AFMA

19 October 2020

Dr Kerry Schott AO
Chair
Energy Security Board

By email: info@esb.org.au

Dear Dr Schott

AFMA Response to P2025 Market Design Consultation Paper

The Australian Financial Markets Association (AFMA) welcomes the opportunity to comment on the Energy Security Board (ESB) *Post 2025 Market Design Consultation Paper* released on 7 September 2020.

AFMA is the leading industry association promoting efficiency, integrity and professionalism in Australia's financial markets. AFMA represents the common interests of its members in dealing with issues relevant to the good reputation and efficiency and competitiveness of wholesale banking and financial markets in Australia. AFMA has more than 120 members reflecting the broad range of participants in financial markets, including Australian and international banks, leading brokers, securities companies, fund managers, energy companies and industry service providers.

Whilst acknowledging the overall objectives of the consultation paper, AFMA's focus is on the efficiency and competitiveness of electricity financial markets. Accordingly, our comments are limited to those areas relevant, with comments provided only on Market Design Initiatives A, C, D and G.

The proper functioning of financial markets is critical to effective risk management for market participants. We note that some of the proposed changes would significantly disrupt existing financial markets if implemented. The impacts on financial markets are often understated; for example, the impact of the 5-minute settlement rule change on the $300/MWh cap market is still being dealt with. As such, we ask that the role of the contract markets is properly considered in development of these initiatives.

Australian Financial Markets Association
ABN 69 793 968 987
Level 25, Angel Place, 123 Pitt Street GPO Box 3655 Sydney NSW 2001
Tel: +612 9776 7900 Email: secretariat@afma.com.au

1. Resource Adequacy Mechanisms – Market Design Initiative A

1.1. Are current resource adequacy mechanisms within NEM sufficient to drive investment in quantity and mix of resources required through transition?

The answer to whether the current resource adequacy mechanisms within the National Electricity Market (NEM) are sufficient to drive investment in the quantity and mix of resources required through transition is unsettled.

Heightened uncertainty from the increased influx of zero marginal cost variable renewable generation, closure of coal plant as well as structural changes to demand side pose real challenges to investing in the right type of firming generation and storage, particularly at the scale required.

It is possible that the current NEM design is already sufficient to provide investment in response to price spikes and thin reliability margins without policy intervention being necessary, however whether this will result in the right mix of resources (in terms of dispatchable resources) cannot be determined until appropriate signals for system services are established. Similarly, whether the exit of thermal generation creates a reliability challenge cannot be assessed until the other market mechanisms have been designed.

1.2. Would signals provided by an operating reserve mechanism or market provide adequate incentives to deliver amount and type of investment needed for a post-2025 market in a timely manner? What are benefits of this approach? What are the costs and risks?

The effectiveness of an operating reserve mechanism will evidently depend on its design. An operating reserve mechanism set by the Australian Energy Market Operator (AEMO) may sharpen real-time prices, thus better reflecting the value of flexible and fast-start resources. However, the capacity mechanism being contemplated seems to only target ramping and no other supply characteristics in terms of managing peak demand and long-term storage/generation to cover wind droughts or limited hydro availability. The design of an effective operating reserve mechanism may need to consider the use of deep storage.

Although an operating reserve mechanism may help cost recovery given increased periods of low or negative pricing, it will suffer the same issues as scarcity pricing in that it will be reliant on price volatility and high prices at times of scarcity. Accordingly, a demand curve set by AEMO requires clear metrics and accountability around it to minimise costs and the risk of over-procurement.

Whatever operating reserve mechanism is developed will need to provide a sufficient forward signal to incentivise the generation investment necessary for future needs and allow participants to form expectations around prices and contract to hedge risks accordingly.

1.3. Would signals provided by an expanded RRO based on financial contracts or a decentralised capacity market provide the type of incentives participants require to deliver the amount and type of investment needed for a post-2025 market in a timely manner? What are benefits of this approach? What are the costs and risks?

AFMA members have provided a range of views on the efficacy of an expanded Retailer Reliability Obligation (RRO) based on financial contracts or a decentralised capacity market to deliver the investment needed for a post-2025 market, noting that while either mechanism could drive investment if appropriately designed, their implementation may involve higher transactional costs than other market design initiatives under consideration.

- Some suggest that an expanded RRO would likely increase the incentives to contract, however whether this is sufficient to bring about significant new investment depends on the appetite of market participants to enter long term contracts and positions. A modified RRO faces this risk as the current design retains a relatively short-term focus. Members have also noted that given that the RRO has only just commenced and already is undergoing a major change, it is unlikely that an expanded RRO will provide investment certainty in the short-term.

- Other views provided include that an expanded RRO should be linked to physical investment, as one based on financial contracts is unlikely to provide sufficient confidence to the market operator and government. Although the linking of RRO and physical obligations may result in lower flexibility to comply with the scheme and increase costs, the key benefits of having the RRO tied to physical obligations outlined are that it would:
    - transfer risk of over procurement from customers to retailers;
    - transfer risk of under procurement from customers to generators;
    - provide additional market signals for investment in firm capacity;
    - give transparency to governments regarding supply levels; and
    - utilise collective analysis to plan for the future.

- Some members believe a decentralised capacity market may be more suitable to ensure a defined level of capacity availability relative to the RRO. The appropriate design of such a market is of critical importance, as it would need to be competitively neutral and provide robust investment signals that can pull through capital intensive and long-lived assets where economically viable.

- It is important that the ESB consider how either reform could assist with providing certainty to both investors and governments. Practical limitations associated with the RRO/decentralised capacity markets that could impede the effectiveness of the mechanism include:
  - The RRO and decentralised capacity markets more broadly, provide a relatively indirect (and consequently uncertain) means of facilitating new investment. Under such frameworks, a retailer's obligation (which is intended to drive new investment) is dependent on factors such as the uncertain nature and timing of its contracting with commercial and industrial (C&I) load. It would therefore be challenging and impractical for retailers to enter into longer-term financial contracts or directly underwrite investment in long-lived generation assets to support C&I load. Changing the nature of the retailer obligation (e.g. by increasing the level to which retailers are required to contract and/or requiring contracts to be supported by physical generation capacity) will not resolve this fundamental issue, or provide governments with assurance that the requisite level of investment will occur in a timely manner.
  - Requiring contracts to be backed by physical generation would likely discourage participation in the Australian Securities Exchange (ASX) futures market (which currently accounts for a significant volume of contract trading activity). It would also disadvantage non-vertically integrated retailers, potentially impeding their ability to compete for C&I customer demand.
  - A full decentralised capacity market would be disruptive. The Consultation Paper states that a decentralised capacity market could be used to remunerate capacity that "is only used very rarely and without a separate revenue stream or allowing unacceptably high real-time prices, will not be provided by the market." However, a decentralised market-wide mechanism would provide increased revenue potential for all existing dispatchable resources. This could lead to windfall gains for existing generators that were likely to be operating regardless of the additional revenue stream and potentially weaken signals for new investment. As identified in the Consultation Paper, this would likely necessitate changes to the current market settings to reduce the Market Price Cap (MPC) and other market caps.

- Members have suggested that before contemplating a decentralised capacity market, market reliability settings should be reviewed (including MPCs and Market Floor Prices (MFPs)), as the introduction of a capacity market mechanism to an existing market that has been functioning well for decades would cause material disruption to secondary markets and existing contracts.

2. Essential System Services – Market Design Initiative C

2.1. The proposed provision of an operating reserve through spot market provision

Will such a mechanism assist to manage greater system uncertainty more efficiently than current arrangements? What other mechanisms might be needed to foster investment needed for a post-2025 NEM? What are benefits of this approach? What are the costs and risks?

As well as supporting resource adequacy, the provision of an operating reserve may reward flexible, on demand plant and help manage uncertainty. This will likely provide AEMO with a level of comfort that there are sufficient system resources available. In this sense, operating reserves are a form of frequency control management, and should be included in a comprehensive review of all frequency control in the NEM. Appropriate design of such a mechanism with clear objectives should foster the investment required to meet future energy needs, providing valuable reserves to respond to contingency events.

While an operating reserve could potentially assist with supporting reliability and security of supply in operational timeframes, the underlying need for the service and its overall design requires further clarification. Further analysis is required to understand:

- whether operational signals are likely to be insufficient to support the provision of ramping capacity by the market following a contingency event, having regard to the impact of the resource adequacy framework reforms discussed above (which is intended to drive further investment in flexible dispatchable plant that can assist with managing ramping events), and potential valuation of other Essential System Services (ESS);
- the design of the products that could be procured through the operating reserve. This includes how the products would be priced; and
- any potential adverse impacts on the existing NEM gross pool and subsequent contract market arrangements.

As noted above, it is not clear how the reserve would provide a sufficient forward signal to incentivise the generation investment necessary for future needs or allow retailers to form expectations around prices and contract accordingly. Whatever solution is developed would need to incentivise appropriate risk management for market participants and address both short and long-term reliability issues.

2.2. Developing Fast Frequency Response with FCAS and developing a demand curve for Frequency Response

Will such a mechanism assist to manage greater system uncertainty more efficiently than current arrangements? What other mechanisms might be needed to foster investment needed for a post-2025 NEM? What are benefits of this approach? What are the costs and risks?

Fast Frequency Response (FFR) is just one solution amongst a whole range of options that need to be evaluated and coordinated, including Primary Frequency Response (PFR) solutions. It is important that the ESB be clear about the issue that it is seeking to solve, as FFR is not really intended to manage system uncertainty but rather to assist in managing high rates of change of frequency after a contingency event.

Although FFR is one approach to better managing frequency, it is not the only option which could include inertia or other technical approaches. While FFR will likely have an efficiency benefit, it needs to be co-optimised with inertia. In order to minimise costs, the market should really be designed to allow all possible solutions.

Frequency Control Ancillary Services (FCAS) markets have not typically produced long term price signals, therefore it remains difficult to build a business case against projected FCAS revenues. ESB must consider whether the additional markets that are added as part of Post-2025 are hedgeable and provide investment signals. If FCAS markets are to provide investment signals, then a demand curve is also necessary.

2.3. The proposed structured procurement for inertia and system strength by way of Network Service Provider (NSP) provision, bilateral contracts, and generator access standards, or through a PSSAS mechanism

Which approach is preferable, what are relative benefits, risks, and costs? Should ESB instead prioritise development of spot market for inertia? What are relative benefits, risks, and costs of such an approach?

Structured procurement for inertia in the near-term is a sensible approach while spot markets for inertia develop to establish and convey investment signals. Ultimately, the efficacy of any approach to structured procurement for inertia and system strength will depend on how it is designed.

Our members have noted that similarly to how the FCAS market has evolved, inertia contracts could be utilised to better understand how the market would need to evolve and function and provide this information to investors.

One approach proposed involves the use of NSP provision, bilateral contracts and changes to standards to ensure full volume, rather than ensuring provision of minimum threshold levels. Under this approach, no Power System Security Ancillary Services (PSSAS) mechanisms would be required, with any unexpected shortfalls instead dealt with via Unit Commitment for Security (UCS) or ahead markets.

Members have also noted that having AEMO responsible for bilaterally contracting with inertia/system strength providers may better allow Transmission Network Service Provider (TNSPs) and generators to compete for service provision.

It is also worth considering existing rule change requests that could create co-optimised markets that reward the provision of services such as inertia.

Importantly, there are risks inherent to being overly ambitious in procurement mechanisms, in that this may result in poorly planned or ineffective mechanisms being implemented which would then need to be either re-designed or reverted. It is essential that the most efficient outcome in the long-term is not compromised by short-term impatience to implement solutions. Accordingly, it may be worth exploring a blend of structured procurement (via reverse auctions or similar) along with real time approaches.

3. Scheduling and Ahead Mechanisms – Market Design Initiative D

3.1. Are there other options for ahead mechanisms than those outlined by the ESB? Are options for a UCS and UCS + ahead markets fit for purpose?

3.2. Do you support the UCS concept? What factors and design features should be considered for detailed development?

Our members have indicated that views in favour of AEMO operated day ahead markets are outdated and not relevant to the NEM, and that an AEMO operated market should not be introduced, as the facility to contract day ahead already exists via existing OTC markets.

At present, the need for certainty of unit commitment through a UCS mechanism has not been clearly demonstrated, though an automatic, standardised approach to streamline the intervention and directions framework should minimise system operator error and improve operation efficiency.

In providing a plan of what AEMO will do, subject to no market or system changes, an appropriately designed UCS may facilitate greater market and dispatch efficiency, by sending more robust and transparent signals about the actions of the market operator. This may allow participants to incorporate these considerations into their own decisions and improve the market's ability to meet any energy or system service deficiencies. However, if a UCS mechanism is not designed correctly, it could completely undermine the entire financial contract market, given that facilities already exist for participants to contract day ahead.

Other options to consider include strengthening the existing frameworks and good faith bidding, utilising existing frameworks for Non-Market Ancillary Services (NMAS).

3.1. What do you consider are the drivers behind why the difference between actual and forecast MW leading up to real time dispatch has been far more stable in last decade than difference between actual and forecast prices ($MWh) leading up to real time dispatch?

The ESB's paper outlines how the generation mix is changing and what this means for uncertainty and variability, noting the effect this has on pre-dispatch forecasts along with changes in dispatch (such as automatic rebidding) and the iterative changes this inspires in pre-dispatch.

Price is dependent on a much wider range of inputs, of which demand is just one. If any of the inputs change, a price change can occur. Additionally, $MWh pricing is more sensitive as it is based on a marginal MW, so a single MW can cause a large change.

4. Transmission Access and Coordination of Generation and Transmission – Market Design Initiative G

4.1. Integrated System Plan

Do you have any comments on how the implementation of the Integrated System Plan can be made more efficient and timelier?

The 2020 Integrated System Plan (ISP) did not completely reflect the latest Actionable ISP rules and several Renewable Energy Zone (REZ) developments announced in recent months. The rules did introduce several changes to improve timeliness, including the ability to incorporate public policy announcements. It is not yet clear if the enhanced ISP can be made more efficient and timelier. The 2022 ISP, for which consultation is already under way, should provide a basis for assessing effectiveness.

The Actionable ISP framework is intended to streamline the process for identifying optimal development paths and the projects that require implementation. The ISP provides the overarching assessment that specifies the identified need and credible options to then be considered in the Regulatory Investment Test for Transmission (RIT-T).

The assessment process for transmission investment should continue to be reviewed to remove duplication and unnecessary steps. Greater scrutiny is also required to ensure assumptions are appropriate, methodologies are defensible, and forecasts are reasonable. The process needs to be balanced against the need for analytical rigour, particularly for large investments, where net benefits are finely balanced, and in an environment where transmission costs are significantly increasing (for example, Project EnergyConnect).

Governments play a role in setting policy parameters that impact the energy market. Some governments have signalled the desire to accelerate the timing of certain projects and the customer impact of this should be fully transparent. We note that in the long-term interest of consumers, the desire of governments to accelerate investment should not be at the expense of rigorous and transparent assessment of projects.

The ISP impacts on market sentiment and investment appetite as it signals future investments and competition. Where options have been identified in the ISP, it could in fact help the market to see these proceed with certainty, as it will remove some unknowns from future market decisions. Developing further interconnection can also help liquidity of hedging products.

4.2. NERA Economic Consulting's modelling of benefits of introducing transmission access reform in national electricity market

What do you think about the modelling? What does this suggest about how fit for purpose current access regime is? What does this reveal, and what are insights, about how power system will change over time, and how risks of congestion will be managed by generators?

The NERA modelling seems overly simplistic and is not representative of the NEM's topology. Transparency of the modelling inputs is required to determine if there is an explanation behind the highly surprising results. On the information provided, NERA has not demonstrated that they understand the physical market or how the forward contract market operates (and as a result, its modelling looks to be founded on incorrect assumptions).

The NERA modelling suffers from severe limitations which bring into question the practicality of the outcomes and benefits put forward, which appear to be substantially overestimated. Some of the key limitations include that the modelling:

- does not incorporate other significant market design changes being considered, nor does it appropriately consider the impact of non-market incentives such as renewable energy targets;
- was based on the draft ISP and does not include REZs, even though they would alleviate congestion concerns and would likely reduce the benefits of reform;
- does not take into account implementation costs, including costs of system changes and IT implementation;
- severely underestimates the impact on financial markets, in terms of the costs of recontracting and reopening of wholesale contracts and Power Purchase Agreements (PPAs);

- outlines outcomes (such as low prices in the short-term) and choices (such as modelling storage as a peaking generator) that are not realistic and may not be appropriate for real world use; and
- does not explore the transitional impact of reforms in terms of investor risk or associated costs for customers being higher due to the inherent complexities in managing congestion risk.

As a result, we do not consider the model to be a good indicator of how fit for purpose the current access regime is, nor a good basis for judging how congestion risks might change over time.

The introduction of transmission access reform would increase risk for generators as they would face an additional price risk, in addition to volume risk. While the proposal includes a hedging mechanism in the form of Financial Transmission Rights (FTRs), this mechanism is only needed to deal with the introduction of basis risk from the reform in the first place and will not provide a perfect hedge.

The modelling fails to account for the costs of FTR purchases and the impact of this on contract prices. We disagree with NERA's assumptions around contract market liquidity and believe there is a significant concern about impacts of the reform to market liquidity of scheduled generation receiving the Locational Marginal Price (LMP).

Overall, the modelling does not have any bearing on the nature of congestion risk and how this should be best allocated, particularly the roles of transmission network providers and AEMO in managing the system. The analysis presumes that congestion risk should be entirely borne by generators who are able to mitigate this through locational decisions, which is overly simplistic.

The reforms may result in generators selling energy at the generator's gate (local connection node), rather than the regional reference node, transferring risks to retailers or end use customers who may not be able to properly manage the risk with securing FTRs. The reforms will also impact Exchange of Futures for Physicals (EFP) contract liquidity as a means for managing credit risk.

It appears that the challenges around transition have been significantly understated, particularly regarding the legal costs of recontracting and likely reopening of wholesale contracts and PPAs. The four-year implementation/transition period proposed will not be sufficient for PPAs which will need to be renegotiated at considerable expense, and with real lasting impacts on risks for renewables investment.

NERA's modelling does not explore the transitional impact of reforms in terms of investor risk and associated costs for consumers due to inherent complexities of managing congestion risk. Better price signals cannot influence the decisions of existing generation plant in terms of locational decisions to manage the new congestion and price risk being introduced.

Though NERA's modelling of how the shift to LMPs would affect physical dispatch and investment patterns appears thorough, the treatment of financial market impacts is highly theoretical. The actual delivery of market benefits will depend on FTR trading and contract markets generally, which will not operate as perfectly as NERA assumes.

There has also been an overestimation of a wealth transfer due to the lack of proper consideration to the implementation of REZs, including the transmission investment in shared network capacity that will be undertaken to support REZs as well as the up to date information on ISP projects. The cost-benefit analysis (CBA) work undertaken by NERA only included specific ISP projects – Group 1 and Group 2 projects from the Draft 2020 ISP – and did not include any REZ network extensions indicated in the Final 2020 ISP report or network augmentation projects listed in the network service providers annual transmission planning reports.

There also appears to be a lack of transparency as to whether the jurisdictional transmission reliability standards for reliable supply to consumers has been met in the reform case, given the use of AEMO's Draft ISP project plan only, without inclusion of the necessary supplementary transmission investment required to support these network augmentations.

4.3. Transmission access reform model released by AEMC

How well do you think the proposal would address identified challenges?

AEMC's transmission access reform proposal (COGATI) does not address the identified issues and will not directly manage the coordination challenge of building efficient transmission infrastructure in locations that best serve efficient generation decisions. While the reforms will alter generation locational decisions, this is not likely to occur in the perfect way as suggested by NERA's modelling. We suggest that the current inefficiencies arising from disorderly bidding are also smaller than the modelling suggests. Arguments in favour of COGATI reforms appear to 'gloss over' the strength and value of existing locational investment signals and the liquidity risk for the contract market.

Issues such as difficulties in connecting to the grid and higher-than-expected curtailment are symptomatic of a lack of coordination of generation investment, with network upgrades often lagging generation build. As the ESB identifies, recently generators have located in areas rich in renewables, which are often located in weak parts of the network. This trend is likely to continue, given the strong locational signals provided by state-based programs such as the Renewable Energy Targets (RETs). Most recently, the Victorian Government has announced a second round of the VRET, which will drive further investment into renewables. In the absence of timely transmission augmentation appropriately coordinated with generation build, congestion issues, curtailment and delays in grid connections are likely to persist, including for VRET2 projects.

There are several risks of the proposed reforms that may impact negatively on many participants in the market and ultimately consumers. The reform creates significant risks and investment uncertainty resulting in disruption to existing long-term energy contracts and added costs for market participants due to the Locational Marginal Pricing regime being proposed.

We are concerned the reform no longer attempts to address the key question posed by the CoAG Energy Council and has diverted from its original objective of coordinating generation and transition investment, to improving access through congestion management.

While the proposal may result in more efficient short-term spot market signals, we think it is unlikely to address congestion. Further, while congestion does provide one type of locational signal, this is not the only factor to be considered. As noted, generator locational decisions are weighed against other key characteristics, such as availability of fuel source (high wind speeds/solar irradiation), land availability, ease of obtaining planning approvals, access to existing infrastructure and non-market incentives such as RETs.

The arguments provided by the AEMC to support the changes appear unclear and the analysis does not comprehensively explore the implications to participants and consumers from both a physical spot market and financial contracts market perspective.

Simpler and more cost-effective market reforms could better address the emerging market risks. Transmission investment, coordinated with generation investment, is now being considered outside the COGATI reforms, by other market, government and regulatory initiatives, such as REZs, actioning AEMO's recommended ISP projects and the transmission network service providers normal Annual Transmission Planning Report and RIT-T process for projects to connect AEMO's ISP projects to the customer load centres. Locational information is also being further supported by the *Transparency of new projects* rule.

Further detail on the implications for contract market efficiency and liquidity of COGATI, and alternative solutions to deal with the issues it seeks to address, are set out below.

<u>Implications for contract market efficiency</u>

COGATI risks having a significant detrimental impact on the efficiency of contract markets, primarily due to increased risk and uncertainty and the added complexity brought by the introduction of LMP and FTRs, which may negatively impact investment signals and create a barrier to investment in new generation.

- The lack of FTR firmness means that nodal price risks will not be able to be addressed properly, meaning that a greater number of FTRs may be required. Where FTRs are not sufficiently firm, not available, or the duration that they are available does not match needs, generators may add risk premiums to cover uncertainty, and price in any volume and basis risk brought on from not being able to access FTRs (or alternatively just sell at point of production, leaving buyers to manage the risk of a constrained transmission grid).

- As FTRs will remain limited to a conservative level set under existing network capacity, a large number of participants are likely to be exposed, which will have a broad impact on the financial market. Risk departments may limit the extent to which counterparties trade across multiple nodes without FTRs. Financial market traders that normally add significant liquidity may be less likely to participate in a larger number of smaller markets. In addition, credit risk may also increase because contracts issued under COGATI may be produced by less credit-worthy counterparts or without clear contractual directions outlining how risks are managed/allocated. This is all combined with the additional uncertainty around how the market will actually evolve, and which products will deal with financial risks. There is also a risk that current product development underway to better facilitate hedging across different times of day to accommodate non-firm renewables may be stifled.

- The introduction of more complex arrangements under the September 2020 model (VWAPs, dynamic losses and staggered FTR auctions) may increase the likelihood of prices for financial instruments not reflecting underlying value because of imperfect information. Many contracts across an increased number of nodes with much analytical investment would be required, favouring more active or resourced market participants, with riskless profits being possible (which goes against idea of perfect market efficiency). While FTR speculation by financial intermediaries is already a large profitable feature of NZ market, the AEMC has typically ignored the role of intermediaries, focusing on the financial market as a point to point exercise (with retailer A buying direct from generator B).

<u>Implications for contract market liquidity</u>

The proposed reform introduces basis risk associated with congestion, which can be covered where FTRs are purchased and will always pay the full amount of price differences in the presence of congestion. This ‘revenue sufficiency’ condition and the associated ‘firming’ of FTRs depends on perfect foresight of the state of the transmission network at the time of FTR auctions, which are proposed to occur progressively from 10 years in advance.

- AEMC assumes that generators will buy transmission rights, which may not in fact occur. If instead, generators decide to only sell financial contracts at the point on the grid that they are connected, rather than at a central point (i.e. the node in each state), there will be a breakdown of liquidity due to a reduction in the number of homogenous products traded at respective state nodes.

- It is likely that some proportion of contracting volume will be pushed to local nodes and settled at LMPS, fracturing traded volumes across numerous nodes. The introduction of basis risk between the LMP and the node will have implications on liquidity as generators seek to transact at the LMP.

- Any reduction in contract market liquidity will have flow-on impacts on the RRO or any future Resource Adequacy Mechanism, the ability of retailers to access contracts, and the ability of generators to comply with the Market Liquidity Obligation. These impacts have not been addressed in the AEMC's work to date.

- Trading activity of generators will likely be limited by the availability of FTRs, meaning the flow of contracts will centre around FTR auctions, making contracts scarce at times which will impact trading flow. The risk of a situation where there are insufficient transmission rights available at a time when an LMP is low, whilst the Regional Reference Price (RRP) used to settle contracts is high, adds an additional layer of risk that buyers and sellers will need to factor into their contracting risk frameworks and contracting decisions.

- To reduce risk, generators may make fewer contracts available in each region, resulting in a detrimental outcome for contract market liquidity and customers who rely on contracts for retail pricing certainty. The retail customer ultimately will be unable to obtain contracts at times or pay a premium for the risk associated with the floating FTR exposure.

- Having the number of FTRs available at a lower volume than the current physical network capability may not meet the minimum required to maintain the existing level of contract liquidity in order to increase "firmness". This will also lower the volume of firm contracts able to be traded. Participants may be incentivised to delay the purchase of FTRs until closer to real time, when their likely value is better known, which may also cause an associated withholding of other contract purchases.

- The complexity brought by COGATI will also add to need for credit support. If financial market traders do not participate in the large number of smaller markets, then this will cause liquidity issues.

Though the AEMC has attempted to address some liquidity concerns in their Interim Report (published September 2020), there are key areas where liquidity needs to be tested further.

Over the interim period between final rule and effective date, and assuming the RRP is changed to a Volume Weighted Average Price (VWAP), there are significant risks associated with renegotiation of existing contracts/PPAs/offer agreements by contract holders and counterparties. It is likely that a number of existing contracts will fall over because of renegotiation costs or the number/impact of contractual clauses means the agreement is no longer workable. This will likely reduce market liquidity. We request AEMC undertakes a specific market modelling exercise to assess this risk, and how it would play out if the RRO was also triggered (or Settlement Residue Auction (SRA) prices dropped). The AEMC should also confirm how the SRA market would be wound back over this period, noting that existing SRA contracts could have legal effect over the same time period where contract renegotiation and initial FTRs (both transitional and auctioned) are assigned.

In its Interim Paper, the AEMC has since changed its view on the number of nodes available at the outset, outlining a preference to start access reform with a smaller number of pre-defined nodes. This is may impact market liquidity by limiting the number of FTR “routes” available, and therefore the level of risk a contract could wear/assign. However, it could also increase competition for these routes, and therefore the value of contracts available.

Even if the use of a reduced number of predefined trading (zonal) hubs could assist in the understanding of inter-zonal risks, basis risk between these zonal hubs remains for those that cannot secure FTRs. In addition, the proposed model retains price basis risk between the zonal hub price and the generators’ LMP. This could be improved if generators in the Zone received the zonal price. As generators will only sell hedges based on FTRs held, uncontracted generators have an incentive to maximise profits via price/volume trade off in the physical market. Generators without FTRs will quickly work out the optimum contracting and dispatch level such that congestion does not bind, such that FTR payoffs are immaterial and speculators will face large losses from FTR purchase. Financial market hedging will suffer as generators will have incentives to not provide hedge cover to competing retailers.

These impacts and market interactions should be subject to independent modelling under a further market assessment by the AEMC. While AEMC have now allowed both physical and non-physical participants access to FTR auctions, which may increase competition, and hopefully the number of contractors in market, this should be analysed further.

Whilst the use of actual real time dynamic marginal losses will more accurately reflect network losses, the reduction in overall costs of losses will at best be marginal compared to the current annual average loss factor allocation.

Having loss factors that change every five minutes will create a lack of certainty over extended periods, making it far more complicated and difficult to predict when compared to the current approach. As such, we expect the introduction of dynamic marginal losses will have a negative impact on the level of contracting. Dynamic losses can increase volatility of losses, varying approximately +/- 20% from the average yearly losses. This will likely reduce the willingness of generators to hedge compared to the current system in place. Generators are settled on the basis of loss adjusted volume. At times of high system demand, and potentially higher prices, generator settlement would be subject to a higher value of losses under dynamic Marginal Loss Factors (MLFs), resulting in lower settlement value at the node. In addition, dynamic losses would increase for some generators under network outage conditions, where higher priced dispatch outcomes would be more likely to occur. As actual losses under a dynamically calculated loss framework would be unknown until dispatch, in our view there would be high probability generators would adjust their contract position to avoid unfunded contract for difference payments, as Contract-For-Difference (CFD) payments in this case may not be supported by spot receipts.

The current annual MLF framework locks in a fixed loss value for each financial year, this allows generators to contract with certainty under all network and demand outcomes.

<u>Alternative solutions</u>

While existing locational signals such as MLFs and constraints may be sufficient to deliver lowest costs for consumers, alternatives approaches to addressing the issues that AEMC's transmission access reform seeks to address include:

- Integrated System Plan - the ISP is effective and in time will be able to solve transmission related issues without the significant market disruption of COGATI. The ISP provides regulated central planning of new transmission investments/grid augmentations, leaving the market to determine (in line with other market signals) the best locations for generation investment. A developer still wears the risk and associated costs of a bad investment decision, so future congestion will naturally dissolve itself. The SRA auctions mechanism should also continue to operate as it can be reviewed or re-purposed for transmission/interconnector use and charging frameworks.

- Renewable Energy Zones - unlocking REZs and establishing mechanisms for a sharing of costs between connecting parties, (noting that the cost of building transmission to new geographic locations needs to be carefully considered to ensure consumers don't ultimately wear excessive costs for new transmission.) A REZ framework integrated with other existing market reforms (i.e. NEM 2025 Review market design initiatives and other AEMC rule changes) could deliver a platform for 'as close as possible' coordinated new investments.

- Increased transparency - improved information provision between NSPs and participants (including connecting parties) such as additional data on congestion and losses (and which may need to build on the recent rule changes which provided for greater transparency with potential and planned generation projects). More transparency and release of information on network hosting capabilities and timing/ location/size etc of intended connecting generation should also improve locational signals.

- Changing dispatch during instances of tie-breaking, which could include preference to generators based on when they connected, or other dispatch/ bidding rules that target more efficient plant. This solution would need to be refined but is still likely to be a far lower cost option that directly targets the incentive for disorderly bidding, the removal of which constitutes the bulk of COGATI's expected benefits.

More targeted transmission planning around known and likely areas of congestion are likely to occur without COGATI reforms. Where the build-out of congestion to meet connecting generation is in line with optimal system planning (e.g. as per locations and timing in the ISP, and in detailed REZ plans) this can be recovered under regulated transmission revenues. Where it is not, funding models are under consideration for generators to fund investment and determine associated access rights themselves with the relevant TNSP.

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AFMA understands that the post-2025 market design project is a massive undertaking, with a potentially infinite number of approaches and combinations of initiatives possible to deal with the challenges involved with reforming the national electricity market. We ask that the role of the contract markets is properly considered in development of these initiatives, so that market participants are able to manage risks and costs associated with the changes while ensuring the security and reliability of the electricity system now and into the future.

Please contact Natalie Thompson either by phone on 02 9776 7979 or by email at nthompson@afma.com.au if further clarification or elaboration is desired.

Yours sincerely

David Love
General Counsel & International Adviser