Government of Western Australia
Department of Finance
Public Utilities Office

Position Paper on Reforms to the Reserve Capacity Mechanism

Department of Finance | Public Utilities Office

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Executive summary

There is currently a large excess of capacity within the Wholesale Electricity Market which is imposing a substantial cost on electricity consumers. The cost of this excess in the 2016-17 Capacity Year is estimated at around $116 million.

Given the load growth currently forecast for the South West Interconnected System and existing accredited capacity, the value of incremental capacity is likely to remain close to zero until the 2024-25 Capacity Year. In contrast the current capacity price is $120,199 per megawatt.

The Reserve Capacity Mechanism in its current form is unlikely to motivate decisions that will return the market to an acceptable level of balance of load and capacity.

There is a need for major change to the Reserve Capacity Mechanism to reduce the cost of the current capacity excess to consumers and to provide stronger signals to the sector for efficient delivery of capacity to the market over the longer term.

This Position Paper outlines the Electricity Market Review's proposed reforms to the Reserve Capacity Mechanism.

The proposed reforms to the Reserve Capacity Mechanism have four principal elements.

1. Adoption of an auction as the basis for procurement of capacity, with the first auction to occur when the market has reached an acceptable level of balance.

2. Transition arrangements for a period for the introduction of the auction that will involve maintaining the existing administered price mechanism but with a steeper pricing curve and a differential treatment of demand side management.

3. Implementation of measures to harmonise demand side management availability requirements with requirements for conventional generators, for both the transitional arrangements and under the capacity auction.

4. Stronger commercial incentives for all forms of capacity to be made available for dispatch.

A capacity auction is considered the best mechanism for establishing a market price for capacity to deliver long term value to electricity users. The Position Paper outlines elements of the proposed high level design for a capacity auction, including an auction demand curve.

The proposed design will need to be calibrated prior to implementation to determine the specific auction parameters. Controls to mitigate the exercise of market power in the capacity auction will also need to be considered.

Conducting an auction with a large level of capacity excess may result in undesirable disruption to the electricity market. Accordingly, it is proposed that the first auction will only occur three years ahead of that capacity year when the capacity excess is forecast by the Market Operator to be at a level of five to six per cent. The time period until an auction is introduced will depend upon the time path of energy demand and on any future additions or withdrawals of capacity in the market.

On current demand and capacity projections, the capacity auction would not be triggered until beyond 2025.

For an auction to be introduced in the nearer term a substantial volume of capacity would need to exit the market. Under current demand projections a forecast withdrawal of around 600 MW of capacity would result in the first auction occurring in 2017 for procurement of capacity in the 2020-21 Capacity Year.

Transitional arrangements are proposed to commence for the (postponed) 2015 Capacity Cycle. There are two principal elements of these proposed transitional arrangements.

- The formula for the calculation of the Reserve Capacity Price will be changed to have a steeper pricing curve for capacity: a price slope of negative five rather than the existing slope of negative one. This price slope will be maintained for the duration of the transition period.
- Demand side management will be removed from the Reserve Capacity Mechanism and subject to a different administered-price arrangement. Demand side management capacity will receive a price based on expected dispatch and the expected economic value of demand side management in meeting the reliability requirement.

The proposed measures to harmonise the requirements for availability of demand side management with other forms of generation capacity are largely those measures previously developed and proposed by the Independent Market Operator. Changes include an increase to daily availability requirements to 12 hours for each business day and 200 hours of dispatch per year, along with changes to the calculation of the capacity baseline. Demand side capacity will also be required to provide real time telemetry data to the system operator.

The proposed measures to strengthen the incentives on capacity providers to make capacity available for dispatch are also largely consistent with those measures previously developed and proposed by the Independent Market Operator, involving dynamic refund pricing reflecting the volume of surplus capacity, with capacity refunds revenue returned to market generators. A limit on the amount of capacity refund exemptions due to planned outages will be introduced.

These reforms to the Reserve Capacity Mechanism will deliver a more efficient capacity procurement process over the longer term and a more value-reflective capacity cost to electricity consumers in the short to medium term. The transition period will facilitate an orderly adjustment in the capacity balance and the auction mechanism.

The Electricity Market Review invites submissions from stakeholders on the proposed reforms to the Reserve Capacity Mechanism.

1. Introduction

This Position Paper proposes reforms to the Reserve Capacity Mechanism in the Wholesale Electricity Market.

There is currently a substantial excess of capacity: 1,061 megawatts in excess of the Reserve Capacity Requirement.[1] Given the Independent Market Operator's latest demand outlook, a large quantity of excess capacity may be sustained into the mid 2020s.[2]

The persistence of substantial excess capacity reveals a fundamental problem with the current form of the Reserve Capacity Mechanism: electricity consumers are paying a large cost for excess capacity that delivers little to no value in delivering the target reliability of the electricity system.

Without reform, the current Reserve Capacity Mechanism is unlikely to resolve this problem. Resolution requires that the capacity price better signal the economic value to the market of incremental capacity.

The Electricity Market Review is therefore considering reforms that will provide a means for capacity pricing to be determined through a market process, and for this pricing mechanism to be introduced in an orderly manner that reduce the current excessive cost to electricity consumers but avoids undue financial disruption of market participants. The intent is to provide stronger price signals for efficient entry and exit of capacity according to the needs of the market, and ensuring that the system security and reliability objectives are achieved at least cost for consumers.

Building on the investigations and recommendations of Phase 1 of the Electricity Market Review, this objective is considered to be best achieved – given the decision of government to maintain a capacity market – by implementing a capacity auction after period of transitional arrangements to bring the capacity market back into reasonable balance of capacity and load.

The purpose of this Position Paper is to set out the rationale, options and preferred high-level design for introduction of a capacity auction. The Position Paper sets out:

- the shortcomings of the existing Reserve Capacity Mechanism that are to be addressed by reforms;
- the objectives and principles for proposed reforms;
- high-level design options for a capacity auction and a preferred design;
- proposed changes to capacity availability requirements; and
- arrangements for a transition period before introduction of a capacity auction.

1 The 2016-17 Reserve Capacity Target is 4,557 MW: http://wa.aemo.com.au/docs/default-source/Reserve-Capacity/2014-electricity-statement-of-opportunities---executive-summary.pdf?sfvrsn=0. For the 2016-17 Capacity Year 5,618.442 MW of capacity was assigned: http://wa.aemo.com.au/docs/default-source/Reserve-Capacity/2016-2017-capacity-yeare6e1953f29c46dc8b2c9ff0000bd36b5.pdf?sfvrsn=0.

2 Public Utilities Office analysis and Independent Market Operator 2014 Electricity Statement of Opportunities.

It is also possible that the other reforms being progressed by the Electricity Market Review will have consequential effects on final design of the Reserve Capacity Mechanism, in particular the introduction of a "constrained access" model of network and market operation. These effects are not addressed in this Position Paper but will be the subject of future consultation.

This Position Paper does not address the Capacity Reliability Requirement, which may also be subject to further consideration.

Submissions from stakeholders are invited on the proposed reforms to the Reserve Capacity Mechanism. While specific matters on which submissions are sought are identified throughout this paper, submissions need not be limited to these items.

2. The need for reform

The Wholesale Electricity Market in Western Australia was designed during a period of forecast high demand growth and concerns of insufficient investment in generation capacity to meet this growth.

On this basis designers of the Wholesale Electricity Market determined that the South West Interconnected System (SWIS) required a separate capacity market with the Independent Market Operator having responsibility to procure sufficient capacity to meet demand plus a margin for system support and reserve.

The resultant (and current) Reserve Capacity Mechanism is a priced-based mechanism to promote investment in capacity. Under this mechanism, the payment for the provision of capacity is set administratively pursuant to a formula established within the Wholesale Electricity Market Rules. Both the reserve capacity price and capacity requirement are established by the Market Operator and there is a supply response from capacity providers that determines the quantity of existing and new capacity in the market.

The administered price is adjusted down when more than the required capacity is offered and procured, but the downwards adjustment of price is relatively gradual and by erring towards encouraging investment results in a high capacity price being offered to the market, even when there is a substantial excess of capacity over the Reserve Capacity Requirement.

It has eventuated that actual demand growth has been far below forecasts made at the time the Wholesale Electricity Market was designed. As a result there is a substantial excess of capacity above the Reserve Capacity Requirement. This imposes a substantial cost to electricity consumers and the Reserve Capacity Mechanism does not provide the necessary mechanisms and incentives to reduce this cost over time, which might occur if generation providers mothballed or retired capacity.

In response to concern that the Reserve Capacity Mechanism required change to address an emerging problem of excess capacity, in 2012 the Independent Market Operator initiated a review of the mechanism. This review identified shortcomings in various aspects of the mechanism, specifically:

- the persistent procuring of excess capacity and the associated cost to electricity consumers;
- pricing of capacity at relatively high values in oversupply conditions;
- attraction to the market of a large quantity of demand side management capacity that has very limited utilisation; and
- inadequate incentives for capacity providers to make capacity available for dispatch.[3]

[3] Capacity credit holders are required to make their capacity available for dispatch throughout the year, with an allowance for planned outages. Where a participant fails to meet this obligation they are required to pay a refund.

The most recent load forecasts are for demand growth to further moderate. In the Independent Market Operator's most recent Electricity Statement of Opportunities[4] the capacity requirement for the 2016-17 Capacity Year reduced by over 500 MW from the previous year, from 5,119 MW to 4,557 MW.

In 2016-17 there will be 23 per cent more capacity in service than the Reserve Capacity Requirement for that year. Taking into account current levels of bilateral contracting, the cost of this excess capacity in 2016-17 will be around $116 million. This imposes a substantial cost on electricity customers.

Demand side capacity that has entered the market in response to the Reserve Capacity Mechanism represents 10 per cent of all capacity in 2016-17 (560 MW of total certified capacity of 5,618 MW).[5] There are two main reasons for this entry of a large amount of demand side capacity.

First, the cost drivers of demand side capacity are very different from supply side capacity. Compared to typical generation assets, demand side capacity has a low upfront investment cost and a high opportunity cost of dispatch.

Secondly, the current requirements placed on the frequency and the duration that demand side capacity can be dispatched are less onerous than for supply side capacity, meaning that demand side capacity is highly unlikely to be dispatched. These two factors combined have presented a strong commercial incentive for the entry of demand side resources to participate in the Reserve Capacity Mechanism that does not align with the needs of electricity users, or the value these resources have contributed to the market.

Factors other than the Reserve Capacity Mechanism have contributed to the over-supply of capacity. These include an over-forecasting of demand by the Independent Market Operator; State Government actions influencing investment in new capacity; and the Commonwealth Government Renewable Energy Target Scheme.

Regardless of the causes of excess capacity, if left unchanged the Reserve Capacity Mechanism will continue to sustain substantial excess capacity (Figure 2.1), with market retailers and, consequently, electricity consumers bearing the cost. In large part, this is because the current price determination under the Reserve Capacity Mechanism will motivate capacity providers to maintain capacity in the system.

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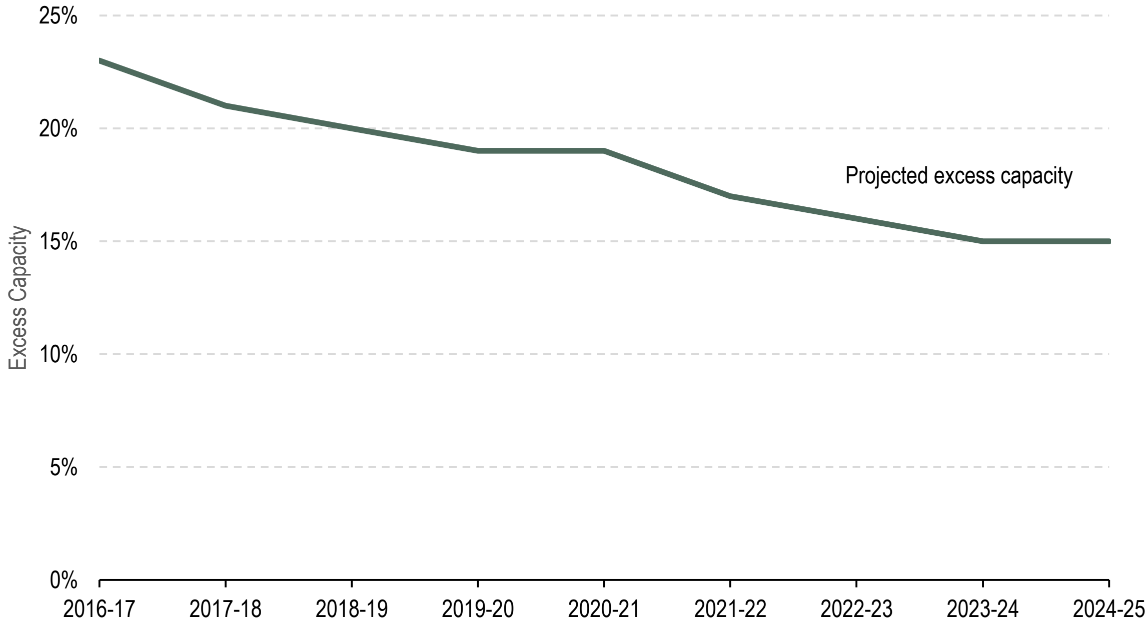
4 http://www.imowa.com.au/docs/default-source/Reserve-Capacity/2014-electricity-statement-of-opportunities76EBFFC3E047.pdf?sfvrsn=0

5 http://wa.aemo.com.au/docs/default-source/Reserve-Capacity/2016-2017-capacity-yeare6e1953f29c46dc8b2c9ff0000bd36b5.pdf?sfvrsn=0

Figure 2.1: Projected excess reserve capacity



Source: Public Utilities Office analysis

Notwithstanding these additional factors, the Reserve Capacity Mechanism does not sufficiently reflect the basic economic principle that prices should be low under surplus supply conditions. The price of capacity should reflect the marginal economic value of capacity to the market in order to send signals for efficient investment in new plant and infrastructure.

This is not the case for the Reserve Capacity Price under the current mechanism which delivers capacity prices that are markedly disconnected from economic value. Accordingly, there needs to be a price correction in the Reserve Capacity Mechanism to reflect the current level of capacity excess and to make the pricing of capacity more responsive to market conditions in the future.

The Electricity Market Review is proposing that this correction occur over by way of competitive capacity auction that determines a capacity price that is reflective of the value of incremental capacity.

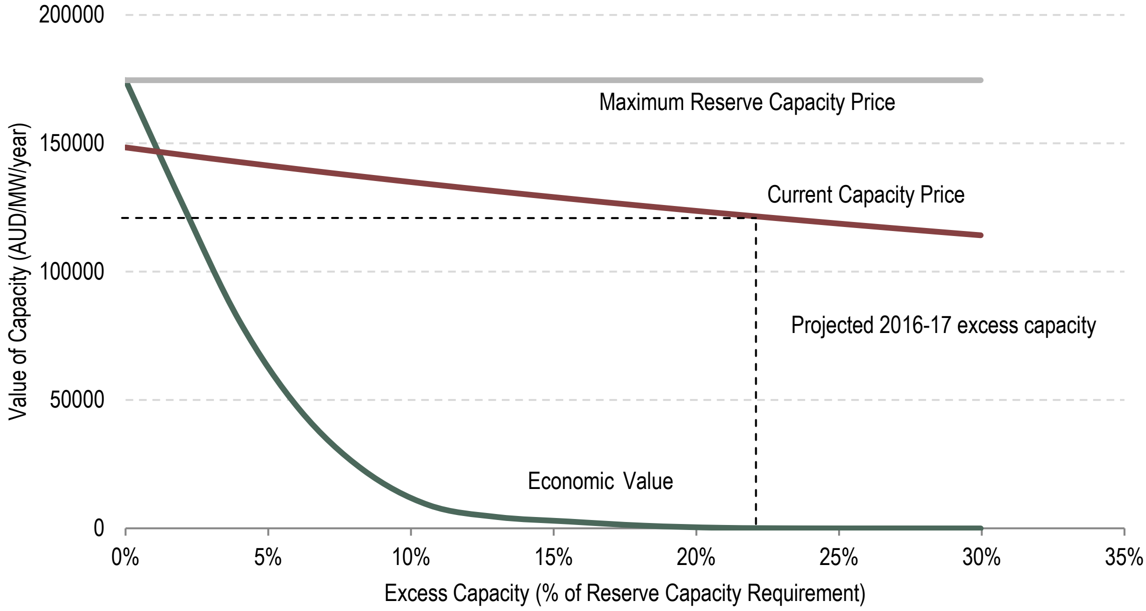
The value of incremental capacity

The value on capacity relates to the purpose of capacity in an electricity market. Capacity is needed to ensure power system reliability: simply put, to avoid blackouts that result from inadequate generation. The value of an additional megawatt of capacity reflects the effect that the additional capacity has by reducing the probability of an avoided loss of load.

As excess capacity increases, the probability of losing load decreases and, hence, the value of additional capacity progressively falls and tends towards zero. This is mathematically represented by a loss of load probability calculation that determines how each incremental megawatt of capacity would alter the probability of load shedding.

Using this calculation the economic value of incremental capacity in the SWIS can be determined as depicted in Figure 2.2.[6]

Figure 2.2: Economic value of capacity in the SWIS against excess capacity



With the current level of certified capacity in the SWIS the incremental value of capacity is effectively zero. At the current level of capacity the probability of losing load is so low that any additional capacity will not materially reduce the likelihood of not meeting demand. Given the load growth currently forecasted for the SWIS and the current levels of capacity, the value of incremental capacity is likely to remain close to zero until the 2024-25 Capacity Year.

In contrast to the value of incremental capacity being close to zero, the current capacity price is $120,199 per megawatt. That is, capacity providers are being paid to maintain capacity in the market, or invest in new capacity, at a price much greater than the value of the incremental capacity to electricity consumers.

6 Specifically this calculation involves probabilistically determining, at a certain level of excess capacity, the likelihood of loss of load occurring under different outage, load and non-scheduled generation scenarios. This delivers a probability of loss of load for each interval across the load duration curve. The cumulative loss of load probability across the whole of the load duration curve is then multiplied by a value representative of the value of lost load. The calculation is conducted at a number of different excess capacity levels and the points in between are interpolated to develop the curve shown in Figure 2.2. The curve has been scaled up to equal the Maximum Reserve Capacity Price at zero % excess to enable the value curve to be compared to the current reserve capacity administered price curve.

3. Reform objectives and principles

The proposed reforms to the Reserve Capacity Mechanism that are set out in this Position Paper have been developed with a view to the following reform objectives and principles.

Objectives

- Capacity market incentives and outcomes are conducive to a least cost, sustainable delivery of capacity and energy to customers.
- The Reserve Capacity Mechanism is to provide strong incentives to introduce capacity when there is a forecasted undersupply and strong incentives to remove capacity in times of oversupply.
- The Reserve Capacity Mechanism is to appropriately provide signals for the efficient retirement of plant.
- The Reserve Capacity Mechanism is to encourage the efficient utilisation of capacity.

Submissions providing feedback on these reform objectives are encouraged.

Principles

- The capacity price should reflect the marginal economic value of capacity.
- The Reserve Capacity Mechanism should not be overly susceptible to volatility but delivers clear and consistent medium term price signals.
- The Reserve Capacity Mechanism should not be susceptible to distortion by the exercise of market power.
- Changes to the Reserve Capacity Mechanism must be consistent with acceptable system security limits.

Submissions providing feedback on these reform principles are encouraged.

4. Proposed reforms to the Reserve Capacity Mechanism

Market-based capacity mechanisms, primarily auction based procurements, have worked well in the United States. In particular, the PJM and ISO-NE (New England) capacity markets have consistently attracted and retained sufficient capacity from private investors to achieve reliability objectives at lower than expected costs. These mechanisms have harnessed vigorous competition across a broad scope of resource types including retro-fitting of plant and the increased participation of demand side management.

A well-designed capacity auction will best achieve the reform objectives and principles for the Reserve Capacity mechanism for the following reasons.

- Capacity prices determined by an auction will be responsive to varying market conditions, producing low prices when there is excess supply and high prices when there is a shortage.
- Capacity prices will better reflect the marginal economic value of capacity.
- Clearer price signals will promote efficient entry and exit of capacity reflective of supply conditions and capacity requirements.

A high-level design has been developed for a capacity auction taking into account features of market designs elsewhere, but tailored specifically to market circumstances in Western Australia. In particular, the proposed design has taken into account relevant experience in the ISO-NE, NYISO (New York) and PJM markets in the United States. Compared to these markets the Wholesale Electricity Market:

- is extremely small and is isolated from other electricity systems;
- has relatively concentrated ownership of generation;
- has a load profile characterised by the potential for extreme summer peaks;
- has relatively low load growth, but with potentially large and lumpy demand additions, creating uncertainties for demand forecasting; and
- has a high level of bilateral contracting.

The dominant market share held by Synergy within the Wholesale Electricity Market presents a challenge for the design of a capacity auction. However, the Electricity Market Review considers that this challenge can be addressed by way of a robust mix of market power mitigation measures and a market design that structurally promotes competition.

The high-level design features of the auction are set out in Table 4.1. A more detailed description of the proposed auction design is provided in Chapter 5.

Table 4.1: High level outline of proposed auction design for Wholesale Electricity Market

Design component	Characteristics	Rationale	Relevant section of paper
Demand curve	• Sloping demand curve • Moderately steep convex demand curve • Moderately high price cap about equal to the Maximum Reserve Capacity Price multiplied by 1.6 • Price to reach the price cap at or near the Reserve Capacity Requirement • Zero-price point at between 15 and 20 per cent excess capacity • Supplementary reserve capacity procurement process not to be used more regularly than one in four years	• Auction would be based on a pre-established demand curve which would be more closely related to the economic value of capacity but take into account the particular circumstances in the Wholesale Electricity Market. • The proposed shape and slope of the demand curve would limit volatility and susceptibility to market power abuse.	5.2
Timing	• Auctions held on a three year forward basis	• A forward period aligned with the construction time of the marginal resource maximises competition and also acts to mitigate the ability to exercise market power.	5.3.2
	• One year delivery period	• A one year delivery period aligns with the definition of the Planning Criterion as a requirement above the annual peak load, and is short enough to allow flexibility for year-to-year entry and exit.	5.3.3
Participation	• Mandatory participation for all capacity providers, including capacity covered by bilateral contracts	• Would promote competition and mitigate against market power abuse.	5.3.1

Design component	Characteristics	Rationale	Relevant section of paper
Auction mechanism	• Single-round sealed bid auction with marginal unit to set auction price	• A single-round sealed bid auction is the simplest design and has worked well in existing capacity markets.	5.3.4
Administration	• Auctions administered by the Australian Energy Market Operator (AEMO), as the entity responsible for administering the Wholesale Electricity Market[7]	• N/A	N/A
Controls	• A back-stop mechanism will be operated by AEMO outside the auction process for meeting any under procurements below the minimum acceptable quantity	• A auction may sometimes result in under procurement. The existing supplementary reserve capacity procurement process will be augmented to procure a capacity shortfall without affecting the integrity of the auction outcome.	5.3.5
Market Power Mitigation	• The auction design will incorporate controls to mitigate the use of market power	• An auction with a steep demand curve is markedly more susceptible to the exercise of market power. A full suite of proposed control measures will not be determined until after the design is finalised. The Electricity Market Review is committed to ensuring robust controls are in place, but without over-regulation.	5.4

[7] As at 30 November 2015, the energy market operator functions performed by the Independent Market Operator were transferred to the Australian Energy Market Operator.

Transition period to a capacity auction

If the auction is implemented in the near-term, the large amount of excess capacity would cause the capacity price to sharply fall to around zero. This sudden reduction in price would be financially disruptive for participants and create risks for the sustainability of the market as a whole.

While is not desirable for consumers to continue paying for capacity that is over-valued, conducting an auction with a large excess of capacity could result in disruption to businesses participating in the capacity market with flow on effects to the energy market. Accordingly, the arrangements for the transition period are intended to balance reducing the cost of the capacity excess to electricity customers against avoiding disruption of the Wholesale Electricity Market from a widespread impairment of generation assets that could occur with a sharp fall in the capacity price.

A period of transition is therefore proposed leading to the first capacity auction. The purpose of the transition is to:

- reduce the cost to customers of the capacity excess by implementing a more value-reflective capacity pricing formula;
- provide greater incentives for the capacity market to move towards balance;
- provide a period of adjustment without widespread disruption of businesses in the Wholesale Electricity Market; and
- allow time to fully design the auction mechanism, and for implementation in an orderly and robust manner.

A transition to a capacity auction arrangement over multiple capacity cycles will provide for a manageable adjustment of the capacity price to better reflect the marginal economic value of capacity and provide participants with a lead-time to prepare for the new capacity market arrangements.

It is proposed that the first reserve capacity auction is triggered where it is expected that there will be a reduction in excess capacity to a level of five to six per cent in the capacity year to which the auction will first apply. This will temper the potential for price shock on introduction of the auction as the auction will return a capacity price that is close to the capacity price under the transitional arrangements. The level of five to six per cent excess capacity will also provide a buffer against higher than forecast growth in demand.

Based on current demand and capacity projections, the capacity auction would not be triggered until beyond 2025.

Earlier implementation of an auction would only occur with retirement of capacity. Retirement of about 500 MW of capacity would bring forward introduction of an auction to 2019 (to apply in the 2022-23 year) and retirement of about 600 MW of capacity would bring forward introduction of an auction to 2017 (to apply in the 2020-21 year) (Table 4.2).[8]

[8] With the three-year-out procurement.

Table 4.2: Projected excess capacity factoring in capacity retirement

Reserve Capacity Year	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25
Current capacity projections	21%	20%	19%	19%	17%	16%	15%	15%
Current capacity projections minus 220 MW of capacity[9]	16%	15%	15%	14%	13%	12%	11%	10%
Current capacity projections minus 495 MW of capacity	10%	9%	9%	8%	7%	**6%**	**5%**	**4%**
Current capacity projections minus 595 MW of capacity	8%	7%	7%	**6%**	**5%**	**4%**	**3%**	**2%**

Changes proposed to treatment of demand side capacity (addressed further below) are expected to lead to a reduction of the volume of excess capacity. However substantial exit of additional capacity would still need to occur to trigger an early commencement of the capacity auction. This could conceivably be achieved through retirement of some ageing and inefficient generation plant in Synergy's portfolio of generation facilities.

For the transition period it is proposed that the administered Reserve Capacity Price adjustment formula will be sharpened to make it more responsive to market conditions and improve price signals. The proposed approach is to replace the existing capacity price formula with a new formula based on a considerably steeper downward sloping demand curve.

It is also proposed that during the transition period demand side resources be removed from the Reserve Capacity Mechanism and priced separately to reflect the value that this form of capacity provides to system reliability. During the transition period and commencing from the next capacity cycle to commence in 2016, the demand side capacity price would be based on an estimate of the expected hours of dispatch and reasonable costs incurred.

Where demand side management capacity is dispatched for more hours than estimated, it will be eligible to receive a higher energy price. These arrangements aim to send more suitable price signals and promote more efficient demand side management participation in the Wholesale Electricity Market. When the auction arrangements commence, demand side management capacity will be subjected to the correct signals to compete on a level playing field with other capacity providers.

There are two further sets of reforms proposed to be introduced in the transition period and maintained when an auction is introduced.

First, changes will be made to the Wholesale Electricity Market Rules to increase the required hours of demand side management availability for dispatch.

[9] The proposed changes to demand side management capacity baseline proposed are expected to reduce demand side capacity by about 220MW.

Secondly, the availability requirements of scheduled generators will be strengthened. It is proposed that Wholesale Electricity Market Rule changes will:

- remove the potential for generators on extended outages to continue to receive full capacity payments;
- adjust capacity refund requirements to better reflect prevailing supply conditions; and
- allow capacity refunds to be recycled to those market generators that are available during the refund periods.

The proposed new arrangements will mirror the package of rule change proposals previously developed by the Independent Market Operator.[10]

Transitional arrangements are described in more detail in Chapter 7 of this paper, and complementary reforms regarding availability and demand side harmonisation are described in Chapter 6.

Proposed reform – introduction of the auction is to be triggered by a forecast of five to six per cent of excess capacity in the year that the capacity price determined by the auction will have effect.

An alternative would be to establish a deadline for introduction of the capacity auction if it has not already been triggered.

Submissions providing feedback on these alternative options are encouraged.

Process to implement transitional reforms and the capacity auction

Following the publication of this Position Paper, there will be a two month submission period for public comment.

Submissions made will be considered during the drafting of changes to the Wholesale Electricity Market Rules for the transitional arrangements, before the proposed changes are published for further consultation.

The target date for commencement of the transitional arrangements is 1 May 2016, in time for the start of the (delayed) 2015 Certification of Reserve Capacity. The transitional reform rules will be required to have commenced prior to the start of the certification period with the aim to remain unchanged throughout the entire capacity cycle, in order to provide certainty to market participants. It is not intended to make retrospective rule changes that affect capacity cycles that have already started.

Detailed design of the capacity auction will commence in the early part of 2016, involving the calibration of the auction parameters as well as developing the required Wholesale Electricity Market Rules. An industry working group is likely to be established for this phase of the reforms.

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[10] Wholesale Electricity Market Rule changes RC_2013_20, RC_2013_10 and RC_2013_09.

5. The capacity auction

5.1 Overview

The fundamental purpose of a reserve capacity mechanism is to promote efficient investment in, and exit of, capacity to maintain long-term reliability of electricity supplies to consumers. This purpose embodies a trade-off between the level of reliability and cost.

Certainty of reliable electricity supplies can only be achieved with a high level of capacity within the electricity system, with consequential high cost for consumers. Balancing reliability and cost is a fundamental design consideration for any capacity market.

This chapter outlines the specifics of the auction design proposed for the Wholesale Electricity Market and how the design chosen responds to the reliability/cost trade-off and meets the other criteria in accordance with the reform principles. As much as possible, design simplicity has also been considered as a benefit when assessing alternative auction designs.

At a high level, this chapter examines:

- why a variable quantity auction design is recommended for the Wholesale Electricity Market and the inherent trade-offs in this consideration;
- the specifics of the auction design proposed and why it is suitable for the Wholesale Electricity Market; and
- potential market power mitigation measures that could be employed in the new auction arrangement.

5.2 Fundamentals of a variable quantity auction

5.2.1 Why use a sloped demand curve?

In an electricity market, and particularly in the context of a reserve capacity auction, the supply and demand for the capacity (and the reliability that capacity provides) are both highly inelastic. On the demand side of the auction inelasticity results from a very high price that users are prepared to pay to avoid a loss of supply.[11] On the supply side, inelasticity results from the high cost of building new capacity and the sunk capacity investment when the new facility has been built; that is, when constructed a generation facility does not readily leave the market.

[11] In the most recent National Electricity Market review of the “Value of Customer Reliability”, the AEMO calculated that the average cost to electricity users of supply being disrupted is $33,460/MWh. http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/SAAF/VCR%20final%20report%20%20PDF%20update%2027%20Nov%2014.ashx

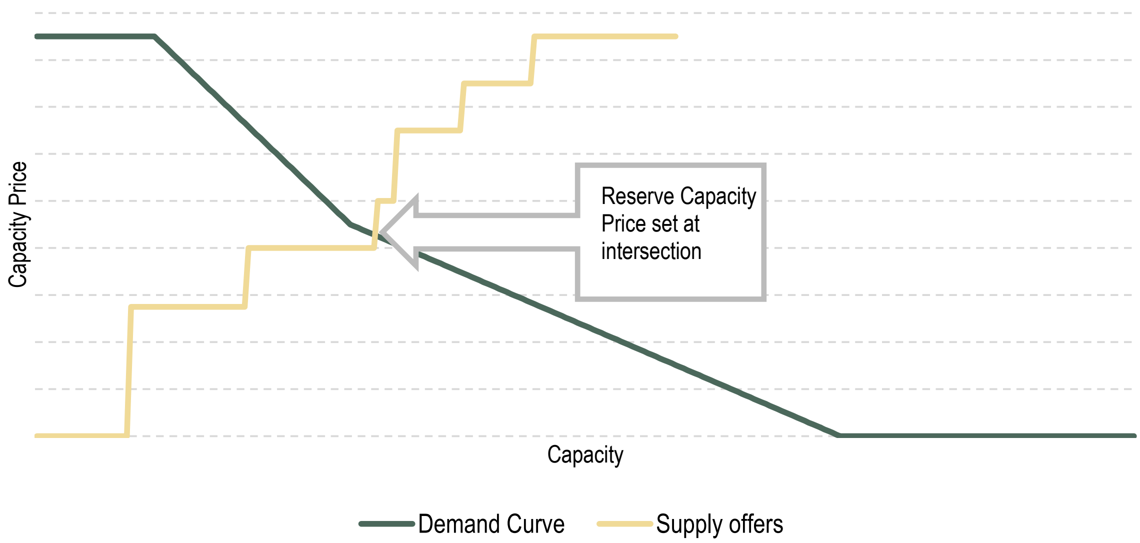
These inelastic qualities of capacity supply and demand mean that an auction with a fixed quantity requirement will, in general, clear at either the price floor or price cap. While this outcome, on a multi-year average basis, is not of itself inefficient, it fails to reflect an incremental value of capacity that is procured over and above the reserve capacity requirement.[12]

Additionally, an implication of a fixed quantity auction with perfectly inelastic demand and supply is that the addition or removal of an incremental unit of capacity can be the difference in the auction clearing at a zero price or at the price cap. A highly volatile price is at odds with the reform principle to minimise price volatility and also makes the capacity auction highly susceptible to the exercise of market power.

This problem is proposed to be addressed in the auction for the Wholesale Electricity Market by using a sloped demand curve that is broadly reflective of the economic value that incremental capacity provides. A sloping demand curve is effectively a variable resource requirement that allows more capacity to be procured where it is offered at a value reflective price.

The schematic below provides an illustrative example of how a sloped demand curve combined with supply offers determines a quantity – price outcome for capacity.

Figure 5.1: Effect of sloped demand curve on clearing of supply offers in a capacity auction



A sloped demand curve has been adopted in each of the capacity markets operating on the east coast of America (PJM, ISO-NE and NY-ISO). The Electricity Market Review has drawn heavily from the experiences of those markets in developing a proposed design for a reserve capacity auction for the Wholesale Electricity Market.

[12] An incremental megawatt of capacity would allow an additional megawatt of load to be served. Past a certain point the cost of the incremental capacity would exceed the value of the lost load.

5.2.2 Demand curve theory and the trade-offs required

In principle the average auction price over all future auctions will equal the long run marginal cost of a new entrant facility. However, individual prices will vary from auction to auction as market conditions fluctuate. Reserve margin outcomes will also fluctuate, especially in the case of an auction with a sloped demand curve.

The degree to which price and quantity outcomes are likely to vary in an auction can be influenced through the auction design, with the design element most affecting the distribution of outcomes being the shape and positioning of the demand curve.

A flatter demand curve will focus on achievement of a tight distribution of price outcomes (similar to the existing Reserve Capacity Mechanism payment function) that minimises price volatility, but the quantity outcomes then become more uncertain. As has also been experienced with the current arrangements, price responsiveness is also reduced. Conversely, a steeper demand curve will minimise quantity uncertainty, but will result in greater price volatility.

Prices and quantities cannot both be precisely pre-specified to the market. These trade-offs reflect the classic “prices versus quantities” problem in regulatory economics.[13]

In addition to the influence that the slope and shape of the demand curve have on expected auction outcomes, the positioning of the curve is also a factor. Positioning means that a demand curve with a defined slope and shape can be moved to the right or left, so that the same price associates with more or less capacity.

“Positioning” in this context is referring to the level of excess capacity that the auction is designed to procure. If the demand curve is positioned to procure, on average, a low level of excess capacity (or no excess), there is a consequential reduction in overall cost but also an erosion in expected reliability levels. A demand curve positioned to procure greater excess capacity will have a higher level of reliability, but also a higher cost.

Positioning of the demand curve must also recognise that the quantity of capacity entering the market will adjust until the price is just high enough to support the incremental entry of the marginal unit of capacity. To achieve a particular target amount of capacity, the demand curve must be positioned so that the reliability requirement corresponds to a price near to the long run marginal cost of capacity.[14]

[13] Weitzman, Martin L. (1974), *“Prices vs. Quantities,”* The Review of Economic Studies, Vol. 41, No. 4 (Oct 1974), pp. 477-491.

[14] More specifically, to achieve a target reliability level (as opposed to megawatt quantity level) it is also necessary to right-shift the demand curve relative to the Planning Criterion (i.e. because there is an asymmetry in that low quantity events hurt reliability more than high quantity events assist). The exact trade-offs among quantity, cost, price volatility, and reliability can be evaluated in simulations to calibrate the demand curve against design objectives. This calibrating of the demand curve will be conducted following a decision on the shape of the demand curve, and is not scheduled to be completed until after the Position Paper has been released for public consultation.

The following sections of this chapter further discuss the above concepts in the context of a capacity auction arrangement for the Wholesale Electricity Market:

- shape and slope of the demand curve and the associated price volatility outcomes; and
- positioning of the demand curve and the associated total cost and reliability outcomes.

5.2.3 Slope and shape of a demand curve for the reserve capacity auction

The Electricity Market Review has assessed three possible demand curve shapes (Figure 5.2).

- **Option 1:** Steep Linear Curve
- **Option 2:** Flat Linear Curve
- **Option 3:** Convex Curve

Figure 5.2: Potential auction demand curves

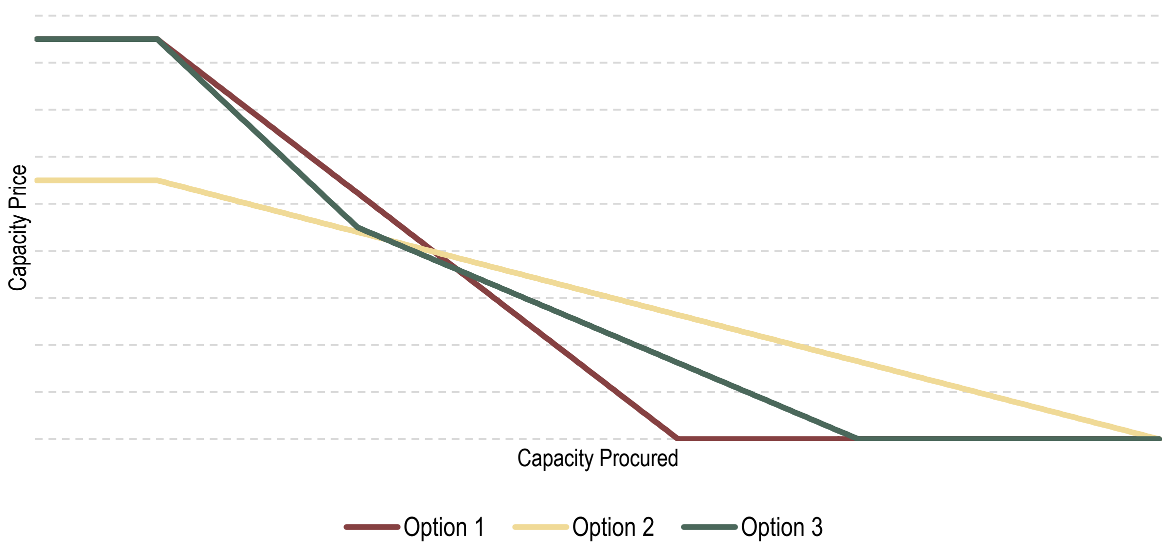


Table 5.1 addresses the degree to which each of these curves meets the reform principles.

In evaluating these three options, one major consideration is the consequences of a steep slope in such a small market as the Wholesale Electricity Market, where the entry or exit of one plant dramatically changes the reserve margin and could move prices a large part of the way from the price cap to the floor if the curve is too steep. Prices would be highly volatile, which could be undesirable for both customers and capacity suppliers; indeed, such volatility could deter entry of an efficient scale plant that would depress its own price for years. This effectively rules out Option 1 (a steep linear curve). NYISO has recognised the need for less steep curves in its smallest Long Island and New York City zones (which are still about twice the size of the capacity market in Western Australia).

A convex shape that is steeper at low reliability values and less steep at high reliability values is favoured (similar to a new curve recently adopted by PJM). The flatter part of the convex curve provides the price stability benefits of a non-steep straight-line curve, without making the entire curve so flat that quantity uncertainty exceeds acceptable deviations from the reserve capacity target. The steeper part of the curve expresses a greater willingness to pay for capacity as the marginal reliability value of capacity increases.

Such a curve would keep the prices from falling too low following entry of capacity but would also let prices rise toward the cap (when the market is in short supply), before the reserve margin becomes intolerably low.

Consumers may be concerned that the slope in the steep portion of a convex curve will incentivise suppliers to withhold capacity. However, the design would ensure that the steep slope occurs only when the system is in short supply and new entry is needed, so competition with new entrants would discipline existing suppliers. Market power considerations are discussed in more detail in section 5.4.

Table 5.1 Alignment of auction demand curves with reform principles

	Performance against reliability criteria	Expected cost	Prices reflective of fundamentals	Price volatility and susceptibility to market power	Simplicity and stability of design
Design option 1: Steep linear curve	• This design is able to be calibrated to ensure any reliability outcome "on average". • Because of the steepness of the slope, the reliability outcomes will be narrowly distributed. • As the reliability outcomes will be narrowly distributed, it is possible to calibrate the curve so that the expected average reliability outcome is close to the reserve capacity requirement (see section 5.2.4 for a discussion on reliability).	This curve, because of the narrowly distributed reliability outcomes, and the ability for the average reliability to be closer to the target reliability outcomes, will result in a low overall cost relative to less steep curves.	A steep demand curve will result in prices relatively reflective of the marginal economic value provided by capacity at the relevant level of excess.	Because there will be a narrow reliability distribution, this design will have a high volatility in price outcomes. Such high volatility makes the market relatively more susceptible to the exercise of market power.	Very simple design option.
Design option 2: Flat linear curve	• This design is able to be calibrated to ensure any reliability outcome "on average". • Unlike Option 1, the distribution of reliability outcomes will be more varied.	This curve, because of the widely distributed reliability outcomes, and the need for the average reliability to be further from the target reliability outcomes, will result in a relatively higher overall cost.	A flatter demand curve will result in prices that are above the marginal value of capacity at the relevant level of excess capacity.	The price outcomes expected from this design will be much more stable relative to the outcomes from a steeper curve. This will make the design much less susceptible to the exercise of market power.	Very simple design option

	Performance against reliability criteria	Expected cost	Prices reflective of fundamentals	Price volatility and susceptibility to market power	Simplicity and stability of design
	• To ensure adequate reliability is procured through the auction each year, the curve will need to be calibrated to have the expected average reliability outcome at a higher level of excess capacity than a steeper curve.				
Design Option 3: Convex curve	• This design is able to be calibrated to ensure any reliability outcome "on average". • This curve will be steeper at low levels of excess capacity and less steep at high levels of excess capacity. • This will result in a distribution of quantity outcomes that is asymmetrical. It is possible to calibrate the curve so that the expected average reliability outcome is close to the reliability requirement.	This curve will likely have capacity costs in between the costs of the flatter and steeper straight-line options above (but will depend on the overall shape and positioning of each).	This design option most accurately reflects the marginal value of capacity.	The price outcomes expected from this design will be more volatile when the supply position is at, or below, the targeted reliability outcome. However, at larger levels of excess capacity, this design option will provide a relatively stable price outcome. Accordingly, this design option is the most susceptible to the exercise of market power when the supply position is at, or below, the targeted reliability outcome (where the exercise of market power is the most disruptive and therefore least desired). However, at larger	Relatively more complex design option than Options 1 and 2, but still simple.

	Performance against reliability criteria	Expected cost	Prices reflective of fundamentals	Price volatility and susceptibility to market power	Simplicity and stability of design
				levels of excess capacity, this design option is the least susceptible to the exercise of market power (where the exercise of market power is generally mitigated and therefore less of a concern).	

5.2.4 Reliability implications of using a sloped demand curve

A sloped demand curve reduces price volatility, allows for the price to reflect the value of incremental capacity additions, and also reduces the potential for the exercise of market power. However, it also increases the uncertainty of the total quantity that will be procured by the auction compared to a vertical demand curve, but will still produce a more certain quantity than under the current design of the Reserve Capacity Mechanism. Quantity uncertainty has obvious implications for ensuring that the reliability objectives of the Reserve Capacity Mechanism are met.

It is possible to address these reliability considerations in the design of the auction by reference to the fundamental auction principle that, over the long run, the average price realised in an auction will equal the long run marginal cost of a marginal new entrant capacity provider.

There is currently an estimated long run marginal cost value of new entrant capacity calculated for the Wholesale Electricity Market.[15] Hence, it is possible to position the demand curve so that the point on the curve equal to the long run marginal cost is located at the desired capacity level. As noted above, “positioned” in this context means moving the demand curve more or less to the right, such that the long run marginal cost price point on the curve can be achieved at different levels of excess capacity (Figure 5.3).

For example, if the point on the demand curve that is equal to the long run marginal cost or Maximum Reserve Capacity Price is set to be equal to the reserve capacity requirement (that is, no excess – Figure 5.3), then it would be expected that, on average, the auction would clear at the reserve capacity requirement.

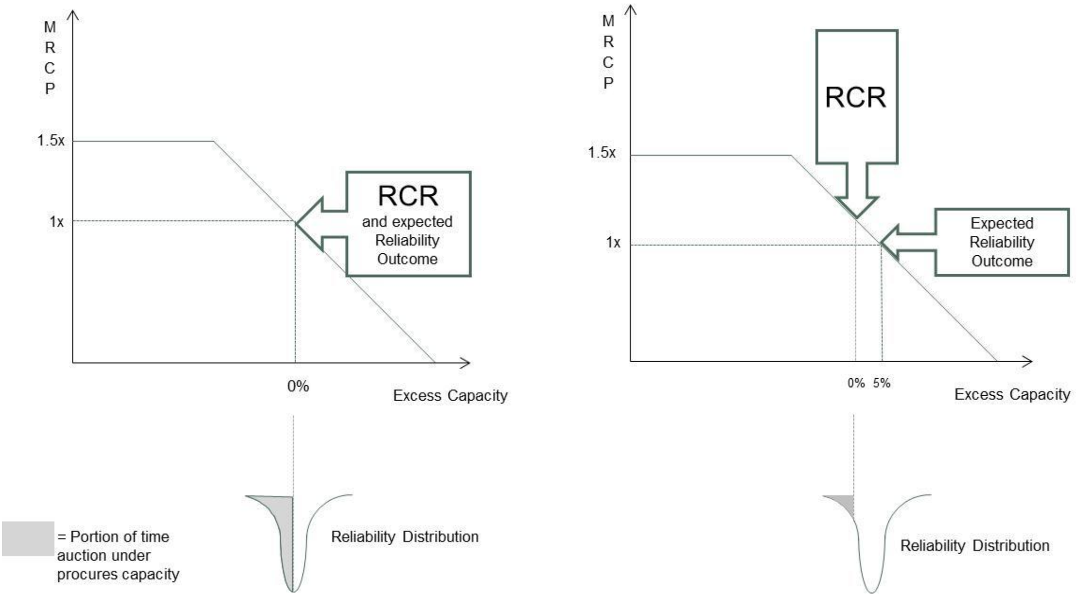
However, this means that “on average” in one out of every two years the reserve capacity auction would not clear sufficient capacity to meet the reserve capacity requirement. To avoid this situation capacity auctions in other markets (for example PJM, ISO-NE and NY-ISO) have been designed so that, on average, their auctions will over procure capacity, and consequently these auctions under procure on a much less regular basis. For example the ISO-NE has recently implemented a demand curve with parameters tuned to procure less than the target quantity only once every three years, and less than the “minimum acceptable” quantity only once every 14 years.[16] This has been achieved by positioning the demand curve further to the right of the reliability target.

The logical implication of designing an auction to under procure less regularly (and therefore increase reliability), is that the auction will have a higher total cost. Hence, there is a trade-off between reliability and cost. The decision on a suitable balance between these two considerations is a matter of judgement.

[15] The Market Operator is required to calculate the current price cap for the administered capacity price mechanism based on an estimate of the LRMC of a 160MW open cycle gas turbine. This value is called the Maximum Reserve Capacity Price (MRCP) under the current Wholesale Electricity Market Rules.

[16] See p. 27 here: http://www.brattle.com/system/testimonies/pdfs/000/000/939/original/Brattle_System_Demand_Curve_Testimony_Newell_Spees_0414.pdf?1400682856

Figure 5.3: Positioning the demand curve - an illustration



For the Wholesale Electricity Market, it is proposed to position the demand curve to ensure the auction is designed to under procure no more than one out of every four years. This proposal is based on the following.

- An auction designed with expectation to under procure, on average, once every four years (i.e. 25 per cent of the time) will decrease the overall costs of the reserve capacity auction by $10 to $20 million per year compared to an auction that is designed to under procure 10 per cent of the time.[17]
- It is likely that there will be alternate capacity resources available to meet the capacity shortfall when it occurs (this capacity would be procured using a modified supplementary reserve capacity procurement process).
- It is unlikely that the cost of the capacity procured through the supplementary reserve capacity procurement process would cost more than the cumulative savings that will result from the lower level of over procurement.[18]
- To date, capacity auctions in the United States have consistently procured additional capacity at average costs below the administratively determined long run marginal cost value.[19] If such an outcome occurs in the Wholesale Electricity Market, it would be expected that under procurement would actually occur less often than 25 per cent of the time.

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[17] These estimates are based the following assumptions:
1. A MRCP = $150,000, increases in this value will increase total savings.
2. A peak forecast error of between 4 and 6 per cent. Reduced forecast error will decrease the total savings.

[18] The total savings are estimated to be between $80 million and $130 million over 10 years [assuming a cap of 1.6*MRCP].

[19] Specific capacity auction results from ISO-NE, PJM, and NYISO can be found at the following locations:
ISO-NE: http://www.iso-ne.com/markets-operations/markets/forward-capacity-market
PJM: http://www.pjm.com/markets-and-operations/rpm.aspx
NYISO: http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

The preliminary position for the Wholesale Electricity Market is to ensure the capacity auction only under-procures capacity, on average, once every four years. This requires the curve to be positioned so that the capacity price equals the long run marginal cost of capacity at about 3 to 4 per cent excess capacity. The exact positioning of the demand curve to achieve this outcome will be finalised during the calibration phase of the auction design.

Appendix A contains a more detailed discussion regarding the theoretical principles and cost estimates contained in this section.

5.2.5 Other demand curve parameters

As outlined in the sections above, the demand curve will have a convex shape and be positioned consistent with an expectation of procuring the reserve capacity requirement in three out of every four years, without the need to use the supplementary reserve capacity procurement process. However, there are several other important demand curve parameters that need to be set to ensure a well-functioning reserve capacity auction. These parameters include:

- the price that the auction should be capped at;
- the level of excess capacity at which the auction should be able to clear at a zero price; and
- the inflection point at which the convex curve changes from very steep in price to a more gradual price reduction.

Each of these matters is addressed in further detail below. The final value of each of the parameters will need to be determined using simulations – this is commonly referred to as “calibrating”, or “tuning” the demand curve. This analysis will be completed following public consultation on the preferred auction design and prior to the Wholesale Electricity Market rule change proposals being prepared.

Auction price cap

One of the most important determinants of how a capacity market demand curve will perform is the price cap. In general, the price cap should be high enough to provide sufficiently strong signals for investment when the reserve margin becomes tight.

How high should the price cap be? One consideration is that the price should be allowed to rise substantially above average when supply is scarce. Higher prices may avoid shortfalls and market interventions if they attract required incremental supply. A very high cap may therefore be desirable, although some limiting of the cap may protect against the exercise of market power (and excessive volatility). The risk of market power being exercised may in any case be partially mitigated by a three year forward market that requires existing suppliers to compete with new entrants, limiting the clearing price to the price at which new entrants are willing to enter.

Another consideration is that, for the demand curves to achieve certain reserve margin targets on average, the price cap should be high enough to allow for occasional high price outcomes that can offset low prices during surplus market conditions. Only then can investors earn a sufficient return on average. Accordingly, the price cap is usually set at a multiple of the long run marginal cost.

One less obvious consideration is uncertainty about the actual value of the net cost of new entrant capacity. The possibility that the administrative estimate of long run marginal cost is too low could set prices throughout the demand curve at an insufficient level to procure new capacity. Both PJM and ISO-NE have set their price caps at the maximum of either:

a. a 1.5 to 1.6 multiple of the net cost of new entry (Net CONE),[20] or

b. long run marginal cost.

A similar price cap arrangement is proposed for the Wholesale Electricity Market. However, to ensure that the auction price is capable of maintaining a long run average price equal to the long run marginal cost of a new entrant facility, the exact value of the cap may vary slightly as part of the calibration phase of this project.

Further, the price should reach the cap when planned reserve margins fall to the lowest acceptable level, so that market signals are maximised and all in-market opportunities for capacity procurement have been exhausted before resorting to back-stop measures. Therefore, the price cap will be set near the reserve capacity requirement. Again, the specifics of this placement will be an outworking of the calibration process.

Zero crossing point

The zero crossing point can be contentious to define because if it is positioned at higher levels of excess capacity, consumers can view it as wastefully paying for large amounts of excess capacity.

However, there are two main reasons to consider keeping it higher. First, a wider, flatter curve helps mitigate price volatility and susceptibility to market power abuse. Secondly, limiting the downside to producers helps attract investment at the target level of reliability without having to set the rest of the curve at an otherwise high price. In other words, if the zero crossing point were moved left on an already-calibrated curve, something else has to increase to provide enough funds to support the target reserve margin.

For the Wholesale Electricity Market, a zero crossing point set between 15 to 20 per cent excess capacity is proposed. This level is based on the following considerations.

- The history of load forecasting inaccuracy for the SWIS suggests an expected level of load forecast uncertainty at the time of capacity procurement in the Wholesale Electricity Market. This forecasting error increases the value of capacity procured three years out from delivery at all levels of excess. The chosen zero crossing point means that a change of 400 MW in the load forecast (which has happened in the SWIS) would move the market halfway from the target to the floor. A zero crossing point that resulted in a price difference between the cap and the floor (or visa-versa) would not be suitable because it would make prices extremely volatile year on year.

[20] Net CONE is the value used in the American markets to estimate the reserve capacity price required to entice investment. Net CONE is equal to the LRMC of the expected marginal new entrant facility minus any expected energy revenue.

- Analysis of the zero crossing points that exist in the smaller markets in the United States when compared to those of the larger markets. For example, the New York City zone (a smaller section of the NY-ISO capacity market that has a locational price for about 10,000 MW of capacity) currently has an 18 per cent zero crossing point. However, the larger ISO-NE and PJM auctions have zero crossing points at less than half of this level of excess (in percentage terms). The demand curve for the Wholesale Electricity Market should be wider than those curves in percentage terms because it is a smaller market.
- The concentration of market share in very few participants within the Wholesale Electricity Market. This means that the auction should, where possible, be designed so as to structurally limit the ability for participants to exercise market power. A demand curve that has a zero crossing point further from zero excess is more structurally competitive, due to the decreased ability to influence market prices through the strategic withholding or development of capacity.

Inflection point

The placement of an inflection point will be largely determined in a calibration exercise after evaluating price volatility, reliability, and cost implications. Factors relevant for consideration include:

- the consistency with the shape of the marginal economic value curve;
- a desire to limit the steepness of the slope (and consequential price volatility and market power implications) on the high-price side; and
- the uncertainty in long run marginal cost (i.e. that the inflection point may be near a low-end estimate of long run marginal cost while the price cap should be substantially above a high-end estimate).

5.3 Auction parameters independent of the demand curve

There are several auction elements that are logically independent of the demand curve:

- participation requirements;
- timing of the auction;
- delivery period;
- style of auction (e.g. sealed bid or descending clock); and
- the supplementary capacity procurement process

How each of these elements is proposed to be dealt with in the specific context of the Wholesale Electricity Market is discussed in detail below.

5.3.1 Participation requirements

The Western Australian market has a large quantity of existing self-supply and bilateral contracts. The auction should not interfere with these arrangements. However, there is the question as to whether contracted capacity (either currently or in the future) should be included in the auction. In other words, should the auction include all resources, or just residual, uncontracted (residual) demand and supply.

Both auction approaches (“all-in” or residual) are nearly equivalent if the demand curve is vertical. In both cases, bilateral contracts are not exposed to market price of capacity. Only the contracted parties’ net positions are exposed (where the quantity exposed to the market price can be exactly determined prior to the auction). This is because bilaterally contracted parties in an all-in auction would likely bid at the floor for any capacity that is contracted bilaterally (because they do not need any money from the auction), and only uncontracted capacity would bid at a price above zero. This is equivalent to a residual auction because bidding at the floor/zero is equivalent to that capacity not being in the market at all.

With a sloping demand curve, because the resource requirement is variable, a higher reserve margin can be procured on behalf of load when more low-cost supplies are available. This in turn increases reliability in an economically efficient manner through reduced probability of loss of load.

Thus, a retail supplier that has contracted for the expected needs of its customers prior to the auction may still end up with a modest additional net purchase or sale of capacity at the resulting auction price. However the uncertainty in that quantity obligation will likely be smaller under a demand curve approach than under the current Reserve Capacity Mechanism design, because of the much steeper demand curve.

Regardless of whether the demand curve is vertical or sloped, a capacity market easily accommodates bilateral contracts since contracted supply and demand are inherently hedged through their contracts. Although the demand and supply settle in the auction at the market (auction) price, the bilateral contract effectively operates as a contract for differences so that the contracted price still applies to the contracted quantity. This is the approach used in ISO-NE and the majority of the PJM market.

An all-in participation requirement is proposed for the Wholesale Electricity Market reserve capacity auction for three main reasons.

1. **User pays philosophy**: If some customers face a variable requirement inside the auction and others face a fixed requirement outside the auction, the two sets of customers would likely procure different reserve margins. The mismatch will be unfair because all customers are equally curtailable during capacity shortages and enjoy the same increased level of reliability procured through the auction. In that case, the set of customers outside of the auction would be leaning on those sponsoring the higher reserve margin.

2. **Maximise competition**: A demand curve based on uncontracted capacity would be very steep, due to the current high level of bilateral contracting. With such a demand curve the prices would change dramatically for even a small unit entering or exiting, and price volatility would increase dramatically. This result would severely undermine the structural competitiveness of the reserve capacity auction. Alternatively, an all-in auction increases the structural competitiveness of the auction.

3. **Market power mitigation**: A steep demand curve, such as the one proposed for the Wholesale Electricity Market, is susceptible to the exercise of market power through the strategic withholding of capacity. The increase in competition that would result from mandatory participation in the auction decreases the ability of any one participant being able to strategically increase the price.

5.3.2 Timing of the auction

The forward period of a capacity market is the time between the capacity auction when prices and resource commitments are determined, and the later delivery period when suppliers must actually fulfil those commitments. There are two considerations relevant to the forward period of an auction.

1. What should be the forward period of the auction; which primarily involves an analysis of prompt auctions versus forward auctions.

2. Whether or not an annual reconfiguration (supplementary) auction, during which commitments can be adjusted, is required.

An auction with a three year forward period (similar to, but slightly longer than, the current forward period) is proposed for the Wholesale Electricity Market on the basis that the complexity introduced through the addition of a supplementary auction would not be warranted.

Prompt auctions versus forward auctions

In the United States, PJM and ISO-NE hold forward auctions about three years before the delivery year, whereas NYISO holds auctions just before the delivery period through monthly spot auctions.[21]

The primary advantage of a three year forward period is that it matches the procurement timeframe to the development timeframe for new peaking generation resources. This enables supply to respond in a more orderly manner as needed, reducing boom-bust cycles. It is especially valuable for adjusting to supply and demand shocks that can be caused by changing environmental regulations and macroeconomic factors.

[21] NYISO also holds voluntary forward auctions for monthly and six-month strip capacity commitments.

For example, three year forward auctions have helped PJM smoothly and economically replace more than 20,000 MW of coal-fired plant retirements.[22] Moreover, by welcoming potential new entrants (and major retro-fits) into the auction, the three year forward period expands the amount of supply that can compete. Increased participation and competition supports more economically efficient outcomes.

A downside of a longer forward period is greater risks for both suppliers and consumers due to the greater volatility of factors affecting the market over the longer period of time. Suppliers bear the risk of committing to provide capacity and then their resource becoming unavailable. Consumers bear the risk of over and under forecasting, and over and under procuring, with the market mechanism locking in outcomes further from the actual year in which these resources are required.

Annual reconfiguration auctions

The PJM and ISONE reserve capacity auctions allow for reconfiguration auctions. The advantage of these auctions is primarily that suppliers are provided with a means to buy replacement capacity if the relevant resources become unavailable, and those whose availability has increased can offer it. One implication of this is that capacity credits become something of a tradable commodity. However, this level of complexity is not warranted in the Wholesale Electricity Market at this time.

Furthermore, under the current and proposed changes to the Reserve Capacity Mechanism, refund exposure for any one resource is capped at one year's repayments. Therefore there is limited incentive for a capacity provider who is no longer able to provide the capacity they cleared in the auction to pay a potentially higher price for replacement capacity.

In the circumstance of an annual reconfiguration auction operating, the system operator may need to buy more capacity if load forecasts increase, or offer to sell back obligations if forecasts decrease. The risk of load forecast inaccuracy three years out has primarily been accounted for in the choice of a wide[23] demand curve, meaning that allowing resources to adjust their positions closer to real time is not required. The enhanced supplementary reserve capacity process (outlined in section 5.3.5 below) will be able to procure sufficient additional capacity should an under procurement event occur.

5.3.3 Delivery period

The delivery period is the time between when a committed resource has to start delivering capacity and when its obligation terminates. For the most part United States' capacity markets transact only a single delivery year. A longer delivery period imposes risks on existing suppliers that they may not be available the whole time (and risks on buyers of locking in and over procuring capacity in a period with declining load). However, longer commitments reduce the risk of making long-lived capital-intensive investments.

Based on an analysis of the United States markets, the Electricity Market Review is proposing to adopt a one year delivery period for the reserve capacity auction. The analysis conducted by the Electricity Market Review is presented briefly below.

[22] See p iii here: https://www.pjm.com/~/media/committees-groups/committees/mrc/20110818/20110826-brattle-report-second-performance-assessment-of-pjm-reliability-pricing-model.ashx

[23] Wide refers to moving the x axis intersection point further to the right on the x axis.

Capacity markets in the United States typically have a one-year commitment period. This means resources would usually enjoy only one year of guaranteed prices. All future revenues would be at risk. Many generation developers and financial entities regularly express concern that a one-year delivery period does not provide sufficient certainty to invest in new generating resources and so assert that a longer commitment period is necessary. While developers express this sentiment in almost every market, experience has demonstrated otherwise.

Most notably, both the PJM and Texas markets have recently attracted large quantities of merchant generation investment without providing any long-term commitments. PJM has attracted more than 12,000 MW of new merchant generation, and the Texas market about 5,000 MW, over the past few years.[24]

There are several reasons for the disconnect between claims that a short delivery period acts as a barrier to new entrant capacity and the reality that a large amount of new supply *has entered* in the US markets. One is a matter of timing versus market conditions: some US market participants claimed the market design was flawed when no new generation entered for several years. However, the real deterrent to additional capacity was not the delivery period but rather that new generation was neither needed nor economic while excess capacity was depressing prices.

One often-proposed option for capacity markets to enhance confidence in new investment is to increase the auction delivery period and allow for multi-year contracts. Several problems are however introduced by multi-year contracts because it is difficult to enable efficient competition among different resource types. For example, demand response and ageing plants that can postpone retirement for only a few years will not be in a position to commit to very long-term contracts and so may be excluded from such a design

Some auctions (for example ISONE) offer a long-term delivery period for new resources, including via price lock-in mechanisms. However this approach would discriminate against existing resources and could inadvertently distort the amount of new versus existing resources in the market.

The proposal for the Wholesale Electricity Market is that offering the same period to all resources through non-discriminatory auctions is more efficient. Such discrimination can bias auction outcomes toward new resources even if they are less economic. This concern is exacerbated in future auctions as well, since it incentivises larger-size new entrants that may enter in a high-price year even though a smaller resource or shorter-term resource may be more economic.

The large new resource can then create an uneconomic excess of supply that can suppress auction prices for many subsequent years. The result can be a bifurcated market in which uneconomic new entrants earn revenues substantially in excess of market prices for a protracted period, while other resources earn a lower price that is persistently below long run marginal cost. Thus, the market may produce uneconomic retirements or forego economic upgrades or demand response in favour of more costly new generation.

[24] Based on a review of PJM auction results and Ventyx Energy Velocity Suite data on new generation recently online or under construction.

5.3.4 Style of auction (sealed bid or descending clock)

Both sealed bid and descending clock auction formats have been used successfully in capacity markets such as ISO-NE and PJM. No single auction style has been shown to offer compelling advantages in the context of auctions for capacity markets in the electricity industry. It appears that the success of a particular auction format depends more on the specifics of its design, including its market monitoring and mitigation provisions, than on the auction format.

One of the main disadvantages of a multi-round, descending clock auction is the increased opportunity to exercise market power through signalling and tacit collusion among suppliers. Price discovery in multi-round auctions may help marginal suppliers decide what to bid by conveying information about other bidders' expectations; however, because multi-round auctions must reveal some information, they are necessarily susceptible to bidders using that information to manipulate auction outcomes.

The primary advantage of multi-round auctions, namely price discovery, does not apply in Western Australia as much as in larger, more competitive markets, because most capacity offers will be submitted by a relatively small number of suppliers that own a large number of plants (limiting the possibility of information exchange among suppliers).

While sealed bid auctions reveal less information to support efficient, timely investment decisions, advantages include the protection of business information, mitigation against gaming potential, and price transparency benefits by revealing some information after the auction. Given the slight disadvantages and the greater complexity of a descending clock auction, a simple, single-round sealed bid auction format is proposed for the Wholesale Electricity Market.

5.3.5 Supplementary capacity procurement process

As outlined in section 5.2.4, because the design of the auction will occasionally under procure relative to the reserve capacity requirement, there is a need for a robust and efficient supplementary reserve capacity process. However, the process must be designed so as to not affect the price outcomes of the reserve capacity auction for future periods. This is to ensure that market participants that participate in the auction are not disadvantaged by the out-of-market process, as such a situation would undermine price outcomes and therefore reduce market efficiencies by introducing uncertainty and risk premiums.

To avoid these detrimental outcomes the supplementary reserve capacity procurement process will be structured such that:

- Supplementary capacity procured must not depress capacity auction prices through the addition of capacity that participates in auctions for future periods.
- There will be restrictions/requirements relating to participation in the supplementary reserve capacity process to avoid participants withholding capacity from the auction and placing upwards pressure on the auction price.
- The Market Operator will calculate and define the requirements for any supplementary reserve capacity to ensure an efficient and tailored product can be procured.

Because the capacity product offered into the supplementary reserve capacity process would be at best equal to the product offered into the reserve capacity auction, and most likely of a lower availability, the price for supplementary reserve capacity would be capped at the auction price cap.

Further and final details of the supplementary reserve capacity procurement process will be developed in line with the principles outlined above during the next phase of the project.

5.4 Market power mitigation

Capacity auctions tend to suffer from structural market power, with several pivotal suppliers controlling supply portfolios that are sufficiently large to profit from economic or physical withholding strategies. Market monitoring and mitigation is therefore an essential element of every capacity market.

For the Wholesale Electricity Market, the proposed market design for the auction includes parameters that limit the ability for participants to exercise market power (e.g. a three year forward period, mandatory participation of all capacity providers and a demand curve that is flatter than a strict value reflective demand curve would be). However, even with these mitigation strategies in place there is still scope for a participant in the auction to exercise a marked degree of market power.

Capacity auctions with a flatter demand curve are still susceptible to exercise of market power as some suppliers may be pivotal in exerting influence over the price of capacity through the strategic submission or withdrawal of capacity to the capacity auction. Pivotal suppliers are large enough that some of their supply is needed to meet demand. They therefore have the opportunity to benefit their portfolios through physical or economic withholding, (i.e. raising some of their resources offers). If they did, consumers would suffer from inflated prices and outcomes would not be economically efficient.

It is also possible for buyers of capacity to have an incentive to manipulate the outcomes of the reserve capacity auction. Net buyers, or entities operating on their behalf, are potentially able to manipulate prices downward; for example by subsidising new entry and offering it into the auction at below-competitive rates. Such subsidies would displace in-market entry and undermine economic efficiency. Perhaps even worse, the prospect of such behaviour could deter merchant generation investors from participating in the market at all: even if they could enter when prices were high, they would worry that future prices could be manipulated downward over most of the life of their investment.

It is not possible to introduce a capacity auction without introducing some new market power mitigation controls and monitoring measures. These requirements would be new to the reserve capacity market and be more extensive than the short run marginal cost constraints operating in the energy market.

The following principles have been followed in relation to the market power mitigation measures that will be introduced for the Wholesale Electricity Market reserve capacity auction.

- There is market power in the capacity market and hence controls are necessary.
- The measures adopted must be the minimum that is necessary.
- Mitigation controls must be sufficient to ensure that private sector market participants have confidence in the operation of the capacity auction.
- The measures must be effective to stop the exercise of market power but not constrain efficient market outcomes.

The following sections outline the market power mitigation measures that exist for other capacity auctions and are intended as a guide to what may be introduced as market power mitigation measures for the Wholesale Electricity Market reserve capacity auction. A possible consideration for the Wholesale Electricity Market capacity auction is implementing a declining generation cap on Synergy as facilities are retired over time, which would reduce the level of market concentration.

5.4.1 Supply-side market power mitigation

Capacity markets that operate in the eastern United States employ different supply-side market power mitigation strategies.

The PJM market requires all existing generation facilities to participate in the capacity market (known as the Reliability Pricing Model), with the aim of addressing the potential withholding of capacity. Through its independent market monitor, Monitoring Analytics, PJM also applies a rigorous process of determining offer caps for facilities.

- A market structure test, known as the Three Pivotal Supplier Test,[25] is conducted to identify suppliers that are likely to have market power. Any supplier identified in this test is subject to an offer cap.
- All existing generation facilities are subject to an offer cap, while potential new generators and demand-side resources are exempt.
- Offer caps are based on estimates of either net going-forward avoidable costs (either a technology-specific default avoidable cost value or a facility-specific avoidable cost estimate) or opportunity costs.

The NYISO has a different mechanism for identifying pivotal suppliers (limited to large suppliers in the New York City zone), but applies a similar offer cap philosophy to that used for PJM. In addition, an audit and review may be conducted in relation to any proposal or decision to retire, remove or de-rate capacity in the New York City zone.

[25] An overview of the Three Pivotal Supplier test is available at http://www.pjm.com/~/media/committees-groups/task-forces/gofstf/20150722/20150722-item-02-imm-tps-education.ashx

ISO-NE employs different techniques for supply-side market power mitigation.

- Any participant wishing to retire, remove or de-rate capacity is required to submit a de-list bid.
- ISO-NE's internal market monitor scrutinises each de-list bid to ensure that it reasonably reflects the costs of that facility.
- All other existing facilities are required to offer at or below a default offer review threshold.

The US evidence indicates that supply-side market power mitigation controls can be particularly onerous, requiring thorough scrutiny of individual auction offers. As this scrutiny requires analysis of participant cost information, it is necessary to consider the degree of information that would be provided by the market participant and which organisation should undertake the monitoring.

Given the larger and more competitive nature of the US markets in comparison to the Western Australian market, it would appear that the reformed Reserve Capacity Mechanism will require market power controls that are no less stringent than in the US. However, the Electricity Market Review proposes to explore a full scope of market power mitigation measures to develop controls that are effective, but without unduly constraining efficient auction bids and, hence, efficient capacity pricing outcomes from the auction.

Nevertheless, it is apparent there will need to be additional scrutiny that will require resources dedicated to market monitoring, potentially over and above the current level in the Wholesale Electricity Market. For instance, due to market concentration most participants are likely to fail the Three Pivotal Supplier Test used in other markets. This in effect would require the market monitor to place offer caps on all market participants.

5.4.2 Buyer-side market power mitigation

Capacity buyers could potentially manipulate the prices resulting from capacity auctions, undermining the efficiency of this mechanism and removing investor confidence in the market. All capacity markets in the United States have recognised that measures were required to protect the auction from any uneconomic capacity being introduced by net buyers, or agents on their behalf, to manipulate the price downward.

All three of the eastern US markets employ a form of Minimum Offer Price Rule, which requires that new capacity resources submit bids that are above a predefined value representing the net going-forward costs of a benchmark resource. However, the applicability of the Minimum Offer Price Rule measures varies.

- PJM only applies the Minimum Offer Price Rule to specific generation types (combustion turbine, combined cycle units and integrated gasification combined cycle units), unless a facility is granted an exemption as a merchant entrant or a self-supplier.
- NYISO applies the Minimum Offer Price Rule only to the New York City zone and new capacity zones. Unless a facility is exempt, the Minimum Offer Price Rule applies until it is cleared in 12 monthly spot auctions.

- ISO-NE determines technology-specific offer floors (Offer Review Trigger Prices) separately for each type of capacity resource, with a limited exemption for renewable source capacity entry.

5.5 Request for comment

Proposed reform – the Electricity Market Review proposes to implement a reserve capacity auction designed in accordance with the principles and proposals outlined in this chapter.

Submissions providing feedback on this recommended reform to the Reserve Capacity Mechanism are encouraged.

6. Complementary reforms

This section details two additional complementary reforms recommended for introduction during the transition period and a mandatory requirement of the capacity auction. The reforms are complementary in the sense that they will assist in improving the value and availability of capacity during the transition period, leading to a Reserve Capacity Mechanism that is more reflective of economic conditions. Furthermore, these reforms are also required so as to ensure efficient outcomes of the capacity auction once in operation.

6.1 Harmonisation of demand side management

The introduction of a capacity auction requires that all resources face equivalent availability and measurement requirements. At present demand side management resources enter the capacity market under more favourable conditions than electricity generation resources. These differences must be remedied prior to the first capacity auction, in order for demand side management capacity to deliver value to electricity consumers.

The Independent Market Operator has proposed many changes aimed at harmonisation of the requirements for demand side management capacity (against other capacity types).[26] These changes should be implemented, with some amendments, to ensure demand side capacity is available at all times when there is potential contribution towards a reduction in unserved energy.

The proposed changes to demand side management availability requirements are summarised in Table 6.1.[27]

[26] Wholesale Electricity Market Rule Change RC_2013_10

[27] The Independent Market Operator also proposed removal of the requirement for a scheduled generator to demonstrate that it holds fuel storage, supply and transport arrangements sufficient to allow 14 hours of continuous operation, in order to receive capacity credits. It is not proposed that the current firm fuel requirement be changed.

Table 6.1: Proposed changes to the demand side management availability requirements

Requirement	Current rules	Proposed reform	Generation facilities
Days of availability	All business days	All business days	All days
Dispatch events per year	Once on at least 6 days[28]	200 hours	Unlimited
Hours per day	4 hours	12 hours	24 hours
Total hours available per year	24 hours	200 hours	8,760 hours
Earliest start	12:00 pm	8:00 am	No limitation
Latest Finish	8:00 pm	8:00 pm	No limitation
Minimum notice period of dispatch	4 hours	Near real time	Near real time (currently 10 minutes)
Measure of availability	N/A	Real time telemetry	Real time telemetry
Capacity baseline	Median 32 intervals	5th percentile of top 200 hours and capped at the Individual Reserve Capacity Requirement level	Sent-out capacity calculated at air temperature of 41 degrees Celsius

The principal elements of harmonisation of demand side management are further described below.

Availability

Capacity is valuable when it will reduce the probability of losing electricity load. Thus the availability requirements of demand side management capacity should be consistent with the capacity of such resources to contribute to a reduction in unserved energy.

To require demand side management resources to be available outside those intervals where it has economic value is inefficient and may cause otherwise valuable capacity to exit the market, reducing competition overall. This rationale has resulted in proposed changes to availability requirements for demand side resources that are different to those recommended by the Independent Market Operator with respect to the following parameters:

- dispatch events per year;
- hours of availability per day;
- total hours available per year; and
- earliest start / latest finish.

28 Demand side management resources are not required to comply with a dispatch instruction made on a third consecutive day (i.e. following dispatch instructions made on two previous days in succession).

Minimum notice period of dispatch

Market generators are required to be ready to respond to dispatch instructions in near real time. This necessitates that generators monitor dispatch forecasts to gauge their likelihood for dispatch and ensure preparedness for dispatch.

Demand side management programs are comprised of many fast reacting loads, which can drop demand quickly. Having equivalent minimum notice requirements to generation facilities will provide System Management more opportunity to use demand side resources to react to market conditions during peak demand events.

Minimum notice requirements will vary depending upon the circumstances of dispatch.

- In the case of dispatch events following the merit order in response to an extreme peak demand event, minimum notice requirements for demand side programs will comprise provision of information to the system operator on how quickly load can be curtailed, similar to the ramp rate of a generation facility.
- In the case of out of merit dispatch, demand side resources will be required to nominate minimum notice periods in their standing data, equivalent to the requirement for generators. A minimum notice period no longer than about two hours may be an adequate length of time for demand side resources to ready themselves for dispatch, while also proving the system operator with reasonable flexibility to react to market conditions.

Real-time telemetry

Demand side resources should therefore be required to have telemetry systems to provide the system operator with real-time information on the availability and performance of demand side capacity.

The system operator does not at present have this information, which reduces the system operator’s confidence in, and ability to, dispatch demand side capacity.

Capacity baseline

The Independent Market Operator only proposed a minor change to the current method of calculating the capacity credits to be allocated to demand side management resources. However this method was still based on the level of demand that can be reduced “at peak times”, as measured by using the median demand of the associated loads. This means half the time the demand side management capacity will be operating at less than the level used for the capacity credit allocation.

It is proposed to set the capacity baseline for demand side resources at a level that reflects the real operating capacity of the resources. The way to achieve this is to set a demand side management capacity baseline using the 5^{th} percentile of the measured demand during hours of availability. This method would reflect the real world operating situation of the associated loads linked to the demand side management capacity. This also makes demand side management capacity more equivalent with setting of the generation capacity baseline. (See Appendix B for an outline of the proposed method.)

Proposed reform – Implement the proposed changes in Table 6.1.

Submissions providing feedback on this recommended reform to demand side management availability requirements are encouraged.

6.2 Reforms to capacity availability

Capacity availability is a critical aspect of the market, which capacity payment requirements encourage. Incentives for capacity availability can be improved by changes to the capacity cost refund regime to incentivise long term and short term operation and maintenance actions to avoid plant outages beyond normal limits.

The existing capacity cost refund regime has several deficiencies, primarily:

- The magnitude of capacity refunds is not reflective of the prevailing market supply conditions, and provides inadequate incentives for capacity to be available when reserves are low (and vice versa).
- Payment of capacity refunds to market customers fails to incentivise generator availability. Rebating refund revenue to other capacity providers as a form of reward for availability would provide better signals.
- Planned outages are exempt from refund payments; this blunts the exit signals inherent in the Reserve Capacity Mechanism if the provider is able to use planned outages to avoid exposure to outage refunds.

It is proposed to adopt the mechanisms to solve these deficiencies as previously proposed by the Independent Market Operator.

Dynamic refunds

An economically efficient capacity refund regime should link the magnitude of refunds (i.e. penalties for non-availability) to the economic value of incremental capacity. The existing capacity cost refund regime does not do this and creates perverse incentives.

Given the current excess of capacity, the economic value of incremental reserve capacity is substantially below the administered capacity price. This means that the costs imposed on generators who are obliged to make refund payments can exceed the economic value when an event occurs that triggers a refund obligation. In times of shortage of capacity the opposite is true, where the capacity refund would be well below the economic value of the outage event.

The existing refund mechanism applies a set of refund factors that vary according to specific time periods,[29] rather than to system conditions. A generator can be exposed to refund factors between 0.25 and 6, and there is only coincidental correlation with the level of available reserve based on seasonal demand. This provides an incentive for a generator to ignore system conditions when scheduling maintenance, as the larger exposure is potentially to the refund factors themselves.

The Independent Market Operator proposed to establish a dynamic refund regime that links more clearly to market conditions.[30] Under this proposal, exposure to refunds would depend, in part, on the amount of reserve capacity available rather than on predefined time periods.

This proposal retained the maximum refund factor of six, which would cap the exposure during a period of low capacity availability. The alternative would be to base the refund on the economic consequence of the outage event; however this has the potential to be extremely volatile. The maximum refund factor caps the exposure a generator faces to refunds, minimising the volatility. However as the market moves towards capacity pricing based on economic value, it may be suitable to re-evaluate the refund caps in the future.

The linkage between the capacity refund regime and the value of capacity credits is an important one. As the market moves to a more economically valued capacity price the capacity refunds should move in a synchronised manner.

Proposed reform – Implement the dynamic refunds proposal developed by the Independent Market Operator.

Submissions providing feedback on this recommended reform for the adoption of dynamic refunds are encouraged.

Refunds recycling

Under the current refunds regime, capacity refunds are paid by market generators and the revenue collected is returned to market customers. The rationale for this arrangement is that retailers are paying for capacity credits and should therefore be reimbursed if capacity does not perform. This arrangement does not recognise that it is the entire capacity mechanism that ensures reliability and not necessarily individual capacity resources.

Retailers who benefit from a capacity payment refund will in most cases not experience a power supply disruption – as other capacity providers deliver aggregate capacity to meet demand. This means that the retailer still receives the service it has paid for in its capacity credit obligation, but also receives a refund on that cost for no diminution in that level of service.

Additionally, in situations where a capacity provider fails to provide capacity, the value of capacity supplied by all other providers increases (due to scarcity of supply). It is therefore logical to compensate these providers for their more valuable capacity.

[29] Such as quarters of the year; business days versus weekends; peak versus off-peak.

[30] Wholesale Electricity Market Rule Change RC_2013_20. This rule change included additional changes to the Reserve Capacity Mechanism outside the refunds regime.

The Independent Market Operator's proposal was for capacity refunds to be distributed back to market generators instead of market customers.[31] The proposal was also that refund revenue be linked to generator availability, so that those with higher availability are rewarded.

During the Independent Market Operator's consultation on this proposal market customers argued that generator outages increase the energy price and the refund of capacity revenue is compensation for such events. However, the capacity refund mechanism is essentially aimed at incentivising capacity availability. Paying refunds to market customers has little effect on encouraging capacity providers to make plant available. Overall, the sharper incentives on generators to make plant available proposed through this reform process will benefit market customers. Generators are expected to respond to these new signals and make capacity available, which in turn would suppress energy prices.

As long as there is uninterrupted electricity supply, the distribution of capacity refunds to market customers represents a loss of value to providers of capacity. Additionally the possibility of capacity outage is not a factor incorporated in the calculation of the capacity price. This means that market customers do not pay a higher price to compensate capacity providers for a loss of revenue through outage. Therefore, market customers are not exposed to the additional costs through the capacity price that would be required to justify a claim for compensation.

The capacity price is reduced as more capacity is acquired and this will be more so in the event that the intended reforms to the establishment of the capacity price are adopted. This reduces the amount of revenue market generators are able to receive. A recycling of the capacity refund back to the generators, rather than market customers, would in part cover for the price reduction that was the result of an unreliable generator reducing the capacity price.

The transitional reforms, and the reserve capacity auction, will increase the price responsiveness to oversupply conditions; which further enhances the argument for refunds to be recycled to available generators.

This proposal, combined with the dynamic refunds regime proposed above, will strengthen incentives for plant availability and competition in the energy market.

Proposed reform - Implement the refunds recycling proposal developed by the Independent Market Operator with limited changes.

Submissions providing feedback on this recommended reform adopting changes to capacity refund recycling arrangements are encouraged.

[31] Wholesale Electricity Market Rule Change Proposal RC_2013_20.

Generator availability

At present any facility on a planned outage is exempt from paying capacity refunds. This appears to have resulted in extremely high planned outage rates but very low forced outage rates. Some facilities have been on planned outage over 60 per cent of a capacity year.

It appears that the capacity market is providing low incentives for availability. Unreliable facilities that would retire with the correct incentives are continuing to receive capacity payments and adding to excess capacity costs. Further, with the sharper pricing signal proposed in the transition period and under the capacity auction, these unreliable facilities will markedly depress the capacity payment made to other generators with higher availability and reduce the signals for new efficient generators to enter the market.

The Independent Market Operator proposed to amend the Wholesale Electricity Market Rules to improve the incentives for market participants to maximise the availability of scheduled generators.[32] This proposal was to impose an upper limit on the number of trading intervals in any 36 month period for which a generator can claim a reduction to their capacity obligations due to planned outages.

> **Proposed reform** - Implement the generator availability proposal developed by the Independent Market Operator with minimal changes.
>
> Submissions providing feedback on this recommended reform to generator availability are encouraged.

[32] Wholesale Electricity Market Rule Change Proposal RC_2013_09.

7. The transition period

7.1 Transitioning from the existing reserve capacity price formula

The transition arrangements described in this chapter are proposed to be in place from 1 May 2016, in time for the start of the 2015 Certification of Reserve Capacity and remain in place until the capacity auction is introduced.

The major change to the Reserve Capacity Mechanism during the transition period will be the implementation of a revised administered capacity price formula. This has two elements: the first is the rate that the capacity price is discounted as excess capacity increases and the second is the maximum cap for the capacity price.

The slope of the capacity pricing curve

The current administered capacity price formula grossly over-values excess capacity. It is proposed to steepen this pricing curve during the transition period to reduce the cost of excess capacity and reduce the incentives to maintain or introduce capacity in an oversupplied capacity market, while avoiding a reduction in the capacity price that is so severe as to result in excessive disruption to the electricity market.

The current capacity price formula modestly reduces the capacity price as excess capacity increases. The simplest way to adjust the capacity price formula to make it more sensitive to market conditions is to adjust the “slope” factor. The slope determines the rate the capacity price is reduced as excess capacity increases. The current slope in the capacity price formula is negative one.

The Electricity Market Review has assessed three options for the introduction of a steeper capacity price adjustment slope. The options were assessed with the aim to strike a balance between the following objectives.

- Reducing the cost of excess capacity to customers.
- Graduating the prevailing capacity price towards a price that is similar to what would be expected under the reserve capacity auction so as to minimise the disruptive effects of the introduction of the auction.
- Discouraging new entry during the transition period unless it provides material benefits to the energy or ancillary services markets.
- Encouraging mothballing/retirement of inefficient capacity (either demand side management or generating capacity): without retirements or mothballing of capacity, the excess capacity situation will not reduce to a level where an auction could reasonably be held within the next 10 years.

The first option is to adopt a revised slope formula and maintain that formula for the duration of the transition period. A single slope determination provides greater certainty on future capacity prices. This approach requires that the adjustment factor (i.e. slope) is steep enough to discourage entry of new capacity unless it provides material benefits in the energy market, such as through displacement of more expensive generators or as a source of valuable ancillary services.

One possibility under this option is adopting the slope of negative 3.75 which was the slope previously proposed by the Independent Market Operator: the "Lantau Curve". This would send stronger signals regarding the market need for capacity than the current formula.

The magnitude of current excess capacity may warrant a sharper price signal.

The second option is to sequentially increase the slope of the capacity price formula during the transition period. Under this approach the slope would become increasingly steeper for each subsequent capacity cycle. A logical progression would be to start with the previously proposed slope of negative 3.5 and move in steps towards the auction demand curve.

The Electricity Market Review prefers the first option of a consistent slope of the pricing curve for the whole transition period. However, it is proposed to steepen the slope of the pricing curve to negative 5. This will increase the rate of price adjustment during the transition sufficient to materially reduce the costs of excess capacity currently being passed on to customers. Such a slope is also more reflective of the economic value of capacity and may expedite the transition towards a demand-supply balance leading to an earlier timing for the first auction.

A slope of negative 5 for the duration of the transition period is considered to provide a sufficient price signal for this adjustment without undue instability, and also provides more price certainty given the uncertain timing of the trigger for the first auction. Table 7.1 presents an indicative view on the reserve capacity price at different levels of excess capacity, using a slope of negative 5.

Table 7.1: Indicative reserve capacity prices with a negative 5 slope

Excess Capacity	Capacity Price
5%	$123,214
10%	$104,545
15%	$90,789
20%	$80,232

(1) Using an assumed Maximum Reserve Capacity Price of $150,000

Proposed reform – A single slope of the capacity pricing curve of negative 5 for the duration of transition period.

Submissions providing feedback on this proposed reform to the capacity price adjustment formula are encouraged.

Capacity price cap

Currently the Market Operator sets the Maximum Reserve Capacity Price, which is a cap on the capacity price.

The Independent Market Operator previously proposed a high cap of 10 per cent above the Maximum Reserve Capacity Price, applying where there is zero excess capacity or a shortage of capacity. The rational for a larger cap is that the value of capacity increases rapidly when there is zero excess capacity or a shortage.

Proposed reform – To increase the capacity price cap to 110 per cent of the Maximum Reserve Capacity Price.

Submissions providing feedback on this proposed reform to the capacity price cap are encouraged.

7.2 Reforms to demand side management for the transition period

The reforms to the capacity price formula during the transition period will result in the price paid for capacity being discounted more heavily when there is excess capacity than is currently the case. This adjustment will result in a lower capacity price and reduce incentives for generation capacity to be maintained in the market or new generation capacity to enter the market.

A lower capacity price will not have the same effect on incentives for demand side management capacity, as it has fundamentally different cost drivers to other forms of capacity.

The price that is "low enough" to moderate adjustment of supply side resources will not result in a moderation of the level of excess demand side resources due to fundamental differences between demand side management and other forms of generation capacity:

- compared to the initial capital investment requirements of supply side generation demand side resources generally have upfront costs many orders of magnitude lower;
- demand side management capacity does not generally involve commitment to a long term "sunk" asset;
- demand side resources have high opportunity costs if and when dispatched, which unlike the opportunity costs for supply resources in the energy market, are likely to be materially higher than the energy market price cap; and
- the viability of demand side management capacity improves as the probability of being dispatched decreases, which is the exact opposite of the situation for other forms of capacity that rely on revenue from the energy market.

These demand side management characteristics demonstrate its fundamentally different commercial drivers to other forms of capacity.

A particular problem of demand side resources in the Reserve Capacity Mechanism (with a shallow sloping price curve) is that a typical resource is very likely to lose money when called to be dispatched. If demand side capacity is called, then any payment that it receives from the energy market is unlikely to cover its opportunity cost and, hence, dispatch reduces the provider's profit from capacity revenue. The commercial driver for a demand side resource to participate in the Reserve Capacity Mechanism is that it expects to have enough money left over from capacity credit revenues after accounting for whatever it loses whenever it is dispatched.

As long as the prospect of dispatch is very low then demand side management capacity will stay in the market until the capacity revenue is at very low levels. In contrast, supply-side resources have a commercial incentive to be dispatched.

During the transition demand side management capacity should face similar incentives to other forms of generation capacity to adjust to an efficient level of participation in the Reserve Capacity Mechanism. It is proposed to achieve this during the transition period by removing demand side resources from the Reserve Capacity Mechanism and instead providing demand side resources with:

- a lower capacity payment based on the expected value provided by this capacity under a forecast of expected dispatch; and
- further payments reflecting opportunity costs incurred if dispatched to an extent in excess of that assumed in determining the capacity payments.

The "expected dispatch" of demand side capacity has been calculated for a one in ten year peak demand event. For 2016-17 the total "expected dispatch" is only 3.9 MWh, rising to 22.2 MWh in 2020-21. Such a low level of "expected dispatch" highlights the low value of demand side resources during this current period of surplus capacity.

Calculating the expected number of hours demand side management capacity will be dispatched

The proposed approach to calculating the expected number of hours of dispatch of demand side management resources is as follows.

- The Market Operator would calculate the expected unserved energy that would likely be avoided through the inclusion of demand side management capacity (based on an assumed one in ten year peak demand event). This "avoided unserved energy" is an indicator of the contribution all demand side management facilities are likely to provide to the system in a year with a one in ten peak demand event.

- The total number of hours calculated above is then pro-rated amongst all demand side management facilities, to determine the number of hours each unit of demand side resources can be expected to be dispatched. For example, if it is calculated that the inclusion of demand side management resources in the market is likely to avoid 1,000 MWh of unserved energy, all demand side management facilities would be assigned a pro-rata share of 1,000 MWh, (i.e. under the current arrangements where there is 550 MW of demand side management capacity in the market, each resource would be allocated 1.82 MWh of "expected dispatch"[33] per MW of accredited capacity).

Capacity payments to demand side management facilities are proposed to be based on the number of hours they are expected to be dispatched plus a margin for the costs associated with running a demand side management program (e.g. costs associated with reserve capacity tests). This margin could be equal to one additional hour of expected dispatch time. In the above example, each MW of demand side management would receive payment based on 2.82 MWh of expected dispatch.

Calculating the amount to be paid to demand side management facilities

The second part of the calculation of the capacity payments to demand side management facilities would be assigning a value to each MWh of "expected dispatch".

It is proposed that an estimate of the value of lost load be used. This value can be considered a proxy for the opportunity cost experienced by the demand side management resource in reducing demand.

The most recent "value of customer reliability" review conducted by AEMO,[34] estimated that the average value of reliability to customers in the National Energy Market ranged from $47,670/MWh for agricultural customers, to $6,050/MWh for customers directly connected to the transmission network. The average value was calculated as $33,460/MWh.

It is expected that demand side management facilities will primarily be comprised of the cheapest available loads that are capable of reducing demand when called. Therefore it is proposed that the demand side management capacity price be based on a value closer to that assigned to direct connect customers. It is proposed that this value be equal to the market price cap in the National Energy Market, which is currently set at $13,800.

Additional considerations

Where a demand side management facility is dispatched for more hours than taken into account in determination of the capacity price, it should be eligible to receive a higher energy price. It is proposed that in these circumstances demand side management facilities should be entitled to a payment equal to the market price cap of the National Energy Market, subject to the amount of extra payment a demand side management facility would be eligible to receive being capped at that year's administratively determined reserve capacity price.

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33 To be precise "expected dispatch" is essentially the estimated reduction in unserved energy that is contributed by demand side management resources.

34 http://www.aemo.com.au/Electricity/Planning/Value-of-Customer-Reliability-review

Finally, to ensure, during the transition, that market customers do not seek to satisfy their reserve capacity obligations by contracting with the new, less expensive demand side management capacity, all demand side management resources would be required to sell capacity credits to the Market Operator, with market customers making payments for demand side capacity on a pro-rata basis. This would prevent a single market retailer from contracting for lower priced capacity, and being able to offer a price with which other retailers cannot compete.

Expected reserve capacity price to be paid to demand side management facilities during the transition period

Applying the calculation method set out above, expected dispatch and capacity prices for demand side management resources have been estimated for 2016-17, 2020-21 and 2024-25 (Table 7.2).

Table 7.2: Estimated capacity payments for demand side management resources

Capacity Year	2016-17	2020-21	2024-25
"Expected dispatch" for all demand side management resources.	3.9 MWh	22.2 MWh	101 MWh
Expected Capacity Price for demand side management/MW based on the current volume of demand side management capacity.	$13,898	$14,357	$16,334

Table 7.3 shows the total payments expected to be paid to demand side management resources under the proposed ("expected dispatch") arrangement. These payments are compared to the expected total payments under both status quo and the price based on the revised negative 5 slope formula proposed to be implemented during the transition period.

Table 7.3: Estimates of payments to demand side management resources under different treatments for capacity payments

Capacity Year	2016-17	2020-21	2024-25
Total payments to demand side management capacity under the current Reserve Capacity Mechanism.	$62,484,995	$64,906,486	$67,287,336
Total payments to demand side management capacity within the Reserve Capacity Mechanism with a capacity pricing curve slope of negative 5.	$45,026,349	$49,993,285	$55,592,533
Total payments to demand side management capacity under the arrangements proposed for the transition period.	$7,643,820	$7,896,360	$8,983,800

(1) Estimated Maximum Reserve Capacity Price $164,800
(2) Each scenario assumes that there is 550 MW of demand side management capacity.

The values in the above tables are indicative only and would be expected to be refined by the Market Operator prior to the first reserve capacity cycle to which the demand side management specific price would apply and be further calibrated during the transition period.

Proposed reform - capacity payments made to demand side management facilities should be calculated in the following manner during the transition period.

- Demand side management resources to receive a lower capacity price than supply-side resources and a higher energy payment (when dispatched for more hours than estimated).
- Capacity payments made to demand side management resources though the transition period to be based on an estimate of the expected hours of dispatch plus a margin for the costs associated with running a demand side program and also testing costs.

Submissions providing feedback on this proposed reform to the treatment of demand side management resources are encouraged.

8. Consultation process

8.1 Invitation for submissions

Respondents are invited to comment on the proposed reforms to the Reserve Capacity Mechanism as outlined in this Position Paper. Submissions need not be limited to those items identified for comment throughout the paper.

Submissions are due by 29 January 2016 and must be sent to the following email address: electricitymarketreview@finance.wa.gov.au

Email submissions are to be entitled "Reserve Capacity Mechanism Position Paper Response - [Name of the submitting company or individual]".

8.2 Publication of submissions

Submissions will be available for public review at www.finance.wa.gov.au/publicutilitiesoffice, unless you request otherwise.

Please indicate clearly on the front of your submission if you wish all or part of it to be treated as confidential. Contact information, other than your name and organisation (where applicable) will not be published.

Requests may be made under the *Freedom of Information Act 1992 (WA)* for any submissions marked confidential to be made available. Requests made in this manner will be determined in accordance with the provisions under that Act.

9. Disclaimer

Appendix A Reliability considerations

Setting the Reserve Capacity Requirement

In an electricity network, the reliability standard specifies the situations that a system is designed to withstand while continuously meeting demand. The reliability standard is used to determine the volume of capacity required to prevent capacity shortfalls. This is an important policy decision in setting the level of tolerable risk of energy outages (unserved energy), with real implications for the quality and cost of supply to consumers.

The current reliability standard in the Wholesale Electricity Market Rules is designed to ensure that enough capacity is procured to minimise the risk of there being insufficient available capacity to meet demand. The standard takes into account:

- unexpected outages of scheduled generation;
- fluctuations in the output of non-scheduled generation; and
- fluctuations in demand.

The current standard is based on the amount of capacity that results in the "optimal" level of unserved energy, where:

- **unserved energy** is the demand that does not receive electricity supplies because of any shortages in capacity; and
- **optimal** is calculated as the point where the cost of additional generation capacity is not offset by the cost of the unserved energy.

An optimal level of capacity can be calculated because the level of unserved energy decreases exponentially with each MW of capacity that is added to the system, while the additional cost of a MW of capacity is an assumed fixed value.

Under the above approach, the reliability standard is defined relative to the expected one-in-ten year peak demand. The 2012 review of the reliability standard, conducted for the Independent Market Operator by Market Reform, estimated that the optimal level of capacity was, on average, 7.6 per cent greater than the forecasted level of peak demand.

The Electricity Market Review does not consider that a change to the reliability standard is warranted at this time as:

- The optimal capacity level methodology is used in other jurisdictions and is regarded as world best practice.[35]
- Following the Independent Market Operator review, the assumptions underlying the calculation of the optimal level of capacity have changed. Most importantly, the value of customer reliability has decreased.
  - Implementing this decreased value at this time would reduce the calculated optimal level of capacity, which, all other things remaining equal, would further increase the amount of calculated excess capacity.

[35] For example, the Electricity Reliability Council of Texas uses this method in Texas to assess the economic efficiency of the "one demand disruption event in any 10 year period" reliability standard employed in that jurisdiction

- As the reliability standard must be reviewed every five years, the Reliability Panel would be required to conduct this review in 2017. This review would also need to asses if the transition towards a constrained network[36] requires locational reliability standards to meet peak demand events.

It is noted that the reliability standard is not central to the other, more pressing, reforms required to the Reserve Capacity Mechanism.

Reliability outcomes in a reserve capacity auction

This appendix deals with the positioning of the curve and how that positioning affects the expected reliability outcomes. The term “positioning” in his context refers to the average reliability outcome the auction is designed to procure. The exact positioning is optional because, as outlined previously, almost any auction design should, in the long-term, result in prices equal to the long run marginal cost of new capacity.

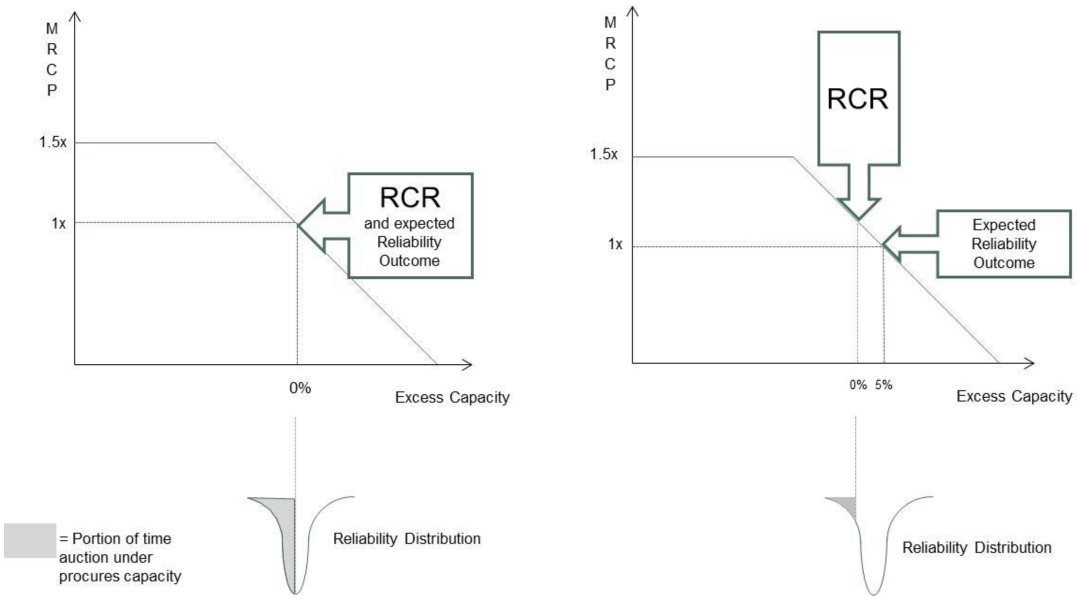
The level of reliability at which the demand curve is designed to equal the long run marginal cost of new capacity, is the level of reliability that the auction will, on average, procure. This point is referred to as the “*expected reliability outcome*”. The exact positioning of the *expected reliability outcome* is important because capacity auctions with a sloped demand curve will not procure a pre-set amount of reserve margin. Instead, auctions will procure a distribution of reserve margins as supply and demand conditions vary across auctions.

In matching an auction design to reliability objectives, the reliability objectives must reflect a distribution of acceptable outcomes, not just a single point. Design of a reserve capacity auction therefore needs to include specification of an acceptable range of reliability outcomes, including the regularity with which the auction will under procure capacity relative to the reserve capacity requirement.

The Electricity Market Review is proposing a reserve capacity auction that incorporates a wide demand curve, meaning there will be a relatively wide distribution of reliability outcomes and a narrow distribution of price outcomes. This means that there is a correspondingly higher chance of reliability outcomes being substantially below the reserve capacity requirement. Figure A1 below is a stylised example that illustrates potential distributions of reliability outcomes, and the regularity of under procurement, with the *expected reliability outcome* positioned at different levels of excess.

[36] Currently being considered by the Electricity Market Review https://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Network_Regulation.aspx

Figure A1: Positioning the demand curve - an illustration



An *expected reliability outcome* level placed closer to the reserve capacity requirement increases the likelihood of the auction under procuring against the requirement. Because the reserve capacity requirement is the optimal level of capacity required, the least cost solution, on a multi-year average basis, would be to have the *expected reliability outcome* equal to the reserve capacity requirement. This setting would however also mean that, on average, every second year the capacity auction would not procure sufficient capacity to efficiently meet an extreme demand event and, therefore, there would need to be a process for the Market Operator to intervene to procure the shortfall (discussed further below).

Alternatively, the auction could be designed so that the *expected reliability outcome* is positioned at a level of reserve much higher than the reserve capacity requirement (i.e. the curve would be moved further to the right). This would result in there being a much lower likelihood of the auction procuring less than the reserve capacity requirement, but this would also greatly increase the cost outcomes of the Reserve Capacity Mechanism. For example, it is estimated that if the *expected reliability outcome* is positioned so as to procure an additional 5 per cent of excess capacity, there would be an increase in total capacity costs of about 5 per cent.

Positioning of the *expected reliability outcome,* and therefore the corresponding regularity of under procurement, is a policy and design decision. In the case of a shortfall, there are two high level options:

1. The market could be designed to accept the risk of an extreme weather event coinciding and under procuring of capacity.
   - This option means that, if there was an extreme weather event in that year, there would be a sub-optimum level of capacity to meet demand, and some energy users would be without electricity.

2. The Market Operator (or some other body) could be required to procure “backstop” capacity when the auction under procures.

   – This is the process currently enshrined in the Wholesale Electricity Market Rules as “supplementary reserve capacity” procurement. A back-stop procurement process similar to the supplementary reserve capacity process is proposed to be maintained as part of the Reserve Capacity Mechanism.

A supplementary reserve capacity process is inherently less competitive than a reserve capacity auction, and hence should not be used on a frequent basis. If supplementary reserve capacity procurement were to be a regular occurrence, it would require a separate market (or a separate product to be incorporated into the auction design) to ensure efficient outcomes.

After the auction has been finalised, and in the event of a shortfall/under procurement, there will be more accurate information available to the Market Operator as to the exact type of capacity required to meet the shortfall. This means that the operator may have the ability to procure a more tailored, and therefore more efficient, capacity product to meet system demands.

For example, demand side management resources that were not eligible to compete in the auction because of insufficient availability may be the ideal product to provide backstop capacity. Therefore, while the supplementary reserve capacity process has the downside of being less competitive, there is the potential to provide a more efficient product aligned with system demand requirements.

A decision on the acceptable reliability outcome necessarily involves a trade–off, as there is no uniquely correct answer.

The trade-off can be summarised as follows.

a. A demand curve with the *expected reliability outcome* positioned **closer** to the reserve capacity requirement (i.e. the curve will be further left) will involve less overall cost with more regular interventions to procure the shortfall, and a correspondingly more complex capacity market structure; or

b. A demand curve with the *expected reliability outcome* positioned **further** from the reserve capacity requirement (i.e. the curve will be further right) will involve more overall cost with less regular interventions to procure the shortfall, and a correspondingly less complex capacity market structure.

Table A.1 and Table A.2 provide an estimate of the average costs of the excess capacity that would be procured if the auction were designed to under procure with different levels of regularity under different forecast error estimates. It is important to note that the tables do not consider the costs to Western Australia of under procurement in the coincident event that there is insufficient supplementary reserve procured to meet the target and there is an extreme weather event resulting in customers going without electricity.

Table A.1: Cost of extra reliability (low forecast error scenario, forecast error standard deviation = 200 MW)

Target frequency of under procurement	Average excess capacity procured (low forecast error scenario)	Average shortage when under procurement occurs (low forecast error scenario)	Average yearly cost of higher reliability[37]	Average yearly cost of supplementary reserve capacity[38]	Total average cost of higher reliability
0.1%	12%	53 MW	$81 million	$0.01 million	$81.0 million
5%	6.6%	77 MW	$44.55 million	$0.92 million	$45.5 million
10%	5.1%	87 MW	$34.5 million	$2.09 million	$36.5 million
25%	2.7%	111 MW	$18.2 million	$6.66 million	$24.9 million
50%	0%	149 MW	$0	$17.9 million	$17.9 million

Example: This table shows that if the auction was designed to under procure, on average, 10 per cent of the time, the auction would, on average, procure 5.1 per cent more capacity than the reliability target. This capacity would theoretically cost the same as the long run marginal cost of a new entrant, and for the purposes of this table this is estimated at $150,000/MW.

Table A.2: Cost of extra reliability (high forecast error scenario, forecast error standard deviation = 300 MW)

Target frequency of under procurement	Average excess capacity procured (low forecast error scenario)	Average shortage when under procurement occurs (low forecast error scenario)	Average yearly cost of higher reliability[39]	Average yearly cost of supplementary reserve capacity[40]	Total average cost of higher reliability
0.1%	18%	79 MW	$121.5 million	$0.02 million	$121.5 million
5%	9.8%	116 MW	$66.15 million	$1.4 million	$67.5 million
10%	7.7%	132 MW	$52 million	$3.16 million	$55.1 million
25%	4.0%	166 MW	$27 million	$9.96 million	$36.9 million
50%	0%	222 MW	$0	$26.6 million	$26.6 million

[37] Assuming a 4,500 MW target and a LRMC of $150,000/MW

[38] Assuming that supplementary reserve capacity is bought at the auction price cap of 1.6*LRMC. This is a very conservative assumption; it is likely this value would be substantially lower.

[39] Assuming a 4,500 MW target and a LRMC of $150,000/MW

[40] Assuming that supplementary reserve capacity is bought at the auction price cap of 1.6*LRMC. This is a very conservative assumption, it is likely this value would be substantially lower.

Appendix B Calculation of demand side capacity baseline

Step 1:
Sort the load from the last Capacity Year from the highest load to the lowest load.

Step 2:
Let **X** = the set of hours associated with the highest 200 hours of load.

Step 3:
Let **Y** = the set of consumption level values, in MW, that each demand side provider was consuming during each of the 200 hours in **X.**

Step 4:
Let the Capacity Baseline = the value in **Y** which is exceeded only 95% of the time (i.e. the value equal to the tenth lowest value out of the 200 values in **Y**).