

Noel Schubert

3 April 2018

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

Submission re: Improving access to Western Power's network – Implementing Constrained Access

Dear Sir/Madam,

Thank you for the opportunity to comment on the three consultation papers released by the Public Utilities Office (PUO) on the above subject.

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, including for Western Power for five years until June 2016. I have worked extensively on demand-side management, renewable energy and non-network solutions.

I generally support the approach proposed in the three papers, to implement constrained access to Western Power's network for generators.

Although it will disadvantage some incumbent generators to varying degrees – as discussed in the papers, I consider it important to allow new generation and other capacity sources to more easily access the network and enter the WA Wholesale Electricity Market (WEM), to compete with incumbent generators to help lower supply costs and reduce environmental impacts.

Incumbent generators would potentially lose revenue from:

- being allocated less capacity credits over time – for which the papers propose no compensation. Given that this loss of revenue would be due to the proposed rule/regulatory changes, a sovereign risk issue arises and I question whether this lack of compensation is fair for generators who are still paying off their capital costs and need the capacity credit revenue to do so.
- supplying less energy when network constraints cause them to be dispatched at lower output – for which the papers discuss potential compensation and modelling to quantify it; and
- supplying less energy due to competition from new entrant generators with lower balancing market bid prices displacing incumbent generator energy output, as is already happening due to increased wind and solar PV generation. No compensation is proposed for this, and I agree with that position. This is a normal result of increased competition and should be encouraged, to deliver better outcomes for customers.

I support the proposed security-constrained market design, and also co-optimisation of energy and ancillary services to ensure generators receive the revenue they ought to, especially if other revenue sources are removed.

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.

‘Allocation of capacity credits’ paper

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 value that different capacity sources provide.

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

A single capacity price will over-pay some sources of capacity and under-pay others.

A variety of capacity sources is required (base-load, intermediate, peaking, extreme-weather peaking and reserve capacity) with different necessary technical/performance, and desirable commercial, attributes. 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?

With regard to the three ‘tie breaker’ options discussed in section 1.1 of this paper, I support the ‘first-come first-served’ approach as it recognises the considerable effort and cost that first-come generators have put into establishing their capacity earlier.

Section 3 of this paper on demand side management discusses the lack of locational information on DSM. It is possible to obtain this information on the location and capacity of DSM sources – to identify which part of the network they are connected to.

In 2015/16 Western Power started to collect this information from former DSM providers to the RCM, for network planning purposes. A substantial amount of this capacity (560 MW as at 1 October 2016¹) was signed up by providers and allocated RCM capacity credits by AEMO.

This information would probably still be available on a confidential basis from the DSM providers based on their past work, even though the quantity of capacity credits now being issued by AEMO to DSM has dropped 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.

As an aside, it is unfortunate that this capacity is called DSM in the WEM. It is really dispatchable demand response (DR), as is now being used in the NEM. It is a subset of the broader demand side management suite of programs that include dispatchable and non-dispatchable sources. A wide range of energy efficiency programs, smarter tariffs and customer behavioural change programs are all examples of the broader DSM label.

¹ 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

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 locational 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, 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?

Other than the above comments, I support the proposed method of allocation of capacity credits and issuing of capacity priorities, providing they recognise the value of available demand response and its locational benefits.

Types of Network Constraints

There are two main categories of network constraints:

- network generation constraints; and
- network load constraints.

The 'constrained access' consultation papers we are dealing with at present are discussing generation constraints, but it would help if the distinction was made clear in future papers because of the interrelationship between generation output and loads on the same side of a network constraint and therefore the potential solutions to such constraints, as follows:

- Adding more load (e.g. by charging dedicated batteries or other forms of energy storage, or dispatching more aggregated discretionary loads, including electric vehicle (EV) charging) can allow more generation output on the same side of a network generation constraint at the times the constraint occurs.

By discretionary loads I mean loads for which the customer accepts reasonable flexibility in timing of when to operate them, without unwanted inconvenience. EV charging, storage battery charging from the grid, and operation of pool pumps, dishwashers, washing machines, clothes dryers etc. are examples at a residential level for willing customers. Commercial and industrial customers also have examples.

- Adding more generation on the constrained-load side of a network load constraint can help manage/relieve a network load constraint at the times it occurs (e.g. at peak demand times).

Utility-scale and behind-the-meter battery storage could help relieve both types of network constraints if, and where, they are more economical than normal network augmentation.

Accommodating the Future – with EVs, battery storage and other dispatchable discretionary loads – for constrained load access

These consultation papers discuss implementing constrained access for larger (registered) generators given the disadvantages of unconstrained generator access that we have at present.

Although it is not part of the current consultations, I would encourage the PUO and industry participants to also bear in mind, when designing the proposed generator constrained access approach, that we also have in place in the WEM an unconstrained network approach to load access.

For much of the transmission network², and more-meshed parts of the distribution network, Western Power uses an N-1 network planning approach (really an unconstrained load access approach) to increases in customer load on the network. Western Power will generally augment the network to be able to cope with the peak loads (demands) on the network, without any constraints on loads - apart from a few recent exceptions where loads are contracted to run back under contingency situations.

However, for much of the year (away from peak demand times) most elements of the network have significant spare capacity and could carry more load. Facilitating this would improve the average utilisation of the network and reduce average supply costs.

Just as for moving to constrained generator access, there would be significant advantages in a future approach to managing discretionary loads – constrained load access for discretionary loads.

I can envisage a future where Western Power's network operation control centre can communicate in near-real-time to market participants when and where there is spare network capacity available to allow discretionary loads to turn on without incurring punitive network demand charges that are designed more for network peak demand times to reflect network augmentation costs.

I understand that in the National Electricity Market (NEM) generator network constraint equations are updated regularly to reflect changing network constraints throughout the day, so the same could occur for network load constraints as a signal of where there is spare network capacity.

Western Power could even take responsibility for turning on discretionary loads agreed to by customers – such as ensuring that your EV is fully charged by the time you leave for work in the morning.

The Internet of Things (IoT) is coming, and will allow much lower cost communication, monitoring and control of many distributed 'things'. See the detail in these two sites: <http://www.iot.org.au/> and <https://iot.engineersaustralia.org.au/>. The IoT will allow easier aggregation of distributed loads (even individual appliances) and generators.

As adoption of distributed energy resources (DER) such as PV generation, battery storage, EVs, and aggregated demand response and loads continue to grow in magnitude and impact on the network, it is important to design network generation and load access regimes to allow for this DER to access the network and be able to provide the benefits it can offer, to help improve the average utilisation of the network (getting more out of the network we already have rather than building more network to satisfy peak generation or load) and improve the economic efficiency of electricity supply.

I would recommend bearing in mind this 'other side of the equation' (constrained load access) in the design of the generator constrained access approach to ensure that we plan as far as practical for this future at least cost.

² The Eastern Goldfields 220kV line to Kalgoorlie is an exception – not designed to N-1 because of the exorbitant cost. This example shows that N-1 network planning is not necessary where there is sufficient local generation to cover the loss of a transmission line.

'Modelling the impacts of constrained access' paper

I generally support the proposed modelling approach, but suggest a need (as intended) to update the assumptions based on confidential 'real world' feedback from existing generators. Some qualifications follow.

Capital cost repayments

At the top of page 24 of the EY 'Modelling' paper, for existing generators it is stated "As such EY assesses the year-on-year net revenue of existing generators in the modelling assuming no capital cost repayments are required,". I don't agree with this assumption because some recently installed generators would still need capital cost repayments.

Generator heat rates check

The table of generator heat rates included in the EY presentation (page 27) at the industry forum on 13 March seemed to be quoting higher efficiencies than I understand to be valid. This may already be accommodated validly in the EY 2-4-C model, but I comment as follows just in case it is not.

Generators often quote efficiencies or heat rates based on the 'lower calorific value' or lower heating value (LHV) of their input fuels. This makes the generator efficiency look better than if the 'higher calorific value' or higher heating value (HHV) is used.

Fuel suppliers generally quote the HHV for their fuel, as it is higher and looks better.

Generators also often quote their efficiencies on a 'generated' (at the generator terminals) basis, ignoring the electricity used on site by their generator auxiliaries, because this gives a higher value.

The useful output of the generator is its 'sent-out' output, after deducting 'used-on-works' electricity consumption.

The result of these different approaches to 'heat rate' figures is significantly different values that could materially affect the modelling results and make them invalid.

I am only raising this so that EY ensures that its modelling is valid, based consistently on one of the heat rate approaches throughout the model, explicitly allowing for the differences between them, and also allowing for the different bases of publicly quoted 'heat rates'.

Level of conservatism in constraint equations

I recommend that the level of 'conservatism' inherent in the constraint equations provided by Western Power be understood and assessed for reasonableness. There is a tendency for network companies to be more conservative than is economically efficient, for various reasons including that they have to wear the flak for power outages. The reason we have unconstrained access is because of conservatism originally, when the rules were being developed, and this is what we are trying to undo now.

Utility-scale battery storage

Although we do not know whether any utility-scale battery storage will be installed in the network during the modelling period, I and others consider that it should not be ignored.

If the early modelling identifies that a network constraint needs rectifying by network augmentation or other means, then I suggest that battery storage be evaluated as one of the options to overcome the constraint rather than just traditional network augmentation. This is because battery storage offers a number of additional advantages to the SWIS.

Marginal network loss factors

For modelling energy aspects over a year, the use of average marginal loss factors is considered to be reasonable.

For modelling capacity aspects at a point in time – e.g. at peak demand time on a network element – it would be more valid to use the actual marginal loss factor at that time rather than an average figure.

For example, when the Eastern Goldfields 220kV line is operating at maximum power flow, the line losses at that time would be of the order of 25 – 30%. This is a much higher figure than the average marginal losses over a year.

The PUO supplied loss factors in the modelling workbook, for the West Kalgoorlie GTs appear to be average marginal loss factors (12.59%), which is probably suitable for energy modelling over a year, but I don't think they would be suitable for capacity modelling at the time of peak loading on the 220kV line.

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

Yours sincerely,

Noel Schubert