EnergyAustralia
LIGHT THE WAY

9 June 2022

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Dear Energy Security Board Members,

TRANSMISSION ACCESS REFORM CONSULTATION PAPER

EnergyAustralia (EA) welcomes the opportunity to comment on the Energy Security Board's (ESB's) Consultation Paper on transmission access reform in the National Electricity Market (NEM). EA is one of Australia's largest energy companies with around 2.4 million electricity and gas accounts in NSW, Victoria, Queensland, South Australia, and the Australian Capital Territory. EA owns, contracts and operates a diversified energy generation portfolio that includes coal, gas, battery storage, demand response, pumped hydro, solar and wind assets. Combined, these assets comprise 4,500MW of generation capacity.

EA is dedicated to building an energy system that lowers emissions and delivers secure, reliable and affordable energy to all households and businesses. This requires being a good neighbour in the communities we operate in. We, therefore, recognise the deep value in working with Aboriginal and Torres Strait Islander peoples as the traditional custodians of this land. We acknowledge and respect their continued connection to all aspects of Country.

EA is appreciative of the ESB's efforts to examine the transmission access settings in the NEM. Ensuring these are fit for purpose will be a vital enabler of a rapid and robust energy market transition. The critical points in this submission are:

- A Congestion Zones (CZ) approach seems more likely to support efficient and effective locational investment, particularly if it leverages and dovetails with the recently developed system strength framework.
- However, we question whether a connection fee would be required under a CZ approach. Improved information provision is likely to substantially increase investment efficiency if timely and transparent.
- Transmission Queueing should not be considered further owing to its many weaknesses. These include its less efficient generation outcomes, the potential for queue gaming, market power concerns, incompatibility with other frameworks and investment and upgrade disincentives.
- We acknowledge the ESB's attempts to improve the Congestion Management Model (CMM), but consider it still falls short of its stated design objectives. Namely, to preserve dispatch outcomes that reflect what would have happened in the absence of congestion and to leave participants no worse off than under the status quo.
- Other potential CMM issues include incentives for inefficient operational outcomes, the poorer financial outlook for storage, more complex and less

effective risk management, increased investment uncertainty, higher costs of capital along with inefficient network utilisation.

- All of these issues risk higher costs for customers and poorer investment outturns. Unfortunately, we consider these are only likely to intensify under multi-generator, multi-constraint, multi-bid situations. That is, in those situations more representative of actual dispatch which have yet to have been modelled.
- We applaud the ESB for undertaking further CMM modelling and strongly support this as part of a broader, comparative Cost-Benefit Analysis (CBA) of all options. However, to the extent this work does not prove the risks above unfounded, we consider CMM should be dropped as an access reform option.
- We acknowledge the ESB's concerns over various models and interpretations of the Congestion Relief Market (CRM) and highlight that a singular, more comprehensive and robust CRM model has been developed by Clean Energy Council (CEC) members.
- Although further scrutiny is warranted, early evidence suggests the revised model results in more efficient dispatch under congestion without creating any perverse operational incentives.
- Should these results hold up under further testing, CRM would seem to be a much more efficient overall solution than CMM in transparently and dynamically valuing and relieving congestion in each dispatch interval. That is, when combined with its other noted advantages.
- We agree that CMM is a simpler model than CRM but find the CRM cost estimates highly questionable. The $300m +/- 30% estimate seems wildly out of step compared with the range of $4-6.5m calculated for implementing Fast Frequency Response (FFR). In particular, when instituting a new FFR market is, if anything, closer in nature to CRM than earlier reforms that the AEMO estimate is based on.
- To reconcile these differences, we strongly suggest a rigorous CRM CBA is undertaken. This should include either an independent assessment of likely CRM implementation costs or an updated AEMO estimate that details exactly where the differences between other similar implementations and a CRM one would lie. Doing so would help to ensure the best operational access model is chosen.
- Both this and the CMM CBA should be assessed against a base case of no change. Recent evidence indicates 5 Minute Settlement (5MS) has resulted in a marked reduction in bidding to the floor after market price spikes. To the extent 5MS has reduced disorderly bidding, the rationale for both CMM and CRM may be weakened.

We would very much appreciate the opportunity to hear more of the ESB's insights on this consultation and look forward to continued collaboration to achieve effective, efficient and equitable access arrangements. To set up a meeting, please contact me on 0435 435 533 or via email at bradley.woods@energyaustralia.com.au.

Regards,

Bradley Woods
Regulatory Affairs Lead

A Congestion Zones Approach Is Preferred But Connection Fees Require Further Thought

EA considers a Congestion Zones (CZ) approach is likely to result in more efficient and effective locational investment than a Transmission Queueing approach. In particular, if it leverages and dovetails with the recently developed system strength framework. Although there have been several other options put forward for how CZ could be developed, these are likely to be inferior to a system strength framework-based approach. Reasons include:

- a lack of rigorous consultation, issue analysis and comprehensive design work as has already taken place with the system strength framework;
- the commensurate lack of industry support and understanding;
- inability to co-optimise and leverage synergies from the system strength framework, particularly around planning processes, connection studies, roles and responsibilities; thereby
- resulting in a slower, less efficient and more administratively burdensome, regulatory planning process.

It is an open question as to whether a connection fee would be required under such a model. Improved information provision is likely to substantially increase investment efficiency by itself if delivered in a timely and transparent fashion. Moreover, it is not clear how such a fee would work for redeveloped or repurposed sites. The prevalence of which is only likely to increase as thermal generation plant retires and sites of high resource quality become scarcer.

We note and agree with the ESB's concern that lacking a connection fee disincentive, new generators may continue to locate in congested areas if a sufficiently favourable generation coefficient results. In particular, if resource quality is high. However, we also note that this risk may be mitigated by other design choices that do not require a fee. For example, by limiting access, requiring some form of congestion self-remediation or introducing mandatory participation in control schemes.

We also highlight that it may still be efficient for generators to connect in congested zones if they can demonstrate improved or at least, no worse, congestion outcomes. This is likely to be the case for storage and generation that might underpin more efficient network use. That is, by providing essential system services such as system strength or inertia, adding load to soak up excess generation or where generation output is uncorrelated with existing generation profiles. This is vitally important because every additional MW increase in hosting capacity wrung from existing lines avoids an extra MW of network augmentation. In effect, a costless transmission upgrade that eliminates further costs to customers.

In this light, we consider a rigorous CBA is required to demonstrate reliably better investment outcomes under an extra congestion fee approach. In particular, given the administrative costs to forecast, calculate and approve congestion charges along with the potential investment distortions and inefficiencies arising from any that are inaccurately set. The impost of which will be magnified by the timeframe they will apply for and how often they change. For example, although providing certainty to investors from long term and unchanging fees will be a key investment incentive, it may not allow dynamic repricing that better reflects lower connection costs facilitated by technological advancement.

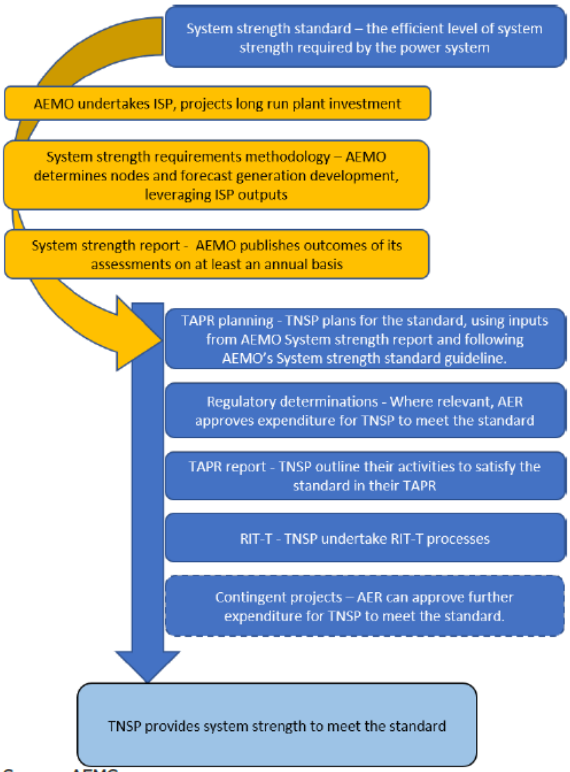
To the extent net benefits to connection fees can be demonstrated, we consider they would be best modelled on the System Strength Mitigation Requirement (SSMR). This would give new connecting generators the choice of remediating the congestion impacts of their connection themselves or paying a congestion charge for Transmission Network

Service Providers (TNSPs) to do so. The congestion charge would be based on the long-run costs of supporting the efficient level of congestion given the network hosting capacity and expected future connections.

As with the System Strength framework, we consider the efficient congestion, hosting capacity and forecasts of future connections should be determined via a zonal congestion standard jointly developed by the Australian Energy Market Operator (AEMO) and relevant TNSPs. This would leverage existing resources such as the Integrated System Plan (ISP), Electricity Statement of Opportunities (ESOO) and Transmission Annual Planning Reports (TAPRs) and would also factor generation output profiles.

TNSPs would be responsible for meeting the congestion standard via a combination of both network and non-network solutions. For example, from contracting with storage or synchronous generators to improve network hosting capacity at times of congestion. The Australian Energy Regulator (AER) would review and approve expenditures to meet the standard. Any under or over-recovery would be handled via existing pass through and other compensatory mechanisms to minimise pricing volatility and customer impacts.

The planning approach of the system strength framework is reproduced below. Although individual steps may differ, particularly if connection fees are not required, replacing system strength with congestion illustrates what a CZ approach might look like.



Source: AEMC

Leveraging the existing system strength framework for a CZ approach would have considerable implementation and operational benefits. In terms of the former, consultation and design work would be much reduced with many relevant issues having already been considered and decided in previous consultations. On the latter, there would be significant economies of scale in considering both system strength and congestion issues together as part of a holistic network investment and connection process.

Despite these advantages, several issues require further consideration. These include:

- whether connection fees are required or whether an information-only approach would achieve much the same outcomes without the commensurate costs and risks;
- if used, how connection fees may impact Renewable Energy Zone (REZ) developments and whether they should depart from long-run efficient assessment to incentivise different locational outcomes as raised in the consultation paper;
- how any inefficiencies, generator and customer impacts from inaccurate forecasting and fee setting could or should be remedied;
- whether additional rules around connections are required in more congested zones; and
- whether the additional planning work and resourcing requirements would markedly slow connection timeframes.

We strongly urge the ESB to consider these and related questions as part of its ongoing investigations.

Transmission Queueing Should Not Be Considered Further

We agree with the ESB that the original tie-breaker-based transmission queue model would do little to protect generator access. In most cases, each generator has different contribution factors for each constraint and typically appears in multiple constraint equations. This makes it highly unlikely that two generators will have the same contribution factor in any given dispatch interval. Allocating preferential access in this manner would, therefore, do little to alter current market outcomes.

Modifications such as conferring advantages in operational timeframes may be a way to improve the transmission queueing approach. However, as proposed they would seem to only weaken each operational model. Allocating priority rebates under the Congestion Management Model (CMM) would undermine universal allocation, something which has only recently been changed in response to locational investment incentive concerns. Similarly, using queue orders to establish who can buy and sell congestion relief under the Congestion Relief Market (CRM) would retard its dynamic efficiency. For example, by impeding the ability of the most efficient supplier to participate.

More important, however, is that none of the variants floated will correct the largest disadvantage of the transmission queueing proposal. Namely, that connection order will be unlikely to promote optimally efficient economic and environmental outcomes. A goal that both industry and the ESB have recognised as a key enabler of an orderly, economic and equitable transition for customers.

This weakness can be readily seen in the case where low marginal cost renewable plant is built near existing thermal generation. At times of high renewables output that results in congestion, the theoretical optimum would see renewables output displacing thermal generation. However, owing to the transmission queue impact, thermal generation output would either be a) prioritised for dispatch or b) compensated for being displaced. Either way, this would reduce economic efficiency and increase costs to customers more than would otherwise be seen.

Beyond this issue, and in addition to those noted in the consultation paper, we highlight other challenges to transmission queueing:

- **Chicken And Egg Concerns –** Transmission queueing risks setting up new chicken and egg situations. For example, from investors needing to know what their queue order will be to invest, but with final queue order only known once relevant technical and modelling outcomes of all connection applicants in an area have been considered.

- **Queue Order –** Having transmission queues defined by connection applications could lead to connection gaming, particularly if queue order was tradeable. However, being based on commissioning date favours technologies and smaller installations that could be built quickly. This may not result in optimally sized and located generation investment, especially larger scale firming options such as Pumped Hydro Energy Storage (PHES).
- **Market Power –** In theory, allowing trading of queue order should result in those with the highest willingness to pay obtaining their preferred order position. While this aligns with optimal auction theory, it may not result in optimal investment or dispatch outcomes. For example, this is likely to favour larger thermal projects who would reap relatively greater benefits from a higher queue position. This may be exacerbated if smaller players are hamstrung by financial constraints such that truly competitive bidding is negated.
- **Plant Changes –** It is unclear how retrofitting or upgrading plant, adding storage or additional generation units would be handled. Keeping the same queue order may disadvantage other players which may not be desirable. However, even if such changes were efficient, no investment may occur if it results in plant being relegated to the back of the queue. Neither result would seem optimal from a system perspective.
- **Framework Compatibility –** The transmission queueing approach is unlikely to work effectively with the Connections Reform Initiative (CRI) being developed jointly by the Clean Energy Council (CEC) and AEMO. This will see a batched approach used to streamline and speed up connection processes. For example, by aggregating the modelling, testing and commissioning of multiple generators simultaneously. It is, therefore, unclear how queue order could reasonably be determined under such arrangements.
- **Achievability –** Although being simple in theory, transmission queuing represents a substantial departure from current NEM functioning in practice. It also creates an artificial and arbitrary divide between generators rather than something based on the benefits they can bring. Neither compares favourably with the more incremental and equitable CZ approach discussed above.

Given these challenges and deficiencies, EA contends no further consideration should be given to transmission queueing. Instead, resources should be directed toward investigating how a CZ approach can be refined and implemented to deliver efficient and effective investment outcomes. Doing so will allow the ESB's scarce yet expert resources to be fully maximised.

The Congestion Management Model Has Key Design Deficiencies

EA acknowledges the ESB's continuing efforts to refine the Congestion Management Model (CMM) in response to stakeholder feedback. We agree that the increased investment certainty from universal rebates should more than offset the cost of diluting locational investment signals. In particular, if combined with an investment timeframe option which incentivises effective locational investment.

We do, however, question the proposal to exclude high marginal cost plant from receiving rebates when the Regional Reference Price (RRP) is low. While agreeing that incentives to game should be eliminated, we note that there are existing mechanisms to help achieve this such as the good faith bidding requirements. Moreover, we highlight that there can be good reasons participants may bid below their Short Run Marginal Cost (SRMC) that are unrelated to gaming or anti-competitive motivations.

The most obvious example is to ensure plant stays on during low price periods in the expectation that future higher price periods will more than offset the loss. A second reason relates to hedge positions. That is, where staying on to generate can see smaller losses than de-committing when the costs of having to meet contractual obligations another way or penalties for non-delivery are factored in.

Beyond mitigating restart costs and risks, staying on minimises plant wear and tear and avoids ramping requirements that might otherwise prevent plant from participating, partly or fully, in later dispatch intervals. The ultimate result is more plant available to keep the system secure and lower prices at times of peak demand.

Unfortunately, imposing additional costs on generators through the congestion charge that may not be compensated through congestion rebates would change this calculus. Plant will not stay synchronised and available if the congestion charges are unlikely to be recovered in later periods. In the initial dispatch intervals, this is likely to aggravate or cause system security issues as high marginal cost synchronous generation withdraws. However, this is also likely to reduce supply in future higher demand periods as restart constraints prevent sufficient generation from being online.

In being unable to effectively differentiate between legitimate and gaming motivations, the proposal to withhold rebates from high marginal costs plants when the RRP is low is unlikely to achieve several of the ESB's other stated aims. Namely, to preserve dispatch outcomes that reflect what would have happened in the absence of congestion and to leave participants no worse off than under the status quo.

Although peaking generators would seemingly stand to lose under the revised CMM, storage proponents may face even poorer outcomes. Currently, the price floor creates strong incentives to charge and thereby alleviate congestion. If CMM works as proposed, however, this would occur less often with pricing resolving to the Local Marginal Price (LMP). While this should be an efficient outcome in most cases, it is unlikely the rebate received by storage would replace the revenue foregone under current arrangements in all cases. This would leave storage proponents worse off and further dampen the already weak signal for storage investment. Ultimately, this may result in a dearth of storage needed to support the optimal transition generation mix such that prices are higher than otherwise necessary.

Even if the problems above could be addressed, we note other CMM issues may result in inefficient operational outcomes. The example below compares a 100MW constraint where participants bid their Short Run Marginal Cost (SRMC) and where one generator bids the other's SRMC. While a profit-maximising generator should theoretically bid as per case one, CMM creates a strong incentive to bid per case 2 to reduce competitor revenue and financial viability over time. That is, with minimal reduction in generator 1 profitability (1.4%), but much larger impacts on generator 2 profitability (33.3%). Although SRMC would still be covered for generator 2, revenue may not cover other costs such as debt servicing. Beyond failing to maximise total efficiency as seen in case 1, this could lead to lower competition and higher prices for customers over time.

	RRP	LMP	Offer	Running Costs	Congestion Charge	Availability	Quantity Gen	Rebate Pool	Rebate	Revenue	Costs	Profit
Gen 1	$20.00	$5.00	$5.00	$5.00	$15.00	120	100	$1,500.00	$782.61	$2,000.00	$2,000.00	$782.61
Gen 2	$20.00	$5.00	$10.00	$10.00	$15.00	110	0		$717.39	$0.00	$0.00	$717.39

	RRP	LMP	Offer	Running Costs	Congestion Charge	Availability	Quantity Gen	Rebate Pool	Rebate	Revenue	Costs	Profit
Gen 1	$20.00	$10.00	$10.00	$5.00	$10.00	120	50	$1,000.00	$521.74	$1,000.00	$750.00	$771.74
Gen 2	$20.00	$10.00	$10.00	$10.00	$10.00	110	50		$478.26	$1,000.00	$1,000.00	$478.26

These operational outcomes will only ramify in the investment timeframe. That is, with any uncertainty inevitably increasing business risks and thereby the cost of capital. As proposed, CMM would increase uncertainty in two key ways. Firstly, from unknown and hard to forecast rebate entitlements and dispatch outcomes. Secondly, from the basis risk introduced between costs and rebates settled at the LMP and hedges and spot energy based on the Regional Reference Price (RRP). This is only likely to complicate and impede efficient risk management unless a full security-constrained optimisation is used[1].

To the extent projects remain viable, these risks and costs will necessarily be reflected in either higher contract or spot energy prices. However, if CMM instead results in fewer projects coming to market, the outcomes will almost certainly be poorer system security and markedly higher energy prices owing to undersupply. None of these investment outcomes or the operational ones noted above would be consistent with the National Electricity Objective (NEO).

The potential for these outcomes is perhaps unsurprising. CMM is a relatively simple approach. This is undoubtedly an advantage. However, with rebates being based solely on availability, rather than the value to participants in each dispatch interval, optimally efficient congestion management is not possible. This effectively means the hosting capacity of the network will not be maximised with higher costs to customers over time the result. Unfortunately, this suboptimal use of congestion surpluses and related costs and risks are only like to intensify under multi-generator, multi-constraint, multi-bid situations. That is, in those situations more representative of actual dispatch which have yet to have been modelled.

We applaud the ESB for engaging consultants to undertake further investigation into the CMM, including modelling more real-world dispatch situations. This is consistent with earlier industry feedback and the ESB's stated objectives to introduce expedient, efficient and effective operational solutions. However, to the extent this work does not support these outcomes or cannot prove the risks above unfounded, we consider CMM should be dropped as an access reform option.

A Congestion Relief Market Holds Promise But Further Testing Is Required

As with CMM, EA agrees with the ESB that an investment timeframe approach be paired with a Congestion Relief Market (CRM) if it is to be implemented. We consider doing so will mitigate both the generation cannibalisation issue and the potential for inefficient locational decisions noted in the consultation paper. For example, the business model of locating only where congestion could be worsened to extract excess congestion relief rents would likely be mitigated or eliminated entirely under a CZ approach. That is, with the rent-seeking generator precluded from connecting, facing higher connection fees, forced to self-remediate or see extra network investment or other resources contracted to alleviate congestion. All of which would undercut the pure 'congestion rents' model.

The ESB is right to note that different CRM variations and interpretations have been presented to date. Feedback has led to a singular, more comprehensive and robust CRM model being developed by CEC members. The updated CRM model coordinates energy, CRM and Frequency Control Ancillary Services (FCAS) in a single pass, uses nodal pricing and takes a holistic approach to constraints rather than relying on a constraint specific, piecemeal approach. The revised model has been tested across a range of real-world bidding scenarios using full SCED consistent with the existing NEM Dispatch Engine (NEMDE). This includes modelling of multi-bus, multi-generator outcomes.

Although further scrutiny is warranted, early evidence suggests the revised model results in more efficient dispatch without creating any additional operational perversities. Should these results hold under further testing, it would add more support to implementing CRM over CMM. Beyond avoiding the CMM issues noted above, CRM would seem to be a much more efficient overall solution in transparently and dynamically relieving congestion as required in each dispatch interval. That is, when combined with its other noted advantages including:

[1] Per the mathematical analysis provided by SW Advisory as part of the Clean Energy Council's submission to this consultation.

- voluntary participation,
- technological agnosticism,
- enhanced signals for storage,
- improved locational information on the value of congestion,
- compatibility with existing jurisdictional REZ schemes, and
- having a clear pathway for developing supporting risk management contracts.

As the ESB highlights, such benefits come with costs. We agree that it is a more complex model than CMM with greater ongoing operational impost to those who participate due to additional bidding requirements. However, we do not see localised market power concerns as material. The ability of a market participant to exercise such power will be necessarily limited by the availability of CRM counterparties, which in turn will be shaped by the voluntary nature of the market. That is, it can be expected that CRM participants will only trade if there are mutually beneficial gains to trade to be had.

We also strongly question the CRM implementation estimates provided in the consultation paper. The $300m +/- 30% estimate seems wildly out of step with the range of $4-6.5m calculated for implementing Fast Frequency Response (FFR)[2]. In particular, when instituting a new FFR market is, if anything, closer in nature to CRM than the Coordination of Generation and Transmission Investment (CoGaTI) reforms. AEMO's estimate is also an order of magnitude above new, full, off-the-shelf installations of market dispatch systems in other jurisdictions such as the Philippines and Singapore, which we understand have been implemented for between $20-50m.

When this issue was raised in an earlier presentation, the ESB suggested the magnitude of the difference was due to CRM being a nodal model similar to CoGaTI that would require changes to the NEMDE to accommodate. This is unlikely given:

a) CRM would not require changes to any constraint equations,
b) CRM would utilise existing market design, processes and limits,
c) The recent Short Term Projected Assessment of System Adequacy (STPASA) changes are considered capable of introducing a full nodal network model at little expense, and
d) with NEMDE already utilising shadow pricing architecture which CRM, CMM and CoGaTI would all share and leverage to calculate LMPs[3].

To truly reconcile these estimates, we strongly suggest a rigorous CRM CBA is undertaken. This should include either an independent assessment of likely CRM implementation costs or an updated AEMO estimate that details exactly where the differences between FFR implementation and a CRM one would lie. Doing so would help to ensure the best operational access model is chosen. In particular, noting that even if such estimates were triple that of FFR, it would still be within the range of $10-20m estimated for CMM system costs.

Should CRM costs prove similar or even slightly above that of CMM, we consider it should be preferred given the advantages noted above. However, these should also be quantified as far as possible to ensure a transparent and thorough analysis.

To aid this objective, we strongly suggest that both the CRM and CMM CBAs be assessed against a base case of no change. Much has been made previously about the costs of disorderly bidding in the presence of congestion as a driver for operational change.

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[2] Per page 21 of the AEMC's Final Determination on Fast Frequency Response available from: https://www.aemc.gov.au/sites/default/files/2021-07/Fast%20frequency%20response%20market%20ancillary%20service%20-%20Final%20Determination.pdf

[3] The difference between them being in how they are settled financially given the differing rights associated with each model.

However, as noted recently by AEMO and shown below, the implementation of 5 Minute Settlement (5MS) has resulted in a marked reduction in bidding to the floor after market price spikes[4]. To the extent that 5MS had reduced such disorderly bidding, the case for both CMM and CRM may be weakened.

Figure 21 Pre 5MS – Rebidding after Qld price spikes

Queensland 5-minute spot prices – 30 September 2021

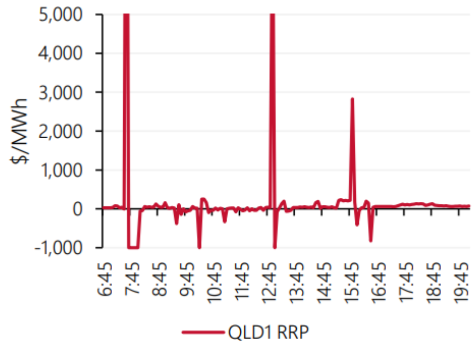
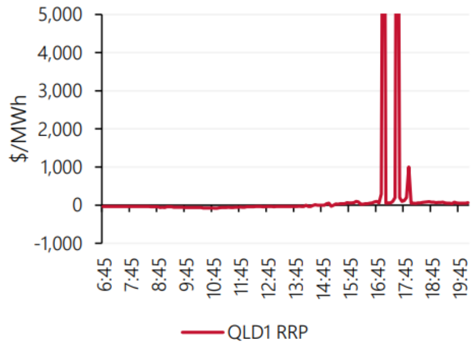


Figure 22 Post 5MS – No rebidding after price spikes

Queensland 5-minute spot prices – 4 Oct 2021



[4] Per page 15 of AEMO's Q4 2021 Quarterly Energy Dynamics report available from: https://aemo.com.au/-/media/files/major-publications/qed/2021/q4-report.pdf