SUBMISSION

AEMC COGATI ACCESS AND CHARGING – DIRECTIONS PAPER
2 AUGUST 2019

EUAA
Energy Users Association of Australia

AEMC
COGATI Implementation - Access and Charging Consultation Paper
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Via: AEMC submission portal: www.aemc.com.au

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INTRODUCTION

The Energy Users Association of Australia (EUAA) is the peak body representing Australian energy users. Our membership covers a broad cross section of the Australian economy including significant retail, manufacturing and materials processing industries. Combined our members employ over 1 million Australians, pay billions in energy bills every year and are desperate to see all parts of the energy supply chain making their contribution to the National Electricity Objective.

Our members are highly exposed to movements in both gas and electricity prices and have been under increasing 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.

We welcome the opportunity to make a submission to the Coordination of Generation and Transmission and Investment (COGATI) – Access and Charging Directions Paper. The EUAA has already made submissions to the COGATI Options Paper in October 2018 and to the COGATI Implementation – Access and Charging Consultation Paper in April 2019.

The consistent theme of these submissions has been to challenge the assumption that consumers would continue to pay the full cost for network augmentation that is required over the coming years, including these already identified in the AEMO Integrated System Plan (ISP).

The EUAA are not opposed to new network assets being built to facilitate new generation, for interconnectors to be built that allow market participants greater access to the market and to provide the market operator with improved flexibility to manage the energy system. Our concerns revolve around the assumption that a vast majority of the costs associated with these new assets will be included in the Regulated Asset Base (RAB) of the network companies involved, meaning consumers would pay the entire cost.

The COGATI process has been both challenging and informative for many stakeholders, including the EUAA and its members. With the benefit of additional information provided in the Directions Paper, with further consultation with other stakeholders and with increased urgency associated with the accelerating energy market transition, we have moved to a position where we support pursuing the reforms in the timeframe suggested in the Directions Paper.

We recognise many of the reforms suggested in the Directions Paper represent a significant change to the way the market will operate for some groups of participants and while supportive of the reforms, we acknowledge that a significant amount of work needs to be undertaken to bring them about.

In particular we would highlight the proposed start of the reforms on 1 July 2022. We recognise there is considerable work to be done for implementation. However, we also recognise that many large capital projects, particularly those in Group 2 of the ISP, may have been committed prior to that date. In the absence of a timely implementation of these reforms, the full benefit to consumers of them in terms of equitable cost and risk sharing, will be lost. While more analysis is required, this should not be used as a reason for delay by those who may see themselves as "losers" from these reforms.

In addition to answering specific questions, this submission will discuss how transitional arrangements might work to reduce the level of risk that consumers bear form these ISP proposed projects. We also comment on our preferred model for funding new transmission projects post 1 July 2022. We currently prefer the model indicated in the Directions Paper – that is, new connections would only be built if there are sufficient hedges i.e. transmission risk is with the generators. We find argument that this would result in a sub-optimal level of investment and that a more central planning approach is required as unconvincing. Central planning has a role to play but it must be recognised it has also contributed to the current inefficient RABs that consumers will be paying for, for many years to come.

In this context we recognise there are a number of alternative models to achieve this that are outside the scope of the AEMC. For example, various forms of direct government funding or direct funding by project proponents of significant transmission upgrades are being actively debated by stakeholders while we have already seen State and Federal Governments provide some initial capital to assist early stage works.

Therefore, it would be very helpful for all COGATI stakeholders, including the AEMC, to be provided with guidance from the COAG Energy Council as to the extent governments intend to take a strategic view on energy market transition and to what level of capital support they are willing to provide. Consumers are very concerned that we may be about to repeat the same mistakes of the past that will inevitably lead to consumers bearing significant stranded asset risk. We would remind COAG Energy Council that we are currently paying for past overly optimistic demand forecasts and overly aggressive reliability standards and their assistance to help avoid a repeat of this is required.

Finally, we must be conscious of the rapid technological developments that are occurring that are likely to lower costs in ways that mean less transmission interconnection is required than is currently proposed. This issue is central to the risks associated with some level of stranded asset risk.

SUMMARY OF EUAA RESPONSES

In response to a question asked on page 46 of the Directions Paper It would certainly be useful for the two proposed models to be compared to determine the most cost-effective outcome. Therefore, we would recommend that the AEMC include this option in any scenario modelling conducted as part of the COGATI reform process.

In response to Question 1 on page 51 of the Directions Paper, unsurprisingly, we prefer Option B where surplus residues are used to further reduce TUOS charges for customers. Of the three options we feel this approach is aligned to NEO objectives of the long-term interests of consumers.

In response to Question 3 on page 60 of the Directions Paper. At this point in time we are not in favour of load being exposed to locational marginal prices unless they specifically "opt in" to this exposure after due consideration to the risks, costs and benefits of doing so.

In response to Question 5 on page 65 of the Directions Paper, the EUAA are very supportive of the AEMC developing reference scenarios, some of which we have already described, so that stakeholders can better understand the impacts, cost and benefits of the proposed reforms.

In response to Question 6 on page 75 of the Directions Paper, the EUAA agree that access reform should be integrated into the AEMO ISP. With the integration of these reforms that the ISP would have a strong market signal making it easier for AEMO to develop future ISP's that reflect market participant preferences and investment plans.

In response to Recommendation 11 on page 88 of the Directions Paper, we agree with the AEMC that:

…the ESB examine the possibility of a Fund to extend transmission assets to connect to Renewable Energy Zones with the cost of this transmission progressively recovered from consumers if and when utilisation increases. The required size of the finance, the source of funds, and how funds should be recovered and managed should be part of the examination.

As we have stated previously, it may be that the risks of committing to such large, long-term investments is too great for investors and transmission providers requiring some level of state and federal government support through measures such as capital support or asset underwriting.

In response to Question 11 on Page 90 of the Directions Paper, we agree that clustering of generators that wish to connect to the network, including the grouping of connection applications, would be valuable in assisting in development of renewable energy zones.

In response to Question 12 on Page 91 of the Directions Paper, we agree that shared cost recovery models should be considered. We agree that the principles of this model, as set out below (Page 91 of the Directions Paper) represent a sound foundation. These are similar to principles put forward previously by the EUAA and developed further by the Public Interest Advocacy Centre (PIAC).

In response to Box 11: Implementation and Timing on Page 95 of the Directions Paper, the EUAA would recommend the AEMC pursue the above as an integral part of phase one.

In response to Box 12: Transitional Principles on Page 96 of the Directions Paper, the EUAA are in general agreement with the principles identified by the AEMC.

THE NEED FOR TRANSMISSION ACCESS REFORM

It is clear from the statements made on page 10 of the Directions Paper that all stakeholders would benefit from access reform:

***Generators and investors** are concerned that the current framework is no longer suitable not only for the current environment, but for a variety of futures for a lower emissions' energy power sector. In light of the electricity market transition, prospective generators require greater certainty that their assets will remain profitable even if subsequent parties connect to the network and create congestion. This is being reflected in the debate around the significant changes in annual marginal loss factors that are currently being experienced.*

*In the current climate, it is also clear that **consumers** have concerns about projected costs and increased bills in order to pay for the new transmission necessary for the transition. This is heightened by the fact that consumers bear the majority of transmission investment risk in the current framework, so are shouldered with unnecessary costs if transmission lines become 'roads to nowhere'.*

*In addition, **network businesses** have voiced their concerns about changes to their rate of return, as well as uncertainty being created by the suggestion of asset write-downs. Network businesses are also being overwhelmed by the scale of connection enquiries being lodged by prospective generators.* [1]

The EUAA agrees with the AEMC assessment that current arrangements do not fully serve the long-term interests of consumers, new entrant generators or networks. While there are undoubtedly significant issues for generators and

[1] https://www.aemc.gov.au/sites/default/files/2019-06/COGATI%20-%20directions%20paper%20-%20for%20publication_0.PDF

transmission and the efficient resolution of these issues will benefit customers through lower costs, our responses to the Directions Paper focus on the consumer issues that need to be addressed and therefore the outcomes consumers are seeking. With this in mind, for consumers, we see two key issues that need to be addressed by the AEMC as it considers transmission access reform.

Rapidly Changing Market

We would point 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.

For example. In the case of Energy Connect there are two fundamental assumptions underpinning the consumer benefits of this project being:

- That the NSW region will continue to be in a state of "oversupply", especially with the type of asset required to provide "firming" of variable generation and,
- Fuel savings that come about when 800 MW of gas fired generation retires in SA (2024) and a further 63 MW of generation fired by liquid fuels retires in 2027.

Yet according to the AEMO ISP, two NSW based coal fired assets in Liddell (in 2022) and Vales Point (2028) are assumed to retire, removing some 3,320 MW of the type of dispatchable generation that is required in both NSW and SA. The assumption that you can continue to "borrow" dispatchable power from your neighbour will be progressively undermined by this paradigm shift in the energy market.

We also note that the cost of thermal coal continues to increase. When taken together, the likelihood of New South Wales providing cheap power to South Australia has been greatly diminished and can't necessarily be relied upon into the future.

Perhaps more importantly is that the South Australian fuel replacement assumption is already under serious threat. While replacing expensive gas with cheaper resources imported from another state is a key value driver for the Energy Connect project, we note that AGL are currently constructing the 210MW gas fired Barker Inlet Power Station[2] and the Federal Government have announced that Alinta's 300MW gas fired Reeves Point Power Station is on the short list for their Underwriting New Generation Investment initiative[3].

While these new projects will be more efficient they will still rely on an expensive fuel source. Therefore, we have serious concerns that some of the key assumptions underpinning the consumer benefits of the project can't be relied upon. In a market that is changing so rapidly, to the extent that the Energy Connect business case identifies consumer benefits, they may be fleeting at best.

This is just one example of where a rapidly changing energy market could significantly impact the consumer benefit of this type of investment. Under the exiting approach, energy consumers would carry the entire risk.

Risk Allocation

In the case of the Energy Connect project, it has been "up-sized" 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. We would point to

[2] https://www.agl.com.au/about-agl/how-we-source-energy/barker-inlet
[3] https://www.energy.gov.au/government-priorities/energy-supply/underwriting-new-generation-investments-program

similar circumstances surrounding Project Marinus and the Snowy 2.0 transmission upgrade. The EUAA made a substantial submission to the AEMC COGATI process in October 2018 on this issue where we argued that a significant beneficiary of new Renewable Energy Zones and therefore of proposed assets like the Energy Connect project will be project proponents and their investors.

It must be recognised that consumers have no control over the financial viability or operation of these assets but are currently expected to carry the cost, volume and technology risks. While consumers may receive some benefit from new transmission assets, given the fluctuating nature of the energy market and the risks involved, these benefits may be fleeting at best. In any case, the principle of only paying for that benefit that is reliably received should guide future cost and risk allocation in this area. Therefore, we firmly believe these commercial entities should make a reasonable co-contribution to the cost and maintenance of these assets.

We recognise that moving to a form of 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.

REFORMING THE TRANSMISSION ACCESS FRAMEWORK

A vast majority of stakeholders agree that transmission access reform is required, that it is complex and will require careful implementation. Additionally, the reform process set out below by the AEMC is occurring concurrently with a range of additional reforms and market transformation including the ESB 2025 market reform process, significant state policies driving clean energy investment, direct federal government investment in Snowy 2.0 and Battery of the Nation, the Underwriting New Generation Investment (UNGI) program, demand response market development and the Retailer Reliability Obligation (RRO).

Table 3.1: **Proposal for access reform in 2018 COGATI review**

PHASE OF RE-FORM	OVERVIEW	PROPOSED COMMENCE-MENT
1. Dynamic regional pricing	The access arrangements would be changed to implement dynamic regions for determining the price payable to generators.	July 2022
2. Improved information	The information that is produced from dynamic regional pricing, including where congestion occurs and the costs of congestion, would be used to supplement the planning arrangements for transmission.	July 2022 to July 2023
3. Generators fund transmission infrastructure	In response to the information on network congestion, connecting parties would be able to purchase transmission hedges (called firm transmission rights or firm access' in the paper) that would allow them to more effectively manage dispatch risks. Generators' collective decisions to hedge would	July 2023

PHASE OF RE-FORM	OVERVIEW	PROPOSED COMMENCE-MENT
	guide TNSPs' planning decisions due to an obligation placed on TNSPs to provide sufficient transmission capacity. This capacity would be consistent with the collective amount of transmission hedges purchased by generators.	

Source: AEMC, *Coordination of generation and transmission investment, Final report,* 21 December 2018

The level and nature of activity that is external to the COGATI is likely to impact aspects of the reform process while also creating additional uncertainty for stakeholders. Therefore, the EUAA would strongly recommend the AEMC work with stakeholders to undertake scenario modelling to gain a better understanding of the effectiveness off the proposed reforms and test if they are likely to produce the desired outcomes. While by no means will this guarantee the desired outcomes will be delivered, it may inform important aspects of the reform design.

DYNAMIC REGIONAL PRICING

We stated in our April 2019 response to Access and Charging Discussion Paper, the we are surprised the issue of disorderly bidding and dynamic regional pricing has made its way into the COGATI at this stage. While we recognised that some of the concepts described under Dynamic Regional Pricing were similar in nature to what the EUAA have suggested the AEMC consider in past submissions, such as Optional Firm Access and Marginal Locational Pricing, we saw potential risks for consumers who may now be exposed to a dynamic regional price that may be greater than the Regional Reference Price (RRP).

In addition, a number of our members had expressed concerns that by creating a discrete locational price that is in conflict with the regional price it would potentially result in a reduction of liquidity and contract availability (including availability of hedge contracts) and potentially discourage the deployment of firming technologies such as grid scale batteries.

With the additional information provided in the Directions Paper we are now better able to understand the "mechanics" of Dynamic Regional Pricing and through which, a number of our initial concerns are allayed.

In particular, our understanding of dynamic regional pricing is:

- Load (customers) will continue to pay the Regional Reference Price (RRP) meaning they will not be exposed to the Local Marginal Price (LMP) should it differ from the RRP.
- LMP will only differ from RRP on occasions where there is congestion. At present, this is likely to have an impact on predominantly new entrant generators and could potentially add to costs, the extent to which will be dependent on the efficiency of the proposed Transmission Hedging arrangements. However, these new entrant generators are facing significant financial impacts of curtailment now, which this reform is designed to address.
- Dynamic Regional Pricing should assist generators address congestion (and MLF) issues and would work to reduce overall financial risk, leading to lower cost of capital and lower energy prices for consumers.
- Because separation of the LMP and RRP will only occur at times of congestion, it should not materially impact a majority of existing thermal generation (although we are aware of exceptions) as constraints are less likely. However, it may have an impact in the future as more generation enters the market. The additional costs being borne by these generators in the future needs to be understood.
- The creation of transmission hedges provides the potential to create additional liquidity and risk management options that may also help underwrite grid scale storage (i.e. batteries).

- Dynamic Regional Pricing, when combined with Transmission Hedges could be an effective tool to move some level of cost and risk associated with new transmission away from consumers to those that benefit from the new asset.

As a vast majority of energy users are not market participants and therefore will not have a day-to-day operational involvement in dynamic regional pricing or transmission hedges, our comments will focus on energy user outcomes and the extent to which these reforms work to reduce consumers costs and mitigate risk.

In response to a question asked on page 46 of the Directions Paper, stakeholders are asked if an alternate model outlined in Box 6 would be worth pursuing. We do not have sufficient information to make an informed comment on this, however if it is a simpler version of the proposed dynamic regional pricing model then it may be worth considering. It would certainly be useful for the two models to be compared to determine the most cost-effective outcome. Therefore, we would recommend that the AEMC include this option in any scenario modelling conducted as part of the COGATI reform process.

The table below appears on page 50 of the Directions Paper, setting on a number of different approaches to allocation of settlement residues under dynamic regional pricing.[4]

Table 4.1: **Options for settlement residue allocation**

SCENARIO	OPTIONS
1. Concurrent implementation of dynamic regional pricing and transmission hedging.	A. Primary allocation on the basis of transmission hedges held. Surplus residues allocated to generators without transmission hedges, on the basis of availability.
	B. Primary allocation on the basis of transmission hedges held. Surplus residues used to offset TUOS charges.
	C. Primary allocation on the basis of transmission hedges held. Surplus residues support fund to increase the firmness of transmission hedges (i.e., to offset scaling back transmission hedge settlement payments when the hedge volume exceeds available transmission capacity).

In response to Question 1 on page 51 of the Directions Paper, unsurprisingly, we prefer Option B where surplus residues are used to further reduce TUOS charges for customers. Of the three options we feel this approach is aligned to NEO objectives of the long-term interests of consumers.

At the very least, settlement residues should be shared between the generators holding sufficient transmission hedges, given they are providing the liquidity in the first instance and customers given they are paying the final bill. Generators without transmission hedges, having not contributed to liquidity or resolving congestion, should not receive any benefit from settlement residues.

Page 57 of the Directions Paper contains the following statement[5]:

Much load is located in the metropolitan regions of state capitals, where locational marginal prices are likely to be very similar to the regional reference price. Few loads currently face wholesale prices, with most subject to fixed retail tariffs, although in some of these cases the retailer may request that the load responds to the wholesale price on their behalf. However, as with

[4] https://www.aemc.gov.au/sites/default/files/2019-06/COGATI%20-%20directions%20paper%20-%20for%20publication_0.PDF

[5] https://www.aemc.gov.au/sites/default/files/2019-06/COGATI%20-%20directions%20paper%20-%20for%20publication_0.PDF

non-scheduled generation, it may be the case that larger loads in certain zones might wish to face a locational marginal price, if this is expected to result in a more favourable price.

In response to Question 3 on page 60 of the Directions Paper. At this point in time we are not in favour of load being exposed to locational marginal prices unless they specifically "opt in" to this exposure after due consideration to the risks, costs and benefits of doing so.

While many large energy users have some level of participation in the National Electricity Market (NEM) most of this involves demand response to high price events and to manage spot market exposure. While there are very few scheduled loads in the NEM, some large energy users may be interested in accessing a local marginal price. However, the additional complexity and risk involved in this would mean it is unlikely many would take the step to becoming market participants and scheduled loads.

We concur with the AEMC that the issues listed (settlement residue, market power, complexity and forward contract market) are relevant issues to be considered.

In response to Question 5 on page 65 of the Directions Paper, the EUAA are very supportive of the AEMC developing reference scenarios, some of which we have already described, so that stakeholders can better understand the impacts, cost and benefits of the proposed reforms. The EUAA would welcome further discussion on this to ensure the focus of both the scenario modelling and reform itself, continues to be focussed on consumer outcomes.

TRANSMISSION HEDGING

The creation of Transmission Hedging as a market-based means of resolving congestion, managing MLF risk and potentially creating a sufficient revenue stream to help off-set transmission costs (in doing so reduce consumer costs and exposure to risk), is a reform worth pursuing.

The EUAA have been a constant voice arguing for a mechanism or mechanisms by which the costs and risks associated with new transmission infrastructure can be allocated in a more equitable way. We welcome this initiative from the AEMC and look forward to further consultation.

For the EUAA, the key questions regarding transmission hedges are:

1. To what extent will transmission hedges (working with dynamic regional pricing) provide sufficient incentive for generators to resolve congestion on existing assets and for transmission providers to invest in marginal grid augmentation.
2. To what extent will transmission hedges (working with dynamic regional pricing) provide sufficient incentive for generators and transmission providers to invest in new grid infrastructure such as Renewable Energy Zones (REZ).

Our initial reaction is that dynamic regional pricing and transmission hedges may prove useful to resolve issues associated with existing assets and provide sufficient incentives for investment. This type of incremental investment tends to be of lower capital value (although not insignificant) and is already largely close to fully utilised (as evidenced by congestion driving the investment).

However, given the significant risks associated with investment in new transmission assets of the nature identified in the AEMO ISP, we are not sure these reforms will provide sufficient incentive. It may be that the risks of committing to such large, long-term investments for all stakeholders is too great, requiring some level of state and federal government support through measures such as capital support or asset underwriting.

At this point in time the EUAA does not have sufficient information to answer either of these questions with any confidence and look forward to the AEMC undertaking scenario modelling to further or understanding.

In response to Question 6 on page 75 of the Directions Paper, the EUAA agree that access reform should be integrated into the AEMO ISP. With the integration of these reforms, the ISP would have a strong market signal making it easier for AEMO to develop future ISP's that reflect market participant preferences and investment plans.

We agree with the following principles on page 74 of the Directions Paper:

In order to achieve this, it is important that there is sufficient:

- *transparency of transmission hedges being purchased, such that AEMO can incorporate it into its planning, and transmission network service providers can reflect this in their annual planning reports*
- *consultation on the ISP, including from generators, so that the ISP is closely aligned with what generators seek from the transmission system i.e. the transmission and generator sectors are effectively coordinated*
- *feedback mechanisms between the two processes, so that the finalised ISP can inform relevant aspects of the access regime. For example, the Commission considers that the ISP could assist with the transmission product pricing process.*

RENEWABLE ENERGY ZONES

The EUAA have been consistent in its advocacy on Renewable Energy Zones (REZ's) over the last 18 months. As we have stated in previous submissions, central to the ISP and COGATI is significant investment in Renewable Energy Zones (REZ's) and self-described "strategic assets" such as interconnectors. In particular, the view that consumers should pay for the deep connection costs of REZ has been a primary concern for the EUAA. We contend that a significant beneficiary of new REZ's are the project proponents, their investors and from time-time, state and federal governments.

The EUAA are of the view that the risk and significant portion of the capital costs associated with the connection and operation of these assets should rightfully reside with those that are the primary beneficiaries and are in the best position to manage both costs and risks. While consumers may receive some marginal price benefit from the operation of projects located in these zones, or indeed from the development of a new interconnector, given the fluctuating nature of the energy market these benefits may be fleeting at best.

We are encouraged that the AEMC and a growing number of industry stakeholders recognise new capital recovery models need to be considered.

In response to Recommendation 11 on page 88 of the Directions Paper, we agree with the AEMC that:

…the ESB examine the possibility of a Fund to extend transmission assets to connect to Renewable Energy Zones with the cost of this transmission progressively recovered from consumers if and when utilisation increases. The required size of the finance, the source of funds, and how funds should be recovered and managed should be part of the examination.

As we have stated previously, it may be that the risks of committing to such large, long-term investments is too great for investors and transmission providers and may therefore require some level of state and federal government support through measures such as capital support or asset underwriting.

In response to Question 11 on Page 90 of the Directions Paper, we agree that clustering of generators that wish to connect to the network, including the grouping of connection applications, would be valuable in assisting in development of renewable energy zones.

In response to Question 12 on Page 91 of the Directions Paper, we agree that shared cost recovery models should be considered. We agree that the principles of this model, as set out below (Page 91 of the Directions Paper) represent a sound foundation. These are similar to principles put forward previously by the EUAA and developed further by the Public Interest Advocacy Centre (PIAC).

In order for the renewable energy zone to be developed, the risks, and costs, would then be shared between multiple parties:

- *A fixed portion of the cost of investment (for example, 50 per cent) would be recovered from consumers in a manner similar to how transmission network service providers currently recover shared network costs.*
- *A further portion of the cost of prescribed capacity would be recovered from generators, who would pay a connection charge to connect to the renewable energy zone. This charge would be proportional to the generator's nameplate capacity and how early they connected. That is, at any given point in time, the cost for generators to access prescribed capacity would be a fixed rate in terms of $/MVA. The rate paid by generators would increase with time according to an escalation factor. Generators connecting early would pay lower costs compared to generators connecting later.*
- *If a TNSP thought the interest in a particular location was more than what was indicated in the Integrated System Plan as the 'efficient' capacity level, then TNSPs could set charges and negotiate with generators as unregulated revenue. TNSPs could then seek higher returns via generator connection charges to compensate for the additional risk of investing in capacity without guaranteed cost-recovery.*

In this way, the costs and risks of a renewable energy zone would be shared between a number of parties. The Commission is interested in stakeholder views on whether a model that allows for shared cost recover should be pursued further. For example, such a model could be made consistent with the proposed access principles.

IMPLEMENTATION

The EUAA are in general agreement with the implementation process although believe there is a need for improved information and scenario modelling to be an integral part of phase one.

We note the AEMC have recognised these concerns on Page 94 of the Directions Paper:

Other stakeholders supported alternative implementation approaches to reduce transitional uncertainty or provide increased information for market participants. Delta Electricity, Stanwell and EUAA considered that increased information should occur as a first stage rather than second, as better information would enable participants to assess the magnitude of the benefits that are likely to be realised by moving to regional pricing.

And again, on Page 95 of the Directions Paper:

The Commission also considers that there is an in-principle case for the information provision stage of access reform happening sooner than 2022. We understand that locational marginal prices are already implicitly calculated as part of the dispatch process, but disregarded for settlement. While the Commission is yet to consider the costs and benefits in detail, it does not expect that it would be particularly costly or onerous for AEMO to publish the following information before the wider changes to the access regime come into effect:

- *historic and forward-looking locational marginal prices*
- *information about when transmission network constraint equations bind.*

In response to Box 11: Implementation and Timing on Page 95 of the Directions Paper, the EUAA would recommend the AEMC pursue the above as an integral part of phase one.

<u>**In response to Box 12: Transitional Principles**</u> on Page 96 of the Directions Paper, the EUAA are in general agreement with the principles identified being:

To guide consideration of these issues, the Commission has developed some high-level transitional principles. These principles are to:

- *mitigate any sudden changes to prices and margins for market participants (generators and retailers) on commencement of the access reforms to encourage and permit (existing and new) generators to acquire and hold the levels of firm access that they would choose to pay for*
- *give time for generators, transmission network service providers and other market participants to develop their internal capabilities to operate new or changed processes under the access reforms without incurring undue operational or financial risks during the learning period*
- *prevent abrupt changes in the amount of available transmission hedges that could create dysfunctional behaviour or outcomes in access procurement or pricing.*

We are conscious that incumbent generators have concerns regarding the preservation of their existing position, having made significant investments based on a certain set of assumptions that now may change due to these reforms. Therefore, we would add the following comments for discussion on the potential role of grandfathering with respect to new transmission investments as proposed in the ISP that are committed prior to 1st July 2022. Assuming that the COGATI reforms are completed by December 2019 and a new transmission investment is approved as a contingent project by the AER on 30th March 2020:

- Those generators on line on 30th March 2020 would receive grandfathering rights based on their existing generation capacity – but there would need to be a discussion around the length e.g. they should not be longer that the generating asset life
- Those generators that announce post 30th March 2020 their commitment to build new or expanded generation would have to pay for transmission hedges
- The income from the sale of hedges would offset TUOS through settlement residues
- We recognise that these hedges may not continue for the life of the transmission asset, nor for the full capacity and so consumers will bear that stranded asset risk; its level of residual risk will also depend on the level of funding from other sources discussed above

For new transmission projects committed to post 1st July 2022, there are two models for how future transmission might be funded (outside of the external funding options):

1. New connections after 1 July 2022 (apart from those required for reliability reasons – this would need to be tightly defined) would only be built if there are sufficient hedges i.e. transmission asset risk is with generators

2. Retain an element of central planning to determine the appropriate level of investment in the transmission system – so quantity of hedges determined/capped by centralised process; still sending right locational signals; risks still with consumers (not clear on all the details)

Our initial view is to favour the former. Some may argue that this approach risks the level of investment being lower than "optimal". We do not find this argument convincing. It relies on a particular definition of "optimal" and an assumption that central planning will always produce a better outcome which is equated with higher investment. This central planning approach in the past has contributed to significant over investment in networks and a legacy RAB level that consumers have been and will be for many years, paying off.

Our concern remains that in the absence of an equitable risk and cost sharing framework to accompany it, AEMO's ISP is proposing huge investments in transmission with what we regard as significant stranded asset risk to consumers from unforeseen future technological developments lower the costs of non-network options.