SUBMISSION

AEMC COGATI IMPLEMENTATION – ACCESS AND CHARGING
26 APRIL 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 COGATI Implementation – Access and Charging Discussion Paper. We appreciate the AEMC allowing additional time for stakeholders to provide input into this important consultation and the clarification it has provided in the Supplementary Information Paper released on 4 April.

The EUAA made a submission to the Coordination of Generation and Transmission and Investment (CoGaTI) Options Paper in October 2018 and we are pleased that a number of issues we raised in that submission have been acknowledged by the AEMC. We are also pleased that a number of our recommendations, in particular the need for co-contribution to network asset augmentation are now being contemplated. We recognise that it will take some time and require substantial stakeholder consultation to bring about these reforms but we are satisfied they are now firmly on the AEMC agenda.

The key issue we raised in our submissions to the CoGaTI process and to several RIT-T assessments has been to challenge the assumption that consumers would continue to pay the full cost for network augmentation including for proposed Renewable Energy Zones (REZ) and interconnectors such as Energy Connect (NSW to SA interconnector), Project Marinus (Tas to Vic interconnector) and deep augmentation costs to facilitate Snowy 2.0.

To be clear, the EUAA are not opposed to new network assets being built to facilitate new generation or for interconnectors to be built that allow market participants and the market operator greater flexibility. Our concerns revolve around the assumption that a vast majority of the costs associated with these projects will be included in the Regulated Asset Base (RAB) of the network companies involved.

We note that AEMO are pursuing the next iteration of the Integrated System Plan (ISP) that is running parallel to the CoGaTI process. Both are important for consumers as they set the direction of energy market investment. While the ISP and CoGaTI may at times appear to be seeking to resolve the same problems we see the key distinction between the two being the ISP has a focus on <u>what</u> transmission we should build while the CoGaTI has a focus on <u>who</u> is best placed to manage the risks and costs associated with these new assets.

With this in mind, AEMO should ensure the ISP retains its role as a guide to investment decisions rather than becoming a prescriptive plan that must be actioned without regard to proper regulatory oversight and a consumer focussed cost benefit analysis. Further to this, we do not see a role for AEMO or the ISP to direct investment decisions by market participants.

The role of the AEMC and CoGaTI should be to create a set of rules and market-based mechanisms that incentivises the right type of investment in both generation and network augmentation. In doing this it should also ensure that these new rule and mechanisms create a more equitable cost and risk sharing framework so that consumers only pay for the benefits and services they actually receive.

We would like to see a greater level of coordination between AEMO and the AEMC such that AEMO identifies the need and the AEMC provides the means to achieve the desired outcome that is in the best interests of consumers.

EXISTING ACCESS AND CHARGING ARANGEMENTS – WHY THEY NEED CHANGING

We are heartened to see the AEMC recognise that the existing access and charging arrangements 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 need to be addressed by the AEMC as it considers implementation of the CoGaTI plan.

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,

[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

- 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 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[3] 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[4].

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 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.

[3] https://www.agl.com.au/about-agl/how-we-source-energy/barker-inlet

[4] https://www.energy.gov.au/government-priorities/energy-supply/underwriting-new-generation-investments-program

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.

AEMC PROPOSED CHANGES

The AEMC have proposed a number of changes to the access and charging arrangements that involve three phases being:

1. Dynamic Regional Pricing
2. Improved Information
3. Generators Fund Transmission Infrastructure

While the remainder of this submission will address these proposed changes, we will pay specific attention to the third phase.

Phase 1: Dynamic Regional Pricing

We are surprised that the issue of disorderly bidding and dynamic regional pricing has made its way into the CoGaTI at this late stage. While we recognise that congestion is an issue in some places of the NEM, especially where we see a significant deployment of new generation, we do not necessarily agree that it should be dealt with here. We feel it is quite out of context with the progress of CoGaTI consultations over the last 12 months and as a result has taken people by surprise.

We recognise that some of the concepts described under Dynamic Regional Pricing are similar in nature to what the EUAA have suggested the AEMC consider in both this submission and past submissions such as Optional Firm Access and Marginal Locational Pricing. This is recognised by the AEMC on page 6 of the Supplementary Information Paper:

> *"The strawman that the Commission put forward in the 2018 CoGaTI final report, and which is currently being consulted on, has some similarities with optional firm access, but there is substantial scope to alter that model in light of differences in the NEM now compared to 2015."* [5]

Our view was that Optional Firm Access and Marginal Locational Pricing should be considered by the AEMC as a means to reduce the risks and costs consumers face from new infrastructure. We had not necessarily contemplated it as a means to resolve disorderly bidding or congestion issues. Expanding the scope of these potential reforms beyond this original intent adds significantly greater complexity and, in hindsight, would require a separate work stream to ensure appropriate consultation and detailed design work is undertaken.

As a result, a number of our members have expressed concerns regarding this proposal as it's currently stated. They are concerned that it appears to be a significant move away from the current operation of the wholesale market; that it will create a discrete locational price that is in conflict with the regional price potentially resulting 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.

[5] https://www.aemc.gov.au/sites/default/files/2019-04/Supplementary%20information%20paper.pdf

The AEMC have stated in the March 2019 Consultation paper and then restated in the April 2019 Supplementary Information Paper that this reform would provide overall benefits to the market and lower relative prices. However, neither paper has fully or clearly explained how this would occur nor did it include analysis of what unintended consequences could arise and how they could be managed.

Whether these issues are material or not isn't relevant at this point in time. The relevant issue is that there has been insufficient information provided to stakeholders and a lack of specific consultation on what would appear to be a significant reform.

While these reforms may benefit consumers in the long-term, clearly more work would need to be done to ensure all market participants fully understand what is being proposed. Stakeholders need to be convinced that this reform would actually solve the problem it sets out to solve (to the extent one exists) and to ensure there are no unintended consequences.

At this stage we would strongly recommend it be removed from the CoGaTI process and be dealt with elsewhere with greater, more specific consultation including the ESB's Post 2025 Market Design for the National Electricity Market (NEM) process.

We remain open to discovering how Dynamic Regional Pricing, Optional Firm Access and Marginal Locational Pricing would work to resolve both congestion issues and drive a more equitable approach to cost recovery of new transmission (including REZ's) and interconnector assets. We look forward to further consultation with the AEMC on these potential reforms.

We also note that 5-minute rule change, which is designed to reduce the instances of disorderly bidding is due to come into effect on 1 July 2021. We suggest that the AEMC watch how bidding behaviour changes with this rule change and make a judgment when a relevant data set is available, to ensure the problem of disorderly bidding still exists and that the solution is appropriate.

Finally, the following passage appears on page 21 of the March Consultation paper:

> ***Should the pricing methodology be modified to allocate costs based on average load, as opposed to peak load?***
> *Transmission locational costs are currently allocated to load points based on their non-coincident peak demand. However, as noted in the CoGaTI final report it is clear that benefits vary depending on a number of factors. While generally a region is more likely to be importing when its demand level is high, there can be other factors that affect this. For example, the proposed SA-NSW interconnector is likely to be flowing towards NSW when it is windy in SA; and towards SA when it is calm, regardless of the underlying demand levels. It may be worth the IR- TUOS arrangements reflecting this. One way to do this could be to consider whether costs should be allocated based on average load, rather than non-coincident peak load. Another way would be to consider the allocation of net benefits that would be an output from any RIT-T assessment.* [6]

The intent of this section is unclear from the consultation paper and we seek clarification as to what this is attempting to achieve and the potential impact on current arrangements. We would be concerned if this led to average load replacing peak load pricing. We seek a maintenance of the current peak load approach as that sends the correct signal to networks of what to build and provides an incentive to customers to manage their load. An average load approach removes all the incentives for efficiency.

Phase 2: Improved Information

As this is linked to Phase 1 we believe it should be dealt with separately as per our recommendations detailed previously.

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

We do not necessarily agree that we need to put in place dynamic regional pricing to understand the nature of the congestion problem or to fully understand the costs and benefits of resolving it as described in the March 2019 Consultation Paper. In fact, one would think that a significant amount of useful information could be gathered through market simulations which we believe should be conducted before the roll out of dynamic regional pricing to ensure we are actually solving the problem in the most efficient way.

Phase 3: Generators Fund Transmission Infrastructure

This is the key issue for the EUAA and its members and as a result we believe achieving a more equitable cost and risk sharing approach should be the primary objective of the CoGaTI.

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 rightfully reside with those who stand to gain significant financial benefit from them. While consumers may receive some marginal price benefit from the operation of projects located in Renewable Energy Zones (REZ) or from the development of a new interconnector, 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 help to support state and federal government policies such as the continued roll out of renewable energy and the regional economic benefits that flow.

In essence, 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)."[7]

We recognise that moving to some 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. However, we contend 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.

As we have stated in previous submissions, recovery of these costs from generators could be managed in a number of ways including:

Capital Cost Recovery

Capital costs could be recovered from generators as they connect based on the total installed capacity of the asset (expressed either in MW or % of line capacity). The assessed capital contribution would then be deducted from the RAB of the

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

participating TNSP's in a form of "reverse contingent project" process. This still requires consumers to take some of the up-front risk that generators may not connect but has the advantage of reducing the network RAB over time.

An alternative would involve the network owner taking a "build it and they will come" approach where they take the capital and future volume risk. This would shield consumers from the risks and costs of the asset which are now transferred to the network operator. Arguably the network operator is in a better position to manage this than consumers as they have an opportunity to put in place a range of agreements with potential generators.

Government could also take equity participation in ISP identified priority assets that would have the effect of reducing the capital expenditure by participating TNSP's, therefore reducing the amount of project cost that would be incorporated into the RAB. Capital could still be recovered from generators as they connect and be re-allocated to other assets in a rolling capital fund arrangement.

These arrangements follow similar concepts to the Scale Efficient Network Extension approach but does not have the problems associated with coordinating a disparate range of project proponents and investors before the network investment is made. This approach could also include access to more favourable debt via the Clean Energy Finance Corporation or Future Fund contribution, having the effect of lowering overall capital costs of the project.

Optional Firm Access and Locational Marginal Pricing

Optional firm access: This would allow generators to purchase a partially firm financial access right to the regional reference node, at a regulated price in order to manage the financial impacts of network congestion. Generators would be entitled to compensation if constrained below their level of firm access. This would change the way in which transmission and generation investment decisions are made, and would mean generators would bear more of the risk associated with some transmission investment. In effect this would introduce firm transmission rights, while providing locational (nodal) pricing signals to generators.

Locational marginal pricing, with deep connection charges: This would establish sub-regional pricing, and generators would have access to their locational marginal price, but would also be able to purchase optional fully firm financial access to defined trading hubs. In order for generators to be able to acquire access rights beyond those available through the existing system, they would have the option of paying deep connection charges, for which they would also receive optional fully firm access. In essence, this option would provide generators with fixed financial access, compared to optional firm access where only firm financial access would be provided (i.e. there would be times under an optional firm access model where there would be operating conditions under which the capacity of the transmission network would be reduced and so access for firm generators might also correspondingly be reduced. The deep connection charge would not reflect locational differences in costs.

The options described in this section would represent a significant change to the way in which the NEM operates. As we have suggested previously under Dynamic Regional Pricing, we would recommend these options be considered as part of a broader 2025 reform process being undertaken by the ESB.

Some of these co-contribution options contemplated above involve direct government action and are therefore outside the scope of the CoGaTI. However, they may have a role to play if a broader market reform process was underway. For example, these types of government led initiatives could serve as a bridging strategy to allow new assets to be built in the years leading up to the broader reforms becoming operational. This would ensure that deployment of new resources would not be unduly delayed while also protecting consumers from being locked into long-term increases in regulatory prices.

Regardless of the method of co-contribution, the aim must be to reduce the amount of capital expenditure of the project that accrues to the participating TNSP's RAB and allocate risks appropriately such that those who have the most to gain and who are in the best position to manage volume risk are making a fair and equitable contribution to the project.

We recognise this is a different approach to how energy infrastructure has been funded in the past and agree with the AEMC when it states:

> "Reforming the access and charging regime is a holistic, long-term solution to current issues being experienced. The existing transmission framework is comprised of a set of elements that are internally consistent and highly interlinked. Addressing an element of the transmission framework in isolation would likely still result in considerable regulatory overhaul of other elements, but would have a high risk of inefficient outcomes, since it would not address the framework holistically."[8]

We are cognisant of the ESB's Post 2025 Market Design for the National Electricity Market (NEM) process that is seeking to develop advice on a long-term, fit-for-purpose market framework to support reliability that could apply from the mid-2020s. A significant revision to the access and charging arrangements would be a key element of this work and we suggest the AEMC coordinate closely with the ESB.

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