perthenergy

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Economic Regulation Authority
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Draft Balancing Submission Guideline

Perth Energy appreciates the opportunity to respond to the draft Balancing Submission Guideline published by the Authority on 3 January 2018. Submitting offers that are in compliance with the Market Rules, especially Rule 7A.2.17, is potentially contentious and it is positive that the Authority is seeking to clarify this matter. Perth Energy has a number of comments which we hope will assist in finalizing this Guideline

Dispatch Engine Shortcoming

The basic problem, as the paper highlights, is that the existing dispatch engine is built around the assumption that marginal production costs increase with output whereas under many circumstances the opposite is true. Over most of a generator's output range (once started) the fuel efficiency improves as output rises. It should be noted that some units may have a short-term power boost capability where efficiency is sacrificed to give an increase in power output, however this is not the "norm". In addition, there is no separate treatment of start-up costs.

Given the substantial amount of unscheduled renewable generation on the SWIS, and the potential closure of further base load coal fired plants over the next decade, we will see increasing reliance being placed on gas turbine plant. These plants will experience more start/stop cycles and increasing variability in the length of these operating cycles. It is also likely that these units will be price-setters for considerable periods. The inaccurate representation of plant operating costs within the dispatch engine will become more significant over time.

Power system models such as Plexos, which has been used by Jacobs in their recent review of margin values, are generally able to accommodate marginal prices that do not increase monotonically and can separately include start-up costs. We would assume that dispatch engines are available that include these capabilities and it would be wise for any decision on a new dispatch engine to consider such capability.

We also note that reducing gate closure times, which allows more accurate bidding and reduces the impact of forecasting errors, will reduce the adverse impact of inaccurate plant cost representation.

Allowance for reserve capacity refunds

One cost that has not been considered by the Authority is the risk that a generating plant may fail to comply with a dispatch instruction and face reserve capacity refunds. Refunds are significant costs and have to be funded out of running revenue as they are not allowed for in the Reserve Capacity Price. For this reason a participant should add an uplift within their offers to cover this risk. A market participant will need to assess both the likelihood that a generator will fail to comply and the likely refund level so the required uplift will be:

- Higher if their generator has experienced past unreliability;
- Higher if the generator is being directed to operate at a level that may be difficult to achieve; and
- Higher if the system reserve margin is tight.

Risk of operating uncertainty

A serious difficulty with bidding, which is exemplified in each of the examples in the draft Guideline, is that the bidder must make assumptions about what level of load the plant will be dispatched at and for how long. The price bid by the generator in example 2 is fundamentally determined by the opening statement "Assume a gas powered unit is running ***and is expected to continue running at 250 MW*** ...". This is the load point at which the heat rate is highest and fuel consumption is lowest. The participant is taking a significant risk in assuming that it will stay at this power output because if they are wrong, and the generator is dispatched either up or down, the fuel cost will rise and the plant will lose money.

Similarly in example 3 the key statement is "The plant is expected to start-up ***and run for 12 Trading Intervals*** ...". This assumption determines how the start-up costs are amortised over the operating hours. If this assumption is wrong then the generator will either lose money or gain excess money. As noted above, this issue is compounded by several factors namely:

- The increasing load variability caused by the high proportion of load that is linked to intermittent solar generation;
- The expected increase in non-dispatchable generations;
- The high variability between forecast and actual load; and
- The long response time due to long gate closure.

In these circumstances there is a strong incentive for generators to bid conservatively which, in turn, will tend to increase costs within the market. However, it would be very difficult for the ERA to mount a case against a participant whose bids appear high because of the current load uncertainties.

Start-up costs for gas turbines

Most of the existing gas turbine generators in the WEM are heavy industrial machines. These machines require overhauls or major inspections after a given number of operating hours, number of starts or a combination of both. For this reason these costs cannot be included in the fixed maintenance costs. For plants where maintenance is driven by the hours run these costs should be included within the of the short run marginal costs. For plants where the overhaul frequency is driven by the number of starts these overhaul costs must be recovered through the start-up costs included within the bid price and are likely to become more significant if the frequency of overhauls is accelerated by fast starts or operation at higher power. These are circumstances that may be accentuated by the various load-forecast uncertainties noted above. This makes it more important to ensure that start-up costs are treated properly.

Estimation of Marginal Heat Rate

There is an error in the process for calculating Marginal Heat Rate in the examples. In example 1 the MHR at 40 MW has been calculated by computing the fuel used in moving from 35 MW to 40 MW whereas it should be calculated by considering a small band either side of 40 MW.

This error is seen most clearly in example 2 where the MHR for the generator when operating at 250 MW output is calculated as 7.40 GJ/MWh. At this output the generator is operating at its best heat rate (7.625 GJ/MWh). Decreasing output to 200 MW or increasing to 270 MW increases the heat rate so the marginal heat rate at 250 MW has to be higher than the average heat rate.

A better estimate of the MHR at 250 MW output would be to consider the heat rate in changing output from 200 MW through 250 MW to 270 MW. This figure is 8.06 GJ/MWh rather than the figure of 7.40 GJ/MWh calculated in the paper. So in this example, the generator's bid should be based on its Short Run Marginal Cost, rather than its Average Variable Cost because any change in output from 250 MW will cause it to lose money.

Yours faithfully

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