1. Background

Summit Southern Cross Power Holdings ('SSCPH') is a 100% subsidiary of Sumitomo Corporation. SSCPH is a 50% owner and the operator of both the Bluewaters power station in Collie and the NewGen Kwinana power station. Between these two assets, SSCPH has been responsible for producing around 25% of the electricity generated in the SWIS for over a decade.

SSCPH is pleased to be able to provide this submission on Initiative 1 and 2 of the WEM Investment Certainty Working Group consultation paper, and on the adequacy of WEM reforms more generally.

1.1 WEM Reform and the RCM

The Reserve Capacity Mechanism (RCM) has always played a central role in the WEM. While meant to act as a 'reserve trader' mechanism, whereby it ensures the system has procured the marginal MW of dispatchable capacity required for a 1-in-10-year peak demand, it's clunky implementation within the market design resulted in it pervading many aspects of the market rules, from setting retailer IRCR obligations through to managing generator performance; even for generators not reliant on capacity credits, such as base load coal and gas, which by market design are reliant on long-term bilateral contracts. As such, reforming the RCM has been fraught – given the wide-ranging implications, reliances and self-interests.

This has proved problematic. The WEM (along with the rest of the world) has undergone such a fundamental change in the nature of supply and demand, that the original design of the RCM is now hopelessly inadequate to perform its function. A completely new methodology for managing adequate supply should have been implemented years ago, when the WEM's 'comfortable' supply/demand balance afforded the opportunity to implement future-proofed market designs. Instead, over the years, rather than properly 'reform' the RCM (and the market in general), regulators and policy bodies have decided to tinker around the edges, with the emphasis being on incentivising an efficient capacity mix through an RCM price model. In order, we have had:

- 2012/13: the RCMWG, after a year of deliberation, adopted the Lantau Curve;
- 2018: the 'Improving Reserve Capacity Pricing Signals' reform expended a great deal of time and energy modifying the Lantau Curve.
- 2024: the WICWG now is again analysing further complex price curve modifications.

To what end? What has the fixation with RCM pricing delivered in the WEM since market start? Only the pure peaking facilities, easily delivered under a 'reserve trader' mechanism (Merredin; Tesla and possibly Neerabup and Western Energy) have relied on the RCM price – and even these investments have preferred bilateral offtakes for capacity to de-risk the year-to-year RCM price volatility[1]. The RCM price played no role in any of the baseload coal and mid-merit gas investments, which rely on long-term bilateral energy contracts (as will the yet-to-be-delivered Waste-to-Energy plants, with long-term waste-disposal and energy supply contracts). The HEGT's were built for Ancillary Service obligations. All renewable facilities are predicated on either federal incentives or bilateral contracts (or a mixture of both). And new battery storage facilities are now being procured by AEMO under the NCESS process – completely separate (and substantially different) from the RCM price. AEMO has called Supplementary Reserve Capacity consistently in recent years – again outside of the RCM process. And let's be clear, involuntary load shedding was called last summer through processes run outside of even the market itself. So it can safely be argued that the WEM's fixation with trying to define the prefect RCM price structure, in order to encourage efficient investment in electricity assets, has not worked in the past. And given the even more volatile looming energy transition, it will almost certainly fall short of doing

[1] It can be argued that Neerabup and Western Energy, by virtue of their gas connections, were not pure capacity plays and were based more on bilateral contracts (Neerabup to Synergy) or IRCR hedging (Western Energy to Perth Energy).

so in the future. Continuing down this pathway is not sensible; risky (especially in the context of an isolated grid); and demonstrates a lack of understanding on investment drivers.

Finally, the benchmark technology for setting the RCP has shifted from an OCGT to a BESS with little fanfare. This one seemingly simplistic change will impact new investment in the WEM by an order of magnitude more than any tweaking of the RCP curve.

1.2 Securing Efficient Investment Going Forward

The RCM was always designed as an adjunct to a bilaterally contracted energy market (gross dispatch but net settlement). Like a reserve trader mechanism, it was structured to provide the marginal MW of supply required by the system under non-standard peak-demand operating states. Forcing participants to bilaterally contract for this 'insurance mechanism' does not make sense – hence it has been socialised via the RCM/IRCR structures.

Today, the WEM still bilaterally trades 85% of its energy, with a small real-time energy market allowing participants to manage their variances. When the majority of energy is dispatchable (traditionally comprising coal and gas in the WEM), it is rational for participants to manage their supply/demand positions[2]. Bilaterally contracted dispatchable generators, often already online, can compete at the margins in the small real-time energy market (and for essential system services[3]), based on their SRMC. Their SRMC will be dependent on the cost of fuel supply and the physical properties and constraints of the assets themselves. This all makes sense.

Fast forward to the likely composition of the future WEM, an isolated grid in a world defined by the energy transition. Renewable generation assets (wind and solar)[4] will provide the majority of the energy. Managing variability will be the job of gas peaking and storage[5]. It is certain that in such a scenario, there will be a requirement for a considerable over-build of renewable generation. This is not controversial, though the amount of over-build can be argued[6]. Periods of low-wind and minimal or no solar will require much more installed capacity than demand requires. More wind farms operating at low capacity factors and in dispersed geographical regions (to ensure some diversity of resource) will require stored energy and gas peaking to fill in the supply gaps. But in periods of high-wind and abundant sunshine, significant generation curtailment will be required and the gas peakers and stored energy will be unused given the oversupply. Crucially, renewable generators have no fuel requirement. SRMC's are close to zero. Energy prices in the market no longer represent the marginal price of online thermal generation. They now are likely to be approaching zero (or negative) for the majority of intervals. In other words… the price of energy becomes irrelevant.

A participant who wants to invest in a wind farm has a simple equation in front of them. In order to attract finance and make a return on their invested capital, they run analysis on their assumed capacity factors (i.e. the product of the wind resource and their turbine capacity, minus any constraints in delivering supply) and the cost of financing, constructing and operating the facility. This is their Long Run Marginal Cost (LRMC) – or the price they require per MWh produced over the life of the asset in order to generate sufficient revenue to repay their debt and make a return. Any curtailment of production simply means their required price per MWh increases. So how does the investor receive its wind farm's LRMC[7] in the future WEM, with wholesale pricing tending towards zero? Historically, it would bilaterally contract with a retailer that has a load obligation. But unlike previously, whereby retailers could manage their supply portfolio to closely mirror their

[2] Though noting that there can only be a very small number of sophisticated participants that have the capacity to bilaterally underwrite the generation necessary assets, given the WEM is a very small market. This means the WEM can never really be a highly competitive system – and so probably should seek to adopt simple over complex market design philosophies.
[3] See above.
[4] Given the prevalence of rooftop solar, new utility-scale renewable generation will most likely be from wind farms.
[5] Storage is currently relatively very expensive and while essential, should be used sparingly where possible.
[6] It depends on the amount of gas peaking and storage – but 200% to 250% is likely.
[7] As at 2024, the LRMC of a wind farm (circa 45% CF) in the SWIS is likely around $100/MWh

demand's load shape (with 1-in-10-year peaking insurance being socialised via the RCM, and smaller renewable obligations being manageable), each retailer will now need to procure significantly more renewable capacity in order to meet their energy demand, as well as forms of firming supply, such as gas peaking or storage. Each retailer needs to ensure multiple wind and solar assets receive their LRMC over 10 to 15 years in order for financing requirements to be met and investments to be made – including for all energy curtailed. Not only would this be terribly inefficient for multiple retailers to do at the same time, but it would provide incentives for other small retailers to 'free ride', investing in firming supply only and offering low-cost 'energy' from the market as the price of energy becomes immaterial relative to the total cost of supply. A more appropriate method to accommodate this future scenario will be to socialise the over-supply of renewables to achieve the most efficient over-supply at least cost.

The current RCM has now adopted a BESS as its benchmark technology in order to set price (BRCP). This could well incentivise significant new BESS assets into the WEM, on top of the large quantity being procured via the NCESS. But storage does not generate energy[8]. The wind farms required to generate this energy, unlikely to be procured bilaterally as described above, will need to be incentivised by another mechanism. And given the uncertainty around the MWh output (due to over-build and curtailment), this will likely be a form of fixed payment… or capacity payment[9]. The most efficient manner to do this is via a single buyer[10].

As it stands, AEMO has already procured circa $3billion worth of storage assets via the NCESS[11]. An additional circa $2billion looks set to be procured via the CIS (actually via future capacity cycles with the CIS simply underwriting the assets). And as set out above, it is likely that AEMO, via some market mechanism (floor prices or a capacity price that enables wind farms), will end up procuring the majority of new renewable energy in the SWIS also. It appears that the WEM is already migrating towards a single buyer model by default. Rather than continuing to implement complex capacity pricing models to procure an ever changing mix of assets to provide energy and essential services, which is only growing in complexity, perhaps it is time to re-think the market more holistically and move to a simpler, centrally planned buying model, using forecast <u>quantities</u> based on real market assumptions, rather than attempting to determine an efficient <u>price</u> model that will mimic market outcomes. A single buyer model does not preclude private participation in the WEM – it can co-exist where private players are able to provide services more efficiently. And it incentivises private investment in generation and storage assets. Some of the most competitive asset procurements in the SWIS occurred when (the then) Western Power ran tender processes. Cost efficiency from competition in the bidding, contract negotiation and construction of generation assets have far outweighed cost efficiencies gained from those assets participating in the complex 'competitive' WEM market structures since[12].

1.3 Reserve Capacity Price Curve

Sections 1.1 and 1.2 provides commentary on reforming the RCM price curve (again).

1.4 Ten-Year Reserve Capacity Price Guarantee for New Technologies

A ten year price guarantee can be adopted in both the current market construct or in a single-buyer market structure. But the notion of offering a <u>price</u> guarantee, based on the prevailing RCP, in order to incentivise an efficient mix of new technology is flawed. The RCP – to be based on BESS as the benchmark reserve capacity

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[8] And expecting rooftop solar and excessive storage to provide a <u>secure</u> and <u>cost effective</u> electricity system for an industrial economy like that exists in the isolated SWIS is a high-risk proposition.
[9] Floor prices may also be adopted, but they will be required to compensate wind farms for curtailed energy also. In any event, some form of fixed revenue will be likely.
[10] The WICWG is considering floor pricing; and the CIS has a contract-for-difference design (which needs to integrate with the WEM); but these are simply additional revenue mechanisms that replace the need for bilateral offtakes. Or looked at another way, they are effectively single-buyer bilateral offtakes with AEMO (with the Federal government subsidising the asset, via AEMO in the CIS instance).
[11] CSIRO capex assumptions is $2.5M/MW for 4hr BESS. Public information suggests Synergy's BESS capex is >$3M/MW
[12] Of course – a central single-buyer body with the correct set of guidelines and obligations would need to be established as the AEMO is unlikely to be best placed to manage this function on behalf of energy users in the SWIS.

technology, will incentivise… BESS[13]. So unless new technologies can be delivered for the same cost as a 4-hour BESS, then they are unlikely to be delivered, even under the 10-year pricing guarantee. The most likely outcome, assuming the proposed duration requirement, will be that existing developers with BESS projects will seek to extend their storage duration to the minimum of 5-hours. This could deliver an unintended and poor outcome whereby a large quantity of 5-hour BESS projects (on top of the significant existing pipeline of 4-hour BESS projects) seek certification in the first cycle that the 10-year guarantee is in place, and at a relatively high RCP. This could then crash the RCP in subsequent cycles (via whatever price curve is adopted) for existing assets (not covered by existing price guarantees); as well as make it harder for new 'energy producing' generation assets to enter in subsequent cycles. With the current timeline for closure of coal generation, the WEM might find itself with a surplus of non-energy-producing storage capacity, with little actual generation. The WEM will shift its traditional problem of ensuring it has enough peak capacity (for 1-in-10-year system peaks), to one of a deficit of actual energy[14].

Long-duration storage technologies (or dispatchable new low-emission technologies) are either not yet evolved enough, or have significantly different capital structures, to compete with BESS. Pumped Hydro, for example, could never be banked on the revenue certainty based on 10 years-worth of a BESS RCP. Yet PHES may last 50+ years compared to the 10 to 15 years of a BESS. Similar with concentrated solar power or even geothermal. In other words, the current RCM price model is inflexible and will likely only deliver the type of technology that it has been specifically designed against[15].

An alternative way to bring new technologies into the market would be for a single buyer to offer a 10-year capacity credit price guarantee (i.e. 10 years of fixed revenue) based on a competitive tender, whereby the targeted facility parameters could be specified and different tendered options compared on the basis of value-for-money[16]. This will lead to differential pricing of capacity in the WEM. But differential pricing already exists[17]. Importantly, the WEM gets what it needs – not what an imperfect RCM price model allows.

Eligibility:

Requiring any storage facility with a 10-year price guarantee to demonstrate it is supplied with 100% renewable energy is unlikely to be workable. Storage performs best by charging when there is excess energy – which by circumstance will be low emission, given it is more likely zero SRMC energy is spilled in excess. This excess energy is low cost and typically occurs in the middle of the day. For a storage facility to ensure 100% renewable supply, it would need to contract for that renewable supply. As we have determined, the LRMC of wind is around $100/MWh[18]. Storage economics break pretty quickly at these charging prices. And there will be no guarantee that a bilateral contract with a renewable facility will provide renewable energy at the times the facility needs to charge. A better solution would be for the storage facility to simply charge at the most appropriate time to support the grid, understanding that the majority of what it will be charging with will be the 'socialised' excess renewable energy.

In the scenario where a dispatchable facility is capable of burning fossil fuels, then it should be able to demonstrate that it only uses renewable fuel. Capacity refunds might be incurred if the facility is called to run but is not able to use renewable fuels. The 10-year price guarantee should only apply to new facilities, otherwise existing (fossil fuel) facilities that migrate to use renewable fuels would receive windfall gains.

[13] It will not incentivise new renewable generation – as wind and solar do not earn enough capacity credits relative to their installed capacity (and capital cost).
[14] Or at least low-cost energy. And not mentioned anywhere is the looming transmission investment problems.
[15] As has been shown with historical investments based on capacity credit revenue – with only diesel peakers being delivered based on the RCP alone.
[16] In other words – a socialised bilateral contract via a single buyer.
[17] The majority of existing generation receives a grandfathered RCP; new facilities have the option to lock in 5-year fixed prices and the prevailing RCP on entry; and all non-scheduled generators get capacity credit accreditation based on variable factors and equal to a fraction of their installed capacity – or on an installed capacity basis, their capacity price is a variable fraction of the RCP.
[18] Solar is cheaper (circa $50/MWh), but the WEM has a surfeit of solar. Adding more would exacerbate current problems.

Duration Comparison:

While the above outlines alternative approaches to the long duration capacity structure, the duration that is also considered "long duration" in the consultation paper can be compared to the approach by other jurisdictions. The UK defines long duration to be at least 6 hours. Markets in India and USA apply 8 hours. The LDES Council, a leading industry body has fixed the definition of long duration as 8 hours and above. NSW also currently specifies LDES as 8 hours and above according to the EII Act in their LTESA tenders[19]. As noted in the sections above, the proposal for 5 hours to qualify as long duration doesn't provide a material change from the current storage solution and there is no incentive to provide storage for any longer duration as an alternative energy solution.

[19] https://www.energy.nsw.gov.au/sites/default/files/2022-08/long-term-energy-services-agreement-design-consultation-paper-210316.pdf