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COGATI Implementation – Access and Charging Directions Paper

The Australian Energy Council ("**AEC**") welcomes the opportunity to make a submission to the directions paper on COGATI Implementation – Access and Charging.

The AEC is the industry body representing 23 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 repeats the most significant views from our earlier submission that:

- neither the concept nor case for change seem anywhere near sufficiently developed to propose an implementation schedule at this time;
- the proposed implementation period for Dynamic Regional Pricing (DRP) is unreasonably ambitious given other systems' development occurring at that time; and
- any of transmission rights will be inextricably designed around the regional, energy-only design of the NEM, and that proposals worked up ahead of the Energy Security Board's NEM 2025 Review (NEM2025) could become inconsistent with future market arrangements.

Introduction

The AEC recognises the long-standing issues that exist in co-ordinating the development of generation and transmission, and the risks for generators in terms of changes in the levels of access they may experience to the shared network over time. The AEC also recognises that challenges have increased with more contemporary developments in:

- The rapid rate of renewable energy generators' connections to more remote parts of the grid, challenging how both radial extensions, and more significantly, the shared network, can be efficiently developed and funded.
- The greater price-sensitivity of consumption drawn from the grid, including both demand-response as well as the charging of storage. This challenges the presumption of load inelasticity implicit in the use of a single regional price for consumption.

Whilst these challenges exist and are increasing, it should be recognised that the status quo, being large single price regions, with implied but inexplicit access rights, supported by a shared network developed and funded socially, has its own advantages. Importantly it includes simplicity which supports deep competitive trade. It is also the regime to which some 390 registered participants have developed business familiarity over two decades, and any disruption will have its own costs.

Whilst the AEC does not support the AEMC's published implementation timetable, this should not be taken that it is dismissive of the challenges in the existing network. The AEC would agree that:

- Accurate marginal incentives on the production or consumption of electricity are beneficial.
    - This benefit must however be traded against the value of simplicity as discussed above.
- Stabilisation of access could reduce risk for generators.
    - However it should be noted that in the existing regional design most generators only experience gradual changes in levels of implicit access, and that explicit transmission hedges may have their own declining characteristic.
    - And further that transmission hedges will necessarily be non-firm to many conditions, and therefore not provide the short-term stabilisation assumed.
- Ideally the costs imposed on the shared transmission network should be internalised in the generation build decision.
    - Whilst the current arrangements do not do this explicitly, it should be noted there are broad drivers through investors assessing congestion risk when siting.
- Ideally the generation should be directly involved in decisions about shared network build.
    - Noting the existing socialised network planning regime does take generators' physical investments and consulted views into account in regulatory investment tests, even if they don't have a direct contractual stake.
    - Noting also that achieving this ideal is incredibly complex if not impossible in any regime due to the broad network effects of all augmentations deep in the shared network.

Transition

Even if inexplicit, the regional model has conferred a level of assumed network access on all generators to the customers across their region. And whilst declines in this access can occur, these tend to be in a very progressive manner and often recover after socialised network investment. This regime represents the presumed level of access that generators have bought into and their business are valued against. This relatively stable level of access generators have come to assume must be retained through any new regime.

The socialised recovery of sunk transmission costs is irrelevant to the value of implied status quo access. Any shift in cost incidence could not have efficiency benefits as the transmission is sunk, and a change would simply represent a major transfer with its own risks.

The proposals in the paper recognise that grandfathering of this assumed level of access is possible, however the question as to what and how much is left open to consultation. This concerns AEC members, as a risk of engaging in the development of a new regime includes a risk that the outcome will result in less access than status quo. The review's progress would therefore be assisted by an immediate statement as to the intended level and length of grandfathering that would apply to any entertained scheme, noting the mechanics of how this is to be delivered can be left to the later development stages.

In the AEC's view this statement would need to fully reflect the volume of existing implied access, and would fix this volume for at least a decade and then decline progressively over a period of no less than a decade.

Transmission hedging firmness

A significant part of the paper's discussion relies on the benefit of greater certainty of short-term access through the provision of transmission hedges which should in turn reduce contracting risk to generators. However the discussion also anticipates that, like the OFA hedges, these will not be fully firm to all network conditions.

General commentary tends to link such non-firmness with transmission outages. However as discovered in the OFA work, the complexity of the real power system creates numerous circumstances where an assumed deliverable network capacity is not achievable. This can be due to transmission element outages, but it can as often due to a range of ambient or network conditions upon which it is difficult to assign responsibility to any one party. For example, it may include:

- Constraints necessary to achieving the safe security operating envelope across a broad electrical area, usually as judged by AEMO. System strength constraints are one example of these.

- Changes in constraint right-hand side values due to network topology, including the number of synchronised units which is in turn an outcome of the market.

- Changes in unscheduled load and generation patterns, for example the assumed loads and unscheduled generation upstream of a thermal constraint.

- The status of the distribution network.

- Whether the ambient conditions are consistent with those assumed at the time of setting the transmission right. For example, line thermal capacity can be highly dependent on wind cooling.

The OFA project considered at length to whom these risks were best allocated. It ultimately decided effectively replicating status quo by leaving the majority of network performance risk with generators. This is because:

- Few of the above variances are unarguably the responsibility of transmission network owner as causer and/or best resolver.

- Because the transmission network owner is a regulated monopoly, the allocation of additional risks to them may need commensurate increases in regulated returns. Instead the risk was limited to a capped incentive scheme in order to create managerial drivers whilst not materially increasing the business' overall financial risk.

The AEC understands why the OFA left delivery risk with generators and suspects that is unlikely to change with COGATI. If so it should then be recognised that these non-firm transmission hedges cannot provide a level of confidence in short-term transmission access that is necessarily lower risks below existing arrangements.

Scheduling

The Optional Firm Access (OFA) regime was confined to large generators through an assumption that small generators and loads were inelastic. It is clear that that assumption has become much weaker since, and elastic consumption (e.g. storage) can often be located well away from the regional reference node. To that extent, any new form of pricing regime should attempt to capture such loads and small generators.

The AEC considers it beneficial to move toward more supply and demand being part of the scheduling process. It seems therefore that any new pricing regime should apply to all scheduled or semi-scheduled generators, storage or load. At the same time we need to avoid allowing the scheduling status to be cherry-picked where there is optionality or legacy arrangements.

Market power

The AEMC has indicated that they are cognisant of the risks of a new regime creating opportunities for the exploitation of market power. In response, the AEC notes:

- A good market design should naturally allow simplified, deep competition to occur of its own course.
- It is not good regulatory practice to attempt to resolve perceptions of existing pockets of market power through deviations from a preferred market design. If it exists, the designer should assume market power will either be resolved through new-entry, or as a last resort, through direct regulatory action.

Implementation Period

The AEC considers that the design and case needs to progress substantially before an implementation schedule should be developed. The AEC has not altered its view expressed to the Consultation Paper that the implementation schedule re-presented in the Directions Paper is unrealistically ambitious.

In contrast, the Transmission Frameworks Review (TFR) was developed over three years, from April 2010 to April 2013. After those years of discussion, the TFR ultimately developed Optional Firm Access (OFA) to a similar conceptual level as that emerging in the COGATI Access Reform Review. The TFR however recognised the scale of the detailed issues to be worked through, and recommended a second review, "OFA testing and design" which ran from March 2014 to July 2015. Whilst this did not ultimately recommend progression, it had recognised that even after this fulsome development of the design, a long implementation period would still be required.

It is not clear where in the proposed COGATI implementation schedule this design and testing is to occur. It is unlikely that the 2014-15 OFA work can be used as a substitute, as the AEMC is contemplating approaches for COGATI that were never contemplated in that work, being:

- Pricing transmission expansion on a "fair value" model rather than Long-Run-Incremental-Cost (LRIC);
- Optionally incorporating local loads and storage into access settlement;
- Potentially paying local price to "constrained on" generators; and
- Use of a Surplus Residues Support Fund.

An analysis of the costs and benefits is also critical. This cannot be done meaningfully whilst the design remains in its existing conceptual stage. The schedule needs to include time, after detailed design, for a fulsome quantification of how it meets the Market Objective.

As stated in our earlier submission, implementation of a first stage in July 2022 allows insufficient time for detailed design and testing and is too close to the implementation of five minute and global settlement. It now also appears to coincide with changes for the wholesale demand-response mechanism.

A clinical analysis of all the matters ahead for the industry in terms of design, testing, making the case, allocating transmission hedges and ultimately implementing the systems necessary implies a realistic mid-2020's implementation. For these reasons there seems no rationale for continuing the separation of the COGATI work from NEM2025. Indeed, considering the matters holistically is in truth more likely to deliver earlier than the alternative.

Renewable Energy Zones

The AEC supports the AEMC progressing research into the development of new branches to the shared network under bespoke planning, funding and access sharing arrangements. The Public Interest Advocacy Centre (PIAC) proposal is a valuable suggestion in that regard. This included generator funding in return for defined access to the new branch along with a sharing between networks and customers in the level of take up.

The AEC accepts that an access right to a dedicated new zone can only extend to where it connects to the shared network, and so it will never be as powerful as a generalised access right, however at the same time it does not introduce the complexities and disruption of a generalised regime. If a few such zones were encouraged to develop, it could prove to be a useful demonstration sandpit from which to gain acceptance of what might be possible with a generalised solution in the future.

Responses to questions

These are contained in the table overleaf.

Conclusion

The AEC agrees with the AEMC's concerns that there are substantial and possibly growing concerns about the co-ordination of generation and transmission, a matter which has been studied many times previously and will probably never be fully resolved. However the Discussion Paper seems to seriously under-estimate the significance of the reform it is contemplating. The work performed in this iteration of access researched has only scratched its surface, and it is thus far too early to be proposing an implementation schedule. The AEC has major concerns about the schedule, in that it:

- Does not seem to provide time for the development, testing and cost-benefit analysis of various designs;
- That the initial start date of July 2022 is close to other major systems developments; and
- That developing an access regime separate to NEM2025 is neither sensible nor expeditious.

Whilst there remain many months, indeed years, of design work ahead for the industry, this work could benefit from an immediate statement of the level of transitional access the AEMC intends to grant in any regime, with the mechanics of its delivery resolved later.

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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Directions Paper Question	AEC Response

Question 1: Allocation of Settlement residues	The chapter covers the main issues of access settlement at a very high level. There are many more detailed design matters that need be explored, some of which emerged during the OFA Testing and Design Review plus others unique to the new concepts being explored here. These include:
	
	• The implications, from a settlement adequacy perspective, of
	  ○ providing locational pricing to only those offtakers that have elected to be exposed to them.
	  ○ providing locational pricing to constrained on generators.
	• The treatment of interconnectors and settlement residue auction instruments in the settlement equations.
	• The handling of load between a scheduling point and a connection point, such as power station auxiliaries or co-generation load. Presently scheduling and settlement work on different metering systems, and if one set is used to create the locational prices and another the settlement, many complexities emerge.
	• Unusual scheduling and metering arrangements, such as:
	  ○ aggregated units,
	  ○ scheduled non-market generators and
	  ○ multiple scheduled generator units sharing settlement meters.
	• Treatment of distribution connected generation, which in the NEM includes cases up to 400MW in size.
	
	Of the approaches listed, option A, being the allocation of surplus residue after transmission hedges to generators on the basis of availability (the OFA design) seems most appropriate in terms of continuity. Option C being a Support Fund is worthy of more investigation, say with testing historical quantities, as to whether it could really provide material confidence against network outage risk. If not, it is not worth pursuing.

Question 2: Scope of Dynamic Regional Pricing	The AEMC is considering a much wider scope for DRP eligibility than was analysed for the OFA Testing and Design access settlement arrangements. The AEC supports this consideration, but recognises it creates considerable additional untested challenges. The initial concern is revenue adequacy. OFA access settlement was not available to constrained-on generators[1] nor any offtakers – load or storage. This allowed settlements to balance, with residues matching the transmission hedges allocated under that model (assuming network capacity was not limited). If however DRP is to locationally price constrained-on generators, and transmission hedges are one-way options (as proposed in Box 4), it is not clear how the hedges of constrained-off generators could be fully funded. Similarly if offtakers are permitted optionality between a regional reference node price and a local price, it can be reasonably assumed only those with a lower local price will select it. This then presents great challenges to the revenue adequacy of the transmission hedges of generators at the same location. Limiting DRP to scheduled and semi-scheduled entities seems appropriate since the "locational" prices that can be generated out of the current dispatch processes are virtual rather than physical. They exist only for the scheduled dispatch unit identifier (DUID) as individual spokes in the hub and spoke constraint model rather than representing a physical location. This does raise issues however where scheduling is optional for a participant, who would then only seek it where it provides benefit under the DRP approach. It would be problematic if, due to a registration category, two otherwise similar entities are exposed to quite different DRP outcomes.
Question 3: Choice of Regional Price	The floating of load-average pricing (LAP) for the regional price appears to have been drawn from US markets without a recognition of the different dispatch platforms. Those markets employ a network model in their dispatch and inherently produce a real locational price for every transmission point, which can be applied to suppliers and offtakers. In contrast the NEM employs a hub and spoke approach where all unscheduled activity is represented at the hub and all scheduled variables at the end of individual spokes. As real load offtake points do not exist as such in the dispatch engine, there is no way of discovering what the NEM's version of a local price is for them. Section 4.6.9 leaps directly into LAP settlement matters without first considering how the prices could be created.
Question 4: Losses	Whilst changes in loss factors create considerable risks to market participants, there is no understood concept which would enable hedging them. Losses face the mathematical problem that, being non-linear unlike congestion, additional supply at the end of a line increases total real losses. As such, new entry is a negative rather than a zero-sum game, and thus losses cannot be stabilised through a compensation arrangement from a new supplier to another.

[1] Constrained on generators are labelled "Capacity support generators" in Appendix C.

	There may in fact be no mathematically feasible way to hedge losses, and it is notable that no loss factor hedging models were presented in its Directions Paper. Yet the Paper nevertheless asks participants' views on such a model, a concept which may in fact be mythical. Rather the Paper should have either developed a strawman concept for providing loss hedging on which to seek views or, quite probably, explained why such a concept is not mathematically feasible.
Question 6: Transmission Planning	Clearly any form of access regime is inextricably part of transmission planning, and the question here of whether it should be linked to the Integrated System Plan is facile. Note that this area proved to be the most challenging part of the OFA process because planning and charging for a shared network that is simultaneously built for both social and private benefit quickly becomes extremely complex, unintuitive and intractable. Because networks are monopolies and revenues for the social part of their services regulated, it becomes necessary to formularise the access arrangements' network planning and cost recovery mechanisms. In OFA this was done through its intricate LRIC arrangements. The Discussion Paper barely touched the surface of this vast area and stakeholders deserve to be presented a reasonably developed design upon which to comment, such as was presented across 106 pages (chapters 5-8 and appendix C & D) of the OFA Design and Testing final report Volume 2. Since that OFA work a new matter will need to be re-engaged. The LRIC design and network access was written around one network condition: summer peak load/system normal, in the reasonable historical assumption that at all other times of the year the network conditions should be the same or less binding. This may no longer be the case with the continued growth in intermittent generation.
Question 7: Access Products	It is too early in the development of the COGATI access regime to be asking participants about preferred product design. Before this can be considered, more clarification on the scope of the dynamic regional price and the level of grandfathering is required. The OFA product was one-way, however this was possible because only constrained-off scheduled and semi-scheduled generator DUIDs were captured. A mechanism capturing constrained on DUIDs, loads and storage might need to be two-way for settlement adequacy, and these DUIDs may need to receive negative grandfathering to provide funds to support positive grandfathering for constrained-off generators. With respect to duration, the AEMC should look to the design of the Settlement Residue Auction which made this question redundant through simultaneous auctions of relatively short products (quarters) and allowing participants to use time-linked bids for strips that suited them.

Question 8: Product Procurement	The AEC anticipates that the vast majority of network access will be allocated via grandfathering. However, to the extent that capacity becomes available, for example after plant closure or following network augmentation planned for social benefit, then release via an auction, with a zero floor price, seems appropriate.
Question 9: Product Pricing	A fair value approach may be superior to LRIC, however the two pages of explanation from which participants are supposed to form a view are inadequate. It first requires an explanation of similar depth to that of LRIC in chapter 6 and Appendix C & D of the OFA Final report Volume 2. The LRIC suffered considerable stakeholder uncertainty regarding what sorts of prices would likely emerge from such a complex engine. Basing the price instead on market modelling of value will also be complex, but will also be critically dependent on the assumptions that a modeller takes into the process. Market price modelling in the NEM is notoriously unreliable. A fair value method would still need to be floored at the cost of the new transmission: clearly lines of zero value should not be built. Determining that floor would still require calculating costs, which implies that the full complexity of LRIC would still be required as part of the calculation, *on top of*, the complexity of market modelling the value.
Question 10: TNSP Incentives and Regulation	The AEC would support the inclusion of a TNSP incentive scheme with an access regime, potentially replacing some of the existing schemes. The OFA project considered at length these questions, and in this case those learnings remain potentially applicable. That conclusion was low - medium powered, i.e. the main purpose is to encourage the best possible network owner behaviour without materially increasing business risk such that the cost of funds would increase.