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Assistant Director Market Regulations

Economic Regulation Authority
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Private Submission re: 2016/17 Wholesale Electricity Market Report for the Minister - Discussion Paper July 2017

Dear Sir/Madam,

Thank you for the opportunity to comment on the above discussion paper. I have worked in the WA electricity industry for 32 years in various roles across the whole supply chain from generation through to customer end-use of electricity.

I support the proposed "Areas for immediate focus" outlined in section 2.1 of the discussion paper and I comment below on particular aspects raised in the discussion paper in the sections numbered as below.

2.1.3 System Support Services

I share the concerns of the ERA regarding the announced closure of some Synergy generation facilities that could be needed to provide system support in future years.

Having worked on generation and network capacity issues in the Eastern Goldfields, supplied by the single 220kV transmission line from Muja and local generation capacity, I consider that the proposed closure of the Synergy gas turbines in Kalgoorlie may not be in the best interests of an economically efficient, reliable supply of electricity to the area. These gas turbines are regularly used to provide support during network outages and other contingencies. They provide black start capability for the local network and provide capacity during peak demand periods.

The actual generators (alternators) of these gas turbines are also capable of providing voltage support to the network by being operated as 'synchronous condensers' – continuing to spin connected with the grid after their turbines are disengaged via a clutch and then turned off. Although not used for this purpose to date, this additional use could be an economical alternative to the future installation of new reactive support equipment, and could also provide backup to the aging saturated reactors that currently provide the main voltage support that allows the 220kV line to have its much-needed higher supply capacity.

There is limited supply capacity in the area to connect new large loads to the network, and it does not appear to be a prudent decision to close this peaking/backup generation capacity. Applications for new load connections exceed the available capacity from the network.

The absence of locational network pricing in the SWIS is a key reason that some economically efficient solutions are not being arranged by market participants in/for the Eastern Goldfields. Network Control Services and/or Dispatch Support Services would only partly address the absence of locational network pricing for the area. When supply to the area is constrained, local generation or demand-side capacity is not adequately incentivised to respond due to the absence of locational network pricing.

2.1.4 Interim access solution

I concur with the issues raised by the ERA in this section of the discussion paper.

In addition I note that a slide in the GIA (Generator Interim Access) presentation to the April 2017 WA Generator Forum – referred to in footnote 29 of the discussion paper – proposed that constraints on generators would be applied “pre-contingent” (before a network or other contingency occurred). This means the constraint on a generator could apply for substantial periods of a year, in case a contingency occurred. If that is really necessary because the contingency would expose the network to an unacceptable operating state immediately, then this approach is understandable.

However many unplanned contingencies are very unlikely or infrequent, or would not cause unacceptable operating states, at least immediately or soon after, and could be managed post-contingent (immediately after the contingency event) via a rapid generator run-back or other methods.

Having the GIA require all generator constraints to apply pre-contingent can be likened to requiring all personnel to remain indoors for long periods of a year in case of a lightning strike. It is unnecessary in many cases.

2.1.5 Planning for increased levels of intermittent generation in the WEM

The Finkel Review and the ENA’s Network Transformation Roadmap provide sensible recommendations to manage the increased levels of intermittent generation and emerging technologies such as battery storage.

A key contributor to the rapid take-up of these alternatives by customers is the lack of cost-reflectively structured network and retail tariffs. Existing tariffs provide greater financial incentives to take up these technologies, and air-conditioners as well, than is economically efficient.

The widely used flat (non-time-varying) energy-based network and retail tariffs (without a demand component to reflect customer demand that drives network and generation capacity capex) are a key reason that customers install solar PVs and avoid more (bill) costs than they should. Similarly customers installing air-conditioners that contribute significantly to annual system peak demand, but which recover insufficient revenue on flat energy-based tariffs to cover the network and generation supply capacity costs, because they don’t operate for enough hours of the year to do so, are being cross-subsidised by other customers and/or consumption.

The introduction of more cost-reflectively structured network and retail electricity tariffs would start to drive more economically efficient outcomes, including the beneficial application of energy storage to the supply system and by customers.

Even peer-to-peer electricity trading is largely driven by the price differences between electricity consumption and export tariffs that are not time-varying (don’t reflect the true time-varying value of the electricity) and do not reflect the actual portion of the network used for the electricity trade (e.g. only to the next door neighbour).

Time varying or demand-based locational network pricing would also help to promote more economically efficient market responses by players.

The need for centralised planning and coordination. Role of governments?
For many years now, the SWIS has not had centralised planning and coordination of generation, network and fuel/energy needs. This disappeared with the role being moved from SECWA to the Energy Policy and Planning Bureau (EPPB) initially. THE EPPB later evolved/merged in function with other bodies. Disaggregation over time has also fragmented the overall planning function even further.

Centralised planning and coordination is important to reinstate for the SWIS because, in the absence of effective regulation, the commercial interests of individual market players have led, and can still lead, to sub-optimal decisions and outcomes for the whole electricity market.

The role of State and Federal governments in this and other aspects of the electricity industry, begs serious consideration. It appears from the history of the Australian electricity and gas industries to date, that political cycles and motives lead to these governments not being prepared to make the hard but beneficial decisions for the long term. A reluctance to reform network and franchise retail electricity tariffs is one long-standing example of this.

2.2 Transitional change in the WEM

On page 18 of the discussion paper is the question "What is causing the change, for example is the change driven by a government policy initiative or are imperfect market signals driving customers' behaviour?" I consider that both are contributing to the change.

There is no doubt that decreasing costs of clean energy and disruptive technologies are contributing to the change, but some examples of contributions from government policy and imperfect market signals are given below.

Overly generous feed-in tariffs (FITs) for renewable energy have clearly encouraged the rapid uptake of residential solar PV systems. The fact that these tariffs are flat, energy-based tariffs that do not reflect the time-varying value of the electricity exported to the grid also distorts customer behaviour from what is economically efficient. Customers on a generous FIT tend to conserve electricity when the sun is shining to export as much as possible to the grid. They then turn on more appliances in the evening which adds to the annual supply system peak demand that drives the need for more network and generation capex to increase supply capacity and thus increases supply costs above what is optimal.

On the other hand, customers who missed out on the generous FITs and only get a low price for their electricity exported to the grid, tend to turn on appliances during the day and consume more energy to match their PV system output so that they avoid purchasing electricity from the grid (charged for on much higher, flat, energy-based tariffs) as far as is practical.

These two opposite behaviours are driven by poor price signals.

Cost-reflectively structured time-varying network and retail tariffs for both the consumption and export of electricity by customers would significantly improve the market responses and deliver more economically efficient outcomes.

Government climate policy, or the lack thereof, and a constantly changing approach, are contributing to transitional change and its volatility. The Renewable Energy Target (RET) and the changes to it have also contributed to transitional change and volatility in developer responses, which makes managing the change more difficult.

The on-again, off-again approach to electricity market reform in WA by different state governments as part of the political cycle is slowing progress to a better overall WA electricity market.

3.1.2 Limiting excess capacity

The original design of the Reserve Capacity Mechanism (RCM) is largely responsible for the combined excess of generation and DSM capacity in the WEM. The design did not cap the amount of capacity that would receive capacity payments and so an over-build of base load and peaking generation capacity occurred together with high levels of dispatchable demand reduction (called DSM) that was signed up and received the same administered capacity price.

The RCM did not procure capacity competitively either, and so the market has no doubt paid more than necessary for it to date.

The interim arrangements put in place by the previous state government to address this excess have already reduced it significantly, for future years. The largest reduction has come from DSM due to the low prices that will be paid in the interim for DSM compared to conventional generation capacity.

I understand the rationale for offering such low prices to get rid of excess capacity from the market, and the fact that DSM is 'easier to decline' than generation plant that has been built and its capex expended. However such low interim payments for DSM are clearly discriminating against DSM (counter to some of the WEM Market Objectives) when you consider that some conventional peaking generation plant is also only likely to be dispatched very infrequently like the DSM. Perhaps this infrequently dispatched conventional generation plant should also receive low payments based on the same calculation methodology as is to be used in the interim for DSM.

A MW of conventional generation capacity is worth the same as a MW of DSM if they are available when required. Being dispatched very infrequently is not a valid argument for being paid less for that capacity. Some of the capacity required by the RCM to meet the Reserve Capacity Target (RCT) is only required to meet a 10% PoE (Probability of Exceedance) demand, theoretically once in ten years, or even less often because of the RCT's 7.6% reserve capacity margin above the 10% PoE demand. However that infrequently required capacity is still required and should be paid for at a market-competitive price.

To avoid such discrimination I support a capacity auction as has been proposed, open to both conventional generation plant and DSM on an equal basis providing that the capacity procured is technically capable of fulfilling the role for which it is procured, and it is the most economical total cost mix of capacity types <u>as dispatched</u> (including variable costs for energy, costs of ancillary services provided and any other costs/benefits), that would meet the security and reliability requirements of the WEM.

I am concerned that the proposed single-tranche auction will not procure the right technical capability mix of capacity types at the most economical total cost.

I suggest that there are four categories of capacity which could form the basis of four tranches in the auction, each capped in capacity at its own clearing price, and each with different technical and economic performance requirements in order to result in the most economically efficient total cost mix of capacity for the market. They are based on the SWIS load-duration curve as follows:

1. **Base-load generation plant tranche** – typically higher capital cost but low operating cost, such as coal-fired or combined cycle gas plant. The former IMO characterised this category of plant as the capacity operating to supply demand that is exceeded for more than 75% of the year on the annual load-duration curve. A base-load tranche could be used in the capacity auction, with a cap on how much capacity of this type of plant will be procured, allowing a margin for base-load plant being out of service for maintenance etc.
2. '**Extreme Peak' tranche** - At the other end of the load-duration curve there is an additional capacity requirement for say less than 1% of a 50% PoE year's demand (in the top 87.6 or perhaps 100 hours of demand in the year), plus the additional capacity required for the extra demand that occurs in a 10% PoE year - the forecast that the Reserve Capacity Target (RCT) is based on, plus the 7.6% Reserve Margin required for the RCT. The total capacity requirement of this 'Extreme Peak' tranche of capacity could be capped and would typically be best met by low capital/fixed cost capacity such as conventional distillate or gas-fired peaking generation plant such as reciprocating engines or open-cycle gas turbines, or by some DSM that is most likely to be even lower total cost.
3. **Normal Peaking Capacity tranche** – dispatched for the extra demand that exists say from 1% (or 100 hrs.) to 10% of the year on the load duration curve. The former IMO characterised this category a being dispatched less than 10% of the year, including the Extreme Peak tranche described above which was not segregated from the normal peaking tranche. Again this normal peaking tranche could have a cap and would typically be met by conventional distillate or gas-fired generation plant such as reciprocating engines or open-cycle gas turbines.
4. **Intermediate (or two-shifting) capacity tranche** – for the remainder of the load-duration curve in the middle, capacity dispatched to meet demand that exists for more than 10% of the year up to 75% of the year. This would typically be met by mid-range capital cost, mid-range operating cost conventional generation plant that is flexible enough to start each morning and shut down each evening reliably (sometimes called 'two-shifting' plant), with load following capability, without suffering undue maintenance costs.

Each tranche's cap could determine that tranche's clearing price for capacity. It is important that plant of the right technical capability and total cost be selected. Base-load plant is typically unable to perform the flexible role needed from peaking plant. Peaking plant is not usually suitable for base-load operation because its operating costs per MWh are too high.

Intermittent generation capacity tends to eat into the dispatched hours of conventional generation plant, and needs to be accommodated in the auction tranches in a way that recognises intermittent plant's availability and economic characteristics.

Some generation companies are opposed to the capacity auction. I suspect it is mainly because there is a risk that their capacity may not clear in the auction and so will miss out on capacity payments. This is a commercial risk of true competition and should not be a reason in itself to forego a competitive process like the auction.

Thank you for the opportunity to comment. I would be pleased to be able to elaborate on these matters.

Yours sincerely,

Noel Schubert