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Ms Audrey Zibelman
CEO and Managing Director
Australian Energy Market Operator
GPO Box 2008
MELBOURNE VIC 3001

Submitted electronically: kevin.ly@aemo.com.au

EnergyAustralia Pty Ltd
ABN 99 086 014 968

Level 33
385 Bourke Street
Melbourne Victoria 3000

Phone +61 3 8628 1000
Facsimile +61 3 8628 1050

enq@energyaustralia.com.au
energyaustralia.com.au

Dear Ms Zibelman

AEMO's market participant fees structure review

EnergyAustralia is one of Australia's largest energy companies with around 2.5 million electricity and gas accounts across eastern Australia. We also own, operate, and contract an energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind, and solar assets, with control of over 4,500MW of generation capacity.

EnergyAustralia welcomes the opportunity to make this submission to the AEMO's market participant fees structure review consultation paper (the options paper). The market has changed significantly since the current fee structure was established, while the AEMO has facilitated the evolution, it has not updated how the associated costs are assigned. We appreciate the AEMO's consideration of how changes in system/s, market participants and operation, should be appropriately applied to participants.

It is understandable that those benefitting from, or driving, the AEMO's expenditure should contribute to their allocation of these costs; however, EnergyAustralia does not support the splitting and allocation of fees to every component in the supply chain such as metering and network parties. EnergyAustralia considers this would only result in more inefficient cost recovery compared with aggregated costs being passed directly through to retailers. As such, we believe the AEMO should not apply fees to any participant where their recovery of the fees could be more simply and efficiently applied under the current structure.

Where there is no inefficient or disproportionate impact on customers, fees should be applicable to participants based on their share of costs incurred by the AEMO to enable their involvement in the NEM. Market participants that have a direct customer billing relationship should be assigned their portion of the AEMO's costs; these currently include, non-scheduled generators, non-market generators, large-scale battery storage, market ancillary service providers, wholesale demand response providers, and small generator aggregators. However, there are new parties that AEMO will interact with, or parties with expanded roles within the industry, such embedded network service providers (when the AEMC's recommendations on updating the regulatory frameworks for embedded networks is implemented), and new entrants like the Consumer Data Right's (CDR) accredited data recipients. These parties have an indirect and complex relationship with market participants and therefore, the AEMO should consider applying fees to those participants directly and not via a market participant.

Market customers

The current fee structure for market customers does not reflect the actual cost incurred by the AEMO for providing its services to market customers, as the consumption of a participant's customers does not generally correlate with higher costs (predominantly data costs) for the AEMO. Movement to a 2-sided market will further complicate how the AEMO will appropriately assign its costs to market customers, as retailers with less Distributed Energy Resources (DER)/ solar may unfairly incur a higher portion of the $/MWh charge; while those with more DER – which arguably drive greater costs for the AEMO – may pay less.

The options paper proposed changes to how market customers are charged, summarised as moving from a $/MWh to a $/connection (NMI). Either basis for the fees can be unfair to different market customers; $/MWh, retailers with more SME/C&I; $/NMI, retailers with a high percentage of 'small' customers. Therefore, EnergyAustralia suggests the AEMO consider a combination of both, as a balanced and fairer allocation of the costs incurred. That is, the AEMO could adopt a similar structure to how it currently charges generators; a 50% capacity ($/NMI connections) and 50% energy basis ($/MWh consumed); or a weighted fee per NMI based on the consumption of customer and their associated costs to the AEMO's operation.

Full retail contestability (FRC)

When considering any changes to the fees applied to market customers, the AEMO should ensure that efficiencies are gained; for example, the FRC fees are currently applied at a $/NMI basis, which creates difficulties for the ESC and the AER when calculating the VDO and DMO, respectively. EnergyAustralia believes efficiencies can be achieved by reverting the FRC charge to a $/MWh basis, and that this fee should be applicable to any market customers that have a direct customer billing relationship.

Generators and Market Network Service Providers (MNSP)

As the energy mix continues to evolve, the AEMO must ensure the allocation of its costs incurred is equitable to market participants, it can achieve this by apportioning this appropriately to the responsible parties. As such, EnergyAustralia believes it is fair to assign the costs incurred by the AEMO to accommodate non-market, non-scheduled, and semi-scheduled generators; the latter should contribute to the increased complexity and associated costs of forecasting.

The options paper considers changes to how generators are charged, to account for the increase in variable renewable generation; specifically, considering whether direct costs should be allocated to generators on a MW or MWh basis. EnergyAustralia believes the 50% capacity (MW) and 50% energy basis (MWh) for charging generators remains the appropriate format for charging the range of generators, as this provides a correlation to the impacts on the AEMO's cost and no disparity between generation methods.

Wholesale demand response and Frequency Control Ancillary Services (FCAS)

Similarly, the AEMO should assign the costs incurred to accommodate system services (FCAS and wholesale demand response), as these entrants are now or are forecast to be receiving revenue for their services. The allocation of costs could be considered as a percentage of revenue received, as it is not appropriate in this instance to follow the generator basis for charging.

Major reforms

EnergyAustralia supports the recovery of major reforms fees over a 10-year period, where the reforms will ultimately benefit customers (Five Minute and Global Settlement, Improvement of the Customer Switching process, etc.), it is reasonable for these costs to be evenly allocated to customers. The AEMO must consider how the costs should be apportioned based on the benefits associated with the reforms to the varying market participant, i.e. assigning the costs more precisely on those that will benefit from the reform.

Where the reforms create a new revenue stream for an existing or new participant, the costs should be assigned more directly; for example, Wholesale Demand Response, CDR, and emergency frequency control schemes, will create revenue streams and additional benefits for some participants so it would not be reasonable for these costs to be dispersed evenly between participants and customers.

CDR specifically will result in significant costs to the AEMO, the costs for enabling this reform should not be assigned solely to retailers, as new entrants accredited data recipients will be one of the largest benefactors. EnergyAustralia request the AEMO provide more information on the expenditure and recovery method for this initiative, as we believe it is prudent to apportion the capital and operating expenditure to those that are utilizing and benefitting from the reform. EnergyAustralia believes it would be equitable for the AEMO to recover costs from retailers (data holders for some information in scope of the CDR) and accredited data recipients, on a per data transaction basis. Clearly, a CDR data transaction covers different scenarios and would need to be defined in an appropriate and easily measurable way. There may be alternative measures that might more accurately reflect AEMO's cost drivers, than having a 'per transaction' measure.

National Transmission Planner (NTP)

As discussed earlier, EnergyAustralia's preference is that fees are not applied where a participant does not have a direct customer billing relationship; however, we appreciate the NTP costs to the AEMO have increased significantly under the Integrated System Plan, as it has absorbed the majority of the transmission planning activity – previously the remit of Transmission Network Service Providers (TNSP) – we therefore believe it is prudent for NTP costs to be assigned to TNSPs.

Other issues

EnergyAustralia accepts the confidence a five-year determination will provide participants; however, we believe that the market is evolving at a pace that is not conducive to a lengthy determination period. Therefore, we suggest the AEMO consider a reduced determination period, that will allow the AEMO to be agile to the rate of change in the energy market; a two/ three year determination period would enable AEMO to assign costs more accurately.

EnergyAustralia appreciates the AEMO's consideration of market participant fee structures, and we believe the transparent and regular review of the AEMO's activities, budgets, and costs, will ensure system and market operation is as efficient as possible.

If you would like to discuss this submission, please contact me on 03 8628 1704 or Travis.Worsteling@energyaustralia.com.au.

Regards

Travis Worsteling
Regulatory Affairs Lead