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Kevin Ly
Group Manager Regulation
Australian Energy Market Operator
Level 2, 20 Bond St
Sydney NSW 2001

Dear Mr Ly

RE: Electricity Market Participant Fee Structure

ERM Power Retail Pty Ltd (ERM Power) welcomes the opportunity to respond to the Australian Energy Market Operator's (AEMO) consultation paper on the Electricity Market Participant Fee Structure.

About ERM Power

ERM Power (ERM) is a subsidiary of Shell Energy Australia Pty Ltd (Shell Energy). ERM is one of Australia's leading commercial and industrial electricity retailers, providing large businesses with end to end energy management, from electricity retailing to integrated solutions that improve energy productivity. Market-leading customer satisfaction has fuelled ERM Power's growth, and today the Company is the second largest electricity provider to commercial businesses and industrials in Australia by load[1]. ERM also operates 662 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland, supporting the industry's transition to renewables.

http://www.ermpower.com.au
https://www.shell.com.au/business-customers/shell-energy-australia.html

General comments

AEMO's consultation paper highlights the huge volume of change underway on the market for not only the market operator but for participants as well. Reforms like Five Minute Settlement (5MS), the Consumer Data Right (CDR) and the continued evolution of the distributed energy resources (DER) market involve significant costs for market participants to change their own internal systems. It is therefore hardly surprising that AEMO will need to consider revising its fee structure in order to adequately support these reforms within the scope of its budget.

One of the principles for cost recovery of fees for operating the NEM that AEMO lists is simplicity. ERM Power considers that the current fee structure leans too heavily on this principle. Other principles such as that fees charged to each participant should be reflective of the extent to which AEMO's budgeted revenue requirements involve that registered participant must also be used in AEMO's setting of the fee structure. We are concerned that AEMO's focus in previous fee structure consultations may have applied an overly simplistic approach at the expense of cost recovery for the range of services provided to the different registration classifications and participant sub-types. We also question whether the principle of simplicity should be replaced by transparency as in our view, transparency, or simplicity of understanding of how the fee structure is applied is far more critical than a simplistic structure.

[1] Based on ERM Power analysis of latest published information.

Clause 2.11.1(b)(1) of the National Electricity Rules indicates that "*the structure of Participant fees should be simple"* as opposed to simple to understand or transparent. However, being simple does not preclude fees recovery on a costs incurred basis which is reflected in Clause 2.11.1 (b)(3): "*the components of Participant fees charged to each Registered Participant should be reflective of the extent to which the budgeted revenue requirements for AEMO involve that Registered Participant."* In this case the fees should be simple whilst allowing cost reflective recovery.

Overall, we consider that there is a lack of transparency in how AEMO's fees are justified and spent. Ultimately, all energy consumers bear the costs of fees through those that are passed on via their retailer, or to the extent that generators incorporate fees in their bids, through higher wholesale prices. We firmly believe that a greater degree of transparency is required, above and beyond the simple way in which AEMO reports its budget and fees. ERM Power shares the views of the Australian Energy Council and the Queensland Energy Users Network who expressed concerns about the minimalist approach to consultation on AEMO's 2020-21 draft budget and fees, which allowed just six business day to seek input on a $250 million budget with limited detail on the assumptions underpinning the budget. While the consultation process for this review involves more time, we hope to see a greater level of engagement from AEMO and increased information sharing over the course of this review.

We contend that so long as there is transparency in the methodology and the factors applied by AEMO in the costs of AEMO operating the NEM this would be far more preferable to adopting a "simple" approach as per the current fee structure methodology. In our view, the fee structure should firstly target the principle that "*the components of Participant fees charged to each Registered Participant should be reflective of the extent to which the budgeted revenue requirements for AEMO involve that Registered Participant."*

Unallocated costs

ERM Power queries AEMO's position of recovering all unallocated costs from Market Customers. Unallocated costs are indicated as reflective of AEMO's overhead costs which includes the costs of high security buildings and cyber secure systems from which AEMO operate the NEM and well as leases on commercial office space from which AEMO staff generally operate. In the current COVID operating regime, it would also contain the costs associated with AEMO staff working from home. All market participants benefit from AEMO's operation of the market and facilitation of market development as well as forecasting functions. It is therefore unclear why this value is solely allocated to Market Customers only. Unless AEMO can clearly demonstrate why all overhead costs associated with AEMO's NEM functions should be allocated solely to Market Customers, then we see that unallocated costs should be split in the same fashion as allocated fees with a proportion paid for by generators, and Market Network Service Providers as well as by Market Customers.

Length of new fee structure

In terms of the length of timing of the new fee structure, ERM Power considers that the potential for significant change in market design as a result of the post-2025 review of the NEM currently being undertaken, it would be appropriate to reassess the fee structure once a new market structure is in force. We acknowledge there is no definitive state date for any of the reforms contained within the Energy Security Board's consultation paper. Nonetheless, the general timing provides a reasonable indicator. As such, we recommend that the fee structure apply for a four or five year period. This would allow for AEMO to examine the different services and service providers operating in the National Electricity Market (NEM) once a new market design is established and determine how fees could be levied appropriately in line with the new market design.

New participants

We support AEMO's intent to include additional participant registration classes in the recovery on the NEM Fees. We believe all registered participant classes who participate in the current Energy, and Market and Non-Market Ancillary Services markets and any future markets developed for power system services and who derive revenue, or other benefits from being scheduled in those markets should contribute to the recovery of costs associated with the real time market operation, facilitation of market development as well as forecasting functions of the NEM. We also disagree with the current methodology where allocated costs recovery is based on outcomes in the Energy Market only, which is only one of nine real time markets operated in the NEM.

ERM Power considers that the entry of Demand Response Service Providers (DRSP) into the market as part of the Wholesale Demand Response Mechanism (WDRM) also creates an interesting situation for AEMO. We believe that DRSPs should be subject to fees as necessary given that they will be competing in the market like many other entities.

Under the WDRM, market customers will be settled on their actual consumption plus any demand response volume (the difference between actual consumption and the baseline at times or demand response dispatch). This may create a scenario where the same service is charged for twice. We firmly believe that market customers should not be required to pay fees to AEMO for demand response provided by their customers, and that DRSPs should instead be levied these fees given they are the primary beneficiaries of the WDRM.

We agree with AEMO that the introduction of new participant categories such as DRSPs, Battery Energy Storage Systems, and Market Small Generation Aggregators (MSGA) which currently do not pay fees (other than registration fees) mean that changes are needed to the split in allocated costs to ensure that all participants are paying a share of AEMO's costs through fees. It would be difficult to nominate a precise split in fees between participant categories that exactly reflects each group's contribution to AEMO's costs.

With some of these participants likely to have a small footprint in terms of total electricity generated it would seem rational to start with a relatively modest contribution in the early phase of the new fee structure where few participants may be active, with fees gradually increasing over time based on AEMO's forecast of their contribution. Purely by means of an example, five per cent of allocated costs could be levied on 'other registered participants' as AEMO classifies them in the first year of the fee structure, rising by one percentage point each year to 10 per cent at the end of a five year fee structure.

Allocated fees

As noted in AEMO's consultation paper, allocated fees for generators and Market Network Service Providers (MNSPs) are currently split 50-50 between capacity and energy. AEMO is proposing to change this split to weight it more heavily towards capacity on the grounds that the trend towards wind and solar generation means that there is more generation coming from lower capacity factor plant.

We note that AEMO has indicated that due increasing volumes of relatively low capacity factor semi-scheduled generation, consideration should be given to amending the ratio applied to registered capacity and energy produced in the generator fee recovery area. Currently these fees are levied on a 50-50 split between capacity and energy generated. It is unclear to us how changing this split would be reasonably reflective of the costs incurred by AEMO in dispatching and settling different generator types and the impact that the different generator classes could have on AEMO's dispatch and settlement process for all nine markets. In addition, whilst AEMO has focussed on the lower capacity factor of semi-scheduled generators as the basis for suggesting a change to the energy/capacity cost recovery ratio, AEMO doesn't appear to have considered that the capacity factor of scheduled generation is also reducing as output from scheduled generation is displaced by semi-scheduled generation. Nor has AEMO appeared to recognise that with projections of higher capacity in the market as a result of more semi-scheduled generation entering the market, the overall fees taken from capacity would increase by just maintaining the existing 50-50 split.

ERM Power also considers that this approach would be beneficial to apply to fee recovery for Market Customers. The current methodology based solely on MWh consumption results in a significant cross subsidy from large consumption customers to small consumption customers. The costs to serve individual large consumption customers would be no greater than that imposed by a small consumption customer. We recommend that the cross subsidy, if not removed entirely should be reduced by the recovery of fees from Market Customers on based on a split between energy consumed and individual NMIs. This would also reduce the risk of under recovery of fees due to the installation of DER at a customer's location where lower energy consumption reduces NEM fees collected from that customer although their individual cost to serve remains the same.

Additionally, ERM Power considers the cost recovery for allocated costs from generators and market customers should more fairly reflect the usage of the various services provided by AEMO and that the costs recovery methodology for different participant sub-types may be different. Cost recovery should be reflective of the overall costs of AEMO operating the nine energy and FCAS markets and other non-market procurement functions with the costs apportioned to each reflective of the actual costs incurred by AEMO. For this reason we believe in considering the Allocated Costs, this should be further separated into Energy Market Allocated Costs and Market and Non-Market Ancillary Services Allocated Costs and allow for separate cost recovery methodologies to apply to each area. This would more adequately reflect the cost impact of registered participants outside the current Energy market cost recovery methodology.

By way of example, when considering AEMO's costs for operating the Frequency Control Ancillary Services (FCAS) markets, as negative price outcomes do not occur in the FCAS markets, then cost recovery on a revenue received basis from FCAS suppliers would seem to be reasonable methodology as opposed to a methodology based on FCAS registered capacity and enablement. This would ensure that registered participants who utilise AEMO's systems for Market and Non-Market Ancillary Services contribute to AEMO's costs in providing these services. As Market Customers also benefit from a power system security perspective from the Market and Non-Market Ancillary Services, a 50-50 apportioning of AEMO's costs of provision of the Market and Non-Market Ancillary Services between suppliers and Market Customers would seem reasonable as both groups benefit equally from the maintenance of a secure power system.

Cost recovery on a revenue basis between energy providers in the energy market however is more difficult due to the potential for negative price outcomes. As AEMO has not provided information in the Consultation Paper as to which classification of generator imposes what level of costs on AEMO systems for dispatch of the Energy market, it is impossible to consider AEMO's proposal in any reasonable detail. We believe there would be benefit in apportioning the costs to serve in the Energy Market on a more granular costs to serve basis between generator scheduling type, AEMO should consider further granularity in the area of cost recovery for Energy Market Allocated Costs from generator scheduling types, i.e. Scheduled, Semi-Scheduled and Non-Scheduled generators based on AEMO's costs of provision of energy market services for each generator scheduling type. This would allow AEMO to more granularly define cost recovery based on scheduling type. As an example, cost recovery from Non-Scheduled generators may be based entirely on capacity, whereas, cost recovery from semi-scheduled generators may be based entirely on energy output and from scheduled generators may remain at the current 50/50 split.

Five Minute Settlement

The recovery of fees relating to the introduction of Five Minute Settlement (5MS) will play an important role given the scale of the costs involved – an estimated $121 million over 10 years according to AEMO. With AEMO providing a 10-year timeframe for the total costs of 5MS, ERM Power considers it would be appropriate to recover these fees over the same period of time. With this revised fee structure applying from 1 July 2021, it would be reasonable to commence recovering costs relating to 5MS from this time, despite the start date being 1 October 2021.

On the question of how the costs should be recovered and from which parties, ERM Power contends that AEMO should look to how 5MS will impact all participants. The system changes required to implement 5MS are clearly significant. All participants will be affected in some way by the shift. As such, splitting the costs between market participants of different types would seem to be the fairest way to recover these costs.

Full Retail Contestability and Consumer Data Right

ERM Power strongly considers that the existing per NMI basis for fees charged for Full Retail Contestability (FRC) should continue as is. Charges for FRC on a per NMI basis only began on 1 July 2019. The rationale for moving to a per NMI basis has not changed and consequently, we do not see there is a case to move away from this.

Additionally, we consider that the rationale for fees related to FRC being charged on a per NMI basis also extends to charges associated with the consumer data right (CDR). The costs incurred by AEMO due to the CDR will either be fixed or variable. Fixed costs include those related to the development of procedures and developing the systems to provide access to a customer's standing data; these costs will be incurred regardless of the number of connections points or volume of energy consumed in the NEM. Variable costs largely relate to the system and personnel requirements associated with managing data for the CDR. The number of transactions that AEMO must support varies by connection point, not by the volume of energy consumed. Put another way, AEMO's CDR costs are more likely to increase if the number of connection points increases, rather than if electricity demand per connection point increases. Therefore, apportioning variable costs relating to CDR by connection point would be a more cost-reflective approach than a volumetric approach.

Please contact me if you would like to discuss this submission further.

Yours sincerely,

[signed]

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