7 November 2019

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Dear Mr Pierce

Coordination of Generation and Transmission Infrastructure Proposed Access Model (EPR0073)

Energy Queensland Limited (Energy Queensland) appreciates the opportunity to provide a submission to the Australian Energy Market Commission (AEMC) in response to the *Coordination of Generation and Transmission Infrastructure Proposed Access Model* discussion paper (discussion paper), which sets out proposed changes to key features of the transmission access framework relating to wholesale pricing and financial risk management.

Energy Queensland's responses to the issues raised by the AEMC in its discussion paper are provided in the attached submission. We would welcome the opportunity to discuss our submission and the issues raised with the AEMC.

Should you require any additional information, please do not hesitate to contact me on (07) 3664 4970 or Charmain Martin on (07) 3664 4105.

Yours sincerely

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Acting Manager Policy and Regulatory Reform

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Energy Queensland

Submission to the Australian Energy Market Commission

Coordination of generation and transmission infrastructure proposed access model

Energy Queensland Limited
7 November 2019

About Energy Queensland

Energy Queensland Limited (Energy Queensland) is a Queensland Government Owned Corporation that operates a group of businesses providing energy services across Queensland and the National Electricity Market (NEM), including:

- Distribution Network Service Providers, Energex Limited (Energex) and Ergon Energy Corporation Limited (Ergon Energy);
- a regional service delivery retailer, Ergon Energy Queensland Pty Ltd (Ergon Energy Retail); and
- an affiliated contestable business, Yurika Pty Ltd (Yurika), which includes Metering Dynamics Pty Ltd (Metering Dynamics).

Energy Queensland's purpose is to safely deliver secure, affordable and sustainable energy solutions with our communities and customers and is focussed on working across its portfolio of activities to deliver customers lower, more predictable power bills while maintaining a safe and reliable supply and a great customer experience.

Our distribution businesses, Energex and Ergon Energy, cover 1.7 million km^2 and supply 37,208 GWh of energy to 2.3 million homes and businesses. Ergon Energy Retail sells electricity to 740,000 customers.

The Energy Queensland Group also includes Yurika, an energy services business creating innovative solutions to deliver customers greater choice and control over their energy needs and access to new solutions and technologies. Metering Dynamics, which is a part of Yurika, is a registered Metering Coordinator, Metering Provider, Metering Data Provider and Embedded Network Manager. Yurika is a key pillar to ensuring that Energy Queensland is able to meet and adapt to changes and developments in the rapidly evolving energy market.

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1. Introduction

On 14 October 2019, the Australian Energy Market Commission (AEMC) published a discussion paper on the *Coordination of Generation and Transmission Infrastructure Proposed Access Model* (discussion paper). The discussion paper forms part of the AEMC's Coordination of Generation and Transmission Investment (COGATI) review on the potential need for changes to the transmission planning and investment decision-making frameworks.

In response to feedback, the AEMC's discussion paper sets out the proposed access model to assist stakeholders in considering the potential impacts that the model may have on their operational and investment decisions. The proposed model focusses on changes to two key features of the transmission access framework:

- ***Wholesale electricity pricing*** – allowing generators and storage to receive a local price that better reflects the marginal cost of supplying electricity at their location in the network rather than the current regional reference price; and
- ***Financial risk management*** – enabling generators and storage to better manage the risks of congestion by purchasing a financial transmission right.

It is intended that these changes will enhance the operation of the NEM, improve signals for investment in generation and transmission and lead to lower costs for customers. It is proposed that the changes will be implemented in July 2022.

The AEMC has requested that interested parties make submissions on the questions raised in the discussion paper by 8 November 2019. Energy Queensland's comments in response to the discussion paper are provided in sections 2 and 3 of this submission.

We are available to discuss this submission or provide further detail regarding the issues raised.

2. General comments

Energy Queensland responded to the AEMC's *Coordination of Generation and Transmission Investment – Access and Charging consultation paper*[1] and *Coordination of Generation and Transmission Investment – Access Reform* directions paper.[2] In both submissions, we highlighted the situation in Queensland which demonstrates that:

- both the Energex and Ergon Energy distribution networks are continuing to experience significant growth in the volume of large-scale embedded generator connections (up to 180 MW), most particularly in regional and rural Queensland; and
- the distribution networks and large embedded generators are experiencing similar challenges to those of generation connecting at the transmission level, including congestion issues.

In light of these considerations, Energy Queensland remains of the view that consideration needs to be given to the treatment of large-scale scheduled and semi-scheduled generation already connected and connecting to the distribution networks and the potential impacts of the proposed transmission access reforms. In Energy Queensland's view, the increasingly distributed nature of generation warrants a whole-of-system approach to ensure an optimised outcome for customers, generator proponents and networks and avoid any unintended consequences or perverse outcomes.

While we note the focus of the proposed access model is on transmission-connected generation projects, Energy Queensland considers that it must be recognised that distribution networks, such as Energex and Ergon Energy, are also receiving a significant number of preliminary and detailed enquiries for large-scale generator connection projects that are greater than 5 MW, including scheduled and semi-scheduled plant. For the AEMC's information, Energex and Ergon Energy currently have:

- thirteen scheduled / semi-scheduled generators connected and commissioned;
- an additional eight scheduled / semi-scheduled generators currently committed; and
- a further six scheduled / semi-scheduled generators entering the application phase.

It is anticipated that the number of large-scale generators seeking to connect to the distribution networks will only continue to increase as the NEM evolves.

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[1] Energy Queensland, *Submission to the Australian Energy Market Commission: CoGaTI implementation – access and charging*, 26 April 2019.
[2] Energy Queensland, *Submission to the Australian Energy Market Commission: Coordination of Generation and Transmission Investment – Access Reform*, 2 August 2019.

As such, Energy Queensland considers further detailed consideration is required of certain aspects of the proposed model, including the following:

- ***Dynamic regional pricing***

  A key concern for Energy Queensland is ensuring that there are no adverse consequences for the 2.3 million homes and businesses connected to our distribution networks, including our 740,000 retail customers, as a result of the proposed reforms. We therefore consider that further analysis is required to determine the effect local pricing will have on the regional price given it is proposed that the regional price will be calculated as the volume weighted average of local prices. Figure 4.1 of the discussion paper provides an example where the volume weighted price is higher than that calculated by the current regional reference price methodology. It is therefore recommended that modelling is undertaken to determine the impact of this pricing reform on costs, including retailer hedging practices, regional reference prices and current prices paid by customers.

- ***Transmission losses***

  With respect to the calculation of transmission losses, Energy Queensland considers that further clarity is required as to:

  - how transmission losses will be calculated for distribution-connected scheduled and semi-scheduled generators;
  - what additional administrative burden will be placed on distribution network service providers to provide information and / or modelling; and
  - interactions and impacts on the annual calculation of distribution loss factors.

- ***Financial transmission rights***

  It is not clear from the detail provided in the discussion paper how scheduled and semi-scheduled generators connected to the distribution networks will be managed under the proposed reforms. The discussion paper notes that every scheduled and semi-scheduled generator will have a local price (presumably at their connection point) and that generators will be able to purchase financial transmission rights to help manage the risk of congestion on the transmission network. However, it is unclear whether financial transmission rights will be

  extended to connection points in the distribution networks and, if not, whether distribution-connected generators will access a local price at their connection point or at the upstream transmission connection point.

  Further, it is unclear how the calculation of financial transmission rights will take growth in small-scale distributed energy resources into consideration. A significant number of zone substations in the Energex and Ergon Energy distribution networks are already experiencing reverse flow during daytime hours. This trend is expected to increase and includes the distribution system being considered a net exporter to transmission nodes in some cases. As such, the amount of transmission capacity available for large generators will gradually decrease unless augmentation of the distribution networks is undertaken. The balance between providing certainty for generation investments and accuracy of forecasts informing the calculation of financial transmission rights will therefore be challenging. This situation also implies that distribution network service providers will have greater involvement in joint planning with the Australian Energy Market Operator (AEMO) and transmission network service providers to enable calculation of financial transmission rights. Further clarity on these matters is therefore required.

- ***System strength***

  In terms of constraints in locational marginal pricing, it is not clear from the discussion paper how system strength will be included or how moving to a local price will incentivise a synchronous generator to bid when there are system strength constraints.

  The example provided on page 88 of the discussion paper states that:

  > *Exposing generators to the dynamic regional price removes the incentive to (sic) for generators to bid 'unavailable' when the regional reference price is lower than their cost of supply. This is because they will be able to access a higher local price if their electricity generation is needed.*

  This statement implies that system strength requirements will be built into a local price, but this is not consistent with the statement provided previously on page 33 of the discussion paper:

  > *To the extent that certain dispatch constraints are currently excluded from the dispatch engine, then they do not impact the regional reference price. They would also not be factored in to locational marginal prices.*

  The discussion paper further implies that, in future, it is anticipated that these system strength constraints would be included in the NEM dispatch engine. If our interpretation of this statement is correct, it would represent a significant step-change in the complexity of modelling compared to that currently undertaken. At present, conservative limitations are often imposed for system strength, as there is a significant challenge in allocating time and resources to modelling every scenario and contingency sufficient to provide a high level of confidence for asynchronous generation by providing a more generous dispatch allowance. Further clarity on these matters is therefore required.

  Further consideration is also required as to whether it is intended that transmission network service providers should formally contract with those generators to provide adequate system strength to comply with AEMO's *System Strength Impact Assessment Guidelines*.

Energy Queensland recognises that the proposed changes are complex and that a full range of modelling and scenario assessment has not yet taken place. We therefore welcome the publication of the discussion paper and the opportunity to comment on the proposed access model. However, Energy Queensland remains of the view that more detailed financial modelling and analysis is required to ensure the costs to implement the proposed reforms are not under-estimated.

Energy Queensland looks forward to participating further in the consultation process on this matter and would welcome the opportunity to discuss our recommendations with the AEMC.

3. Detailed comments

Energy Queensland provides comment on the following questions raised in the discussion paper:

<table>
<tr><th>AEMC Question</th><th>Energy Queensland Response</th></tr>
<tr><td colspan="2">QUESTION 1: Scope of dynamic regional pricing</td></tr>
<tr><td>• Do stakeholders consider that the scheduled / non-scheduled distinction offers a sensible basis for determining which parties should face local or regional pricing?</td><td>Energy Queensland has concerns about scheduled and non-scheduled customer loads seeing a different market price and the potential for perverse market outcomes. Matters that require further consideration include:
• The potential for a new customer load making a location decision avoiding a high locational marginal price by signing a retail contract based on the regional reference price.
• Retailers offering their customers a non-scheduled demand side response product based on the regional reference price. Assuming the new market participant category of demand response service provider is introduced, that participant could offer their customers a scheduled demand side response product based on a locational marginal price. This would result in demand response by customers varying depending on whether their demand response is provided through a retailer or a demand response service provider, leading to perverse outcomes, including:
− A customer with a retailer-provided demand side response product decreasing load at times of high regional reference prices even if the relevant locational marginal price was low, exacerbating the local issue of surplus generation for local demand; and</td></tr>
</table>

AEMC Question	Energy Queensland Response
	− Situations where retail demand response is reducing customer load while the demand response service provider is increasing customer load (e.g. from storage).
• Is the proposed waiting period of 12 months to reverse a change to a participant's categorisation workable and appropriate?	Energy Queensland considers the proposed waiting period of 12 months to reverse categorisation to be workable. However, this approach will not prevent the initial decision by a customer to be scheduled or non-scheduled being based on "cherry-picking" a regional reference price or a locational marginal price. There is also nothing to prevent this initial choice remaining in place long-term which does not resolve the underlying issue of load that should be scheduled locating in an area that has insufficient generation or is downstream of a constraint avoiding the locational marginal price signal by entering into a retail contract.
QUESTION 2: Constraints in pricing	
• Do stakeholders agree with characterisation of the constraints that would be reflected in locational marginal prices?	It will be important to quantify the costs associated with incorporating all constraints that influence dynamic regional pricing into the existing NEM dispatch engine and assess whether the anticipated benefits will outweigh those costs. Care should also be taken to identify all potential impacts to ensure system modification costs are not under-estimated. For example, consideration will also need to be given to the need for AEMO to provide pre-dispatch forecasts and pre-dispatch sensitivities for each locational marginal price to enable generators to manage risk.

AEMC Question	Energy Queensland Response
QUESTION 3: Regional pricing method	
• Do stakeholders agree with characterisation of the benefits and costs of moving to a volume weighted average price?	Energy Queensland generally agrees with the AEMC's characterisation of the benefits and costs of moving to a volume weighted average price. However, this assessment needs to be supported by a cost-benefit analysis.
• What other costs and benefits do stakeholders think should be taken into account?	Many market participants utilise sophisticated market modelling tools to generate pool price forecasts to develop trading and energy risk management strategies. If the proposed reforms are implemented, these tools will need to use a volume weighted average price of the locational marginal prices. The costs for market participants to make the necessary system changes will be substantial and should not be under-estimated.
QUESTION 4: Losses under dynamic regional pricing	
• Do stakeholders agree with the Commission's qualitative analysis of the potential dispatch efficiency benefits that could result from adopting dynamic loss factors?	Energy Queensland broadly agrees with the AEMC's qualitative analysis of the benefits of adopting dynamic loss factors. However, the costs associated with implementing dynamic loss factors need to be quantified to ensure they do not outweigh those benefits.
• What other costs and benefits do stakeholders think should be taken into account?	No comment.
• Do stakeholders agree that the alternative *ex ante* approach to incorporating dynamic loss factors should not be pursued further at this stage?	Energy Queensland considers it is too early to abandon this option as it is likely that it could be delivered at a substantially lower cost while potentially capturing many of the benefits. The cost-benefit analysis should consider both options.

AEMC Question	Energy Queensland Response
QUESTION 5: Mitigating market power	
• Do stakeholders agree with our characterisation of how market power issues may arise under dynamic regional pricing?	Energy Queensland agrees with the AEMC's characterisation of market power issues.
• Do you agree with our proposed response to market power issues?	Energy Queensland agrees with the proposed response in principle. However, further details are required to enable a meaningful assessment.
• What other costs and benefits may result from this response to market power issues?	No comment.
QUESTION 6: Type of financial transmission rights	
• Should financial transmission rights be limited to options instruments?	Energy Queensland is of the view that financial transmission rights should be limited to options instruments.
QUESTION 7: Liquidity	
• Do stakeholders agree with our characterisation about how the financial transmission rights should support liquidity?	Energy Queensland agrees with the AEMC's characterisation of how financial transmission rights should support liquidity.
QUESTION 8: Prices that can be hedged	
• Have we appropriately identified the pairs of prices that can be hedged through the instruments?	The AEMC has appropriately identified the pairs of prices that can be hedged through instruments.

AEMC Question	Energy Queensland Response
• Would more or less flexibility than that recommended be preferred?	No comment.
QUESTION 9: When financial transmission rights are active	
• Are continuous and time of use rights appropriate, given the trade-offs identified above?	Energy Queensland considers continuous and time of use rights are appropriate.
• Are more bespoke products desirable through the auction, and how might they be accommodated?	Energy Queensland does not support selling bespoke products through the auction. We support bespoke products being developed and traded in secondary markets.
• What are your expectations of a secondary market emerging to provide bespoke products, if desired by the market?	It is possible that a limited, illiquid secondary market for bespoke products may emerge to meet market demands.
QUESTION 10: Revenue to back FTRs	
• How the number of FTRs sold should be determined? How, specifically, might this be achieved/targeted?	No comment.
• How should excess settlement revenue not required to fund financial transmission rights be treated?	No comment.
• Who should pay for any shortfall in settlement revenue?	No comment.
• Should the revenue from the sale of the financial transmission rights be used to back the FTRs?	No comment.

AEMC Question	Energy Queensland Response
QUESTION 11: Non-thermal constraints	
• Has the Commission identified the challenges relating to non-thermal constraints? How might these challenges be accommodated in the design of the FTRs?	No comment.
QUESTION 12: Losses	
• Has the Commission identified the challenges relating to losses? How might these challenges be accommodated in the design of the FTRs?	No comment.
QUESTION 13: Method of sale	
• Do you agree with the proposal to use a simultaneous feasibility auction to determine the quantity and combination of financial transmission rights to be sold?	Energy Queensland agrees with the proposal to use a simultaneous feasibility auction to determine the quantity and combination of financial transmission rights to be sold.
• Should AEMO be responsible for this auction?	Energy Queensland supports AEMO having responsibility for the auction.
• Should the reserve price be zero?	We agree that a reserve price of zero is appropriate.
• What other insights do you have on the design of the auction?	No comment.

AEMC Question	Energy Queensland Response
QUESTION 14: Tenure and lead time	
• What is the appropriate tenure for the financial transmission rights?	No comment.
• How far in advance should the financial transmission rights be made available? What factors should the Commission take into consideration when determining the lead time?	No comment.
QUESTION 15: Auction participants	
• Should participants to the auction be limited to physical market participants in the case of financial transmission rights between local and regional prices?	Energy Queensland agrees that participation in the auction should be limited to physical market participants.
• Should non-physical participants be allowed to buy financial transmission rights between regional prices?	We support non-physical participants being allowed to buy financial transmission rights between regional prices in secondary markets.
QUESTION 16: Financial transmission rights transparency	
• What information relating to the sale of financial transmission rights should be made transparent?	No comment.

AEMC Question	Energy Queensland Response
QUESTION 17: Costs of implementing the proposed model	
• Do stakeholders agree with our proposed approach to ascertain estimates of the costs of implementing the proposed model?	Energy Queensland agrees with the AEMC's proposed approach.
QUESTION 18: Additional benefits	
• Beyond the benefits identified, are there additional benefits that stakeholders think should be taken into consideration?	No comment.
QUESTION 19: Better risk management	
• What additional implications from better risk management do stakeholders think should be considered, beyond a lower cost of capital?	Energy Queensland does not consider that a lower cost of capital can be assumed. Locational marginal prices could be viewed as introducing additional, new risks. For example, generators will be exposed to more volatile locational marginal prices as well as continuing to face the risk of reduced production.
QUESTION 20: Benefits of reforms overseas	
• What overseas markets or studies could be relevant? What important differences should be taken into account?	No comment.

AEMC Question	Energy Queensland Response
QUESTION 21: Improved operating incentives	
• What literature in relation to race to the floor behaviour and bidding unavailable behaviour do stakeholders think should be taken into account?	No comment.
QUESTION 22: Improved dispatch efficiency	
• Is the proposed methodology in relation to the efficiency gains from adopting dynamic loss factors likely to capture all the benefits from such a change?	No comment.
QUESTION 23: Better locational incentives to invest	
• Do stakeholders agree with the methodology described in relation to using the estimated historic cost of congestion as a basis for an estimate of the 'size of the prize' of better locational signals for investment that would be provided under the proposed model?	No comment.
QUESTION 24: Additional policy design areas	
• Are there areas of policy design in addition to the three identified that stakeholders consider should be included in the quantitative modelling exercise?	No comment.

AEMC Question	Energy Queensland Response
QUESTION 25: Market power	
• What issues should be taken into account in the proposed modelling of the impact of dynamic regional pricing on market power?	No comment.
QUESTION 26: Revenue adequacy of financial transmission rights	
• What factors do stakeholders think should be taken into consideration in modelling the demand for financial transmission rights at each point in the network?	No comment.
QUESTION 27: The effect of VWAP pricing	
• What impacts do stakeholders see from the introduction of volume weighted average pricing in place of the existing regional reference price? What considerations do stakeholders think should be taken into account in modelling the effect of volume weighted average pricing?	No comment.
QUESTION 28: Distributional impacts	
• What issues should be taken into account in the proposed modelling of distributional impacts?	No comment.

AEMC Question	Energy Queensland Response
QUESTION 29: Communication	
• What particular aspects of the operation of the model would stakeholders like to see in operation in a paper trial?	No comment.
QUESTION 30: Alternative approaches	
• Are there alternative approaches to a full quantitative model that stakeholders think should be considered that might avoid the pitfalls identified in the three approaches?	No comment.
QUESTION 31: Grandfathering of access	
• Do stakeholders agree with the proposed principles and approach?	No comment.
QUESTION 32: Transition for transmission network service providers	
• Do stakeholders agree with our considerations for transmission network service providers in relation to transition?	No comment.

AEMC Question	Energy Queensland Response
QUESTION 33: Implementation	
• In light of the proposed access model specification put forward in this paper, do stakeholders have views on an appropriate implementation date?	Energy Queensland is of the view that the proposed implementation date of July 2022 is not practical as market participants will still be embedding the five-minute settlement and global settlement system solutions and, possibly, system changes required to support a wholesale demand response mechanism. Energy Queensland therefore considers that a later commencement date for the proposed reforms, for example July 2023, may be more appropriate. However, before a realistic implementation date can be determined, further consideration of current work programs and the extent of market and participant system changes required to support the proposed access reforms is required.