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To	Energy Policy WA – energymarkets@dmirs.wa.gov.au
Subject	Response to RCM Review Stage 1 Consultation Paper
Date	21 September 2022

Good Morning

Perth Energy appreciates the opportunity to respond to the Consultation Paper for Stage 1 of the Reserve Capacity Mechanism (RCM) Review. This is a significant issue for us as it is a fundamental driver to ensuring that electricity customers in the SWIS can enjoy reliable electricity supplies at the lowest possible cost and, as one of those providers, that we can continue to provide supply in an efficient manner and continuously monitor the opportunity to enhance these or establish new assets elsewhere. As we have commented before, we are concerned that there are significant pressures on customer prices at a time when inflation appears to be strong across the community.

As an overall comment we commend Energy Policy WA, and its consultants RBP, on the extensive work undertaken as part of this review. In Perth Energy's view, the Consultation Paper addresses the full range of the Scope of Works. The Paper, along with the supporting International Review undertaken by RBP, provides a broad understanding of what is a technically challenging market arrangement. It is sobering to note that that there are no easy overseas solutions to the issues discussed and that WA is already well abreast of these.

The need for a review of the RCM

Since implementation of the RCM there have been several significant changes that require a review to be undertaken. The suitability of any proposed change needs to be assessed against these issues to ensure that they have been appropriately addressed.

There are three key changes driving the need for a review:

1. Increase in intermittent generation;
2. Investment risk; and
3. The energy transition.

The first change is that increasing quantities of energy are now provided by intermittent renewable generating facilities. Both supply and demand are now strongly influenced by the availability of sunshine and wind, meaning that predicting when the system is under supply-demand stress is harder to predict. It is also uncertain what plant will actually be available to meet stress events.

The reduction in capital costs and technical efficiency of both windfarms and solar PV systems justifies their increased market share. However, these generators also receive significant income from outside of the wholesale market, such as through renewable energy certificates, which has pushed investment beyond what would otherwise be deemed their "economic" share. This, and their low variable cost, has driven down the balancing price for significant periods thereby challenging the economics of dispatchable plant, which is critical to maintaining system stability.

The second major change is that the risk associated with investment in conventional plant has increased substantially due to various changes in the market rules. The basis of calculating the reserve capacity price (RCP) has changed several times. The most significant effect is that the risk of excess capacity is placed on existing generators who cannot hedge this in any way.

Perth Energy notes that no new dispatchable generation has been installed in the WEM for around a decade which, we believe, is in large part due to the uncertainty surrounding returns available to investors.

The third main reason for this review is the major transition planned for the wholesale market with the closure of Synergy's coal fired plant and concurrent installation of more renewable plant and storage.

At the same time we will see the establishment of markets for essential system services (ESS), introduction of electric vehicles and increased, or possibly saturation, of solar PV systems. All of this uncertainty will require the RCM to draw the optimum mix of new plant onto the system in an efficient and timely manner if we are to avoid electricity shortfalls or over expenditure.

Perth Energy has addressed the questions posed in the Consultation Paper and added some additional commentary.

Response to questions posed in the Consultation Paper

1. *Do stakeholders support the retention of the existing peak capacity product?*

   Yes. Perth Energy notes that peak demand will most likely continue to be a time of system stress that needs to be addressed through the RCM, and dispatchable plant will be crucial to managing system security during these periods.

2. *Do stakeholders support not including a product in the RCM to manage minimum demand?*

   Yes. Perth Energy considers that this is a separate issue that needs to be addressed through other, more appropriate mechanisms, such as solar soak tariffs and export tariffs.

3. *Do stakeholders support inserting a new flexible capacity product in the design of the RCM?*

   Yes. Perth Energy notes that AEMO reported that on 1 August there was a demand reduction of 549 MW in 28 minutes followed by a second fall of 448 MW in 22 minutes. Flexible plant is essential to meet these significant levels of load movement.

4. *Do stakeholders support not amending the Planning Criterion to include consideration of the volatility of intermittent generators?*

   At present, yes, we consider that ESS should be used to accommodate this volatility. This should be monitored over time and it may be necessary to change the planning criteria to address volatility if ESS is insufficient or if changing the RCM criteria gives lower overall costs.

5. *Do stakeholders support retention of the current two limbs of the Planning Criterion?*

   Yes. It is unclear as to which of these two limbs will bind in the future. While peak demand is clearly the current risk there is also the potential risk of lack of energy generation during wind droughts or similar unpredictable events. Both potential shortfalls need to be addressed through the RCM.

6a. *Do stakeholders support amending the reserve margin as indicated in Conceptual Design Proposal 6?*

   Perth Energy supports amending the hard coded outage percentage in sub clause 4.5.9(a)(i) with the expected forced outage.

6b. *Do stakeholders have any concerns about the proposed amendments to clause 4.5.9(a)(ii)?*

   Perth Energy agrees in principle with using the largest contingency on the power system as part of the planning criteria. Our concern is that with the implementation of constrained network access this could be a very large MW figure if substantial quantities of new generation capacity are connected through a single potential failure point. We recall that this matter arose when the Interim Access Arrangement was implemented by Western Power.

   Some arrangement would be required to ensure that any increased cost of reserve capacity (and spinning reserve) is optimised with the cost of mitigating potential weak points on the network.

6c. *Do stakeholders support commencing the proposed amendments to clause 4.5.9(a)(ii) for the 2023 Reserve Capacity Cycle?*

   Our understanding is that AEMO System Management strongly desires this change so we support it.

7. *Do stakeholders support retaining the target EUE percentage of 0.002?*

   Yes. The Consultants' work supports the UEU percentage remaining at 0.002.

8. *Do stakeholders support the proposed third limb of the Planning Criterion to require AEMO to procure flexible capacity? If so, is the proposed criterion appropriate?*

   Yes, Perth Energy supports the proposed third limb of flexible capacity. The approach proposed appears to be sound but should be monitored to ensure that it is sufficient as intermittent renewable generation becomes dominant.

9a. *Do stakeholders support retaining the ERA as the agency that is to set the BRCP?*

   Yes. The ERA is sufficiently independent and has demonstrated the capability to undertake this role.

9b. Do stakeholders support providing guidance to the ERA in the WEM Rules on the factors to consider in setting the BRCP?

Yes. It is appropriate that guidance be provided.

10a. Do stakeholders support the proposed approach to the BRCP?

Yes

10b. Do stakeholders support the calculation of separate BRCPs for the peak and flexible capacity products?

Yes.

10c. Do stakeholders support the proposed factors for the ERA to consider in reviewing the BRCPs?

In principle, yes. However, we suggest that using the design life of some plants may be excessive given the way in which new technologies are being developed and implemented. While difficult, it may be more appropriate for the ERA to consider the commercial or effective life of the facility rather than its design life.

11. Do stakeholders support the proposed consideration of gross CONE and net CONE for determining the BRCP, as indicated in Conceptual Design Proposal 11?

Yes. Perth Energy agrees that using of gross cost of new entrant (CONE) is appropriate at the present time but that nett CONE may be appropriate when the benchmark plant earns extra revenue in the market. While not directly on-topic it raises the issue of how storage will be required to bid into the market which is addressed later on in this submission.

12a. Do stakeholders support using the same price curve for peak and flexible capacity products?

Yes.

12b. Do stakeholders support the proposed pricing arrangements for the flexible capacity product?

Yes.

12c. Do stakeholders support a 5-year fixed price option for proposed flexible capacity facilities?

Perth Energy supports a fixed price option but considers five years to be too short given the market risks. This is addressed further below.

13a. Do stakeholders support replacement of the current Availability Classes with Capability Classes?

Yes. This appears to be logical and reflects changes in technology.

13b. Do stakeholders support the conceptual design proposal for the Capability Classes?

In principle, yes. Our hesitation relates to the 14-hour fuel obligation. Assuming that this remains unchanged then generators that cannot demonstrate that they meet this obligation can move from Capability Class 1 to Class 2. Would these generators then only be required to be available within the Storage Obligation Duration window that is set for storage? It would be inequitable if generators were required to meet a higher obligation than storage systems. On the other hand, the gap in obligation between being available for four hours per day rather than continuously is substantial. If the 14-hour obligation is to be retained, then perhaps Capability Class 1 should have sub-categories.

13c. Do stakeholders support retaining the 14-hour fuel requirement, with its practical implementation to be considered in stage 2 of the review, with the all-hours availability requirement for Capability Class 1?

There are already two strong incentives for generators to ensure that they have access to sufficient fuel. The whole purpose of having a generator is to be able to produce electricity to earn revenue for the business. Having an adequate fuel supply is an integral part of ensuring that the plant can fulfil this primary revenue generating role. It is no different from the strong incentive to making sure that adequate maintenance is undertaken and appropriate spare parts are held. These are all just parts of running a good business.

The second driver is the substantial refunds, and potential loss of capacity credits, that will be incurred through failure to meet capacity obligations. As such, we see the additional, externally monitored fuel obligation as unnecessary.

The operators of gas fired plant have been rigorous in ensuring that sufficient fuel is available for operation whenever their plants are required to be dispatched. The only significant disruptions have been major supply issues, such as with Varanus Island's problems, which would not have been addressed by the 14-hour rule. There is every reason to expect that facility owners will maintain this very high level of supply reliability into the future.

We note that it is coal fired plant operators, who are fully compliant with the 14-hour rule with long term contracts and substantial stockpile facilities, that are currently struggling to maintain fuel supply.

There is also the practical issue of just what this clause actually means. AEMO appears to be interpreting it to mean that a generator has contracted fuel supply sufficient to run at maximum output for 14 hours each and every day. Further, that contract needs to be in place to cover the period up to three years in advance. This is totally impractical for a gas peaking plant, that may only be dispatched for a few hours a month to meet extreme supply-demand stress situations. It also ignores the realities of gas contracting in the current market.

Perth Energy does not support retaining this obligation. However, if it is decided that this obligation is to be retained, Perth Energy suggests that this should not be an obligation to secure certification but should be demonstrated once the plant is in operation, perhaps at the same time that capacity testing is undertaken.

One unintended consequence of the current approach is that it forces an operator with limited generation capacity to build that as dual-fuel, certify it on diesel and hold diesel on site. This is probably also true for a plant using green hydrogen as its primary fuel which adds another barrier to such developments, and may unnecessarily skew any carbon targets.

14a. Do stakeholders support the proposal for AEMO to calculate the availability duration requirement for each capacity year?

The availability duration requirement is a key driver for the capital cost of storage. Conceptual Design Proposal 10 suggests that storage will eventually become the lowest expected capital cost plant, so will be used by the ERA to set the BRCP. It is critical that the ERA and AEMO are both using the same duration requirement. Perth Energy supports the proposal that AEMO should set the duration requirement but that this should be in liaison with the ERA.

14b. Do stakeholders support pro-rating the CRC for Capability Class 2 facilities in proportion to the availability duration requirement?

Yes.

14c. Do stakeholders support allowing proponents to request a 5-year fixed availability requirement?

Class 2 facilities should be able to request a fixed availability requirement, but we do not believe that five years is sufficient. This issue is addressed in a separate section below.

15a. Do stakeholders support continuing to allocate CRC on an ICAP basis?

Yes. While UCAP may be a "purer" economic approach there do not appear to be any significant drivers for changing from the present approach. This, plus the necessary consequential changes to the setting of the BRCP, is yet one more change at a time when we are trying to ensure sufficient certainty to drive major investment in the WEM.

15b. Do stakeholders support the conceptual design for treatment of outages?

The Consultation states in section 5.3.3 that:

> *The current refund regime is working well to incentivise availability, particularly when the reserve margin is low:*

Perth Energy agrees with this comment, noting that load shedding due to generator system outages has been limited to short intervals where spinning reserve has been insufficient to cover unit trips. Generator unavailability has not adversely impacted supply reliability. The current mechanism works well and does not need much further change.

This outcome should not be surprising, as companies invest in generating plant to secure revenue from energy sales, meaning that there is a strong incentive to ensure availability remains high, as we have noted in our comments on the 14-hour fuel obligation. This is especially true when reserve margins are low because generator failure means that the plant owner misses out on revenue at the time when prices are highest. For contracted plant an outage when reserves are low means buying from the market at high prices.

We understand the motive behind the threat of losing capacity credits if forced outages exceed a certain target, but note that as a performance motivator, it is third in line behind the incentives of lost revenue and reserve capacity refunds. As such, while it is a weak driver of behaviour for an operational perspective, it is still perceived by investors and bankers as a significant investment risk. As such, it is actually a disincentive for the installation of adequate reserve capacity.

The Paper states that the details of the capacity credit reduction process will be considered in Stage 2. As part of this review, we ask that EPWA notes the significant impact on plant maintenance caused by covid restrictions preventing technical support staff coming to WA. The past two years are not a good indication of likely plant performance without these restrictions in place and suggest that the pre-covid experience is more relevant.

16. Do stakeholders support requiring AEMO to procure expert reports on behalf of participants?

No. The expert report is a critical part of the project development, approval and financing process. An investor needs to be fully confident in their consultant which, in turn, requires careful assessment of the potential service providers. We question whether AEMO has the competency, or the underlying level of incentive, to undertake this work. It would also place AEMO in a difficult legal position should the expert's work subsequently be challenged as having led to an "incorrect" investment decision.

Figure 24 in the Paper does indicate that the expert reports are not necessarily a good guide to future wind farm output. It is hard to say whether this is due to inadequate data or over optimism on the experts' part or just the complexity in estimating output in the face of climate change impacting weather and wind patterns. If it is the latter, then a consultant appointed by AEMO is no more likely to get an "accurate" result than anyone else.

17a. Do stakeholders support using a different methodology to assign CRC to facilities in each Capability Class?

Yes.

17b. Do stakeholders support the proposed methodology to assign CRC to facilities in Capability Class 1?

Yes

17c. Do stakeholders support the proposed methodology to assign CRC to facilities in Capability Class 2?

The term "required availability duration" needs to be defined. For a facility that has limited fuel availability it would be equitable for this period to be the same as for a storage system, currently four hours. However, this is a substantial reduction on the Class 1 obligation and may not be optimal for the power system.

17d. Do stakeholders prefer one of the three identified methodologies for assigning CRC to facilities in Capability Class 3 and what are the reasons for the preference?

Perth Energy's preference is for an arrangement that provides a consistent evaluation of CRC for Capability Class 3 facilities as this is more likely to facilitate investment through reducing risk. The hybrid approach suggested by Colgar appears to be the most suitable and we would like to see this investigated further. We also strongly favour protecting the CRC of existing facilities, to minimise investor risk, and do not support an approach where newer plant takes CRC from existing facilities.

Investor risks and customer benefits

Reserve capacity payments are the primary income for peaking power stations and are likely to be the main income stream for storage systems. To date, capacity payments have not been as critical for wind farms, but this situation will change as they become the dominant energy producing plant on the SWIS. Adequate wind farm capacity will be needed to reliably meet demand in low-wind years, so in years with normal or high wind the output will be much higher resulting in low energy prices. This means that capacity payments will become very important for windfarms as well.

In the larger market scheme, tying capacity payments to excess capacity may not be appropriate, particularly when the generation mix is moving to a predominantly renewable base. For example, there may be excess wind or solar capacity available, but the average and peak outputs will not be adequate, as they depend on weather. In these scenarios, dispatchable generation may be critical for system security, but cannot receive adequate capacity payments, because the system is oversupplied by renewable resources.

Tying the RCP which is paid to generators to the level of system wide excess capacity places a significant risk on generators that cannot be hedged. At present, new generators can seek a five-year price guarantee, but Perth Energy contends that this still places a major risk on investors. We do not consider that this duration is compatible with the timescale over which capital is to be paid off given the determination of the weighted average cost of capital used to determine the BRCP.

This risk is accentuated by the dominance of Synergy in the market. Part of the justification for the linkage of excess capacity and the RCP was that it should provide a signal to remove excess capacity from the market. This has not occurred. Even when Synergy could have increased its revenue by reducing its overall certified capacity, without closing plant, it did not do so. We are not suggesting any malice or misuse of market power, but Synergy's actions caused financial harm to other market participants.

During this transition there will be immense pressure on Government to ensure that there is always sufficient generation capacity to meet demand. An excess of capacity will potentially raise customers' electricity costs by a small amount but shortages will create substantial economic loss to the community and reduce confidence in system reliability, with the flow on economic impacts, as well as inconvenience and disruptions. Consequently, the rational approach for Government, via Synergy, is to err towards excess capacity rather than shortfall. In reality, the WEM will be driven by tighter reliability standards than are assumed within the RCM processes, resulting in investors receiving less than anticipated capacity revenue.

The risk of inadequate returns due to there being excess capacity is not just an issue for private investors. The Government has indicated its intention to invest some three billion dollars, through Synergy, into new renewable generation and storage facilities. Government needs to secure an appropriate return on this massive investment.

If the RCP is depressed because of excess capacity, and Synergy cannot make an appropriate return from energy sales, then the resulting shortfall in dividends to Government will require revenue to be raised from elsewhere in the community or services reduced. This loss would be more serious than a private investor loss in that the Western Australian community must bear the loss, not just a group of private investors.

The RBP International Review ascertained that the price guarantee varies considerably in different jurisdictions. PJM offers three years, ISO-NE offers five years, France seven years, Ireland up to 10 years, UK up to 15 years and Columbia up to 20 years. In recognition of the real risk profile in the WEM, Perth Energy suggests that the guarantee for new providers should be at least seven years and preferably 10 years.

While this may appear to be making life too easy for investors, it needs to be acknowledged that there must be enough investor confidence to provide the new capacity required over the coming seven years to replace all of Synergy's coal fired plant and potentially other aging plant. This needs to be completed while meeting AEMO's projected load growth as well as potential additional growth from electrification of industry.

We note that this out-of-scope for Stage 1 but consider that it is critical to the success of the RCM and should be addressed as part of the current process.

Long term support for inappropriate plant

One downside of the current RCM arrangements is that existing plant receive capacity credits for as long as they remain reliable irrespective of their suitability. In a perfect market, a new generation plant will displace an older unit when its capacity and operating costs are less than the cost of keeping the older plant in service. In the WEM, however, older plant is supported by the continuing contribution from the RCP.

A more appropriate approach

One of the criteria for the Working Group was to minimise changes to the RCM and focus on tuning or adapting the current arrangements to suit future needs. However, even if the proposed changes are fully implemented significant issues with the RCM will remain.

The need to balance customers' desire for cost minimisation with investors' requirement for adequate recompense parallels the situation with the provision of other infrastructure such as electricity network systems and components. The comparison between generating plant and network assets becomes even stronger as more plant is installed which has high capital cost, near-zero operating cost and unpredictable usage.

Perth Energy suggests that a more appropriate approach would be to treat new generation in a similar fashion to a regulated asset, such as a network asset, and set a regulated rate of return over an appropriate depreciation life. This would allow recognition of the different functions of various plant types in the transitioning market, differing plant lives and different fixed capital and operating costs.

The fundamental concepts of using such an approach to establish an asset return are well understood by regulators, however, some analysis would be required if it was to be used within a market process, such as the RCM payments. Nevertheless, we consider that this would be worthwhile in terms of meeting the requirements of both electricity users and generation investors.

Additional targets

One point raised by the consultants during Working Group meetings was that there is a potential trade-off between installation of wind farms and installation of storage. This is not necessarily on a one-to-one basis. These plants bring different "qualities" of MWs to the WEM and Perth Energy suggests that this should be assessed further to determine whether a single MW capacity target is appropriate. Higher, or lower, levels of storage relative to wind may give a lower overall electricity price.

The appropriate mix of wind and storage could be encouraged by setting different RCPs for each, in a similar way to having different RCPs for capacity plant and flexible capacity. Given the extent and breadth of the forthcoming transition, consideration could even be given to setting a storage target to be applied over the coming 5-7 years as an interim arrangement.

Bidding storage into the energy market

The RCM paper indicates that battery storage may become the benchmark technology, due to its price falling below that of open cycle gas turbines, in which case its potential revenue may need to be considered in setting the BRCP. In assessing this, the ERA will need to consider how storage systems will bid into the energy market.

It is assumed in the paper that storage will purchase energy when this is cheap and then sell it back into the market when prices are high. There is also the assumption, by way of having AEMO set the duration obligation, that storage will be dispatched into the market at times of system peak. These assumptions may not hold true.

It has been suggested that batteries should, like other plant, offer energy into the market at close to their short run marginal cost. However, if this is based on the cost of electricity used to charge it the price may be very low. Alternatively, the battery may be forced to charge during a peak period if it has discharged earlier for market reasons (eg security) and must be charged to meet its RCM obligations.

To ensure that storage is dispatched at times that support its desired role, it must be allowed to offer into the market at prices well above its marginal cost. The guidance provided by the ERA under market power mitigation activities must recognise this.

Summary

Overall, Perth Energy supports the main changes proposed by EPWA and its consultants. The major shortcomings of the RCM have been identified and are largely addressed. If implemented, we consider that the proposed changes will be foundational in ensuring that the RCM will be able to fulfil its role in encouraging sufficient and appropriate generation and storage capacity into the WEM.

We do still have significant concern in respect to investor risk, for both private industry and Government (through Synergy). This is particularly acute where small levels of excess capacity will drive down the RCP and hence undermine the potential returns for new plant. We strongly suggest that a guaranteed price for new generators, and capacity credit assignment for new storage systems, should be increased to at least seven and preferably 10 years, to mitigate this risk.

Should you have any questions please do not hesitate to contact me at p.peake@perthenergy.com.au or on 0437 209 972. This submission may be made public.

Kind regards

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I am based in the Perth Office and work Tuesday, Wednesday and Thursday