perthenergy

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Review of incentives to improve the availability of generators

Perth Energy welcomes the opportunity to respond to the Economic Regulation Authority's (ERA) Issues Paper: 2020 Review of incentives to improve the availability of generators published on 24 April 2020.

Perth Energy highlights that while the incentives for generator availability in the Wholesale Electricity Market (WEM) Rules are important, they are not the primary driver, or even a major incentive for achieving high availability. Availability is primarily driven by the need for generators to earn revenue. Revenue is earnt by generators generating, and inherent in this is the need to prudently and efficiently minimise maintenance (planned and more importantly unplanned) to be more available.

The effectiveness of incentives in the WEM Rules, therefore, is limited to acting as a compliance and penalty mechanism, which is limited to recovering capacity revenue and signalling the need to increase generator reliability.

It is in this context we make the overarching comments and answer the ERA's specific questions in the following sections.

Overarching comments

There are a number of significant changes occurring in the WEM that make this review timely. The most important of these, from the point of view of generator availability are:

- the substantial increase in intermittent generation which is forcing Scheduled Generators away from "stable" (base load) operation into more of a back-up and fill-in operating role;
- the reduction in summer daytime demand due to the increase in behind-the-meter solar systems; and
- the move towards a five-minute Balancing Market and co-optimised dispatch of energy and essential system services.

Each of these strongly influences how individual generators are operating and this, in turn, will have a substantial impact on their short term and longer term maintenance requirements, reliability and availability. While operators make considerable efforts to adjust their maintenance practices to changing operating scenarios it is not possible to accurately forecast the future operating regime, or how this will impact a specific generator.

One point that needs to be stressed in any consideration of performance incentives, is that generators already have strong commercial incentives to maintain high levels of availability:

- Generators exist to generate:
    - Some generators have bilateral energy sales contracts which must be met to avoid penalty payments.
    - Some generators, such as Western Energy's Kwinana Swift Power Station, seek to maximise their operations in the WEM to act as a hedge for retail sales operations and to secure sales in the Balancing Market.
- Generators face substantial capacity refunds in the event of unavailability due to Outages (Forced Outages and high overall Outage rates).

These all provide a very strong incentive to minimise down time for maintenance and especially unscheduled maintenance.

It should be noted that there is often little that a generator can do to reduce the time during which their plant is out of service. Although generators employ their own internal staff, power plant maintenance is heavily dependent on limited external specialist contractors and services. This external support is often drawn from international providers who are servicing power equipment world-wide in a range of industries and cannot respond instantaneously to a local issue.

One approach is for generators to hold a broad range of spare parts. However, spares are expensive so it is often uneconomic to hold large stocks or even critical but significantly expensive parts. Furthermore, the changing operating regime means that there are likely to be failures of parts that would be expected to have had longer lives under more expected, normal circumstances. Market Participants in the WEM do, however, seek to share spares and assist each other wherever possible.

Responses to the ERA's specific questions

Question 1

AEMO has not reduced the certified reserve capacity of a facility that had outage rates in excess of the outage thresholds specified in the market rules. Considering the above, how do stakeholders view the efficiency and usefulness of this mechanism?

As noted above, most generators have a strong incentive to keep their plant in operation to generate energy and earn revenue. They also seek to minimise the level of capacity refunds that they make. These two factors combine to provide a very strong incentive. It is therefore doubtful that the additional threat of losing Capacity Credits would change a generator's behaviour.

All generators are required to have an independent audit undertaken of their asset management system as part of the licence review process. For most generators, the ERA is extending the interval between these audits towards the maximum permitted level of five years which indicates that the generation fleet is perceived as being well managed. This suggests that the ERA itself does not consider the mechanism necessary.

We also note that there have not been any significant loss of customer supply events due to generation maintenance outages, either planned or unplanned. There have been outages due to trips, but not excessive maintenance.

For these reasons, Perth Energy does not consider the mechanism necessary.

Question 2

Do stakeholders consider that determining the availability of the generator fleet in the WEM in line with IEEE Standard 762 is appropriate for the ERA's review? What other approaches could be undertaken?

Perth Energy considers that this standard is appropriate and would not recommend any deviation from it. One good reason for this is that the North American Reliability Council uses this as the basis for its reporting which allows generators in the WEM to be directly compared to those in the USA to give a broad benchmark.

We note, however, that the ERA has not accurately applied the IEEE Standard where it has treated:

- a delayed response to a Dispatch Instruction as a full plant failure; and
- ramping at less than the Dispatch Instruction ramping requirement as a partial plant failure.

Under the IEEE Standard, a failure to start would be logged as a Forced Outage but as soon as the plant starts and synchronises it would be declared fully available. The ERA's approach is therefore assigning generators with higher Forced Outage rates than they otherwise would if the ERA was to accurately apply the IEEE Standard.

We also note that the ERA is applying this inaccurate definition for a full Trading Interval (30 minutes), when delayed responses or lower ramping events, in the instance of fast-start plant, affect output for as little as a dispatch interval (10 minutes) and the Dispatch Instruction can be fully met within the Trading Interval.

Accurately applying the IEEE Standard gives a better indication of actual performance and is in line with international standards. Perth Energy therefore recommends the ERA accurately apply the IEEE Standard in relation to all relevant decisions on Outages.

Question 3

What level of outage rates and what factors do stakeholders consider should be used to assess the outage thresholds stated in clause 4.11.1D?

The Australian Energy Market Operator (AEMO) already has processes to ensure that scheduled maintenance is only undertaken at times when the units can be spared from service. Because it is Forced Outages that put system security at risk, generators should be encouraged to use the optimum level of scheduled maintenance time they need to minimise the levels of Forced Outages.

The capacity refund rates are now based on the availability of the generation fleet, rather than summer and winter seasons. This provides incentives for generators to perform scheduled maintenance at times where the level of generator planned outages are lowest to avoid higher capacity refunds. This has spread the planned maintenance more evenly over the year, rather than all being undertake in winter as they once were.

Perhaps more importantly, the WEM continues to have excess capacity. Therefore, placing any restrictions on scheduled outages, beyond the operational restrictions required for AEMO's plant scheduling, is unnecessary as it is not achieving any shortage of supply.

Perth Energy therefore recommends there should not be any Outage threshold with respect to scheduled maintenance.

However, if the ERA decides to continue with the implementation of outage thresholds, it should consider that as more intermittent generation is brought into service, and as older Synergy plant is scheduled for retirement, the duty required of the remaining synchronous plant will be more arduous and more unpredictable. This is likely to lead to higher maintenance requirements which will need to be reflected in the Outage thresholds.

Question 4

Is the possibility of breaching the outage thresholds a strong incentive to raise a generator reliability or retire an asset?

The possibility of breaching the outage thresholds is immaterial as an incentive to raise a generator reliability and is not a signal to retire an asset.

As noted above the loss of energy revenue and capacity refunds is the primary driver to raise generator reliability.

As has been highlighted in the various reviews and cases for WEM reform, there are insufficient signals for generator retirement. This includes outage thresholds. The only plant at retirement age is owned by Synergy and closure of this plant was directed by Government rather than resulting from economic signals in the WEM.

Question 5

Do the outage thresholds, and the possibility of AEMO exercising its discretion to reduce a facility's certified reserve capacity, strike an appropriate balance between signalling for generators to exit and motivating other generators to ensure an adequate level of availability.

Outage thresholds, and the possibility of AEMO exercising its discretion to reduce a facility's Certified Reserve Capacity are immaterial as an incentive to raise a generator reliability and is not a signal to retire an asset for the same reasons provided in response to question 4.

Question 6

What are the stakeholder's opinions on the one-size-fits-all approach to the outage thresholds in the market rules? If the incentives to increase availability are being met, how important should the composition of the generation fleet be in assessing the outage thresholds?

The primary function of synchronous plant over recent years has been energy production and coal fired plant has provided the bulk of this. Over coming years, with the planned retirement of Muja C and increased investment in intermittent generation, it is likely that gas fired plant will take on a more important role. It could be considered that this will mean that fleet availability will increase because gas plant has, all things being equal, lower maintenance needs.

However, the increase in intermittent generation will force gas fired plants more into a peaking and back-up role with increased stop-start and cycling operations. This will increase the maintenance requirements of the gas fleet especially as most of these generators are heavy industrial-type machines. It is to be expected that the maintenance requirements of the gas fleet will move to match those of the coal fired plant which may also expect to degrade as it is forced to fill-in around intermittent generation.

Perth Energy recommends continuing to treat all synchronous plant with the same criteria.

Question 7

Should the reference technology for establishing the benchmark reserve capacity price be used to set the availability thresholds in the market rules? What are the benefits and problems of this approach?

Perth Energy does not consider the maintenance of a liquid fuelled open cycle gas turbine, the reference plant for the Benchmark Reserve Capacity Price, is appropriate to use for other plant because it is only expected to run for a minimum period of time during the year so is quite atypical of most generating plant. Gas turbine maintenance is dictated in large part by their operating hours and the number of starts. As such, a liquid fuelled plant will have very little maintenance due to its very limited operation. On the other hand, gas and coal fired generators both operate for far longer periods of time than the reference liquid fuelled peaking plant, and as such require far more maintenance time.

Question 8

Should the assessment for setting the benchmark reserve capacity price also incorporate considerations for capacity availability and outage rates?

As the range of different technologies available in the WEM increases it would be increasingly difficult to take specific outage and availability rates into account. The variation in maintenance needs for coal plant, open and combined cycle gas turbines, waste to energy and other types of plant is considerable. The danger of setting specific targets is that certain types of very economical plant may be excluded. This is parallel to the way in which intermittent generators do not have maintenance targets.

Question 9

Should there be a distinction between forced outage rates and planned outage rates as currently stated in the market rules? What are the implications of using a combined planned and forced outage rate threshold instead of two separate outage threshold levels?

Also, as noted in response to question 3, generators can only take scheduled maintenance at times when AEMO considers that the plant can be removed from service without creating an unnecessary risk to customer supply. As long as this restriction remains in place then there is no reason for any other limitation to be placed on the amount of scheduled maintenance that a generator can take. AEMO's actions ensure the purpose of the Reserve Capacity Mechanism, which is to ensure reliable supply to customers, is satisfied.

Moreover, the capacity refund rates are now based on the availability of the generation fleet, rather than summer and winter seasons. This provides incentives for generators to perform scheduled maintenance at times where the level of generator planned outages are lowest to avoid higher capacity refunds. This has spread the planned maintenance more evenly over the year, rather than all being undertaken in winter as they once were.

The WEM currently has excess installed capacity so there is little requirement to limit scheduled maintenance beyond AEMO's operational requirements. Generators should take whatever scheduled maintenance they need to optimise their reliability when called to run.

Perth Energy recommends the distinction between Planned and Forced Outage rates should remain.

Question 10

Do stakeholders consider that a facility's historical outage rate should be a material consideration for AEMO when setting reserve capacity for a future year?

If the generator has received a satisfactory review of its asset management system as part of an independent audit under the ERA's license review process, then there is no justification for AEMO to take its historical outage rate into consideration. To do so would force AEMO, with limited detailed knowledge of the generator's operations, to second guess the detailed independent audit. It is putting a responsibility onto AEMO which it is not qualified to fulfil.

Question 11

What has been market participants' experience of using a facility's prior 36-month forced and planned outage rates as a predictor of future generator availability?

Perth Energy's experience at the Kwinana Swift Power Station is that past performance gives a general prediction of future performance, but no more. A key reason for this is that operations in the WEM are changing significantly. Kwinana Swift has moved from "super-peaking" towards a peaking / mid-merit role but that change has also been coupled with substantial numbers of stop-start cycles as it supports an increase in intermittent generation. This results in a very different maintenance regime.

It is our understanding that operations for this plant, and many others, will continue to change in unexpected ways as the market transitions to integrate more renewables and facilitate the co-optimisation of energy and essential system services. Therefore, past performance will be a weak predictor of future performance.

Question 12

What other mechanism or incentives could be used to increase the availability of generation capacity?

As noted above, Perth Energy questions what customer benefits can be achieved by adding further incentives to what is already a strongly incentivised aspect of the market.

The Reserve Capacity Mechanism determines the amount of installed capacity needed and the cost per megawatt. Once this has been determined, there is no commercial benefit to customers in driving availability to higher levels. Increased availability benefits will flow to customers through lower energy costs but generators already have the incentive to do this in their normal operations and commercial arrangements.

As an adjunct, the ERA may wish to consider reviewing the definition of availability. As an example, an old coal-fired power station can have extremely long start up times. In terms of outages, the facility is available but when starting it is actually not available for dispatch. The now retired Vinalco units which had start up times between 48 and 72 hours would be an extreme example for available plant which can't be dispatched within the Balancing Horizon. Not considering the Balancing Gate Closure, the Kwinana Swift plant could be at full load within 5 minutes if incentivised to do so. This is a substantially higher "availability" than plants with long start up times. Fast ramping plants can support system security and reliability in emergency situations when other plants have tripped unexpectedly. Under this scenario the "availability" of a fast start generator is far greater than the availability of another type of generator when considering a return from outage.

Question 13

What are the market participants' opinions on the REPO count limit of 8,400 and the associated calculation period of 1,000 trading days prior to the scheduled generator's planned outage? Is this limit and calculation period appropriate?

It is unclear what the problem the ERA is addressing here. Moreover, the suggested 1,000 Trading Days appears to be an arbitrary number. It is a round number of days, but would equate to 2.74 years or 32.88 months, which is unlikely to reflect any better operating or maintenance pattern than the existing 36-month timeframe currently used for the calculation of the outage rates for the purpose of clause 4.11.1D of the WEM Rules.

As noted above, the substantial changes to the WEM operations over the past few years and expected future changes make past performance little more than a guide to the future operations. Perth Energy therefore recommends avoiding change for the sake of change and retaining the current 36-month timeframe.

Question 14

What are the repercussion of the REPO count limit on scheduled generators in the WEM, particularly for operational and investment decisions?

There is a danger that if a generator is coming close to the REPO limit that it will restrict its scheduled maintenance to "leave room" in case there is a major Forced Outage. Cutting back on scheduled maintenance is inefficient and imprudent so the REPO limit can perversely make generator reliability worse.

It should be noted that the move to constrained network access may have a bearing on this incentive in respect to investment. Currently, because generators are only connected where there is unconstrained access, any loss of capacity revenue as a result of the REPO limit are limited to a single year.

Under the constrained network access regime, however, this may no longer be true. If the REPO limit results in the reduction of credits they may well be transferred to another generator located behind the same network constraint[1]. If the loss of Capacity Credits then became permanent, the generator has no way in which the associated revenue loss can be managed. While this may appear to be a very small risk it is precisely the undefinable risk that makes it very hard for an investor to secure finance. If AEMO were ever to implement a capacity reduction, the impact on future investment and refinancing of existing plant could be drastic.

Question 15

What has been the experience of scheduled generators participating in the reserve capacity mechanism since the introduction of the REPO count limit? Has the REPO count limit had positive, detrimental or negligible effects on scheduled generator planned outage planning?

The REPO count limit has had a negligible effect on Western Energy's planning of scheduled outages, as under normal circumstances Kwinana Swift requires two Planned Outages per year with a duration between two and four weeks, and during those periods full plant outages are able to be minimised, which lowers the REPO count even further.

Kwinana Swift currently has a turbine in the US for an extended overhaul (replacing an internal seal), and the implementation of COVID-19 restrictions has extended the timeframe on this outage – both for the original equipment manufacturer to undertake the works and being able to get the turbine shipped internationally. Because of these unforeseen delays, the REPO count limit may become an issue for future planned maintenance activities.

[1] The detail of reserve capacity allocation specifics are yet to be provided by EPWA

Question 16

What are market participants' experiences of changes in the mix of scheduled generators within the WEM prior to and since the introduction (1 October 2017) of the REPO count limit?

Generation mix in the WEM has not been impacted to date by the REPO count limit. Larger driving forces such as the increased penetration of household and transmission connected intermittent generation will have a greater impact on the mix.

As the need for plant capabilities changes in response to these developments, the market will require a far more dynamic performance incentive and maintenance scheduling approach, in which the concept of the REPO count limit may not be applicable at all.

Further comments

The current performance incentive and maintenance scheduling regimes were put in place at a time when power station operations were much more predictable and less dynamic. As noted above, substantial behind-the-meter solar generation coupled with significant large scale solar and wind developments has absolutely transformed WEM operations. Perth Energy suggests that the ERA could make a major contribution to the success of the new market by expanding the scope of this current review to look at a number of related matters.

Firstly, there needs to be an agreed definition of what is an Outage and how it is measured. Perth Energy supports the IEEE Standard but notes that the ERA currently uses a much broader definition that includes slow response to a Dispatch Instruction as an Outage. This needs to be resolved especially as Synergy's generators will soon be dispatched individually rather than as a fleet so variance from Dispatch Instructions is likely to increase substantially.

Linked to this is the level of accuracy of compliance. Generator capacity in the WEM is defined to three decimal places of a MW – ie one kilowatt. If Dispatch Instructions are defined to this same level, it will be impossible for any generator ever to comply when they are on automatic generation control (AGC), which is also a requirement in the WEM. This position must be clarified.

Recognising that an increasing proportion of generation capacity in the WEM is intermittent, and that weather has a major impact on system load, there needs to be a more dynamic performance Outage scheduling approach. The WEM still has the concept of a hot season from December to March during which high availability is encouraged and maintenance is embargoed. Current experience is that the system appears to be coping very well with summer demand. Not only is this demand not growing but it is now concentrated into the (low) morning peak and (higher) evening peak. Plant outages through the middle of the day are not as much of an issue as they were at market start. Similarly, the Christmas and New Year holiday period is a time when there is generally adequate plant margin for maintenance. At the same time, winter peaks are rising relative to summer and these may well be the driving factor in the requirements for non-intermittent generation and storage systems.

In summary, Perth Energy does not consider that the incentive arrangements currently in the WEM Rules provide a significant driver for generator availability.

Perth Energy does not consider that the threat of losing capacity credits is a significant incentive for generator performance because the commercial drive to produce energy and the cost of refunds is already sufficient incentive. Further, if this clause were ever to be invoked it would be seen by investors as a major risk, especially given the move to constrained access.

Perth Energy does not consider that the whole performance incentive and maintenance scheduling regime is fit-for-purpose because of the major variability in both supply and demand caused by solar and wind generation.

As a final point, we reiterate that the regular Asset Management System reviews show that generator maintenance practices are well up to the ERA's standard as is demonstrated by the extension of most reviews/audits intervals towards the maximum of five years.

Should you have any questions or want to discuss these matters further, please contact me on 0437 209 972 or at p.peake@perthenergy.com.au.

Yours faithfully

[redacted]

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