19 October 2020

Ms Merryn York
Acting Chair
Australian Energy Market Commission
GPO Box 2603
SYDNEY NSW 2000

Dear Ms York

Consultation Paper: Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis Interim Report

Energy Queensland Limited (Energy Queensland) welcomes the opportunity to provide comment to the Australian Energy Market Commission in response to the *Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis Interim Report.*

The attached submission is provided by Energy Queensland, on behalf of its related entities, including:

- Distribution network service providers, Energex Limited and Ergon Energy Corporation Limited;
- Regional service delivery retailer, Ergon Energy Queensland Pty Ltd; and
- Affiliated contestable business, Yurika Pty Ltd including its subsidiary, Metering Dynamics Pty Ltd.

Should you require additional information or wish to discuss any aspect of this submission, please do not hesitate to contact me or Charmain Martin on 0438 021 254.

Yours sincerely

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Energy Queensland

Submission to the Australian Energy Market Commission

Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis Interim Report

Energy Queensland Limited

19 October 2020

About Energy Queensland

Energy Queensland Limited (Energy Queensland) is a Queensland Government Owned Corporation that operates businesses providing energy services across Queensland, 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
- 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 focused 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 service experience.

Our distribution businesses, Energex and Ergon Energy Network, cover 1.7 million km^2 and supply 34,000GWh of energy to 2.25 million homes and businesses each year.

Ergon Energy Retail sells electricity to 738,000 customers in regional Queensland.

Energy Queensland 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 7 September 2020, the Australian Energy Market Commission (AEMC) published the *Transmission Access Reform: Updated Technical Specifications and Cost-Benefit Analysis Interim Report* (interim report). The interim report sets out updated technical specifications of the access reform model and a quantitative cost-benefit analysis of the reform.

The consultation paper seeks feedback on the following:

- Locational marginal price (LMP) design components;
- Financial transmission rights (FTR) design;
- The quantitative impact assessment; and
- Implementation and transitional arrangements for FTR.

The AEMC is seeking feedback on the issues and questions raised in the interim report by 19 October 2020. Energy Queensland's comments are provided in sections 2 and 3 of this submission.

2 General comments

Energy Queensland welcomes the opportunity to provide feedback in response to the AEMC's consultation on transmission access reform. Energy Queensland acknowledges that, until recently, the current market design, including the transmission access framework, has operated efficiently. However, given the significant volume of generators seeking to connect to the system and increasing periods of congestion on elements of the transmission network, we understand that there may be a case for market reform to improve signals for investment, manage the risks of congestion on the transmission network and maintain supply at lowest cost for customers. However, while Energy Queensland is supportive of enhancing the transmission access arrangements, we have difficulty in understanding the value of the reforms as proposed.

In Energy Queensland's view, the proposed changes to the transmission access arrangements will introduce more complexity into the settlement process, potentially increasing the risk for investors and prices for customers. In our view, the intent to move generators to nodal pricing while retailers continue to settle on the regional reference price (RRP) creates new risks for participants (i.e. retailers, generators and loads) given the different pricing outcomes. Of particular concern is that the proposed model will dilute any intended locational signals. It is Energy Queensland's experience that generators and customers often choose their location for reasons other than access to transmission networks. For example, coal thermal plants locate close to coal, water resources and gas plants locate near pipelines, wind and solar farms choose open land locations that are low-cost and have good solar or wind resources, while large customers select sites that have access to labour and transport corridors (resulting in generation and loads locating in inopportune locations with respect to each other and to suitable network infrastructure). In our view, it would be more economically efficient to move all participants to nodal pricing to provide consistency in locational pricing signals. However, this should only be done after a thorough review of the planning and approvals processes governing the siting of these resources, including how potential congestion issues are identified and managed. Otherwise, Energy Queensland considers that all participants should continue to settle on the RRP to prevent gaming by customers or participants.

Further, as noted in previous submissions,[1] Energy Queensland acknowledges that the transmission access reforms are focussed on the coordination of future transmission and generation investment. Notwithstanding this, given the volume and growth in large-scale

[1] Energy Queensland, *Submission on the Transparency of New Projects Consultation Paper*, May 2019; Energy Queensland, *Submission to the AEMC: Coordination of Generation and Transmission Investment Implementation – access and charging*, April 2019; Energy Queensland, *Submission to the AEMC: Coordination of generation and transmission investment – access reform*, August 2019; Energy Queensland, *Submission to the AEMC: Coordination of generation and transmission infrastructure proposed access model*, November 2019; Energy Queensland: *Submission to AEMC: Renewable Energy Zones*, November, 2019; Energy Queensland, *Submission to AEMC: Investigation into System Strength Frameworks in the NEM*, May 2020.

generation connecting to Queensland's distribution networks (especially registered generation), it is important that the potential flow-on impacts of these reforms on distribution networks and embedded generators (i.e. generators that connect under Chapter 5.3A of the National Electricity Rules) are also considered. For example, Ergon Energy Network just recently connected a 103 MW solar farm to its network. It remains unclear how large-scale distribution-connected generators are to be treated and whether the proposed transmission access reforms will result in a perverse outcome for embedded generators, distribution networks and electricity consumers. Energy Queensland remains of the view that the framework must be appropriate for all large-scale generation, regardless of whether they are connected to a transmission or distribution network. We would therefore appreciate further discussion with the AEMC on this matter.

Our feedback on the questions raised in the AEMC's interim report is provided in section 3 of this submission. We are available to discuss this submission or provide further detail regarding the issues raised.

3 Specific comments

Energy Queensland provides the following comments on the questions raised in the consultation paper:

CHAPTER 2 – DESIGN COMPONENTS LMP

1. Do stakeholders agree with the use of the Volume Weighted Average Price as the regional price?	Energy Queensland notes that NERA's modelling priced the Volume Weighted Average Price (VWAP) slightly higher than the RRP. Therefore, it would appear that no benefit will be achieved for the customer under this approach. We acknowledge that the intent of the design of the LMP is to expose different market participants to different prices. However, it is our view that this design can drive ineffective outcomes. For example, a customer at a LMP node will not be incentivised to use their non-scheduled demand management capabilities when the LMP is high and they are paying a lower VWAP. We also note that the LMP will likely be more volatile and often higher than the VWAP (as the VWAP is an average price). If customers are not incentivised to effectively reduce load during high local prices, then the result will be a higher priced market than is necessary.
2. Do stakeholders agree that dynamic marginal losses should be reflected in LMPs?	Energy Queensland notes that the NERA report did not include the impacts of dynamic marginal losses on the LMP in its modelling.[2] We also note that financial contracts, such as Power Purchase Agreements (PPAs), and other long-term arrangements that extend into the access reform market may need to be renegotiated to account for LMPs and loss factor adjustments. This will result in additional legal costs and financial risks for counterparties.
3. Do stakeholders agree that some form of pricing mitigation should be introduced to apply an offer cap on LMPs in certain conditions?	Energy Queensland welcomes proposals to mitigate high price outcomes, especially where participants' market power is being exercised. However, we understand that the fundamental economic principle that underlies the introduction of LMPs is to allow price to be a signal for investment, as price will stimulate investment and competition will drive prices down. We accept that it will be important to balance the mitigation of market power with the preservation of a price signal but note that the introduction of a cap to manage high prices due to market power could contradict the point of the reform by mitigating the price signal. Further analysis should therefore be undertaken to adequately evaluate the solutions.
4. Do stakeholders agree that an ex ante mitigation mechanism is the best method for pricing mitigation?	As observed in international markets, the introduction of ex-ante markets will complicate the calculation of the individual LMP's balancing market spot price and may impact the publication of real time pricing to which the National Electricity Market (NEM) is accustomed. If the spot price is not published in real time, then the beneficial effects of any adjustment to the market would be outweighed by inefficiencies caused by lack of market visibility and transparency for participants.

[2] https://www.aemc.gov.au/sites/default/files/2020-09/NERA%20report%20Cost%20Benefit%20of%20Access%20Reform%202020_09_07.pdf, p. VI.

5. Do stakeholders have any other comments on any of the other design elements of LMP?	Energy Queensland expects that the LMP will be more volatile and often higher than the VWAP, as the VWAP is an average price. Further, exposing different market participants to different price points will create inefficiencies (as described in answer to Question 1). For example, retailers and demand response service providers will see a different price at the same location driving a different demand response from each market participant. Large customers will be able to cherry-pick which price they wish to be exposed to. The 12-month wait time to change would seem to do little to prevent cherry-picking. We also note that the examples of locational marginal pricing in international markets are not reflective of the reform being proposed in the NEM. The current proposals are expected to settle all load in the spot at the reflective LMP point or VWAP, whereas international markets where the LMP / FTR model exists primarily settle their load ex-ante. However, ex-ante markets are inherently less volatile. If introduced in the NEM, volatility due to the spring washer effect will be imposed on all load in the spot market without the ex-ante buffer. This issue appears to have been overlooked and can have a dramatic impact. Consequently, the FTR will be impossible to model and value ahead of time.

CHAPTER 3 – FINANCIAL TRANSMISSION RIGHTS DESIGN

6. Do stakeholders agree that no additional measures are required to address competition in the FTR market?	Energy Queensland notes that FTRs in international markets, such as the PJM[3], settle against a day-ahead ex-ante mechanism and do not represent the real time price differences in the market. This aspect has not been made clear in the analysis to date. As noted in response to question 5 above, international markets where the LMP / FTR model exists primarily settle their load ex-ante. In these markets, the majority of the volume is traded ex-ante and the financial contracts and FTRs generally settle against the day-ahead ex-ante market. In this environment FTRs are relatively easy to settle as they are not confined by live constraints. Most of the volume at the LMP points also settles ex-ante and therefore is not exposed to the volatility and extremes of the spot market spring washer effects. If applied to the NEM, volatility due to the spring washer effect will be imposed on all load in the spot market without the ex-ante buffer and the FTRs will be impossible to model and value ahead of time. Given the different time-of-use of generation on the network and the intention for the FTRs to be available for such requirements, more clarity is required as to how the FTRs will be auctioned. For example, it is unclear whether FTRs will be an interval basis contract to allow for effective time-of-use hedging. We also note that NERA's report identified over 1,000 LMP nodes while conducting its modelling of the NEM. If each LMP node can trade FTRs with adjoining nodes and with the RRP, then the number of FTR auctions required will be numbered in the thousands. This complexity will be exacerbated by having to account for the granularity of each settlement interval for each of these locational contracts and potentially dual directional FTRs. Due to this complexity, we seek further clarification on how this market will operate.

[3] https://www.pjm.com/markets-and-operations/ftr.aspx FTRs are a financial contract entitling the FTR holder to a stream of revenues (or charges) based on the day-ahead hourly congestion price difference across an energy path.

	Finally, we note the significant potential for additional costs and inefficiencies to arise from FTRs whereby perfect hedging is limited by time-of-use access, dispatch knowledge ahead of time and costs of FTR contracts for congested lines and periods.
7. Do stakeholders agree with FTRs being made available in the auction up to ten years in advance, albeit a small portion of the network capacity?	Energy Queensland expects that longer dated FTRs will disproportionately benefit larger market participants as they have greater access to market analytics and financial resources to absorb FTRs of value for the long-term. The likely result is that larger participants will be able to obtain additional profits while smaller participants will pay higher contract prices for periods in demand or times of expected constraint.
8. Is the measure outlined above useful to participants if only a small portion is made available?	No comment.
9. Do stakeholders agree that both physical and non-physical participants should be able to purchase FTRs?	Energy Queensland considers that it would be beneficial to fair price discovery if non-physical participants can also purchase FTRs. However, we suggest that only physical participants should be able to participate in the primary market (auctions) with non-physical participants limited to purchasing FTRs through secondary markets.
10. Do stakeholders agree that there should not be a reserve price for FTRs?	Energy Queensland agrees that there should not be a reserve price for FTRs.
11. A) Do stakeholders see a benefit in terms of simplification of the reform with FTRs only being available between a limited number of pre-defined nodes on implementation?	We acknowledge the logic in reducing the number of locational nodes for FTRs. However, we expect that this approach will dilute the hedge effectiveness of the contracts. The best way to reduce the number of FTRs would be to reduce the number of LMPs.
12. Do stakeholders agree that STIPS should be adjusted to be based on the cost of congestion, rather than instances of material congestion?	No comment.
13. Do stakeholders agree that FTRs should not hedge price differences that arise due to marginal losses?	As stated above in response to Question 2, the LMPs and FTRs should not include loss factors. However, if the LMPs and regional prices are adjusted by loss factors then it would be prudent for hedge effectiveness to include the loss adjustment in the FTRs.
14. Do stakeholders have any other comments on any of the other design elements of FTRs?	FTRs in international markets such as the PJM settle against a day-ahead ex-ante mechanism and do not represent the real time flows of electricity on the grid. As such, any further reference to international markets should clarify whether market prices are published in real time or otherwise. Energy Queensland notes that it is often the case that where ex-ante markets are in operation, the balancing market price is published post real time, as the complexity of the calculations require a time delay.

	Although simple in its application, the current NEM dispatch engine for energy pricing is published in real time and creates fast, effective response to market conditions. This encourages active participation and real time adjustment of positions. Project investments on the grid can be managed through a regulated process that requires the additional asset applications to include a business case for grid connection. The additional asset should ultimately be of benefit to the grid. Where applications are made for grid connection in areas of high constraint, project worthiness to the grid should be considered.

CHAPTER 4 – QUANTITATIVE IMPACT ASSESSMENT

15. What are the views of stakeholders regarding the estimation of a range of total consumer benefit of \$6.2 – 8.2 billion over fifteen years operation of the NEM from 2026 to 2040?	We note that the current market already encourages race to the bottom bidding behaviour. This is shown in the modelling, with benefits not being observed in the front end. Most of the benefits are observed in later years 2036 to 2040[4] where the inaccuracies of assumptions and modelling bias are exposed. We also note that the consumer benefit calculation assumes that FTRs would not add additional costs and, as such, FTRs were not included in the modelling. However, we expect that FTRs will add substantial additional cost to the marginal costs of operation as the new market will be complex to manage from an IT systems, resource, and credit and risk management perspective. In effect, it is an additional cost line item for participants that will disproportionately impact smaller participants. Additional costs may also arise from lack of perfect hedging limited by time-of-use access, dispatch knowledge ahead of time and the cost of FTR contracts for congested lines and periods.
16. What are stakeholder views on the modelling that has been undertaken, including the methodology?	FTRs were not included in the PLEXOS modelling, so inefficiencies or additional costs in their application and operation have not been accounted for. This has the potential to outweigh any perceived benefit of the proposed reforms. We suggest that further modelling of the operational application of FTRs should be conducted as they are fundamental to the reforms being considered. We also note that the international markets analysed for LMP / FTR are not real time markets and therefore not representative of the NEM. The modelling has assumed that the proposed reforms would drive more efficient outcomes, and therefore more efficient outcomes were observed in the later years. However, we consider this to be a bias led result.
17. What are stakeholder views on the different categories of benefits included?	No comment.

[4] NERA *Cost Benefit Analysis of Reform* Figure 3.3, p. 26.

18. What are the views of stakeholders regarding the preliminary cost assessment that has been undertaken, and the indicative cost range provided?	Energy Queensland notes that the cost estimates seem to be low given the costs incurred by the market for the implementation of recent major reforms, such as Power of Choice and five minute and global settlements. We also note that the methodologies for determining costs and benefits are completely different. Estimates of costs are based on short-term firm actual costs, while the estimates for benefits are based on long-term economic modelling with many uncertainties and limitations. This raises serious questions regarding the accuracy of the modelled benefits.

CHAPTER 5 – IMPLEMENTATION AND TRANSITIONAL FTR ARRANGEMENTS

19. Do stakeholders agree with a four-year implementation period for transmission access reform, following the finalisation of rules?	Energy Queensland expects that many long-term PPAs would be linked to the end of the national Renewable Energy Target in 2030, making that date potentially suitable for implementation to avoid the need for expensive and potentially litigious negotiations between PPA counterparties. We consider a four-year implementation period to be a minimum requirement and would prefer a longer timeframe.
20. Do stakeholders agree with the objectives or benefits of the transitional allocation of FTRs?	Energy Queensland supports the transitional allocation of FTRs.
21. Do stakeholders believe that the proposal for allocating transitional FTRs is appropriate?	We consider the proposal for allocating transitional FTRs is appropriate.
22. Do stakeholders agree with the eligibility criteria set out in the paper?	Energy Queensland considers that the eligible entity should be the party that would receive the LMP from the Australian Energy Market Operator.