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COGATI Proposed Access Model – Discussion Paper

The Australian Energy Council ("**AEC**") welcomes the opportunity to make a submission to the consultation paper on the three rule changes associated with Co-ordination of Generation And Transmission Infrastructure (COGATI) Proposed Access Model.

The AEC is the industry body representing 22 electricity and downstream natural gas businesses operating in the competitive wholesale and retail energy markets. These businesses collectively generate the overwhelming majority of electricity in Australia and sell gas and electricity to over 10 million homes and businesses.

The AEC is providing four representatives to the Technical Working Group and thanks the Review's staff for expending considerable effort to explain the reform directly to its members.

Summary

The AEC understands the Discussion Paper's rationale to remove the third leg from the Review's Scope – direct planning of transmission through sale of access. The AEC agrees that whilst that had theoretical attractions, it would have involved a major change in direction from the centrally planned paradigm. Whilst that leg would have been very challenging, there should be no misconception that the remaining scope is straightforward. It will still involve very major changes to the operation of the competitive parts of the market, and at the same time its theoretical benefits are smaller.

This reduction in scope does not affect AEC's primary concern from the Directions Paper stage: that COGATI and the Energy Security Board's (ESB) ESB2025 Market Design work are inextricably linked. COGATI progress in advance of ESB2025 pre-judges that that process will conclude in favour of the existing energy-only market design.

The AEC considers it still too early in the design process to be proposing any implementation dates, but in any case, 2022 is unachievable. After consideration of all the relevant decisions and transitional matters that have to be managed, a date in the order of 2025 is realistic – providing further rationale for combining COGATI with ESB2025.

The AEC is concerned about the process outlined for the detailed development of the reform – which is to occur within the AEMC's Rule Making function. This would be more appropriate to occur within its Directed Market Review function. The AEC suggests the COGATI Review should only release an interim report in December 2019, and then extend through 2020.

As stated in our Discussion Paper submission, transitional access arrangements are critical to provide investor confidence in the reform. Whilst it is pleasing that the Review appears to agree with this sentiment, it continues to defer clarification of its intentions until completion of the detailed mechanism. This should not be necessary: the Review can provide a statement of its intent, pending development of the mechanism.

Whilst the AEC is pleased at the Review's attempts to further explain the concepts with respect to dispatch incentives in the presence of congestion, there remain significant gaps in the provided algebra, particularly in respect of the handling of losses and settlement adequacy. It is difficult to engage confidently with the reform until these are resolved.

The sharing of transmission performance risk across a broader population of generators compared to status quo potentially has some risk management advantages. However it may also unintentionally lessen the sharpness of existing incentives for generators to take network robustness into account when investing or contracting. This challenging trade-off requires further explanation and discussion with stakeholders.

The sharing of transmission instrument risks and proceeds across the entire NEM has broader contextual implications for a market that has to date contained such matters intrastate. This requires fuller discussion.

The scope of the cost – benefit analysis proposed in the Paper appears to capture the main matters. The timeframes however appear unreasonably short as much analysis is proposed ahead of the model's full description. It is recommended that the target date of both stages be pushed back approximately six months from the Discussion Paper's suggestion.

Scope of Review

The AEC understands the rationale behind the review's change in direction to discard its third leg: a direct contractual link between planning of generation and planning of the shared transmission grid. This was always conceptually attractive, but the AEC agrees there are no obvious models where it has been successfully employed elsewhere, and that it would prove very challenging for a rapidly transitioning and highly complex network.

The AEC also recognises the large role the Integrated System Plan (ISP) is now expected to play in the development of the industry, an direction which tends to reinforce the current approach. In accepting this consolidation behind central planning, the AEC notes that the quality of independent regulation is ever more essential to ensure those networks are planned efficiently, and, equally important to market investors, predictably.

The review has however maintained a limited role for generator development of specific parts of the grid in the Renewable Energy Zones (REZ) line of work. In its separate submission to REZ, the AEC supports continuing to work on this concept and does not consider it necessarily incompatible with the central planning regime for the main shared grid. It is noted that the form of the REZ right is dependent upon the access regime across the broader system. A challenge emerges that the REZ line of work necessarily pre-judges an outcome in the broader access work.

Context

Despite the reduction in scope, the AEC maintains the view it put to the Directions Paper of a disconnect between the AEMC's COGATI line of work and ESB2025. The Discussion Paper has emphasised a close liaison between the two processes. Despite these undoubtedly worthy efforts, the AEC cannot see how it is possible to develop an electricity market's access regime without knowing its capacity reward mechanism.

This dissonance is exemplified by the recent release of "Allocation of Capacity Credits in a constrained network – Design Proposal" by the Energy Transformation Implementation unit of the Government of Western Australia[1]. The removal of Wholesale Electricity Market (WEM) physical firm access has necessitated a change to its capacity reward mechanism. A new transmission access arrangement must be created to support the

[1] "Allocation of Capacity Credits in a constrained network – Design Proposal" Working Paper Western Australian Government Energy Transformation Unit 16 October 2019 https://www.wa.gov.au/sites/default/files/2019-10/Allocation%20of%20Capacity%20Credits%20in%20a%20constrained%20network%20-%20Design%20Proposal.pdf

WEM's capacity market to ensure capacity payments remain limited to generators only in accordance with their ability to deliver capacity to customers.

This points to the need to integrate fundamental capacity reward and network access design paths: ideally they should evolve together. The AEMC is approaching the COGATI review, necessarily, on the basis of the existing energy-only NEM design. This means any access regime will almost certainly be incompatible with any other capacity reward design that the ESB might consider. This implies that after a COGATI direction is recommended to COAG, either:

- The ESB will be more reluctant to consider alternative capacity reward designs due to the efforts so recently made in an access regime linked to the current design; or

- An ESB recommendation for a change in capacity reward, not expected before 2021, will require a new access regime – as per the WEM - sending COGATI back to the drawing board.

This observation of the need for co-ordination between congruent reforms is the theme of a recent report produced by KPMG for the Energy Council – Co-ordinating Electricity Market Reform[2]. The inter-relationship between COGATI and ESB2025 is one of its major reflections.

Process

The AEC is uncomfortable with the process outlined for the reform, in that the COGATI review will conclude with the December 2019 report to COAG, with the majority of the detailed design work deferred to the consideration of a Rule Change proposed back to the AEMC by COAG in 2020. In the AEC's mind this confuses AEMC's statutory roles in each of Directed Reviews[3] and Rule Making[4].

The AEMC's Rule Making power contextually exists in the National Electricity Law as one of merit assessment only – intentionally separated from the AEMC's market design role. It is intended that fully described rule changes will be proposed into its Rule Making process, and the AEMC's role is only to decide whether that rule, as presented, furthers the market objective.

Section 91A – AEMC may make more preferred Rule in certain cases – permits the AEMC to improve a rule, a provision that gives less sophisticated proponents access to Rule Making by allowing the AEMC to refine their concepts into workable Rules. "in certain cases" implies it was intended to be used in a limited fashion, only where necessary. Instead the AEMC appears to be intending to use this power to perform sweeping market design work. Use of the power is particularly problematic where the Rule Change being improved is one that originated out of its own Directed Review.

The AEC considers that the long and intricate COGATI development work ahead should be run within the AEMC's Review function rather than its Rule Making function. The AEMC should therefore provide only an interim report to COAG in December, and defer its Final Report. During 2020, in parallel with the ESB2025 process (and in conjunction with stakeholders), the AEMC can develop the many details of this most complex reform proposal. When, ultimately, a fully developed Rule is proposed into the Rule Making function, the assessment can then be limited to whether it meets the market objective.

Implementation

The AEC repeats its view from its previous submission that the COGATI review should not be recommending an implementation date at this time for the following reasons:

- The co-dependencies with ESB2025 described above will mean that key design features of an access regime cannot be reasonably determined until at least early 2021.

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[2] https://www.energycouncil.com.au/media/17223/coordinating-electricity-market-reform-full-report-final.pdf
[3] National Electricity Law Section 41
[4] National Electricity Law Section 91

- There is a considerable effort yet to be undertaken to demonstrate the case for proceeding. Proposing an implementation date ahead of that effort creates a perception that a decision has already been made.
- The proposals will necessarily be complex, and at this stage in the project it is impossible to undertake a reasonable assessment of the lead time necessary to accommodate:
    - Major changes to systems, including potentially a new NEM dispatch engine; and
    - Major changes to contractual arrangements such as hedge and settlement residue instruments.
- A desire to deliver a solution by an arbitrary date unnecessarily constrains the range of solutions that can be reasonably explored.

Whilst the AEC feels that no date should be proposed at this time, the suggested timing of July 2022 in the Paper appears entirely unrealistic. The rule making process proposed will necessarily require considerably more detailed design development and justification against the NEO. This seems very likely to consume the entire calendar year 2020, therefore it should be assumed that a decision to go ahead could not occur before the start of 2021. After that the AEMC must consider the following:

- Participant systems – the significance of the required changes would appear to be at least as significant as those required for the introduction of five minute settlement. That project had 3 ½ years' lead-time, and a number of participants are nevertheless reporting challenges in achieving readiness for that deadline.
- AEMO systems – the proposed model includes Volume Weighted Regional Pricing (VWAP). This in turn requires marginal prices to be determined at the location of unscheduled participants, which is not achievable with the current dispatch engine's (NEMDE) hub and spoke design. Should the reform recommend implementation of a Full Network Model (FNM) dispatch engine, this will require a very major re-design to be undertaken by AEMO.
- Participant contractual arrangements – existing derivative contracts are written around the Regional Reference Node (RRN). A VWAP will be a change event with impacts upon those instruments which preferably occurs with notice beyond the tenor of the majority of these contracts, or at least sufficient time for applicable change mechanisms to be developed.
- Settlement Residue Auction (SRA) Instruments – as these become redundant in the Financial Transmission Rights (FTR) regime, it is preferable that the notice period occurs beyond the maximum tenor of these, which is three years.
- Release of auctioned FTRs – these should be made available in a progressive manner in the period leading up to start of the arrangements.
- Consequential legislations –
    - The Renewable Energy Target applies the existing Marginal Loss Factor (MLF) construct to adjust the value of generation. As MLFs will be abolished by the reform, there will need to be time for the Clean Energy Regulator to determine and set a replacement approach.
    - For the Retailer Reliability Obligation, adaptations will be required in its Market Liquidity Obligation.

Taken as a whole, an implementation timeframe in the order of 3-4 years would seem essential, suggesting a settlement start date in the order of 2025. This further supports evolving this reform with proposals developed within ESB2025.

Transition

The AEC welcomes the AEMC's acknowledgment of the need for grandfathering of existing transmission access into an FTR regime. It is crucial for investor confidence that the proposal does not introduce any financial shock to existing investments. To not grandfather existing access would create a sudden, severe and random wealth transfer without any efficiency benefit.

The AEC recognises that the specifics of how to grandfather FTRs must await much further detailed design of the model itself. However, as noted in our previous submission, considerably increased confidence in the reform could be gained by the Review making a clear early statement of what level and tenure of grandfathering it intends to implement.

The AEC's view is that grandfathering should fully recognise existing access to the network and maintain this access for at least a decade where the generation and relevant transmission capacity remain operational. After this period, access should be tapered. It is noted that the WEM proposal with respect to access rights to its capacity mechanism proposes lifetime grandfathering[5].

Algebra

The examples provided in the discussion paper and forums of constrained generation are very helpful in explaining the concept and objectives of the model. The AEC encourages the AEMC to continue to develop these to assist industry understanding, particularly in more complex examples with loop flows.

The material however seems to not yet incorporate a full mathematical demonstration of all the settlement flows. Settlement adequacy has not yet been fully explained – particularly with respect to physical losses. The mathematics should holistically demonstrate adequacy of all the settlements' flows incorporating VWAP, scheduled entities, inter-regional flows, physical losses and FTRs.

Losses

The creation of a single nodal price and FTR incorporating the marginal effects of both congestion and losses as discussed in section 5.7 is a significant change for the industry from status quo and from previous models such as Optional Firm Access (OFA), which separated the two effects.

The COGATI approach promises an efficiency benefit by incorporating dynamic losses into dispatch, whilst also providing the multi-year financial stability for the generator through an FTR. This appears potentially superior on both fronts compared to the existing annualised static loss factors. However, as acknowledged in the paper, the mathematics for settling such FTRs are difficult and yet to be demonstrated. It is also difficult to grasp how and why losses remain hedged at times when generators are not running.

Incumbent generators would presumably receive a grandfathered FTR that is reflective of their existing loss characteristic. The manner by which the grandfathered FTR is discounted for this is of great interest and should be accompanied by a proof of settlement adequacy.

For auctioned FTRs, more information needs to be provided as to how these can adequately insure the cost of real losses. As noted in the paper, existing loss residues (caused by marginal loss pricing) are insufficient on their own to cover the real losses in the network. To achieve the AEMC's desire for a single instrument, it may be necessary to apply a loss reserve price at the auction and retain this from the auction proceeds in order to cover real losses.

Another approach may be to subtract a stable loss discount from the on-going settlement payout of an FTR. This discount could be developed similarly to AEMO's existing annual static loss factor approach, but in doing so would appear to negate the financial stability benefits intended by the AEMC's preferred model.

Notwithstanding the attractions of combining loss and congestion risk into one FTR instrument, the complexities it raises do appear very challenging and it may prove necessary to retain separation.

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[5] "Allocation of Capacity Credits in a constrained network – Design Proposal" Working Paper Western Australian Government Energy Transformation Unit 16 October 2019– see section 5

With respect to settlement of non-scheduled loads and generators, it is not yet clear from the paper whether the existing intra-regional loss factor granularity is intended to be, or can be, applied to these transactions within a VWAP. It would be disappointing if this settlement cost reflectivity was lost as a result of the reform.

Use of auction proceeds

At 5.5.7 the Paper proposes that all auction proceeds are used to offset customer costs in funding the transmission network. The AEC recognises the academic background for position – an FTR attempts to replicate a carriage service that might be sold by a competitive transport firm. However, in the AEC's mind, the academic position is not particularly relevant here because:

- As a natural monopoly, the TNSP is highly regulated and not commercially involved in the scheme. The FTR itself is an artificial construct of regulation.

- Having removing the third leg from COGATI (transmission planning through FTRs), it has been accepted that there will be no relationship between the cost of the transmission assets supporting FTRs and the revenue generated by them.

Thus, the AEC does not consider the AEMC should feel bound to allocate auction proceeds according to an irrelevant academic theory. This would open other options that could be highly beneficial, by providing firming support as occurs with New Zealand FTRs.

Auction revenue could be retained for a time, say one or two years, to provide additional support to FTRs if needed. This would in turn enable FTRs to be confidently sold at nominal capacity rather than an arbitrarily conservative capacity.

This should not be seen as drawing value away from customers by requiring them to pay a greater share of TUOS. Indeed the reverse may be true. If more FTRs are sold, and they are seen as firmer, then, in theory, the auction proceeds should also increase by as much as the expected losses of non-firmness. In fact, as a superior insurance instrument, the auction proceeds should increase by *more* than the expected losses.

Socialisation of transmission outage risk

A key difference between this model and status quo or the OFA model is the socialisation of transmission outage risk:

1. In the status quo, the trading risk caused by variability in networks' performance falls directly and wholly upon those caught in the resultant constraint equation. The OFA design intended to maintain that risk incidence by scaling back the firm access shares of those same generators.

2. In the COGATI model, FTRs are deliberately under-provided below system normal capacity, accumulating a surplus account to be used in the case of under-delivery of capacity. And then, when it falls to zero, all FTR payments are scaled back in a socialised manner.

Considering this key difference, the following matters emerge:

- The socialisation of risk has some attractions as a form of co-insurance. From a generator's perspective, there is effectively nothing that can be done to manage network outages. Thus, it could be argued that allocating it specifically to the affected generators provides no valuable signal – it simply increases their risks, for example discouraging them from contracting - which ultimately increases costs to customers. If there is no alternative to placing network performance risk upon generators, then efficient taxation theory suggests that the least harm is achieved by smearing it across the broadest possible base. Or, in other words, exposures to frequent small risks would be expected to provide generators more operational confidence than rare large risks. This will affect their preparedness to, for example, contract to a higher output of their plant.

- Parts of the network are inherently more robust than others. Notwithstanding the comments above, it is beneficial if investors take into account the fragility of the network at various locations. More remote generators in less meshed parts of the network are clearly more at risk of outage work or de-rating due to ambient conditions. The proposal would seem to equalise the relative outage risks between, *in extremis*, a generator relying on a long set of single towers passing through fire-prone forest to a generator located within a metropolitan area. This seems problematic.

- Smearing of transmission risk may encourage generators in fragile locations to contract to a level that is rarely physically deliverable, which in turn may put customer reliability at risk. The existing arrangements, or OFA, would discourage heavy contracting across weak networks, leaving an investment signal for generation to be built at strong locations to meet peak demand.

- A NEM-wide socialisation of transmission risk is a very significant shift for an industry which has typically limited socialisations intra-state. For example, Queensland generators may find their FTRs scaled back to ensure performance of FTRs in the Tasmanian network. If going down this path, it is important to have a broad conversation upon its implications.

- The socialisation allows an FTR's active volume to exceed physical network capacity during poor network performance. This would create a new incentive to offer at the market floor price (MFP) as the FTR's active volume will be larger than the volume of generation dispatch necessary to suppress a nodal price.

Load-weighted customer pricing

VWAP also implies a fundamental change to the industry's dispatch, pricing and contracting arrangements:

- As discussed in the paper, VWAP requires conversion of the existing hub and spoke NEMDE to a FNM. It is agreed this would have co-benefits, however the scale of the technical undertaking should not be underestimated. It would be a very large project for AEMO, but it also implies major changes to trading systems in participants who have developed their capabilities around the existing constraint formulations. The development project would need a long trial period to ensure robustness in the system and also to provide participant familiarity.

- All hedging contracts and Power Purchase Agreements are presently settled at a Regional Reference Price (RRP). VWAP prices will be different to RRP prices, in ways that are difficult to predict. This leads to a question as to whether existing agreements can be transferred to a VWAP reference price – i.e. how it is likely to be dealt with under "applicable change" of a standard hedging contract. Legal advice on this matter could be helpful.

It is recognised that the change relates to concerns about settlement inadequacy if relying upon the existing RRP model. Given the above challenges of shifting across to VWAP, it is worthwhile investing more effort into assessing the scale of this inadequacy and whether, for example, rules limiting shifting between scheduled statuses and rules regarding pockets of market power will limit this exposure to manageable levels.

Auction Proceed Division

It is recognised that the model intends to work across the NEM and would make irrelevant the region within which a scheduled generator sits with respect to trading; i.e. it will be equally easy to purchase an FTR from a generator into any region– and all instruments would be equally firm. This is a potentially attractive vision, albeit radically different to status quo.

One feature of such an arrangement is that the auction proceeds are, by definition, pooled. However in the NEM, transmission costs are contained and recovered within co-ordinating Transmission Network Service Provider (TNSP) regions. On the assumption that state-based recovery is to continue, this presents a new challenge for the reform work as to how to allocate such pooled revenue between co-ordinating TNSPs.

Auction Model

NEM participants have had no experience with the release of FTRs through a simultaneous feasibility auction. Understanding of the review would be assisted with a detailed explanation of how such a system solves auction bids against network capacity and grandfathered FTRs. Furthermore, a sandpit system should be built to allow participants to gain operational familiarity with the concept.

Quantitative Analysis

The AEC welcomes the Paper's focus on the need to perform detailed Quantitative Analysis on the reform. Table 7.1 appears to have captured the broad themes that will need to be assessed and also the sequencing, with mostly qualitative assessment in the first stage and quantitative analysis when the model is better defined and when time permits.

It is noted that the paper appears to be approaching the initial qualitative assessment as a guide to help the design into the next stage. Whilst not disagreeing with its value for that, its primary function should be as an initial test to determine whether to move to the more detailed stage.

The AEC's most significant concerns with respect to table 7.1 are however the tight timeframes and the earlier mentioned appropriateness of task division between the AEMC's Market Review and Rule Change function. Timeframes that appear too ambitious are:

- "Initial estimate of improved risk management" by December 2019. The model with respect to hedging of losses and impacts of variations in network performance are insufficiently developed for even a qualitative analysis by this deadline.

- "Initial assessment of the benefits from dynamic loss factors" by Dec 2019. This appears to greatly under-estimate the challenge of this quantification. This can be reasonably accurately quantified historically, and modelled forward, but both are require a major computational effort using AEMO's loss factor software. It has not, for example, yet been attempted in the relevant rule change ERC0251. It should be undertaken in a fulsome manner, and the AEC suggests it become a "Full assessment from dynamic loss factors" in the second stage.

- All the second stage activities would be challenging to complete by Mid-2020. This is because:

    - They rely first on completion of the detailed design, which is likely to extend into that timeframe.

    - Surveying implementation costs of participants is a time consuming task which requires effectively co-operating with participants to prepare a rudimentary agreed systems project scope. The design should be fully specified before seeking participant co-operation. Late 2020 would be more appropriate for scheduling of these tasks.

    - Determining impacts of VWAP will similarly need time. This requires, in sequence:

        - Completion of the design;

        - Modelling of the changes in price compared RRP;

        - Assessment of the legal implications of the change upon existing contracts.

As discussed previously, the AEC considers it inappropriate to conduct market design work within a Rule Change. However the reverse does not hold: it is entirely acceptable to perform cost – benefit work within a Directed Review. Any such results can then be used as evidence in a subsequent Rule Change to make the case before the Market Objective. For these reasons, AEC suggests that all this analysis work be performed within an extension to the existing Review, and that this should not lead to duplication.

Transparency Enhancements to Existing Structure

The AEMC's Congestion Management Review 2005 - 2008 (CMR) considered many of the same issues now being considered within COGATI and concluded that the benefits of moving away from the existing regional structure to more granular pricing were outweighed by the costs. It did however recognise it was difficult for investors to unpack the levels of congestion that already existed, and therefore locational decisions were being made in ignorance of the risks. This could be addressed at low cost through the provision of more information, for example by publishing locational prices, even where they are not settled.

This led to rule changes obliging AEMO to produce the Congestion Information Resource (CIR)[6]. This was intended to be a highly accessible resource, with locational values readily observable, as occurs in markets with locational pricing. It was recognised that this would require on-going technical development, so a process of continuous improvement through consultation was enshrined in the rules.

The CIR began well but over time awareness has waned, along with enthusiasm towards ongoing improvement. Whilst it continues to provide regular information on binding constraints and network outages, it requires considerable skill and resources to draw from the information a granular picture of congestion. It appears to have only a narrow spread of readership.

For a sophisticated participant it is quite possible to use some of the very detailed CIR information to effectively simulate a locational price. However the CMR's intent was for a broad reach, particularly intending investors. An attempt to provide more accessible locational pricing information was once made through production of "Mispricing Analysis" reports, however these have since been withdrawn.

In contrast AEMO produces a Quarterly Energy Dynamics publication[7] on market trends (but not congestion). This is presented in an accessible format with insightful commentary, for which AEMO goes to some effort to advertise and present. And, as a result, the publication is widely known and read by investors. The CMR intended for a similarly successful CIR, however this unfortunately appears to have not been achieved.

COGATI could look to means to adapt or otherwise re-invigorate the CIR concept to provide better information on the level of actual congestion being experienced in the NEM, and the prices likely to be settled should locational pricing reforms be implemented at a future time.

Conclusion

The AEC recognises the significant decisions made in the Review as described by the Discussion Paper. Whilst understanding the rationale and academic basis for such a reform, it remains a very significant and ambitious proposal with major implications to the way the NEM's competitive sector operates. It is therefore necessary to avoid ambitious implementation targets and to ensure this work is fully integrated with that being carried out by the ESB on the market design.

There remains considerable further work on the design to occur, and the AEC recommends that sufficient time, managed within the AEMC's Market Review powers be provided to allow industry to participate in that development.

Any questions about our submission should be addressed to me by email to ben.skinner@energycouncil.com.au by telephone on (03) 9205 3116.

Yours sincerely,

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[6] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information
[7] https://www.aemo.com.au/Media-Centre/AEMO-publishes-Quarterly-Energy-Dynamics---Q2-2019