# SUBMISSION

**TRANSMISSION ACCESS REFORM - A CONSUMER PERSPECTIVE**
**EPR0073**
**19 OCTOBER 2020**

EUAA
Energy Users Association of Australia

## INTRODUCTION

The Energy Users Association of Australia (EUAA) is the peak body representing Australian commercial and industrial energy users. Our membership covers a broad cross section of the Australian economy including significant retail, manufacturing, building materials and food processing industries. Combined our members employ over 1 million Australians, pay billions in energy bills every year and in many cases are exposed to the fluctuations and challenges of international trade.

Our members are highly exposed to movements in both gas and electricity prices and have been under increasing financial stress due to escalating energy costs. These increased costs are either absorbed by the business, making it more difficult to maintain existing levels of employment or passed through to consumers in the form of increases in the prices paid for many everyday items.

The EUAA welcome this opportunity to make submission to the AEMC Transmission Access Reform Interim Report and would like to take this opportunity to recognise the extensive consultation undertaken by the AEMC over the last 18 months. The EUAA commend the AEMC on its efforts to explain this complex reform to energy users especially during a period of continuous volatility in the energy policy and regulatory landscape.

However, after consulting with a wide range of EUAA stakeholders including substantive discussion with a number of highly engaged energy users, we are of the view that the transmission access reform package as presented should not proceed. In this submission we will explain our reasons for this position and provide some views on a more equitable approach to funding Renewable Energy Zones.

## MULTIPLE STAKEHOLDERS – COMPETING AGENDAS

Transmission access reform has been a topic of debate for several years as market bodies, market participants and consumers grapple with a rapidly changing market environment. As we identify below, the focus of the debate, and therefore the desired outcome of any proposed reform, differs from stakeholder to stakeholder.

- Consumers; facing a significant increase in network costs due to the rapid transition of energy markets (and having already suffered from network "gold plating"), are looking for alternate models of cost recovery and risk allocation. We are seeking a more equitable approach where all market participants pay costs where they are beneficiaries (or where they have caused a problem) of new investment and carry risks where it is clear they are in the best position to manage them. Consumers also have growing concerns associated with stranded asset risk driven by a combination of fundamental changes in technology and consumer usage patterns and a mismatch of asset lifecycle where 50-year transmission assets are largely being built to connect generation assets with an operational life of 20 years. Under the existing method of cost recovery, consumers bear all of this stranded asset risk.
- Transmission Network Services Providers; facing a significant investment challenge driven by the rapid transition of energy markets and the emergence of the "actionable" Integrated System Plan (ISP) are looking to protect as much of their capital expenditure as possible by including all network augmentation as part of their Regulated Asset Base (RAB). As with consumers, networks too see emerging issues associated with stranded asset risk and the prospect they may be required to write off the residual value of

underutilised or stranded assets (as per recent discussion about writing down asset values post so called network "gold plating").

- New entrant generators having soaked up all available network access while making minimal financial contribution beyond their own connection assets, are looking to continue to gain access to vastly expanded network capacity while avoiding deep augmentation costs that are, in many cases, being driven by the location of new generation in weak parts of the network or where there is no network at all. To be fair, a growing number of new entrant generators are open to part or fulling funding of new transmission provided they are given appropriate, long-term access rights, which we think is a reasonable request.
- Existing generators, regardless of fuel source, are beginning to face significant constraint issues and adverse Marginal Loss Factors (MLF) associated with a transmission network straining to accept new generation in diverse locations. This situation is having a significant negative impact on the financial viability of these generators who, after careful due diligence, find their projects are now being materially impacted by poorly located new entrant generators. Arguments have been made that congestion should be a problem for equity to solve, not customers. However, experience to date points to customers continuing to pay for new transmission to relieve congestion, essentially paying to resolve problems created by others.
- AEMO, are keen to see the "actionable" ISP come to fruition. The 2020 ISP is a significant piece of work and has the support of governments who seem willing to assist actionable projects so they are built ASAP. From what we have observed, the main game of many market participants is to see congestion solved via the ISP and REZ, which means consumers will end up paying for a regulated transmission solution, which is no different to the current state.
- Governments, either through their concern regarding reliability, consumer prices or to help fulfil ambitious renewable energy targets, want to see the rapid roll-out of new transmission assets. The ISP provides a viable vehicle for this, hence their support. Beyond the ISP we see "independent" action being taken by state governments to relieve congestion where it has occurred, even going so far as to avoid the RIT-T framework and proper scrutiny by the AER.

Unfortunately for consumers (and the AEMC), many of these agendas compete directly with the proposed transmission access reform package. Consumers see the real danger that even if these reforms are implemented they become largely irrelevant and modelled benefits evaporate. Our reality is that we do not see the actions of other stakeholders subsiding, if anything we see these actions increasing over time.

We recognise that attempting to model long-term net benefits in this environment would be like trying to nail jelly to a wall whilst the wall is moving. It must be a near impossible task which also means the results of such modelling must be treated with extreme caution. We provide specific member feedback regarding the modelling later in this submission.

In this environment, genuine sharing of risks and cost across a broad group of market participants is not only warranted but essential.

## WHAT WE WANTED FROM ACCESS REFROM AND WHY THE CURRENT PACKAGE DOESN'T DELIVER.

In earlier discussion papers we are heartened to see the AEMC recognise that the existing access and charging arrangements for transmission may no longer be fit for purpose.

> *"…the current access regime needs to evolve to allow the risk and cost of generation investment to compliment planning and investment in transmission. Building transmission to benefit generators means that generators should pay for this transmission investment."*[1]
>
> *"While generators are able to underwrite transmission investment on the shared network to reduce congestion, doing so would improve the access of all generators. Each individual generator would prefer for other generators to underwrite transmission investment, to avoid the cost of doing so while enjoying the benefits that the transmission infrastructure provides to all generators: a free-rider problem. As a consequence, a regulated, centralised approach to transmission investment has been adopted to date, which may be poorly coordinated with the market-based approach to generation investment. As generators only pay the direct costs associated with facilitating their connection, the price they face does not fully reflect locational signals, and generators do not receive any guaranteed level of access to the transmission network."* [2]

The EUAA are of the view that the current arrangements do not fully serve the long-term interests of consumers, new entrant generators or networks. For consumers, we see two key issues that needed to be addressed by the AEMC as it considered transmission access reform that sadly, the current reform package does not resolve.

Equitable Risk Allocation

In our many submissions on the transmission access reforms and in our advocacy generally we have continually pointed to the risks associated with the rapidly changing energy market and the impacts on the feasibility of a number of proposed transmission assets such as the Energy Connect project, Project Marinus and the transmission upgrade to facilitate Snowy 2.0.

Project Energy Connect, an ISP priority project, is the most current example of the risk consumers are being asked to take. Over the last 12 months we have seen the capital cost of this project escalate from the original $1.53 billion to $2.4 billion and net benefits decrease from $924 million to as low as $150 million. Aside from the project now delivering significantly lower, some may say "skinny" benefits, especially given the cost, the gas market forecasts used to drive the fuel cost savings, and therefore the benefits to consumers, are highly contested.

We also see significant changes in at either end of the interconnector, that over time could seriously undermine the expected net benefits for consumers. New generation is being committed within regions to ensure supply as is technology to address system strength, while consumer usage is changing (and will continue to change). This is not meant to be a criticism of Project Energy Connect, it may over time deliver benefits to consumers, but there may also be periods of time where it does not.

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[1] https://www.aemc.gov.au/sites/default/files/2019-03/Consultation%20paper_0.pdf
[2] https://www.aemc.gov.au/sites/default/files/2019-03/Consultation%20paper_0.pdf

Unfortunately, the current transmission access reform package does not address the issue of risk allocation in a volatile environment so consumers will be expected to absorb these risks via their monthly energy bill for decades to come.

Equitable Cost Allocation

The existing cost recovery model for regulated assets like transmission assumes that as society in general is the beneficiary of the investment that all costs should also be socialised. This is reasonable provided all benefits are socialised, which progressively they are not.

Once again, using Project Energy Connect as an example, it has been designed, in part, to facilitate significant new generation, specifically via a number of ISP identified Renewable Energy Zone. This new generation, being privately owned and operated, is set to gain significant financial benefit from this asset while consumers cover the cost associated with this access. This is a similar situation to a vast majority of ISP "actionable" projects and is certainly the case for the many REZ's identified in the ISP, which are being pursued for the sole purpose of connecting new entrant generators to the NEM.

It must be recognised that consumers have no control over where these assets are being located nor do they have any control over the financial viability or operation of these assets, but are currently expected to carry the cost, volume and technology risks associated with these decision.

We are not arguing that consumers do not benefit from most of these investments but we do argue that they are not the sole beneficiaries. We do contest that all parties who benefit from investments in new transmission should pay their fair share.

We recognise that moving to generator co-contribution could result in slightly higher contract prices (i.e. PPA's) as project proponents seek to recover these additional costs. So yes, while the customer will always pay we should not continue to be asked to absorb aspects of project risks and costs that we have no control over or be faced with paying "full weight" for underutilised assets. Further, we contend that that exposing more network costs to open markets and competition will drive better outcomes for consumers compared to a regulated environment that, despite good intentions to deliver a result that replicates a competitive market outcome, has not always proven to be so.

Therefore, we firmly believe that commercial entities should make a reasonable co-contribution to the cost and maintenance of new transmission assets, and in the case of REZ, perhaps the entire cost. This being the case we believe it entirely reasonable that new entrant generators who make a significant financial contribution should be granted firm access rights or a form of financial transmission right.

To achieve this outcome, we had hoped that a form of Optional Firm Access (OFR), working in concert with an enhanced Scale Efficient Network Extension (SENE) framework would be central to the transmission access reform agenda. Unfortunately, we do not see how the current transmission access and reform package achieves any of this.

## SPECIFIC ISSUES WITH THE CURRENT REFORM.

The following issues should be viewed in conjunction with the broader concerns already raised in this submission.

Based on discussions with key stakeholders and member companies the EUAA is concerned about the following issues regarding **Locational Marginal Pricing**:

- There is a general concern that splitting the market into numerous smaller nodes will increase risk of participation and may negatively impact levels of liquidity and contracting levels amongst counterparties. While this is not a direct issue for most consumers there are a number of large commercial and industrial customers who have some level of market exposure who remain concerned what this reform will mean to their current and future contract position. The primary concern amongst many stakeholders is it will increase risks for market participants who lose the benefits associated with running a diversified portfolio of assets, the cost of which will ultimately be passed through to consumers.
- Large commercial and industrial energy users with long-term contacts (i.e. PPA's) may end up facing the local price instead of the reference price if the contract term extends beyond the proposed 2025 start date. Some continue to express concerns that they may find themselves also paying for the generator's costs associated with purchasing FTR's.
- The complexity of electricity contracting market and the financial relationships between market participants and energy users should require that the AEMC undertake specific scenario modelling to stress test the potential financial outcomes that could occur when LMP is introduced to ensure that there are no unintended consequences that adversely impact costs paid by energy consumers. The work undertaken by NERA on behalf of the AEMC was, understandably due to the complexity involved, unable to provide much insight.
- The EUAA is also unclear what the impact to consumer energy costs may occur from moving from a Regional Reference Price (RRP) to a Volume Weighted Average Price (VWAP). A chart that appears on page 37 of the Proposed Access Model Discussion Paper seems to indicate that consumers will pay more, not less under this model. It would be useful to discuss this outcome.

Based on discussions with key stakeholders and member companies the EUAA is concerned about the following issues regarding **Firm Transmission Rights**:

- Concerns have been raised about the possibility that the costs to acquire transmission rights may not cover the total revenue received by the transmission right holders. This concern is further heightened by the proposal to access settlement residues to fund FTR pay-outs. Further discussions with AEMC has helped our understanding of this issue and we have suggested the AEMC be careful with the language they use as it is easy to give the impression that existing inter-regional settlement residues will be used rather than new intra-regional settlement residues that come about when nodal and regional reference prices separate.
- Concerns have been raised that generators in non-congested transmission areas are unlikely to be motivated to purchase transmission rights if they believe there is little benefit to obtaining them. The concern is that this may mean the introduction of transmission rights leads to a net loss that would need to be recovered from energy consumers.
- Concerns have been raised that perverse outcomes may also occur if transmission right holders are paid based only on the volume of rights purchased and that it is not linked to a generators physical dispatch. We are concerned that not linking revenues paid to transmission right holders to physical dispatch will open the

door for market participants to game purchasing transmission rights at locations where the revenues received are expected to be high leading to higher costs being passed through to energy consumers.

- Grandfathering of FTR's will be a thorny issue. EUAA would be concerned if there was a significant overallocation of FTR's and/or the grandfathering period was extensive, such that their value is virtually zero meaning future FTR auction revenue being much less than required. This would be an unsatisfactory outcome and could lead to less benefits accruing to consumers as both new and existing settlement residues may be required to cover FTR pay-out shortfalls. Grandfathering should not be seen as a permanent "risk subsidy" but a means of helping participants re-adjust their business model (i.e. debt arrangements) to deal with a changed circumstance.
- Overallocation of grandfathered FTR's to variable generators, based on capacity rather than dispatch volumes, could provide a windfall gain to those generators.
- There is also a concern regarding what circumstances or risks the FTR is meant to cover. Our view is that it should only cover additional risks associated with congestion that has arisen and not normal or existing risks that all market participants currently consider, such as a major grid outage.

Based on discussions with key stakeholders and member companies the EUAA is concerned about the following issues regarding the **Market Benefits Modelling.** There is a strong view expressed by a number of EUAA members that the modelling is fundamentally flawed and/or appears incapable of dealing with the myriad of complexity**:**

- The modelling is based on the Central ISP scenario for Dec-19, which includes DER capacity much below current actuals and very slow growth as it assumes incentives for DER are abolished after 2021. As a result, grid demand is much higher than is likely, increasing the modelled benefits.
- High oil price assumptions drive high gas prices and increase the modelled benefits. We note there is an ongoing debate about forward gas prices and recognise both the significant uncertainty of forward prices but also the sensitivity final net benefit outcomes are to it. We should also acknowledge the significant announcements made recently by Federal Government with a stated intent to drive down the cost of domestic gas prices.
- Much of the savings (net benefits) is in the last five years, when assumptions are likely to be least accurate. This is particularly problematic given the assumptions show little to no nominal decreases in renewable generation cost after 2030. In addition, given the high prices forecast there would likely be significant demand destruction at such prices, reducing the benefits even further.
- The high prices forecast (especially in the last five years) also appear inconsistent with the latest residential price index assumption for the 2020 ESOO which suggests level to decreasing residential cost of energy over the same period.
- In calculating the subsidy to generators, the model appears to assume unlimited ability for renewable generators in extracting a rent from the market to compensate for reduced capacity factors, when in actual fact these generators will have to compete to get projects developed and generators in less congested areas will be able offer PPAs at lower prices. Recent reforms to improve information provision between TNSP's and prospective generators will also assist in avoiding future congestion.
- The modelling fails to vary loss factors between the reform and no reform scenarios when increased losses (due to increased renewable generation in remote areas) should influence where generation connects.
- The model fails to properly model storage (because it is hard with many feedback loops), and inflates the cost at which it is dispatched using the LRMC, failing to recognise storage gets revenues in many markets

and needs maximise cycling over time to gain revenue given all cost is sunk. In addition, the model fails to consider portfolio benefits which can drive storage investment.

- There is no clear evidence of how the cost of "race to the floor bidding" actually flows to consumers. The report fails to acknowledge that race to the floor bidding actually reduces prices at times when constraints are resolved and prices fall. In addition, there are many reasons for race to the floor bidding including shut-down and start-up costs. In addition, much of the benefit will be lost in grandfathering of FTRs to existing generators (which doesn't appear to be recognised in the modelling).
- In terms of increased competition and as we have already discussed, the ISP will reduce the risk of price separation between regions by massively increasing transmission capacity. There are significant questions to what extent FTRs can increase competition beyond this benefit.

## ALTERNATIVE APPROACHES

While we do not believe it is the best interests of consumers to proceed with the broader reform package, we do think an opportunity exists to develop a more equitable approach to costs and risks associated with Renewable Energy Zones (REZ).

As we have stated previously, the EUAA are of the view that the risk and significant portion of the capital costs associated with the connection and operation of new transmission assets should reside with those who stand to gain significant financial benefit from them. While consumers may receive some price benefit from the operation of projects located in a REZ or from the development of a new interconnectors, given the fluctuating nature of the energy market these benefits may be fleeting at best.

In the case of REZ's and the ISP, much of this additional investment is largely driven by a need of new entrant generators to gain access to the National Electricity Market, from which they will gain significant financial benefit. In some cases, these additional investments (including interconnectors) will also help to support state and federal government policies such as the continued roll out of renewable energy and the regional economic benefits that flow.

Recognising that changing the open access regime to facilitate a shared cost arrangement has a range of challenges, an easier place to start would be with REZ's.

We believe these REZ related assets, being built specifically for new entrant generators, should be considered dedicated connection assets. We agree with the AEMC position, outlined in their April 2018 Discussion Paper, that there is little justification for the consumers to effectively subsidise new entrant generators selling into the NEM.

As the AEMC has rightfully pointed out in previous CoGaTI consultations:

> "Under the transmission framework, as amended by the TCAPA Rule from 1 July 2018, the assets associated with REZ's would most likely be considered dedicated connection assets and identified assets that are required to connect a group of generators to the shared transmission network. In other words, these

assets would be considered connection assets, providing connection services, and so would be paid for by the connecting party/is (i.e. generators)."[3]

In light of this, we offer the following alternative approaches to REZ access and charging.

Optional Firm Access

We were surprised that Optional Firm Access, or variants to it, was discarded early on in the discussion about transmission access reform. We understand it was reviewed extensively in the past and was not pursued as the need for such a reform did not seem compelling. Clearly this has changed and there is a compelling need for change, something that is recognised by the AEMC.

We see a model that would allow generators to purchase a dispatch right (or firm access) to a new REZ as a reasonable step forward. The revenue paid by the purchase of these dispatch rights would be used to offset the costs associated with the REZ. Other generators may still wish to connect into the REZ and not purchase dispatch rights but they would run the risk of being constrained. Alternatively, they may see investment in large scale storage as a better long-term strategy than purchasing a dispatch or access right.

This would change the way in which transmission and generation investment decisions are made, and would mean generators would bear the cost and risk associated with REZ investment and potentially encourage innovation in storage and dispatch. The costs associated with the purchase of these rights would be recovered from customers via a competitive market rather than a regulated pricing framework, which should always be the goal.

A further variation of the current of the above would be to apply locational marginal pricing to the REZ. This would establish sub-regional pricing but only for new REZ, not the entire market therefore avoiding the significant transitional issues being raised by stakeholders. Generators would have access to their locational marginal price (or REZ nodal price), but would also be able to purchase FTR's to manage congestion risk.

Generator Transmission Use of System Charges (GTUOS)

Currently, only customers pay TUOS and in doing so bear all the costs and risks associated with transmission augmentation. We think it would be highly beneficial to look at ways of distributing TUOS across a broader group of participants, i.e. generators.

At first this could apply to new REZ developments where new entrant generators connecting to the REZ pay a share of TUOS associated with their generation output. This could cover all or part the costs associated with the REZ.

As these GTUOS charges would make up part of the generators overall cost base, this approach would have no impact on the operation of wholesale markets and would not require any change to existing RIT-T or cost recovery approaches by TNSP's. It would also send strong price signals to new entrant generators about the overall cost and efficiency of asset location.

[3] AEMC Discussion Paper, Coordination of Generation and Transmission Investment: Page 56

GTUOS could also be applied more generally to the NEM where existing TUOS charges are divided between customers and generators who are both using the shared transmission assets. This does increase the costs for generators but would be competitively neutral given all generators are treated equally.  If existing shared networks need to be upgraded then either:

1. New entrant generators who have created the need for the transmission augmentation pay a higher GTUOS charge for a period of time (i.e. 15 years).  This avoids any issues associated with existing generators cross-subsidising new entrant generators access to the market and would be more aligned with the causer pays principle.
2. The increased GTUOS is shared across all generators.

GTUOS is a significant change to the allocation of TUOS and would increase the costs of generators, although these costs would be recovered via the wholesale electricity market.  No doubt there be transitional issues, however we do not perceive it having a material impact on the operation of wholesale markets or dispatch and will have limited impact on existing contracts.  It also likely to mean that TNSP's will maintain a risk level that facilitate attracting low cost capital and could also allow a smoother path for ISP projects to be delivered.  A GTUOS model would also allow for governments to provide direct financial assistance to transmission projects, allowing a reduction in overall TUOS charges paid by both generators and consumers.

Under GTUOS consumers will end up paying for a majority of transmission but it has the advantages of taking a large portion of the costs out of the regulated environment, where all costs and risks are borne be consumers. Therefore, a significant amount of transmission costs will be exposed to market forces meaning consumers will have more confidence in the efficiency of prices they finally pay.  It also puts some of the risks and costs directly onto generators, particularly new entrant generators, making them more responsible for the decisions they make while encouraging supply side technical and operational innovation.

Once again, we greatly appreciate the effort by the AEMC to engage with stakeholders on such a complex issue and we look forward to engaging further on new approaches to equitable cost and risk sharing.

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