta Power Line	Alberta, Canada	▶ Transmission line	▶ Incumbent TNSP:	Develop, finance, construct,	▶ Alberta Electricity System Operator (AESO) is responsible

Case study	Jurisdiction	Asset classification / type	Party awarded	Role of delivery party	System operations
			Alberta Line / ATCO	operate and maintain	for operating and monitoring the transmission network in Alberta.
Victorian Big Battery	Victoria, Australia	▶ Battery facility and transmission connection	▶ Third party (partnered with incumbent TNSP) ▶ AusNet Services, Neoen and Tesla	Develop, finance, construct, operate and maintain	▶ Australian Electricity Market Operator (AEMO)
Western Victoria Transmission Network Project	Victoria, Australia	▶ Transmission line	▶ Incumbent TNSP, AusNet	Plan, design, build, own and operate	▶ Australian Electricity Market Operator (AEMO)
CopperString	Queensland, Australia	▶ Transmission line	▶ Third party, CuString Pty Ltd	Owner and operator	▶ Australian Electricity Market Operator (AEMO) and incumbent TNSP, PowerLink
UK Office of Gas and Electricity Markets	United Kingdom	Offshore transmission systems	▶ 21 licenses awarded to date	Own and operate (constructed by offshore generator)	▶ Third party owner and incumbent TNSP

6.2.2 Outcomes

The success of contestability in transmission assets appears to be supported by a strong framework around the operation of those assets:

- Where there is contestability in radial transmission lines or interconnectors, a private incumbent operator or private third-party operator or an independent system operator; and
- Where there is contestability in the meshed network, an independent system operator.

The introduction of contestability in the US has led to some competition, however implementation is yet to reach scale. For example, only 3% of transmission investments between 2013 to 2017 were competitively developed projects. This is partly because of the challenges (as described above) in introducing contestability into the meshed network. This means that contestability is largely implemented for radial transmission lines and interconnectors.

There is some evidence from the examples to support competition in transmission procurement leading to reduced bid costs. For the 15 projects that were procured on a contestable basis, new entrants out-bid incumbent TSPs of 8 occasions. On average, the winning bids of these 15 competitive transmission projects have been priced 40% below the ISO/RTOs'[24] or incumbent TO's

[24] Regional transmission operators (RTOs) are transmission operators that are independent from all market participants and have a separate governance structure. They are responsible for (within the region) grid operations, reliability and transmission service. To do this, they plan and coordinate transmission additions and upgrades, as well as provide for comprehensive regional transmission expansion planning.

initial project cost estimates. However, at the time of the Brattle research (2019), all 15 projects were still under development (in-service dates post-2019), so final outturn costs were not yet known.

The majority of competitive transmission projects to be delivered by new entrants in North America have also included a cost containment mechanism built into the contracts with the TSPs, reducing any impact of cost overruns on the project. By contrast, the majority of projects awarded to incumbents did not contain such a mechanism.[25]

The Federal Energy Regulatory Commission (FERC) passed the FERC 1000 Order in 2011. The Order removed the right of first refusal for incumbent TNSPs. Part of the reason why FERC Order 1000 has not been more successful is because of the difficulty for bidders to accurately price and allocate risk to different parties.[26] This is because the definition of roles and responsibilities of parties in the meshed network is more difficult to define. In addition, complexities are largely a function of the indivisibility of system operations risk (i.e. the difficulty in subdividing and therefore efficiently allocating system operations risk between different parties).

Further, the small share of contestable projects results from the allowances granted to ISOs/RTOs to exclude projects (such as local transmission projects) from competitive processes. This can be for a wide variety of reasons, including short required timeframes, minimum cost requirements and voltage specification. It has also been suggested that part of the reason why FERC Order 1000 has not been more successful are due to individual state Right of First Refusal laws.[27]

Despite this, competitive processes to date have been reported to deliver material cost savings compared to the pricing offered by incumbents. Globally, cost efficiency appears to improve for contested transmission assets. According to Brattle Group, the range of potential savings include 22% in NYISO, 21% in Alberta, 16% in Ontario, 23% to 34% in the UK and about 25% in Brazil.[28] It is unclear, however, whether in practice these cost efficiencies were achieved in full.

[25] Brattle Group, Cost savings offered by Competition in Electric Transmission, 2019.
[26] Norton Rose Fulbright, Suffering from lack of transmission.
[27] Norton Rose Fulbright, Suffering from lack of transmission.
[28] Brattle Group, Cost savings offered by Competition in Electric Transmission, 2019.

Appendix A Contestability case studies

This section details the current status of contestability in mature electricity markets, particularly in relation to major transmission assets and how system operations are managed. In particular, it focuses on examples in:

- North America;
- South America;
- Europe; and
- Asia Pacific.

A.1 North America

In North America, the operation of transmission assets is the responsibility of the associated independent system operator, which is typically subject to regulatory oversight (for example, FERC in America). In this regard, the ISO model in the US and Canada allows for ISOs to operate the transmission network assets owned by either investor-owned or state-owned entities. ISOs also undertake planning and development work before releasing a competitive tender process. Contestability in the existing electricity transmission system in the United States and Canada is discussed below.

A.1.1 United States of America

Overview of transmission market

There are two major wide area synchronous grids in North America, the Eastern Interconnection and the Western Interconnection, and two minor power grids in the U.S., the Alaska Interconnection and the Texas Interconnection. The Eastern, Western and Texas Interconnections are linked at various points with DC interconnects, which allow electricity to be transmitted throughout the U.S., Canada and Mexico.

The synchronous grids are operated by transmission system operators (TSOs), which are not-for profit companies that tend to be owned by the utilities in their respective service areas. These TSOs are responsible with coordinating, controlling and monitoring the operation of the transmission network. TSOs provide non-discriminatory transmission access to electricity generators and customers. TSOs are either an:

- Independent System Operator (ISO); or a
- Regional Transmission Organizations (RTO).

ISOs operated within a single state, whereas TSO cover wider areas crossing state borders.

There are four RTOs in the U.S.:

- ISO New England (ISO-NE);
- Midcontinent Independent System Operator;
- PJM Interconnection (PJM) in the Mid-Atlantic region; and
- Southwest Power Pool (SPP) covering Oklahoma, Kansas and parts of Arkansas, Missouri, Texas and New Mexico.

There are also three ISOs:

- California Independent System Operator (California ISO);
- New York Independent System Operator (NYISO); and
- Electric Reliability Council of Texas (ERCOT, an ISO).

Tasked with the role of improving the reliability and security of the bulk power system in the US, there are nine not for profit Regional Reliability Councils (RRCs) in the North American Electric Reliability Corporation (NERC). These RRCs also operate in Canada and the northern part of Baja California in Mexico. The members of the RRCs include private, public and cooperative utilities, power marketers and final customers. The RRCs include:

- Eastern Interconnection
- Florida Reliability Coordinating Council (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- ReliabilityFirst Corporation (RFC)
- SERC Reliability Corporation (SERC)
- Southwest Power Pool (SPP)
- Western Interconnection
- Western Electricity Coordinating Council (WECC)
- Texas Interconnection
- Electric Reliability Council of Texas (ERCOT)

The FERC distinguishes between 10 power markets in the US, including the seven for which RTOs have been established, as well as:

- Northwest
- Southwest (covering Arizona, most of New Mexico and Colorado)
- Southeast

ISOs and RTOs were established in the 1990s, when states and regions established wholesale competition for electricity. The NERC Functional Model requires that "all transmission elements" of the bulk electric system are the responsibility and control of one and only one transmission planning, planning authority and transmission operator in that region.

Competition in transmission procurement

According to the Brattle Group[29], since the implementation of FERC Order 1000 in 2013, there were 29 competitive transmission project solicitations until 2017, 15 of which resulted in competitive projects. This investment in competitive processes represents only 2% of all FERC-jurisdictional transmission investments. The small share of contestable projects results from the allowances granted to ISOs/RTOs to exclude projects from competitive processes. This can be for a wide variety of reasons, including short required timeframes, minimum cost requirements and voltage specification. It has also been reported that since the FERC Order, a number of states, including Iowa, Minnesota, North Dakota, South Dakota and Texas, have enacted their own ROFR requirements for electric transmission. This potentially inhibits the construction of large, multi-state projects as utilities in states with a ROFR law can break the project into smaller pieces in order to comply with that law.

For the 15 projects that were procured on a contestable basis, new entrants out-bid incumbent TSPs of 8 occasions. On average, the winning bids of these 15 competitive transmission projects have been priced 40% below the ISO/RTOs' or incumbent TO's initial project cost estimates.

[29] The Brattle Group, Transmission Competition Under FERC Order No. 1000 at a Crossroads: Reinforce or Repeal? Discussion Paper, 2018.

However, at the time of the Brattle research (2018), all 15 projects were still under development (in-service dates post-2019), so final costs were not yet known.

Since this Brattle research, there have been cases, such as MISO's first competitive auction, where projects have been delivered within the cost cap and ahead of schedule. The majority of competitive transmission projects to be delivered by new entrants in North America have also included a cost containment mechanism built into the contracts with the TSPs, reducing any impact of cost overruns on the project. By contrast, the majority of projects awarded to incumbents did not contain such a mechanism.[30] In contrast, non-competitive transmission projects over the same period have experienced a weighted average cost escalation (calculated by Brattle Group) of 34%.

New York

The New York Independent System Operator (NYISO) is a not-for-profit organisation that operates the New York state's bulk electricity grid, administers New York's competitive wholesale electricity markets, conducts planning for the state's electricity network, and advances electricity infrastructure.

The NYISO was established by FERC in 1998, and in November 1999, New York State's competitive wholesale electricity markets were opened to utility and non-utility suppliers and consumers as the NYISO began its management of the bulk electricity grid. The formal transfer of the grid operation responsibilities from the New York Power Pool to the NYISO took place on December 1, 1999.

The NYISO's market-based approach to transmission network planning varies from other regions' transmission planning processes. The NYISO's role is to evaluate and monitor the reliability of the system, assess reliability needs, and solicit market solutions. The market and TOs provide solutions to meet reliability needs, and control which resources are financed, built, and operated.

The NYISO's Comprehensive System Planning Process (CSPP) is a continuous market-based process that evaluates resource capability and transmission system security of the state's bulk electricity grid and evaluates solutions to meet reliability and congestion relief needs. The CSPP contains four major components:

- Local Transmission Planning Process (TPP)
- Reliability Planning Process (RPP)
- Congestion Assessment and Resource Integration Study (CARIS)
- Public Policy Transmission Planning Process (Public Policy Process).

Alongside these components, interregional planning is conducted with the NYISO's neighbouring switch areas in the United States and Canada under the Northeastern ISO/RTO Planning Coordination Protocol. The NYISO participates in interregional planning and may contemplate Interregional Transmission Projects in its regional planning processes.

Texas

The Electric Reliability Council of Texas (ERCOT) was the first independent system operator in the U.S. and only one created under State law (instead of FERC). With its unique, partially deregulated market and a grid system not interconnected with the rest of the United States (it has only a few small DC interconnections with neighbouring markets and reliability councils intrastate), Texas has been allowed to operate differently and largely autonomously from other states. ERCOT manages the flow of electric power for c. 90% of the state's electric load under an "energy-only market" (as opposed to a capacity market).

ERCOT is a membership-based non-profit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas (PUCT) and the Texas Legislature. Its major functions are to operate the electricity network in Texas, schedule and manage how electricity will

[30] Brattle Group, Cost savings offered by Competition in Electric Transmission, 2019.

flow through the network, plan for new power plant additions, and perform financial settlements for sellers and buyers. The PUCT oversees the ERCOT market and serves as the market monitor and regulator.

The ERCOT Protocols detail the roles and responsibilities of ERCOT and the TSPs, among other relevant parties. Under the protocols, the TSP must abide by direct orders from ERCOT and report to the ERCOT (as soon as practicable) of any changes in status of Transmission Elements or any inability to meet minimum TSP reactive requirements. Each TSP has to design, implement, operate, and maintain its systems to meet the Telemetry Standards and at ERCOT's request. The TSP has to notify ERCOT of any planned construction or outages.

Outside of the ERCOT region, electric utilities are vertically integrated, owning generation, transmission, and distribution assets, as well as retail operations. These include El Paso Electric Company, Southwestern Public Service Company, Southwestern Electric Power Company, and Entergy Texas. The PUCT sets retail rates for the vertically integrated utilities and FERC has regulatory jurisdiction over the wholesale power transactions and transmission rates for these utilities. The Legislature has granted the PUCT authority to retain outside counsel and consultants. Within these non-ERCOT regions, two other Transmission Operators are active:

- Southwest Power Pool (SPP), which acts as the ISO for Northeast Texas and the Texas Panhandle and is under the authority of FERC
- Midcontinent Independent System Operator (MISO), which acts as a Regional Transmission Operator (RTO) operates in 15 states including Eastern Texas, which is the location of the utility Entergy Texas.

Competitive Renewable Energy Zones (Texas)

Competitive Renewable Energy Zones (CREZs) were in introduced in 2005 as the first REZ policy. Texas Legislature adopted SB 408 designating the creation of CREZs and providing authority to PUCT to direct ERCOT to plan for transmission to connect approximately 18 GW of wind capacity.[31]

PUCT contestably procured the identified transmission projects through an iterative process whereby the selected TSP would finance, license, construct, operate, and maintain the transmission assets. A mixture of 14 incumbent and new entrant TSPs were ultimately selected, depending on the project categorisation[32]:

- For 'default' projects, which are existing transmission facilities that required upgrades or modifications, the existing owner of the asset was selected to deliver the project.
- Priority projects, to relieve current congestion from existing wind generation, were given precedence in the permitting and review process and were assigned to incumbent TSPs given that they already held a Certificate of Convenience and Necessity (CCN) required under law. The PUCT also sought to assign geographically proximate projects to the same TSP when possible.
- A mix of incumbent and new entrant TSPs were awarded the remaining 'Subsequent' projects. The PUCT considered the trade-off between selecting a large pool of TSPs to participate in order to spread financial risk, introduce novel technologies, and diversify sources of skills and materials against selecting a small number of TSPs in order to avoid unnecessary complexity and coordination difficulties.

Each selected TSP was required to apply for a CNN, which guaranteed that all costs associated with building and maintaining the network will be passed through to consumers equally via tariffs[33] (akin to TUoS in the NEM). The issuing of the certificate was contingent on generators demonstrating a

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[31] Energy Institute, The University of Texas at Austin, The Timeline and Events of the February 2021 Texas Electric Grid Blackouts, 2021.
[32] AESO, Competitive Process for Critical Transmission Infrastructure, 2011.
[33] World Bank, Transmitting Renewable Energy to the Grid: The Case of Texas, 2014.

sufficient financial commitment in the form of a security deposit to project the TSPs in case they backed out.

The PUCT implemented monitoring, oversight and reporting requirements as a means to deliver efficient costs.[34] Project oversight involved delegating authority to an executive director to select, engage and oversee persons with responsibility for oversight of the planning, financing, and construction of all CREZ facilities to ensure timely completion. In addition, new entrants were required to submit plans for operation, maintenance, and ongoing control of assigned CREZ facilities, as required by the Executive Director or project oversight monitor. The reporting requirements set by the PUCT stated:

- Within six months of the PUCT granting the certificate, transmission operators file cost estimates and schedules
- At any time, transmission operators must report within ten working days of becoming aware of any change in circumstance that will affect the transmission operator's ability to complete a project, or that would change any of the most current cost estimates provided to the Commission by more than 15%
- One year after CCN approval (and updated yearly until service begins), each designated transmission operator must file updated total cost for each of its CTP facilities.

Outcome of CREZ

The projects ultimately went overbudget and was borne by customers. However, a degree of cost overrun can be attributed to the additional length of transmission lines. Originally the entire project was estimated at $4.97B for 2,963 miles of new 345kV transmission lines, while as of October 2013, the cost was $6.81B for 3,588 miles of new lines. [35]

More recent power system failures in Texas have occurred during record low temperatures, which caused generators to turn off, uninsulated gas pipelines to freeze and demand to spike as homes used increased heating. While this is predominantly a generation as opposed to transmission issue, enquiries have been raised in recent times as to the ability of the network to respond to extreme weather conditions.

This has called into question the strength of the interconnection between the REZ assets and the rest of the system. Due to the State's disaggregated network, rolling blackouts were unsuccessful to curb demand and critical infrastructure were not always on the same circuit to allow local grids to easily direct power to, leaving some hospitals out of power.

It has been reported that ERCOT had issued winterisation recommendations, but those were largely ignored by major Texas power companies, as compliance was voluntary.[36]

MISO - The Duff-Coleman Project

MISO has competitively tendered two projects, and in both cases selected (new entrant) proponent has offered cost containment. The Duff-Coleman project was the first project and is now an operational 345-kV transmission line between the Indiana and Kentucky border (see Figure 5), connecting the existing Duff substation located in Dubois County, Indiana with the existing Coleman EHV substation located in Hancock County, Kentucky. The project was identified in the 2015 MISO Transmission Expansion Plan to enhance grid reliability in the region and had an estimated cost of c. $60m.[37]

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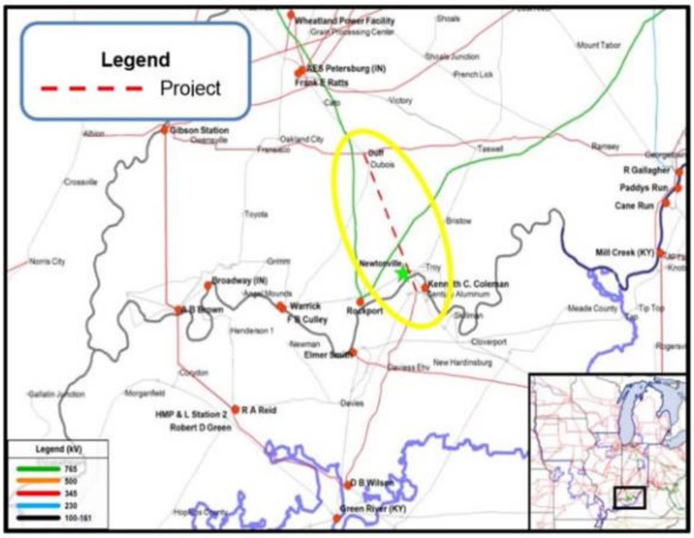
[34] Houston Kemp, Regulatory treatment of large, discrete electricity transmission assets, 2020.
[35] Brattle Group, Competition in Transmission Planning and Development, 2014.
[36] Heinrich Böll Foundation, Texas Power Grid Failure, 2021.
[37] TransmissionHub, MISO: Republic Transmission, 2020.

Figure 5 The Duff-Coleman Project



Source: MISO Energy, 2020.

MISO determined that a new extra-high voltage transmission line would increase reliability by strengthening the regions' transmission backbone and reduce congestion, allowing lower cost generation resources to reach load.

MISO selected Republic Transmission LLC (indirectly owned by LS Power and Hoosier Energy) under the competitive selection process to build, own, operate and maintain the new Duff-Coleman 345-kV project in southern Indiana and northern Kentucky. As the first project in the MISO region to undergo competitive selection, a process established by FERC Order 1000, MISO received 11 comprehensive proposals from RFP Respondents listed below[38]:

- Ameren Transmission Company of Illinois and PPL TransLink, Inc.
- Duke-American Transmission Company, LLC
- Edison Transmission, LLC
- GridAmerica Holdings, Inc.
- ITC Midcontinent Development, LLC
- Midcontinent MCN, LLC
- NextEra Energy Transmission Midwest, LLC
- Republic Transmission, LLC
- Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of
- Indiana, Incorporated and Public Service Enterprise Group. Inc.
- Transource Energy, LLC
- Xcel Energy Transmission Development Company, LLC.

MISO's Tariff requires MISO to evaluate and score proposals for mixed projects – transmission lines and substations. In each category, MISO looked for certainty, risk mitigation, low cost, and specificity. Republic made the following cost commitments for the Project:

[38] MISO, Selection Report, Duff-Coleman EHV 345 kV Competitive Transmission Project, 2016.

- Cost Cap – Project Costs may not exceed the binding cost cap of $58.1M ($47M in 2016 dollars), subject to certain exclusions. MISO initially estimated the project cost to be $58.9M.
- ROE Cap – Republic is subject to a return on equity (ROE) cap on the initial investment in the Project stating that ROE shall be the lesser of:
  - 9.80% (inclusive of all ROE adders), or
  - The MISO region-wide base ROE plus the RTO adder (currently 10.30%)
- Equity Cap – Republic is subject to an Equity Percentage Cap of 45% for the Project

The selection report indicates that MISO evaluated Republic Transmission's Local Balancing Authority, real-time operations monitoring and control, and switching abilities. The proponent indicated how it would work with the substation owners to incorporate the project into existing Local Balancing Authority operations, as well as monitor operation of the line in real time and coordinate switching.

The Duff-Coleman Project was delivered 6 months ahead of schedule in June 2020 and within budget.

MISO – The Hartburg-Sabine Junction Project

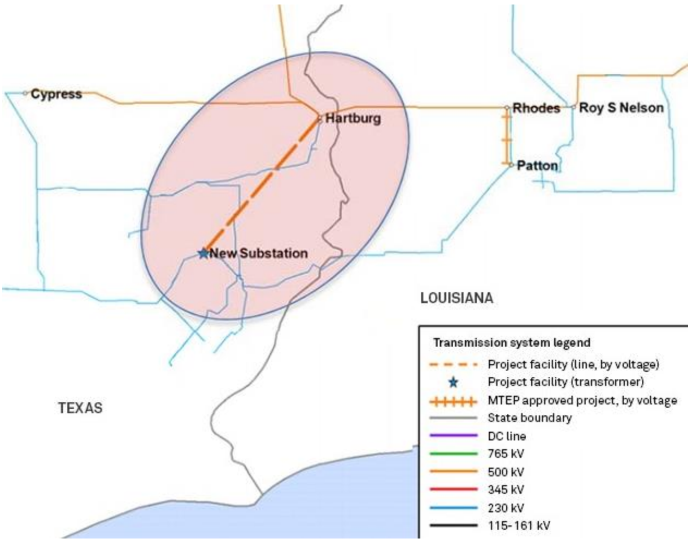
The c. $115m Hartburg-Sabine Junction project is MISO's second project after the Duff-Coleman project to undergo competitive selection. The project involves a 500-kV single circuit transmission line, four 230-kV transmission lines along with a new substation in East Texas (see Figure 6) and appears to be part of the meshed network. The project's new single-circuit 500 kV transmission line will interconnect the existing Hartburg 500 kV substation (owned by Entergy Texas, Inc. ("Entergy")) to a new substation, which will interconnect with two of Entergy's existing 230 kV transmission lines.

The project is currently in planning stage with construction expecting to commence this year in 2021 with operations in 2023. MISO selected NextEra Energy Transmission Midwest LLC under a competitive selection process that included 12 proposals from 10 proponents. Respondents at RFP stage, who were MISO Qualified Transmission Developers, are listed below[39]:

- Avangrid Networks, Inc.
- EasTex TransCo, LLC
- GridLiance Heartland, LLC
- ITC Midcontinent Development, LLC / Hunt Transmission Services, L.L.C.
- Midwest Power Transmission Arkansas, LLC
- NextEra Energy Transmission Midwest, LLC
- Transource Energy, LLC
- Verdant Plains Electric, LLC
- Xcel Energy Transmission Development Company, LLC

[39] MISO, Selection Report, Hartburg-Sabine Junction 500 kV Competitive Transmission Project, 2018.

Figure 6 Hartburg – Sabine Project



Source: MISO Energy, 2018.

MISO's Tariff requires MISO to evaluate and score proposals for mixed projects – transmission lines and substations – according to four evaluation criteria: cost and design, weighted at 35%; project implementation, weighted at 30%; operations and maintenance, weighted at 30%; and transmission planning participation, weighted at 5%. NextEra submitted a comparatively low estimated annual transmission revenue requirement of $95m (capped for the first 10 years) and provided greater cost certainty through its proposed cost caps and cost containment features.[40]

The MISO selection report describes NextEra's plan for future coordination for Entergy as the interconnecting utility. It states that NextEra has an affiliated company with an existing Local Balancing Authority agreement with Entergy and that it intended to add the project to that agreement. One of NextEra's affiliates has a control centre that operates EHV facilities in the ERCOT portion of Texas. NextEra documented its affiliates' extensive successful 500 kV experience operating in the Eastern Interconnection in hurricane-prone areas and their commitment to support the project.

PJM

PJM is an RTO that operates across 14 states in the Eastern part of the US. PJM identifies and assesses economic; reliability and public policy needs for transmission investment. All PJM projects are eligible for competition unless they fall under of the following exemptions:

- The need is immediate;
- The need is below 200kV;
- Relates to substation equipment; or
- Excluded per FERC Order 1000 rules (system upgrades and local projects).

Between 2013 and 2017, 16 competitive tenders were completed, and seven projects were approved.[41] PJM uses a very early DBO model, where the tender is initiated after the need is identified. This allows for a more innovative and broader range of proposals albeit a more complex selection process.

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[40] Transmission Hub, MISO selects Nextera energy transmission Midwest, 2018.

[41] Brattle Group, Cost Savings Offered by Competition in Electric Transmission, prepared for LSP Transmission Holdings, 2019.

PJM is the system operator for all transmission lines in its region. It has the responsibility for planning and directing the operation of PJM transmission facilities in accordance with applicable NERC, RFC, SERC and PJM standards. Those requirements cover all the following areas:

- Security, including emergency operations, outage coordination and ratings coordination;
- Transmission operations including voltage control, real-time monitoring, system restoration, operator coordination and reporting; and
- Operations planning.

Since PJM member TOs assist PJM in carrying out its responsibilities it is considered essential to clearly define relationships to ensure all compliance obligations are met and compliance activities are properly coordinated, including when blackouts occur.

PJM – Artificial Island

The Artificial Island project was tendered in 2013. The winning project is a radial transmission line that involves a new:

- 230 kV to be constructed under the Delaware River from the Salem substation to a new substation tapping an existing 230 kV line
- 500/230 kV Transformer at Salem substation.

Seven potential developers submitted 26 proposals with cost estimates ranging from $100m to $1.2bn. Of the 26 proposals received, 14 were submitted by PSE&G, the incumbent TO, with costs ranging from $592m to $1.5bn.[42] The following table shows the entities that submitted proposals:

- Virginia Electric - is a vertically integrated utility and is a subsidiary of Dominion, an investor owned utility (IOU). Virginia Electric's cost range was between $126m to $133m.
- Transource – is jointly owned by AEP and Great Plains Energy, both are vertically integrated IOUs. Transource's cost range was between $123m to $994m.
- First Energy – is a vertically integrated IOU. First Energy's proposal cost was $410m.
- PHI/Exelon – are vertically integrated IOUs. The proposal cost was $475m.
- LS Power (winner) – is a privately held transmission and generation developer. LS Power's proposal cost range was between $116m to $170m.
- Atlantic Wind – is a consortium between an experienced developer (Trans-Source), Google, Bregal Energy and Marubeni Corp (Japanese investment bank). Atlantic Wind also received funding from Macquarie Capital. Its proposal cost was $1,012m.
- PSE&G (incumbent) – is a vertically integrated IOU. Its proposal cost ranged between $692m and $1,548m.

The proposals varied in scope and whether transmission lines were overhead or underground. PJM selected the LS Power proposal because of its proposed construction technique and cost containment model provided significant advantages over other proposals. The LS Power cost containment included obtaining permits and other government approvals, acquiring land and land rights, performing environmental assessments and design and engineering.

Proposals that demonstrated minimal impact to transmission operations were also preferred, including plans for ongoing maintenance, black-start and route diversity. Proposals that involved a

[42] PJM, Artificial Island Project Recommendation White Paper, 29 July 2015.

new project route that is not parallel to an existing line and not integrated into the meshed network were assessed to have lower operational risk and therefore preferred.

A.1.2 Canada

The electricity market in Canada varies from province to province. Under Canada's constitution, each province controls the electricity generation, intra-provincial electricity transmission, electricity distribution and market structure within its borders.

In some provinces (e.g. Manitoba), the model is a traditional vertically integrated structure. In this system, large monopoly providers of bundled electricity services dominate the market. Other provinces (e.g. Alberta and Ontario) have an electricity sector that is based on market competition and traditional cost-of-service regulation only in the transmission sector. As a result, Alberta and Ontario have strict requirements (in relation to transmission and operation) relative to other provinces.[43]

The competitive sector for transmission assets in Alberta and Ontario is owned by a handful of players (such as ATCO, Hydro One, Atlalink and ENMAX) but are operated collectively by non-profit independent system operators. Transmission assets are planned by system operators and then tendered under a DFBOT structure. Increasingly, non-incumbent companies are winning tenders that are of higher complexity. This includes the East-West Tie Project, a 400km 230kV transmission line in Ontario. NextBridge (a consortium between NextEra, Borealis and Enbridge) won the contract over the incumbent (Hydro One) (see below).

While contestable transmission projects delivered by the non-incumbent exists, operation of these assets within the wider system remains the responsibility of the Ontario Independent System Operator (OISO). There also appears to be contestability as part of an existing transmission system and therefore becomes complicated from an operations perspective. The OISO has the following functions:

- Scheduling of imports and exports
- Interconnecting with other transmission grids
- Coordinating with other ISOs
- Monitoring conformance of transmission users to transmission rules
- Monitoring real-time flows on the transmission grid
- Identifying transmission constraints
- Curtailing specific generation transactions

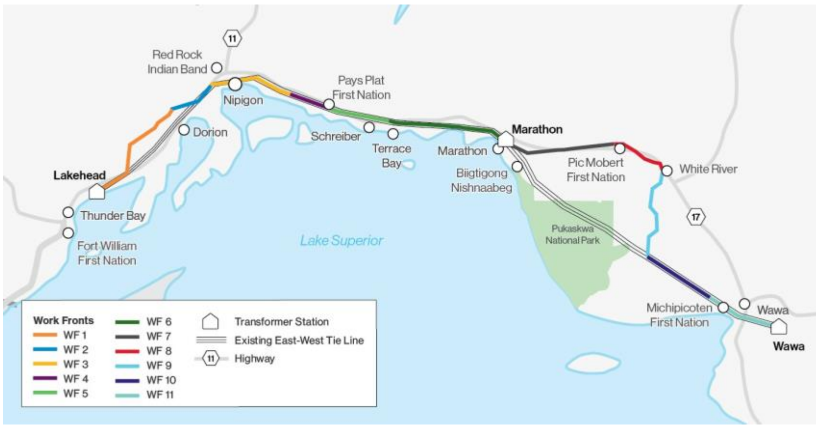
This helps to mitigate system operation risks associated with two third-party transmission asset owners in a single transmission network.

East-West Tie Project - Ontario

The East-West Tie is a 400km, 230 kV transmission line (see Figure 7) that will run from Wawa to the Lakehead substation near Thunder Bay, Ontario. It is a radial asset that has 25% of the line connecting into the existing line operated by the incumbent (HydroOne).

[43] Thomson Reuters, Electricity Regulation in Canada: Overview, 2020.

Figure 7 East-West Tie



Source: NextBridge, 2021.

The Ontario Energy Board solicited proposals to encourage new entrants to tender for the East-West Tie Project for a contract to develop, finance, construct, operate and maintain the transmission asset. The purpose of this was to use competition as a mechanism to achieve economic efficiency for the benefit of consumers. Six bids were received, including the incumbent (HydroOne) and NextBridge (winner), a consortium between NextEra, Borealis and Enbridge.

When construction of the project is completed, IESO will maintain operational responsibilities of the system and NextBridge will operate the asset under a 30-year concessional period.

Since the project initiated, costs have increased from CAD $439m to CAD $777m, which still falls 16% below the incumbent transmission owner's estimate for a comparable line.[44] The range of savings from competitive transmission in Ontario is within the range of estimated savings achieved by the competitive solicitations in the US.

A.2 Central and South America

In Central and South America, system operation is largely the role and responsibility of an Independent System Operator. This is where system operation is unbundled from the transmission asset ownership. The ISO is commonly a non-profit organisation, managed by technical staff and governed by a board in which market participants are represented. There is typically an incumbent transmission company that owns the majority of the assets, but expansion can be carried out by independent transmission companies. Increasingly, this model has become more complex with the introduction of contestability in both radial and meshed networks, which varies across Argentina and Brazil. This is discussed further in the sections below.

A.2.1 Mexico

In 2013, a new legal and regulatory framework in Mexico established the possibility for any government entity to enter into contracts with private parties to carry out the construction, maintenance and operation of the transmission and distribution grids. In 2017, Mexico's Ministry of Energy (SENER) and the Federal Electricity Commission (CFE) tendered the first two competitive electricity transmission projects, including:

- The SENER-Baja California (SENER-BC) Project: a radial transmission line
- The CFE-Yautepec Project: five transmission lines within a meshed system with seven electrical substations.

[44] Brattle Group, Cost savings offered by Competition in Electric Transmission, 2019.

The delivery of these projects was intended to be structured as DFBOT (design, finance, build, operate and transfer). The basis of this structure is the execution of an electric energy transmission management agreement (the SENER Agreement) between SENER and the winner of the tender. This Agreement allows SENER to operate the electric energy transmission utility before the CRE and Centro Nacional de Control De Energia (CENACE).[45]

CENACE, as the operator of the transmission system, anticipated increased operating risks due to third party delivery of transmission assets. This included risk of asset and connection failure, termination, change of control, force majeure and payment provisions. As such, several contractual obligations were included into the Agreement, including:

- Third parties must design the infrastructure of the SENER-BC Project and CFE-Yautepec Project based on minimum specifications established by SENER in the tender
- Carry out the operation and maintenance of the SENER-BC Project and CFE-Yautepec Project in accordance with the provisions of the SENER Agreement and applicable regulations.

These risks are typically mitigated through including performance guarantees and abatement regimes into the contract.

Note that these projects have been cancelled due to decreased political appetite for private ownership of transmission assets in Mexico.

A.2.2 Brazil

A series of law changes in the late 1990's enabled third party investors to build, own, maintain and operate transmission assets. The Brazilian Government enacted these changes in response to budget constraints, growing demand for electricity and the need to establish a reliable and secure electricity network. Brazil's energy regulator, Agencia Nacional de Energia Electrica (ANEEL) is responsible for the planning and tender processes. The Brazilian Government established a national independent system operator, the Operator of the National Electricity System (ONS) to provide supervision, control and operation over the power grid.[46] This functions to manage risks associated with the increased delivery of transmission assets by third parties.

Although state-run Electrobras remains the biggest power transmission operator in the country, managing ~71,042km (47% of the total in Brazil) of transmission lines, several non-incumbent companies have also started operating in Brazil.[47] Private companies which have won contracts to build, operate and maintain assets include State Grid, Neoenergia and Engie. Recent examples of third-party contracts awarded through competitive processes include:

- State Grid – China: The Belo Monte-Rio de Janeiro UHVDC transmission line: the 2,539km-long transmission project is a radial line, owned and operated by Xingu Rio Transmissora de Energia, a subsidiary of Chinese state-owned State Grid Corporation of China. From six other international bids, State Grid won over the incumbent (Electronas) because of its UHV technologies, high level of experience and localisation project management team.
- Engie SA - France: 1,800km transmission line in Northern Brazil: Engie SA won a competitive tender for the acquisition of a 30-year concession to construct, operate and maintain a 1,800km meshed electric power transmission line.
- Engie SA - France: 700km Gralha Azul project: Engie SA won a transmission auction in December 2017 to deliver the Gralhal Azul project, which is in a meshed network.

For competitive bidding processes, third parties receive a regulated cost of capital. Some of these transmission assets are part of a meshed network, which exposes the system operator (ONS) to increased operating risks. Under ONS's rule, all transmission facilities are subjected to quality

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[45] CENACE serves as the independent electric grid and market operator, similar to ERCOT and MISO, and others.

[46] In Brazil, it is found that transmission lines are managed and controlled by the ONS.

[47] RAP, Regulatory Framework and Cost Regulations for the Brazilian National Grid (Transmission System), 2013.

control, according to technical rules and grid procedures that they must follow. This is administered by ANEEL and monitored by ONS. There are financial penalties for private entities that do not meet quality standards.

It is estimated that the total maximum annual revenue requirement on this investment would have been $4.45bn, which ANEEL auctions reduced to $3.35bn, an average 25% cost reduction.[48]

A.3 Europe

There are contestable frameworks and regulations for transmission assets in all jurisdictions across Europe. The most common structure between the transmission and system operator is the Transmission System Operator.[49] In the EU, the trend is for the incumbent TSO to have a monopoly on transmission activity and asset ownership. Some asset ownership by third parties may occur in exceptional cases, subject to approval by the operator.

A.3.1 United Kingdom

The Office of Gas and Electricity Markets (Ofgem) is responsible for regulating the electricity and gas industries in the United Kingdom. The UK's onshore electricity transmission network is currently planned, constructed and operated by three transmission owners (TOs): National Grid Electricity Transmission, SP Transmission and SHE Transmission.

While in its current form, Ofgem's onshore regime is similar to that implemented in the NEM, Ofgem has been working to introduce contestability (particularly in radial lines) within transmission in the future. This followed the successful introduction of competition in the development of offshore transmission assets, which connect floating wind farms to the onshore network.[50,51] However, the implementation of competition in more assets have been limited due to a range of issues, including difficulties with legislative change and potentially heightened operating risks.

In 2020, Ofgem announced that if transmission projects are 'new', 'separable' and 'high value', competition should be introduced under the Competitively Appointed Transmission Owner (CATO) regime.[52,53,54] It is noted that the UK do not intend to implement the ISO model *per se*, and the incumbent TOs will remain system operators. This has meant that competition in radial lines are likely to be the only assets feasible for contestability in this market.

It is anticipated that the operation of transmission assets will also be contestable, where specific activities include legal responsibility for operations, asset management and maintenance, network control and monitoring and regulatory reporting.

With respect to increased cost outcomes and operational risks under a fully contestable delivery option, the following risks are anticipated:

- Depending on the financing of the project, having control of the asset removed from ownership will be perceived as adding risk to the owner and therefore the cost of finance will likely increase

[48] Brattle Group, Cost savings offered by competition in electric transmission, 2019.

[49] One company fulfills the role of system operator and owner of the transmission assets.

[50] Houston Kemp, Regulatory treatment of large transmission assets, 2020.

[51] Ofgem estimates that the contestable offshore transmission regime saved consumers between $1bn and $2bn (more than 20% of connection cost).

[52] Ofgem, Update on competition in onshore electricity transmission, 2018.

[53] Ofgem describes these criteria as follows:
(a) New means a 'competitively new transmission asset or a complete replacement of an existing transmission asset';
(b) Separable means 'the boundaries of ownership between these assets and other (existing) assets can be clearly delineated'; and
(c) High-value means a 'threshold set at or above BP$100m of expected capital expenditure'.
Ofgem, Guidance on the criteria for competition, 2019.

[54] The regime is one where the system operator defines the functional specification as part of the panning process. Everything else is contestable and tendered by Ofgem. This regime is similar to the Victorian regime.

- If risks are not clearly allocated, they could be priced in by both parties, resulting in increased costs for consumers. Risks to the incumbent operator include breaches of the host transmission operator's license obligations
- Clear articulation of the operational responsibility between the incumbent system operator and the third party delivering the transmission asset, including distinction between "operational control" and "day-to-day O&M" will be required to reduce interface risks.

To mitigate some of these risks, it is anticipated that a number of financial incentives will reinforce CATO obligations under the regulatory framework:[55]

- An availability incentive to ensure CATO's assets are available when they are needed
- A penalty for failing to fulfil obligations to enable new connections
- Financial and reputational incentives to cover transmission losses
- CATO reporting on asset condition at regular intervals, with revenue at risk through a performance bond if a CATO's assets are not in the expected condition at the end of the revenue term.

In practice, the CATO regime is moving forward with various consultations. As such, no competitive tenders for onshore projects have been undertaken.

A.3.2 Sweden and Germany

In Sweden and Germany, the electricity sectors have been characterised by a coexistence of public, mixed-economy and private companies in the delivery of transmission assets. However, not all segments of the value chain (distribution, transmission and system operation) are contestable and they continue to be regulated and operated by the incumbent transmission operator.[56] The TSOs in these countries also develop grid expansion plans, which the regulator assesses and approves.

In Germany, TSOs are licensed to operate by the Federal Network Agency. TSOs must operate, maintain and optimise, reinforce and expand a secure, reliable and efficient network.

There does not appear to be a contestable market for electricity transmission in Sweden or Germany.

A.4 Asia Pacific

EY is not aware of any forms of contestability in systems operations in Asia. In our view, transmission assets remain government owned and operated.

A.4.1 Oceania

New Zealand

In New Zealand, while there are no barriers to the contestability of transmission assets under the Electricity Authority (EA)[57], in practice, there have been no examples of major transmission infrastructure that are located in the meshed network being built, owned and operated by third parties. This is most likely because Transpower Ltd (the National Grid Owner and System Operator) is publicly owned.

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[55] Ofgem, Extending competition in electricity transmission, 2016.

[56] Research Unity EU Integration, Privatisations in Europe's liberalised electricity markets – the cases of the United Kingdom, Sweden, Germany, and France, 2007.

[57] The EA is the regulator of system operations and market participants.

There are some instances where distribution lines are radial and are operated and owned by third parties. Major third-party distribution companies include Vector Ltd and Orion. Their involvement in the electricity network system include:

- Sub-transmission that forms part of the distribution system, operated by Vector
- HVAC lines that are radial (i.e. taking power from the main transmission grid into Auckland for distribution) and are operated by Vector. Vector's grid can be operated in a manner that allows for flow-through between two transmission grid exit points (GXPs).

Australia

In Australia, contestability appears to be of increasing interest to policy makers and energy regulators, as Section 3 describes. Some examples are noted below.

Western Victoria Transmission Network Project

The Western Victorian Transmission Network Project (WVTNP) is the first major Greenfield transmission asset delivered in many years via a contestable process.[58]

A bespoke commercial model was developed to balance the request for proponents to determine final design and route alignment with the need for the TNSP to secure land easements:

- An outputs based specification was tendered which allowed bidders to consider a range of approaches to meeting the service specification
- Pricing of all elements were provided at Bid Submission, except for land and easement acquisition
- Securing necessary approvals, land easement acquisition and stakeholder engagement activities and costs were adjusted for in the final price
- Construction costs were determined through the open book tender process
- Transmission charges were determined once construction and practical completion is achieved with availability payment adjustments
- TNSP to provide service delivery under build own operation maintain and operate model to ensure service levels are met for 30 year term.

System Integrity Protection Scheme (Victorian Big Battery)

SIPS is a thermal service capable of delivering up to 250MW of continuous power generation to increase the transfer capacity of the Victoria-New South Wales interconnector. Also known as the Victorian Big Battery, the asset will be delivered in partnership between the incumbent TNSP (AusNet), Tesla and Neoen.[59] The project's approvals were fast tracked by a Ministerial Order under s16Y of National Electricity (Victoria) Act.

The Act allows for a Ministerial Order to replace or displace the RiT-T test. In the case of SIPS, the Ministerial Order directed AEMO to procure SIPS and run a competitive tender, but did not specify any alternative test to be used in place of the RiT-T.[60]

These amendments enabled the Victorian Government to work with AEMO to reduce the time required during procurement, regulatory and other development decisions and approvals, investment decisions and financing.

The successful tenderer was Neoen, a global renewable energy producer who partnered with Tesla and the incumbent TNSP, Ausnet Services.

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[58] EY was AEMO's commercial and financial advisor on this project

[59] Victorian Big Battery, 2021.

[60] Victorian Government Gazette, No. S 238 Friday 15 May 2020, *VNI SIPS Ministerial Order*.

CopperString

The proposed $1.7bn CopperString high-voltage transmission line would connect Mount Isa and the North-West Minerals Province to the National Electricity Market.[61] CuString Pty Ltd plans to be the owner and operator of the line. Currently, under the *Electricity – National Scheme (Queensland) Act 1997*, transmission lines in Queensland are non-contestable and there is limited precedent in the development of greenfield lines by third party TNSPs:

- To mitigate regulatory risks, CuString have executed an Implementation Agreement with the State Government.[62]
- CuString is seeking to have the transmission line approved as a regulated asset. The consortium pose a competitive threat to the incumbent TNSP if their proposal is approved.
- In 2020, the Queensland Government announced conditional funding to accelerate the project, and in 2021, the Federal Government announced funding to support progress to a Final Investment Decision.[63]
- Off the back of this funding, CuString have awarded a $7m ECI contract to CIMIC Group's UGL and CPB contractors to undertake pre-construction works. This is preliminary works only and does not guarantee that the CIMIC Group will be contracted in the construction phase.[64]

[61] Infrastructure Pipeline, CopperString, 2021.
[62] PV Magazine, CuString ready to 'pull trigger' on $1.5bn transmission project, 2021.
[63] Infrastructure Pipeline, CopperString, 2021.
[64] CIMIC, Analyst and investor presentation, 2021.

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The commercial viability of major electricity transmission projects

A report prepared for TransGrid | 27 September 2021

1 The commercial viability of major electricity transmission projects

Overview

1. Frontier Economics has been retained by TransGrid to provide our views in relation to the AEMC's Transmission Planning and Investment Review. This report presents our independent opinion on the issues raised in the Consultation Paper released on 19 August 2021.

2. In our view, it is important to begin by considering the context of this review. Project EnergyConnect is a major ISP project that connects the NSW, South Australian and Victorian transmission networks. The project is recognised widely as being in the long-term interests of consumers. The project satisfied the AER's Regulatory Investment Test for transmission (RIT-T), meaning that the AER agreed that of all the alternative options available, the project:

> *maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option).* [1]

3. The project was also identified as a key element of the Australian Energy Market Operator's (AEMO's) Integrated System Plan (ISP).[2]

4. However, the project sponsors, TransGrid and ElectraNet, indicated that the project could not be made commercially viable under the current regulatory framework and proposed a Rule change that was considered by the AEMC.[3] The project was eventually made commercially viable by a tranche of subordinated debt funding supplied by the Clean Energy Finance Corporation.

5. This event raises a number of important issues for consideration such as:

   a Why was a project that is clearly in the long-term interests of consumer not commercially viable under the current regulatory framework; and

   b What changes to the current regulatory framework would be required to make such projects commercially viable?

6. However, the Consultation Paper does not focus on these questions, but essentially assumes that they will be addressed by the AER as part of its 2022 Rate of Return Instrument (RoRI) review.

[1] AER, South Australian Energy Transformation, Determination that the preferred option satisfies the regulatory investment test for transmission, Decision, January 2020, p. 5.

[2] AEMO, 2020 Integrated System Plan, July 2020.

[3] As explained at paragraph 19 below, to avoid confusion, we define 'commercial viability' as meaning that the timing of the allowed cash flows in relation to the new project must be sufficient to support the credit rating and gearing parameters that are assumed when setting the allowed return.

However, we demonstrate in this report that the AER will not, and cannot, address the commercial viability issue as part of its RoRI review.

7. Consequently, the key point that we make in this report is that the AEMC must address the commercial viability issue as part of this review – because it will not be addressed anywhere else.

8. Only after the commercial viability issue has been addressed does it make sense to consider the merits of making major transmission projects contestable and/or imposing development obligations on incumbent TNSPs. In our view, it would be best to address commercial viability issues through design of the regulatory framework—by ensuring that that the regulatory framework ensures the commercial viability of major projects that are in the long-term interests of consumers—rather than through a separate process that seeks to introduce contestability into the delivery of major transmission investments.

9. For these reasons, our key recommendation is the development of a 'commercial viability' test, as an integral part of the regulatory framework, to ensure that major transmission projects that are identified as being in the long-term interests of consumers are commercially viable and will therefore proceed. Issues of contestability and TNSP development obligations can then be considered after the commercial viability issue has been considered.

TransGrid's role in the transformation of the Australian energy system

10. Efficient investment has the potential to improve reliability, safety and security of energy supply to millions of consumers—households and businesses—across the NEM. Transmission network service providers, such as TransGrid, have a particularly important role in supporting the transformation of the NEM that is currently underway.

11. We understand that TransGrid has identified transmission network investment needs totalling nearly $7 billion that could be made over our next regulatory period alone. This attests to the scale of the investment required across the entire NEM over the next decade. These projects include:

    a Energy Connect, an interconnector between NSW and SA with an added connection to Victoria, with $1.8 billion of financing from TransGrid;

    b HumeLink, a new 500kV transmission line that would carry electricity to customers from new generation sources, including the expanded Snowy Hydro scheme, and which has been identified by AEMO as a priority investment. We understand that this project will require approximately $3 billion of financing from TransGrid; and

    c Other projects including the QLD-NSW interconnector (QNI) upgrade, the VIC-NSW interconnector (VNI) upgrade, the VIC-NSW interconnector West (VNI West), a new transmission cable from Potts Hill to Alexandria (Powering Sydney's Future). We understand that these projects will require approximately $2 billion of financing from TransGrid.

12. A number of these projects, such as HumeLink and the interconnector upgrade projects, are still under consideration and can only proceed if they are commercially viable.

13. We also understand that TransGrid has received feedback through its stakeholder engagement processes to the effect that these projects are supported by customers on the basis that they will deliver savings to current and future consumers. It appears to be generally accepted that it would be in the long-term interests of consumers for these projects to proceed.

Projects must be commercially viable to proceed

14. No matter how beneficial these projects would be to consumers, they cannot be expected to proceed unless they are commercially viable as standalone projects. There are two key elements to commercial viability:

    a The allowed return on capital committed to the projects must be sufficient to compensate investors fairly for the risks and opportunity costs they incur when they commit capital to those network investments. The best way to support efficient investment is to set the allowed return in line with the best possible estimate of the market cost of capital at the time of each regulatory decision.

    It is worth noting that the risks associated with major transmission projects may differ from those compensated through the RoRI – for instance, because of the significant construction activity required in delivering major transmission projects that is not involved in business-as-usual operation and maintenance of an existing network that is not expanding significantly; and

    b The timing of regulatory allowances must be such that the business is able to support the investment grade credit rating that is required for the purpose of financing investment and operating in the NEM. The significant cash flow demands associated with delivering very large transmission projects, with significant upfront design and construction costs, may mean that the timing of cash flows delivered by the standard regulatory framework are insufficient to support an investment grade credit rating.

15. To support the efficient level of investment, it is important that *both* of these elements are calibrated appropriately. That is, it is important that the allowed return on capital properly reflects the market cost of capital *and* that the timing of regulatory allowances is sufficient to support the required investment grade credit rating.

16. It is not the case that the cash flow timing issue should be 'fixed' by increasing the allowed return above the efficient level. And it is not the case that an inadequate allowed return should be 'fixed' by accelerating the timing of regulatory allowances. Rather, efficiency requires that both elements must be properly addressed.

17. This is because *either* an inadequate allowed return on capital *or* inadequate cash flow timing may be sufficient to render an otherwise efficient and net-beneficial project commercially unviable, thus preventing such a project from proceeding.

Commercial viability vs. 'financeability'

18. We note that, in recent times, there are a number of different interpretations of the concept of 'financeability' that have been proposed and considered by various stakeholders and regulators. For example, 'financeability' has variously been interpreted by various parties as:

    a A test of whether a particular regulated entity is likely to become insolvent, or to experience some form of financial distress, over the course of a particular regulatory period; or

    b A test of whether a particular regulated entity is likely to be able to raise capital in accordance with the relevant regulatory determination (e.g., in accordance with the assumed gearing and credit rating); or c A test of whether a particular regulated entity might be able to raise capital on terms that are inferior to the relevant regulatory determination (e.g., at a lower credit rating, or with lower gearing, or after an equity injection);

d A test of whether a particular regulated entity might be able to raise capital at all over a regulatory control period; or

e Any of the above tests, but from the perspective of the benchmark efficient entity rather than the particular regulated entity; or

f A cross check of the reasonableness of the allowed return on capital such that the allowed return would pass the cross check unless there was evidence of likely financial distress for the benchmark efficient entity.

19. Thus, any proposed test of 'financeability' runs the risk of being misconstrued, depending in which of the various interpretations above are adopted.

20. Consequently, we propose a test of 'commercial viability' to be applied to major new transmission investments. Under this test, we define 'commercial viability' explicitly to mean that the timing of the allowed cash flows in relation to the new project must be sufficient to support the credit rating and gearing parameters that are assumed when setting the regulated allowed return. Whilst this test would be applied when setting regulatory allowances for individual TNSP proponents of major transmission projects, the test would be performed to assess the commercial viability of a benchmark efficient business in the TNSP's circumstances, rather than the commercial viability of the actual TNSP in question. Furthermore, the test would be applied to benchmark efficient business as a whole, rather than to individual projects. That is, a benchmark efficient entity in the TNSP's circumstances would (in its entirety) need to be able to maintain the benchmark credit rating and benchmark level of gearing that are assumed when setting the regulatory allowed return, after implementation of the proposed project.

21. This test would require an amendment to the Rules to require the regulator to set a series of allowed cash flows such that the proposed new investment would be 'commercially viable' according to the above definition.

22. This test would be implemented as follows:

a The default allowance would be based on the standard allowed return on capital and the standard arrangements in relation to depreciation and RAB indexation.

b If the TNSP was able to establish that this allowance would fail the 'commercial viability' test (as defined above), the regulator would accelerate the cash flow allowance in an NPV-neutral manner – just to the extent required to satisfy the commercial viability test.

c The test would be evaluated at the initiation of the project and at the time of each determination.

23. Note that we are <u>not</u> proposing:

a A higher allowed return for large transmission projects; nor

b A nominal rate of return allowance (such as proposed by TransGrid in the recent Rule change process); nor

c A shortening of the depreciable asset life for the project.

24. Rather, commercial viability would be satisfied by increasing depreciation allowances, in an NPV-neutral way, just to the extent required to support commercial viability. For example, it may be that the TNSP identifies a financeability issue in relation to the first five years of the life of a new project – representing the construction period and the initial years of operation. In this case, the depreciation allowance would be increased for those five years only, in an NPV-neutral way, and only by the amount required to address the commercial viability issue. The depreciable asset life could remain unchanged. This would mean that the TNSP would receive a correspondingly lower depreciation allowance in the later years of the project.

25. The key objective of this approach is to accelerate cash flows in an NPV-neutral manner only to the extent that is (just) required to ensure that a benchmark efficient entity can maintain, over the forthcoming regulatory period, the benchmark credit rating and gearing assumptions adopted when setting the TNSP's allowed rate of return over that regulatory period.

26. By contrast, moving to a nominal rate of return allowance (as proposed in the recent Rule change process) may produce cash flows that are more than sufficient for longer than is required to establish commercial viability. Similarly, reducing the depreciable asset life accelerates cash flows over the entire life of the project, rather than just for the period that might be required to ensure financial viability.

27. The key objective of this approach, in contrast with TransGrid's recent Rule change proposal in relation to Project EnergyConnect, is:

   a To establish a 'commercial viability' test in the Rules to guide the AER's assessment of major ISP/transmission projects; and

   b To accelerate cash flows in an NPV-neutral manner only to the extent that is (just) required to establish the commercial viability of the project.

28. In the remainder of this report, we explain the rationale for this test and why commercial viability should be considered before turning to contestability.

29. This report also explains why the issue is something that must be addressed by the AEMC (rather than the AER) – because solving this problem will require a change to the Rules.

The allowed return on capital does not address any cash flow timing issues

30. The allowed return on capital is currently the subject of a review being conducted by the AER, culminating in the 2022 RoRI. That process will produce a single allowed return on capital for all transmission and distribution businesses – consistent with the AER's approach since its inception. That allowed return will reflect the AER's assessment of the return that investors require from an investment in a generic benchmark network. It is a 'business-as-usual' return that will include no additional premium to the standard allowed rate of return to encourage investment, and no premium to reflect the higher level of risk associated with large new construction projects. As we explain below, there is no sense in which the allowed return will 'fix' or even consider the cash flow timing issue explained above.

31. In our view, for the purposes of the current review, the AEMC should assume that the AER's process produces an allowed return on capital that provides (just) appropriate compensation to investors for the risk involved in business-as-usual network operations. The AER's RoRI will not be capable of producing an allowed rate of return that is set specifically to:

   a encourage major new transmission investment; or b compensate investors for the additional risks (over and above those associated with smaller-scale, business-as-usual investments that do not involve very large construction work); or

c address any cash flow timing issues.

Cash flow timing issues cannot be solved via a subsidy from equity holders

32. It is possible for large, new capital projects to be affected by cash flow timing issues that have a potential impact on the level of allowed returns. For example, consider the case where a new project requires substantial cash outflows during a construction period, and where the standard regulatory allowances are insufficient to meet those required cash outflows and, therefore, to support an investment grade credit rating. In such circumstances, there are two potential courses of action:

a Accelerate the regulatory allowances in an NPV-neutral manner, just sufficient to support the required credit rating. Note that this involves no change to the allowed return and no additional regulatory allowance of any kind – just a change in the timing of those allowances; or

b Leave it to the network business to undertake 'countermeasures' to support its credit rating. This would take the form of an equity injection in the amount required to support the required credit rating.

33. The first course of action has no impact on investor returns. All investors would receive the same cash flows in NPV terms and consumers would pay the amount in NPV terms over the life of the asset.

34. By contrast, the 'countermeasures' approach does impact the returns received by investors. The allowed return assumes a particular capital structure (currently 60% debt) and credit rating (currently BBB+). Thus, the regulatory allowance is sufficient to pay an equity return to the 40% equity investors and a BBB+ debt return to the 60% debt investors. Thus:

a Any additional equity injection required to support the current credit rating will be bearing equity risk, but receiving a regulatory allowance commensurate with (tax deductible) debt; and

b If the credit rating falls to (say) BBB, the regulatory allowance will be insufficient to meet the cost of servicing debt. Any deficit would then have to be met by the equity holders.

35. In both of these cases, investors are being asked to provide capital and to accept a return below that which is appropriate for the risk involved. This would amount to equity holders in the benchmark efficient business being asked to subsidise the development of new projects: the AER will provide equity holders with an allowed return set as the unbiased estimate of the market cost of capital for a business-as-usual investment, but the equity holders would be required to accept a lower return because:

a they would receive less than the required return on equity on any additional equity capital (over and above the assumed 40%); and/or

b meet the additional costs of servicing lower-rated debt than the BBB+ assumed when setting the business-as-usual allowed rate of return.

36. It is certainly the case that equity holders could prevent the firm from becoming financially distressed (or falling to sub investment grade) by providing equity on non-commercial terms. Indeed, it will *always* be the case that *some* amount of equity on *some* non-commercial terms would

be sufficient to support the required credit rating. However, such outcomes would, by definition, not be commercially viable. In our view, it is unreasonable to assume that investors choosing to allocate their scarce capital freely would agree to invest in commercially unviable projects. This has been the standard understanding underpinning regulatory frameworks in Australia and elsewhere for decades. Regulatory allowances should be set at a level that is sufficient to allow efficient investments to proceed.

37. If additional equity is required, it will only be forthcoming if investors receive the appropriate return on that equity. Equity investors cannot reasonably be expected to subsidise a project by accepting less than a reasonable rate of return.

38. That is, the question is not one of whether the required credit rating *could* be maintained by such a subsidy from equity holders, but whether equity holders *would* provide such a subsidy – and whether they could be reasonably expected (or required) to do so within an incentive-based regulatory framework.

The example of Project EnergyConnect

39. A good example of cash flow timing and commercial viability issues is TransGrid's recent experience with Project Energy Connect . With a total cost of $2.28 billion (of which $1.8 billion is to be financed by TransGrid), Project Energy Connect is one of Australia's largest energy infrastructure projects (the largest ever financed under the Rules), and is the largest single investment project undertaken by TransGrid to date.

40. Our understanding is that Project Energy Connect will deliver vital infrastructure required to connect the power grids of NSW, SA and Victoria and expand the wholesale energy market across these three states—increasing reliability and security of electricity supply, while lowering power bills for consumers. It will also make a significant contribution to the decarbonisation of Australia's economy.

41. The project has been identified as a critical priority project in AEMO's ISP and was broadly supported as being in the long-term interests of consumers of electricity.

42. TransGrid stated that the regulatory allowances over the initial years of this project were insufficient to support a commercially viable business case under the regulatory regime that would have applied to it. TransGrid sought a Rule change that would have altered the timing of the cash flows in a way that would have enabled the business case to move forward. Whereas much of the Rule change process focused on different interpretations of the meaning of 'financeability,' the core issue was whether or not the project was commercially viable.

43. TransGrid was eventually able to secure nearly $300 million in Federal Government support provided by the Clean Energy Finance Corporation (CEFC)—the largest investment the CEFC has made to date. It is certainly not clear that future transmission projects will be able to rely on finance (at least to a similar scale) from government entities to address concerns about commercial viability that remain unaddressed by the regulatory framework.

44. Moreover, our view is that a regulatory framework that compels network service providers to rely on discretionary lines of funding provided by government entities in order to deliver investments that are clearly in the long-term interest of consumers is neither fit for purpose nor sustainable.

Immediate benefits to current consumers

45. It is important to recognise that the transmission augmentation projects currently planned by TransGrid is expected to deliver *immediate* benefits for *current* consumers. These projects will bring additional transmission capacity and connect more businesses and communities to more sources of electricity generation. This inevitably has two effects:

    a There is a direct effect that acts to lower prices as lower-cost generation sources are able to be dispatched to more consumers, lowering wholesale energy costs; and

    b There is an indirect effect in that a more extensive and robust transmission network results in fewer network outages and fewer price spikes in the spot market. This has the effect of lowering the risk premiums embedded into swap and cap prices, which are a key driver of retail electricity prices.[4] To see why this is the case, consider the example of a $300 cap. This product pays off the difference between the spot price and the $300 strike price. To the extent that the market expects fewer instances of spot prices exceeding $300, the expected payoff on this instrument will be lower, and consequently the cost of purchasing such instruments will be lower (all else remaining equal). The retail cost of electricity includes the costs of these instruments.

46. It is important to note that these reductions in *current* prices will arise even if the new project has relatively low utilisation. It is the ability to use the additional network capacity to prevent price spikes that drives the reductions in swap and cap prices. It is entirely feasible that a network augmentation could have a material impact on retail electricity prices over the course of a year even if it is not used at all during that year. Moreover, new transmission projects can have the effect of reducing prices to current consumers even before they are built. The knowledge that a project is proceeding can immediately reduce the cost of multi-year swap and cap products – in anticipation of a reduction in price spikes in future years.

47. Transmission investments do not benefit consumers in proportion to their utilisation, but rather in proportion to their impact on the prices that consumers pay.

48. We agree that intergenerational equity is an important principle. Each cohort of consumers should pay in proportion to the benefits they receive. However, in relation to new transmission projects, utilisation is a very poor proxy for the benefits that consumers receive. The impact on prices is the appropriate proxy and these new projects have an immediate impact on current prices for the reasons set out above.

49. Furthermore, major transmission investments support the long-term interests of consumers by enhancing the safety, security and reliability of the system – and by facilitating the transition to a low-carbon economy over the long-term. The Rules state that the purpose of the ISP is to establish a whole of system plan for the efficient development of the power system that achieves power

[4] Under a 'swap' contract, a given volume of energy is traded during a fixed period for a fixed price. The variable wholesale market spot price is, in effect, swapped for the fixed strike price. The contract is settled through payment between the counterparties based on the difference between the spot price and the strike price. Under a 'cap' contract, a fixed volume of energy is traded during a fixed period for a fixed price but only when the spot price exceeds a specified price. It provides electricity purchasers with insurance against high prices. Suppose the capped price is $300/MWh. This means the seller of a cap is required to pay to the buyer the difference between the spot price and $300/MWh every time the spot price exceeds $300/MWh during the specified contract period.

system needs for a planning horizon of at least 20 years "for the long term interests of the consumers of electricity."[5]

The roles of the AER and AEMC

50. As noted above, there are two key elements to commercial viability:

    a The allowed return on capital must be sufficient to compensate investors fairly for the risks and opportunity costs they incur when they commit capital to those network investments; and

    b The timing of regulatory allowances must be such that the business is able to support the investment grade credit rating that is required for the purpose of financing investment and operating in the NEM.

51. The allowed return on capital is determined by the AER. That allowed return will be set to provide compensation for the business-as-usual operation of a generic benchmark Australian distribution/transmission network. Current evidence commissioned by the AER indicates that its currently allowed returns are below those of many regulators in comparable jurisdictions overseas,[6] contributing to concerns over the commercial viability of major transmission projects in the absence of any remedial action. Even if set at efficient levels on an ex ante basis, however, the allowed return will not 'fix' or address any cash flow timing or financeability problems that arise in relation to significant transmission projects.

52. Thus, any cash flow timing issues must be addressed by the AEMC via a rule change that permits the AER to have regard to cash flow timing and credit rating issues—for a benchmark efficient business—when setting its regulatory allowances.

The legal limits of the role of the AER

53. The AER is required to make a RoRI under section 18I of the National Electricity Law (NEL). We understand that the RoRI is binding on the AER and network service providers in the making of transmission determinations.

54. We understand that the NEL imposes statutory requirements on the RoRI to be made by the AER. In particular, section 18J of the NEL requires the RoRI to do the following:

    a If the RoRI states the value of imputation credits, to state a single value to apply to all regulated network service providers;

    b If the RoRI states a way to calculate the rate of return on capital or the value of imputation credits, then the RoRI must:

        i provide the same methodology to apply to all regulated network service providers in calculating the rate or value; and

        ii provide for the methodology to apply automatically without the exercise of any discretion by the AER.

[5] NER, rule 5.22.2.

[6] The Brattle Group, A Review of International Approaches to Regulated Rates of Return, June 2020.

55. We understand that the effect of these requirements is to require the AER to develop a single 'business-as-usual' RoRI. That is, the RoRI developed cannot take account of the specific requirements of a regulated network service provider when developing major transmission project as contemplated by the ISP. It may consider these requirements at a general level across all regulated network service providers, but such consideration is unlikely to adequately address the financing concerns from projects of the size contemplated by the ISP.

56. For this reason, our understanding is that the AER cannot appropriately address the financing needs of regulated network service providers that undertake investments of the size and complexity contemplated by the ISP through the RoRI. Specific provisions to meet the specific requirements of the network service provider are needed.

57. Furthermore, the AER has made clear in submissions to the AEMC that it has no obligation under the existing Rules to consider the financeability implications of its regulatory decisions. The AER has also indicated its view that if financeability concerns arise as a consequence of its regulatory decisions, the primary responsibility for managing those financeability concerns rest with the regulated network service provider:

> *The AER does not have a formal obligation to consider financeability under the rules, however, where regulators have included financeability tests within the regulatory regime they have generally stressed that the primary responsibility for managing financeability rests with the regulated businesses.*[7]

58. Hence, whilst there is no legal impediment to the AER taking account of the impact of its decisions on the commercial viability of regulated network service providers, the AER has expressed an unwillingness to do so under the existing Rules.

The practical limits of the role of the AER

59. In its recent draft working papers,[8] the AER has set out its preliminary views about:

   a What it considers 'financeability testing' to mean;

   b What it considers can be achieved by financeability testing; and

   c Its preliminary views about the role of financeability testing in the 2022 RoRI.

60. In particular, the AER has been clear that it would only consider financeability metrics insofar as those metrics might provide information about the required return on capital. In this regard, the AER has stated recently that:

[7] AER, – Consultation on TransGrid and ElectraNet participant derogations – Financeability of ISP projects, Submission, 3 December 2020, p. 2.

[8] AER, July 2021, Overall rate of return: Draft working paper; AER, May 2021, Rate of return and cashflows in a low interest rate environment: Draft Working Paper.

> *Our current evidence suggests that financeability tests carry limitations, which makes their use for informing the overall rate of return unclear. However, we are seeking stakeholder feedback on the potential use of financeability metrics as a cross check on the overall rate of return.* [9]

61. The AER has also indicated strongly that it does not consider that its regulatory process extends to ensuring that required transmission projects are commercially viable for a benchmark efficient entity:

> *The regulatory framework does not require NSPs to be able to achieve the benchmark assumptions used in making and applying the RORI at all times. We consider sector benchmarks rather than firm specific details in making the RORI and that the NSPs have flexibility in their capital structure decisions and employ this accordingly. However, NSPs' actual practice will help us inform the characteristics of the benchmark firm.*
>
> *Therefore we remain of the view that we should not use measures of financeability directly when setting the rate of return. For example, we should not adjust the return on equity or the parameters that inform our return on equity in proportion to movements in financeability measures. Further, at this time we do not consider that changes to our usual approach to estimating depreciation are warranted in order to address financeability issues.* [10]

The premise of the current AEMC review

62. By contrast, the AEMC's consultation paper indicates that the commercial viability of major transmission projects *is* a matter to be addressed by the AER:

> *While it is the Commission's view that these commercial concerns may warrant consideration, it notes that the AER is best placed to explore detailed concerns regarding financeability and risk compensation given its statutory function in setting the rate of return and its role as the economic regulator under the Australian Energy Market Agreement (AEMA).* [11]

63. But, as set out above, the AER:

[9] AER, July 2021, Overall rate of return: Draft working paper, p. 58.

[10] AER, May 2021, Rate of return and cashflows in a low interest rate environment: Draft Working Paper, p. 47.

[11] AEMC, August 2021, Transmission planning and investment review, p. 34.

a Is *not* considering the commercial viability of major transmission projects as part of its 2022 RoRI review process, and

b The AER *cannot* address this issue in the absence of a Rule change.

64. Moreover, the AEMC's consultation paper states that its review is not intended to consider the commercial viability of major transmission projects under the current regulatory framework:

> *The Commission noted that it did not intend for the Review to consider future arrangements to support project specific ISP financeability under the existing framework.*[12]

65. That is, the commercial viability of major transmission projects, under the current regulatory framework, is not being addressed by either the AER or the AEMC.

66. Rather, the consultation paper focuses only on the issue of whether incumbent TNSPs should maintain an exclusive right with no corresponding obligation to invest:

> *As such, the focus of feedback sought as part of this Review is with regard to TNSPs' exclusive right to build and own major transmission projects but with no corresponding obligation to invest.*[13]

67. In summary, the current review appears to be focused on determining whether incumbent TNSPs should either:

a Lose their exclusive right to develop projects within their network jurisdiction; or

b Be obliged to develop projects irrespective of whether or not they are commercially viable.

The problem to be addressed

68. The problem to be addressed here is that major transmission projects that are widely regarded as being beneficial and in the long-term interests of consumers might not be developed because they are not commercially viable under the current regulatory framework.

69. In addressing this problem, the starting point must be a consideration of:

a Whether the current regulatory framework might result in a beneficial project being commercially unviable; and

b If so, what changes would have to be made to the current regulatory framework to ensure that beneficial projects are commercially viable.

70. However, the AEMC review does not address these core issues. It assumes that commercial viability will be addressed by the AER, when that will not and cannot be addressed by the AER. The

[12] AEMC, August 2021, Transmission planning and investment review, p. 34.

[13] AEMC, August 2021, Transmission planning and investment review, p. 34.

Consultation Paper then proposes potential solutions in the form of the introduction of contestability of projects or obligating development of projects, without first considering whether those projects would be commercially viable under the existing regulatory arrangements.

71. For the reasons set out above, our view is that the AEMC must address the issue of commercial viability as part of the current review. Our view is that it would be unsound to proceed to considerations of contestability and obligatory project development without first addressing the core issue of commercial viability. The commercial viability issue will not, and cannot, be addressed by the AER as part of its RoRI process.

The potential role of contestability

72. In theory, making large transmission investments contestable could provide benefits to consumers if there were TNSPs (or, more specifically, investors in such firms) who were willing and able to:

    a Provide capital for a return lower than that allowed by the AER; and/or

    b Address any cash flow timing or credit rating issues without accelerating any regulatory allowances.

73. However, making such large transmission project subject to contestability will inevitably create complexity and risk, for the reasons set out below. It is not clear how that complexity and risk would be managed, who would bear any resulting risks, and how they would be compensated for bearing those risks. Thus, a risk allocation and compensation framework would be a key part of any consideration of contestability.

What is to be made contestable?

74. There are a number of issues to consider in terms of how contestability would work or precisely what would be made contestable.

75. The first consideration is the stage at which a project becomes contestable. Under the current process, major projects are developed via a staged process. Under this process, a number of activities are usually completed prior to final approval and financial close of the project, including:

    a Design and specification work;

    b Route selection;

    c Purchasing of land, easements and options along the preferred route;

    d Booking of steel production slots; and

    e Preparation for construction tender processes.

76. Relative to an approach where commitment to the entire project is required from the outset, this staged approach has a number of advantages in terms of cost efficiencies. For example:

    a The project can be abandoned at any stage if it is determined that costs are higher than expected, outweighing the likely benefits from the project;

    b The project can be changed to accommodate new information. For example, land costs or availability may require a change to the preferred route and consequential changes to the timing and number of steel production slots; and c Much of the uncertainty surrounding the construction costs can be resolved prior to having to lock in financing, reducing the cost of those funds.

77. There would seem to be two possible approaches to the timing of contestability:

a The contestability 'auction' could be conducted at the outset of the project. Under this approach, firm bids would be made for the entire project prior to any preparatory work. Presumably, bids would differ not just in terms of cost, but also route, timing, and specification/quality. Under this approach, there would be no efficiency benefits from the staged implementation of the project. Finance would be required to enable financial close prior to any preparatory work being done, and the successful bidder would be required to deliver a completed project even if costs turned out to materially exceed expectations. This risk would need to be priced into any bid.

b The alternative is to run a contestability 'auction' for one or more stages of the project, rather than for the entire project. But there are two problems with this approach:

i It would not seem to be commercially viable for one party (e.g., the incumbent TNSP) to perform the initial preparatory work such as project design and specification, route selection and land purchasing, and booking steel production slots and then have to transfer this work to a different entity (e.g., another TNSP or a financial sponsor) that had been awarded the next stage of the project. That preparatory work is likely to contain information that is commercially sensitive such that it is not clear that it could be feasibly transferred to a competitor. Moreover, the entity undertaking the preparatory work is likely to perform that work in a different way if there is a risk that it will have to be transferred to a competitor entity. Such a 'baton-passing' approach may also create an environment that is open to legal disputes. For these reasons, it seems unlikely that large and complex multi-stage transmission projects could be separated into stages with the ownership of the project passing to different entities as each stage is completed.

ii To the extent that it is possible to separately contract each stage of the process, we understand that incumbent TNSPs are already doing that. For example, we are aware that TransGrid runs competitive processes for steel production and for construction work, while maintaining ownership and overall control of the project from start to finish. This approach achieves the benefits of the competitive tendering process, without incurring the costs (or infeasibility) of project ownership and control passing from one entity to another.

78. The second consideration is whether bidders are free to propose alternative routes, designs and specifications. Presumably all bidders would have to perform all of this preparatory work as it would be infeasible for one bidder to perform that work and for it to be then made public as the basis for bidding on the project. Potential bidders would then have to consider whether to incur the cost of performing this work, and any other preparatory work required to construct a bid, when there is some chance that their bid may be unsuccessful. In some jurisdictions, and particularly in the context of public private partnerships, this issue has led to all bidders being paid the reasonable costs of preparing a bid. In the case at hand, this would involve consumers paying several times for the same preparatory bid work. This would not seem to be an efficient outcome for consumers.

79. A third consideration is the elements of the regulatory allowance that are open to submission as part of the contestability process. Presumably, bidders would be free to propose different combinations of:

a Regulated asset base (RAB);

b Allowed return (WACC); and

c Timing of cash flows (depreciation schedule).

80. Different bidders are likely to propose different combinations of these inputs. For example, one bidder may be willing to accept a lower rate of return than another bidder, but require accelerated cash flows via the depreciation schedule.

81. It is not clear how a decision-maker would trade off different approaches to these different financial elements.

82. It is also unclear how a decision-maker would trade off financial elements against different design specifications and different track records and evidence of capability of delivering the project.

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30 September 2021
TransGrid

Financeability Duty for Transmission Assets

Evidence from other jurisdictions

Table of contents

1. Executive Summary

1.1 FTI Consulting ("**FTI**") has been engaged by TransGrid to describe the financeability duty of regulators in regulated markets in response to the Australian Energy Market Commission ("**AEMC**")'s Transmission Planning and Investment Review. We understand this review aims to identify issues with the existing regulatory framework in relation to the timely and efficient delivery of major transmission assets, explore options to improve the framework, and recommend possible changes to these frameworks.

1.2 In this report we discuss the financeability duty observed for regulators in other jurisdictions. In particular, we draw on precedent from Great Britain ("**GB**") and the GB energy regulator ("**Ofgem**"). We explore how regulators have approached complying with their financeability duty and the benefits of having a financeability duty as part of this report.

1.3 Currently, the AER does not have a duty to consider the financeability of the companies that it regulates and therefore does not explicitly need to consider the financeability of licensees.[1] This represents one area of potential development for the Australian regulatory system.

Financeability

1.4 Financeability is often defined as the ability of an efficient company to finance its activities, including both debt and equity finance. This ability to finance activities is particularly important in regulated industries due to the need to meet licence requirements such as the particular standards of service. Fulfilling these duties often requires significant upfront expenditure. Transmission assets also have a long investment horizon due to the long-lived nature of the assets. This creates risks for investors as it will take a long time to recoup their investment.

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1 AER, Rate of return International regulatory approaches to rate of return Final working paper, December 2020, (link).

1.5 As such, regulators in several jurisdictions, including in GB, have a financeability duty.[2] For instance, GB's energy regulator, Ofgem, is required to consider the licensees ability to finance their activities in an efficient and economic manner in order to protect the interests of existing and future customers. Ofgem interprets this duty by requiring each licensee to maintain an investment grade credit rating. Therefore, when setting the allowed revenue for a regulated business, Ofgem assesses whether, for a notional company, each licence holder will be able to achieve and maintain an investment grade credit rating during the price control period.

1.6 Licensees also have a financeability duty, which requires the regulated business to maintain an investment grade credit rating. This ensures licensees do not take excessive risks with their capital structure.

1.7 The GB financeability duty has benefits for both consumers and companies, as it lowers financing costs for licensees which in turn reduces consumer bills due to a lower required rate of return. It also ensures licensees can attract the required capital to provide improved service for consumers, thus protecting consumer interests. Measures to improve the financeability of a licence holder often increase consumer bills, and therefore the magnitude of the bill impact must be balanced with the improvements to financeability of the licensee.

2 Regulators in the United States of America also have a financeability duty but it is often referred to as 'financial integrity'.

1.8 Ofgem and other regulators have several regulatory levers to improve the financeability of licensees when required. These include:

- **increasing the weighted average cost of capital ('WACC'):** this increases the amount of profits and cash the licensee has, which allows the company to meet its debt obligations with more headroom;
- **increasing the proportion of index-linked debt**: this reduces the immediate cash interest expense, improving credit metrics that differentiate between non-cash and cash interest expense;
- **decreasing notional gearing**: this reduces the amount of debt issued by the notional company, which in turn reduces the interest expense;
- **lowering the capitalisation rate:** in a total expenditure framework,[3] this increases the proportion of expenditure received today, increasing the licensee's cash flows enabling it to meet its debt obligations with more headroom; and
- **shortening total asset lives:** this depreciates the RAV more quickly, increasing the cash flow of the licensee and enabling it to meet its debt obligations with more headroom.

1.9 These levers have an impact on both financeability and consumer bills, and the relative scale of this impact influences a regulator's decision when selecting which is the most appropriate regulatory parameters to adjust to ensure the financeability obligations are met. We summarise the impact of each lever in Figure 1-1 below.

1.10 Not all of these regulatory levers are available in the Australian regulatory system due to the difference between the GB and Australian regulatory frameworks. For example, increasing the proportion of index-linked debt and lowering the capitalisation rate are not possible under the Australian framework as the it does not use a total expenditure framework and does not consider the split between different types of debt.

[3] GB regulators use a total expenditure or "Totex" framework for setting cost allowances i.e. it does not differentiate between operating and capital expenditures. We understand that the AER does not use a Totex framework which is likely to limit the ability of the AER to use this lever to solve financeability constraints.

Figure 1-1: Impact of each lever on financeability and customer bills

Lever	Impact on financeability	Impact on customer bills
Increase the WACC	Permanent solution to increase financeability.	Increase in customer bills.
Increase proportion of CPIH index-linked debt	Permanent solution to increase financeability.	No impact on customer bills.
Decrease notional gearing	Permanent solution to increase financeability.	Increase in customer bills due to increase in tax.
Decrease the capitalisation rate	? Not seen as credit positive by credit rating agencies.	Increase due to more costs recovered immediately.*
Shorten total asset lives	? Not seen as credit positive by credit rating agencies.	Increase in customer bills due to increase in revenue.*

Source: FTI analysis
*Note: * The increase in customer bills is in the short-term with a reduction in the long-term due to the acceleration of the recovery of revenue. Some credit rating agencies adjust credit metrics to reflect the underlying economics of the business e.g. useful economic lives of assets and actual cost structure. Therefore, companies have informed Ofgem that these measures do not improve financeability. However, Ofgem has not accepted this as they believe this is an oversimplification as some ratings agencies, lenders and market participants have conflicting views on whether they improve credit quality (link).*

Implications for assessing financeability in Australia

1.11 This report demonstrates that it may be beneficial for both consumers and TransGrid, along with other potential licensees, for the AER to have a financeability duty. This will ensure that consumers bills are minimised through lower financing costs and allow licensees to access finance at competitive rates.

1.12 As such, implementing a financeability duty would allow TranGrid and other transmission operators to deliver the Integrated System Plan ("**ISP**") projects to the requested scope as per the agreed timeline. This would allow customers to benefit from the projects earlier and at a lower cost.

1.13 We recommend the AEMC to implement a similar financeability framework to the one used in GB for the Australian regulatory system. This would involve using the Moody's framework for estimating credit ratings with the addition of equity metrics such as dividend yield to ensure sufficient return for equity investors. This would ensure the Australian regulatory system follows regulatory best practice adopted in other jurisdictions.

1.14 Additionally, we have described how GB regulators have solved financeability constraints historically. We note that recent determinations in GB have focused on increasing the allowed cost of capital to solve financeability constraints. The impact of this and other levers is to increase the cash flow that a company has to finance its debt and provide an adequate return to shareholders.

1.15 We have evaluated the AEMC's position that equity investors could be relied on to maintain an investment grade credit rating. In our view, the AEMC should consider the cost of this action against other possible levers which could be used to solve financeability constraints, namely increasing the allowed WACC. Additionally, the AEMC should ensure that all the costs incurred due to any changes in financial assumptions e.g. equity issuance costs are reflected in the revenue allowance of companies.

2. Introduction

Background

2.1 The Integrated System Plan ("**ISP**") is a roadmap for the development of the Australian National Electricity Market ("**NEM**") over the next decade. It is aimed at maximising value for customers by providing a reliable and sustainable energy system at an acceptable risk level and lowest cost. TransGrid is responsible for financing and setting up a share of the projects under the ISP, including Project EnergyConnect and HumeLink.

2.2 We understand that TransGrid submitted a request for a change in the financeability rules in October 2020, in the form of participation derogation, to allow for the financing of TransGrid's share of the ISP projects. Specifically, TransGrid requested the following changes:

- Remove indexation of the regulatory asset base; and
- require that depreciation is calculated on capex 'as incurred' and not 'as commissioned'.

2.3 Under the current regulatory framework, returns are assessed in conjunction with the regulatory and commercial risks borne by a hypothetical efficient firm, known as the notional firm. The revenue model under this framework combines this nominal rate of return and the indexed RAB to account for inflation.

2.4 The Australian Energy Regulator ("**AER**") reflects this by applying a negative revenue adjustment to the maximum allowed revenue ("**MAR**"), in order to prevent double compensation of inflation. This allows the network providers to receive a real rate of return instead of a nominal rate of return. Further, under the current regulatory regime, depreciation is recovered when an asset is commissioned.

2.5 Following the receipt of TransGrid's submission for rule change, the Commission triggered the standard rule change progress under an accelerated timeline.

2.6 We understand TransGrid raised this rule change as the AER does not have a duty to consider the financeability of the companies that it regulates and therefore does not explicitly need to consider the financeability of licensees.[4] This represents one area of potential development for the Australian regulatory system.

2.7 In April 2021, the Australian Energy Market Commission ("**AEMC**") denied this request. The Commission does not consider the current financeability framework a barrier to the financing of these projects, as they expect TransGrid to be able to finance such projects through the issuance of new equity.

2.8 Following this request, AEMC has now opened the Transmission Planning and Investment Review. This review aims to identify issues with the existing regulatory framework for the delivery of major new transmission assets, explore options to improve the framework, and make recommendations for changes to these frameworks. This includes the potential for financeability challenges in the delivery of major transmission projects under the current Australian regulatory framework.

Contents of report

2.9 FTI Consulting ("**FTI**") has been engaged by TransGrid to describe the financeability duty of regulators in regulated markets in response to the Australian Energy Market Commission ("**AEMC**")'s Transmission Planning and Investment Review.

2.10 In this report we discuss the financeability duty observed for regulators in other jurisdictions. In particular, we draw on precedent from Great Britain ("**GB**") and the GB energy regulator ("**Ofgem**"). We explore how GB regulators have approached complying with their financeability duty and the benefits of having a financeability duty.

Restrictions

2.11 This report has been prepared solely for the benefit of TransGrid for the purpose described in this introduction.

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4 AER, Rate of return International regulatory approaches to rate of return Final working paper, December 2020, (link).

2.12 FTI Consulting accepts no liability or duty of care to any person other than TransGrid for the content of the report and disclaims all responsibility for the consequences of any person other than TransGrid acting or refraining to act in reliance on the report or for any decisions made or not made which are based upon the report.

Limitations to the scope of our work

2.13 This report contains information obtained or derived from a variety of sources. FTI Consulting has not sought to establish the reliability of those sources or verified the information provided.

2.14 No representation or warranty of any kind (whether express or implied) is given by FTI Consulting to any person (except to TransGrid under the relevant terms of our engagement) as to the accuracy or completeness of this report.

2.15 This report is based on information available to FTI Consulting at the time of writing of the report and does not take into account any new information which becomes known to us after the date of the report. We accept no responsibility for updating the report or informing any recipient of the report of any such new information.

2.16 This report covers (in order):

- the financeability duty for the GB energy regulator and its interpretation;
- why financeability matters;
- financeability in practice;
- levers available to solve financeability constraints;
- AEMC’s choice of lever to solve financeability constraints; and
- concludes with recommendations for the Australian regulatory system.

3. Financeability duty in other jurisdictions

3.1 Financeability is often defined as the ability of an efficient company to finance its activities.[5] In certain jurisdictions, such as GB, regulators are required to ensure the companies or licensees regulated by the regulator are financeable.

The financeability duty in GB

3.2 Several regulators in GB have a financeability duty, including the GB energy regulator, the Office of Gas and Electricity Markets ("**Ofgem**"). Ofgem is required to consider the licensees ability to finance their activities in an efficient and economic manner in order to protect the interests of existing and future customers.

3.3 Ofgem typically interprets an 'efficient' financing of activities to be consistent with the licence holder being able to achieve and maintain an investment grade credit rating (the minimum investment grade credit rating is defined as either Baa3 for Moody's or BBB- for S&P and Fitch). We note licensees also have a financeability duty, which requires licensees to achieve an investment grade credit rating. This ensures that licensees can obtain financing at lower rates and can pass through these lower costs of financing to consumers in the form of lower bills.[6]

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5 Ofwat, Financeability and financing the asset base – a discussion paper, November 2015, (link).

6 For example, the yield on 20-year USD BB and 20-year USD BBB corporate debt differs by more than 300bp (according to data from Capital IQ), despite only being one credit rating apart. It may be cheaper for consumers to increase the allowed return on equity by up to 300bp (assuming notional gearing is greater than 50%) if this ensures the licensee is financeable. We illustrate this through the following example, assuming the cost of non-investment grade debt is 500bp with notional gearing of 60% and allowed cost of equity is 300bp. This gives a cost of capital of 420bp i.e. 60% × 500bp + 40% × 300bp. If we assume an allowed cost of equity of 600bp is consistent with an investment grade credit rating and investment grade cost of debt of 200bp i.e. 300bp lower. Then the cost of capital falls to 360bp i.e. 60% × 200bp + 40% × 600bp. Which is lower than if the company had a non-investment grade credit rating.

3.4 There is some discretion with what level of an investment grade credit rating to target by the regulator, and Ofgem typically seeks to maintain at least one 'notch' of headroom above the minimum investment grade level.[7]

Why does financeability matter?

3.5 A financeability duty is beneficial for both consumers and companies as ensuring an efficient company can achieve an investment-grade credit rating has positive impacts on the cost of financing for regulated entities.

3.6 Firstly, investment grade debt is over 300bp cheaper than non-investment grade debt for 20-year USD denominated corporate bonds, based on data from Capital IQ. Additionally, having an investment grade credit rating will reduce the cost of equity financing for companies. This further reduces the cost of capital for regulated entities.

3.7 Second, having a financeability duty also provides a commitment to investors they will be able to earn a sufficient rate of return. This commitment increases the certainty of returns for investors and can further lower the cost of capital for regulated entities.

3.8 This commitment is important for investors in long-lived assets, such as transmission assets, where the investment horizon is typically longer than it is for other assets.[8] Longer time horizons increase the risk for investors due to the time it takes to recoup investment. Therefore, this commitment further aides companies with attracting capital to fulfil their license obligations, allowing them to make timely investments that would benefit consumers through improved service.

3.9 Therefore, the financeability duty has two positive impacts: lower cost of financing and higher quality of service. The lower cost of financing has a direct impact on consumer bills as the regulator can pass on the cost financing savings by setting a lower cost of capital than if there was no financeability duty. The higher quality of service is likely to result in greater consumer benefits in the form of lower loss load and enabling the decarbonisation of the Australian economy.

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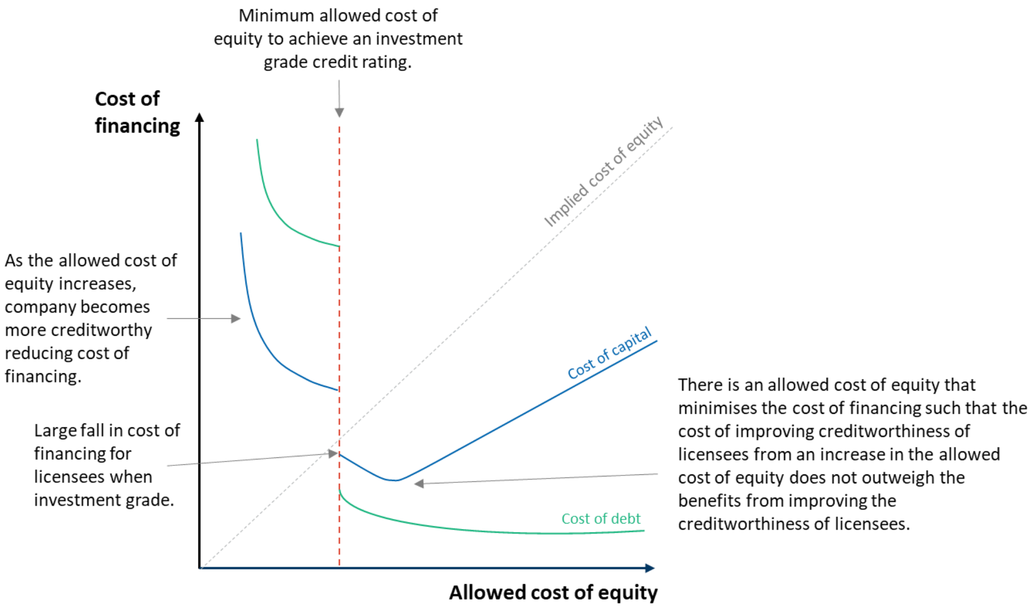
7 Each credit rating contains three levels of notches e.g. BBB-, BBB and BBB+. The minimum investment credit rating is BBB-. Therefore, Ofgem target a credit rating of BBB.

8 For example, the regulatory assets lives for some assets in TransGrid's asset base are 40 years. This means it takes 40 years for the cost of these assets to be fully recovered through allowed depreciation. This long recovery period creates risk for investors.

3.10 When undertaking its financeability duty, a regulator will need to decide on the level of financeability it wishes to achieve. This could be measured in the form of the credit rating the company could achieve. That is, the regulator could target a high investment grade credit rating or the minimum investment grade credit rating.

3.11 The cost of achieving a higher investment grade may be not be worth it for consumers due to the level of return required to achieve improvements in creditworthiness. Therefore, there may be an optimal level of allowed return for consumers in terms of ensuring licensees are able to achieve an investment grade credit rating and minimise financing costs but do not overpay for services received. We illustrate this in Figure 3-1 below.

Figure 3-1: Impact of allowed return on equity on cost of financing



Source: FTI analysis
Note: The Figure above is illustrative. We assume a constant notional gearing and that the allowed cost of equity equals the implied cost of equity.

3.12 As shown in Figure 3-1, when the allowed cost of equity is set very low, the limited headroom on debt costs can result in the regulated company no longer being considered investment grade. In turn, this means the cost of financing (which represents the cost of capital) is higher than if the company was investment grade. This is due to non-investment grade debt being significantly more expensive than investment grade debt.

3.13 Once an investment grade rating is achieved, the regulated company's cost of financing continues to fall initially, as when the company is close to being non-investment grade, it's cost of debt will reflect the yield on both investment grade and non-investment grade debt to some extent.[9] Once the company is comfortably investment grade, the cost of additional creditworthiness provided by increases in the allowed cost of equity (e.g. higher bills for consumers) is more than the benefits provided by the improvements in creditworthiness (e.g. lower cost of debt).

3.14 This example illustrates that it can be beneficial for consumers for the regulator to ensure licensees are able to achieve an investment grade credit rating. This is because it ensures financing costs are minimised, which in turn lowers consumer bills.

3.15 Regulators use their discretion to determine optimal credit rating by trading off the costs of providing additional creditworthiness through a higher allowed cost of equity with the benefits of a reduced cost of debt. Ofgem has historically believed a minimum threshold of Baa2 or BBB is consistent with this level. However, we note that in its notional financeability assessment for the recent RIIO-2 price control, the lowest indicative credit rating for a licensee was Baa1 or BBB+. This implies Ofgem targets a credit rating above its minimum threshold.

Financeability in practice

3.16 Ofgem assesses financeability using a 'notional company', which reflects the regulator's view on how an efficient licence holder finances its activities and is informed by the licence holders themselves. Ofgem typically assumes zero outperformance by the notional company. The use of a notional company allows the regulator to control for the heterogeneity that may be observed across the sector in terms of capital structures. It is important that the notional company broadly reflects the licensees so as to adequately represent the challenges faced by the licensees.

[9] For example, if a company is rated BBB-/Baa3 or the minimum credit rating for an investment grade credit rating, then investors will price the company's debt based on the probability of the company becoming non-investment grade and will require an additional risk premium (in the form of higher yield) in return for bearing this risk.

3.17 Licence holders are free to finance themselves differently from the notional company. It is important to note when constructing the notional company or assessing whether it has satisfied its financeability duty, regulators will only consider the capital structures of licensees and ignore other companies in the group structure e.g. holding companies, which are outside the regulatory ringfence. This is because GB regulators only have a duty of financeability to the licence holder e.g. the operating company and not to the group itself.

3.18 Ofgem conducts its financeability assessment 'in the round'[10] using Moody's criteria for assessing each metric. This is due to the transparency associated with Moody's criteria.[11] Unlike credit rating agencies, who focus on debt financeability or creditworthiness, Ofgem also considers equity metrics such as dividend yield. Common metrics when assessing a licensees financeability are:

[10] An 'in-the round' assessment of credit metrics means that as long as the overall company is investment grade, Ofgem and credit rating agencies will allow some credit metrics to be below investment grade. For instance, in RIIO-T2/GD2 (the gas distribution and transmission price control period expected to start in April 2021), we observe that all companies are projected to have an AICR above the investment grade threshold of 1.4x for the base case scenario. However, for FFO/Net debt, all gas companies are projected to be under the 11% threshold at the beginning of RIIO-2.

[11] Ofgem, RIIO-2 Final Determination: Finance Annex, 3 February 2021, (link).

- Funds from operations (FFO) / Net debt[12];
- Adjusted interest coverage ratio (AICR)[13];
- Gearing (Net debt / RAV)[14]; and
- Dividend yield.[15]

3.19 When determining the overall allowed revenue in a forthcoming price control period, Ofgem assesses whether each notional company will be financeable under different scenarios.[16] If the company is not financeable under most of these scenarios, Ofgem will amend the regulatory settlement to ensure the licence holder is financeable. This will typically involve increasing the cash flow the company receives in order to meet its debt payments.

3.20 Financeability tests such as these allow the regulator to ensure that the network companies are able to raise the required capital for investments at lowest possible cost, which directly impacts both consumer bills and the quality of service received by consumers.

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12 This metric assesses a company's ability to generate the required cash flows to cover future debt repayments. The higher the FFO / Net debt, the more creditworthy the company is, all else equal.

13 Adjusted Interest Coverage Ratio ("**AICR**") assesses a company's ability to pay interest on its outstanding debt. This ratio is adjusted to account for factors such as regulatory depreciation, the timing of cost recovery (i.e. proportion allocated to 'fast money') and other such factors that would affect the cash flow profile and thus the company's ability to cover the interest on outstanding debt. The higher the AICR, the more creditworthy the company is, all else equal.

14 In regulation, notional gearing is an input and not an output like the other metrics, and therefore can be influenced by the regulator directly. This can help to improve the creditworthiness of the licensee directly.

15 Ofgem set a dividend yield of 3% for the RIIO-2 price control. This was based on the dividend yield for the FTSE 100 Index. This is designed to replicate what an investor would earn on its investment if it were to invest in another non-regulated company. See Ofgem, RIIO-2 Final Determination: Finance Annex, 3 February 2021, (link).

16 These scenarios include sensitivities on expenditure and interest rates. Greater detail on these scenarios is provided in the Finance Annex of Ofgem's RIIO-ED2 sector specific methodology decision. This can be located here.

3.21 We believe a financeability framework similar to the GB one could be implemented in Australia. This would involve the AEMC implementing framework for the AER to follow as part of the regulatory system in Australia. This framework would involve undertaking an in-the-round assessment calculating both debt and equity metrics to ensuring the notional company would be able to achieve and maintain an investment grade credit rating. We believe having a financeability duty is consistent with best practice regulation.

3.22 We discuss how Ofgem and other regulators would adjust the price control determination to ensure the licence holder is financeable below.

Levers to improve financeability

3.23 Ofgem and other regulators have several levers to improve the financeability of licensees if its initial regulatory settlement is not financeable. The majority of these levers are 'NPV-neutral' i.e. they do not result in an increase in the value of the notional company to consumers. However NPV-positive levers can also be used to improve financeability. The levers available to regulators are as follows:

- **increasing the WACC:** this increases the amount of profits and cash the licensee has, which allows the company to meet its debt obligations with more headroom;
- **increasing the proportion of index-linked debt**: this reduces the immediate cash interest expense, improving credit metrics which differentiate between non-cash and cash interest expense;
- **decreasing notional gearing:** this reduces the amount of debt issued by the notional company, which in turn reduces the interest expense;[17]
- **lowering the capitalisation rate:** in a total expenditure framework,[18] this increases the proportion of expenditure received today, increasing the licensee's cash flows enabling it to meet its debt obligations with more headroom; and
- **shortening total asset lives:** this depreciates the RAV quicker, increasing the cash flow of the licensee and enabling it to meet its debt obligations with more headroom.

3.24 We discuss all five levers in detail in Appendix 1. Not all of these regulatory levers are available in the Australian regulatory system due to the difference between the GB and Australian regulatory frameworks. For example, increasing the proportion of index-linked debt and lowering the capitalisation rate are not possible in Australia as the regulatory framework does not use a total expenditure framework and does not consider the split between different types of debt.

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17 If Ofgem and other regulators assume a change in the level of notional gearing then they include an allowance for the transaction costs incurred with issuing new equity. Ofgem assume transaction costs equal to 5% of the face value of any equity issued. For example, if equity of £100m is issued then Ofgem would include an allowance of £5m i.e. 5% × £100m. Ofgem will also include an allowance for rebalancing the capital structure if the gearing of the notional company is projected to exceed the notional gearing assumption by more than 2.5% during the price control.

Choosing the appropriate lever

3.25 Regulators such as Ofgem have a primary duty to safeguard consumer interests and one way in which they do this is to ensure energy bills are affordable for both current and future consumers, while being commensurate with the service received. As such, the choice of financeability lever is influenced by the potential impact on consumer bills.

3.26 However, financeability takes priority over lower consumer bills, as the financeability duty is a specified duty that Ofgem has to meet. Whereas, lowering consumer bills is a secondary priority for Ofgem.

3.27 Several factors can influence a regulator's decision when balancing customer bills and improvements in creditworthiness, including macroeconomic factors. For example, regulatory levers such as shortening total asset lives or the proportion of costs which are capitalised (known as the 'capitalisation rate' in a total expenditure framework), can impact the financial metrics of the licence holders.[19] However, Moody's, along with credit rating agencies, and Ofgem remove the impact of regulatory levers on certain credit metrics such as AICR (which is not affected by capitalisation rates and length of asset lives) when assessing creditworthiness.

3.28 This is because certain regulatory levers involve the acceleration of cash flows from the future which will harm companies in future price controls (albeit to the benefit of the current price control). Credit rating agencies take account of this by removing the impact of regulatory levers. Therefore, credit rating agencies do not consider adjustments which over accelerate revenues to be credit positive. We note the GB water regulator, Ofwat, take a different approach and include the impact from regulatory levers as it prefers to reflect the actual cash received by companies.

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18 GB regulators use a total expenditure or "Totex" framework for setting cost allowances i.e. it does not differentiate between operating and capital expenditures. We understand that the AER does not use a Totex framework which may limit the ability of the AER to use this lever to solve financeability constraints.

19 In the gas sector in GB, depreciation is not calculated using straight-line depreciation as is the case for most regulatory frameworks, instead adopting a 'sum-of-the-year's' depreciation policy. This results in higher depreciation expense in earlier years and lower in later years. The impact of this policy is to improve cash flows in the short-term when the asset is being constructed. This can aide financeability in the short-term during the construction phase when cash constraints are highest for assets. We understand rating agencies are open to this depreciation policy but are more concerned when the assumed regulatory asset lives are less than the useful economic life of the asset.

3.29 Macroeconomic factors such as the current low interest rate environment, which is projected to continue for the foreseeable future, means the allowed return is below the social time preference rate (i.e. society's discount rate as determined by the government) in GB. This is the same in Australia, with the discount rate used as part of the RIT-T, 5.5%, being higher than the real WACC allowed for TransGrid as part of its latest determination, 4.6%.[20] This suggests consumers would prefer to pay later, not sooner and this preference may mean regulators look to defer bill increases into the future.

3.30 Another macroeconomic factor which can influence a regulator's decision is the growth in the general economy, for example if the wider economy is in recession and has low growth in real incomes, the regulator may look to maintain affordability of bills through lower customer bills. However, as stated previously, regulators will always need to prioritise financeability over the affordability of bills.

3.31 We summarise the impacts of each lever on financeability and customer bills in Figure 3-2 below.

Figure 3-2: Impact of each lever on financeability and customer bills

Lever	Impact on financeability	Impact on customer bills
Increase the WACC	Permanent solution to increase financeability.	Increase in customer bills.
Increase proportion of CPIH index-linked debt	Permanent solution to increase financeability.	No impact on customer bills.
Decrease notional gearing	Permanent solution to increase financeability.	Increase in customer bills due to increase in tax.
Decrease the capitalisation rate	Not seen as credit positive by credit rating agencies.	Increase due to more costs recovered immediately.*
Shorten total asset lives	Not seen as credit positive by credit rating agencies.	Increase in customer bills due to increase in revenue.*

Source: FTI analysis

20 AEMO , 2021 Inputs, Assumptions and Scenarios Report, July 2021, (link) and AER , Final Decision TransGrid transmission determination 2018 to 2023, May 2018, (link).

Note: The increase in customer bills is in the short-term with a reduction in the long-term due to the acceleration of the recovery of revenue. Some credit rating agencies adjust credit metrics to reflect the underlying economics of the business e.g. useful economic lives of assets and actual cost structure. Therefore, companies have informed Ofgem that these measures do not improve financeability. However, Ofgem has not accepted this as they believe this is an oversimplification as some ratings agencies, lenders and market participants have conflicting views on whether they improve credit quality (link).

3.32 With regards to ensuring creditworthiness of licence holders, of the five levers cited above, regulators often prioritise the latter four options as they are 'NPV-neutral' i.e. do not change the value of the notional company to consumers. Other regulators may disagree with this preference. For instance, the Competition and Markets Authority ("**CMA**")[21] believes that NPV-positive solutions can be cheaper than NPV-neutral solutions for consumers, while also achieving real creditworthiness improvements.[22] The CMA acknowledges that levers such as capitalisation rate and depreciation do not improve creditworthiness in credit rating agencies' opinions. Regardless of the choice of lever or levers, the purpose of most of these levers is to try and increase the cash flows the company receives in order to service it debt and provide an adequate rate of return to shareholders.

3.33 There is also disagreement among GB regulators on whether financeability is a cross-check on the allowed cost of capital, which also impacts the choice of financeability lever used by regulators. For example, Ofgem say the financeability assessment can reflect historic market rates while the cost of capital estimation, in particular the cost of equity, reflects market rates.[23] The CMA disagree with this, citing that the Capital Asset Pricing Model (CAPM) can result in estimates that are inconsistent with an investment grade credit rating.[24]

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[21] In the GB regulatory system, licence holders are able to appeal their final determination to the CMA. This means the CMA is essentially the arbitrator in the GB regulatory system and provides the final view on regulatory settlements. Therefore, a lot of attention is devoted to the precedent from CMA decisions when GB regulators set its respective regulatory settlements.

[22] CMA, Water Redeterminations 2020; Choosing a point estimate for the Cost of Capital – Working paper, January 2021 (link).

[23] Ofgem, RIIO-2 Final Determination: Finance Annex, 3 February 2021, (link).

[24] CMA, Water Redeterminations 2020; Choosing a point estimate for the Cost of Capital – Working paper, January 2021 (link).

Case study: Financeability of Scottish transmission companies during RIIO-T1

In RIIO-T1 (covering the period 2013-21), SHE-T and SPTL (both Scottish transmission networks) proposed to increase their RAVs by over 200% and 70% respectively, which presented a challenge with respect to financeability due to the cash required to fund the RAV expansion. As a result, Ofgem utilised multiple levers (as detailed below in Figure 3-3) to ensure both companies remained financeable and able to fulfil their licence obligations.

Figure 3-3: Adjustments to the SHE-T and SPTL determinations to ensure financeability

	English and Welsh transmission company	Scottish transmission companies
1 Higher asset beta	National Grid Electricity Transmission's asset beta was set at 0.38.	SHE-T and SPTL's asset beta was set at 0.43. This was to reflect the higher capital intensity, which increases a company's exposure to systematic risk, all else equal.
2 Bespoke debt index	The allowed cost of debt was set using a simple (i.e. unweighted) 10-year trailing average.	SHE-T was granted a different index – a RAV-weighted 10-year trailing average – to better match the profile of its planned new debt issuances.
3 Decrease notional gearing	Ofgem used a notional gearing assumption of 60% for National Grid.	For both Scottish transmission networks, notional gearing was set at 55% to aid financeability.
4 Higher depreciation	Asset lives were projected to increase from 20 to 45-years during T1/GD1 (reducing allowed depreciation costs) implemented by a smoothing mechanism over RIIO-T1/GD1.	For SHE-T, the smoothing period was lengthened, resulting in a higher allowed depreciation, compared to the other companies, aiding financeability.

Source: Ofgem, RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd, 23 April 2012, (link).

Note: Ofgem uses a non-parametric approach to setting the cost of equity for RIIO-T1 and thus the values stated above are the implied asset betas based on the published decisions.

Figure 3-3 above illustrates the suite of changes Ofgem had to make to ensure the financeability of the Scottish Transmission companies during RIIO-T1. The purpose of these changes was to increase the cash flows of the companies through a higher asset beta and depreciation while also de-risking the companies through the bespoke cost of debt index and lower notional gearing.

In RIIO-T2 (covering the period 2021-26), Ofgem also made changes to ensure the financeability of licensees, with National Grid Electricity Transmission's notional gearing being reduced to 55% from 60%.[25] This had no impact on the cost of capital as Ofgem assume the Modigliani-Miller principle holds.[26] This demonstrates that Ofgem does prioritise notional gearing as a lever, but as described previously this lever can only be utilised to the extent it reflects actual licensee capital structures.

25 As part of this change, Ofgem included an allowance for National Grid to issue more equity as part of the final determination for RIIO-2. See Ofgem, RIIO-2 Final Determination: Finance Annex, 3 February 2021, (link).

26 The Modigliani-Miller principle assumes that when there are no taxes or market frictions such as asymmetric information, there is no impact on the value of the firm or the cost of capital from changes in capital structure. Most GB regulators use a vanilla WACC to set the allowed cost of capital. The vanilla WACC compromises a post-tax cost of equity and a pre-tax cost of debt. This WACC is assumed to be unchanged with respect to gearing.

AEMC's choice of lever to solve financeability constraints

3.34 TransGrid has asked FTI to comment on AEMC's suggestion as part of the financeability of ISP projects decision, that equity investors should be relied on during periods of high capital spending to maintain its investment-grade credit rating.[27] We discuss this below.

3.35 Firstly, it should be noted that the equity raised by companies is not costless, with equity investors having a required rate of return consisting of a cash return (reflected by dividend yield) and capital appreciation (reflected by RAV growth). This reflects the fact that any equity holder would need to be compensated for investing in the company.

3.36 GB regulators have looked to reflect the required rate of return for equity investors by considered both debt and equity metrics as part of the financeability assessment. For example, Ofgem assume a dividend yield consistent with the local equity index to reflect the cash return required by equity investors. Based on the FTSE 100, this figure is 3%. In Australia, this figure would be around 4%, based on the average dividend yield for the S&P/ASX 300 index over the past five years.[28]

3.37 Ofgem maintains this dividend yield assumption even if it reduces the level of notional gearing to maintain the notional company's investment grade credit rating, as it did for National Grid Electricity Transmission as part of the latest price control.[29] This ensures that regulated companies have sufficient cash to pay a dividend consistent with a competitive company.

3.38 Ofgem even maintains this dividend yield assumption when there is high RAV growth including situations where a companies' RAV grows by over 40% per annum in real terms.[30] This illustrates that Ofgem treat the maintaining of a licensee's dividend yield as a hard constraint when undertaking the financeability assessment. This avoids the need for Ofgem to tailor the dividend yield to periods of high and low capital intensity, which creates regulatory uncertainty for investors due to increased uncertainty about the return they will receive during each price control increasing the cost of capital for companies.

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27 AEMC , Participant Derogation – Financeability of ISP projects (TransGrid), 8 April 2021, (link).

28 Based on data from CapitalIQ.

29 Ofgem, RIIO-2 Final Determination: Finance Annex, 3 February 2021, (link).

30 During RIIO-T1, SHE-T's RAV grew was projected to grow by an average of over 40% per annum in real terms. See the price control financial model here for more detail.

3.39 We note the cash constraint on the notional company of maintaining this dividend yield may be higher than if it had maintained its original level of gearing. For example, if the market cost of debt is lower than the dividend yield assumption then the cash constraint this debt places on the regulated company is lower than maintaining the dividend yield for the notional company.[31]

3.40 There are also additional costs associated with issuing more equity, such as legal and advisory fees. Ofgem include an allowance for issuance costs of 5% of the face value of any equity issued due to a change in the notional gearing assumption or if the modelled notional gearing is estimated to increase by more than 2.5% above the notional gearing assumption.[32] We believe it would be best practice to reflect issuance costs when considering any changes in the notional gearing assumption.

3.41 The impact of these provisions in the GB regulatory system is to create greater investor confidence. This allows companies to attract the required capital from global capital markets and offer a risk-adjusted rate of return comparable to other jurisdictions and sectors. This may not be the case for Australian networks and could result in an increase in the cost of capital compared to other jurisdictions which include these financeability duties.

3.42 Second, an additional issue to consider with changing the capital structure of the notional company is the impact it would have on other components on the allowed revenue formula. By lowering the level of notional gearing and holding the WACC constant, the proportion of the allowed return that is reflected by the allowed return on equity will increase, this impacts the level of post-tax profit.[33]

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31 For example, if the notional company needed to raise $100 of new capital to finance a new asset, and the market dividend yield is 4% and the market cost of debt is 3%, then if it raises this capital using 100% equity it would need to pay a dividend of $4 per annum (100 × 4%), whereas if it raise this capital by issuing debt it would need to pay a coupon of $3 per annum (100 × 3%).

32 For example, if modelled notional gearing in the price control financial model increases to 63% and notional gearing is assumed to be 60%, Ofgem would include an allowance for equity issuance costs equal to 5% times 3% (i.e. 63% – 60%) of the RAV.

33 For example, assuming a post-tax cost of equity of 5% and a pre-tax cost of debt of 2% at 60% notional gearing with a tax rate of 20%, the pre-tax cost of capital is 3.7%, i.e. (60% × 2%) + ((40% × 5%) ÷ (1 – 20%)) = 3.7%. Assuming a constant vanilla WACC irrespective of gearing, in line with Ofgem's assumption and the Modigliani-Miller proposition, and a reduction in gearing to 55%., the post-tax cost of equity is 4.67%, i.e. ((60% × 2%) + (40% × 5%)) – (55% x 2%)) ÷ 45% = 4.67%. The pre-tax WACC is therefore 3.73% i.e. (55% x 2%) + ((45% x 4.67%) ÷ (1 – 20%)).

3.43 This impacts the allowed revenue formula as regulated entities in Australia are allowed to recover efficient tax costs. Therefore, by increasing the proportion of equity financing, the tax efficiency of the regulated company reduces and the pre-tax WACC increases as a result. This increases the bills faced by consumers, all else equal.

3.44 As a result, when choosing the appropriate lever to solve financeability constraints, the AEMC and other regulators should consider the additional costs incurred by licensees which may be passed onto consumers. These costs should be evaluated against other options available to solving financeability constraints. For example, as described previously, the CMA noted that increasing the cost of capital may be cheaper and more appropriate for solving financeability constraints in the long-run, compared to measures which involve the acceleration of cash flows or the changing of capital structures.[34]

34 CMA, Water Redeterminations 2020; Choosing a point estimate for the Cost of Capital – Working paper, January 2021 (link).

4. Conclusion

4.1 In this report we have set out why adopting a financeability test as part of the Australian regulatory framework could be beneficial for both consumers and companies. These benefits include minimising consumer bills and ensuring companies can attract the required capital to finance their activities.

4.2 Additionally, we have described how regulators in GB performed their financeability duty. We consider it appropriate for the AEMC to implement a similar framework for the Australian regulatory system. This would involve using the Moody's framework for estimating credit ratings with the addition of equity metrics such as dividend yield to ensure sufficient return for equity investors. This would ensure the Australian regulatory system follows regulatory best practice.

4.3 Additionally, we have described how GB regulators have solved financeability constraints historically. We note that recent determinations in GB have focused on increasing the allowed cost of capital to solve financeability constraints. The impact of this and other levers is to increase the amount of cash flow the company has to finance its debt and provide an adequate return to shareholders.

4.4 Finally, we considered the suggestion from the AEMC that equity investors should be used to maintain an investment grade credit rating during periods of high capital intensity. We note that any proposals to solve financeability constraints should consider the cost of those actions against potential alternatives and should ensure that companies are remunerated for the costs associated with raising the required finance to undertake its activities.

Appendix 1 Levers to improve financeability

A1.1 As discussion in Section 3, regulators have several levers available to it to improve the financeability of licence holders. We discuss the potential levers and the impact on financeability in detail below.

Increasing the allowed WACC

A1.2 Increasing the allowed WACC increases the ‘allowed return’ (estimated as WACC multiplied by RAV) component of allowed revenue. This increases the profitability of the licence holder, which means more profits are able to cover the debt costs of the licence holder. Therefore, improving credit metrics and financeability. However, this will result in consumer bills increasing which may be undesirable to the regulator.

A1.3 We note that the use of this lever improves financeability in both the short and long term and is the only lever which is NPV-positive.

Increasing the proportion of index-linked debt

A1.4 The cost of debt of a company can include a cash and non-cash component if it has issued index-linked debt. Index-linked debt consists of both a cash expense through the coupon and a non-cash expense as the principal is indexed to inflation.

A1.5 Therefore, by increasing the proportion of index-linked debt issued by the notional company, the regulator can reduce the cash interest expense of the notional company today deferring this expense into the future. This results in a cosmetic increase in profit (on a cash-basis), which improves credit metrics and therefore financeability. There is no impact on the allowed revenue of the licensee or the value of the notional company i.e. it is NPV-neutral from this change.

A1.6 Assuming, the RAV of the licensee is growing, the deferring of debt expenses into the future is not problematic for the regulator. There is also a natural limit to this assumption as the proportion of index-linked debt of the notional company should be informed by the licensees themselves so as to ensure the notional company is consistent with the licensees.

Decreasing notional gearing

A1.7 Decreasing notional gearing reduces the amount of debt issued by the notional company, which in turn reduces the interest expense, all else equal. This means the credit metrics FFO / Net debt and AICR improve.

A1.8 We note Ofgem and the CMA believe the Modigliani-Miller principle holds for the notional company and therefore this lever does not affect the allowed return on capital. This means that by changing the gearing assumption, the ratio of allowed return on equity to allowed return to debt increases while the sum of allowed return on equity and debt i.e. allowed return on capital remains unchanged.

A1.9 As there is a reduction in the interest expense, the pre-tax WACC actually increases as there is less interest deducted from the revenues of the licensee, reducing the interest tax shield.[35] This means there is an increase in the tax allowance of the licensee, resulting in higher bills for consumers.[36]

A1.10 Although lowering notional gearing improves financeability in both the short and long-term and is NPV-neutral, setting the notional gearing significantly lower than the licensee's actual gearing may not be considered credible. For example, Ofgem's lower bound for notional gearing is around 55% due to wanting to reflect licensees' actual gearing. Companies are free to choose an actual gearing different to this level.

Lowering the capitalisation rate

A1.11 In GB, regulators typically use a total expenditure ('Totex') framework. This requires the regulator to specify what proportion of the expenditure is capitalised and added to the RAV. The proportion that is capitalised is called the capitalisation rate.

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35 In most jurisdictions, interest expense is tax deductible i.e. reduces the amount of taxable income. The amount of interest that is deducted from taxable income reduces the tax bill of the company by tax rate multiplied by interest expense, this is known as the interest tax shield i.e. interest tax shield = interest expense × tax rate.

36 For example, assuming a RAV of 100, and an allowed return on capital of 5% with no Opex or depreciation. The allowed return is 5 i.e. 100 × 5%. If notional gearing is 60% with a cost of debt of 3%, then the allowed post-tax return on equity is 3.2 i.e. 5 – 100 × 60% × 3%. If the corporate tax rate is 20% then the tax uplift required is 1.2× i.e. 1 ÷ (1 – corporate tax rate). If notional gearing is 50% with the same cost of debt, then the allowed post-tax return on equity is 3.5. The extra tax revenue required is 0.36, as there is an extra 0.3 of post-tax allowed return on equity times the tax uplift of 1.2 i.e. (3.5 – 3.2) × 1.2.

A1.12 By lowering the capitalisation rate, the licence holder receives a greater proportion of its expenditure today, accelerating when a company receives its revenue. This provides the company with more cash to be able to cover debt costs today. This increases consumer bills today but can result in lower bills in the future as there is lower RAV growth resulting in less depreciation and allowed return in the future. This lever is also NPV-neutral increasing its attractiveness to regulators.

A1.13 However, as described previously acceleration of cash flows from the future will harm companies in future price controls. Credit rating agencies take account of this by removing the impact of these regulatory levers when calculating credit metrics such as AICR. Therefore, credit rating agencies do not consider changes to capitalisation rate to be credit positive.

Shortening asset lives

A1.14 A key component of the allowed revenue calculation is depreciation. Regulators typically assume straight-line depreciation i.e. depreciation = RAV ÷ asset lives. By shortening asset lives, the allowed depreciation and allowed revenue increases.

A1.15 This increases the licensee's ability to cover debt costs in the short term as revenues are accelerated from the future. This increases consumer bills today but can result in lower bills in the future as there is lower RAV growth resulting in less depreciation and allowed return in the future. This lever is also NPV-neutral increasing its attractiveness to regulators.

A1.16 As with capitalisation rate, credit rating agencies do not consider the acceleration of revenues to be credit positive and remove the impact of these regulatory levers when calculating credit metrics such as AICR. This limits the ability to improve financeability through changing asset lives.