perthenergy

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Dear Simon

Role of the Australian Energy Market Operator in Local Transmission Network Planning

General

It is with considerable regret that Perth Energy must express its great disappointment in the way that the electricity reform process is unfolding. The original statement of objectives set by Government, and the broad ideas discussed by the Steering Committee, raised hopes that we would see genuine reform that would enable the market to cope with the massive changes expected in the electricity industry. Instead we have seen Government back away from genuine reform and simply move to protect its commercial interest as the owner of major electricity assets.

This approach is very clear in the arbitrary changes being made to the pricing of reserve capacity and PUO's reluctance to even acknowledge the sovereign risk perceived by investors. Private investments, built in response to the concern that high electricity growth rates would see the State short of power, are now being commercially savaged. This is being done, supposedly, to reduce excess generation capacity despite the clear knowledge that the problem is too much base load generation capacity most of which is either owned by Synergy or contracted to it through power purchase agreements. It will be most illuminating to see whether Synergy responds to these signals.

We are now seeing this focus on commercial protection in the decision to absolve Western Power from any liability for the removal of contractual transmission access rights with neither discussion nor compensation. Perth Energy is most concerned at the Government and PUO's cavalier approach to these matters not only because of the commercial impact on private merchant generators' operations, which are based on facility bidding compared to Synergy's advantageous portfolio bidding operations, but because it also is undermining the market reform process and damaging Western Australia's brand as an investment opportunity.

Because of this Perth Energy is very keen to draw independent bodies into the electricity market processes to limit the opportunity for the State Government manipulation. Perth Energy strongly supports the proposal that the Australian Energy Market Operator (AEMO) be empowered to produce a Transmission Network Outlook in parallel with the Statement of Opportunities Report. While there is no indication that Western Power's Annual Planning Report is being driven in quite the same partisan way having AEMO publish a Transmission Network Outlook on a regular basis will, to some extent, restore confidence in the market.

Unrelated to this particular network planning topic, but supporting our call for AEMO to reaffirm its overall market operations role, Perth Energy sees this role as also enforcing efficient dispatch of the WEM's generation fleet.

There is nothing in the Market Rules that requires System Management to consider the impact on balancing prices when scheduling outage planning for generation and transmission assets (see Attachment). The criteria are about meeting load (2nd deviation forecast), LFAS and providing sufficient capacity to meet the ready reserve standard. This lack of an efficiency criterion gives rise to volatility in balancing prices as seen recently in the June quarter of 2016. Approved outages allowed unnecessary price surges, seen particularly in May and June, in a system purportedly carrying 23% (>1000MW) excess capacity.

The Short Run Marginal Cost rule applicable to Synergy clearly does not work in a portfolio bidding environment. ERA has been unable to call on Synergy to explain the balancing price hikes. The EMR has put the critical facility bidding requirement on the table for reform but so far has been agonizingly slow in making it happen. All its effort has been in destabilizing the RCM with the end result being significant sovereign risk to merchant plants as discussed above.

AEMO must run a dispatch model as a matter of course in approving planned outages. Synergy, due to commercial interests as allowed by the Government, does not have any incentive to operate in the most efficient (lowest cost) manner in its dispatch. As it controls 80% of the generation fleet and is an integrated entity with a dominant retail arm, it can see the state of the market on both sides and can easily lever the balancing price to suit its ends.

In addition, the present ring-fencing arrangement permits RBU to take a fully unhedged position in the retail market, with no regard to Synergy's out-of-the-market power purchase agreements, and thereby price at balancing price to undercut competitors. If the balancing price goes up, RBU could lose but this would be offset by WBU's and GBU's gain. No other market players have this market power with a structure enabling them to fully expose themselves to the balancing market without risk. They must take a hedged position in a market where virtually all hedging products are sold by their major retail competitor. The entire generation dispatch and retail pricing environment has become irrational as a result of the Verve-Synergy merger.

The only mitigation would be for ERA and AEMO to enforce economically efficient dispatch in order to enforce the SRMC rule to maintain a degree of market integrity. This should be done at least until facility bidding is in full operation at Synergy.

Responses to questions raised in the Paper

Section 3.1.1 - As noted in the Position Paper, information on energy flows, security of supply and trends in network constraints would be very useful to support market participants with both operations and development plans. Information on potential constraints will be especially valuable as this is a completely new feature of the market and participants do not have any experience or history to work with. An independent assessment of potential constraints is essential if this information is to be used in setting the level of certified capacity that is assigned to generators. Some measured commentary that draws on AEMO's experience in the NEM would be very helpful.

Section 3.1.2 - Perth Energy supports the proposal that AEMO prepare market scenarios and development strategies for all "major transmission corridors". We also support the definition of these to be those portions of the system that carry significant amounts of electricity between generation centres and load centres. However, there may be portions of the system that do not fully meet this definition but which still need to be independently assessed so Perth Energy supports AEMO using its own judgement to expand its review.

Section 3.1.3 - We also support AEMO determining the level of Network Support and Control Ancillary Services.

Section 3.1.4 – We support giving AEMO the power to seek information from Western Power and other market participants to develop connection point electricity and demand forecasts. We see it as essential that AEMO can require this information to be provided.

Section 3.1.5 – We note that AEMO is the jurisdictional planning body in Victoria and suggest that this may be a better approach for Western Australia rather than having Western Power as both owner and planner for the network. Our reasoning here is:

- There is common ownership between the transmission network and the dominant generator-retailer raising the potential for transmission planning to favour Synergy's needs;
- This risk is accentuated by the fact that a number of other major market generators are contracted to this generator-retailer;
- Network planning should be totally independent of the Government's financial policies or constraints; and
- It raises the possibility of private investment in network upgrades where this could be economically justified.

Section 3.1.6 – We consider that the Transmission Network Outlook should be a separate document from the Electricity Statement of Opportunities report but this is not critical. Both are likely to be large documents and the emphasis of each, and the stakeholder interest, will differ. They should however be published at the same time. An alternative would be one report but with two distinct volumes.

Given the rapid changes occurring in the electricity market a 10 year horizon, in parallel with the ESOO, appears reasonable.

Section 3.1.7 – We have found the Western Power Annual Planning report to be a very useful document and one that has developed in response to stakeholder feedback. We are pleased that Western Power will now be formally obligated to produce this by the National Electricity Rules.

Section 3.2 – We can see the benefit of AEMO publishing a database containing the information that is listed on Page 12 of the Paper. Much of this data is publicly available and drawing it into one place will be a useful planning asset as well as showing the data that AEMO is using in its assessments. The publication of assumed fuel prices must be done in a way that protects confidentiality and does not prejudice the commercial interests of generators. There is also the potential for generators to face challenges to their bidding processes based on simplistic analysis of published assumed fuel costs. We would hope that this would be a relatively minor issue.

Section 5 – We do not see any real alternative to recovering the costs of producing the Transmission Network Outlook via the existing fee structure.

Please do not hesitate to contact me should you or your staff wish to discuss any of these matters further.

Yours faithfully

Andrew Rowe

Chief Executive Officer

ATTACHMENT

Criteria for Outage Planning (Wholesale Market Rules)

System Management must assess the acceptability of Outage Plans using the criteria specified in the Market Rules [MR 3.18.11 (a) to (d) & MR 3.18.12], based on the information specified in the PSOP: Power System Security.

MR 3.18.11. System Management must apply the following criteria when evaluating Outage Plans:

(a) the capacity of the total generation and Demand Side Management Facilities remaining in service must be greater than the second deviation load forecast published in accordance with clause 3.16.9(a)(iii) or clause 3.17.9(a)(iii), as applicable;

(aA) the total capacity of the generation Facilities remaining in service, and System Management's reasonable forecast of the total available Demand Side Management, must satisfy the Ready Reserve Standard described in clause 3.18.11A;

(b) the transmission capacity remaining in service must be capable of allowing the dispatch of the capacity referred to in clause 3.18.11(a);

(c) the Facilities remaining in service must be capable of meeting the applicable Ancillary Service Requirements;

(d) the Facilities remaining in service must allow System Management to ensure the power system is operated within the Technical Envelope; and

(e) notwithstanding the criteria set out in clause 3.18.11(a) to (d), System Management may allow an outage to proceed if it considers that preventing the outage would pose a greater threat to Power System Security or Power System Reliability over the long term than allowing the outage.

3.18.11A. The Ready Reserve Standard requires that the available generation and demand side capacity at any time satisfies the following principles:

(a) Subject to clause 3.18.11A(c), the additional energy available within fifteen minutes must be sufficient to cover:

i. 30% of the total output, including Parasitic Load, of the generation unit synchronized to the SWIS with the highest total output at that time;

ii. plus the Minimum Frequency Keeping Capacity as defined in clause 3.10.1(a).

(b) Subject to clause 3.18.11A(c), and in addition to the additional energy described in clause 3.18.11A(a), the additional energy available within four hours must be sufficient to cover:

i. 70% of the total output, including Parasitic Load, of the generation unit synchronized to the SWIS with the second highest total output at that time;

ii. less the Minimum Frequency Keeping Capacity as defined in clause 3.10.1(a).

(c) System Management may relax the requirements in clause 3.18.11A(a) and (b) in the following circumstances:

i. where System Management expects that the load demand will be such that it exceeds the second standard deviation peak load forecast level, as described in clause 3.17.9(a), used in the most recently published Short Term PASA for that Trading Interval;

ii. during the four hours following an event that has caused System Management to call on additional energy maintained in accordance with clauses 3.18.11A(a) or (b).

3.18.12. Except to the extent required by the criteria in clause 3.18.11 and to the extent allowed by clause 3.18.5A, in evaluating Outage Plans, System Management must not show bias towards a Market Participant or Network Operator in regard to its Outage Plans.