WEM Review Phase 2

Perth Energy Submission on

Reserve Capacity Mechanism Position Paper

perthenergy

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Executive Summary

Perth Energy would like to thank the Public Utilities Office (PUO) for the Position Paper on the Reserve Capacity Mechanism (RCM) and the rules and regulations associated with the operation of the RCM.

This submission assesses the Position Paper against the stated objectives of the Electricity Market Review (EMR), namely:

1. ***Reducing costs of production and supply of electricity and electricity related services, without compromising safe and reliable supply***
2. ***Reducing Government exposure to energy market risks, with a particular focus on having future generation built by the private sector without Government investment, underwriting or other financial support***
3. ***Attracting to the electricity market private-sector participants that are of a scale and capitalisation sufficient to facilitate long-term stability and investment***[1]

The RCM Position Paper sets out a separate set of objectives[2]. These RCM Paper objectives make no specific mention of private sector investment and, in the context of current excess supply, the Paper appears focused on making changes to regulation that will drive down payments to merchant plant owners in an attempt to have capacity exit the market.

Regulatory changes of the type proposed constitute an environment of **sovereign risk** that is in direct conflict with EMR objectives 2 and 3, above. Driving down the value of private sector generation investments is not going to change capacity (as they will be sold on by owners or banks), but will certainly deter future private sector investment in the market and damage the reputation of Western Australia as an investment destination.

The proposed changes are also equally likely to be ineffective and unnecessary. The Government, through its policy settings and ownership of Synergy, has created the problem of excess capacity and also possesses the tools required to fix the problem.

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[1] https://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Electricity_Market_Review.aspx

[2] RCM Position Paper p9

Excess capacity is a major issue for the market but it is not caused by the Reserve Capacity Mechanism. Excess supply has fundamentally been caused by:

1. IMO's misapplication of the Market Rules to certify Demand Side Management (DSM) as equivalent to generation capacity and pay DSM the full Reserve Capacity Price (RCP); and
2. The Government allowing Synergy to breach the 3000 MW generation cap and to retain 1000 MW of excess capacity procured under the previous Vesting Contract's Capacity Displacement Program.[3]

The solution to the excess capacity problem is to reverse the past mistakes by:

1. Treating DSM loads as energy products to be bid for dispatch in the Balancing Market, with appropriate changes to this energy market for DSM to legitimately make a return on investment, and
2. Directing Synergy to close the excess capacity that it continues to operate, with clear options being Pinjar, Cockburn 1 and Muja AB.

Synergy's Pinjar station has a number of very old peaking units several of the smaller ones can be closed. Cockburn 1 is a baseload combined cycle gas turbine plant but due to high gas price it is being run inefficiently at low capacity factor. This plant can be mothballed and brought back online in the future if and when required. Muja AB was refurbished as a hedge against gas supply disruption following the Varanus Island crisis that cut gas supply to the South West by one-third. The strategy was to provide short term cover (10 years) instead of the Government committing to a 30-40 year coal plant. It was partly to support the mining boom.

Now that WA has a gas emergency strategy in place and excess baseload generation capacity, Muja AB should be shut down due to high operating costs and very low fuel efficiency.

Returning the market to equilibrium in this way also negates the concerns about excess costs. In reality, the cost of the RCM was already fixed as unit payments reduce in proportion with excess capacity volume, thereby keeping total costs the same. The Position Paper confuses cost with economic value.

With the market back in equilibrium through these steps, proper attention can be given to longer term market structure. Perth Energy does not believe, however, that the current capacity market structure has caused, or is likely to cause in future, major imbalances.

Fundamentally, the RCM and (energy) Balancing Market (BM) make up the structure of the WEM and it is not appropriate to change the RCM without changing the BM to match. In an energy-only

[3] The Vesting Contract was construed by the government to govern supply between Verve Energy, the State owned generation business, and Synergy, the State owned retailing business, when these entities were separate businesses following the disaggregation of Western Power Corporation in 2006. Under the Vesting Contract's Capacity Displacement Program (CDP), Synergy was allowed to tender for capacity in the market to displace Verve's capacity if Verve lost the bids. Under CDP, Synergy signed power purchase agreements (PPAs) with private projects totalling over 1000 MW. This private capacity includes the 220 MW coal plant Bluewaters 2, 320 MW Newgen Kwinana combined cycle gas plant, 330 MW Neerabup peaking power station and 207 MW (certified at <100 MW) Collgar Wind Farm. Verve was supposed to close down the equivalent of this 1000 MW but instead it went on to refurbish the 220 MW Muja AB coal plant in addition to the newly built 290 MW Kemerton Peaking Power Station, adding capacity to the system in breach of the government's own 3000 MW cap. The government commissioned Oates Report, released in 2010, warns of significant excess capacity arising from this situation.

market like the National Electricity Market (NEM), the energy price can go to $13,500/MWh to accommodate economic return to peaking power stations. In the WEM, the wholesale energy price caps are $200-350/MWh according to fuel use, to reflect the capacity payment to peaking power stations via the RCP. The Position Paper risks making the WEM uninvestable by not allowing return on investment through either the RCM or BM – which must be considered in combination.

BM price caps should be raised significantly for energy products like DSM while remaining at SRMC levels for Synergy to pre-empt exertion of market power in bidding behaviour.

The proposed “transition” regime with a -5 price curve with the RCP reaching zero at 20% excess capacity is not transitional but will be a shock to the market, no less than an auction regime – it would lead to severe volatility in the capacity market and raise the risk of default by generators not holding a Government backed contract. This would defeat totally the objectives of the EMR.

Sovereign Risk

Australia has an excellent global reputation as an attractive investment destination. This reputation has been established over many decades, with predictable and stable policy frameworks at the core of this reputation. Our submission is aimed at maintaining this quality of environment for investment at the WA level.

Sovereign risk is very different to market risk. Investors accept free and fair market competition risks, whether these are from competitors or new technologies or changing market conditions.

In the current environment, the reduction of demand for energy due to lower resource sector demand, efficient appliances, unsubsidised solar installation etc, would all be seen as market risks. Entry of new capacity on the same terms and conditions as existing players, even if this creates excess capacity and lowers unit capacity price, would also be seen as a market risk.

But investors are very concerned about Government policy risks that have the effect of distorting price signals in the market or changing the market structure and rules of the game after they have invested.

In the current context, the changes proposed in the RCM Position Paper represent a clear and extreme sovereign risk as they directly seek to lower returns on investment of private participants through a change of market regime, against the background of the recent Verve-Synergy merger that has re-created a dominant State owned market competitor that would stand to gain in market position from the proposed regime change.

The bipartisan reform program of the last decade was based on a clear objective of implementing a competitive generation and retail market for the benefit of consumers. It established the WEM, disaggregated Western Power Corporation and placed a moratorium on Verve not to retail and Synergy not to generate until further advice from the Economic Regulation Authority (ERA) to address the utilities’ market power.

The Government at the time complemented the program with a 3000 MW cap on Verve’s portfolio and a Vesting Contract that required Verve to retire capacity that would be displaced by private sector capacity should the latter win tender contracts to supply Synergy under the Vesting Contract Capacity Displacement Program (CDP).[4]

The fundamental industry changes introduced in 2006 brought in an efficient wholesale energy market and $3 billion of private sector investment that averted black-outs during the Varanus crisis and provided sufficient new generation to cover the mining boom. Reform legislation also provided for annual and 5-yearly market reviews as conducted by the ERA for the benefit of the Minister and Parliament.

Perth Energy participated in the market as called for by express Government policy and Market Rules. We entered into supply contracts with stand-alone generator Verve to compete against Synergy and brought in two merchant power stations to support our retail business as targeted in the Market Rules. We are the only new entrant participant not inheriting a legacy retail customer base (electricity or gas) or relying on taxpayer backed contracts to supply Synergy.

Perth Energy now supplies nearly 15% of the contestable market or 10% of the total SWIS market. We are still awaiting Government decision to deregulate the remaining one-third of the SWIS, the so called franchise market comprising the small business and residential segment so that the 1 million consumers still held captive to Synergy would be able to enjoy the fruit of supply competition. Retail tariffs applicable to residential consumers have surged by around 90% since WEM commencement in 2006 while contestable retail prices have in the main not changed during the same period.

The purpose of placing a moratorium on Verve as stand-alone generator supplying Synergy and private retailers on an equal footing was to develop retail competition for the benefit of consumers. The purpose of having a Reserve Capacity Mechanism is to facilitate private sector investment in generation capacity without recourse to taxpayer guarantee under traditional power purchase agreements (PPAs) with Synergy.

Perth Energy believes that since WEM formation in 2006 the WA Government has made two significant errors in judgment being:

- It has continued to provide Government support to Synergy, first through Synergy's procurement of excess baseload capacity as stand-alone retailer, and now through the large Tariff Adjustment Payment (TAP) subsidy as merged entity, and
- It re-merged Verve and Synergy in 2013 to re-create a dominant State owned vertically integrated utility that ironically deprives the utility of incentives to operate efficiently for the benefit of consumers.

The Verve-Synergy merger is a 180-degree policy backflip that has turned the competitive market structure upside down and severely damaged private sector participants with no Government contract support (merchant participants). More details are provided in the sections below. The merger has re-introduced into the market severe distortions that had by and large been addressed under the bipartisan reform program of the early 2000s.

The merger, together with the TAP subsidy and Government allowance for Synergy to retain excess capacity in breach of the capacity cap and Vesting Contract CDP, has been a very significant contributor to the rise in franchise market consumer tariffs.

[4] *Supply Procurement 2008 – Expression of Interest – Invitation to Potential Suppliers*, Synergy

This policy environment represents sovereign risk writ large.

Clarity of Policy Message

Perth Energy acknowledges that since 2014 the Government has made significant effort in trying to reset the course of market reform in the right direction through the Electricity Market Review Phase 1 and Phase 2 and have expressed our strong support for this.

Perth Energy would have preferred more of the recommendations made by the EMR Phase 1 Committee to be adopted by the Government, the most critical being horizontal disaggregation and sale of Synergy. We see EMR Phase 2 as being limited in scope, to modifying the technical and operational rules governing the RCM, while those critical aspects of 1) Government ownership, 2) Synergy's 80% control of the generation market, and 3) continued TAP subsidy to Synergy, are not being addressed.

Perth Energy will try to draw Government attention to these key issues with the hope that the Government will implement policies that will achieve the reform objectives that it has expressly retained from EMR Phase 1. These objectives are also consistent with the reform program of the early 2000s, which is aimed at creating a competitive market that attracts private participants and relieves Government obligations in the electricity market.

To achieve these consistent market objectives, EMR Phase 2 work needs to be based on the principles of:

- Addressing, avoiding and reducing **sovereign risk** faced by merchant participants
- Rolling back **market concentration** that has been intensified by the Verve-Synergy merger
- Withdrawing State support or involvement in the retail and generation markets that prevents **full cost recovery** or distorts **competitive neutrality** (eg, through subsidies or provision of credit support to Synergy engaging in PPAs with suppliers).

The Government should not be seen to waver in its policy actions in transiting the market firmly to a competitive structure within a short time frame. It needs to regain confidence among the finance and investment community that it will minimise structural and financial risk of participation following the Verve-Synergy merger. The goal of reform should be about the economy-wide benefits and not the interests of any State owned trading enterprise.

The best way to resolve real or perceived conflict of interest would be for the Government to sell Synergy as proposed by Synergy's Chairman at a recent (2015) Committee for Economic Development of Australia forum.

The merger has had severely negative impact on the market and particularly merchant participants. The Government should be especially concerned about ensuring retention of these merchant participants in the market as they represent the only true source of future competition to Synergy and the only sustainable prospect for Government's exit from the industry.

Reserve Capacity Mechanism

Purpose of RCM

The Reserve Capacity Mechanism (RCM) was designed to ensure that the South West Interconnected System (SWIS) would have adequate installed capacity available from generators to:

- Cover the expected system peak demand while providing adequate capacity in the event of failure of the largest generator to meet the reliability planning criterion
- Have the capability to respond to a degree of frequency variation
- Remove the need for very high (and with it volatile) energy prices to provide adequate revenue for peaking facilities and to trigger new investment
- Decouple generation from retailing to circumvent market power held by once Western Power Corporation, and then Verve, at the time by having a wholesale mechanism for capacity trading.

The Reserve Capacity Price (RCP) is designed to ensure **reliability of supply** and not as a market equilibrium price driven by supply and demand as mistaken in the Position Paper. The job of securing supply to match peak demand in the system, subject to a reliability standard, is carried out by the Independent Market Operator (IMO), now AEMO[5], through its demand forecast.

IMO demand forecast, as published annually in the Statement of Opportunities (SOO), sets the Reserve Capacity Target (RCT) looking forward and invites generators to offer additional supply if required based on this published target every year through the Reserve Capacity Certification process. Generator offers are based on the RCP as determined by the IMO to satisfy the RCT. Once IMO has set the system's needs on the demand side and calculated the market cost of delivering an optimal peaking power station to the system as defined in the Market Rules, the total cost of capacity in the system is locked in at RCT MW x $RCP.

Additional MW supply in excess of the RCT will lead to a proportional (-1 relationship) reduction in the RCP so that the total capacity cost remains unchanged. Excess capacity beyond what the system needs is NOT paid for by consumers but will lead to lower return to all generators.

If actual demand comes in below the RCT, consumers pay for this gap since the IMO, on behalf of consumers, has called generators to supply the RCT so actual demand shortfall is not the generators' fault. The -1 price curve for the RCP in relation to excess capacity is therefore rational and fair as it allocates the risk and cost of excess capacity to the right owner of the cause of deviation from the RCT.

Importantly, if actual demand remains below the RCT in the following year, the IMO will revise down the RCT accordingly in the next certification round, effectively raising the excess capacity above the RCT so that generators will receive a lower RCP, deterring new capacity – this process can go on for a

[5] The WA Government closed down the IMO and transferred its WEM operation functions to the Australian Energy Market Operator (AEMO) in November 2015. However, the issues associated with the WEM and discussed in this submission have been in relation to the previous IMO and this submission refers to the IMO for accuracy.

number of years until supply and demand are in relative balance through a forecast adjustment process undertaken by the IMO.

So, even if excess capacity is caused by the demand side initially, over time, the RCM allows for the cost to be shifted to the generators through IMO adjustment of its demand forecast.

If there are insufficient applications to offer generation resources to meet the forecast RCT the IMO has the ability to call for an auction to procure Supplementary Reserve Capacity. The RCM is therefore critical to the functioning of the WEM to satisfy market objectives.

As observed over the last 9 years since WEM formation, the RCP has moved up and down by significant proportions up to 30% in a single year. Such gyrations have been of a higher order than what the RCM was designed for but they also attest to the fact that the IMO has seen fit to use certain levers to move the RCP to respond to its own misforecasts. The RCP is currently below its inaugural level 10 years ago (30% fall in real terms).

Thus, the RCM as it stands cannot sustain excess capacity, especially in terms of value of capacity in the system – there may be capacity volume excess but not value excess as there is sufficient built-in mechanism to drive the market back to equilibrium.

Likewise, the current low RCP cannot be blamed for drawing in excess capacity and it would be wrong to suggest that the RCP needed to be artificially depressed further to resolve the excess capacity problem as contended in the Position Paper.

RCM and Excess Capacity

The current excess capacity in the system has been caused by:

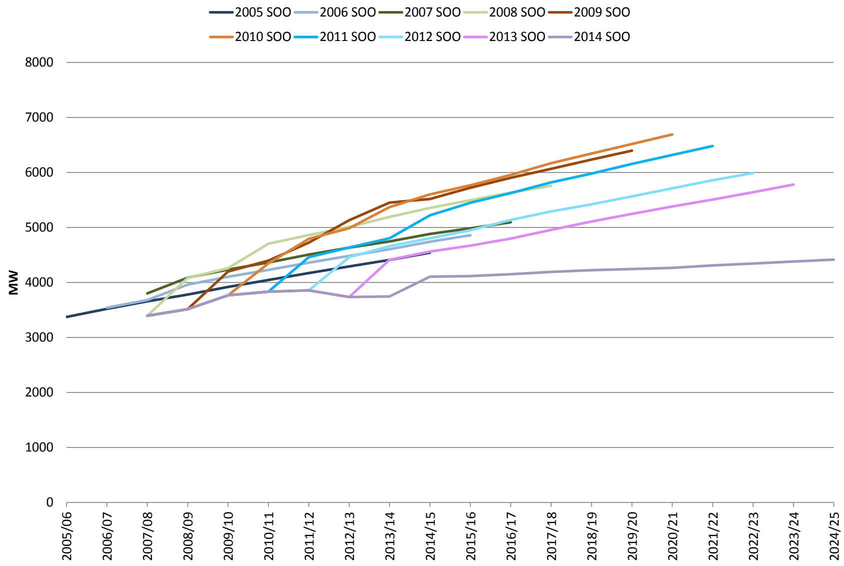
1. **IMO over-forecasting of demand (RCT) in the past**
2. **IMO certifying Demand Side Management as generation capacity for payment of full Reserve Capacity Price**
3. **Verve (now Synergy) not closing down generation capacity that had been displaced by Synergy's purchase of private sector capacity under the Vesting Contract Capacity Displacement Program**
4. **Increased Government subsidy to Synergy in the form of Tariff Adjustment Payment, which has been used by the utility to mask the cost of holding on to excess capacity.**

These factors do not relate to the RCM design or RCP determination methodology.

With the benefit of hindsight, IMO demand forecasts were influenced by the resources boom and made inaccurate by the heavily subsidised entry of solar PV systems in the residential market. The forecasts have been revised downwards in recent years.

The Vesting Contract was a financial construct by Government for its own utilities Verve and Synergy at the time, not an instrument of the WEM or RCM. Under the Vesting Contract, Synergy as retailer was allowed to call for tender for capacity from the market under the Capacity Displacement Program (CDP), with Verve and private generators vying to bid to offer supply to Synergy. If Verve lost the bids, as happened for a number of years, it was supposed to close down its capacity to maintain market balance. The CDP, together with the 3000 MW cap on total Verve capacity, were designed by Government to reduce Verve's market power and to foster generation competition over time.

Chart 1: IMO Forecast of Peak Demand (10% POE)



Source: IMO SOO 2014

Under the CDP, Synergy signed PPAs for 1000 MW from private projects including the 220 MW coal plant Bluewaters 2, 320 MW combined cycle gas plant Newgen Kwinana, 330 MW peaking gas plant at Neerabup and 207 MW (certified at <100 MW) Collgar Wind Farm. Verve was supposed to close down 1000 MW but instead it went on to refurbish the 220 MW Muja AB in addition to the newly built 290 MW Kemerton Peaking Power Station, adding capacity to the system in breach of the Government's 3000 MW cap.

The Government commissioned Oates Report dated August 2009 warns that if Verve did not close down capacity there would be excess supply in the market. A sample of excerpts from the Report (with our emphases added):

> *Section 10.5 The risk of excess capacity*
>
> "…When Bluewaters 2 comes online and combines with base load supply from Bluewaters 1 and NewGen, Verve expects to have its Cockburn power station on reserve shutdown for most of the year and at least one unit of Muja C cycling down or off. <u>These new displacing plants are expected to represent a significant contribution to the SWIS overnight load which is approximately 1,500 MW…"</u>
>
> *Page 39*
>
> "…In this rapidly changing industry environment, the existing rules, regulations and practices designed to coordinate and guide development and provide policy direction to State owned entities urgently need to be reviewed. The changes may well constitute a paradigm shift in areas such as new generation and networks investment, <u>the retirement and utilisation of existing plant</u> and gas procurement and storage (as significant gas will be required for peaking generation). There are also major new risks associated with the trading of carbon

and RECs, potentially affecting the equity requirements and credit standing of entities in the sector…"

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"…The matter of the rapid nature of the displacement schedule between Verve and Synergy is a threat, particularly given current issues in the design of the capacity and balancing markets with respect to wind generation, differences in the views of Verve and Synergy regarding the response to climate change and the current lack of a State strategy to deal with the interrelated impacts of climate change and economic gas availability in the electricity sector. This gives rise to risks of sub-optimal investment, asset stranding, over-capacity, reduced cost effectiveness and unnecessary damage to the value of the State's investment in Verve…"

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"…Various scenarios need to be considered ranging from the maintenance of the current largely coal fired base load generation environment, to an environment with significantly increased utilisation of gas and full compliance with renewable energy targets within the SWIS. The full implications in terms of operating costs, new capital expenditure, the stranding or early retirement of current plant and ultimately the impact on the price of electricity need to be modelled and evaluated. The impact on the value of the State's investment in both Verve and Synergy also needs to be evaluated under all scenarios…"

Of the new capacity that has entered the market since WEM formation, only 18% is peaking capacity and 60% of this has come in for planned co-generation purposes but is temporarily being used as peaking due to project delay. Only 230 MW can be categorised as pure merchant peaking plant, representing just 7% of total new entries.[6]

Table 1: Key Drivers of Additional Capacity Credits since 2005-06

Key Drivers	Capacity Credits (MW)	% of Total Capacity Credits
DSM	561	18%
RCP Formula	561	18%
Energy Generation	1,276	40%
LRET	62	2%
Fuel Security	220	7%
Ancillary Services	196	6%
Other	287	9%
Total	**3,162**	**100%**

[6] This category is made up of Kwinana Swift (109 MW), Merredin Power Station (82 MW) and Tesla (39 MW).

Verve's refurbishment of Muja AB could be attributed to the Varanus Island crisis in 2008 that severely disrupted gas supply to the South West. This project was designed to provide Verve with a short term hedge compared to building a new coal plant with a 30-40 year commitment. The cost blow-out associated with the project was unfortunate but the strategy was understandable.

But once the South West gas management strategy was put in place in 2010, Verve should have proceeded to schedule closure of Muja AB and other plants in accord with the Oates Report's warnings.

In 2014-15, to his credit, the Minister for Energy directed Synergy to close down the 380 MW Kwinana Stage C. This leaves approx. 600 MW to be taken out of the capacity market.

Other than Kwinana Stage C, Verve/Synergy has not closed down any other plant. It is now Synergy's responsibility to put away the displaced capacity. The RCM has nothing to do with it.

Demand Side Management

The other key component of excess capacity is the inexplicable certification of Demand Side Management (DSM) as generation capacity by the IMO.

DSM is contractual arrangement between a load and a market participant (System Manager, retailer or broker) to cut consumption at certain time when the cost to the system of supplying energy is high. Under a flat tariff regime DSM has value as price signals do not reflect high peak costs, so DSM providers could arbitrage to gain for themselves and the system from cutting peak consumption. In an efficient market with time-of-use pricing, appropriately high peak rates would discourage consumers using power during the peak as a matter of course.

But the IMO has misapplied the concept of capacity under the RCM and has been paying the full RCP to DSM loads, who share the capacity price windfall with their contracted aggregators. Since the RCP is formulated in the Market Rules to pay for a 160 MW peaking power station to be delivered, it is much higher than the cost at which DSM contracts can be procured in the market. As DSM loads are not subject to the same stringent dispatch requirements as generators under the Market Rules, the investment required in preparing DSM contracts is minimal compared to delivering a power station. Misapplication of Rules by the IMO has contributed to excess "capacity" in the system.

Take away DSM from the capacity market and peaking capacity is not in excess but is in balance, with excess being only in baseload capacity that is exacerbated by Collgar Wind Farm, a plant underwritten by Synergy.

DSM is a legitimate energy product that should be bid into the Balancing (energy) Market and priced appropriately at point of use to cover for emergency situations where all peaking plant dispatches have been exhausted. It would be up to aggregators to work out with the DSM loads to take this arbitrage opportunity, with aggregators paying the loads a "preparedness fee" in return for gaining high energy prices if and when their DSM loads are called by the IMO.

Under law, the System Manager can already trigger load-shedding under emergency, so DSM is a form of economic compensation to encourage loads that can be shut down for a price to do so first in order to make load-shedding more efficient – but DSM is not a necessity for supply reliability, the target of the RCM regime.

If used, DSM should be paid a higher price than the short run marginal cost (SRMC) cap imposed on the Balancing Market to improve efficiency of load shedding. This is consistent with our point above that the RCM must be viewed in conjunction with the BM.

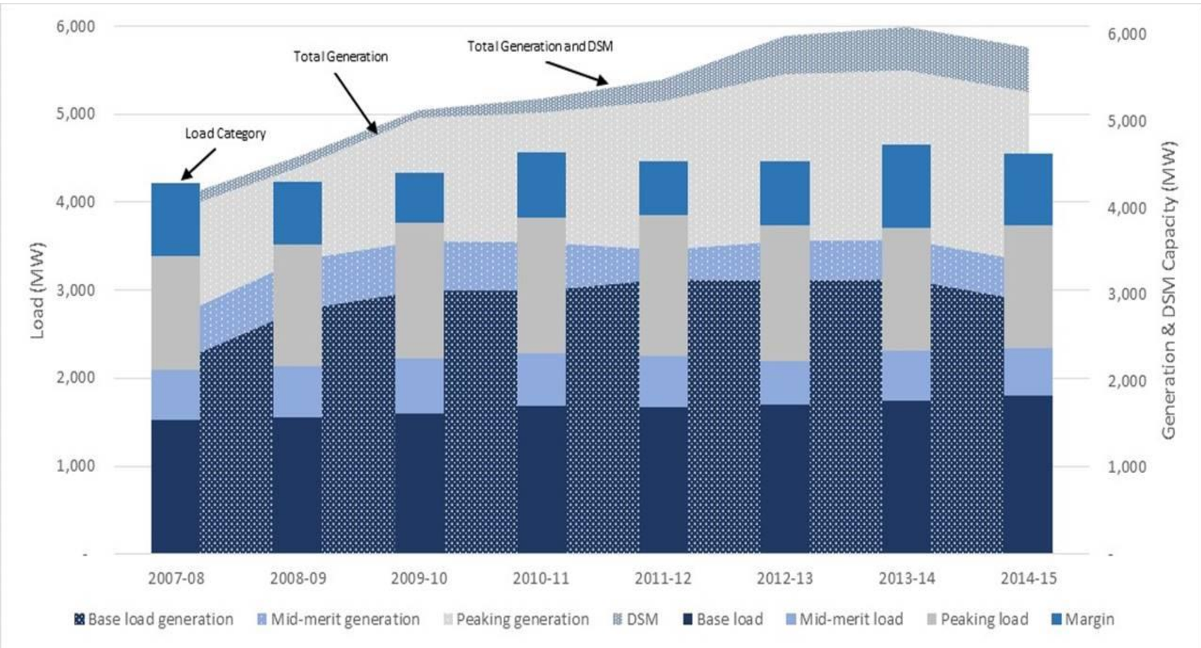
IMO's certification of DSM as generation capacity and payment of the full RCP to DSM loads breach the Market Rules where the intent is for the RCP to be paid to generation capacity. This is evidenced in IMO's unsuccessful attempt in the last several years to try to make DSM comply with the Rules applicable to peaking capacity through a "rule harmonisation" proposal – an explicit admission that DSM is not generation capacity.

At 560 MW, DSM accounts for half of the estimated excess capacity in the SWIS, with the balance made up of capacity that Synergy should have retired. Addressing these 2 components of excess capacity would resolve the problem in the SWIS.

Plant Mix

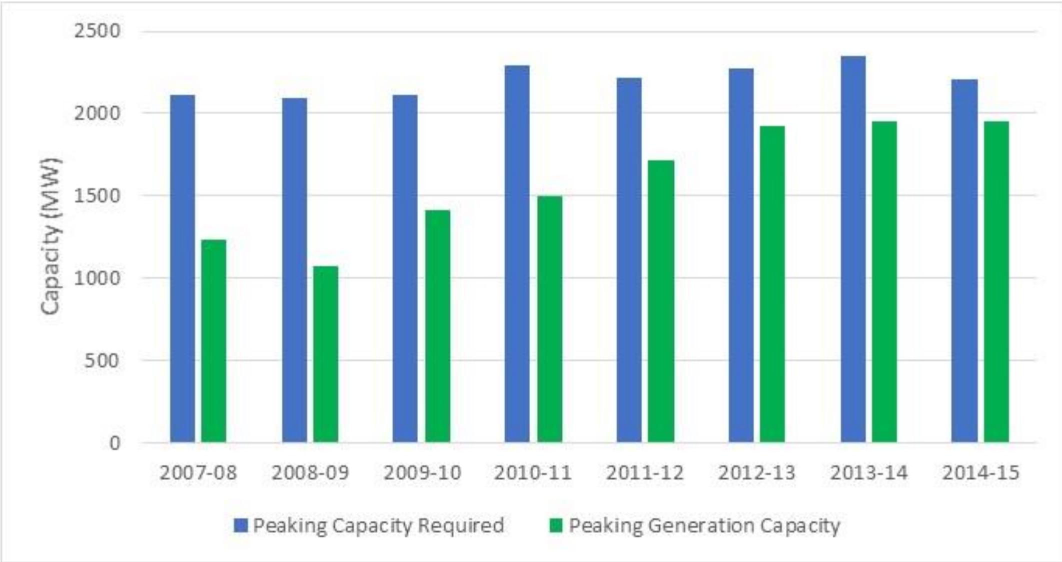
Charts 2, 3 and 4 show the main categories of generation capacity – baseload, mid-merit and peaking – in relation to system load demand. It can be seen that once DSM is shifted from the peaking generation classification to be used appropriately in the Balancing Market, the system peak load is just about covered by peaking capacity. There is NO excess peaking capacity.

Chart 2: Generation Requirement by Load Type



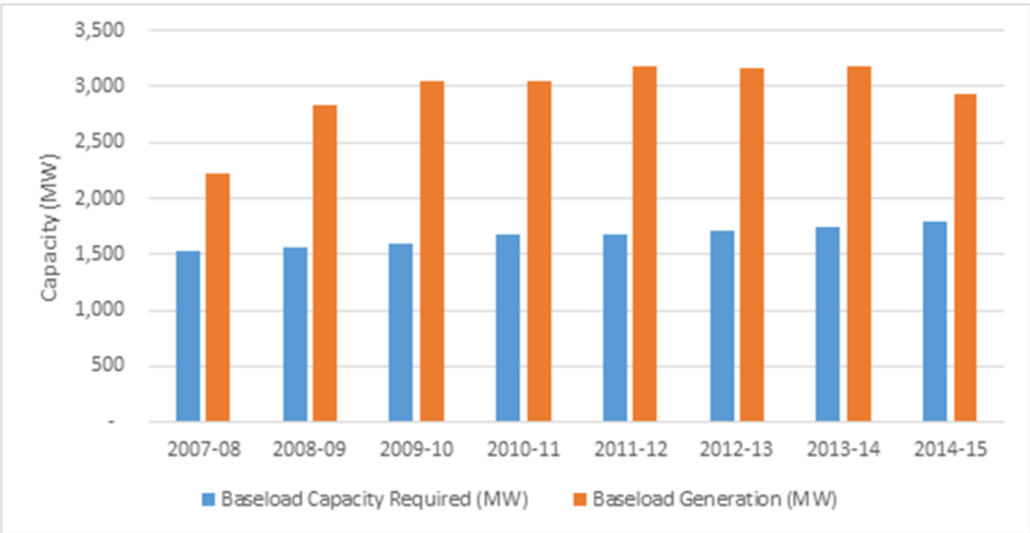
Source: IMO SOO 2014 data

Chart 3: Peaking Load and Margin versus Peaking Generation Capacity



Source: IMO SOO 2014 data

Chart 4: Base Load Generation Capacity versus Base Load Demand



Source: IMO SOO 2014 data

Fast-response peaking plants are needed to provide backup to renewable energy generation, a fast increasing phenomenon with the entry of residential solar PV systems. With the Mandatory Renewable Energy Target scheme now set to run to 2030 and beyond, energy balancing for renewable plants will assume increasing importance as a function for peaking plants, besides providing coverage for plant forced outage, Reserve Margin and Ancillary Services. Any gap between system peak load and peaking capacity is currently covered by the dispatch of baseload generation, which is an inefficient exercise.

These charts reinforce the view that artificial depression of the RCP through manipulation of the price curve is not the solution as this would damage only the economics of peaking plants. DSM,

with an entirely different cost structure due to its non-generation capacity characteristics, would not be impacted and excess baseload capacity held by Synergy would also not be affected due to Government subsidy.

Artificially depressing the RCP to damage the economic value of new and more efficient merchant peaking plants while protecting Synergy's older and less inefficient plants would not reduce capacity in the market. It would only result in long term economic costs to the State and soaring sovereign risk as it would place Synergy in a position to buy merchant plants at fire-sale price. **If this is the outcome of the Position Paper then the Government would have undertaken the most blatant misappropriation of private property in the history of WA public policy making. Clearly this is not the intent of Government**.

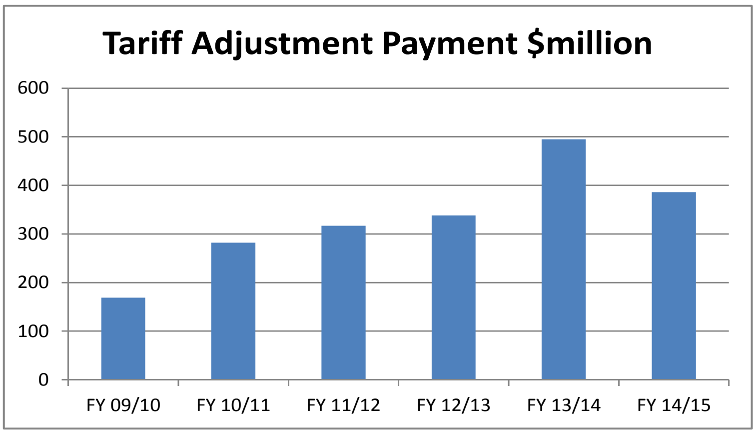
Synergy Subsidy

Synergy received a Tariff Adjustment Payment (TAP) from Government totalling $495 million in 2013-14 and $386 million in 2014-15. This represents on average one-third of Synergy's total energy + capacity cost of supply to its franchise and contestable customers. Government budget estimates forecast that the TAP will remain $400 million per year until at least 2017-18.[7]

TAP revenue is intended to subsidise Synergy for the difference between cost reflective tariffs and the gazetted tariffs Synergy charges its franchise customers. However, our calculations show that this subsidy has also been used to repay Synergy debt and support Synergy's actions in the contestable market.

Chart 5 shows the growth in the TAP in the six financial years to 2014-15 and Chart 6 shows Synergy's main residential A1 Tariff covering the same period.

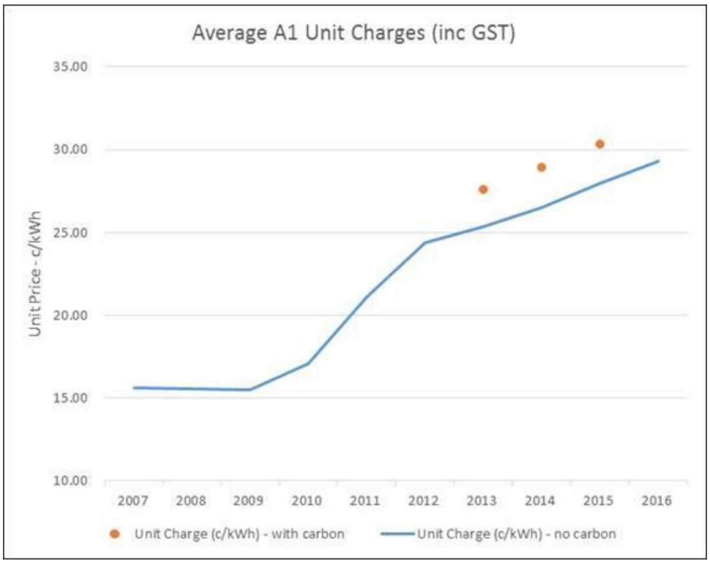
Chart 5: Tariff Adjustment Payment $M



Source: Synergy Annual Reports

[7] Department of Treasury, 2014-15 WA Budget Paper No.3, (Economic and Fiscal Outlook).

Chart 6: Synergy Residential A1 Tariff Movement



Source: Synergy

Both the A1 tariff and TAP subsidy have grown substantially over the last 6 years. Since the TAP is supposed to be covering for the cost of supply to the franchise market, small businesses and mums and dads consumers have faced a near 100% increase in tariff in combination with the near 300% TAP growth that would have raised the effective revenue from the franchise segment to Synergy in the order of near 400%. Something is clearly wrong here.

The TAP is based not on actual costs carried by Synergy but on a theoretical "new entrant optimal portfolio generator's cost of supply" assuming a full suite of new build power stations. Disconnected from actual costs, the TAP gives zero incentives to Synergy to improve its performance.

Using a theoretical construct also assumes that the PUO, which estimates this subsidy, knows what the future holds for a supplier wishing to source generation to supply the franchise market once Full Retail Contestability arrives. Considering the current excess capacity in the market that EMR is trying to resolve at this very moment, with no new build forecast for the next 10 years and with new technologies entering the market, this is a brave assumption.

The TAP subsidy in 2013-14 and 2014-15 represents on average 25% of total SWIS cost of energy + capacity supply (excluding network charges). **This obliterated the industry's margin**. Essentially, the Government has given Synergy enough money in the last 6 years to:

- **price in the contestable retail market at basement levels to deprive its competitors of a margin, and**
- **repay all of Synergy's debt, part of which has also been just transferred to WA Treasury Corporation, so that the utility would not be encumbered by normal financing constraints associated with holding a generation portfolio, effectively shifting all investment risks directly onto the taxpayers.**

The Synergy 2015 Annual Report shows Group revenue declining by 17% to $3.23 billion, driven by the removal of carbon revenue in FY 2013-14, reduced energy sales and a decline in average electricity prices. Electricity gross profit was down by $159 million or 20.7% on FY 2013-14. This was attributable to declining retail franchise and contestable sales (in total down 553.1 GWh or 5.2% on 2013-14) and reduced TAP (down $124.3 million or 24.3% on 2013-14).

The apparent decline in Synergy's market share has been due to 1) continued subsidised solar PV systems entry in the franchise market, and 2) retailers large and small following Synergy down to basement wholesale price levels for retail pricing in the contestable market as forced on them by Synergy's holding of excess capacity. But while competitors carry losses due to this depressed pricing environment, Synergy receives TAP to mask its commercially damaging business model.

EBITDA for the Group declined significantly, by 28.7%, over FY 2013-14. So, while Synergy claims that its regulated segment is loss-making due to regulated tariffs sitting below cost (requiring a subsidy), it has also been willing to accept losses in the contestable market by holding on to a substantial amount of old, poor-reliability and fuel inefficient baseload capacity that drives down its own wholesale prices. This confirms that the TAP is not associated with just franchise market losses and should be reviewed and terminated by the Government.

More than that, the Government should require Synergy to re-incur the amount of debt that it has repaid or transferred to WATC using TAP money over the last 6 years, and return this money to the taxpayers. The current debt-free balance sheet is a false construct and is in preparation for Synergy to sustain very low RCP as now proposed in the Position Paper. A low RCP would have the effect of unfairly damaging newer and more efficient merchant peaking plants while retaining very old and inefficient Synergy plants. The conflict of interest in EMR Phase 2 is significant.

In its submission to the EMR Committee Phase 1 in 2014, IMO provided estimates of cost breakdowns for Synergy's contestable and franchise segments, and the proportions of total energy costs and capacity costs attributed to each segment. Commercial data was provided to IMO by Synergy for this purpose. The analysis provided by IMO is summarised in Table 2.

IMO concludes that the cost of energy and capacity in the WEM to serve the franchise customer base was $148/MWh in 2013-14, materially lower than Synergy's reported wholesale energy cost of $180/MWh.[8] From the data provided in Synergy's quarterly report for June 2015 it can be estimated that Synergy's Retail Business Unit (RBU) has an approximate wholesale cost of above $150/MWh.

The 2012 ERA Review (of Synergy tariffs) applied an optimal efficient Long Run Marginal Cost (LRMC) modelled portfolio[9] and determined Synergy's efficient wholesale energy costs for this segment at $117/MWh in 2012-13. A similar optimal LRMC approach by the Australian Energy Regulator (AER) on 2013 Residential Price Trends estimated this at $108/MWh.

The IMO, ERA and AER figures show that, using actual or optimal LRMC as a base, the Synergy A1 tariff has been close to, if not at, full cost recovery so the TAP has not been needed for franchise market supply.

The actual cost figures also say that prior to the merger the stand-alone Synergy had been carrying higher portfolio (contracted and uncontracted) energy and capacity costs than what RBU pays today. After the merger, these costs seem to have vanished from RBU's book together with its responsibility to recover full (LRMC) cost. This responsibility has been shifted to Synergy's generation business unit (GBU). It has freed RBU to price to contestable customers at unhedged

[8] IMO Submission to Electricity Market Review Discussion Paper, September 2014.
[9] *Synergy's Costs and Electricity Tariffs*, Economic Regulatory Authority, July 2012.

wholesale spot (SRMC or below) energy and capacity price. **It is in the contestable market that the TAP has been deployed to retain market share.**

Table 2: Comparison of Cost to Serve Notional Wholesale Meter relative to Contestable Customers

			Percentage share			Cost (c/kWh)		
Financial year	Energy GWh	Capacity MW	Energy consumed	Energy cost	Capacity	Energy	Capacity	Total
Notional Wholesale Meter								
2007/08	8,309	2,251	51%	54%	57%	8.6	3.5	12.1
2008/09	8,280	2,458	51%	53%	58%	10.0	3.2	13.2
2009/10	8,111	2,634	47%	50%	58%	3.8	3.7	7.6
2010/11	8,035	2,847	46%	48%	57%	4.4	5.0	9.4
2011/12	7,456	2,815	42%	46%	54%	5.5	5.3	10.8
2012/13	7,091	2,969	40%	42%	55%	5.6	7.9	13.5
2013/14	6,802	2,855	38%	40%	53%	6.2	8.6	14.8
Contestable Synergy								
2007/08	5,041	1,164	31%	30%	30%	8.0	3.0	11.0
2008/09	4,995	1,209	31%	30%	29%	9.2	2.6	11.8
2009/10	4,803	1,133	28%	28%	25%	3.6	2.7	6.3
2010/11	4,591	1,206	26%	25%	24%	4.1	3.7	7.8
2011/12	4,210	1,171	24%	23%	23%	4.9	3.9	8.8
2012/13	4,328	1,133	25%	24%	21%	5.3	4.9	10.2
2013/14	4,244	1,215	24%	24%	23%	6.0	5.9	11.8
Non-Synergy								
2007/08	2,887	521	18%	16%	13%	7.3	2.3	9.6
2008/09	3,018	574	19%	17%	14%	8.6	2.1	10.6
2009/10	4,173	770	24%	22%	17%	3.3	2.1	5.5
2010/11	5,033	958	28%	27%	19%	4.0	2.7	6.7
2011/12	5,921	1,193	34%	31%	23%	4.8	2.8	7.6
2012/13	6,170	1,321	35%	34%	24%	5.1	4.0	9.2
2013/14	6,670	1,289	38%	37%	24%	5.9	4.0	9.8

Source: IMO Submission to Electricity Market Review Discussion Paper, September 2014

Synergy's Group segment results for FY 2014-15 are summarised in Table 3. Cost allocations have been interpolated from the cost breakdowns provided in the June Quarterly Report, adjusted for the latest Annual Report updates, to align with the same Consolidated EBITDA as published in the Annual Report. [10] Note that these figures include the TAP subsidy and gas revenue.[11]

Table 3: Synergy Segment Results 2014-15

$M	GBU	WBU	RBU	CSS	Eliminations	Consolidated
Revenue External Customers	100	291	2,812	14		3,217
Inter-Segment		1,544			-1,544	
Total Revenue	**100**	**1,834**	**2,812**	**14**	**-1,544**	
Cost of Sales	434	780	2,733	112		
Operating Costs	279	6	74			
EBITDA	**-614**	**1,049**	**5**	**-98**		**341**

Source: Synergy Annual Report 2014-15

[10] Figures have been rounded to the nearest million.

[11] The Annual Report did not provide segmented cost data. The Quarterly Report figures were adjusted to provide a best fit to each segment published EBITDA in the Annual Report.

Removing estimated gas revenues and costs, the average unit cost of retail electricity is estimated at $262/MWh, comprised of: **wholesale transfer cost of $158/MWh**; network cost of $95/MWh; and REC cost of $9/MWh (based on retail sales volume of 10,107 GWh). Retail operating costs is around $8/MWh, giving a total average retail cost of supply of $270/MWh.

Synergy's June Quarterly Report states that "…Currently, there exists a formal arrangement between WBU and RBU, whereby WBU sells energy to RBU on an arms-length basis. No transfer pricing arrangements exist between GBU and WBU or between CSS and other business units..." The lack of transparent transfer pricing between GBU and WBU is a concern as it is not clear which business unit is responsible for the losses accumulated in the contestable market by RBU and how the TAP is used.

Against the average electricity wholesale transfer price to RBU of $158/MWh referenced above, the IMO has stated that the average cost of energy + capacity traded through the WEM in 2013-14 was $120/MWh.[12] These figures show that Synergy has been carrying excess actual wholesale energy costs estimated to be in >$200 million per annum. This shows a significant under-recovery of costs in the contestable market where Synergy prices customers at SRMC.

One way to look at this picture: If the FY 2014-15 TAP subsidy of $386 million is applied to the estimated retail franchise segment sales volume, the average unit rate for the TAP will be at $60/MWh, which significantly exceeds the differential between the reported Synergy average wholesale transfer price and an efficient LRMC for the franchise segment as determined by ERA and AER. This implies the subsidy has been at least partly allocated to the contestable customer segment.

But when applied to both franchise and contestable customers (ie. total retail sales), the TAP subsidy equates to a unit rate of $38/MWh, which more closely matches the differential between the wholesale transfer price and an efficient LRMC. **This confirms that all Synergy retail sales (both franchise and contestable) have received a subsidy for excess actual wholesale costs in the last several years.**

These figures corroborate Perth Energy's view that the TAP has been applied across the wholes Synergy customer base and should be re-allocated to all incumbent retailers in the WEM according to market share on an annual basis, or paid directly to electricity consumers to allow them to choose their own supplier.

Another significant source of cross-subsidy is the way Synergy allocates the cost of Capacity Credits, which have been disproportionately applied to the franchise segment.

The ERA Review states that, based on the method of allocation of capacity credit charges employed by Synergy, its contestable contracts account for 955 MW of its total Independent Reserve Capacity Requirement (IRCR) in the 2012-13 Capacity Year. This represents 22% of Synergy's total IRCR. The IMO sourced data in Table 2 show that the actual (metered) contestable segment Reserve Capacity Requirement for FY 2012-13 accounted for 1133 MW or 27.6% of Synergy's IRCR. Both ERA and IMO figures indicate a disproportionately small allocation of IRCR to the contestable segment considering this segment made up 38.5% of total Synergy GWh sales.

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[12] IMO Submission to Electricity Market Review Discussion Paper, September 2014.

The capacity cost allocated to the contestable segment is inexplicably low, at $49/MWh, while that for the franchise segment is $79/MWh for 2012-13. The difference in load factor between the two segments does not justify this cost gap. The volume and price over-allocation to the franchise segment resulted in 72.4% of total capacity charge assigned to this segment.

In addition, Table 2 over-estimates the non-Synergy share of the market. This share includes such arrangements as applied to the Karara mine that uses a nominal "retailer" entity to front a direct sale from Synergy to the load. Rather than the >6000 GWh volume attributed to non-Synergy, our estimates are that true non-Synergy sales are closer to half that figure.

This means the share of franchise segment to total Synergy sales would be around 55% and not 62% as implied in Table 2. This would make it evident that there has been significant over-allocation of capacity costs to the franchise segment to justify receipt of the TAP.

The ERA Review also notes that Synergy's cost allocation for retail operating costs is based on customer numbers rather than volume consumption, and this will likely over-allocate costs to the franchise segment.

Further, Synergy carries average retailing costs of $120/customer, compared with an efficient cost to serve benchmark for residential customers of $80/customer.[13] [14] With a million residential customers in SWIS, this equates to $40 million of excess costs within Synergy's retail operations.

Being more efficient would go a long way towards mitigating any price rise pressure in the contestable market when the Government decides to terminate the TAP.

In total, the Government is covering Synergy's excess costs and cross-subsidies and absolves it from recovering full costs in relation to the utility's operation in the contestable market. The Government is either 1) assisting Synergy to undercut the utility's competitors by the full industry margin, or 2) permitting Synergy to remain highly inefficient in its supply to the franchise market.

Perth Energy does not believe either is the intention of Government and we seek urgent Government review of the TAP subsidy and how it should be allocated to eliminate discrimination against private participants and franchise consumers.

Pre-conditions for RCM Change

The above exposition shows that the Position Paper is very limited in its scope and requires a much more expansive and integrated look at the RCM in the context of the WEM structure as a whole and the interplay between the RCM and the unintended anti-competitive effects of Government policy.

Prior to contemplating any change to the RCM the Government should address these critical issues:

1. **Sovereign risk**
2. **Excess capacity**

[13] *Synergy's Costs and Electricity Tariffs*, Economic Regulatory Authority, July 2012.
[14] Synergy Annual Report 2012-13.

3. **Interrelationship between RCM and Balancing Market**
4. **Synergy subsidy, and**
5. **Market power.**

The following steps need to be taken prior to address the above issues:

- Introduction of Full Retail Contestability – we have shown in this submission that the concerns surrounding FRC and arguments for delaying FRC are invalid, particularly with regard to the risk of higher TAP faced by Government or higher tariffs faced by small business and residential consumers. If the TAP is based on an optimal LRMC structure then it cannot go up just because of FRC implementation. In any case, we have shown that the TAP is not needed in the franchise market.
- The price caps in the Balancing Market be raised to levels that would work with any chosen degree of volatility in the RCP. DSM should be allowed to earn very high energy prices whenever it is called in exchange for not being the RCP, which is formulated for generation plant delivery.
- As long as Synergy is not disaggregated to effectively carry generation portfolios with each being less than 30% of total WEM capacity, Synergy should continue to be subject to the SRMC bidding rule.
- DSM should be shifted from the capacity market to the Balancing Market as the Market Rules specify the RCP to apply to defined peaking capacity (160 MW open cycle gas turbine).
- Synergy be required to bid by facility, not as a portfolio, like any other generator in the WEM; this will flush out the economic viability of each plant and help Synergy consider retirement of oldest, most inefficient baseload plant under rational business operation.
- Together with facility bidding there should be an increase in availability standards to incentivise old inefficient plant to retire if it can no longer meet those standards economically (eg, on maintenance costs).
- Mothballing plant that is not viable to run due to high fuel cost and excess generation – eg, Cockburn 1 CCGT which is operating at <30% capacity factor due to high gas price despite being commissioned as a base load generator. Its mothballing will raise the capacity factor of other Synergy plants to help the latter run more efficiently.
- Muja AB, which was refurbished on the back of the Varanus crisis and gathering mining boom, should be closed down ASAP. Since the gas crisis, the industry has moved on and Muja AB has satisfied its original purpose as a hedge instrument for the State, and should now be closed.
- The effect of removing DSM (560 MW), retiring Muja AB (220 MW) or Muja C (385 MW), mothballing Cockburn 1 (239 MW) and some Pinjar units (36 MW each), would bring the generation portfolio close to the RCT for the period 2015-16 to 2020-21 as shown in Charts 7a, 7b and 7c. After 2020-21, Cockburn 1 could be reinstated if need be to delay new investment in generation to meet the RCT.

Chart 7a: Achieving Supply Demand Balance by excluding DSM & closing Cockburn 1 & Muja AB

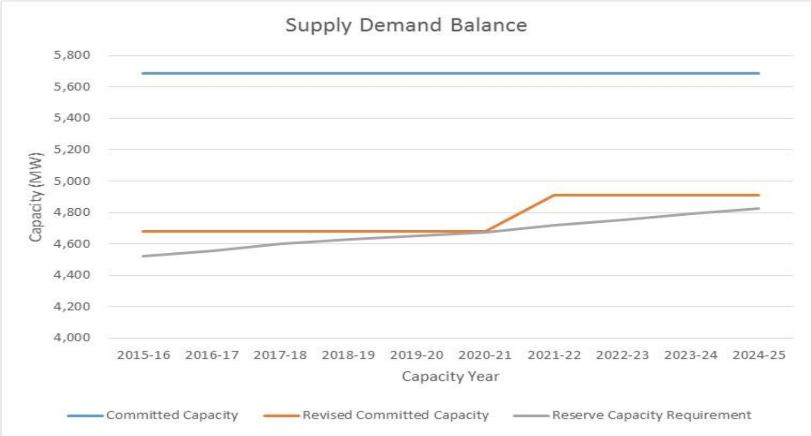


Chart 7b: Achieving Supply Demand Balance by excluding DSM & closing Cockburn 1 & Muja C

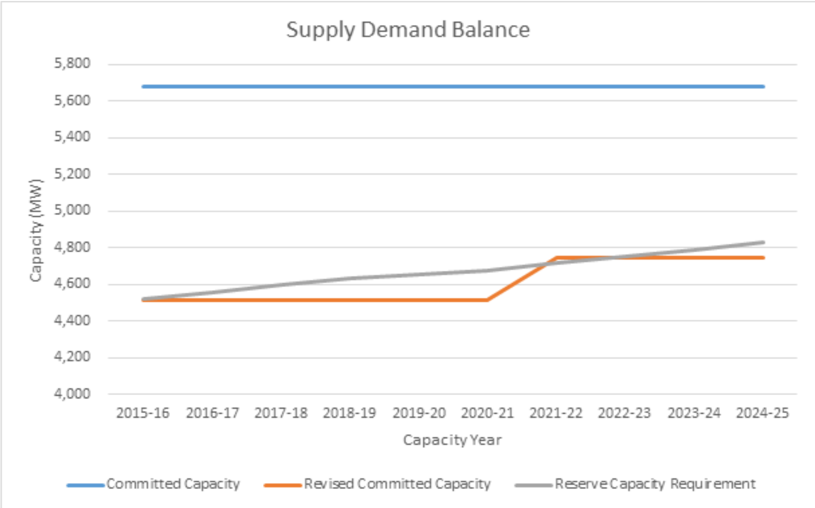
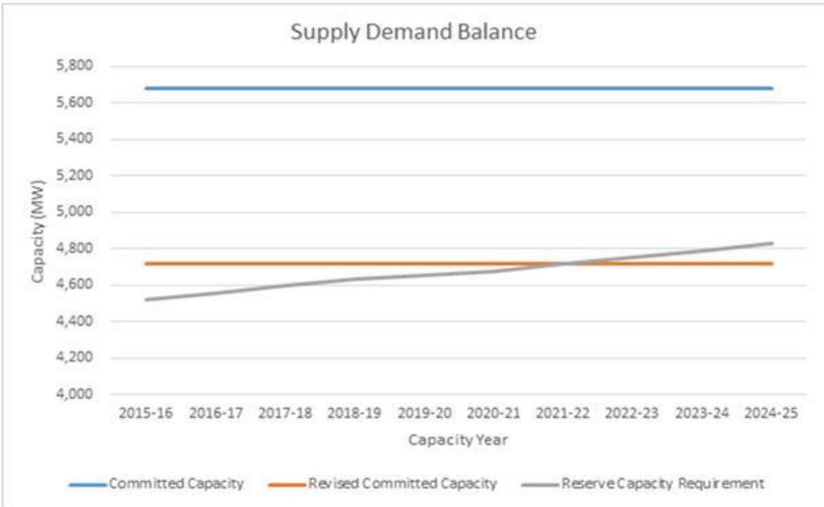


Chart 7c: Achieving Supply Demand Balance by excluding DSM & closing Muja C & Pinjar Unit



Source: IMO SOO 2014 data

Key practical reform steps that can contribute to the optimal plant mix in the WEM, resolve the excess issue and encourage competitive outcomes are:

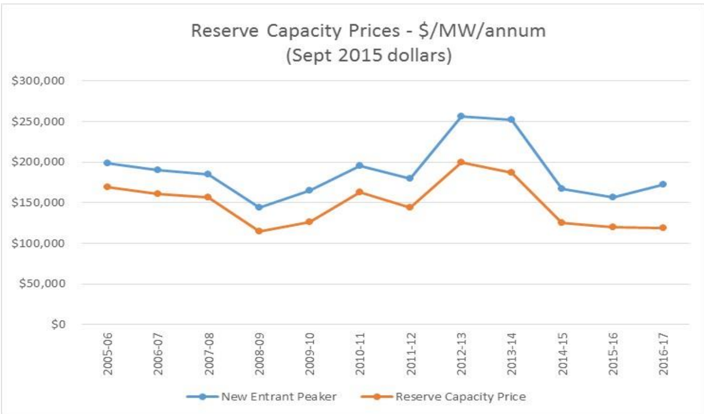
- To implement a dynamic capacity refunds system whereby the level of capacity refunds is reflective of system conditions and the "true" value of capacity at that time (i.e. cost of shortages). Capacity refunds should continue to be paid to retailers (and therefore customers) as retailers have not received the supply reliability paid for.
- To ensure that the Federal Large Renewable Energy Technologies (LRET) do not drive excessive investment in renewable generation in the WEM, the WA Government should direct Synergy to procure Large-Scale Generation Certificates (LGCs) from the NEM.

Plant Closure

Plant closure by Synergy should be the central concern of Government. As laid out above, this is the only efficient solution to take with regard excess capacity.

Chart 8 shows that the RCP is 31% below new entrant levels for a new peaking plant in the 2016-17 Capacity Year. It has fallen by almost 30% in real terms since 2005-06. It has fallen by over 40% in real terms since 2012-13 despite the $A having fallen against the $US by 30% since. A lower $A leads to higher power plant and equipment costs given the high import component.

Chart 8: New Entrant Peaking Capacity Cost versus RCP



Source: IMO data

Due to excess baseload generation, balancing energy prices have been depressed, exacerbated by Collgar Wind Farm's relatively high capacity factor overnight. The net loss to Synergy of low RCP and low balancing energy prices, set against Synergy's higher than RCP capacity price payable to its IPP suppliers under long term PPAs, is significant. This loss is the more pronounced considering Synergy also has to back off its coal plants at night to accommodate Collgar and Bluewaters power stations or receive deeply negative price for its spilled energy.

This is setting the industry up for significant instability in the near term given that contestable customer pricing is mostly unhedged and so low that Synergy is incurring significant losses. This situation will be requiring long term TAP support at a time when the Government wants it cut back.

Synergy should be focused on closing unneeded capacity and improving margin for the balance of its portfolio to ensure a sustainable market where cost reflective pricing is the rule rather than the exception. This will avert the inevitable price shock to contestable customers in the near future.

The decision to refurbish Muja AB was made in the fall-out of the Varanus crisis that cut gas supply to the SWIS by one-third. It was a precautionary measure that called for a coal plant's life to be extended for a short period and provide a baseload buffer against the gathering mining boom.

But circumstances have since changed with the resources sector down-cycle and the gas emergency management strategy implemented. A similar crisis to Varanus will not have anywhere near the same impact as in 2008. The once high WA feed-in-tariff of 40c/kWh and Federal subsidy programs for solar PV, such as the Small Technology Certificates, have also eaten into the historical grid peak demand growth, putting pressure on baseload coal plants to retire.

The purpose of refurbishing Muja AB has been met and the plant is no longer required. The Government should have no case to answer if it were to close down this plant due to its high operating costs and low fuel conversion efficiency.

Cockburn 1 was predicated on it being used as a base load generator but it is operating at a low capacity factor of around 30% due to high gas cost and excess coal plant. Removal of the Carbon Tax has made coal generation more economic than gas generation for baseload supply. Even if the tax had continued it would have required it to be $60/ton for Synergy to shift from coal to gas.

The new high efficiency gas turbines (HEGT's) that Synergy installed recently in Kwinana are better able to provide ancillary services than Cockburn 1 will ever be. Synergy's portfolio gas price will increase when Gorgon supplies commence in 2016, making Cockburn 1 even less economic.

Cockburn 1 might be re-activated when gas price falls and/or grid electricity demand increases sufficiently to justify its operation.

There should be no net capacity cost impact on consumers as a whole, as the total bucket of capacity cost at RCT will not change with plant closure.

Plant retirements will help restore market balance, avoid the high risk of upside price shocks to contestable customers and provide a better platform for undertaking further market structural reform such as Synergy disaggregation and sale.

Plant closure is consistent with the EMR objectives and should be urgently pursued by Government.

RCM Regime Options

Once the market is in balance, the options for reforming the WEM would essentially be:

1. Changing the RCM so that the RCP would be more "market" driven instead of process driven as currently the case with an administered price; or
2. Scrapping the RCM altogether to transit the WEM to an energy-only market like the NEM.

If the RCM is retained, as stated by the Minister at WA Power & Gas conference in March 2015, and if such retention is to work, then the following conditions for an RCP regime will need to be met:

- RCP methodology must take account of the reality of non-recourse project finance or any other form of finance – a price floor in any one year must be set at the Market Rules assumed debt repayment level to keep a new plant from financial default. This price floor can use the "efficient" gearing level and WACC as determined in the RCP formula.
- This price floor is not to simply de-risk projects for investors but reflects the "infrastructure asset" nature of generation capacity. Just as a major private toll road cannot be built on volatile year on year toll charges, a private power station cannot be built based on academic assertion that such an infrastructure asset could be subject to rapid price response akin to a low tech commodity. This thinking will ensure the State will continue to write 20-30 year PPAs to entice capacity entry.
- RCP outcomes must have some systemic predictability. Currently investors can project a capacity price using the determination methodology in the Market Rules. In the NEM, price forecast can be based on a long history of the wholesale energy price movement.
- WEM's history is neither long nor untainted by Government policy intervention. If the RCM is moved from its current administered pricing, it will not be possible for investors to forecast a capacity price given the significant distortions in the market.

A "transition" regime with a -5 price curve is not transitional but will cause the same shock to the market as if the market goes straight to an Auction regime. A change from -1 price curve has no basis and represents a central planning guess of how price and quantity would interact.

If and when all the pre-conditions are achieved, the WEM could adopt an Auction regime to work with the current -1 price curve that has been rationally set for risk allocation purposes. This will provide a less volatile framework for an Auction regime to operate.

An Auction regime with a steep price as outlined in the Position Paper would also face the following serious practical problems for the WEM that, if left unaddressed, could lead to a market collapse:

- The lumpy generation capacity market is prone to short term imbalance that could easily generate binary pricing (zero or cap) for some years.
- A large power station on a bundled PPA with a large (eg. mining) load will likely bid in at $zero to ensure certification – if enough plants bid on this basis the clearing price may be so low as it cannot work for most plants.
- This risk of basement pricing is high in the WEM due to the large concentration of capacity in Synergy, with plants held under long term PPAs expected to bid in around $zero as this price would not be the price they would receive but the PPA price. They just need certification.
- Capacity concentration would also give Synergy the ability to set a price stack by it bidding mostly around $zero but with, say, one plant bid in at a price high enough for Synergy to make money for its uncontracted capacity from that single clearing price. This strategy could force out existing private plants without a Synergy contract and prevent new entry.
- Multiple rounds of auction in the same year would be needed so that a supply stack could be formed with multiple clearing prices for must-run base load plant, base load but not must-run, mid-merit, peaking, super peaking and more, similar to an energy supply stack.

- Each clearing price would have to be offered for a long term, even though auctions could be called every year. This means each new auction price would apply to new capacity, not existing capacity, the latter facing a new auction price only on expiry of its existing RCP term.
- The RCP would need to be set in a band, with the minimum price being debt coverage under project finance, and maximum price being capped at a level that would reflect symmetry with the price floor and vice versa. Eg, if the price cap is limited to 150% of MRCP – which should also be the RCP as the current 15% automatic discount factor has no basis and should be removed – the floor price must equate to 1/150%, which is 67%, of the RCP.
- Coincidentally, this suggested floor price based on the suggested cap in the Position Paper turns out to be consistent with a floor price level required to prevent debt default using the debt parameters in the RCP determination formula.
- It can be taken for granted that a change of RCM to an auction regime would mean a hiatus in new capacity entry until the market could work out an alternative way of valuing capacity to the RCP. Cap products such as exist in energy-only pool markets could take 5-10 years to develop due to the need for historical data. An initial transition period should be realistically long to allow new measures to be used to accommodate a fundamental change to WEM.

Whether or not an Auction regime would be adopted in the future, the most efficient price slope for the WEM is a unity downward-sloping curve as discussed above. It would be a matter for the Government to choose the degree of "hybridness" for the WEM, ie. in accord with the fundamental economic relationship between the capacity market and energy market within the continuum of market design from a capacity-only to an energy-only structure: at what level of supply reliability does the Government wishes the WEM to have.

In terms of practicality it would be extremely difficult for a capacity market to work without an upper price limit and a lower price limit. By definition, if there were no price limits then there would be no capacity market, or there might be one but only in name.

For a capacity market to work, ie for merchant plants to be able to be priced for financing purposes, a price floor must be present. Otherwise, the cost of capital would be unworkably high. As a result, an Auction regime's price band should be based on the following:

Price Cap

An appropriate price cap should be based on the gross cost of new entry (gross CONE). That is, the annualised capital costs of new plant that is required to meet future load growth. Currently, the MRCP (equivalent to CONE) is based on the cost of building and financing a 160 MW Open Cycle Gas Turbine (OCGT). However, System Management can testify that smaller units are better suited to the WEM so a different plant type should be considered.

Price Floor

An appropriate price floor should be set theoretically at a symmetric level to the price cap – so that risk / return is correctly related – and practically at a level that enables a peaking generator to cover debt servicing and fixed O&M costs (no return to equity holders). For instance, this level can be estimated at around $116,000/MW based on the nominal interest rate used in IMO's MRCP model for 2017-18 and a leverage of 60% to reflect commercial reality. This minimum price will continue to deter further investment in peaking plant since

WEM has not seen any real entry (assuming there have been expressions of interest, which there have been none either) in the last few years with a higher RCP.

The $116,000 price floor is relatively consistent with the level at which a symmetrical application to the price cap factor is used to determine a floor. For the above suggested factor of 0.67 of MRCP, the derived price floor for 2017-18 could be $164,600 x 0.67 = $110,282 and for 2018-19 $156,400 x 0.67 = $104,788.