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Submission re: Effectiveness of the Wholesale Electricity Market 2017/18 Report to the Minister - Discussion Paper, December 2018

To the ERA,

Thank you for the opportunity to comment on the above discussion paper. I comment below on particular aspects raised in the discussion paper sections numbered as below.

2. Pricing trends in the WEM and potential drivers

There are a number of factors that would explain part of the observed increase in balancing prices of the wholesale electricity market (WEM) such as:

- The actual MW output levels at which dispatched generators are required to operate, which affects their heat rate (efficiency). Operating at lower output (due to increasing wind and solar PV generation) would be likely to increase short-run marginal costs of generators aside from the effect of more frequent starts/stops and generator run times in between.
- Synergy's long term fuel contracts and bilateral contracts for purchase of electricity from other generators, often with take-or-pay and/or escalation provisions, could mean that short-run marginal costs of Synergy's generators do not follow shorter term fuel market price trends. Synergy will no doubt cover such matters in its response.

Electricity price signals and peak demand management

Both generation and network wholesale electricity supply costs are higher than they could be due to very blunt and/or improperly focussed network and retail tariff price signals as follows.[1]

- The existing energy-based tariffs cause substantial cross subsidies to rooftop PV and air conditioners. Both of these cause the already significant and increasing variability in system demand that the network and generators must cope with under Western Power's and AEMO's management respectively. This adds to supply costs and causes other issues.
- As well as the energy-based tariffs, the network demand-based tariffs, and probably many retail tariffs based on them, are blunt and poorly focussed because they do not effectively incentivise customers to move demand away from network and system-wide peak demand periods into low demand periods, including the new middle-of-the-day low demand period caused by the rapid uptake of rooftop PV.

Customers are doing what they currently do, and causing issues - like the 'duck curve', the high evening demand peaks, the loss of energy sales revenue by Synergy and Western Power in excess of

[1] More explanation of this can be found in my submission to the ERA on Western Power's initial AA4 proposal at: https://www.erawa.com.au/cproot/18520/2/Mr%20Noel,%20Schubert.pdf

their cost reductions – because of the absence of better price signals and demand management programs.

A huge amount of market reform work is underway, stretching resources, to enable the SWIS to cope with 'supply-side' issues, such as constrained network access for generators, reserve capacity mechanism and capacity pricing reform, the future generation mix, market design, utility-scale energy storage participation, policy and more.

However there is very little work being done on influencing the 'demand-side' issues - customers' use of electricity and new technologies like solar PV, batteries and electric vehicles, as well as the usual appliances and loads.

This is a very significant gap in the focus on improving the broader SWIS electricity market and it results in higher wholesale electricity supply costs.

Although total SWIS peak demand growth has been low in recent years (see further comment below), an ongoing lack of peak demand management focus in the SWIS will result in the need for more/earlier network augmentation in future. Peak demand is still growing in certain areas of the network like the coastal strip from Mandurah to Margaret River and new Perth suburbs. Each time we have extreme weather it causes more network augmentation to be done because it shows up shortages in network capacity at particular locations. Managing such peak demands in advance can economically defer augmentations and lower supply costs.

3. Future risks and the investment environment

The discussion paper covers various aspects of when more generation capacity will be required in the SWIS to cover peak demand growth and the next-decade retirement of older Synergy generation plant like Muja C, D, and Pinjar, Mungarra and Kalgoorlie gas turbines. The paper suggests a need for early signals to incentivise the building of replacement generation or adoption of new technologies such as energy storage.

However there is currently capacity already available in the SWIS, but not being made available to the capacity market, that could defer the need for some replacement generation:

- Past demand response (DSM) capacity that could be made available under terms that are lower cost than new conventional generation capacity; and
- The Mungarra and Kalgoorlie gas turbines, while they are available, currently restricted to network support roles.

These are discussed in more detail later in this submission.

Peak demand growth

My view, on one hand, is that peak demand is likely to grow at a faster rate than has been forecast by AEMO and Western Power unless new measures, technologies or responses manage its growth.

On the other hand, it would be possible to economically contain peak demand growth through tariff reform, demand management and adoption of new technologies so that no new thermal generation capacity is required for some time even if Muja C is retired. Muja D is slightly younger and so should be able to operate for a little longer. I'm not sure how long the operationally-more-flexible, but higher-short-run-marginal-cost, gas turbines can be kept in service economically.

Peak demand in a recovered WA economy

If the WA economy recovers and is "humming along" nicely in future, peak demand in extreme weather events (heat waves, as distinct from one or two extreme days at a time) will be higher and surprise forecasters. The last two milder (from an extreme weather perspective) summers (2017, and 2018) have not shown up all underlying temperature-dependent load growth that has occurred, which is also still suppressed due to the economic downturn.

The 8th-10th February 2016 heat wave, also during the economic downturn, caused the highest SWIS demand to date and showed up most, but not all, of the underlying demand to that point in time because that heat wave was not as extreme as a 10% PoE weather event would have been.[2] Forecast 10% PoE demand is used to determine the reserve capacity target for generation capacity.

Rooftop PV SWIS peak demand reduction has reached its limit

Without battery storage, customers installing more PV capacity 'behind the meter' will not reduce the hot weather maximum demand further than it has been already, because the maximum demand now occurs near sunset when PV output drops off rapidly to zero.

IRCR response

The IRCR (Individual Reserve Capacity Requirement) response – lowering peak demand and therefore affecting forecast and actual peak demand growth - could vary in future and, if it does, would need to be analysed and perhaps modelled to understand and predict better.

I suspect that the IRCR response will vary in future for the following reasons:

1. The predictability (in advance) of when the 12 IRCR intervals are likely to occur (on which days and their timing), so that IRCR responders can take action to reduce demand for those intervals, will affect responders' participation and the overall level of demand reduction.

   In the two most recent summers, the weather was much milder than in the 2016 summer. The milder weather made it more difficult to predict which days would be included in the final 12 IRCR intervals given that these days are usually characterised by being extremely hot. I understand that at least one winter day was included in the final 12 intervals due to the milder summer conditions. So I suspect that participation and demand reduction was lower in these milder summers than it would have been if the IRCR days were hotter and therefore more predictable.

   Also the greater the total IRCR demand reduction on a particular day, the more likely that day will not end up being included in the final 12 intervals because the resultant demand ends up lower due to IRCR participation on that day. If there is enough IRCR participation and demand reduction it will make prediction of the IRCR days more difficult.

2. The demand management effort by IRCR responders will depend to some degree on how much assistance or incentive to participate is given to them by demand response aggregators or their electricity retailers. This is also related to how much of such demand-

[2] The AEMO classified the 8 February 2016 peak as a 10% PoE (probability of exceedance) weather event (see pages 54 & 55 of the June 2016 AEMO "Deferred 2015 ESOO"), but Western Power's forecasting team later classified it as a 20% PoE peak which I consider to be more correct for reasons I can explain. See Appendix E of Western Power's 2017 Annual Planning Report https://westernpower.com.au/media/2360/annual-planning-report-2017.pdf

response capability is reserved for the capacity credit allocation of the Reserve Capacity Mechanism (RCM).

Some demand response capacity will be used for IRCR reduction purposes. Some will be used for RCM capacity credit allocation. A particular source of demand response capacity should not be used for both purposes.

The relative allocation of customer's demand response capability to either of these two purposes will depend on their relative attractiveness due to IRCR savings versus capacity credit value and their respective participation rules and terms.

Given that the reserve capacity pricing is likely to change as part of the market reform program, this may change the amount of demand response capacity that is then reserved for capacity credits and so the amount of other demand response capability that will be used for IRCR response.

Reduction in capacity due to retirement of older generation

In the absence of other measures or responses as discussed above, this retirement could result in a shortage of generation capacity.

However as mentioned above there is additional capacity already available in the SWIS that is not currently participating in the capacity market.

The original design of the Reserve Capacity Mechanism (RCM) and the past 'displacement mechanism'[3] were largely responsible for the combined (~1000MW) excess of generation and DSM capacity in the WEM until recently. The design did not effectively cap the amount of capacity that would receive capacity payments and so an over-build of base-load[4] and peaking generation capacity occurred together with high levels (560MW) of dispatchable demand reduction (called DSM) that was signed up and received the same administered capacity price.

Since then the current (interim) market rules have caused around 500MW of the DSM to be withdrawn from the capacity market. 387MW of Synergy generation capacity has also been withdrawn from the capacity market as a result of the ministerial direction to do so.

However, 150MW of that withdrawn capacity (the Mungarra and Kalgoorlie gas turbines) has been kept available for network support requirements. While it is available and could, in practise, be dispatched during extreme weather high demand periods, it could offset the need for that quantity of other generation capacity to meet peak demand. The Reserve Capacity Target could be reduced by that amount (~150MW) if these gas turbines were allowed to be dispatched during high demand periods.[5]

The existing latent demand response (DSM) capability, which is not being made available to the capacity market or used for IRCR demand reduction, could be encouraged to re-enter the capacity

[3] The Displacement Mechanism required Synergy (as a retailer only - before Verve Energy (generator) was amalgamated into Synergy) to tender for additional capacity from the market to reduce Verve's generation dominance.

[4] Retirement of baseload Muja C would help to rebalance the mix of generation types towards a more optimal mix for the needs of the SWIS.

[5] A gazetted ministerial direction currently prevents dispatch of these gas turbines for reasons other than for network support. This could be changed if more generation capacity was needed in the capacity market.

market under terms that would be more economical than building new conventional thermal generation plant.

Treatment of DSM

The quantity of capacity credits now being issued by the AEMO to DSM has dropped from around 560 MW (as at 1 October 2016[6]) to 60 MW in the recent 2017/18 allocation, well below past PUO estimates of 250 MW, due to the current very low 'interim' payments available to DSM since the rule changes.

These very low payments to DSM are discriminatory, contrary to the WEM Objectives, and need to be rectified as part of the capacity pricing work currently underway.

Dispatchable demand response has a valid and economically efficient role in the WEM as an extreme weather peaking and reserve capacity resource. It would be lower cost than conventional generation plant for those roles if capacity payments were changed sufficiently to encourage its return without paying the same capacity price as for scheduled generation plant. It also can provide localised peak demand reduction in the network to defer or avoid network augmentation for demand that only occurs for a few hours each year.

When there is a substantial amount (560 MW) of demand response available from customers at lower cost, why would you build expensive network peaking capacity and generation peaking capacity if it is only required in extreme weather conditions for very few hours each year, and even less often for the 10% PoE demands that theoretically only occur once in ten years?

A competitive process for choosing the extreme weather peaking capacity would result in lower costs and would likely result in demand response providing that type of capacity.

As discussed above, some of the DSM capacity no longer receiving capacity credits is still operating usefully to reduce demand during IRCR intervals. The IRCR is working at intended in this regard, and I support its retention because it works very effectively to reduce annual system peak demand to defer the need for other capacity.

Other ("non-IRCR") DSM capacity that was receiving capacity credits previously would come back into the market if DSM was paid fairly, which I consider important to do.

This would then delay the need for procurement of additional capacity from new sources and so I consider the need to provide signals for new capacity to not be as urgent as it may seem.

Notification of planned generator retirement

I support the need for early notification of the planned retirement of generators to give the market time to respond.

Deferral strategy

Given the changing energy technology and policy environment, I consider that it would be valuable to defer the installation of new network and thermal generation capacity, to lower costs to the WEM, for as long as is prudent from economical, system security, reliability, and climate change perspectives so that, as changes unfold, better-informed capacity augmentation decisions can be made.

[6] See page 63 of AEMO's 2017 ESOO at: https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2017/2017-Electricity-Statement-of-Opportunities-for-the-WEM.pdf

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To this end, I also consider that centralised, integrated planning to identify SWIS network and generation capacity needs, is necessary to provide more certainty and guidance for investment.

For many years now, the SWIS has not had centralised planning and coordination of generation, network and fuel/energy needs.

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.

Currently Western Power carries out transmission and distribution planning and produces information on its plans in its Annual Planning Report.

The AEMO produces its WEM Electricity Statement of Opportunities report with limited input from Western Power.

Given the rapidly changing electricity market, with increasing adoption of new technologies and greater customer participation, there is considerable need and opportunity for a more integrated "Needs Analysis" function to identify what the network needs and what the WEM needs.

The AEMO could perform this function.

Western Power could provide much more information to AEMO on network needs. Provision of network constraint equations under the proposed constrained access regime is one step towards this information provision.

Western Power could also provide a description of the circumstances under which, how often, and when, each network constraint typically occurs, and potential solutions to these constraints – for both generation constraints and load constraints.

The AEMO could then integrate this with its knowledge of WEM needs and perform this 'Needs Analysis' function. The AEMO could then provide much more information to market participants on the types of solutions that are needed, when, and where they are needed in the network, to meet both network needs and WEM needs more optimally. Some solutions can satisfy both sets of needs rather than disparate solutions being implemented at higher cost by separate entities.

We need to ensure that the total combined cost of WEM capacity, ancillary services, and energy, and network solutions, is optimised, and not just separately manage these.

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

Yours sincerely,

Noel Schubert