Government of Western Australia
Department of Treasury

# Improving Reserve Capacity pricing signals – a recommended capacity pricing model

## Final Recommendations Report

**Department of Treasury | Public Utilities Office**

**7 February 2019**

# Disclaimer

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# Abbreviations

| Term | Definition |
|---|---|
| AEMO | Australian Energy Market Operator |
| BRCP | Benchmark Reserve Capacity Price |
| LOLP | Loss of Load Probability |
| Market Rules | Wholesale Electricity Market Rules |
| NEM | National Electricity Market |
| RCM | Reserve Capacity Mechanism |
| SWIS | South West Interconnected System |
| VCR | Value of Customer Reliability |
| WEM | Wholesale Electricity Market |

# Executive Summary

This report outlines recommended reforms to the reserve capacity pricing and procurement arrangements in the Wholesale Electricity Market.

Deficiencies in the capacity pricing model have been recognised as far back as 2012 when the then Independent Market Operator instigated a review of the Reserve Capacity Mechanism. The primary problem has been a tendency toward significant over-procurement of capacity, with the level of excess capacity over the market requirement reaching 23 per cent by 2016-17, at an estimated cost to electricity consumers of around $116 million.

The electricity market reform process conducted under the previous government recommended introduction of a capacity auction to replace the existing administrative process for procuring and pricing capacity. Changes to the Wholesale Electricity Market Rules, implemented on 31 May 2016, introduced new transitional arrangements pending the development of a detailed capacity auction design. The Market Rule changes included progressive adjustments to the capacity price curve to better reflect the value of incremental capacity and a new arrangement for remuneration of demand side management capacity resources.

The high level of excess capacity has only been reduced by Government intervention, not by self-adjustment within the capacity market. The proportion of excess capacity in the market has reduced to 4 per cent for the 2018-19 Capacity Year.

The workability of a capacity auction in a small market like the South West Interconnected System has been a major concern of industry participants since it was proposed. Consequently, the Minister for Energy requested the Public Utilities Office to undertake a further review to provide advice as to whether a capacity auction is still the most appropriate approach. This Final Recommendations Report outlines the Public Utilities Office's advice in response, with recommended reforms to the capacity pricing and procurement arrangements.

The reforms are intended to ensure the capacity pricing model better signals the economic value to the market of incremental capacity when supply is tight, as well as when it is in excess. The current capacity pricing arrangement is deficient in both respects.

The Public Utilities Office evaluated three alternative capacity pricing models that included a modification of the current administered capacity pricing arrangement, a reliability obligation approach and a capacity auction. A consultation paper released by the Public Utilities Office in April 2018 outlined these three approaches and sought comments from industry participants to inform development of recommendations as detailed in this report.

Alternative approaches to capacity procurement considered as part of the review process were determined to be more costly to establish and administer, and with significant market power concerns that would require intrusive regulation, largely eradicating the benefits associated with a more market-based approach to reserve capacity pricing. It is noted that all international capacity markets considered as part of this review process have some form of administered component to ensure acceptable outcomes to industry participants and ultimately electricity consumers.

A Draft Recommendations Report released by the Public Utilities Office on 22 August 2018 outlined the proposed changes to the capacity pricing and procurement model, including retention of the current administered capacity pricing arrangement albeit with a sharper pricing curve. This Final Recommendations Report, informed by the consideration of stakeholder submissions on the proposed reforms outlined in the Draft Recommendations Report, outlines the Public Utilities Office's final position on these matters.

The evaluation informing these changes was based on three core considerations, simplicity of operation, susceptibility to market power and efficiency of pricing outcomes

The recommended capacity price curve will continue to be based around the benchmark cost of an efficient new entrant technology and comprise the following three points, joined in a linear manner using parameters consistent with those applied in international capacity markets:

- **Price Cap** – the capacity value associated with no capacity surplus, to be set at 1.3 times the Benchmark Reserve Capacity Price.
- **Absolute zero point** – the point where the amount of excess capacity is deemed to be sufficiently high for the capacity price to be zero, set at a 30 per cent level of excess capacity.
- **Economic zero point –** a level of capacity surplus and price at which no additional resources should enter the system under a very wide range of market conditions, set at a capacity price equal to 50 per cent of the Benchmark Reserve Capacity Price and at a level of excess capacity of 10 per cent, an increase from the level of eight per cent proposed in the Draft Recommendations Report.

Transitional arrangements are recommended involving a price band for existing generation facilities between $110,000 and $135,000 per megawatt (Consumer Price Index (CPI) adjusted) for a period of ten years. New entrants would have the option to take the "floating" capacity price in each capacity year or to lock in the price in the year of entry for five years. These measures are intended to assist existing generation assets in moving to a sharper capacity pricing regime and facilitate entry of new capacity resources by providing some revenue certainty in the early years.

The transitional pricing thresholds have been adjusted upwards from the levels proposed in Draft Recommendations Report of $105,000 and $130,000 respectively, in acknowledgement of stakeholder views as to the potential to more closely reflect the range of potential capacity price outcomes that would result without the recommended reforms.

It is intended that the Australian Energy Market Operator will first award capacity credits to new floating price capacity and existing capacity providers and, if an adequate level of capacity is not achieved, then award all capacity resources that opted for a price lock-in.

Demand side management resources can provide considerable value to an electricity system, meaning that it is preferable that these resources receive the same price as other forms of capacity. However, it is important to avoid over-rewarding this type of capacity resource and provide for greater harmonisation with requirements applied to other capacity types.

Accordingly, as part of a move to enable demand side management resources to receive the same capacity price as other providers, the Public Utilities Office is recommending that these resources be required to provide a Reserve Capacity Security deposit each year of capacity certification, equal to 25 per cent of anticipated annual capacity payments, in line with the existing requirements for new capacity providers. Annual random testing of each demand side program is also recommended.

The introduction of a much steeper capacity pricing curve in a market as small and concentrated as the Wholesale Electricity Market necessitates additional transparency around planned capacity retirements to allow the market time to respond and facilitate an orderly transition. In recognition of this requirement, the Public Utilities Office is recommending that all generators be required to provide three years of notice ahead of closure prior to the commencement of Capacity Credit Certification.

Implementation of these recommended changes to the reserve capacity pricing and procurement arrangements will occur at the same time as the development of other initiatives by the Public Utilities Office to give effect to broader improvements to the Wholesale Electricity Market. These initiatives will necessitate the consideration of further enhancements to the Reserve Capacity Mechanism arrangements, to allow it to remain effective in ensuring power supply security in the south west of the State.

# 1. Introduction

## 1.1 Background

The need for a reformed capacity pricing model was recognised as far back as 2012 when the then Independent Market Operator instigated a review of the Reserve Capacity Mechanism in Western Australia's Wholesale Electricity Market (WEM).

The primary problem with the mechanism was that it was leading to a significant over-procurement of capacity and this problem continued, with the level of excess capacity over the market requirement reaching 23 per cent by 2016-17 at an estimated cost of around $116 million.[1] The inability of the Reserve Capacity Mechanism to self-adjust the capacity supply-demand balance represents a serious design flaw with these arrangements.

The electricity market reform process conducted under the previous government recommended introduction of a capacity auction to replace the existing administrative process for procuring and pricing capacity. Changes to the Wholesale Electricity Market Rules (Market Rules) were implemented on 31 May 2016 to introduce new transitional arrangements pending the development of a detailed capacity auction design. The Market Rule changes included progressive adjustments to the capacity price curve to better reflect the value of incremental capacity and implemented a new arrangement for the remuneration of demand side management capacity resources.

However, the workability of a capacity auction in a small market like the WEM in the South West Interconnected System (SWIS) has been a major concern of industry participants since it was proposed.

In response to these concerns, in 2017 the Minister for Energy (the Minister) asked the Public Utilities Office to undertake a further review to provide informed advice as to whether a capacity auction is still the most appropriate approach. The Public Utilities Office was also asked to consider whether some other alternative pricing arrangement will provide a better outcome in overcoming the lack of price responsiveness to achieving a supply-demand capacity balance.

## 1.2 Scope of this report

This Final Recommendations Report outlines recommended reforms to the Reserve Capacity Mechanism following a review process conducted by the Public Utilities Office.

This report details the reforms the Public Utilities Office considers are necessary to the Reserve Capacity Mechanism pricing and procurement arrangements to support the future requirements of the WEM. The recommended reforms are intended to ensure that the capacity pricing model better signals the economic value to the market of incremental capacity. The recommendations outlined in the report have been informed by extensive stakeholder engagement and input.

[1] See Public Utilities Office, Position Paper on Reforms to the Reserve Capacity Mechanism, 3 December 2015.

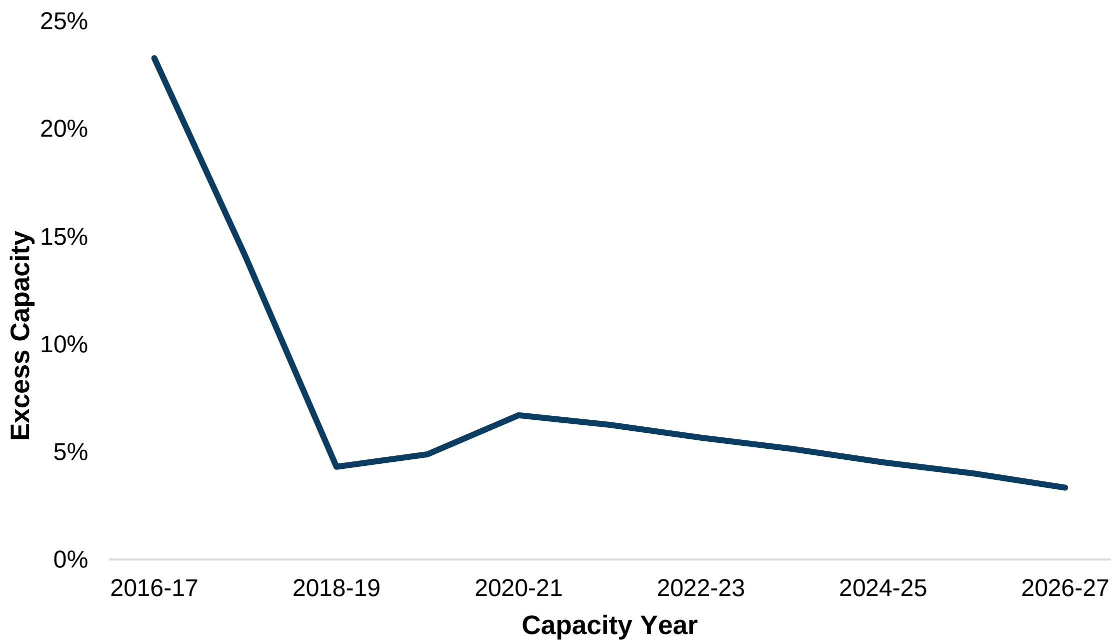
During the previous review of these arrangements that concluded in 2016, the amount of excess capacity was a primary focal point given concern about the associated cost pressures on electricity consumers. The allocation of cost and risk between consumers and investors through the Reserve Capacity Mechanism was also generally recognised as being deficient and this problem remains.

The high level of excess capacity in the WEM has only been reduced by the actions of Government and regulatory intervention, not by self-adjustment within the capacity market. The proportion of excess capacity in the market has reduced from a high of around 23 per cent in 2016-17 to 4 per cent for the 2018-19 Capacity Year. Australian Energy Market Operator (AEMO) projections indicate that with existing capacity commitments there will still be sufficient resources to meet demand over the coming ten years, with a modest level of surplus – see Figure 1.1 below.

As the market is shifting from a prolonged period of excess capacity to a tighter supply-demand balance, going forward, there is a need not only for new capacity investments, but that these investment be in the types of capacity that is required by the market.

The Reserve Capacity Mechanism must therefore provide effective price signals when supply is tight, as well as when it is in excess. As the current capacity pricing arrangement is deficient in both respects the reforms recommended in this report seek to address this problem.

**Figure 1.1: Excess capacity in the South West Interconnected System – 2016-17 to 2026-27 Capacity Year**




Source: AEMO, 2018 Electricity Statement of Opportunities.

The intent is to provide stronger pricing signals for efficient entry and exit of capacity, according to the needs of the market, while ensuring that system security and reliability objectives are achieved at least cost for consumers. It is also intended that implementation of the recommended reforms occur in an orderly manner that avoids undue financial disruption to market participants.

## 1.3 Consultation process

In undertaking the review, in April 2018 the Public Utilities Office published a consultation paper[2] seeking feedback on the merits of three approaches to capacity procurement:

- Option 1: Retained administered pricing under an improved arrangement;
- Option 2: A retailer led contracting model supported by a bulletin board trading mechanism; or
- Option 3: A capacity auction.

Industry participants were also invited to propose additional options. Fifteen submissions were received in response to the consultation paper indicating broad support for retention of an improved administered capacity pricing arrangement.

The Public Utilities Office published a Draft Recommendations Report outlining a proposed capacity pricing and procurement model on 22 August 2018. Fourteen submissions were received in response to the report indicating broad support for the proposed reforms with one exception. The supportive submissions contained several recurring themes:

- High level of support for the general shape of the proposed administrative price curve, including use of a straight line to link the price cap, economic zero point and absolute zero point. The feedback received on administrative pricing focused on the appropriate setting of price cap, economic zero point and absolute zero point on the price curve.
- Submissions were divided on the proposed treatment of demand side management capacity resources. Some supported retention of the existing pricing arrangements, while others were supportive of proposed reforms albeit that some of these submitters considered the strengthened security deposit requirements as being unnecessary.
- The proposed transitional arrangements were broadly supported, with commentary being focused on setting of the floor and ceiling of the price band.
- Near unanimous support was received for commencement of the reforms as part of the 2019 Reserve Capacity Cycle.

Section 4.2 of this report provides more detail on specific comments and concerns raised in the submissions.

[2] The Consultation Paper: Improving Reserve Capacity pricing signals – alternative capacity pricing options, Draft Recommendations Report: Improved Reserve Capacity pricing signals - a proposed capacity pricing model and submissions received in response to these papers are available at www.treasury.wa.gov.au.

# 2. A sustainable capacity pricing arrangement

## 2.1 Capacity pricing fundamentals

This section addresses issues relevant to a more efficient and effective capacity pricing arrangement. A particular focus is whether capacity availability should be rewarded at times other than the traditional 10 per cent probability of exceedance system peak, which to date has underpinned derivation of the Reserve Capacity Target and capacity credit allocation. Some market participants have indicated that a change of this nature is necessary to accommodate the new profile of daily electricity demand driven by roof top solar PV penetration in the SWIS.

The relevant matters are as follows.

- What is capacity?
- How should capacity be remunerated, i.e. what are providers of capacity being paid for?
- What functions should a sustainable capacity price curve seek to fulfil?
- What problems with the current capacity pricing arrangements must the recommended price curve resolve?
- Will the capacity price curve encourage a suitable mix of generation facilities over time?

### 2.1.1 What is capacity and how should it be remunerated?

In electricity markets the term "capacity" is often used interchangeably with "adequacy", presuming that capacity is a source of power system adequacy such that sufficient resources exist at any point in time to meet electricity demand if called upon to do so. Capacity resources are remunerated for being present in the electricity system, regardless of whether they are dispatched.

A related concept is reliability, meaning that capacity resources are "available" to meet demand when required. In other words, electricity can be generated from enough of the capacity resources that are available so that demand is actually met within the probability established by an overall reliability standard. For a power system to be reliable, those who own capacity resources must be prepared to commit them to use and be capable of being dispatched, when and if called upon by the system operator. In the WEM capacity requirements incorporate both the adequacy and availability of resources.

Over time, the financial incentives for reliability, as opposed to adequacy, principally relate to remuneration received from actually being dispatched against any penalties associated with being unavailable at a time of need. A capacity resource is remunerated for both "being there" and "being available". The times at which a resource is required to be available are governed by the reliability standard set for the power system, as further discussed in section 2.3.2 below.

Remuneration of resources in a capacity market must address two fundamental problems in the form of "missing money" and "missing markets".

### *The Missing Money Problem*

An electricity market needs to ensure capacity facilities are adequately remunerated for availability, meaning that there should be no "*missing money*" for capacity resources required to maintain the reliability standard.

Most electricity markets impose energy price caps to limit real time price increases for consumers, mitigate market power and prevent excessive price volatility. This is also the case in the WEM, which imposes price caps on energy bids. This constraint on revenue gives rise to a missing money problem.

Missing money is simply the gap between what can be earned by an investor from operating in the energy and ancillary services markets[3], and the level of remuneration that the investor requires to actually invest in a capacity resource.

A capacity mechanism is a means of recovering this revenue deficiency. Such an arrangement does not assure that individual capacity investments will be profitable, rather it aims to ensure that, in aggregate, it is profitable to maintain at least the amount of supply and demand side management resources deemed to be adequate according to the established reliability standard. The capacity pricing model must deliver this outcome.

The determination of the amount of missing money through a capacity pricing mechanism cannot be precise. Rather, it necessitates a balance between over or under-compensation. A capacity pricing mechanism that over-compensates will result in excess capacity beyond the level necessary for system reliability, resulting in higher electricity costs. Conversely, under-compensation risks not attracting enough capacity to ensure the reliability standard can always be met.

### *The Missing Markets Problem*

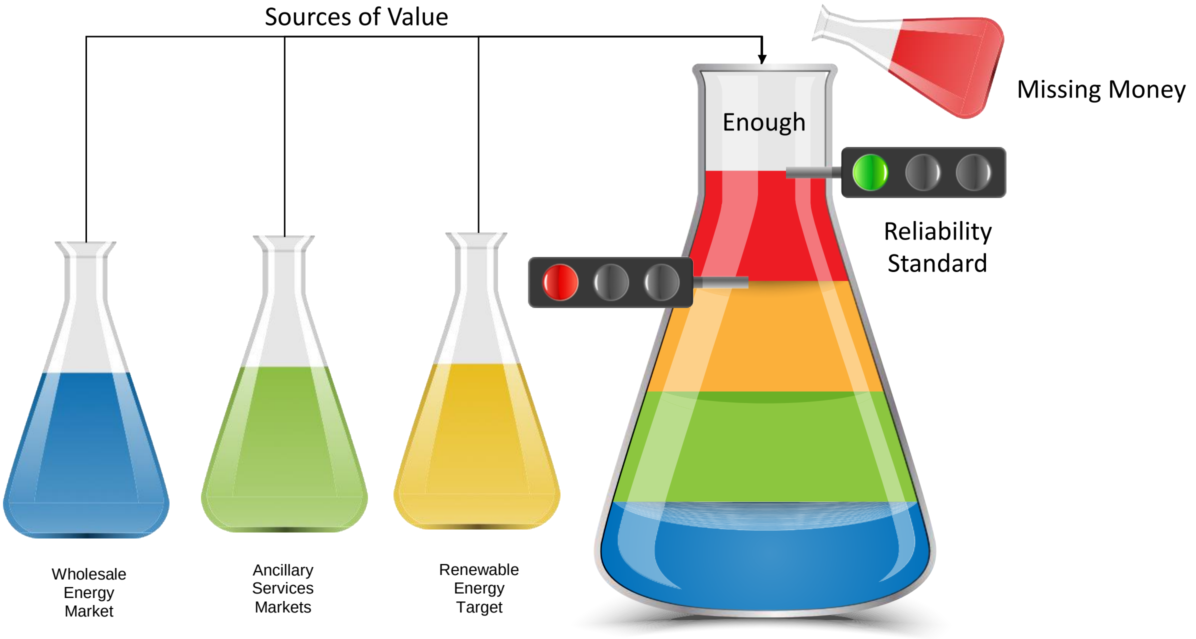
The *missing markets* problem emerges when revenues to generators are *theoretically* sufficient, but not perceived or expected to be sufficient, or sufficiently reliable, in a practical sense. Also, externalities in the form of additional sources of value or costs, may not have been incorporated in investment decisions, potentially leading to a sub-optimal generation mix or inadequate total resources.

The problem, in particular, arises when even if markets technically exist, trading within them may be very thin or they may be dominated by a monopoly/oligopoly or by monopoly/oligopoly structures. These limitations to pure market functionality can equate to a missing market in terms of potential impact on commercial investment incentives or outcomes.

Whether it is the demand curve shape in an auction, or a contracting framework to meet obligations in a reliability options approach, or the slope of an administered pricing curve, the same issue arises. Every capacity market globally uses an approach by which outcomes are managed within some acceptable, administratively determined bounds.

[3] For the purposes of this report, ancillary services markets includes the procurement of ancillary services through other means (e.g. contract arrangements).

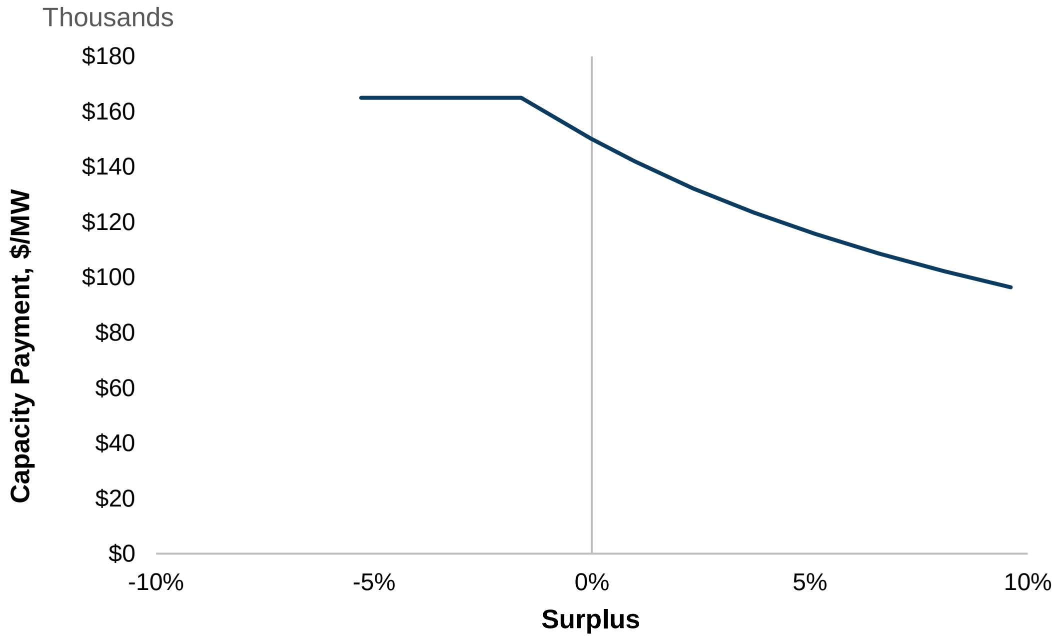
**Figure 2.1: Capacity mechanism addresses both the missing money and missing markets problems**




## 2.2 Deficiencies of the existing capacity pricing arrangements

The Reserve Capacity Price is currently determined each year pursuant to a formula in the Market Rules.[4] The existing capacity price curve is shown in Figure 2.2.

**Figure 2.2: Current WEM capacity pricing curve**




4 Market Rules clause 4.29.1.

Experience across global capacity markets suggests that to be sustainable, a capacity price curve should fulfil several key functions, as listed in Table 2.1. Achieving these objectives simultaneously requires a suitably dynamic mechanism with a clear allocation of risk; definable parameters that can be reasonably referenced, benchmarked, or estimated; and a mechanism supported by effective monitoring of the exercise of market power.

The assessment detailed in Table 2.1 shows that the current administered capacity pricing and procurement arrangements do not rate well compared to these criteria:

- In the WEM, there is no competitive rivalry for capacity provision and the relatively flat slope of the pricing curve across high levels of excess capacity means that consumers continue to reward capacity well above its economic value. The Reserve Capacity Mechanism is essentially absent of pricing signals that reflect the value consumers place on reliability at various levels of supply-demand balance.
  - The mechanism is not capable of self-adjustment by sending strong signals for plant retirement when there is excess capacity. The recent withdrawal of capacity in the WEM has been in response to a Government direction to Synergy and reforms to remunerate demand side management resources differently to other forms of capacity.
- Conversely, there is the risk of inadequate incentives for new capacity when needed.
  - The price cap of 1.1 times the Benchmark Reserve Capacity Price (BRCP) is reached only when there is a capacity shortfall. Given the timelines for development of new capacity, this signal is likely to be too late to incentivise the delivery of capacity required to meet the shortfall.

**Table 2.1: Assessment of current capacity pricing and procurement arrangements against global capacity market benchmarks**

| | Benchmark | Existing Capacity Pricing Model | Rating |
|---|---|---|---|
| Price signal for investment | Capacity price must reach a level sufficient to incentivise new capacity at any point where such capacity is anticipated to be needed. | Existing price curve provides inadequate price signals during tight supply-demand balance. | ✘ |
| Appropriate exposure to risk | Capacity pricing arrangements should expose participants to risk to the extent that they have a robust incentive to perform reasonable due diligence on whether or not to invest in new capacity or contract with existing capacity resources. | Existing price curve lacks incentive for participants to contract to hedge against high or low capacity prices. | ✘ |
| Signals for capacity withdrawal or retirement | When persistent excess capacity exists the capacity price should send a credible signal that capacity should be retired or withdrawn from service. | Recent experience suggests that the existing price curve is still too shallow to send effective signals for the capacity market to adjust to balance at higher levels of excess. | ✘ |

| | Benchmark | Existing Capacity Pricing Model | Rating |
|---|---|---|---|
| Same capacity price for equal qualifying resources | Capacity price should work equitably with all forms of capacity (supply and demand) that meet accepted minimum performance targets, including developing technologies, such as energy storage resources. | Reserve Capacity Mechanism arrangements apply a different capacity price to demand side management resources. Also, certain storage resources, such as large scale batteries, would not qualify for capacity certification under the Market Rules. | ✗ |
| Capacity price should only compensate credible, verifiable resources | The Reserve Capacity Mechanism should compensate only credible, verifiable capacity under all scenarios deemed relevant to the establishment and achievement of the resource adequacy target. | The Reserve Capacity Mechanism currently achieves these requirements through certification, security deposits and penalties for non-availability. | ✓ |
| Promotion of the most appropriate capacity mix over time as demand profiles change | The capacity price curve should accommodate a changing demand profile over time. In particular, it should cope with the possibility that a focus on resource adequacy primarily to meet system peak demand may at a future point in time not be the most relevant means of considering resource adequacy. | The Reserve Capacity Mechanism currently achieves this requirement through interaction of the two components of the Planning Criteria. | ✓ |
| Binding contract against exit | The Reserve Capacity Mechanism should form a binding contract to avoid the possibility of proposed capacity resources collecting reserve capacity payments and subsequently exiting the market without risk or penalty, in a manner that compromises replacement capacity resources being developed in a timely manner. This is particularly relevant to demand side management capacity resources, which generally face lower entry and exit costs. | Reserve Capacity Mechanism has limited transparency on planned capacity retirements. | ✗ |

The recommended capacity pricing arrangement as outlined in this report is intended to address the deficiencies listed above. Section 5.2 provides a checklist as to how the recommended reforms improve on the delivery of these benchmarks.

## 2.3 A suitable mix of capacity resources

The capacity pricing arrangements within the WEM are under consideration at a time of considerable debate about the impact of increasing penetration of intermittent (renewable) energy resources and a changing profile of daily electricity demand. Some submissions made in response to the Consultation Paper argued that the traditional system peak is no longer when the power system is most exposed to the risk of a supply shortfall. These submissions, correctly, note that the rapid uptake of roof top solar PV facilities is pushing back the daily peak, reducing daytime net demand and steepening the evening ramp-up in electricity consumption.

This consideration of system adequacy outside the traditional (summer) system peak warrants, according to some participants, a different mix of capacity and, therefore, a capacity pricing arrangement that rewards contributions a resource makes to system reliability at these times. This approach implies that capacity should have a different value depending on the type of technology that delivers it.

The Public Utilities Office considers the Reserve Capacity Mechanism, as currently designed, will enable the capacity mix to respond to changing demand dynamics. As such, the capacity pricing methodology does not need to change and should continue to be based on system adequacy as defined by the reliability standard.

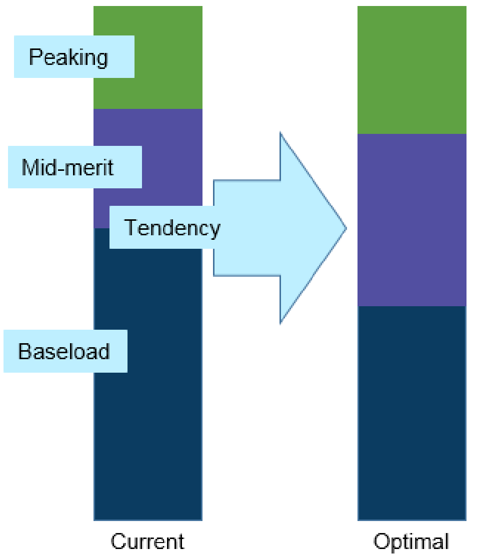
There are two ways in which the Reserve Capacity Mechanism will drive the most suitable capacity mix:

- through the interaction between the capacity, energy and ancillary services markets; and
- by the reliability standard itself.

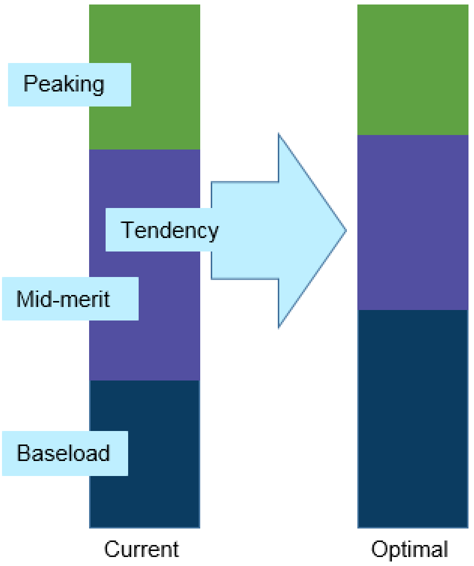
### 2.3.1 Inter-relation of the capacity, energy and ancillary services markets

The capacity price must compensate a capacity resource to sufficiently address the missing money from participation in the energy and ancillary services markets. The Reserve Capacity Mechanism currently achieves this by basing a capacity price curve on the missing money for the marginal capacity unit. While this marginal facility is currently defined as an open cycle gas turbine, the technology of the marginal capacity unit could change over time.

At any point in time the WEM has a particular mix of capacity types, which is likely to differ to the optimal or least cost mix of capacity due to market imperfection. An important purpose of capacity, energy and ancillary service market interaction is to signal to investors how, over time, to invest in the appropriate generation sources to bring the actual mix closer to the optimal mix, as demand grows and changes, or as opportunities to add, displace, or replace capacity arise.




If the current mix is long in baseload and short in peaking capacity, the WEM would expect to yield relatively lower short-term energy (spot) prices due to abundant baseload plant setting the marginal energy clearing price. These lower energy prices should dissuade investors from building new baseload plant because of the higher capital cost of these capacity investments. As demand increases, the market would become short of peaking capacity before baseload capacity, meaning prices captured by a peaking unit would increase faster than average prices for a new baseload unit. Eventually, capacity prices will increase such that either peaking or mid-merit facilities, each with lower capital intensity than baseload plant, will be commercially viable. Gradually, the tendency will be to rebalance the generation mix towards an optimal level.




Conversely, for a market short of baseload capacity relative to the least-cost optimal mix, energy prices will increase because mid-merit or peaking capacity is required to meet load in many hours. Given the excess of peaking capacity, but shortage of baseload capacity (compared to the optimal level), energy prices will be higher in most hours than they would otherwise be with an optimal mix of resources. Even if the market has sufficient total capacity overall, higher energy market revenue can become sufficient to trigger baseload capacity investments, even if capacity payments are below the BRCP. The market will then shift from being short of baseload generation towards the more optimal level, and energy prices would come down in those hours when mid-merit or peaking capacity would otherwise have been required.

The combined overall effect of the market arrangements using combinations of capacity, energy and ancillary services pricing, should guide capacity investment towards the optimal mix over time. As long as whatever is "short" is allowed to increase sufficiently in value (price), and whatever is "long" is allowed to decrease sufficiently in value, the investment signal will balance the need for less expensive pure capacity, more expensive capacity with higher thermal efficiency, and more flexible generation technologies.

The effectiveness of this investment signal is reliant on effective market design. The Public Utilities Office recognises that the current ancillary market arrangements appear to be deficient in providing price signals for provision of particular energy services to support power system security, such as inertia, spinning reserve, frequency response, etc. Reforms to address these deficiencies form part of a separate component of the WEM reform program, involving assessment of the types of ancillary services likely to be required in the South West Interconnected System (SWIS) and the form of market arrangements necessary to support delivery of these services.

The effects of differing pricing combinations across the capacity, energy and ancillary services markets on capacity investment and operation are detailed in Table 2.2.

**Table 2.2: Triangulation of the capacity mix**

| Capacity Price | Energy Price | Ancillary Services Value | Optimal eventual investment response |
|---|---|---|---|
| Low | High | Low | Even with lower capacity prices, new baseload capacity may capture energy value required to build. Otherwise the investor will wait until the capacity price rises enough such that, in combination with higher energy prices, a baseload technology can be contracted and committed. |

| Capacity Price | Energy Price | Ancillary Services Value | Optimal eventual investment response |
|---|---|---|---|
| High | Low | Low | New traditional, least cost, peaking capacity to provide resource adequacy. |
| High | Low | High | Faster responding, somewhat more expensive, peaking capacity to provide resource adequacy, with this capacity also being capable of providing valuable ancillary services. |
| Low | Low | High | Upgrades and maintenance to enhance capacity responsiveness, or willingness to operate capacity more flexibly at some cost penalty to capture ancillary services revenue. |
| Low | Low | Low | Will depend on future expectations, but possibly a capacity retirement signal. |
| High | High | Low | Potential opportunity to construct plant with reduced flexibility (and therefore lower capital cost than more flexible plant). |

Notwithstanding that all technologies receive the same capacity price, the mix of revenues to alternative capacity types will differ. Consequently, the decision to invest in different capacity types will also be influenced, for example, by how ancillary services costs are allocated, the different prices for various ancillary services and the application of non-performance penalties, such as capacity refunds.

### 2.3.2 The reliability standard

The basis for capacity remuneration under the Reserve Capacity Mechanism arrangements is the ability of the resource to contribute to meeting the reliability standard. In the WEM the reliability standard is reflected in the Planning Criterion that AEMO uses to derive a Reserve Capacity Target for each Capacity Year.[5]

The Planning Criterion has two components:

1. A "peak demand" component that indicates the amount of capacity required to meet forecast peak demand plus a reserve margin (Market Rule 4.5.9(a)). This component ensures that the SWIS has enough capacity <u>to meet peak load</u>.

[5] The Planning Criterion is defined in Clause 4.5.9 of the Market Rules.

2. A "reliability" component that ensures there is adequate capacity so as to limit expected Unserved Energy to less than 0.002 per cent of forecast annual energy consumption (Market Rule 4.5.9(b)). This component highlights the importance of ensuring sufficient capacity is available throughout the year to satisfy user needs and accommodate outage scheduling requirements.

Importantly, the Market Rules require the Reserve Capacity Target to meet both requirements.

Since the inception of the WEM the Reserve Capacity Target has been dominated by the peak demand component. The high level of the system peak, means that the peak demand requirement has always been more than sufficient to ensure the maximum acceptable level of expected Unserved Energy is not breached. Historically the periods of system peak demand have coincided with the times of highest risk of unserved energy.[6]

For this pattern to hold into the future there would need to be a continuing presumption that a resource available at a specified output level during peak demand periods, is either equally available at any other period for sufficient time to be effective as an *adequacy* resource or that at the time when a resource might not be available other resources will be sufficient to meet the shortfall.

Increasingly, this presumption appears dubious.[7] Some variable generation resources, like solar technologies, have output aligned with traditional daytime peak hours. However recently a high evening second peak has emerged, over which electricity demand reaches nearly the same level as for the peak day hours, without the availability of solar resources.

Wind resources may, or may not, also be available at these times. It is possible that after adjusting for wind availability there are less available resources in relation to demand at points that are not traditionally peak consumption periods; leaving a performance gap. In fact, under this scenario, the missing money problem effectively shifts to the non-traditional period.

It is not sensible to reward greater capacity availability at the peak demand hour if such capacity will not in fact be available during periods which no longer meet the reliability standard. In such cases, the missing money problem becomes one of remunerating capacity able to address those periods that are subject to a higher likelihood of Unserved Energy. In this situation the Planning Criterion would give the reliability, or Unserved Energy, component increased primacy.

A resource that is available at the precise point of peak demand, but not at any other time, is clearly not equally "adequate" in comparison to resources that are available at all times. This means resources that are unable to contribute to the Unserved Energy standard would need to be either de-rated in terms of eligibility for capacity credits or risk higher penalties for unavailability. The existing Reserve Capacity Mechanism provides for this adjustment, through means such as the Relevant Level Methodology used for the allocation of capacity credits to intermittent generators.[8]

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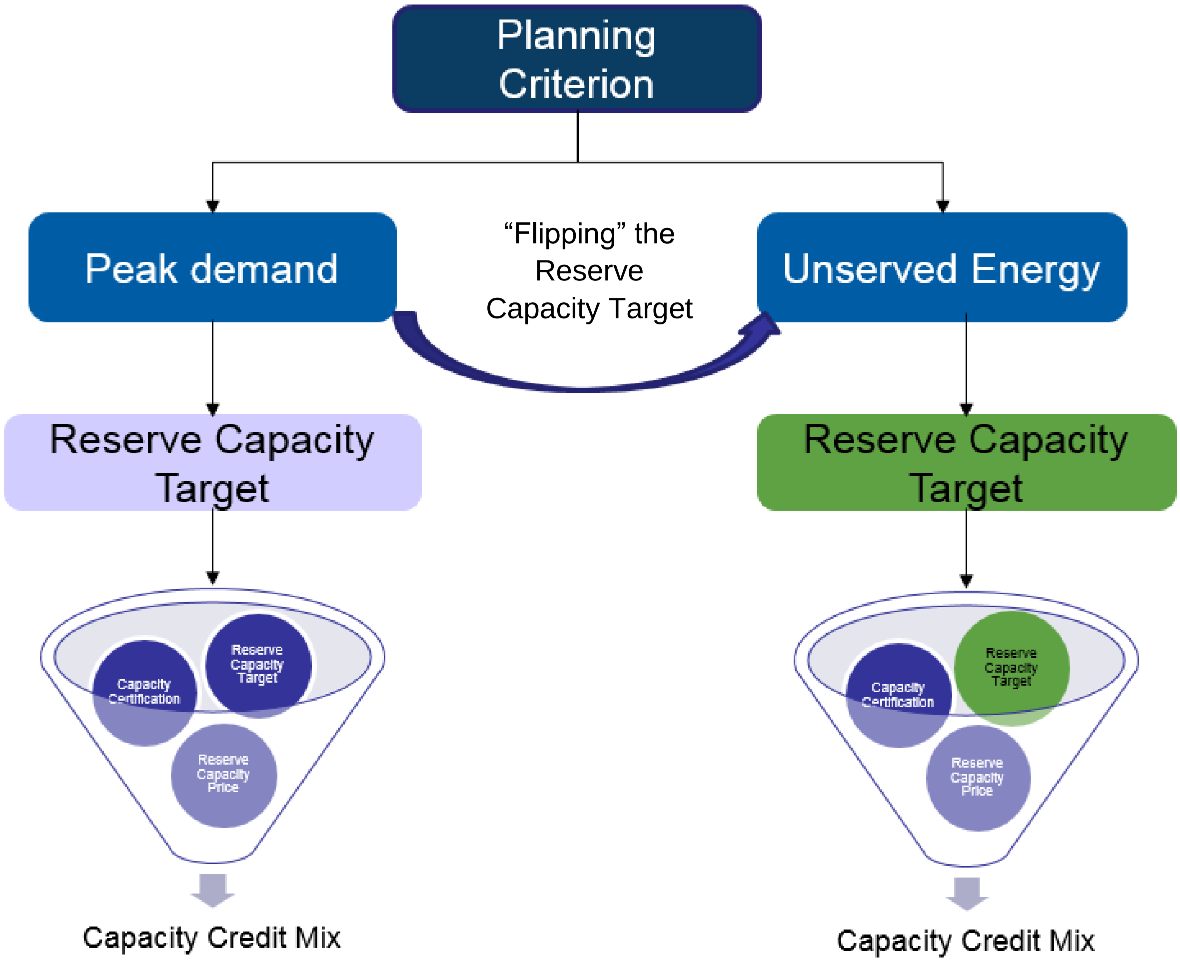
6 See Reliability Assessment and Development of the Availability Curve, Report for the Independent Market Operator by PA Consulting, June 2013.

7 See AEMO submission to WA Parliament Enquiry into MicroGrids at: http://www.parliament.wa.gov.au/Parliament/commit.nsf/(EvidenceOnly)/8C9FB0B8AA10E88D4825823B0019BAA3?opendocument.

8 The Economic Regulation Authority is currently conducting a review of the Relevant Level Methodology.

**Figure 2.3: "Flipping" the setting of the Reserve Capacity Target**




Importantly, with such a "flip" in primacy of the Planning Criterion from a peak demand to Unserved Energy component the value to the consumer of a 1MW contribution to system reliability will not change. Rather, the eligibility of a particular resource to share in that value will differ with its availability across relevant trading intervals. The Reserve Capacity Mechanism, by being required to ensure both elements of the Planning Criterion are met, provides for this adjustment.

The conclusion is that both the Planning Criterion and the inter-relationship between the capacity, energy and ancillary services markets will, over time, influence required adjustments in the capacity mix and therefore no fundamental change to the design of the Reserve Capacity Mechanism is necessary to achieve this outcome.

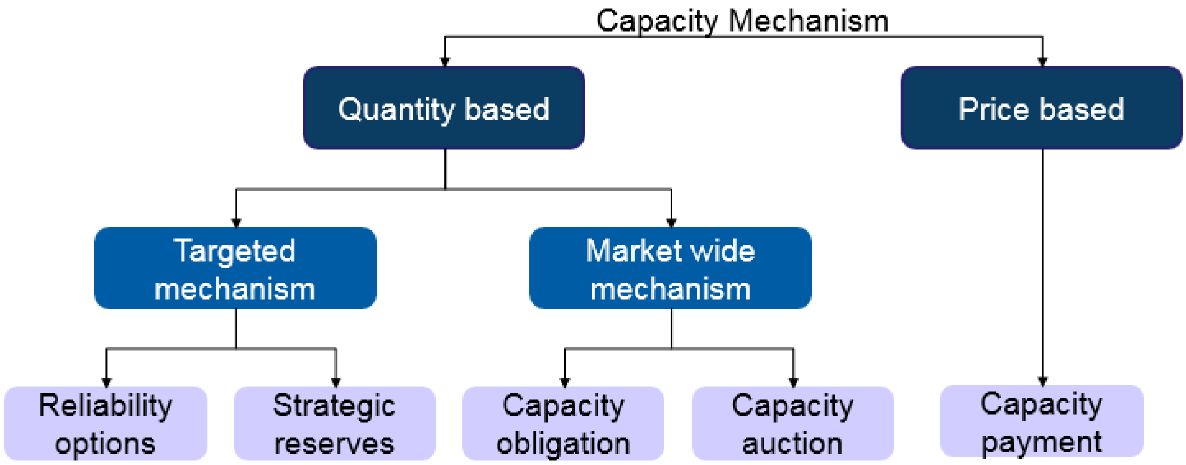
# 3. Evaluation of alternative capacity pricing solutions

## 3.1 Capacity pricing options

To assist the identification of options to improve reserve capacity pricing signals, the Public Utilities Office reviewed capacity pricing models in electricity markets in the European Union countries and North America. This review only included deregulated markets, as distinct from those jurisdictions with a centralised approach to electricity provision, as is the case in some parts of the United States.

The results of this assessment were presented in the Consultation Paper published in April 2018, outlining five approaches to capacity procurement and pricing through a mechanism separate to the energy market, as shown in Figure 3.1 below.

**Figure 3.1: Global approaches to capacity procurement and pricing**




This review identified the following common features across the procurement and pricing models:

- Market discovery of the capacity price
  - All of the markets reviewed have some form of competitive process to procure and price capacity, regardless of the market design.
- No other market has a similar mechanism to the current Western Australian design
  - The Reserve Capacity Mechanism approach of centrally contracting all capacity that is certified, with an administered price, regardless of the level of excess supply, is unique compared to the European and North American markets reviewed.
- New investment price certainty
  - Some markets offer new entrants the option to lock in the entry price for a number of years to reduce risk and assist investment viability.
- No price floors
  - None of the markets reviewed have implemented a capacity price floor.

- Technology neutral
  - Virtually all of the markets reviewed are technology neutral, although varying forms of capacity are rated differently based on availability benchmarks.
- Capacity prices below new entrant costs
  - While comparison of capacity prices across jurisdictions requires caution, a majority of the markets reviewed have been procuring required capacity at prices below the estimated new entrant cost.

The Consultation Paper discussed the alternative capacity market models and identified three models as potential candidates for application under the Reserve Capacity Mechanism arrangements, including the current administered capacity payment model, and reliability obligation and capacity auction as alternatives.

### *Administered Capacity Payment*

This model would continue the administered pricing arrangement, with a modified price curve to improve investment signals, relating the shape of the curve to the value of capacity to customers across different levels of excess.

### *Reliability Obligation*

A reliability obligation model would impose a requirement on each electricity retailer to contract sufficient capacity to meet its share of system reliability up to peak load. Capacity procurement and pricing would be deregulated. The market operator would administer a trading platform, such as a bulletin board, to facilitate contracting.

The model would require additional regulation to provide contract liquidity and mitigate market power, given the high concentration of the WEM.

### *Capacity Auction*

A capacity auction arrangement involves centralised procurement of capacity through an auction for each capacity year, with the capacity price being set by the auction clearing price. The auction would need to be supported by a re-balancing auction to enable adjustment of contractual positions, and robust market power mitigation measures.[9]

The Consultation Paper invited industry participants to comment on the capacity pricing models and propose any additional arrangements considered to merit further assessment. Submissions received in response to the paper indicated strong support for retention of the current administrative pricing arrangement.

Following evaluation of alternative capacity pricing reform options, informed by the stakeholder submissions received, the Public Utilities Office recommends that the administered pricing arrangements be retained for the Reserve Capacity Mechanism, contingent on significant changes to the capacity pricing curve to ensure a sustainable pricing model.

[9] The Public Utilities Office has previously undertaken considerable work on a high-level auction design, as detailed in the report, Reserve Capacity Auction – Final Design and Implementation, 23 January 2017 (available at www.treasury.wa.gov.au).

## 3.2 Option evaluation

Evaluation of the capacity pricing models was based on three core considerations:

- **Simplicity:** Can the pricing approach be designed and implemented in a prompt and cost effective manner. Once implemented, will operation of the model be administratively complex for the market operator and for the required actions by market participants?
- **Market power:** Are the pricing outcomes susceptible to the influence of market power? Does the approach exacerbate the likely level of market concentration?
- **Efficiency:** Does the pricing approach deliver economically efficient capacity pricing outcomes? Would the design of the model provide effective entry/exit signals?

### 3.2.1 Capacity auction

Under this model, the market operator sets a reliability target and undertakes a competitive auction for capacity procurement to meet this target. The market determines both the price and the quantity of capacity supplied.

Capacity auctions are generally regarded as industry best practice, however, designing and implementing a fit for purpose capacity auction for the WEM would face significant challenges. Of the models considered a capacity auction would be the most complex to design and implement. While the Public Utilities Office has previously developed a high-level capacity auction design for the SWIS, important design considerations would still need to be addressed before such a model would be ready for implementation.

Given these circumstances, the capacity auction is considered to be the most costly to develop, implement and administer compared to the other two pricing models. The market operator would need to extensively revise all market systems to operate a capacity auction and all capacity market participants would be required to modify their systems and processes.

A majority of submissions in response to the Consultation Paper highlighted these concerns as barriers to the implementation of a capacity auction for the SWIS. Synergy provided the following observation:

> *Synergy notes that industry opposition to the previously proposed capacity auction was primarily driven by concerns it would be too complex and costly to administer given the small size and illiquidity in the Wholesale Electricity Market.*[10]

Equally, Merredin Energy was not supportive of a capacity auction given concerns about complexity, suitability of the arrangements for the WEM and implications for financing and re-financing of generation projects:

> *A capacity auction (as proposed by the Energy Market Review) is too complicated and would provide uncertain outcomes in a small, isolated and relatively peaky electricity system (such as the SWIS). Adopting capacity auction models from electricity markets*

[10] Synergy, 9 May 2018 submission in response to the Public Utilities Office Consultation Paper, p 2.

> *in Europe (e.g. UK, France) and North America (e.g. PJM3) that are many times the size of the WEM is inappropriate and not likely to be efficient.*
>
> *Given uncertain outcomes with an auction mechanism in a small market like the WEM, it is very unlikely that the Reserve Capacity Mechanism would be bankable on a project finance basis.*[11]

The Public Utilities Office also considers the design and implementation of a capacity auction arrangement would be more complex if it was to occur concurrently with required changes to capacity certification processes to accommodate a constrained network access model, and the required introduction of new market and system arrangements as part of the broader WEM reform program.

A successful capacity auction is dependent on intrusive regulation to mitigate market power. Given the high level of concentration in the WEM a capacity auction would not be feasible without a suite of market power mitigation measures, particularly in relation to the control of bidding practices. Industry submissions made in response to the Consultation Paper did not consider that the negative effects of existing market concentration on capacity auction outcomes could be overcome through additional regulation.

Community Electricity highlighted the difficulties in attempting to address the effects of the existing level of market concentration:

> *A considerable issue with an auction is the mitigation of market power. We suggest that Synergy, as the principal capacity provider, is caught in an irreconcilable bind; anything it does, reasonable or not, is an exercise of market power that hugely influences the capacity price.*[12]

Alinta Energy's submission summarised the barriers to implementation of a capacity auction:

> *Alinta considers that the implementation of a capacity auction in the WEM would:*
>
> - *Not deliver any greater efficiencies to the market than a refined administered pricing regime;*
> - *Introduce a new set of associated risks, particularly given the potential for more volatile pricing outcomes to which a number of existing generators will be exposed as a consequence of the limited incentives for bilateral contracting under the current regime;*
> - *Require the current issues associated with Synergy's continued dominance in both the retail and wholesale market to be addressed through a disaggregation and privatisation process; and*

11 Merredin Energy, 4 May 2018 submission in response to the Public Utilities Office Consultation Paper, p 2.
12 Community Electricity, 6 May 2018 submission in response to the Public Utilities Office Consultation Paper, p 2.

- *Require both significant design work and a reasonable transition for existing participants. In particular Alinta notes that effective auction design is not-trivial, as evidenced by frequent change in auction design that have been required to address, mitigate, or avoid various problems in other (much larger) markets.*[13]

### 3.2.2 Reliability obligation

A reliability obligation model deregulates determination of the capacity price, however administrative arrangements are still required to establish financial penalties in the event of under-contracting by electricity retailers or under-performance by generators. This model also requires arrangements to ensure capacity market participants can adjust their contracted capacity positions in the lead up to resource delivery through a re-balancing process.

A weakness of this approach is that it is inherently impossible, with current technology, to ensure that customers of a fully compliant retailer receive preferential treatment in the event of a capacity supply shortfall, and are not impacted by load shedding in such an event or in situations where a contracted capacity provider does not deliver against these requirements.

In the French reliability obligation based market arrangements, withholding of capacity resources is acknowledged as being a key risk. The market design includes complex rules to increase transparency and a mandatory offering of surplus capacity, with a backstop threat of regulatory intervention to manage other contingencies. A similar risk profile would exist in the WEM with a requirement for intrusive regulatory monitoring.

Changing the WEM from the current arrangement of administered pricing and ex-ante determination of the amount of capacity required, to an ex-post assessment of whether disaggregated capacity acquisition processes run by obligated parties have each met their obligation, would be a significant and complex reform process. Such a change would necessitate a view that, on balance, the advantages and complexities of the reliability obligation design represent an improvement over the current capacity market design, and that the cost of this change in approach is warranted.

The Public Utilities Office considers that it would be difficult to reach this position. For the WEM, the most problematic feature of the French design is the management of market power and lack of market liquidity. Despite some complex market rules, the French market operator has noted that the ultimate mechanism to control market power is the threat of regulatory intervention. In the concentrated WEM it is likely that market power mitigation controls would be required from the outset of such an arrangement, even if only to enhance the credibility of the market for small players.

The reliability obligation model therefore has many of the same challenges as the capacity auction, including the level of risk faced by market participants, complexity and requirement for a large amount of regulation of both ex-ante and ex-post capacity market outcomes. Synergy reaffirmed these concerns in its response to the Consultation Paper:

13 Alinta Energy, 4 May 2018 submission in response to the Public Utilities Office Consultation Paper, p 1.

> *Synergy considers that Option 2 [Reliability Obligation] may present similar risks to the auction while also providing significantly muted short-term economically efficient price signals due to the likelihood of extremely volatile prices.*
>
> *Option 2 [Reliability Obligation], while theoretically appealing, is untested in the WEM, was only recently implemented in France, and represents a significant shift from the Reserve Capacity Mechanism's more mature administered pricing structure. Synergy perceives a risk in implementing this new, potentially inflexible model, given it is unclear how it will interact with the emerging market conditions in the WEM, including the growing, large scale and distributed renewable generation capacity, and concurrent market reforms such as the proposed implementation of competitive ancillary services markets.*[14]

Equally, Bluewaters Power was concerned with the suitability of a reliability obligation approach:

> *Option 2 [Reliability Obligation] is a more fundamental change. Hence, consequential changes to the Market Rules need to be considered. For example, how would the capacity refund be quantified in the absence of a reserve capacity price? Changes under Option 1 [Administered Pricing], on the other hand, are likely to require less consequential changes in the Market Rules. Under Option 2 [Reliability Obligation], the capacity contracting is likely to be less transparent compared to the Option 1 [Administered Pricing] mechanism where capacity trading is expected to be centrally administered (and centrally priced) by the AEMO. This makes market power monitoring and mitigation far easier (and less costly) under Option 1 [Administered Pricing].*[15]

Perth Energy highlighted similar concerns:

> *This mechanism is reliant on:*
>
> - *a sufficiently liquid market;*
> - *an effective financial incentive regime; and*
> - *a meaningful penalty regime to drive compliance, to deliver an efficient outcome.*
>
> *In a market in which there is such a dominant market generator this option is unworkable. Investors are unlikely to commit to new capacity until any new arrangement has been in place long enough to demonstrate that it works.*[16]

[14] Synergy, 9 May 2018 submission in response to the Public Utilities Office Consultation Paper, p 2.
[15] Bluewaters Power, 4 May 2018 submission in response to the Public Utilities Office Consultation Paper, p 2.
[16] Perth Energy, 3 May 2018 submission in response to the Public Utilities Office Consultation Paper, p 4.

### 3.2.3 Administered pricing curve

From its inception the current administered capacity pricing arrangement has been subject to various reviews and refinements. The most recent changes implemented in May 2016 were designed to progressively improve price responsiveness of the Reserve Capacity Mechanism, to reduce the level of excess capacity, in anticipation of the introduction of a reserve capacity auction process. The changes also reduced incentives provided to demand side management capacity resources.

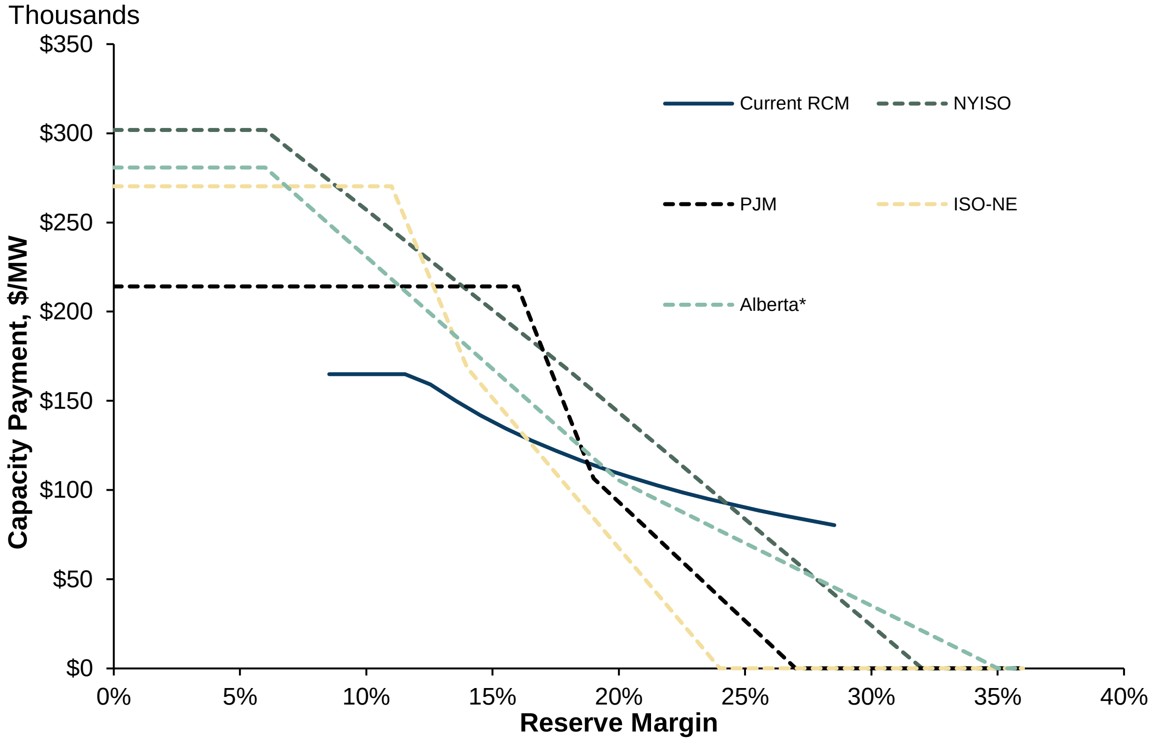
As noted in Section 2, the existing design has some considerable weaknesses. Efficient outcomes are critically dependent on an accurate view of the cost of providing capacity, in the WEM being the BRCP.

In contrast, capacity auctions start with a BRCP equivalent value as a price upper bound, but solve for the lowest capacity price that will clear the auction at a target capacity level. The administered capacity pricing curve starts with the BRCP but allows as much capacity to enter as can profitably do so at lower prices, with the pricing curve formula determining the rate of capacity price reduction with an increased amount of excess capacity.

Any administered pricing curve, therefore, is not as efficient as an auction in identifying the least cost quantum of capacity required. However, if sufficient steepness can be incorporated in the capacity pricing formula, the cost impact for consumers of any additional significant levels of excess capacity can be made negligible, with the associated financial risk being primarily shifted to investors. As long as this allocation of financial risk can be counter-balanced by upside or bilateral contracting incentives as the market requires new capacity resources, then a suitable capacity value and risk trade-off can be achieved.

Figure 3.2 compares the capacity demand/pricing curves for auctions in the North American markets to the WEM. Making a comparison between these curves is not straight-forward as each market has a different load duration curve, although they all use a similar methodology to arrive at the demand/pricing curve. The comparison below is focused on the reserve margin, rather than the excess capacity, primarily to compare slope and intercept points.

**Figure 3.2: Comparison of capacity demand/pricing curves[17]**




The first point to note is that the prevailing capacity pricing curve for the WEM is less steep than all of the other markets.

As highlighted in submissions made in response to the Consultation Paper, implementing an enhanced administered pricing arrangement with more efficient entry and exit signals, and therefore capturing most of the benefits that a capacity auction would provide, is not a complex exercise. It involves refinement of, rather than fundamental change to, the Reserve Capacity Mechanism arrangements.

ERM Power agreed with this observation in its submission:

> *ERM believes the current administrative pricing methodology would require only slight adjustment to provide better pricing signals to the market to highlight under or over supply situations.[18]*

Tesla Corporation provided a similar view:

> *In our view, an Administered Pricing Approach should be retained. However, some changes should be made to the shape of the capacity demand curve and what facilities can qualify for capacity certification in the future.[19]*

---

[17] London Economics, Issue Related to the Demand Curve in Capacity Markets, July 2017.
[18] ERM Power, 3 May 2018 submission in response to the Public Utilities Office Consultation Paper, p 2.
[19] Tesla Corporation, 4 May 2018 submission in response to the Public Utilities Office Consultation Paper, p 5.

Alinta Energy highlighted the requirement for refinement of the administered pricing curve:

> *In supporting the retention of the current administered pricing mechanism, Alinta recognises that some refinements will be necessary to ensure that this mechanism meets the following objectives of:*
>
> - *Providing an efficient signal for new entry of generation;*
> - *Providing an efficient signal for exit of older or inefficient generation;*
> - *Providing sufficient certainty for investors; and*
> - *Reflecting short term market conditions, where appropriate.*
>
> *To that end, Alinta agrees with the PUO's suggestion that changes to the price curve will be necessary.*[20]

## 3.3 Assessment of the pricing models

A summary assessment of the suitability of alternative capacity pricing models for the WEM is provided in Table 3.1 below, supporting retention of a refined administered capacity pricing arrangement. Section 4 of this report outlines these recommended enhancements to the pricing curve.

**Table 3.1: Comparative assessment of alternative capacity pricing models**

| | Refined Administered Pricing Arrangement | Capacity Auction | Reliability Obligation |
|---|---|---|---|
| **Simplicity**<br>• Design<br>• Implementation<br>• Complexity to administer | ✓✓ | × | × |
| **Market Power**<br>• Ability to influence price | ✓✓ | × | × |
| **Efficiency**<br>• Market determined price<br>• Price competition | ✓ | ✓✓ | ✓✓ |
| **Score** | **5** | **2** | **2** |

20 Alinta Energy, 4 May 2018 submission in response to the Public Utilities Office Consultation Paper, p 2.

# 4. Recommended capacity pricing model

This section of the report outlines the recommended design parameters for setting of the new capacity pricing curve and includes information on stakeholder feedback on these matters received in response to the Draft Recommendations Report.

## 4.1 Constructing an administered capacity pricing curve

Economic pricing efficiency is based on the marginal value of the product or service as determined by consumer demand. Applying this concept to the supply of electricity means that a customer should not want to pay more than the value placed on being able to use one more unit of reliable power, effectively the "value of customer reliability" (VCR).

The VCR is an approximation with a number of estimation challenges and usage caveats. However, it does provide an important starting point, as well as context, in considering how best to establish appropriate signals to ensure adequacy of capacity resources. A specific estimation of the VCR for Western Australia and associated methodology is provided in Appendix A.

The concept encompasses customer willingness to pay (in $/MWh terms) for an incremental reduction in the risk of an interruption to power supplies. The Public Utilities Office has adopted the concept in deriving a capacity price curve by relating movements in Expected Unserved Energy (EUE) to changes in the amount of available capacity.

Ultimately, the EUE depends on the amount of capacity available relative to possible demand. Usually the level of EUE falls away quickly towards zero, as there is a move from system peak, or other system stress events, as sufficient capacity is deemed to exist during these other periods.

The VCR estimate, can be transformed into an equivalent $/MW VCR based capacity payment by calculating the changes to EUE as total capacity is increased or reduced[21]. Essentially this means converting the VCR to a $/MW capacity value curve based on the contribution that each additional megawatt of capacity makes to system reliability, by reducing the probability of load not being served. Under this approach the capacity price formula can be expressed as follows:

$$Capacity\ Price = \Delta EUE(Excess\ Capacity) \times VCR$$

[21] This is calculated using a model of the change in Loss of Load Probability (LOLP).

**Figure 4.1: Comparison of existing capacity price curve with an estimated VCR curve**

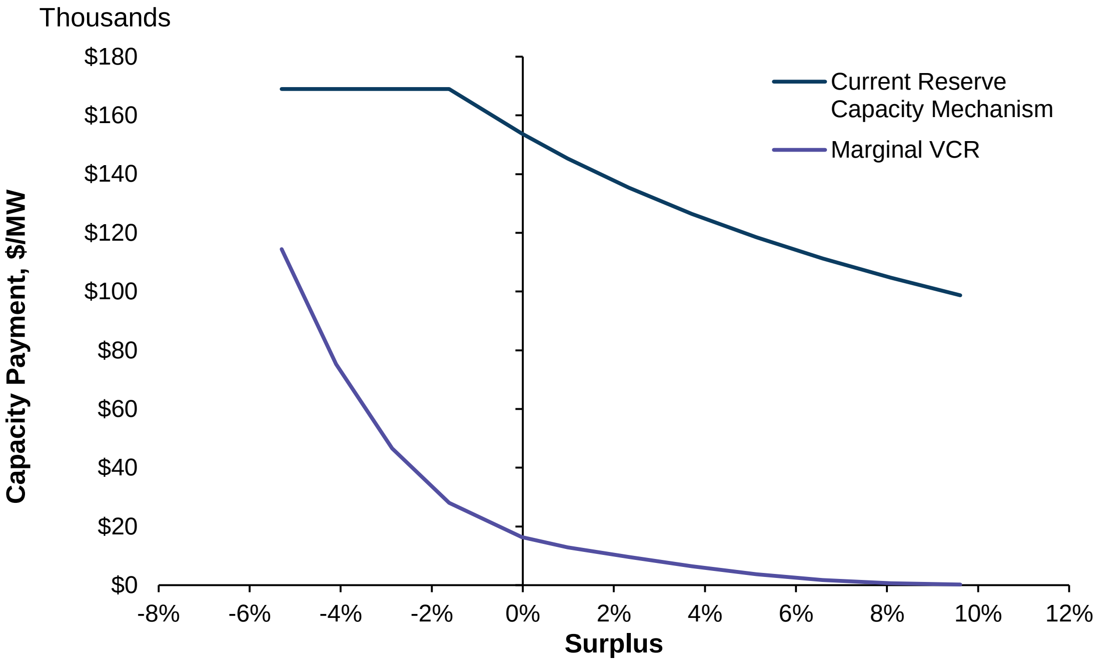



Figure 4.1 indicates a much lower capacity value for the VCR-based curve compared to the current Reserve Capacity Mechanism pricing curve. As the VCR yields a value far lower than that required to meet the Reserve Capacity Target, this means that it cannot be used directly for capacity pricing purposes. It can however be used to provide guidance on the rate of change in consumer value as more or less capacity is available.

To ensure sufficient capacity resources, the Reserve Capacity Mechanism must provide remuneration equal to the marginal cost of a new asset that assures a desired level of reliability. In the WEM this is achieved by setting the BRCP at the point where the amount of excess capacity, that is capacity above the reserve margin, is equal to zero.

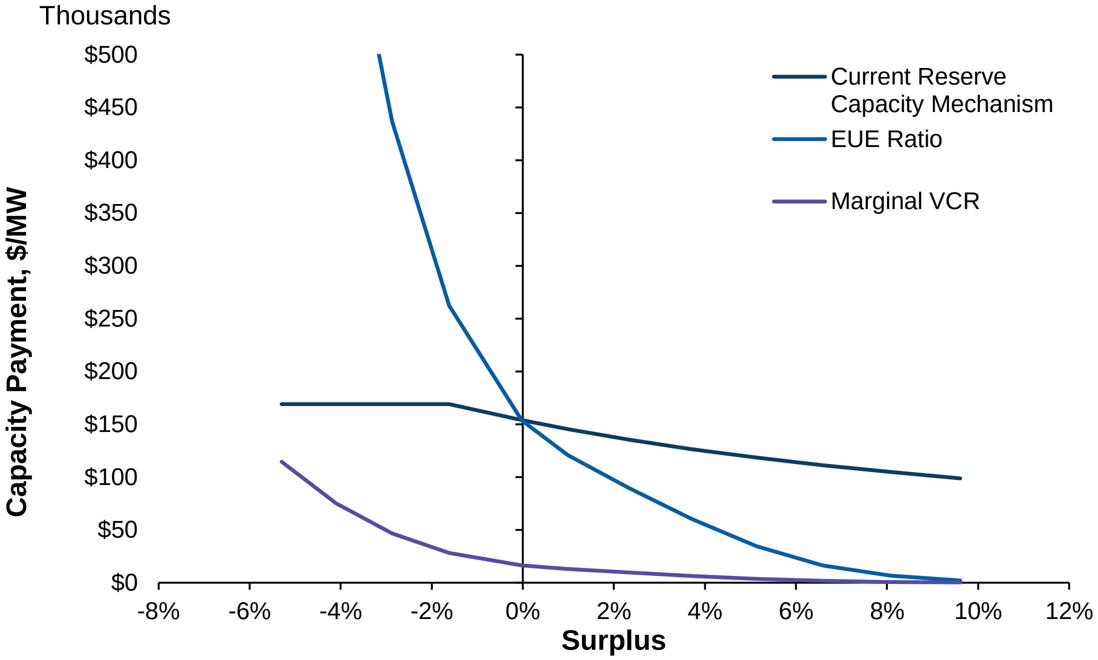
To adjust the BRCP for incremental excess reserve capacity, the capacity price can be linked to incremental changes in the level of expected unserved energy to provide the following capacity price formula:[22]

$$CP = BRCP \times \frac{\Delta EUE}{EUE_{RM\ target}}$$

The resulting EUE based capacity price curve is shown in Figure 4.2 and falls between the current capacity pricing curve and a VCR curve for any level of excess capacity, also highlighting how much steeper and higher the capacity price must be in the event of an expected shortage. The analysis also indicates that the capacity price should approach zero at some point of excess capacity relatively quickly. These are useful insights for shaping a more economically efficient and effective capacity price curve.

[22] $\frac{\Delta EUE}{EUE_{RM\ target}}$ is a measure of the change in EUE at a given reserve margin to that at the target reserve margin.

**Figure 4.2: Comparison of existing capacity price curve with VCR and EUE-based curves**

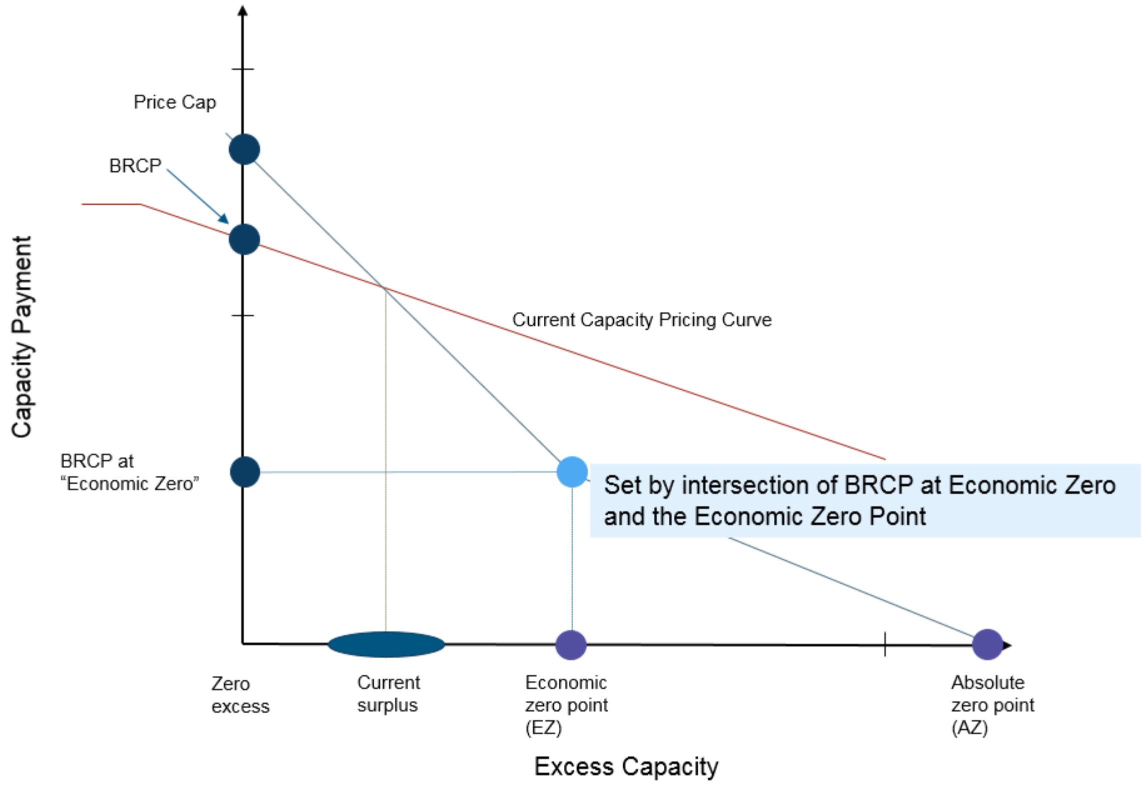



To capture the essential features of a VCR based value curve the Public Utilities Office is recommending a capacity price curve that uses the following three points:

- **Economic zero point**: the level of capacity surplus and price at which no additional resources will enter the system under a very wide range of market conditions.
  - This point accounts for the likelihood that a combination of technologies, sites, fuel sources and other conditions, may yield an opportunity for an investor to introduce capacity additions at a price well below the BRCP.
  - In essence it is the "as good as zero" point in terms of economic impact, as there is likely no more entry of capacity resources beyond this point, and it is the point at which there is a strong economic case for capacity to exit the market. At these levels of surplus it should also become uneconomic to undertake major refurbishment projects unless they are significantly more commercial than new capacity developments.
- **Price Cap**: the capacity value associated with no capacity surplus.
- **Absolute zero point**: the point where the amount of excess capacity is deemed to be sufficiently high for the capacity price to be zero.
  - International capacity markets indicate that a zero point is typically set around a level of capacity surplus of 25 to 30 per cent. Setting the zero point at a higher level of surplus increases the risk of prolonged support for a capacity resource beyond the point where it is needed or should be supported by other revenue or value streams.

The Public Utilities Office also considers that the administrative benefits of connecting the three points via straight lines, outweigh the potential benefits of increased economic efficiency through the use of a convex price curve.

**Figure 4.3: Conceptual design of the enhanced capacity price curve**




## *Industry response to proposal*

The majority of submissions received supported the retention and refinement of the administered price curve as proposed in the Draft Recommendations Report. Synergy noted that:

> *Compared to the alternative approaches considered, refining the administered mechanism appears most likely to be administratively efficient, deliver efficient price signals and least cost outcomes, and be fit for purpose within the South West Interconnected System (SWIS).*[23]

Alinta Energy stated:

> *Alinta supports retaining, and refining, the current administered pricing mechanism to incentivise the efficient entry and exit of capacity. Subject to the consideration of the minor enhancements to the proposal, as outlined in this submission, Alinta supports the Public Utilities Office's recommendations.*[24]

EnerNOC supported the proposed method for constructing the administered pricing curve but cautioned against making the curve too steep, as it could lead to price volatility risks.

[23] Synergy, 19 September 2018 submission in response to the Public Utilities Office Draft Recommendations Report, p 1.
[24] Alinta Energy, 19 September 2018 submission in response to the Public Utilities Office Draft Recommendations Report, p 3.

The Australian Energy Council proposed that use of the VCR, rather than the BRCP, to construct the price curve would be a preferred approach, on the basis that the VCR takes into account factors such as outage duration and frequency, season, day of the week and the time of day in determining the consumer value of capacity. However, in recognition of the comments made by the Public Utilities Office as to the difficulties associated with use of the VCR to establish the capacity price, the Council supported the use of the VCR to inform the rate of change in consumer value, and therefore the capacity price curve.

## 4.2 Setting the parameters of the recommended capacity pricing model

### 4.2.1 Price cap

It is important that the capacity price adequately compensates an investor for an additional unit of capacity when there is a risk of looming shortage, meaning that the price should be allowed to reach the cap ahead of a failure to achieve the required reliability standard. Rather than wait for a capacity shortfall to trigger higher prices, the Public Utilities Office has recommended that the price cap should be set at zero excess capacity. The result is a small but persistent increase in commercially viable reserve capacity, but given the steeper slope of the curve and associated additional commercial risk faced by uncontracted retailers, there should be a limited impact on consumers.

Consistent with the practices in other international capacity markets, the Public Utilities Office is recommending that the price cap be set at 1.3 times the BRCP.

#### *Industry response to proposal*

Bluewaters Power and NewGen Kwinana supported the proposed price cap. Tesla Corporation and Merredin Energy proposed a higher price cap of 1.6 times and 1.5 times the BRCP respectively, and/or recommended that the BRCP methodology should be reviewed. Merredin Energy suggested the use of a smaller generation facility of 30 to 50 MW capacity, rather than the current capacity size of 160 MW, to calculate the BRCP, on the basis that this would be more reflective of recent plant investment. Merredin Energy also proposed that the BRCP methodology should use a higher risk free rate of return to determine the weighted average cost of capital in annualising the capital costs.

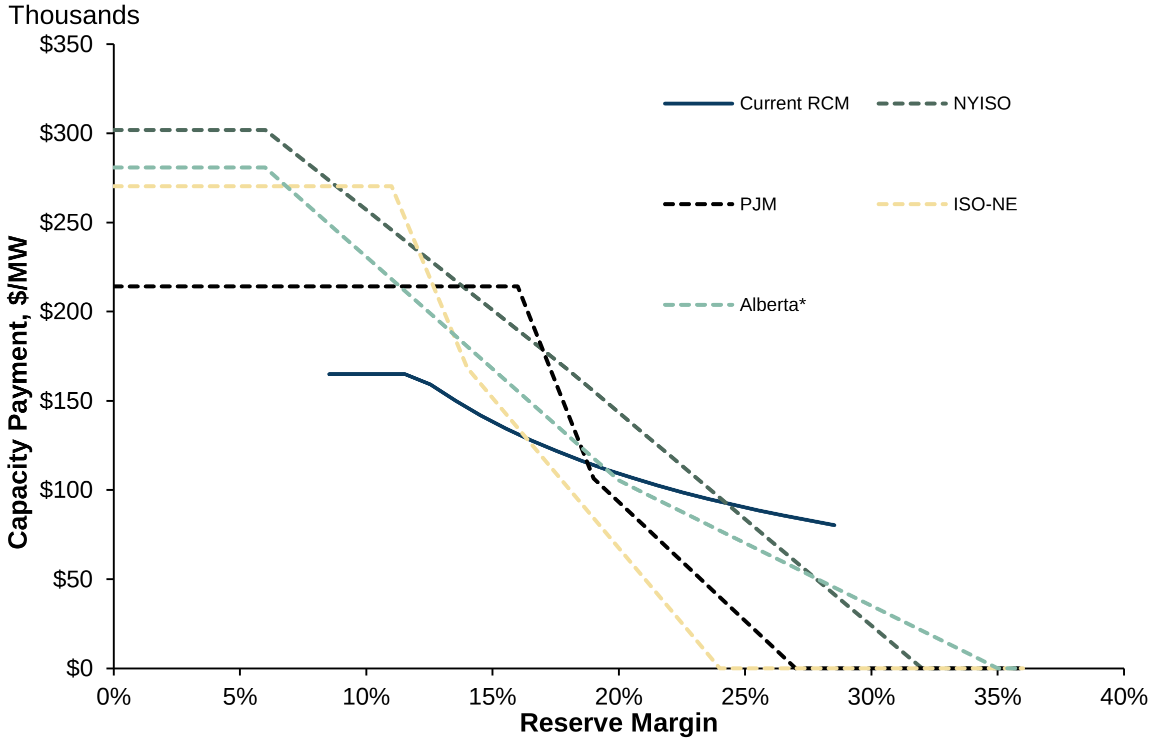
The Public Utilities Office maintains the view that setting the price cap at 1.3 times the BRCP is appropriate, as this approach limits the potential financial burden on electricity consumers, provides a suitable pricing incentive for new entry of capacity and is consistent with international practices.

The Public Utilities Office also notes that the Economic Regulation Authority is scheduled to review the BRCP methodology in 2019 and that the review process will be required to address the matters raised by Tesla Corporation and Merredin Energy. As the price cap proposal involves a multiple of the BRCP, it is not expected that any changes to the BRCP methodology would require consequential revisions to the recommended capacity pricing model.

### 4.2.2 Absolute zero point

Most capacity markets allow the value of capacity to fall to zero in situations of persistent and material surplus. Absolute zero points in other international markets are set at levels of excess capacity of around 25 per cent or more, see Figure 4.4 below.

**Figure 4.4: Comparison of absolute zero points in international capacity markets[25]**

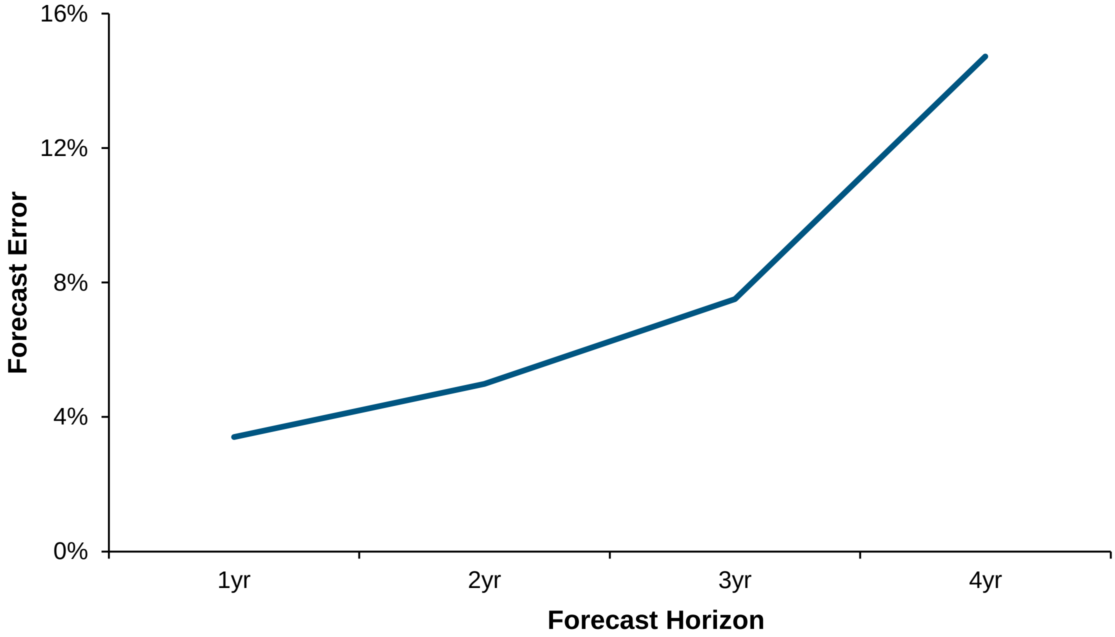



In considering the absolute zero point for the WEM the Public Utilities Office analysed the historical standard deviation of demand forecast error by AEMO, as a function of the forecast horizon. Demand forecast error presents a risk to both investors and consumers that must be balanced.[26]

25 London Economics, Issue Related to the Demand Curve in Capacity Markets, July 2017. Note that the Reserve Capacity Mechanism price curve has been shifted by 5.9% to reflect the difference between the corresponding POE10 and POE50 forecasts.

26 The risk is on the investor side if the capacity price is adjusted after the investment decision has been made, or on the customer side if price is locked in at the time of investment commitment.

**Figure 4.5: Standard deviation of electricity demand forecast error in the South West Interconnected System**




Source: Analysis commissioned by the Public Utilities Office using information contained in the Electricity Statement of Opportunities publications and other market data compiled by AEMO and the Independent Market Operator for the 2008-09 to 2014-15 Capacity Years.

As seen in Figure 4.5, the standard deviation of the forecast error grows non-linearly with the forecast horizon, following approximately geometric growth between a one to four year horizon. These results indicate that with each year further out the forecast risk is being doubled. Based on these historical observations, the forecast error band for a T-4 capacity cycle would be just under 15 per cent and for a T-3 capacity cycle just under eight per cent.

To be confident that the capacity price will not fall to zero unless there is truly a persistent and material capacity excess, the absolute zero point must have regard to forecast uncertainty. Otherwise the capacity market design would be subjecting investors to the considerable demand volatility that exists in a small market. The challenges arising as a result of the missing market problem support the value of such a moderated approach.

The Public Utilities Office is recommending setting an absolute zero point at a level of excess capacity of 30 per cent, exceeding approximately two standard deviations of forecast error for a forecast made four years into the future. This timeframe equates to that for investor decisions to commit to the establishment of additional capacity resources in the SWIS.

### *Industry response to proposal*

Bluewaters Power acknowledged that an absolute zero point of 30 per cent excess capacity is conservative compared to other international markets. However it made the following observation:

> *Going forward however, there are possible scenarios where the continued adoption of behind-the-meter solar and particularly storage, coupled with energy efficiency and low economic growth conditions will see demand (and peak demand) decline. This could mean that, rather than new investment creating a greater capacity surplus and triggering*

*an absolute zero capacity value, a lower reserve capacity requirement may do so. This might present a problem if the capacity that exits the market at this point is also a relatively low-cost energy producer. Unless the ancillary service market provides appropriate value streams, there might be times when extended periods of low solar irradiation place the system at higher risk, or at least increases price volatility.*[27]

Tesla Corporation expressed the view that capacity price reductions may not be enough to deter new investment where capacity investors are likely insensitive to capacity prices, with demand side management facilities and renewable plants being proposed as examples of this. Tesla Corporation proposed an absolute limit on the amount of excess capacity in each capacity year, with additional capacity entering the market not being accredited until the level of excess capacity is reduced to below the threshold. Support for an absolute zero point set at 30 per cent excess capacity was expressed, should the alternative proposal not be capable of implementation.

The Public Utilities Office acknowledges the concerns raised by Bluewaters Power, however it also notes that the intent of an absolute zero point is to provide a signal to capacity providers to exit the market and not excessively burden consumers with the cost of significant levels of excess capacity.

The Public Utilities Office does not support Tesla Corporation's proposal to set an absolute limit on the amount of excess capacity that can be accredited in the market. Allowing all capacity that satisfies the certification criteria to be eligible for capacity credits is a fundamental feature of the Reserve Capacity Mechanism arrangements. A change of this nature would represent a major shift in the design of these arrangements.

Additionally, the administered pricing arrangement means that every capacity provider is effectively a price taker, making allocation of a fixed amount of capacity amongst competing providers problematic.

### 4.2.3 Economic zero point

A corollary to the absolute zero point is the concept of an economic zero point, where the amount of capacity surplus is such that it is reasonable to assume that barring some fuel market disruption, policy shift, or new technology development, no investor would be interested in developing new capacity resources. The capacity price that applies at the economic zero point would need to be:

- highly unlikely to support the development of new capacity resources;
- not so low that debt service cannot be maintained for required capacity to achieve the capacity target; and

[27] Bluewaters Power, 19 September 2018 submission in response to the Public Utilities Office Draft Recommendations Report, p 4.

- a reasonable inflection point between the steeper part of the capacity pricing curve, where value risk is greatest, and the less steep part of the capacity pricing curve that corresponds to an exit signal as the capacity market trends towards the absolute zero point.

The level of capacity surplus at the economic zero point is intended to align with a circumstance where there is no material economic value to additional capacity resources. This can be estimated from the economic value curve, which suggests a level of excess between six and 10 per cent.

The Draft Recommendations Report included a recommendation that the economic zero point be set at a capacity price equal to 50 per cent of BRCP and level of excess capacity at eight per cent.

### *Industry response to proposal*

Bluewaters Power and NewGen Kwinana considered the proposed settings for the economic zero point to be reasonable. Merredin Energy and Tesla Corporation supported the setting of an economic zero point at eight per cent excess capacity but each proposed the use of a higher capacity price setting of 65 and 70 per cent of the BRCP, respectively. Tesla Corporation submitted that:

> *This will help increase resultant prices and ensure that dispatchable peaking plant is not incentivised to exit the market if excess capacity increases to relatively modest levels of 4 to 6 per cent (which is highly likely to occur given the re-entry of Demand Side Management facilities into the Reserve Capacity Mechanism and committed investment in renewable plant to meet the LRET).*[28]

In light of the small size and isolation of the WEM, where new capacity investments can result in significant changes to the supply-demand balance, Tesla Corporation also highlighted that:

> *Significant investment in new capacity and incorrect demand forecasts (i.e. demand is lower than expected) could result in excess capacity levels between 7 to 10 per cent, with capacity prices falling below 50 per cent of the BRCP if exceeding 8 per cent.*[29]

The Public Utilities Office considers that the capacity price at the economic zero point should be low enough to discourage new capacity from market entry, but not so low that existing generation providers cannot service debt associated with the capacity investments required to meet the reserve capacity target. Given this, and the concerns raised, the Public Utilities Office is recommending that setting of the economic zero point price at 50 per cent of the BRCP be retained, but that setting of the level of excess capacity be increased to 10 per cent.

[28] Tesla Corporation, 19 September 2018 submission in response to the Public Utilities Office Draft Recommendations Report, p 6.
[29] Ibid, p 5.

This adjustment will provide for a more gradual change to the capacity price compared to the setting of eight per cent, while being consistent with value outcomes using a VCR based curve as discussed in section 4.1.

### 4.2.4 Demand side management

The latest changes to the Reserve Capacity Mechanism arrangements implemented in May 2016 included measures to address incentives available to demand side management capacity resources, as for these resources higher levels of excess capacity mean a reduced risk of being dispatched. In these situations even very low capacity payment values can be highly attractive. As a transitional measure anticipating implementation of a capacity auction a separate remuneration arrangement was introduced, with payments being more aligned with the economic value of the resources given the capacity supply-demand balance at that time.

As demand side management resources provide considerable value to an electricity system it is preferable that the resources be remunerated using the same price as other forms of capacity. However, in achieving this aim it is important to not replicate the situation that previously lead to over-rewarding of this type of capacity resources.

To mitigate against this potential the Public Utilities Office is recommending that demand side management resources be required to provide a Reserve Capacity Security deposit each year of capacity certification. Demand side management resources are currently only required to provide a security deposit until they pass their first capacity test.

The security deposit is analogous to the investment that a supply side investor must make to develop a capacity resource, given that it is reasonable to expect that supply side resources will continue to be available if suddenly called on to generate, as the resource has no other purpose. Demand side management providers, however, have other commercial drivers and unlike generators tend to lose revenues when dispatched. To verify performance capability the Public Utilities Office is also recommending more stringent testing of demand side management resources, through the use of random testing requiring load curtailment equivalent to the level of capacity certification.

#### *Industry response to proposal*

Submissions received in response to the Draft Recommendations Report indicated a broad acknowledgement of the valid role played by demand side management resources in the WEM. The submissions generally agreed with capacity price equivalency amongst all capacity types, with some submissions asserting that price equivalency is necessary in order to comply with the WEM Objectives.

A major caveat for this broad level of support of price equivalency was that demand side management capacity resources should be subject to sufficient controls to ensure the resources are capable and available in an equivalent manner to generation capacity. This sentiment was expressed in Alinta Energy's submission:

> *Alinta is strongly of the opinion that a number of mechanisms are required to ensure that Demand Side Management is a "real" and useable product for the market to utilise and is therefore treated as closely to conventional generation as possible.*[30]

There were two particular areas of concern raised in the submissions. Firstly, that the controls on demand side management providers are required to be further strengthened to ensure the availability of these resources when required, and secondly that demand side management resources may enter and exit the market too frequently to provide useful capacity during times of tight supply.

For example, Bluewaters Power observed:

> *A Demand Side Management provider has an opportunity cost to being called that is likely to be well above the value of energy earned (under the usual WEM price limits). A prudent risk strategy for Demand Side Management providers might be to withdraw from the market during years of tight capacity adequacy, exacerbating the situation.*[31]

The Public Utilities Office remains confident that the proposed Reserve Capacity Mechanism arrangements will be effective in addressing these concerns. In particular, the Public Utilities Office considers that the security deposit requirement and increased random testing will ensure that demand side management resources will be available when required. Additionally, the Public Utilities Office considers that the higher capacity price associated with times of a tighter supply-demand balance, will be sufficient to incentivise the continued participation of demand side management resources in the capacity market during these periods.

Simcoa expressed concerns that the proposed obligations for demand side management resources were unwarranted and an overly onerous burden on the business. This position was supported by Synergy who contended that these requirements should not be imposed in situations where the resources are proven and are readily identifiable:

> *However, for demand response capacity where the capacity to be certified is a specified and previously proven, reliable, fixed load program, it appears inefficient to require ongoing security deposits and randomised testing (in the event the randomised testing for demand response is intended to be any more onerous than for other capacity types).*[32]

The Public Utilities Office remains of the view that capacity price equivalency requires a corresponding set of obligations on demand side management resources to ensure availability when required, noting that there is a balance to be reached in ensuring the obligations are not unnecessarily onerous.

[30] Alinta Energy, 19 September 2018 submission in response to the Public Utilities Office Draft Recommendations Report, p 2.
[31] Bluewaters Power, 19 September 2018 submission in response to the Public Utilities Office Draft Recommendations Report, p 3.
[32] Synergy, 19 September 2018 submission in response to the Public Utilities Office Draft Recommendations Report, p 2.

The Public Utilities Office will address these matters in the implementation of the reforms informed by stakeholder consultation throughout the drafting of Market Rule changes to ensure the testing requirements are pragmatic. Additionally, it will explore measures to allow AEMO to waive a security deposit requirement where a demand side management provider is able to demonstrate the resource is proven and readily identifiable.

### 4.2.5 Capacity withdrawal notice

The introduction of a much steeper capacity pricing curve in a market as small and concentrated as the WEM necessitates additional transparency around planned capacity retirements to allow the market time to respond. In response to a planned retirement, market participants may choose to enter into new contracts to protect themselves from potential higher capacity prices or may choose to bring new capacity resources online.

To facilitate this greater market transparency, the Public Utilities Office is recommending that all generators in the SWIS be required to provide three years notice ahead of closure. This recommendation is similar to that included in the Finkel report[33], with the measure being designed to encourage an orderly transition to new generation sources. The Public Utilities Office recommends that the notification requirements be linked to capacity certification timeframes so that applicants for capacity credits are made aware of this change in market circumstances before applications are lodged for the relevant Reserve Capacity Cycle.

#### *Industry response to proposal*

Submissions received in response to the Draft Recommendations Report indicated support for this proposal.

In commenting on the proposal submitters indicated that ideally the arrangements should be consistent with those currently proposed for introduction in the National Electricity Market. A further matter for practical consideration was raised by Perth Energy proposing that generators should be permitted to exit within the notice period if they become uneconomic during times of sufficient excess capacity supplies.

The Public Utilities Office will consider these practical implications in drafting of the Market Rule changes and will look to provide relevant exceptions, for example in the event a generator has an unexpected failure or in the case of financial insolvency of the capacity provider.

### 4.2.6 Price lock-in for new capacity

A disadvantage of an administered capacity pricing arrangement is the absence of competitive procurement processes which, as the cost of new technologies falls over time, would be expected to place downwards pressure on capacity prices. Certainly the experience in capacity markets in Europe and North America is that, for various reasons, capacity is being sourced at prices below the estimated new entrant cost.

The Public Utilities Office considers that the steeper slope of the recommended administered pricing curve, linked to a consumer based value of capacity, will deliver an improved risk allocation between capacity providers and users. It is important that new capacity resources are exposed to the prevalent capacity price at the time of market entry and confront the risk of capacity price outcomes over the full life of the project.

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[33] https://www.energy.gov.au/sites/g/files/net3411/f/independent-review-future-nem-blueprint-for-the-future-2017.pdf

This risk exposure must however be balanced against the requirement to ensure that new projects that will contribute to system reliability are "bankable". During formal and informal consultation conducted by the Public Utilities Office, some industry participants have noted that a sharper price curve will likely require some form of price guarantee to provide a bankable level of revenue certainty over the early stages of a project and avoid an increase in the hurdle rate of return for these investments, the cost of which would ultimately be passed through to consumers. To address these concerns capacity markets in other jurisdictions, including Ireland and the United Kingdom, have recently introduced a price lock-in period for new market entrants.

The Public Utilities Office considers that allowing new capacity resources an option to lock in the capacity price at the time of market entry, limited to a five year period, is appropriate to facilitate investment. To give priority to new entrant facilities that will likely impose lower costs to the market, it is recommended that under this arrangement as a first stage AEMO would award capacity credits to new floating price capacity and existing capacity providers. AEMO would then award all capacity resources that opted for a price lock-in, only if an adequate level[34] of capacity is not achieved through the first stage.

### *Industry response to proposal*

Submissions received indicated that generator bankability is a primary consideration in designing an electricity market, with a majority of submitters expressing support for a lock-in period of five years, although Perth Energy suggested that a minimum 10 year period would be required to secure financing. The Australian Energy Council offered cautious acceptance of the five year lock-in proposal given the potential for market distortion effects, indicating concern that new projects may lock in a certain price while pushing the price lower for incumbents in the following year.

The Public Utilities Office remains of the view that a five year lock-in period is appropriate in likely providing sufficient support for project financing, while minimising the potential for distortionary market impacts.

### 4.2.7 Energy storage technologies

Large scale energy storage is likely to become an increasingly important participant in international energy markets. There is strong evidence that battery costs will steeply decline into the early 2020's, with still meaningful declines thereafter also driven by balance of plant efficiencies.[35]

In Western Australia stand-alone battery storage and batteries combined with less reliable capacity resources, e.g. those with an intermittent fuel source, may well have future prevalence in the market. However, storage technology is currently unable to participate in the WEM as an individual facility, as the registration requirements are inconsistent with how a storage facility would operate.

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34 Ensuring the Reserve Capacity Target is achieved factoring in the availability class requirements.

35 See CSIRO, Electricity generation technology cost projections 2017-2050, December 2017.

To date, only a few international capacity markets have active participation of energy storage facilities, the United Kingdom being a notable example. However, the participation of storage facilities in this market dropped significantly after the market operator applied the correction factor to address the equivalency of capacity service provided. In the WEM storage capacity will likely seek to maximise value across the capacity, energy and ancillary services markets, requiring appropriate definitions for eligibility and participation in each value stream.

The capacity value of battery storage facilities is most likely to be manifest in two areas, the extent to which storage combined with a variable generating resource can be packaged and operated to up-rate capacity eligibility of the variable resource; and the extent to which storage can be treated as firm capacity.

While large scale energy storage facilities may not be able to register to participate in the WEM or the Reserve Capacity Mechanism arrangements at present, the Public Utilities Office does not consider that the recommended capacity pricing model will require significant change to include battery or other storage technologies. Barriers to WEM participation by energy storage facilities more generally, including the Reserve Capacity Mechanism arrangements, are being considered in the other components of the broader WEM reform work program.

### *Industry response to proposal*

Submissions received broadly acknowledged the complexities associated with enabling and supporting emerging technologies, especially energy storage technology. Most submissions recognised the present and developing technical challenges in managing power system security and reliability in the SWIS, and supported the need for capacity that is capable of responding to these challenges.

Synergy elaborated on these views summarising a recurring theme in many submissions, indicating that:

> *Any changes made to the administered pricing mechanism should not impede or preclude consideration of future changes that may be required to accommodate the expected increased participation of utility scale storage. Further consideration will also be required regarding the role and services that can be provided by utility scale storage, such as generation capacity and ancillary services.*[36]

The Public Utilities Office acknowledges and supports the views expressed, highlighting the priority for completion of a review of future ancillary services requirements and procurement arrangements for the WEM, and ensuring the Reserve Capacity Mechanism arrangements are conducive to market participation by alternative types of capacity.

[36] Synergy, 19 September 2018 submission in response to the Public Utilities Office Draft Recommendations Report, p 3.

# 5. Transitional measures and implementation

## 5.1 Transitional measures

The recommended new capacity pricing model represents a significant change to the Reserve Capacity Mechanism arrangements. Consequently, the Public Utilities Office considers it is appropriate that, for existing capacity assets, there should be a period of transition to ameliorate perceived revenue risk associated with the new capacity pricing and procurement framework, within reasonable limitations.

The Public Utilities Office is proposing a time limited price band as a transitional measure for all existing providers to limit the scope of capacity price movements in respect of existing capacity assets. The Draft Recommendations Report included a recommendation that the transitional measure remain for a 10 year period with a lower price band of $105,000 and an upper price band of $130,000, adjusted for annual CPI movements.

### *Industry response to proposal*

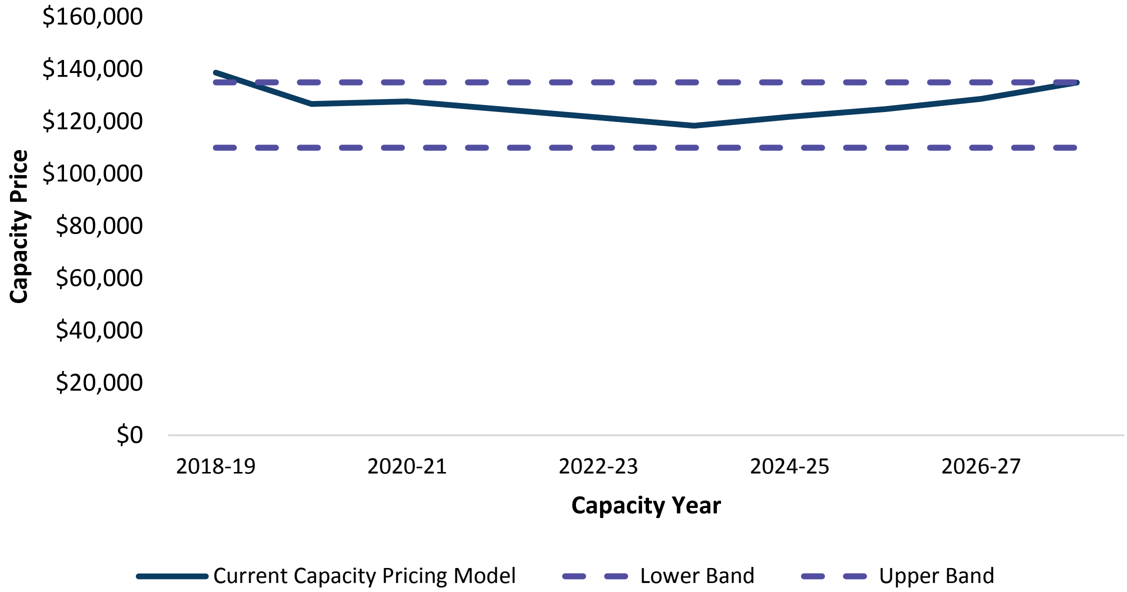
Submissions received in response to the Draft Recommendations Report were largely supportive of the need for transitional arrangements, highlighting the importance of minimising sovereign risk and recognising that existing capacity providers have made long-term decisions under prevailing regulatory arrangements. Simcoa indicated a contrasting view on the basis that no transitional arrangements were provided to demand side management capacity providers under previous government reforms to the Reserve Capacity Mechanism arrangements.

While the use of a transitional price band was supported by all generator submissions, there was some conjecture as to the setting of the upper and lower threshold. While some submissions supported the thresholds proposed, others advocated for a significant increase with a floor price above $130,000 to allow a sufficient return on equity investments.

A majority of the submissions received accepted the approach utilised by the Public Utilities Office in developing the proposed price band, giving consideration to AEMO's independent forecasts as a basis for assessing the range of prices that would have resulted in the absence of the proposed reforms. Figure 5.1 below shows the expected capacity price outcomes under existing arrangements, based on information contained in the AEMO 2018 Electricity Statement of Opportunities. These submissions did however suggest that the upper and lower threshold should be set to ensure that all of the forecast prices considered were within the price band.

On balance, the Public Utilities Office considers that a slight upwards adjustment of the proposed price band upwards to capture all of the AEMO price forecasts is appropriate. Accordingly, the Public Utilities office recommends that the transitional measure remain for a 10 year period, with a lower price band of $110,000 and an upper price band of $135,000, adjusted for annual CPI movements.

**Figure 5.1: Forecast of capacity price outcomes under existing arrangements compared to proposed pricing bands**




Note: Calculated using a Benchmark Capacity Price of $153,600 and excess capacity figures sourced from the 2018 ESOO.

## 5.2 Implementation timeline

The Public Utilities Office has considered two possible options for timing to introduce the proposed changes to the capacity pricing arrangements.

1. Implementation as soon as practicable.
2. Implementation of the reforms concurrent with the introduction of constrained network access, i.e. effective from the 2020 Reserve Capacity Cycle.

As the 2018 Reserve Capacity Cycle has already commenced with applications for capacity credits closing on 29 February 2019, the earliest possible timeframe for implementation of the recommended changes to the Reserve Capacity Mechanism arrangements is for the 2019 Reserve Capacity Cycle.[37]

The Public Utilities Office recommends that implementation occur in time for the 2019 Reserve Capacity Cycle in order to provide earlier market benefits resulting from improved capacity pricing arrangements and reduce the level of market uncertainty as to design of the Reserve Capacity Mechanism.

This timing would also avoid distraction of focus from implementation of a constrained network access model for the SWIS, noting that the revised approach to capacity pricing is discrete from these reforms. Industry feedback was nearly unanimous in expressing support for a 2019 Reserve Capacity Cycle implementation timeframe.

[37] For details on the extension of the 2018 Reserve Capacity Cycle see http://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Reserve-capacity-timetable.

The Public Utilities Office has worked with AEMO to develop the implementation timeline detailed below in Table 5.1. Delays to this schedule could occur should unexpected complexity arise during the implementation process. The Public Utilities Office is continuing to work closely with AEMO to ensure that suitable contingency arrangements can be implemented, if required, to ensure implementation of the recommended reforms coincident with the 2019 Reserve Capacity Cycle.

**Table 5.1: Implementation schedule for capacity pricing reforms**

| Milestone | Due Date |
|---|---|
| Ministerial endorsement and public release of the Final Recommendation Report | Late February 2019 |
| Stakeholder consultation on draft Market Rule amendments to assist preparation of a final set of Market Rules | Late February to late April 2019 |
| Minister for Energy makes Market Rule amendments using repeal and replace process | Late April 2019 |
| 2019 Reserve Capacity Cycle certification process commences | 1 May 2019 |

## 5.3 Overview of recommended capacity pricing model for implementation

The Public Utilities Office is recommending that the following changes to the Reserve Capacity Mechanism arrangements be implemented effective from the 2019 Reserve Capacity Cycle onwards:

- Capacity price curve to be based on linear joining of three price points:
  - A price cap of 1.3 times the BRCP;
  - An absolute zero (AZ) point at a level of 30 per cent excess capacity; and
  - An economic zero (EZ) point at a capacity price equal to 50 per cent of the BRCP and at a level of excess capacity of 10 per cent.
- That the price curve formula below be prescribed in the Market Rules:
  - $Capacity\ Price = Max\ (Segment\ 1,\ Segment\ 2,\ 0) * BRCP$
    - $Segment\ 1 = \frac{EZ\ BRCP\ Factor\ - BRCP\ Cap\ Factor}{EZ} \times Excess\ Capacity + BRCP\ Cap\ Factor$
    - $Segment\ 2 = \frac{EZ\ BRCP\ Factor}{EZ - AZ} \times (Excess\ Capacity - AZ)$

Where

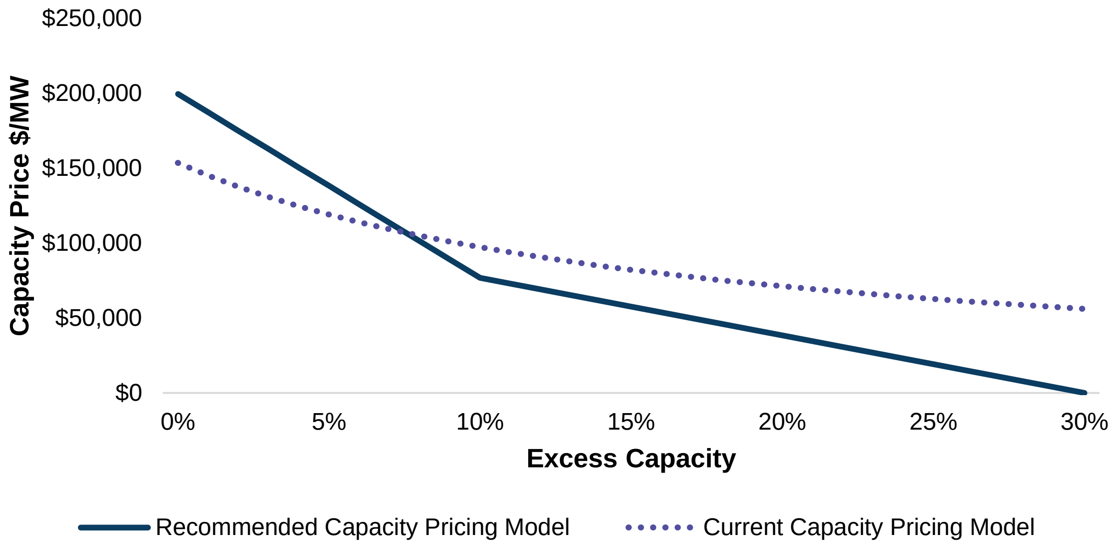
- BRCP Cap Factor = 1.3
- EZ BRCP Factor = 0.5
- EZ = 10 per cent
- AZ = 30 per cent

- All new capacity resources entering the WEM following implementation of the revised capacity price arrangements receive a capacity price for each capacity year based on the above formula.
- New capacity providers will have the option of the “floating” price or a five-year price lock-in set at the capacity price in their year of entry.
- Existing capacity resources at the time of implementation of the new arrangements to receive capacity prices based on the above formula, with annual capacity prices being restricted to a band between $110,000 and $135,000 per megawatt of certified capacity (CPI adjusted) for a period of 10 years.
- AEMO to award capacity credits to new floating price capacity and existing capacity providers first and, if an adequate level of capacity is not achieved, then award all capacity resources that opted for a price lock-in.
- All uncontracted capacity will be settled by AEMO at the respective price and settled under the Targeted Reserve Capacity Cost and Shared Reserve Capacity Cost settlement calculations.
- Demand side management capacity resources to be priced based on the above formula, however these resources will be ineligible for a five-year price lock-in.
- Demand side management capacity resources will be required to provide a yearly Reserve Capacity Security of 25 per cent of anticipated annual capacity payments, in line with existing requirements for new capacity providers. [38]
- A yearly random test of each Demand Side Program.
- All generators to be required to provide three years of notice ahead of closure.
- Capacity refunds to be charged at the respective capacity price received by the capacity provider.

[38] See clause 4.13 of the Market Rules.

Figure 5.2 shows the existing and proposed capacity price curves.

**Figure 5.2: Comparison of expected capacity price outcomes under existing and recommended arrangements**




Note: Calculated using a Benchmark Reserve Capacity Price of $153,600.

The Draft Recommendations Report showed forward capacity prices under the existing and proposed reform arrangements based on data in the AEMO 2018 Electricity Statement of Opportunities, noting that the AEMO forecast of excess capacity at levels between four and six percent, reducing to two per cent in 2026-27 Capacity Year, meant that the expected pricing outcomes under the two approaches were not significantly different. It was also noted that should the level of excess capacity increase, the new pricing model would result in a much sharper reduction in capacity price outcomes.

Forecasting the capacity supply-demand balance, and therefore capacity prices, in the current state of the WEM is challenging, due to future uncertainty as to the quantum and timing of the market entry and exit of capacity, including the types of capacity services that may be required to maintain system frequency addressing the effects of increasing intermittent generation and a changing profile of electricity consumption. Other factors include the effects of separate initiatives being pursued as part of the broader WEM reform program and outcomes of the current Economic Regulation Authority review on the method for capacity certification of intermittent generation facilities and a future review as to the methodology for setting of the BRCP.

Considering the potential entry of new certified capacity through the Generator Interim Access solution and other means, additional demand side management resources and potential capacity withdrawals, the Public Utilities Office anticipates that excess capacity will remain between one extreme of a tight supply-demand balance (zero to four per cent excess capacity) and a higher level of surplus (of eight to 12 per cent). The in-built incentives under the recommended pricing model are intended to encourage a suitable supply-demand balance.

Table 5.3 details the incremental changes in capacity pricing outcomes as the level of excess capacity in the WEM increases, again demonstrating that the recommended pricing model will result in a much sharper reduction in capacity price outcomes.

**Table 5.2: Capacity price outcomes under existing and recommended arrangements with increasing excess capacity**

| Level of Excess Capacity | Current Arrangements | Recommended Arrangements |
|---|---|---|
| 0% | $153,600 | $199,680 |
| 1% | $145,200 | $187,392 |
| 2% | $137,671 | $175,104 |
| 3% | $130,885 | $162,816 |
| 4% | $124,736 | $150,528 |
| 5% | $119,138 | $138,240 |
| 6% | $114,022 | $125,952 |
| 7% | $109,327 | $113,664 |
| 8% | $105,003 | $101,376 |
| 9% | $101,009 | $89,088 |
| 10% | $97,307 | $76,800 |
| 11% | $93,867 | $72,960 |
| 12% | $90,661 | $69,120 |
| 13% | $87,668 | $65,280 |
| 14% | $84,866 | $61,440 |
| 15% | $82,237 | $57,600 |
| 16% | $79,767 | $53,760 |
| 17% | $77,440 | $49,920 |
| 18% | $75,245 | $46,080 |
| 19% | $73,172 | $42,240 |
| 20% | $71,209 | $38,400 |
| 21% | $69,349 | $34,560 |
| 22% | $67,584 | $30,720 |
| 23% | $65,906 | $26,880 |
| 24% | $64,310 | $23,040 |
| 25% | $62,789 | $19,200 |
| 26% | $61,339 | $15,360 |
| 27% | $59,954 | $11,520 |
| 28% | $58,630 | $7,680 |
| 29% | $57,363 | $3,840 |
| 30% | $56,150 | $– |

Note: Calculated using a Benchmark Reserve Capacity Price of $153,600.

Table 5.3 provides an assessment of the recommended capacity pricing model against the seven design objectives from Section 2.

**Table 5.3: Assessment of recommended capacity pricing model**

| | Benchmark | Recommended capacity pricing model | Rating |
|---|---|---|---|
| Price signal for investment | Capacity price needs to reach a high enough level to support new capacity at any point where such capacity is anticipated to be needed. | Recommended capacity pricing model provides adequate price signals at low levels of excess. | ✓ |
| Appropriate exposure to risk | Capacity price should expose participants to risk to an extent that they have a robust incentive to perform reasonable due diligence on whether or not to invest in capacity or contract with capacity resources. | Recommended capacity pricing model creates incentives for participants to contract to hedge against high or low capacity prices. | ✓ |
| Signals for withdrawal or retirement | When persistent excess reserve capacity exists the capacity price should send a credible signal that capacity should be retired or withdrawn from service. | Recommended capacity pricing model will provide signals for capacity withdrawal from the WEM after a desired level of excess capacity is achieved. | ✓ |
| Same capacity price for all equally qualifying resources | Capacity price should work equitably and in a non-discriminatory manner with all forms of capacity (supply and demand) that meet accepted minimum performance targets, including developing forms of capacity such as energy storage resources. | All capacity providers to receive prices based on the same capacity pricing formula. | ✓ |
| Capacity price should only compensate credible, verifiable resources | The Reserve Capacity Mechanism should compensate only credible, verifiable capacity under all scenarios deemed relevant to the establishment and achievement of the resource adequacy target. | The Reserve Capacity Mechanism currently achieves this through certification, security deposits and penalties for non-availability. This will be enhanced by periodic testing of demand side management capacity resources and yearly Security Deposits for this capacity type. | ✓ |
| Promote the most suitable capacity mix over time as demand profiles change | The capacity price curve should accommodate a changing demand profile over time. In particular, it should cope with the possibility that a focus on resource adequacy primarily to meet system "peak" may at a future point in time not be the most relevant way to think about resource adequacy. | The Reserve Capacity Mechanism currently achieves this through interaction of the two components of the Planning Criterion. | ✓ |
| Binding contract against exit | Reserve Capacity Mechanism should form a binding contract such that it is not possible for a resource to propose to exist at some point in the future, collect a reserve capacity payment, and exit without risk or penalty in a way that compromises the ability of replacement capacity resources to be developed in a timely | Improved measures around capacity security deposits for demand side management capacity resources and notice of planned retirements will strengthen capacity commitment. | ✓ |

| | Benchmark | Recommended capacity pricing model | Rating |
|---|---|---|---|
| | manner. This is particularly relevant to demand side management resources. | | |

# Appendix A : Calculating a Western Australian Value of Customer Reliability

## A.1 Overview

The basic VCR inputs were taken from the 2014 AEMO study of the Value of Customer Reliability in the National Electricity Market (NEM)[39]. The AEMO study determined different VCRs for residential customers; small, medium and large commercial customers; and industrial customers with regard to outages:

- of different durations, and
- occurring in different seasons, on different days (i.e. weekdays vs weekends) and at different times of day (i.e. peak vs off-peak hours).

Following an approach used by Western Power in adapting the NEM VCR results for use in Western Australia, the South Australian residential VCR results were considered as the most suitable proxy for the VCR of locally based residential customers and the national VCR results for non-residential customers in Western Australia[40].

The analysis for Western Australia focused on the VCR results for the top end of the load duration curve, specifically the 200 half hours of highest generation system demand. To characterise outages occurring in these trading intervals:

- AEMO load summary data was used to identify the top 200 half hours in each year from 2010 to 2017, inclusive;
- the season, day-type and time-of-day period in which each of those half hours occurred in each year was also identified, based on the following definitions:
  - seasons:
    - summer: December through to March inclusive;
    - winter: June to August inclusive; and
    - shoulder: all other months.
  - day type:
    - weekdays: Monday through Friday; and
    - weekends: Saturday and Sunday.
  - time of day (for all seasons):
    - peak period: 7.00 am to 10.00 pm on weekdays
    - off-peak period: all other hours on weekdays and all hours on weekends; and

39 AEMO, Value of Customer Reliability - Final Report, September 2014.

40 See Western Power, Attachment 6.4, Estimation of value of customer reliability for Western Power's network, Access Arrangement Information, 2 October 2017. The Western Power study determined that South Australia provided the best proxy for Western Australia for the residential customer class, noting that the AEMO study did not report non-residential VCR results at the jurisdictional level.

- re-assembled the half hours in each year to identify the extent to which they were contiguous, so that the duration of each outage could be determined.

Table A.1 and Table A.2 below characterise the outages identified in terms of the season, day type and time of day on which they occurred, and their duration.

**Table A.1: Distribution of outages in top 200 half hours by season, day type and time of day, 2010 to 2017**

| Season and time of day of outage | Half hours of outage | Per cent of total outage time in the 200 highest load half hours |
|---|---|---|
| Summer weekday peak | 1,405 | 87.8% |
| Summer weekday off-peak | 0 | 0 |
| Summer weekend | 130 | 8.1% |
| Winter weekday peak | 54 | 3.4% |
| Winter weekday off-peak | 0 | 0 |
| Winter weekend | 4 | 0.3% |
| Shoulder | 7 | 0.4% |
| Total | 1,600 | |

Source: Oakley Greenwood (OGW) analysis of AEMO metered generation data for the Public Utilities Office.

**Table A.2: Distribution of outage durations in top 200 half hours by season, day type and time of day, 2010 to 2017**

| Season, day type and time of day of outage | Percentage of top outages of different durations occurring in the 200 highest load half hours | | | | |
|---|---|---|---|---|---|
| | 0 to 1 hr | 1 to 3 hrs | 3 to 6 hrs | 6 to 12 hrs | Total |
| Summer weekday peak | 16.7% | 16.7% | 20.7% | 22.7% | 76.8% |
| Summer weekday off-peak | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Summer weekend | 3.4% | 2.0% | 3.4% | 1.0% | 9.9% |
| Winter weekday peak | 3.9% | 2.5% | 0 | 0 | 6.4% |
| Winter weekday off-peak | 4.4% | 0.5% | 0 | 0 | 4.9% |
| Winter weekend | 1.5% | 0 | 0 | 0 | 1.5% |
| Shoulder | 0 | 0 | 0.5% | 0 | 0.5% |
| Total | 30.0% | 21.7% | 24.6% | 23.6% | 100% |

Source: OGW analysis of AEMO metered generation data.

It was not possible from the AEMO data to establish separate outage characteristics for different customer classes.

### A.1.1 Residential top 200 half hour VCR

The VCR values determined in the 2014 AEMO study for South Australian residential customers are shown in Table A.3 below.

**Table A.3: Residential VCR values ($2014/kWh) by season, day type, time of day and duration**

| Season, day type and time of day of outage | VCR ($2014/kWh) for different outage durations | | | |
|---|---|---|---|---|
| | 0 to 1 hr | 1 to 3 hrs | 3 to 6 hrs | 6 to 12 hrs |
| Summer weekday peak | 41.49 | 36.2 | 28.07 | 18.11 |
| Summer weekday off-peak | 14.36 | 33.25 | 29.32 | 19.84 |
| Summer weekend | 14.36 | 33.25 | 29.32 | 19.84 |
| Winter weekday peak | 41.49 | 36.2 | 28.07 | 18.11 |
| Winter weekday off-peak | 14.36 | 33.25 | 29.32 | 19.84 |
| Winter weekend | 14.36 | 33.25 | 29.32 | 19.84 |
| Shoulder | 14.36 | 33.25 | 29.32 | 19.84 |

Source: AEMO, Value of Customer Reliability, September 2014, Appendix – Table 8.

Combining the information in Tables 2 and 3 yields a residential VCR of $28.96/kWh in 2014 dollars. Using the Reserve Bank of Australia CPI inflator for Western Australia of 102.4%[41], this figure becomes $29.66/kWh.

### A.1.2 Non-residential top 200 half hour VCR

The AEMO study calculated VCRs for the following non-residential customer segments:

- small, medium and large agricultural customers,
- small, medium and large commercial customers, and
- small, medium and large industrial customers.

VCRs were also calculated for the following types of transmission-connected industrial customers: metals; wood, pulp and paper; and mining.

All of these VCRs were calculated at the NEM level as the number of completed VCR surveys completed by these customers was insufficient to support analysis at the jurisdictional level.

Western Power used the small and large commercial customer and industrial customer segments in work to develop a Western Australia VCR based on the 2014 AEMO study findings.

Table A.4, Table A.5 and Table A.6 present the VCR values identified in the 2014 AEMO study for these customer segments.

[41] Australian Bureau of Statistics, 6401.0 Consumer Price Index, Australia.

**Table A.4: Small commercial VCR values ($2014/kWh) by season, day type, time of day and duration**

| Season, day type and time of day of outage | VCR ($2014/kWh) for different outage durations | | | |
|---|---|---|---|---|
| | 0 to 1 hr | 1 to 3 hrs | 3 to 6 hrs | 6 to 12 hrs |
| Summer weekday peak | 94.83 | 48.87 | 28.03 | 17.03 |
| Summer weekday off-peak | 96.66 | 54.19 | 31.67 | 19.67 |
| Summer weekend | 76.86 | 55.62 | 34.21 | 22.37 |
| Winter weekday peak | 94.83 | 48.87 | 28.03 | 17.03 |
| Winter weekday off-peak | 96.66 | 54.19 | 31.67 | 19.67 |
| Winter weekend | 76.86 | 55.62 | 34.21 | 22.37 |
| Shoulder | 76.86 | 55.62 | 34.21 | 22.37 |

Source: AEMO, Value of Customer Reliability, September 2014, Appendix – Table 13.

**Table A.5: Large commercial VCR values ($2014/kWh) by season, day type, time of day and duration**

| Season, day type and time of day of outage | VCR ($2014/kWh) for different outage durations | | | |
|---|---|---|---|---|
| | 0 to 1 hr | 1 to 3 hrs | 3 to 6 hrs | 6 to 12 hrs |
| Summer weekday peak | 69.93 | 36.04 | 20.67 | 12.56 |
| Summer weekday off-peak | 71.28 | 39.96 | 23.36 | 14.50 |
| Summer weekend | 56.68 | 41.17 | 25.23 | 16.50 |
| Winter weekday peak | 69.93 | 36.04 | 20.67 | 12.56 |
| Winter weekday off-peak | 71.28 | 39.96 | 23.36 | 14.50 |
| Winter weekend | 56.68 | 41.17 | 25.23 | 16.50 |
| Shoulder | 56.68 | 41.17 | 25.23 | 16.50 |

Source: AEMO, Value of Customer Reliability, September 2014, Appendix – Table 15.

**Table A.6: Industrial VCR values ($2014/kWh) by season, day type, time of day and duration**

| Season, day type and time of day of outage | VCR ($2014/kWh) for different outage durations | | | |
|---|---|---|---|---|
| | 0 to 1 hr | 1 to 3 hrs | 3 to 6 hrs | 6 to 12 hrs |
| Summer weekday peak | 123.54 | 59.95 | 33.73 | 18.29 |
| Summer weekday off peak | 100.97 | 52.43 | 29.97 | 16.41 |
| Summer weekend | 86.61 | 54.68 | 32.49 | 18.21 |
| Winter weekday peak | 123.54 | 59.95 | 33.73 | 18.29 |
| Winter weekday off peak | 100.97 | 52.43 | 29.97 | 16.41 |
| Winter weekend | 86.61 | 54.68 | 32.49 | 18.21 |
| Shoulder | 86.61 | 54.68 | 32.49 | 18.21 |

Source: AEMO, Value of Customer Reliability, September 2014, Appendix (average of values in Tables 16, 17 and 18).

Combining the information in Tables A.4, A.5 and A.6 with information on the distribution of outage durations in the top 200 half hours by season, day type and time of day provides the VCR values for non-residential customer segments shown in Table A.7 below.

**Table A.7: Non-residential customer segment VCRs for the top 200 load half hours**

| Non-residential customer segment | VCR ($/kWh) | |
|---|---|---|
| | $2014 | $2017 |
| Small commercial | 49.67 | 50.86 |
| Large commercial | 36.63 | 37.51 |
| Industrial | 59.74 | 61.17 |

Source: OGW analysis.

### A.1.3 SWIS-wide top 200 half hour VCR

Combining the residential and non-residential customer segment VCRs to produce a VCR value for the SWIS requires weighting of the segment VCRs by the relative consumption of these customer segments over the 200 half hours of highest load. While Western Power does not specifically record data by customer class and consumption by the top load half hours, it was able to provide energy consumption by the various customer segments based on the 2018 system peak.

Using that information to create weighting factors, the SWIS-level VCR was calculated as shown in Table A.8.

**Table A.8: Segment contributions and SWIS-level VCR ($2017/kWh)**

| Segment | VCR ($2017/kWh) | Weighting factor | Contribution to SWIS level VCR ($2017/kWh) |
|---|---|---|---|
| Residential | 29.66 | 35.2% | 10.44 |
| Small commercial | 50.86 | 8.0% | 4.07 |
| Large commercial | 37.51 | 23.4% | 8.78 |
| Industrial | 61.17 | 33.4% | 20.43 |
| Total | | 100% | 43.72 |

Source: OGW analysis, weighting factors provided by Western Power.

Table A.9 shows the results of a separate VCR calculation conducted by Western Power.

**Table A.9: Western Power segment and SWIS-level VCR values**

| Segment | VCR ($indexed 2017/kWh) | Weighting factor | Contribution to SWIS level VCR ($2017/kWh) |
|---|---|---|---|
| Residential | 34.2 | 35.2% | 12.04 |
| Small commercial | 52.1 | 8.0% | 4.17 |
| Large commercial | 42.7 | 23.4% | 9.99 |
| Industrial | 65.8 | 33.4% | 21.98 |
| Total | | 100% | 48.18 |

Source: Western Power

Comparing Tables A.8 and A.9, Western Power's SWIS-level VCR is 10 per cent higher than the value calculated by Public Utilities Office. This reflects the fact that the segment VCR values differ between the two calculations and may be because the segment VCR values were derived for different periods.

Western Power's segment VCR values were based on input data used for its Fourth Access Arrangement (AA4) submission (2 October 2017), which used five years of data (2013-14 to 2017-18 inclusive). By contrast the Public Utilities Office analysis used an eight-year timeframe (2010-11 to 2017-18 inclusive).

The Public Utilities Office repeated the analysis for the same five-year period used by Western Power. Table A.10 outlines the results of this analysis.

**Table A.10: Segment contributions and SWIS-level VCR ($2017/kWh) for 2013-14 to 2017-18**

| Segment | VCR ($2017/kWh) | Weighting factor | Contribution to SWIS level VCR ($2017/kWh) |
|---|---|---|---|
| Residential | 29.96 | 35.2% | 10.55 |
| Small commercial | 55.76 | 8.0% | 4.46 |
| Large commercial | 41.12 | 23.4% | 9.62 |
| Industrial | 67.11 | 33.4% | 22.42 |
| Total | | 100% | 47.04 |

Source: OGW analysis, weighting factors provided by Western Power.

Use of the same analysis timeframe reduced the difference between the Western Power and Public Utilities Office SWIS-level VCR values to just 2.4 per cent, though more sizeable differences exist at the segment VCR levels.

As the SWIS-level VCR is of most relevance to development of the capacity price curve the two values were sufficiently similar to warrant the use of either. Western Power's calculation used a similar base for its AA4 submission. This value was considered more useful for its consistency with other regulatory processes and on the basis that the higher SWIS-level VCR value provided for a more conservative assessment in contributing to a marginally higher value of reserve capacity at peak periods.