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Public Utilities Office
Department of Treasury
David Malcolm Justice Centre
28 Barrack Street
Perth 6000

Submission re: Improving Reserve Capacity pricing signals – alternative capacity pricing options

Dear Sir/Madam,

Thank you for the opportunity to comment on the above consultation paper. It is basically seeking comment on two alternative capacity pricing options, to compare against the capacity auction proposed by the previous Electricity Market Review, to arrive at a single, market-wide capacity price for each capacity year.

Integrated Planning

I acknowledge that there are a number of other electricity market reform streams and studies underway or planned (e.g. constrained network access, the SWIS generation mix, security-constrained market design, and co-optimisation of energy and ancillary services to name a few).

I consider that the integration of these and other necessary reform streams is absolutely necessary to ensure a well-functioning and economically efficient electricity market in future, especially given the rate of technological and other disruption that is occurring.

I consider that key electricity market functions in the SWIS have become so disaggregated to date that, without a centralised independent body performing integrated network and wholesale market system planning, it is unlikely that a single market-wide capacity price, with separate energy and ancillary services markets will deliver from year to year an optimised mix of supply solutions.

I question whether a single market-wide capacity price is appropriate, even though the current arrangements are reliant on this for simplicity and minimising the changes required.

A single capacity price will over-pay some sources of capacity and under-pay others, and does not recognise the differences in the value of capacity at different network locations or the different value of various attributes of different capacity sources.

A variety of capacity source types is required (base-load, intermediate, peaking, extreme-weather peaking and reserve capacity) with different necessary technical/performance, and desirable commercial, attributes. The different capacity sources will also differ in whether they can provide the other ancillary services efficiently. The capacity types required will also vary from year to year.

How do you ensure the market will provide sufficient of each capacity type required, and not too much more, at least cost, with a single market price for capacity unless you pay for the non-capacity attributes effectively through other market mechanisms and have some central oversight of what is needed and arranged?

The need for centralised planning and coordination.
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.

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.

Retailer-led contracting with bulletin board trading mechanism

The key reservations I have with this option are:

1. This option would appear to move processes even further away from the centralised planning approach that I consider needs to be restored in the SWIS.
2. It requires major changes from the RCM model that is currently in place and would take considerable time and cost to design, implement and then manage for the regulator (ERA), market operator (AEMO) and market participants.
3. Each Retailer would also need to establish an expert team to carry out their obligations, and I have no confidence that these teams collectively would choose options that overall are best for the WEM and its customers.

4. This option seems to be relatively new, not well proven and not widely adopted in other capacity markets.
5. Based on past WEM experience it is doubtful that this option would lead to economically efficient outcomes. Since the start of the WEM a retailer-led procurement and contracting approach actually occurred in the SWIS under the RCM and other incentives that were in place.

   EM retailers to date have acted in their own interests and not necessarily chosen capacity sources that as a whole mix (covering all retailer procured capacity) was an appropriate mix of generation types, capabilities and efficient costs for the SWIS, including energy costs and ancillary services provision.

   Under the "Displacement Mechanism[1]" Synergy (as a retailer only) procured significant capacity from private power stations in several tendering rounds to satisfy their obligations under this mechanism. It was designed to reduce the dominance of government-owned generation capacity as the market grew.

   In some instances private retailers/gentailers also procured their own generation capacity as the attractive RCM payments for capacity credits helped justify such investments.

   The outcome of both of these retailer-led procurement and contracting streams was an 'over-build' of both base-load and peaking generation capacity. It resulted in over 1000 MW of excess capacity being certified, including the 560 MW of DSM (dispatchable demand response).

   The recent RCM changes under the previous government sought to rectify this excess capacity problem to reduce its cost to the market and customers.

Administered pricing, and limiting excess WEM capacity

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

If fixed capacity cap(s) are used, then capacity cut-off level(s) are required and choosing which capacity to select up to those levels requires a competitive procurement process, to be fair to capacity providers. Someone has to pick the "winners" and "losers".

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

The consultation paper states that for European and North American capacity market designs "All of the major recent capacity market reforms rely on a competitive procurement process for price determination. Evidence from international markets suggests that competitive bidding for capacity is clearly the preferred best practice approach. This is the case regardless of the market design. Germany (strategic reserve), the United Kingdom (capacity auction), France (decentralised reliability

[1] 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.

obligation) and Italy and Ireland (reliability options) have all implemented competitive processes for capacity procurement. In the North American markets reviewed, all capacity is subject to a market discovered price."

It also states "there is a strong recent trend in those markets where capacity is sourced by a competitive process for the capacity price to be below the estimated price required by the marginal new entrant" and "The United Kingdom capacity auction has also delivered clearing prices much lower than expectations."

The interim arrangements put in place by the previous state government to address the WEM capacity excess have already reduced it significantly, for future years. The largest reduction has come from DSM due to the low prices that are being 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. If this approach was to be even-handed, the infrequently dispatched conventional generation plant should also receive low payments based on the same calculation methodology as is being 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 and have similar attributes to meet a peaking need. 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 whether it is from conventional generation or DSM.

Differences in the value of different capacity sources are justified when all valuable attributes of the capacity sources are valued appropriately (e.g. flexibility, start-up times, response times, ramp rates, inertia, load following capability, etc.).

To avoid such discrimination against DSM or other capacity sources, I support a competitive capacity procurement option that is open to all capacity sources 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 as dispatched (including variable costs for energy, costs of ancillary services provided and any other valuable attribute costs/benefits), that would meet the security and reliability requirements of the WEM.

I am concerned that the proposed single market-wide capacity price and the previously proposed single-tranche capacity 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 capacity payment tranches, 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 procurement, 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 - reciprocating engines or open-cycle gas turbines, by storage solutions, or by 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 25% of the year, including the Extreme Peak tranche described above which was not segregated from the Normal Peaking tranche. I consider that 10% is a more appropriate cut-off point for such capacity – at the noticeable point of inflection on the load duration curve around this point. 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, or storage solutions.
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 capacity procurement tranches in a way that recognises intermittent plant's availability and economic characteristics.

Existing generation companies are often opposed to a competitive capacity procurement approach. It is, no doubt, because there is a risk that their capacity may not clear in the process and so will miss out on capacity payments all together, or that the clearing price will be too low. This is a commercial risk of true competition and should not be a reason in itself to forego a competitive process.

In ancillary services considerations it is important to recognise all of the services of value to the WEM that are provided by the different types of generators, battery storage, demand response (called DSM in the WEM) etc. Services like rotational and synthetic inertia, and fast response times, to name a few, are also of value besides spinning reserve, LFAS and FCAS. The current WEM does not adequately pay for all services of value.

The proposed retention of a single capacity market price for the Reserve Capacity Mechanism makes it more imperative that other services, besides capacity at the time of annual system peak demand, are properly valued and paid for to distinguish between the values that different capacity sources provide.

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[2]) to 60 MW in the recent 2017/18 allocation, well below past PUO estimates of 250 MW, due to the current low 'interim' payments available to DSM since the rule changes.

These 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. 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?

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 procurement of new capacity to not be as urgent as suggested by the consultation paper. Battery storage to some extent, and significant intermittent generation construction, will also add to that delay.

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

Yours sincerely,

Noel Schubert

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[2] 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