Resource Adequacy in Western Australia

Alternatives to the Reserve Capacity Mechanism

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This report was sponsored by EnerNOC, Inc. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or its clients. As a demand response owner and developer in Western Australia, EnerNOC has a material interest in the region's market design for resource adequacy. While EnerNOC has commissioned this whitepaper, its contents represent our independent view and assessment of Western Australia's options for pursuing an energy-only market design or reforming the current RCM. The conclusions that we draw in this whitepaper are based solely on our review and analysis of the Western Australian market design for resource adequacy and draw heavily on our findings from similar analyses we have undertaken in other international energy-only and capacity markets. For examples of these prior studies, see Newell, *et al.* (2009, 2010, 2012, 2014a-b); Pfeifenberger, *et al.* (2008, 2009, 2011a-b, 2012, 2013a-b, 2014a-b); LaPlante, *et al.* (2009); and Spees, *et al.* (2013).

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Executive Summary

Western Australia's (WA's) market design for resource adequacy is currently the subject of a number of market reform initiatives. These discussions have been ongoing since 2011, when The Lantau Group examined the Reserve Capacity Mechanism (RCM) and recommended a number of reforms.[1] These reforms have been considered by the Independent Market Operator (IMO) and its stakeholder groups, culminating in a set of recommended changes to the design.[2] At the extreme, some parties have suggested that the RCM should not be reformed but rather eliminated in its entirety and replaced with an energy-only market designed after the eastern National Electricity Market (NEM), or that WA might join the NEM as a non-interconnected zone with no interties. Others have suggested more moderate changes or none at all. Presently, these initiatives are on hold while the Government conducts a comprehensive review of the entire energy sector of Western Australia, covering not only the RCM and the energy-only alternative, but also the approach to retail competition, transmission and distribution investments, and gas pipeline infrastructure.[3]

These initiatives have been fueled by a set of concerns about the RCM, including a focus on the current quantity of excess capacity and questions about whether the design will attract an efficient mix of resource types.[4] Debate about the RCM has intermingled with general concerns about the high cost of electric supply in Western Australia, most of which has little to do with the RCM. In this context, concerns about the RCM and excess supply must be kept in perspective, given that total capacity payments reflect roughly 17% of total system costs estimated for 2016/17, and **payments earned by the portion of capacity in excess of the reliability requirement make up less than 2% of total costs**.[5]

While the costs of capacity procurement in WA can likely be reduced through appropriate and efficient reforms to the market design for resource adequacy, the scale of these potential cost reductions is likely less than some observers have assumed. Further, improving the market design for resource adequacy can address only one of the many drivers of cost increases in Western Australia. Other cost drivers can be addressed by looking at other aspects of regulatory policy, such as the approach to transmission planning, supporting renewables, or retail rate-setting. The remaining cost drivers, such as increases in fuel, labor,

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1 See Lantau (2011).

2 See IMO (2014b).

3 See PUO (2014).

4 For example, see a summary of such concerns as expressed in IMO (2014b), Appendix 1. See also the issues addressed in ERA (2013b), pp. 6-8, 10-12, and 31-42.

5 The 17% of total system costs from RCM is based on a visual approximation for year 2016/17 from Challen/PUO (2013), p. 6. Of that 17%, only a portion of the payments go to capacity in excess of the requirement. Using the 11% of excess supply realized from 2015/16, the total fraction of system costs associated with excess supply is 11% * 17% or 2%. Excess supply from IMO (2014a), Appendix D.

and materials costs, largely reflect the underlying market fundamentals that cannot be avoided.

In the midst of these many initiatives and views, we have been asked by EnerNOC, a demand response provider in Western Australia and many international markets, to provide our perspective on what the region might achieve by reforming its market design for resource adequacy.[6] We have analyzed similar questions in many other international markets, and we draw on lessons learned from those regions to recommend market design enhancements that Western Australia could implement under either an energy-only or capacity market design for resource adequacy. We also aim to provide a realistic assessment of how a well-designed market would function in Western Australia, and describe the primary tradeoffs between these two designs.

To guide our analysis, we begin with the underlying policy objectives articulated in the current market review effort, which are consistent with the previously-established Wholesale Electricity Market Objectives.[7] These documents establish that the resource adequacy construct in Western Australia must support "reducing costs of production and supply of electricity and electricity related services, without compromising safe and reliable supply" and enable "future generation built by the private sector without Government investment, underwriting, or other financial support." These objectives provide clear support for a competitive, efficient marketplace but leave open some important questions for resource adequacy, including the relative emphasis on reliability versus cost objectives, the exact definition of a reliable system, and whether and how volatility and uncertainty are to be considered.

If the Western Australian government decides to eliminate its resource adequacy requirement, it could either implement a stand-alone energy-only market or join the NEM as a non-interconnected zone. Both of these options pose challenges given Western Australia's context as a small, islanded system, and we recommend following either path only with a clear understanding of and plan for addressing these concerns.

It must be understood that moving to an energy-only market in Western Australia would mean more than simply eliminating the RCM, and would require reforming the energy market to support higher and more volatile prices that would be able to attract investment when reserve margins decline. The current energy market would not be able to attract such investments due to the strict monitoring and mitigation regime, low price cap, and lack of scarcity pricing mechanisms. Implementing an energy-only market capable of supporting the region's resource adequacy needs would require: (a) establishing a regulatory commitment to the energy-only market design, including the ability to withstand political pressures or

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6 The conclusions that we draw in this whitepaper are solely based on our review and analysis of the Western Australian market design for resource adequacy and draw heavily on our findings from similar analyses we have undertaken in other international energy-only and capacity markets. For examples of these prior studies, see Newell, *et al.* (2009, 2010, 2012, 2014a-b); Pfeifenberger, *et al.* (2008, 2009, 2011a-b, 2012, 2013a-b, 2014); LaPlante, *et al.* (2009); and Spees, *et al.* (2013).

7 See PUO (2014), and IMO (2014f).

backlash in the event of the periodic (and necessary) high price, low reliability events that characterize energy-only markets; (b) anticipating the higher and more volatile energy market prices that would need to be realized in a sustainable design that supports resource adequacy; and (c) reforming monitoring and mitigation practices and/or introducing efficient administrative or market-based scarcity pricing mechanisms to support higher prices.

Joining the NEM would address some of these concerns by increasing the price cap from approximately \$562/MWh to \$13,500/MWh, eliminating the current energy market monitoring and mitigation rules, and setting the stage for higher and more volatile prices.[8] However, we caution that simply joining the NEM could have substantial unintended consequences in such a small, non-interconnected region with highly concentrated supply ownership. The price cap and monitoring and mitigation framework in the NEM have been developed to support resource adequacy in a much larger and more structurally competitive market. Adopting identical rules in Western Australia could expose the region to substantial concerns that market power prevents the formation of competitive prices and efficient operational and investment outcomes. Even if Western Australia were made more structurally competitive through a forced divestiture, the small market would still be susceptible to wide variations in reserve margin, *e.g.* periods of low reliability and high prices following unanticipated events such as two coincident retirements. Therefore, these concerns would need to be carefully analyzed and appropriate mitigating measures instituted before moving forward.

If Western Australia instead opts to maintain a resource adequacy standard, we recommend doing so with a reformed capacity market that is designed to achieve resource adequacy objectives at least cost. This begins with either confirming or re-evaluating the current resource adequacy standard.[9] While the current reliability standard is already in line with international norms, we note that some have questioned whether the standard is set at an appropriate level for Western Australia. The resource adequacy standard could reflect only reliability objectives, or it may also reflect economic or price mitigation objectives as in some other regions.[10] Finally, the question of what the resource adequacy standard should be must be clearly distinguished from the question of how to address the issue of over-supply in excess of this standard.

Once the resource adequacy standard is confirmed or revised, we recommend reforms to the RCM. The current design has attracted a substantial quantity of excess supply into an already long market as the product of two fundamental problems with the RCM design: (1) the relatively high and flat Reserve Capacity Price (RCP) function that pays more than the

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8 The Western Australian maximum price reflects the Alternative Maximum Short Term Energy Market price that is incurred if liquid-fueled plants are needed, with the quoted price current as of July 2014, from IMO (2014c). The NEM Market Price Cap is from AEMC (2014a), p. 7.

9 The current standard is a reserve margin based on the more stringent of either: (a) the reserve margin required on top of a 90th percentile peak load year to account for expected outages or the largest contingency; or (b) limiting unserved energy to 0.002%. See Section IV.A.

10 For a comprehensive review of reliability-based and economically-based approaches to determining reserve margin targets, see Pfeifenberger, *et al.* (2013b).

incremental cost of new supply even at high levels of supply excess; and (2) the lack of competitive procurement auctions to procure needed capacity from the lowest-cost sources of new supply.

These concerns with the RCM could be addressed by implementing two primary reforms. First, we recommend implementing a more rational demand curve for capacity, with prices declining to zero as the magnitude of capacity excess becomes large. The Lantau Group in its review proposed a slightly steeper curve, but it is likely still too gradual to fully address the current excess supply problem. If a steeper curve is adopted, it may be developed following the U.S. practice of drawing a downward-sloping curve through or near the target supply quantity and the net cost of new entry (Net CONE), with the shape designed to balance price volatility, quantity volatility, or other objectives.[11]

However, we strongly caution against considering a completely vertical demand curve, which would make the market more susceptible to the exercise of market power, produce a high level of price volatility, and potentially introduce reliability concerns as have been observed in other markets with vertical demand curves. For example, the sudden implementation of a very steep or vertical supply curve could precipitate a sudden large contraction in supply, potentially even an over-reaction which might push the market from a large excess to a shortage condition.[12]

Second, we recommend eliminating the current practice of awarding capacity payments to all qualified suppliers and instead adopting competitive, non-discriminatory, single-price auctions that meet the capacity demand by procuring supplies from only the lowest-cost supply offers. Note that a modest change to the demand curve slope could be implemented without such a competitive auction, but adopting a materially steeper demand curve requires moving to a competitive auction structure. This is because suppliers must be able to ensure that they would only be committed to sell capacity if prices were above their competitive offer levels (under the current mechanism, a materially steeper capacity payment formula could leave suppliers with payments far below cost if they guessed wrong on the quantity of excess).

Moving to a competitive capacity auction, combined with efficient energy and ancillary services markets, will provide efficient investment incentives to develop the least-cost mix of resources, including baseload, peaking, uprates, demand response, deferred retirements, and

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11 For examples of how these objectives have been used to develop alternative capacity demand curve shapes in the U.S. markets of PJM and ISO New England, see Newell*, et al.* (2014a) and Pfeifenberger, *et al.* (2014). See also the discussion in Pfeifenberger (2013b), Sections IV.B.3-4. It will also be useful to monitor developments in the European markets that are in various stages of considering or implementing capacity markets, and may develop other types of capacity demand curves over the coming years, including the United Kingdom, Italy, France, and Germany.

12 This price instability with a vertical demand curve has recently been illustrated in ISO-NE, where a price floor supported an excess in that market for several years. When the floor was finally eliminated, the expectation of lower revenues along with other factors pushed the market suddenly from an excess supply to shortage condition with prices at the cap. See additional discussion in Newell and Spees (2014a).

new generation. This type of capacity auction must be designed to address the potential exercise of market power, which, as in an energy-only market, is substantial in a small, concentrated capacity market. A less concentrated market structure would substantially alleviate such concerns under either a capacity or energy-only market. Although we have not analyzed exactly what level of market concentration could be effectively addressed by particular monitoring and mitigation measures, we view these problems as generally easier to effectively address in a capacity market than in a similarly-sized and concentrated energy-only market.[13]

Regardless of whether Western Australia opts to pursue an energy-only or capacity market design for resource adequacy, we would recommend building on lessons learned from the NEM and international energy and capacity markets to design a sustainable solution for Western Australia and to implement changes gradually to avoid a sudden shock to the market.

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13 This is because a forward capacity market has far fewer transactions, typically having only one auction per year compared to dozens per day or more in an energy market. Further, a capacity market can operate efficiently and effectively when supplier offer levels and prices are mitigated to individual units' net going forward costs (which is typically zero for most of the generating fleet); in contrast, strict monitoring and mitigation measures can be problematic in an energy-only market since they may also prevent prices from rising high enough to attract investment when needed.

I. Motivation

Western Australia's (WA's) market design for resource adequacy is currently the subject of a number of market reform initiatives. These discussions have been ongoing since 2011, when The Lantau Group examined the Reserve Capacity Mechanism (RCM) and recommended a number of reforms.[14] These reforms have been considered by the Independent Market Operator (IMO) and its stakeholder groups, culminating in a set of recommended changes to the design.[15] At the extreme, some parties have suggested that the RCM should not be reformed but rather eliminated in its entirety and replaced with an energy-only market designed after the eastern National Electricity Market (NEM), or that WA might join the NEM as a non-interconnected zone with no interties. Others have suggested more moderate changes or none at all. Presently, these initiatives are on hold while the Government conducts a comprehensive review of the entire energy sector of Western Australia, covering not only the RCM and the energy-only alternative, but also the approach to retail competition, transmission and distribution investments, and gas pipeline infrastructure.[16]

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14 See Lantau (2011).

15 See IMO (2014b).

16 See PUO (2014).

17 For example, see a summary of such concerns as expressed in IMO (2014b), Appendix 1. See also the issues addressed in ERA (2013b), pp. 6-8, 10-12, and 31-42.

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II. What are the Primary Tradeoffs between Energy-Only and Capacity Markets?

Energy-only and capacity markets each have advantages and disadvantages, with the most beneficial design in any particular market depending on the over-arching policy objectives and unique market characteristics. The primary difference between the two is that, in capacity markets, the system reserve margin is pre-determined by regulators (then met through market mechanisms); while in an energy-only market, the reserve margin is determined by market forces. The implications of either design for likely prices and reserve margin outcomes depend on market design details (such as the magnitude of a required reserve margin and the price cap in the energy market) as well as the supply/demand characteristics of the system.

[19] The conclusions that we draw in this whitepaper are solely based on our review and analysis of the Western Australian market design for resource adequacy and draw heavily on our findings from similar analyses we have undertaken in other international energy-only and capacity markets. For examples of these prior studies, see Newell, *et al.* (2009, 2010, 2012, 2014a-b); Pfeifenberger, *et al.* (2008, 2009, 2011a-b, 2012, 2013a-b, 2014); LaPlante, *et al.* (2009); and Spees, *et al.* (2013).

[20] See PUO (2014), and IMO (2014f).

A. Regulated Versus Market-Based Reserve Margins

Western Australia, like most power systems around the world, has a regulated resource adequacy standard that translates to an enforceable minimum reserve margin.[21] Regions with traditional regulation of vertically-integrated utilities meet this requirement through regulated planning supported by regulated cost-of-service generation rates. Liberalized markets also meet these regulatory requirements, but through competitive capacity procurement auctions (and some regions have both traditional planning and centralized capacity markets to support transactions at the margin, still meeting the regulated reserve margin).

In contrast, the distinguishing feature of energy-only markets is that they have no such mandatory reserve margin or associated reliability level.[22] Instead, the level of generation investment and corresponding reserve margin depend on market prices for energy. Investors build generation whenever they project energy prices high enough to recover their investment costs. If the reserve margin is very low, frequent shortage conditions will lead to high expected prices, increased investment in new generation, and higher reserve margins. However, if the reserve margin becomes too high, prices will not be sufficient to support investment. Thus, the market can be expected to fluctuate around an "equilibrium reserve margin" where suppliers are recovering their investments and earn an adequate return on average, but no more.

We illustrate this equilibrium reserve margin point in Figure 1 from a market simulation analysis we conducted on behalf of the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas (ERCOT), as part of their ongoing review of the current energy-only market in Texas. At the market equilibrium reserve margin, the net revenues for a new combined-cycle plant (shown in red) are just equal to its annualized capital and fixed costs at the gross Cost of New Entry (CONE) (shown in blue).[23]

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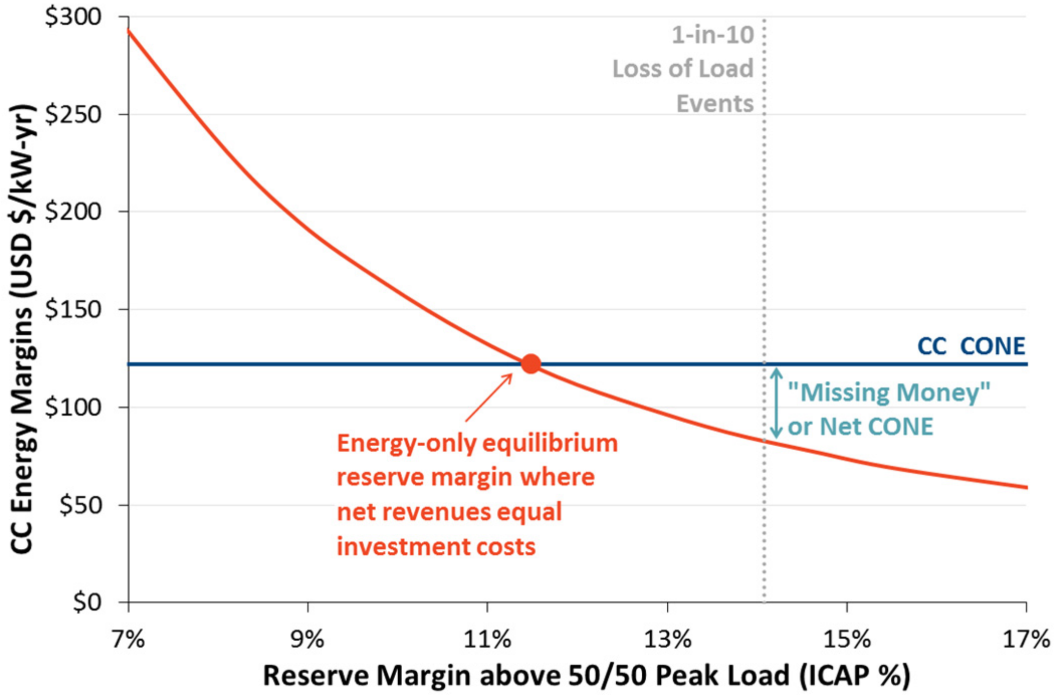
21 See a recent review used to estimate Western Australia's current reserve margin standard, in Market Reform (2012).

22 Some energy-only markets have an unenforceable "target" reliability level, and most also include some form of out-of-market reliability backstop mechanism that intervenes once the market approaches unacceptably low resource adequacy levels. For example, Scandinavian markets pay for "strategic reserves" of older plants with high operating costs that are dispatched only under emergency conditions at very high prices (*i.e.*, with market prices approximately reflecting a world in which those strategic reserves did not exist at all). Similarly, Texas regularly procures demand response on a capacity basis that is deployed only in emergency conditions. Many markets, including Texas and Alberta for example, have mechanisms for administrative intervention into the markets if resource adequacy is expected to drop to unacceptably low levels. However, such out-of-market backstop mechanisms can undermine market signals and exacerbate an inadequate investment problem if they are not carefully designed and administered. See Pfeifenberger, *et al.* (2009), pp. 28-29; AESO (2008); European Commission (2012), p. 8.

23 Gross CONE reflects the average annualized cost of building and fixed cost of maintaining a new power plant over its economic life, including an appropriate return on investment; in other words a supplier would need to expect to earn gross CONE on average over many years to invest in building a plant.

Figure 1
Combined Cycle Energy Margins and Equilibrium Reserve Margin in an Energy-Only Market



Sources and Notes:
Adapted from Newell, *et al.* (2014b), Section IV.A.1.

The figure also illustrates the "missing money" problem that can arise if an energy-only market does not provide returns high enough to maintain the planning reserve margin that regulators desire. There are two distinct possible causes of missing money. First, energy and ancillary service prices may be artificially suppressed by operator interventions for reliability, by low energy market price caps, or inadequate scarcity pricing when there is not enough generation to meet load and provide the required amount of operating reserves.[24] Second, even if price formation is efficient and the energy-only market would achieve an economically-efficient level of resource adequacy, this level may be below what is deemed acceptable to policymakers, regulators, or system operators. This topic is the subject of current market reform efforts in Texas, where regulators traditionally desired to achieve a 1-in-10 reliability standard that the present energy-only market design will not sustain.[25]

An energy-only market instituted in Western Australia would definitely need to address the first type of missing money problem by reforming its scarcity pricing provisions to support the formation of increasingly high prices as shortage conditions become severe, as discussed further in Section III.C. One necessary change would be to increase the price cap from

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24 For example, see Joskow (2008).

25 While other studies and reports may use different definitions, throughout this paper we adopt the most common interpretation of "1-in-10" as referring to "one outage event per 10 years," "0.1 outage events per year," or "0.1 loss of load events (LOLE) per year." We also clarify that an "event" is specified as a single outage event, without regard to the size or duration of such event. See Newell, *et al.* (2012), Sections I.D-F.

$562/MWh to a higher, more economically efficient level that approximates the lost economic value any time insufficient supply exists, which would result in prices hitting the cap and necessitate involuntary load shedding.[26] Recent estimates of the Value of Lost Load (VOLL) in Western Australia range between approximately $38,000 and $57,000/MWh, although the most efficient price cap may be lower if involuntary load shedding would be primarily focused on customers that value reliability less or if some high-value loads have backup power.[27] Considering such issues, as well as the estimated price cap required to meet the target reliability level, the current NEM price cap has been set at $13,500/MWh.[28]

Solving the second type of missing money problem is a bit more challenging in an energy-only market, in that an efficiently designed energy market may not attract sufficient investment to meet regulators' reliability preferences. This situation has recently been encountered in Texas, where after increasing the wholesale price cap to $9,000/MWh USD ($9,610 AUD) and improving administrative scarcity pricing mechanisms, it still appears that the energy market will not be able to sustain the traditional 1-event-in-10-years loss of load event (LOLE) standard.[29] This leaves the region currently reviewing its options, which include: (a) revising expectations to accept the lower level of reliability consistent with the current energy-only design; (b) inflating energy prices further above marginal cost; or (c) imposing a mandatory reserve margin requirement.[30]

These high energy market prices also pose a market monitoring and mitigation challenge. Most regions with reserve margin standards like Western Australia have relatively strict monitoring and mitigation rules allowing suppliers to offer their power into the energy market at marginal cost or possibly with a small markup. By comparison, most energy-only markets substantially relax such rules and allow suppliers to offer at higher prices far above marginal cost in order to produce high prices during scarcity events. This creates a tension between competitive objectives and resource adequacy objectives in energy-only markets because it is difficult to distinguish between the exercise of market power and true scarcity events, and over-mitigating an energy-only market may reduce energy prices to a level below what is needed to sustain adequate investments. We discuss these challenges further in Section III.

Relying on the market to determine the realized reserve margin poses substantial challenges from a reliability perspective, in that regulators cannot be certain what the realized reserve margin will be (although it can be estimated for the short-term by tracking supply developments and for the long-term through market modeling). Further, even if an energy-only market is likely to achieve an adequate level of investment on average, the lack of

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[26] The Western Australian maximum price reflects the Alternative Maximum Short Term Energy Market price that is incurred if liquid-fueled plants are needed, with the quoted price current as of July 2014, from IMO (2014c).

[27] Value of Lost Load from Market Reform (2012), p. 47.

[28] For the current maximum clearing price and a discussion of how to consider the value of customer reliability in setting wholesale market parameters, see AEMC (2014a), p. 7; and AEMO (2013).

[29] Exchange rate of 0.9366 USD/AUD from Bloomberg (2014).

[30] See Newell, *at al.* (2012, 2014b).

coordinated entry and exit leaves energy-only markets susceptible to large year-to-year variations in reserve margins caused by investment cycles and supply and demand uncertainties. This is particularly the case in a small 3,900 MW market like Western Australia, where two coincident retirements could push the market from its current large surplus into a severe shortage condition, as compared to the much larger 35,800 MW NEM, where two plants entering and exiting makes a much smaller relative impact.[31]

The lack of a regulator-determined reserve margin can be seen as an advantage by those who believe a regulated reserve margin forces all customers to pay the same price to maintain the specified planning reserve margin regardless of the value they place on reliability (which is not true to the extent that demand response opportunities allow customers to effectively buy less). A perfectly-designed energy-only market with substantial demand-side participation would solve this problem by allowing customers to determine for themselves the level of reliability they are willing to pay for. Customers that place a low value on reliability could reduce their consumption whenever market prices rise to unacceptable levels, whereas customers that place a high value on reliability may continue to consume power even at very high prices. Real-world wholesale power markets are not able to fully achieve this theoretical ideal, however, either because they have insufficient levels of demand response, inefficiently low energy prices during scarcity conditions, or both.

B. Capacity Prices Increase as Energy Prices and Volatility Decrease

Some regulators would wish to achieve a higher level of reliability than the energy-only market would support. In that case, the missing money can be solved in a liberalized market by imposing a resource adequacy standard on retail providers. The standard requires each retail provider to procure sufficient capacity to meet the peak load of their customers, plus a mandated reserve margin. Retailers could procure that capacity bilaterally, or be assigned their share of total costs after the capacity has been procured by the system operator.[32]

The long-term equilibrium average value of capacity payments in a well-designed bilateral or centralized capacity market is equal to the size of the "missing money" or Net Cost of New Entry (Net CONE) as illustrated in Figure 1 above. This reflects the additional capacity payments on top of energy margins that a developer would require in order to invest. These required capacity payments increase with reserve margins because the anticipated energy prices and energy margins decline. Ultimately, the total energy margins plus capacity payments must equal the Gross CONE of a new entrant to sustain resource adequacy regardless of the mandated reserve margin (although the relative importance of the capacity market increases as the target reserve margin gets higher).

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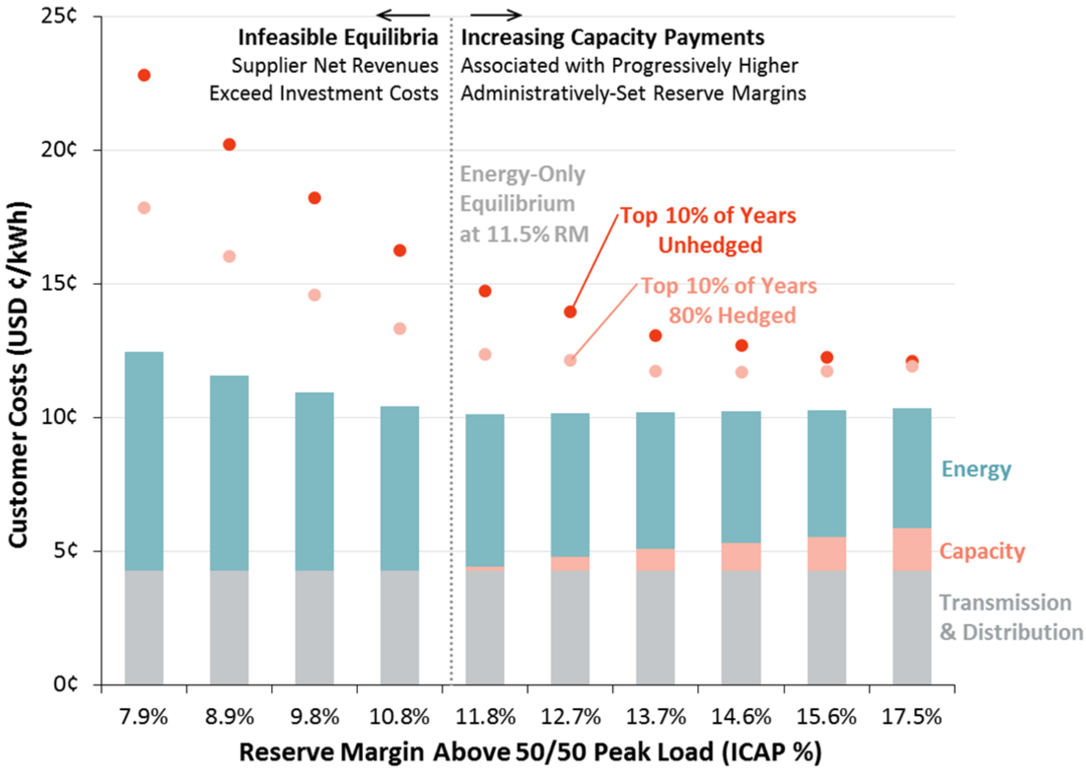
31 Reporting the highest peak load historically observed, rounded to the nearest 100 MW. See IMO (2013), p. 98 and AER (2014a).

32 Most markets follow a model similar to the RCM, where retailers can bilaterally contract for their needs prior to a specific deadline, after which the market operator will procure any residual need on their behalf. See additional discussion in Pfeifenberger, *et al.* (2009).

From the customer's perspective, one of the most important insights is that the cost of a capacity market is far less than the sum of the fleet-wide capacity payments. This is because total capacity payments are partially (but not totally) offset by a reduction in energy prices achieved at higher reserve margins. This net impact on long-run average customer rates is illustrated as a stacked bar chart in Figure 2 from the same simulation analysis of the Texas energy-only market that we referenced above. In that market, we estimated that the net effect of introducing a capacity market would be a modest 1% increase in customer bills.[33]

Figure 2
Total Customer Costs on Average and in Highest 10% of Years



Sources and Notes:
Adapted from Newell, *et al.* (2014b), Section IV.C.1.

Customers care not only about long-term average rates but also about year-to-year, and month-to-month variability and uncertainty. Rate stability depends on both the amount of hedging embedded in retail arrangements and on wholesale spot market prices. At a given planning reserve margin, wholesale spot prices for energy fluctuate because of variations in

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33 Increasing the market reserve margin from the 11.5% that an energy-only market would support to the 14.1% needed to meet the traditional reliability target would cost customers approximately $400 million per year at equilibrium market conditions (from a $2.8 billion reduction in energy costs offset by a $3.2 billion increase in capacity costs). These estimates are based on analysis of long-run costs over many years, without considering the shorter-term differences during a transition period. The analysis includes only an analysis of energy and capacity prices, but does not constitute a full cost-benefit analysis, including factors such as administrative costs or intangible benefits. See Newell, *et al.* (2014b).

load and generation availability, among other things. Capacity prices will also fluctuate with supply and demand conditions.

The combined effect of energy and capacity price uncertainty is reflected in the red dots in Figure 2, representing the average of retail prices for the highest 10% of years, reflecting a once-per-decade scarcity year. As reserve margins increase, this variability declines because the largest factor driving it is volatility in energy prices, which make up a large portion of total customer costs.[34] For reference, we show the realized price in this high scarcity year for a customer that is totally exposed to this price risk (red dots), and for the more typical one that is hedged against 80% of the energy price risk on a seasonal forward basis (pink dots).

Particularly for unhedged customers, but even for hedged customers, the risk mitigation benefit of increasing reserve margins can be substantial. In this example, the once-per-decade scarcity year would produce unhedged customer costs 50% higher than average costs under the energy-only market, but only 26% above average under the capacity market at a 1-in-10 reliability standard.

[34] Volatility from uncertain capacity prices increases with reserve margins, but this effect is less important since capacity costs are a relatively smaller portion of total customer costs and because we assumed that capacity prices are capped at 2 times CONE. See Newell, *et al.* (2014b), Section IV.B.2.

C. Policy Objectives and Market Design Tradeoffs

There are a number of fundamental tradeoffs between energy-only and capacity markets, with each type of market design having merits that might make them more attractive depending on the underlying policy objectives, regulatory regime, and market fundamentals. We summarize these tradeoffs in Table 1, comparing the primary characteristics and relative advantages of each. We more fully discuss these alternative market designs in the context of Western Australia, by: (1) examining the challenges that would need to be addressed if implementing an energy-only market in the region in Section III; and (2) examining the limitations of the current RCM and recommending improvements that could be adopted for a more efficient capacity market design in Section IV.

Table 1
Summary Comparison of Energy-Only versus Capacity Markets

	Energy-Only Markets	Capacity Markets
Reliability	• Reserve margin and reliability determined by market (can be advantage or disadvantage)	• Minimum reliability and reserve margin standard mandated by regulator
Average Prices	• Higher energy prices (due to the lower reserve margin, relaxed monitoring and mitigation, higher price cap, and administrative scarcity pricing) • No capacity prices	• Lower energy prices • Offset by capacity prices high enough to attract investment when needed • Net customer cost impacts are modest (estimated in Texas at 1% net customer costs increase to increase reserve margin by 2.6%)
Price Volatility	• Higher price volatility, with suppliers earning their investment costs during periodic severe price spikes during shortage events	• Lower price volatility • Some markets have introduced higher administrative scarcity pricing and associated volatility to increase energy market efficiency (but realized volatility is still lower overall if reserve margins are higher)
Total Costs	• Can be the same or lower than with capacity market (if the realized reserve margin is lower)	• Can be the same or slightly higher than energy-only (if the mandated reserve margin is higher)
Monitoring and Mitigation	• Oversight has to strike a difficult balance between the need for high prices sufficient to attract investment, and preventing uneconomic excess exercise of market power	• Regulators can impose relatively strict monitoring and mitigation measures, as long as suppliers are able to bid up to marginal cost for energy and net going-forward costs for capacity

III. What Enhancements Would Be Required for Developing a Sustainable Energy-Only Market in Western Australia?

One option suggested for Western Australia would be to eliminate the RCM entirely, and move to an energy-only market. Under this path, Western Australia would no longer impose a mandatory resource adequacy standard and would instead rely on the market to determine the realized reserve margin and reliability outcomes. Suppliers would develop new resources only to the extent that they anticipate energy market prices high enough to recover their investment costs. Relying on the market to determine reliability outcomes can be viewed as either an advantage or disadvantage of energy-only markets depending on one's perspective, although it is not a purely philosophical debate. There are many practical realities and implications of each market design that must be considered in determining the best path for Western Australia.

In this section we describe the primary challenges and energy market design enhancements that would need to be addressed if eliminating the reliability standard and moving to an energy-only market, whether by joining the NEM or forming a new market. These challenges include: (a) establishing a regulatory commitment to the energy-only market design including the ability to withstand political pressures or backlash in the event of the periodic (and necessary) high price, low reliability events that characterize energy-only markets; (b) anticipating the higher and more volatile energy market prices that would need to be realized in a sustainable design that supports resource adequacy; and (c) reforming monitoring and mitigation practices and/or introducing efficient administrative or market-based scarcity pricing mechanisms to enable higher prices.

A. Establish Regulatory Commitment to Withstand Pressures

Implementing an effective and sustainable energy-only market would require strong and consistent regulatory support, even in the face of future challenges and political pressures. Energy-only markets do tend to face these challenges periodically, typically in the wake of transient low-reliability, high price periods that characterize energy-only markets. These events sometimes precipitate a backlash from customers, press, and policymakers wishing to intervene in the market or otherwise dampen prices. For example, in Texas in 2011 a combination of declining reserve margins, an extreme extended heat wave, and a set of coincident outages combined to produce very high prices and a series of reliability events, leading to customer, press, and legislator calls for action and an ongoing contentious debate about resource adequacy in that region.[35]

It is critical to avoid regulatory intervention in the market under such circumstances, because the high prices realized during scarcity periods are necessary to attract investment into a market with diminishing levels of supply. If investors are sure that regulators will not intervene, then they can invest as soon as they anticipate high prices will occur frequently enough to earn an adequate return. However, investors will also evaluate the risk of regulatory intervention that might reduce or eliminate those returns in future years. Lack of regulatory commitment or discord among politicians and regulators will tend to increase this

[35] See discussion in Newell, *et al.* (2012), Section I.

regulatory uncertainty from an investors perspective. In that case, investors will discount the anticipated revenues and reserve margins will drop to a lower and less reliable level before generation will be built.[36]

Successful energy-only markets such as the NEM and Alberta have demonstrated strong regulatory commitment and legal authority to resist calls for intervention for over a decade. Investor confidence that regulators are committed to the energy-only design and will resist intervention can only be established over a substantial period of time, by expressing commitment to the design in the wake of periodic scarcity events. For example, regulators in Alberta have on many occasions faced close press scrutiny and customer backlash after periodic price spikes, and have offered measured responses or addressed the responses in ways that provide more opportunities for stability in retail rates without intervening in the wholesale market.[37]

Challenges to the market design can be expected to emerge in future years as market fundamentals, regulatory objectives, and interacting policies evolve. Such changes can cause a single energy-only market design to produce different levels of investment signals and realized reserve margins at different points in time. For example, the profitability of a natural gas-fired combined-cycle investment is determined not only by the current system reserve margin, but also by many other factors including gas and carbon prices, and subsidies for renewables. Over the past few years, the NEM has been facing such challenges, particularly as associated with the regulatory uncertainty over carbon pricing and downward pressure on energy margins driven by renewable energy targets.[38]

The ability to develop and sustain such an energy-only market design depends on the regulatory and political context, because investors must assess the commitment not only of current regulators but of future regulators and other potential political forces that may change the regulatory landscape. Therefore, Western Australia would need to develop a common understanding of the policy objectives and market vision if the region were to implement a sustainable energy-only design. Failure to do so could result in a short-lived design that would fail to attract investment even as reserves decline, prices rise, and reliability worsens.

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[36] Capacity markets also face regulatory risk, but less so due to the higher degree of stability in both prices and reserve margins.

[37] As one example, a 2012 cold snap and generator outages combined to create a severe spike in wholesale prices that translated into higher monthly customer retail bills. Some consumer advocates responded with deep criticisms of the design, for example saying that the deregulated market had "set up a Ponzi scheme that's fleecing Albertans," while the Energy Minister, Premier, and system operator representatives made more measured statements explaining the price drivers and supporting the market design. For examples of these press reports and regulator responses in response to that and other events, see Kaufmann (2012), Henton (2014), and Alberta Energy (2012).

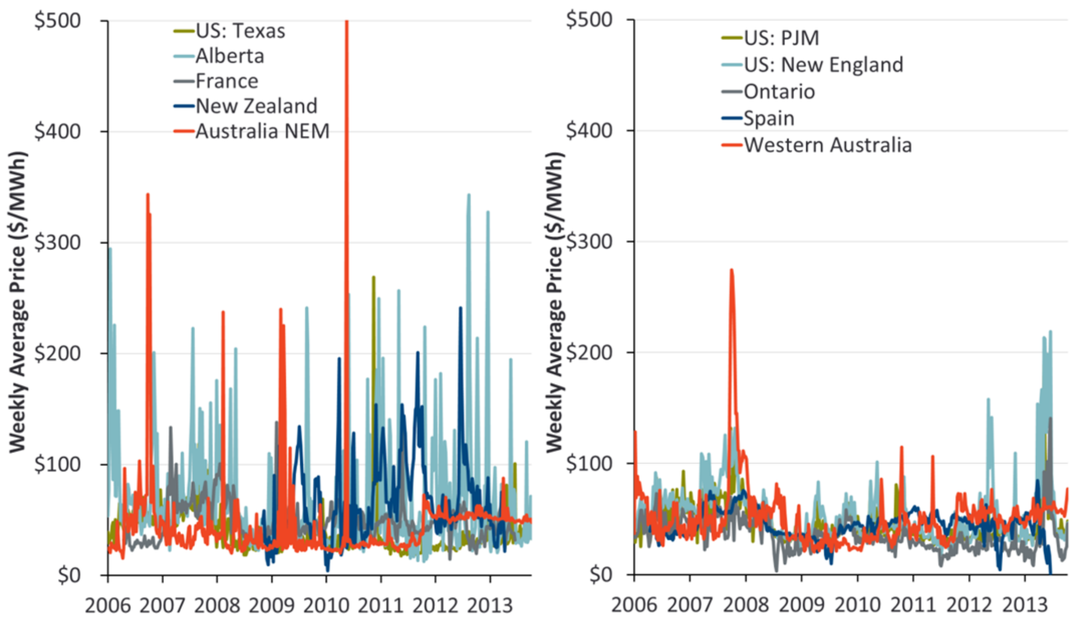
[38] See a thorough discussion of these and other challenges to the NEM as articulated by the AEMC Chairman in Pierce (2012).

B. Expect Higher and More Volatile Energy Prices

As explained in Section II above, adopting an energy-only market does not simply mean eliminating the reliability requirement and RCM. Under its current form, the Western Australian energy market would produce prices far too low to attract investment, even if reserve margins dropped to unacceptably low levels. Instead the energy market would need to undergo substantial reforms such as those discussed in the following two sections to enable higher energy prices.

The result would be energy prices that are higher and more volatile than Western Australia has previously experienced. We illustrate the type of price volatility that should be expected in Figure 3, by comparing the weekly average prices experienced in a selection of international energy-only markets on the left, and a selection of markets with resource adequacy requirements on the right (including Western Australia).

Figure 3
Energy Prices in Energy-Only Markets (Left) and Markets with Reliability Requirements (Right)



Source and Notes:

Weekly average prices for US: PJM, US: New England (ISO-NE), Texas (ERCOT), Alberta, and Ontario from Ventyx (2014); Weekly average prices for Australia are from AEMO (2014); Weekly average prices for New Zealand from the New Zealand Electricity Authority (2014); Weekly average prices for France from EPEX (2014); and Weekly average prices for Spain are from OMIE (2014). ISO-NE prices are at the System. NEM prices are at New South Wales. Prices from Western Australia were aggregated from day-ahead prices in the day-ahead Short-Term Energy Market (STEM) due to the longer data history than real-time, while weekly average prices from all other markets are aggregated from real-time price data where those prices were available or from day-ahead prices in markets where only data exist.

As illustrated in the figure, spot prices in energy-only markets are characterized by moderate prices most of the time and occasional severe price spikes during shortage conditions. Price spikes are essential to a well-functioning energy-only market because they signal resource shortages and provide revenues that can attract new investments.

Similar price spikes may be avoided in most markets with a resource adequacy standard, because those markets' high reserve margins reduce the likelihood of scarcity events. In addition, markets with resource adequacy standards generally impose a lower price cap when scarcity does occur, and enforce a more restrictive set of monitoring and mitigation measures that prevent prices from exceeding marginal generation costs. However, over the past few years, particularly in the U.S., even non-energy-only markets have begun to revise their scarcity pricing mechanisms to allow for more efficient high prices during shortage events.[39] They will still likely experience lower and less volatile prices than their energy-only counterparts, since their higher reserve margins reduce the frequency and depth of scarcity events.

C. Reform Energy Market to Enable High Scarcity Prices

Western Australia currently enjoys relatively low and stable prices compared to international energy-only markets. Prices are prevented from reaching high levels by: (a) the relatively low price cap of approximately $562/MWh, based on the dispatch cost of the highest-cost peaking unit in the system; (b) strict monitoring and mitigation measures that prevent suppliers with structural market power from offering at prices above their marginal production costs, even during emergency conditions; (c) lack of measures for enabling demand response and price-responsive demand to set prices at efficiently high levels during shortage conditions that reflect customers' willingness to pay for reliability; and (d) lack of any administrative scarcity pricing measures that would push prices to a higher level commensurate with marginal system costs during emergency events.[40] Building an energy-only market capable of sustaining resource adequacy in Western Australia would require enabling higher scarcity prices through some combination of reforms to these mechanisms.

The approach to market monitoring and mitigation poses a particular challenge in an energy-only market, because the design must balance between the need for high prices and the need to protect against abuse of market power. Too much mitigation will push prices too low and undermine incentives to invest; too little mitigation and unfettered market power exercise may result in extreme extended periods of excessively high prices as observed in the California power crisis of 2000-01.[41] Energy-only markets also rely heavily on new entry from non-incumbent suppliers to discipline against extended periods of excessive market power exercise since new entrants can theoretically enter the market and undercut withholding strategies. However, new entrants may not perform this function if there are material barriers to entry or if non-incumbents view high prices as unsustainable because they perceive them to be driven by larger suppliers' offer strategies rather than by market fundamentals.

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39 See FERC (2008), and, for example, PJM (2010).

40 The Western Australian maximum price reflects the Alternative Maximum Short Term Energy Market price that is incurred if liquid-fueled plants are needed, with the quoted price current as of July 2014, from IMO (2014c). For the relevant sections of the Market Rules governing offer behavior, see IMO (2014d), Sections 2.16.9(b), 6.6.3, 7A.2.17.

41 During the power crisis of 2000-01, a combination of high loads, low hydro conditions, tightening reserve margins, and alleged exercise of market power combined to create extended periods of high prices throughout western North America and rolling blackouts in California. See Wolak (2003), pp. 17-18.

So an energy-only market must be designed to reflect a balance between these competing objectives. This tension is exacerbated by the difficulty in distinguishing between legitimate high scarcity pricing and abuse of market power, and in determining the appropriate level of scarcity pricing as the system approaches scarcity conditions. For example, a very contentious case arose in New Zealand in 2011 when a pivotal supplier set energy prices at above $19,000/MWh ($14,600/MWh AUD) for several hours, resulting in widespread claims of market manipulation. After a lengthy proceeding to evaluate these claims, and evaluating concerns about intervention under-cutting prices and investor confidence, the regulator decided to retroactively re-price the hours at $3,000/MWh ($2,300/MWh AUD) while at the same time concluding that no manipulative behavior had occurred.[42]

There is no one ideal approach to managing this tension, but we illustrate three very different approaches by comparing the energy-only markets of the NEM, Alberta, and Texas as summarized in Table 2. The general approach in each market is that:

- **Australia's NEM** supports high prices with a high price cap of $13,500/MWh and a relatively permissive approach to market monitoring and mitigation.[43] Suppliers are allowed to offer into the market at prices far above their marginal production costs, resulting in severe but relatively infrequent price spikes.[44] The regulator provides some guidance on acceptable bidding behavior, stating that offers and rebids must be made in "good faith."[45] Price spikes above $5,000/MWh are followed by administrative review and potential penalties if misbehavior is identified, but few events have resulted in material enforcement.[46] Sustained multi-week extreme high prices are also mitigated through the Cumulative Price Threshold that imposes a lower administered price cap of $300/MWh if the rolling seven-day cumulative price exceeds a particular threshold.[47]
- **Alberta's** market enables high prices through permissive market monitoring and mitigation rules that explicitly contemplate "portfolio bidding" above marginal costs for assets under each supplier's offer control.[48] However, exercise of market power is limited by a rule that prevents any one supplier from gaining offer control over more

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42 See Electricity Authority (2012). Average exchange rate of 1.3047 AUD/NZD from the year 2011 applied, from Investing.com (2014).

43 For the current maximum clearing price and a discussion of how to consider the value of customer reliability in setting wholesale market parameters, see AEMC (2014a), p. 7; and AEMO (2013).

44 For example see AER (2013b), Section 1.7.2.

45 See AER (2009, 2013a, 2014a); and AEMC (2014b), Chapter 3, multiple subsections.

46 See AER's large number of "$5,000 Reports" (under *Market Performance*), and relatively few enforcement activities with minor penalties (under *Compliance Reporting* and *Enforcement Matters*), AER (2014c).

47 For the 2014/15 year, the CPT is set at $201,900, meaning that if the simple sum of prices across 336 half-hour trading intervals (or seven days) were greater than $201,900, or, equivalently, if average prices across that period exceeded $601/MWh, then the price cap would be reduced. See AEMC (2014a), Section 2.2.

48 See MSA (2011), Section 2.2.

than 30% of the Alberta fleet.[49] These rules, combined with a low price cap of $1,000/MWh CAD ($991/MWh AUD) result in price spikes that are more frequent but less extreme than in the NEM (but far more extreme than the prices historically observed in Western Australia).[50]

- **Texas** is unlike the other energy-only markets in that it imposes a relatively strict level of monitoring and mitigation, with most suppliers prevented from making offers that are substantially above their marginal costs.[51] However, the market design does produce periodic extreme high prices through a set of advanced administrative scarcity pricing mechanisms that are intended to produce prices consistent with marginal system costs during shortage conditions.[52] These administrative prices rise gradually to the price cap with the severity of the scarcity conditions, with the price cap increasing to $9,000/MWh ($9,600/MWh AUD) by 2015.[53]

Each of these regions has opted to take a different approach to enabling high scarcity prices while protecting against abuse of market power, as summarized in Table 2 below. Finding a workable balance may be more difficult in Western Australia than simply adopting the NEM model without change, because Western Australia is much smaller and more concentrated than the NEM and other energy-only markets.

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49 Note that "offer control" is distinguished from "ownership", with the entity having offer control being that party with the right to schedule a unit into the market and earn the associated net revenues. See *Id.* Section 3.2.4.

50 Current exchange rate of 0.991 AUD/CAD from Bloomberg (2014). For additional analysis of the frequency and severity of these price spikes, as well as the net generator margins associated with these price fluctuations, see Pfeifenberger, *et al.* (2011a, 2013a).

51 "Small fish" with less than 5% offer share are allowed to offer at very high prices, with the offer share tests being conducted on both a system-wide and locational basis. In addition, larger suppliers are allowed to submit Voluntary Mitigation Plans that may permit higher offers on some of their capacity under some circumstances. Newell, *et al.* (2012), Section V.A.5.

52 We describe these mechanisms in a general way here, but substantially more detail on their design, implementation status, and theoretical underpinning is available in Newell, *et al.* (2014b), Section II.F.

53 See Newell, *et al.* (2014b). Current exchange rate of 0.9390 USD/AUD from Bloomberg (2014).

Table 2
Approach to Balancing Need for Scarcity Pricing with Monitoring and Mitigation In Select Energy-Only Markets

	NEM	Alberta	Texas
Price Cap	• $13,500/MWh • Price cap estimated to achieve reliability objectives	• $1,000/MWh CAD ($991/MWh AUD)	• $9,000/MWh ($9,600/MWh AUD) by 2015 • Loosely tied to VOLL, but not supported by a formal study
Administrative Scarcity Pricing	• "Intervention pricing" corrects for administrative interventions during scarcity events • Price set at the cap during load shed	• Only in load shed (price set at cap)	• Administrative scarcity pricing mechanisms push prices up to VOLL as operating reserves deplete
Allowing High-Price Supplier Offers	• Suppliers allowed to offer substantially above marginal cost up to the price cap	• "Portfolio bidding" above marginal cost is explicitly allowed up to the price cap	• Only "small fish" with less than 5% market share are allowed to offer above cost
Integrating Demand Response into Energy Price Formation	• Price-dependent demand bids allowed, but requirements for strict adherence to consuming exact cleared quantities prevent participation	• Offers allowed in wholesale, with small amounts of participation	• DR offers allowed to set prices, through a combination of administrative pricing for emergency DR calls and market-based DR offers
Monitoring and Mitigation	• The AER monitors behavior with some guidelines but minimal enforcement	• Offer control limited to a maximum of 30% for any one large supplier	• Strict monitoring and mitigation with offers no more than 10% above cost for most suppliers
Preventing Extreme Sustained High Prices	• Cumulative Price Threshold limits persistent high prices	• None	• Peaker Net Margin limits persistent scarcity prices over the year

Western Australia's small size of 3,900 MW peak load makes it more susceptible to extended scarcity pricing periods, whether caused by random outages, uncoordinated market entry and exit, or abuse of market power.[54] For example, two plants undergoing coincident retirement or unplanned outages could push the market from a large surplus into an extreme shortage condition. Even Alberta's market with 11,100 MW of peak load is relatively small for an energy only market, and subject to such events.[55] By comparison, Texas and the NEM are less

54 See IMO (2013), p. 98.

55 For example, the unanticipated failure of two large units (Sundance 1 and 2) in 2010 caused a large unanticipated tip in the supply-demand balance of the region, precipitating a substantial period of sustained high prices and uncertainty until an arbitration panel ordered that the units be returned

Continued on next page

susceptible to such events given their much larger sizes of 67,000 MW and 35,800 MW in peak load respectively.[56]

Western Australia's market is also starting from a position of much greater concentration, and therefore greater exposure to the potential for exercise of market power. Synergy holds a 52% supply share in Western Australia (likely a greater share when considering bilateral contracts), while the largest suppliers in Texas, the NEM, and Alberta have 18%, 25-33% (depending on region), and 17% ownership or offer control share respectively.[57] Making the market structurally more competitive would require a relatively large upheaval of the market, for example by forcing divestiture. Another option could be to follow Alberta's model from the inception of its energy-only market, where incumbents did not divest, but instead auctioned off Power Purchase Agreements (PPAs) representing the rights to sell power from their assets into the market or bilaterally (thereby transferring offer control of assets to a larger number of players even though ownership did not change hands).[58]

Overall, designing a well-functioning and sustainable energy-only market is a complex market design and public policy effort that requires analyzing these various tradeoffs and incorporating lessons learned from other markets into the local context. If embarking on such an initiative, Western Australia would need to address each of these challenges while maintaining a realistic understanding of what the end result will be.

IV. What Improvements Can Be Made if Western Australia Opts to Maintain a Resource Adequacy Standard?

If policymakers in Western Australia opt to maintain a resource adequacy standard, there are several steps that can be taken to improve the efficiency of the RCM construct. First is to establish a clear set of objectives, starting by evaluating and/or re-affirming the standard itself. Second is to reform the market construct for meeting that standard cost-effectively, with competitive auctions in which all types of supply compete to clear against a rational demand curve for capacity. We address these topics below by comparing Western Australia's current standard and construct to international best practices, and provide a summary of the specific steps Western Australia would have to undertake in order to transition from its current construct into a well-functioning capacity market.

A. Evaluate the Resource Adequacy Standard

Western Australia's Reserve Capacity Requirement is set to have sufficient resources to meet two different standards that allow for extreme weather, resource outages, and the need for

Continued from previous page

to service despite the owner's protest, see Pfeifenberger, *et al.* (2013a), pp. 17-18, 23-24. Peak load is the maximum all-time system peak from 2013, see AESO (2013).

56 Texas peak load is a forecast peak load for 2013, while the NEM peak load reflects maximum observed. See ERCOT (2012), and AER (2014a).

57 MSA (2013), Table 1; AER (2013b), Figure 1.31; Newell, *et al.* (2012), Table 14; and IMO (2014f).

58 See a description of these arrangements in Pfeifenberger, *et al.* (2011a), Section III.B.

operating reserves. The standards are set to: (1) meet a forecast of peak demand supplied through the SWIS assuming once-in-ten years hottest weather, plus a margin equal to the greater of 7.6% (similar to anticipated generator outage rates) or the capacity of the largest generating unit;[59] and (2) limit expected energy shortfalls due to insufficient resources to 0.002% of annual energy consumption, based on probabilistic modeling of generator availability, without considering transmission or distribution outages or fuel disruptions.[60]

The more stringent of these two requirements governs. To date, and for the next several years that have been evaluated, the binding standard has been the 7.6% margin above the one-in-ten year peak demand, plus a load following requirement.[61] For the 2015/16 delivery year, this translated into a 9.7% reserve margin above the 90/10 peak load or an 18% planning reserve margin over the expected 50/50 peak load forecast.[62]

The Western Australian resource adequacy standard was evaluated from both reliability and economic perspectives in 2012, resulting in a recommendation to reduce the reliability standard compared to prior years, which has been implemented with effect from 2015/16.[63] However, we acknowledge that some continue to ask whether the standard is appropriate or if it should be reconsidered. Because the resource adequacy standard is the most fundamental component of any capacity market design and must reflect policy objectives, we recommend that the first step in improving the design would be to either reaffirm the current standard, or else reconsider whether policy objectives have changed sufficiently to revise the standard.

If the standard is to be re-evaluated it may mean simply revisiting the results of the 2012 Market Reform study in light of revised policy objectives, or it may involve an updated study that is tailored to address specific questions that have not been previously examined. In general, such a review could include a benchmark comparison against other systems' standards, a reliability analysis examining the level of reliability achieved across reserve margins, a cost-benefit analysis of increasing the reserve margin, or a market analysis considering customer cost, supplier net revenue, and volatility impacts.[64]

With respect to a benchmarking exercise, Table 3 illustrates that the current requirement is in line with other electricity systems in the world. Some types of reliability or economic

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59 An additional allowance is added for capacity reserved for load following.

60 See Market Reform (2012).

61 See IMO (2013), Sections 6.1 and 6.2. "For the 2015/16 Capacity Year, the peak demand-based capacity requirement exceeds the energy-based requirement by more than 700 MW. Based on this, it is expected that the peak demand forecast will continue to set the Reserve Capacity Target for the immediate future."

62 Based on the IMO's 2013 "Electricity Statement of Opportunities," this resulted in a Reserve Capacity Requirement for 2015/16 of 5,119 MW, compared to a one-in-ten year peak forecast of 4,668 MW and an expected peak of 4,336 MW. This amount would be the Reserve Capacity Requirement for the 2013 Reserve Capacity Cycle. See IMO (2013).

63 See the recent study and recommended changes by Market Reform (2012).

64 As examples of how such studies can be conducted, see Newell, *et al.* (2014b); Pfeifenberger, *et al.* (2013b); Market Reform (2012); PUCT (2014).

criteria are relatively widely used, while some systems' requirements reflect idiosyncratic reliability concerns such as hydro dependency or large contingencies. Western Australia's standard is in line with international norms when expressed in reserve margin terms, although it is on the higher end of the range, as would be expected in a small, islanded system.[65] As the table shows, energy-only markets often have reliability standards that form either a benchmark for the target reliability level, or else a minimum threshold below which administrative intervention would be activated to maintain reliability.

Table 3
Comparison of Western Australia Reliability Standard to International Norms

	Definition of Reliabilty Standard	50/50 Peak Load in MW	Reserve Margin Above 50/50 Peak
Western Australia	Greater of: (a) 7.6% margin or largest contingency above 90/10 peak load, plus load following, or (b) 0.002% unserved energy	4,337	18%
New Zealand	1-in-60 hydro year for energy standard, plus economic capacity standard	4,281 North, 6,500 Total	18% North Island
Maritimes (CA)	Greater of 0.1 events per year and 20% reserve margin	5,449	20%
Ireland	8 hours per year	6,781	~19%
Singapore	3 days per year	6,814	30%
Alberta (CA)	1,600 MWh per two years	11,100	n/a
British Columbia (CA)	0.1 events per year plus expected hydro energy assessment	11,681	14%
Duke Carolinas (US)	Consider minimum customer cost and 0.1 events per year	12,376	14.5%
Southern Company (US)	Minimum customer cost, plus a risk premium	17,985	15%
Netherlands	4 hours per year	19,900	n/a
Ontario (CA)	0.1 events per year	22,770	19.2%
ISO New England (US)	0.1 events per year	29,790	13.6%
Tennessee Valley (US)	Minimum customer cost, plus a risk premium	34,000	15%
Australia NEM	0.002% unserved energy	35,800	n/a
United Kingdom	3 hrs per year based on economic evaluation	56,040	~18%
Texas (US)	0.1 events per year	67,000	13.75%
Midcontinent ISO (US)	0.1 events per year	124,212	14.8%
PJM (US)	0.1 events per year	164,479	15.7%

Sources and Notes:

We define 1-in-10 as "0.1 loss of load events (LOLE) per year," "0.1 LOLE," or "1 event per 10 years," regardless of the load shed event's size or duration.

Approximate UK and Ireland reserve margins are approximate, see SONI (2012) and Ofgem (2013). See IMO (2013); Maritimes from NBSO (2011); ERCOT (2012); BC Hydro (2008), pp. 2-3; (2010); Duke (2012); TVA (2011); Southern Company from Georgia Power (2010); PJM (2013, 2014c); ISO-NE (2014); MISO (2013, 2014); Singapore from EMA (2014a-b); AESO (2014); AEMC (2014a); New Zealand from Market Reform (2012); Netherlands from TenneT (2011).

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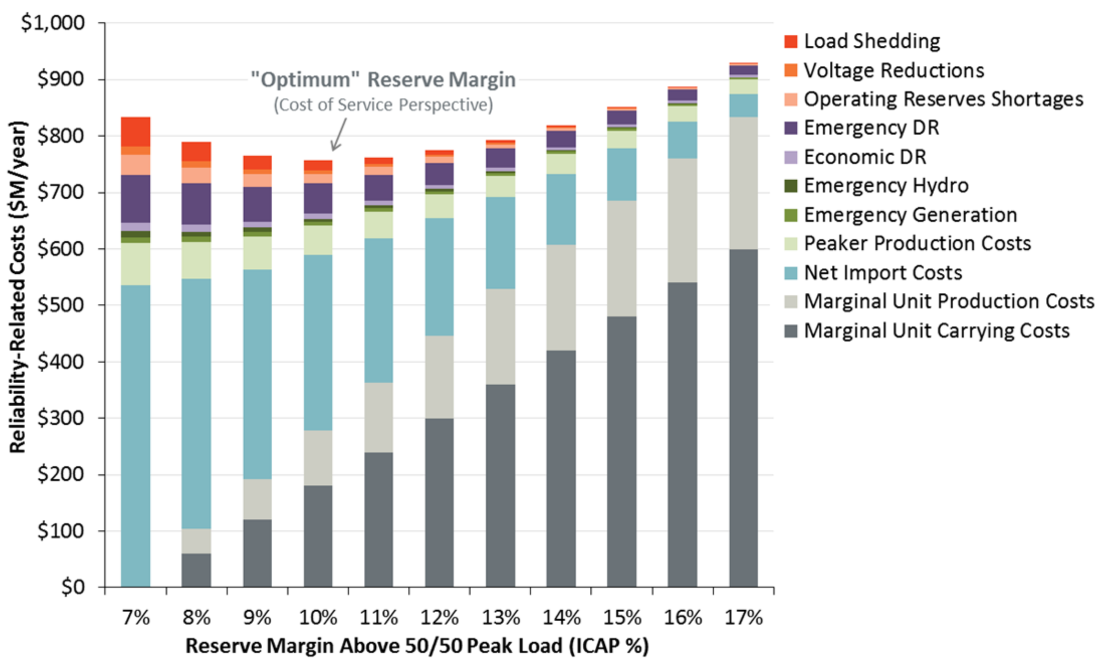
65 Both reliability-based and economically-based reserve margin requirements are higher in: (a) small systems, because they are more severely affected by individual contingencies; and (b) islanded systems, because they are unable to rely on neighboring regions' resources to meet some reliability needs. For additional discussion, see Pfeifenberger, *et al.* (2013b).

Although most electric systems set their resource adequacy targets using engineering-based reliability standards, others rely either partially or fully on economic criteria. One level of economic analysis, as conducted in Western Australia and the United Kingdom, is to compare the frequency and cost of load shedding to the incremental capacity cost to develop an approximate cost-benefit tradeoff.

Another level of analysis, as conducted in the Southeastern U.S. and recently in Texas, includes a more comprehensive probabilistic calculation of costs and benefits when estimating an economically optimal reserve margin.[66] In these cases, economic optimality is defined as the reserve margin where total system costs are minimized, *i.e.*, where the marginal economic benefits just equal the marginal cost of capacity. Marginal benefits include not only reduced cost of load shedding, but also lower incidence of costly emergency events, lower dispatch costs, and others. This type of analysis allows regulators to determine whether the incremental costs of a higher reserve margin may be justified from a public policy perspective to achieve risk mitigation benefits.

Figure 4 illustrates this economic optimality concept for a hypothetical electricity system, drawn from a study we conducted for the U.S. Federal Energy Regulatory Commission (FERC). Tailoring such an analysis to a particular system such as Western Australia would require a fairly intensive economic-reliability modeling effort.

Figure 4
Study of Economically Optimal Reserve Margin on a Hypothetical System



Sources and Notes:
Adapted from Pfeifenberger, *et al.* (2013b).

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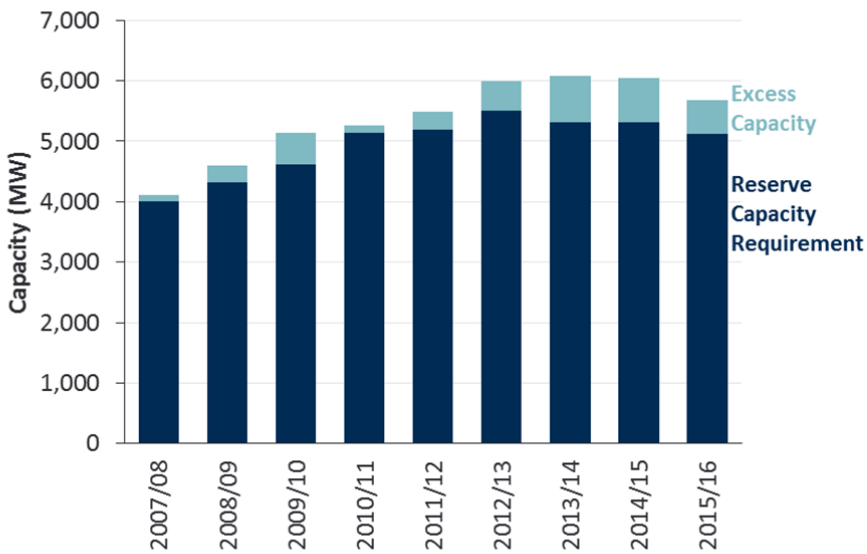
66 See Pfeifenberger, *et al.* (2013b); and Newell, *et al.* (2014b).

B. Adopt a More Rational Capacity Demand Curve

Apart from the question of the level of the resource adequacy standard itself, Western Australia currently faces an excess supply problem, as shown in Figure 5. After starting with a small excess in 2007/08, another 1,925 MW of net additional supply was committed between 2007/08 and 2014/15, while the requirement increased by 1,308 over that same period. A reduction in the load forecast has further contributed to the excess of supply relative to demand, although it has contracted somewhat in the most recent reserve capacity cycle and is expected to contract further in the years ahead.[67]

Figure 5
Western Australia Committed Capacity vs. Reserve Capacity Requirement



Sources and Notes:
2007/08 through 2014/15 from ERA (2013a), p. 13.
2015/16 Reserve Capacity Requirement from ERA (2013b), p. 5.
2015/16 Excess Capacity from IMO(2014a), p. 43.

One reason for this current supply excess is that total net energy plus capacity payments available for new suppliers exceed the incremental cost of supply. In a well-functioning capacity construct, the capacity payments available to suppliers should exceed Net CONE only when the region is short and new investment is needed. During excess, capacity prices must drop below Net CONE to avoid attracting additional investment into an already long market. This is not the case in Western Australia, where capacity prices have remained unnecessarily high at administratively-determined levels exceeding Net CONE even in a supply surplus condition (and decline only gradually as the amount of surplus increases), rather than relying on competitive auctions to find a lower-cost, lower-quantity outcome.

In other words, Western Australia's high capacity prices are a product of two fundamental problems with the RCM design: (1) the relatively high and flat Reserve Capacity Price (RCP) function that pays more than the incremental cost of new supply even at high levels of supply

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67 IMO (2014e), p. 8.

excess; and (2) the lack of competitive procurement auctions to procure needed capacity from the lowest-cost sources of new supply as discussed in the following Section IV.C.

Other international capacity markets have adopted more rationalized capacity demand curves that prevent such excess supply concerns. Under these other curves, capacity prices fall off more quickly as the level of supply excess increases. For example, in the New York ISO capacity market, prices reach zero at a 12% excess above the reliability requirement.[68] By comparison, under the current RCP formula, prices will drop to only 30% below the maximum even at a large 20% excess.[69] This concern with the RCP formula has been examined by the Lantau Group and others, with the proposed revised Lantau formula dropping 40% below the current RCP in an extreme 20% excess condition.[70] While the revised Lantau formula would be more rationalized, it would be unlikely to entirely mitigate the current excess supply problem. Payments would still exceed international norms and likely the payments necessary to achieve reliability objectives (although we have not explicitly analyzed this latter question).[71]

To address these concerns and develop a more rationalized demand curve for capacity, we would recommend following approaches similar to those used in international markets to develop a curve that meets policy objectives, including maintaining resource adequacy, mitigating capacity price volatility, and procurement cost-effectiveness. The approach in U.S. markets including ISO New England, PJM, and New York ISO has been to draw a downward-sloping curve through or near the target quantity and the Net CONE, with the exact shape informed by factors including estimated price volatility, quantity uncertainty, and susceptibility to exercise of market power.[72]

We also clarify that although we recommend a steeper curve than the one that is currently implemented, we caution that we *do not* recommend adopting a curve that is too steep or vertical. While several capacity markets including ISO-NE and PJM began with vertical curves, these markets have moved toward downward-sloping curves because of the problematic price volatility and reliability concerns that materialize with a vertical curve. These concerns arise because capacity market supply curves tend to be quite steep, with the majority of supply offering at a zero price consistent with their net going forward costs and only a portion of the fleet offering at higher prices. If combined with a very steep or vertical demand curve, realized market prices become extremely sensitive to small changes to supply

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68 Reporting NYISO parameters from the 2016/17 NYCA curve. See NYISO (2014).

69 See current RCP Formula from IMO (2014b), pp. 58-60.

70 IMO (2014b), pp. 58-60.

71 We note that a modest change to the demand curve slope such as under the Lantau formula could be implemented without a competitive auction, but adopting a materially steeper demand curve requires moving to a competitive auction structure as discussed in the following section. This is because suppliers must be able to ensure that they would only be committed to sell capacity if prices would be above their competitive offer levels (under the current mechanism, a materially steeper capacity payment formula could leave suppliers with payments far below cost if they guessed wrong on the quantity of excess).

72 See Newell, *et al* (2014a), Pfeifenberger, *et al.* (2014a)

or demand. This means that a small increase in load forecast, one unit retirement, or a small quantity of withholding could move prices from near zero to the cap. This is especially true in small markets like Western Australia.

The result is that a vertical demand curve will produce highly volatile, bimodal price outcomes with prices either near zero or at the cap with few years at more moderate price levels. If the curve is vertical at the target procurement quantity, each outcome at the cap also corresponds to a supply shortfall event. Because these cap-shortfall events must be frequent enough to bring prices up to Net CONE on average, a vertical curve would also procure quantities materially below the target on average across years. Even on a very short-term basis, the implementation of a vertical curve would likely precipitate a large simultaneous contraction in supply that could push the market from an excess to a shortage or near-shortage condition.[73] Thus, a vertical curve can produce problematic lower reliability outcomes along with problematic high price volatility in both the near term and long term.

Therefore, it would be important to adopt a sloped demand curve. While other markets have considered many factors in developing their curves, the precise shape for Western Australia is not as important as developing a curve with: (a) a price cap sufficiently high so that prices could be expected to reach Net CONE on a long-run average basis (without requiring a very large number of years at the price cap); (b) a quantity that is somewhat right-shifted compared to the RCP at a price of Net CONE, to prevent too many low-quantity events from reducing reliability outcomes on average; and (c) a slope that is flat enough to materially mitigate price volatility, but steep enough to prevent excess quantity uncertainty.

The best slope for Western Australia would likely be less steep than those used in other markets as summarized above. A small market like Western Australia needs a more gently downward-sloping curve, when expressed in terms of price per reserve margin percent. For example, it is important to avoid defining a curve where adding a single generating unit could exceed the width of the curve and depress the price to zero, or where retiring or mothballing a single plant could drive the market into shortage and increase the price to the cap.

Because this revised curve would represent a large change from the current market design, changes should be implemented gradually to avoid a sudden shock to realized price and quantity outcomes. For example, if the final demand curve would produce a zero price at a quantity far below the current supply quantity, then a more gradual implementation might start with a curve that produces a zero price at the current level of excess and moves toward the final steeper shape over a matter of a few years. This type of graduated implementation would allow time for regulators and market participants to build familiarity and confidence in the new design while encouraging incremental (rather than sudden) reductions in the current supply excess.

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73 This price instability with a vertical demand curve has recently been illustrated in ISO-NE, where a price floor supported an excess in that market for several years. When the floor was finally eliminated, the expectation of lower revenues along with other factors pushed the market suddenly from an excess supply to shortage condition with prices at the cap. See additional discussion in Newell and Spees (2014a).

C. Attract an Efficient Resource Mix through Competitive Auctions

Currently Western Australia's market rules call for a competitive capacity auction only in cases where capacity declarations fall short of the RCR prior to the deadline, which has not happened to date.[74] Such declarations reflect a non-binding intention to sell capacity bilaterally, with the declared supplies earning a capacity payment regardless of the size of the capacity surplus. However, if there is a surplus of supply above RCR, the value of these payments declines gradually as discussed in the prior section. The result is to eliminate efficient incentives for bilateral trading prior to the auction, sidestep competition among all supply resources, and instead produce the incentive for an arbitrarily large quantity of supply to enter as long as their costs are below the administratively-defined payment rate.

We recommend changing the current design to conduct a competitive centralized auction for capacity procurement in every year, rather than allowing all potential suppliers to earn a payment. Under such a competitive design, Western Australia would enable competition among all resource types, procure only the lowest-cost set of supplies, and reduce the total quantity of excess when combined with a steeper capacity demand curve as explained above.

Evidence from the U.S. capacity markets in PJM, ISO-NE, and NYISO shows that open, non-discriminatory procurement auctions are able to maintain or exceed reliability requirements by mobilizing large quantities of low-cost capacity supply from unconventional and unanticipated sources. For example, when PJM's capacity market, the Reliability Pricing Model (RPM), was implemented in 2007, one of the primary drivers was a fear that the system was approaching capacity shortages in some locations and that a new forward approach was needed to attract new generation investments.[75] However, after the initial focus on trying to attract new generation, the surprising result was that many other resources were attracted at prices below the cost of new generation.

Despite the fact that capacity prices remained persistently below the cost of new generation, RPM auctions for the first eight delivery years attracted 28,400 MW of additional installed capacity (ICAP) commitments, or 13,100 MW of net commitments after considering retirements and other reductions in supply.[76] While the RPM did attract 4,800 MW of new generation (largely not merchant), most new capacity additions came from lower-cost alternatives including: 11,800 MW of new DR and EE, 6,900 MW of increases in net imports, 4,100 MW of uprates to existing plants, and 800 MW of plant reactivations.[77] These unexpected, low-cost, unconventional resources (combined with the economic recession) postponed the need for costly new generation investments by almost a decade, while capacity

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[74] See detailed descriptions of these rules in IMO (2014d).

[75] See PJM (2005), pp. 1-9.

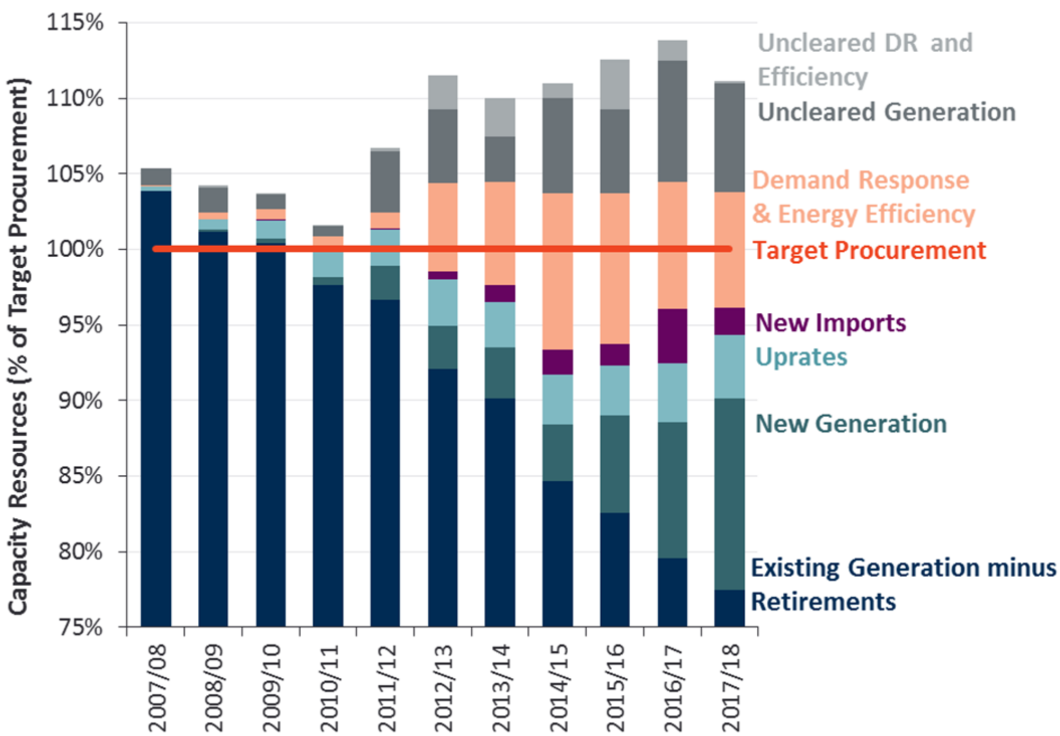
[76] See Pfeifenberger, *et al.* (2011b), Section II.C.

[77] Note that these numbers exclude incremental resources committed in the most recent auction for the 2015/16 delivery year, due to the timing of the underlying analysis. The gross incremental commitments from 2015/16 and on would be even greater than from other years, given that a large quantity of retirements resulted in PJM procuring a large quantity of new generation and some additional demand-side resources, as explained further in the subsequent text.

market prices were generally far below the cost of new entry.[78] We show the diversity of these many supply additions on a normalized basis compared to PJM's procurement target in Figure 6.

The role of competitive auctions to attract the most cost-effective supply resources has become even more apparent in the most recent three auctions for delivery in 2015/16, 2016/17, and 2017/18. These auctions have been notable for attracting large amounts of new merchant generation to maintain and exceed reliability targets, compensating for an unprecedented amount of environmentally-driven retirements and a slowdown (or retreat) of unconventional resources. These three auctions together cleared more than 15,000 MW of new generation supply, of which at least 7,700 MW were from merchant suppliers.[79] Again a surprise, the investors in these projects were willing to enter the market at prices below the administratively-estimated Net CONE, suggesting either the prevalence of especially economic projects or administrative over-estimation error.

Figure 6
PJM Offered and Cleared Capacity Compared to Target Procurement Levels



Sources and Notes:
Compiled from PJM auction parameters and results, PJM (2014c), and Pfeifenberger, *et al.* (2011b).

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78 For a more comprehensive discussion and supporting documentation of PRM results and pricing, see Pfeifenberger, *et al.* (2011b), Section II.

79 The 7,700 MW in merchant supply reflect results from only the two most recent auctions and reflects 76% of the total new generation cleared in those auctions. The breakdown of new cleared generation into merchant and regulated was not reported for the 4,900 MW that cleared in 2015/16. See PJM (2014c), Base Residual Auction Reports for 2015/16, 2016/17, and 2017/18.

There are at least three essential elements of RPM that have enabled the market to meet resource adequacy targets at unexpectedly low costs:

- **Non-discriminatory auctions** allow all resource types to compete in the same auctions to identify the least-cost set of options. Eligible resource types include new and existing generation, demand response, energy efficiency, and imports. Different types of resources face slightly different qualification requirements and participation rules that recognize their different attributes while aiming to provide the same credit to resources that provide the same amount of reliability value. It helps that the Base auction is three years forward (enough lead time for a gas-fired generator in development to compete before it has made large financial commitments), and that shorter-term auctions are also conducted to allow further entry and exchange of capacity supply obligations.
- **Market monitoring and mitigation** ensure competitive outcomes. Monitoring and mitigation are essential since capacity auctions are not always structurally competitive, with pivotal suppliers that could drive prices to the cap if not prevented from withholding. Thus, almost every resource is mitigated to its verifiable avoidable going-forward cost.[80]
- **A rational demand curve,** described above in Section IV.B, procures more supply when there are plentiful low-priced offers and less otherwise; clearing prices are allowed to fall as capacity excesses increase, but not so rapidly as to result in excessively volatile prices.

Some elements of RPM still draw concerns from PJM stakeholders, especially the volatility of prices, and ongoing debates about the relative reliability value and participation rules for various resources types, among others. Nevertheless, the PJM experience strongly demonstrates the benefits of non-discriminatory procurement through centralized competitive auctions.

D. Implement the Essential Elements of an Effective and Efficient Capacity Market

If Western Australia opts to maintain a resource adequacy requirement, it can minimize the cost of meeting that requirement by implementing market-based mechanisms along the lines discussed above. Successfully transitioning will require three distinct steps: (1) defining objectives; (2) developing a market design; and (3) establishing a transitional implementation schedule. Each of these will be most successful if the IMO or PUO take the lead to develop a proposal (or at least a small number of coherent options) then seek stakeholder input before finalizing the plan.

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[80] Control of so-called "buyer market power" has been important to prevent states from subsidizing new entrants to flood the market and depress the price paid by load serving entities. PJM has responded to this challenge with its Minimum Offer Price Rule (MOPR) that it applies to certain entrants. This has been important for supporting merchant generation investment by reducing the prospect of future prices being manipulated downward.

Step 1 is to **clearly articulate policy objectives** as the guiding principles for the market design. The primary dimension is defining the resource adequacy standard, and we note that the current standard is within international norms and may not require modification. However, there are various nuances, such as whether the standard is an absolute minimum or something to achieve on average with a lower minimum acceptable amount before regulatory interventions. Other policy dimensions may include limiting capacity price volatility and limiting susceptibility to the exercise of market power.

Step 2 is to **develop a market design** that meets the policy objectives above. We recommend starting with a "strawman" proposal, along with analyses of likely implications for reliability, prices, and costs. This will allow stakeholders to understand the implications and provide comments before finalizing the rules. The candidate design would have to address the key elements described below and summarized in Table 4 below:

- *The shape of the demand curve*. The existing price curve decreases too slowly as reserve margin increases, effectively locking in an administratively-determined payment level (price times quantity) and inducing excess capacity. Steeper demand curves, such as those described in Section IV.B above, could be used instead, in an auction context, to let the market find an equilibrium price and quantity closer to the reliability target (*e.g.*, if the administratively-determined benchmark price is too high, the market will clear at a lower price more reflective of net costs, with only a small amount of excess capacity). The key decision variables are the target price, the price cap, and the slope of the curve, which together determine how well the curve will meet the design objectives.
- *Competitive procurement auction design*, including short-term adjustment mechanisms. Section IV.C explained the many benefits of holding competitive auctions (and the necessity if implementing a more steeply declining demand curve). Western Australia would have to determine the auction design (*e.g.*, a single-price, sealed bid auction), the forward period (*e.g.*, three years forward), the delivery period (*e.g.*, 1 delivery year), among other specifications. In addition, if conducting three-year forward auctions, it is valuable to design similarly-structured short-term auctions where incremental needs can be procured and where suppliers can exchange positions.
- *Resource qualification and participation rules*. Clear rules are needed to define the amount of capacity credit each type of resource can receive (*e.g.*, it is lower for intermittent resources), how they have to perform, and penalties for non-performance. This tends to be one of the more contentious components of other capacity markets. If Western Australia can adapt the qualification rules it already has, it will save time both in developing the rules and in qualifying individual resources.
- *Monitoring and mitigation*. As under an energy-only market design, a Western Australian capacity market must be designed to be robust against the potential exercise of market power. All capacity markets must have some monitoring and mitigation measures, because otherwise there would be pivotal suppliers who could withhold a portion of their capacity to drive up the price. However, capacity markets become most susceptible to exercise of market power if they: (a) have a very steep or vertical demand curve, or (b) have a high level of supply concentration as Western

Australia does now.[81] To address these concerns, Western Australia would have to develop clear rules, establish competitive benchmark prices or a process for doing so, and determine under which circumstances certain types of resources or owners could be exempt. For example, in PJM existing generation resources have their supply offer prices capped an their net going-forward costs (fixed costs minus expected energy margins), which results in most supply offering at a zero price unless those generators are facing documented reinvestment or retrofit costs. However, other types of supply such as new generation investments, energy efficiency, and demand response may offer at unrestricted higher levels.

Finally, Step 3 is to **develop an implementation plan**. This includes an implementation schedule that allows enough time to develop detailed rules, processes, and software, and to qualify resources before the first auction. This process might take perhaps two years or less if certain elements of the current design are largely retained, such as resource qualification. For example, if the proposed design includes three-year forward capacity auctions, the first auction could be scheduled for two years from now (for delivery three years later). The interim delivery years could follow the existing design with a declining payment schedule as proposed by The Lantau Group or declining more steeply. Once the competitive auction is implemented, it may also be implemented with a relatively flatter demand curve that gradually moves to its final, steeper shape over a number of transition years.

[81] We have not analyzed how effective different types of monitoring and mitigation measures would be in a market of Western Australia's size and at different levels of supply concentration, but do convey that a structurally more competitive market (e.g. as achieved through a forced divestiture or carefully structured PPA arrangements) would produce natural disincentives against exercise of market power and produce more competitive outcomes even with relatively less stringent monitoring and mitigation measures.

Table 4
Status of RCM Design Elements Compared to International Best Practice

Design Element	Current Approach in Western Australia RCM	Changes to Adopt International Best Practice
Resource Adequacy Standard	• Currently at the greater of: (a) 7.6% margin or largest contingency above 90/10 peak load, plus load following, or (b) 0.002% unserved energy • Some have questioned the standard	• Already in line with international norms • Can be re-evaluated to ensure consistency with policy objectives • Need to define the standard along with related objectives regarding the volatility of capacity prices and reserve margins.
Resource Qualification	• Rules already exist for qualifying capacity credits	• No essential changes although refinements can be anticipated over time
Administrative Demand Curve	• All non-bilaterally contracted resources are eligible to receive the administrative RCP price, subject to pro-rating when there is excess capacity. In effect, this is a very gently sloping curve.	• Develop a more steeply-sloped demand curve, consistent with the principles discussed in Section IV.B above
Competitive Procurement Auctions	• Capacity suppliers make a non-binding declaration of intent to sell capacity, and receive a payment that declines slightly as the level of excess increases • No auctions have taken place	• Develop centralized, competitive auctions similar to PJM's • Also need short-term auctions or other adjustment mechanisms, again similar to PJM
Monitoring and Mitigation	• None needed currently with purely administrative pricing outside of bilaterals	• Need to develop rules for determining whom, when, and how much to mitigate supply offers above competitive levels • Also consider including "buyer market power" rules similar to PJM's "MOPR"

V. Recommendations for Resource Adequacy in Western Australia

If the Western Australian government decides to eliminate its resource adequacy requirement, it could either implement a stand-alone energy-only market or join the NEM as a non-interconnected zone. Both of these options pose challenges given Western Australia's context as a small, islanded system, and we recommend following either path only with a clear understanding of and plan for addressing these concerns.

It must be understood that moving to an energy-only market in Western Australia would mean more than simply eliminating the RCM, and would require reforming the energy market to support higher and more volatile prices that would be able to attract investment when reserve margins decline. The current energy market would not be able to attract such investments due to the strict monitoring and mitigation regime, low price cap, and lack of scarcity pricing mechanisms. Implementing an energy-only market capable of supporting the region's resource adequacy needs would require: (a) establishing a regulatory commitment to the energy-only market design, including the ability to withstand political pressures or backlash in the event of the periodic (and necessary) high price, low reliability events that characterize energy-only markets; (b) anticipating the higher and more volatile energy market prices that would need to be realized in a sustainable design that supports resource adequacy; and (c) reforming monitoring and mitigation practices and/or introducing efficient administrative or market-based scarcity pricing mechanisms to support higher prices.

Joining the NEM would address some of these concerns by increasing the price cap from approximately $562/MWh to $13,500/MWh, eliminating the current energy market monitoring and mitigation rules, and setting the stage for higher and more volatile prices.[82] However, we caution that simply joining the NEM could have substantial unintended consequences in such a small, non-interconnected region with highly concentrated supply ownership. The price cap and monitoring and mitigation framework in the NEM have been developed to support resource adequacy in a much larger and more structurally competitive market. Adopting identical rules in Western Australia could expose the region to substantial concerns that market power prevents the formation of competitive prices and efficient operational and investment outcomes. Even if Western Australia were made more structurally competitive through a forced divestiture, the small market would still be susceptible to wide variations in reserve margin, *e.g.* periods of low reliability and high prices following unanticipated events such as two coincident retirements. Therefore, these concerns would need to be carefully analyzed and appropriate mitigating measures instituted before moving forward.

If Western Australia instead opts to maintain a resource adequacy standard, we recommend doing so with a reformed capacity market that is designed to achieve resource adequacy objectives at least cost. This begins with either confirming or re-evaluating the current

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[82] The Western Australian maximum price reflects the Alternative Maximum Short Term Energy Market price that is incurred if liquid-fueled plants are needed, with the quoted price current as of July 2014, from IMO (2014c). The NEM Market Price Cap is from AEMC (2014a), p. 7.

resource adequacy standard.[83] While the current reliability standard is already in line with international norms, we note that some have questioned whether the standard is set at an appropriate level for Western Australia. The resource adequacy standard could reflect only reliability objectives, or it may also reflect economic or price mitigation objectives as in some other regions.[84] Finally, the question of what the resource adequacy standard should be must be clearly distinguished from the question of how to address the issue of over-supply in excess of this standard.

Once the resource adequacy standard is confirmed or revised, we recommend reforms to the RCM. The current design has attracted a substantial quantity of excess supply into an already long market as the product of two fundamental problems with the RCM design: (1) the relatively high and flat Reserve Capacity Price (RCP) function that pays more than the incremental cost of new supply even at high levels of supply excess; and (2) the lack of competitive procurement auctions to procure needed capacity from the lowest-cost sources of new supply.

These concerns with the RCM could be addressed by implementing two primary reforms. First, we recommend implementing a more rational demand curve for capacity, with prices declining to zero as the magnitude of capacity excess becomes large. The Lantau Group in its review proposed a slightly steeper curve, but it is likely still too gradual to fully address the current excess supply problem. If a steeper curve is adopted, it may be developed following the U.S. practice of drawing a downward-sloping curve through or near the target supply quantity and the net cost of new entry (Net CONE), with the shape designed to balance price volatility, quantity volatility, or other objectives.[85]

However, we strongly caution against considering a completely vertical demand curve, which would make the market more susceptible to the exercise of market power, produce a high level of price volatility, and potentially introduce reliability concerns as have been observed in other markets with vertical demand curves. For example, the sudden implementation of a very steep or vertical supply curve could precipitate a sudden large contraction in supply, potentially even an over-reaction which might push the market from a large excess to a shortage condition.[86]

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83 The current standard is a reserve margin based on the more stringent of either: (a) the reserve margin required on top of a 90th percentile peak load year to account for expected outages or the largest contingency; or (b) limiting unserved energy to 0.002%. See Section IV.A.

84 For a comprehensive review of reliability-based and economically-based approaches to determining reserve margin targets, see Pfeifenberger, *et al.* (2013b).

85 For examples of how these objectives have been used to develop alternative capacity demand curve shapes in the U.S. markets of PJM and ISO New England, see Newell, *et al.* (2014a) and Pfeifenberger, *et al.* (2014). See also the discussion in Pfeifenberger (2013b), Sections IV.B.3-4. It will also be useful to monitor developments in the European markets that are in various stages of considering or implementing capacity markets, and may develop other types of capacity demand curves over the coming years, including the United Kingdom, Italy, France, and Germany.

86 This price instability with a vertical demand curve has recently been illustrated in ISO-NE, where a price floor supported an excess in that market for several years. When the floor was finally eliminated, the expectation of lower revenues along with other factors pushed the market

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Second, we recommend eliminating the current practice of awarding capacity payments to all qualified suppliers and instead adopting competitive, non-discriminatory, single-price auctions that meet the capacity demand by procuring supplies from only the lowest-cost supply offers. Note that a modest change to the demand curve slope could be implemented without such a competitive auction, but adopting a materially steeper demand curve requires moving to a competitive auction structure. This is because suppliers must be able to ensure that they would only be committed to sell capacity if prices were above their competitive offer levels (under the current mechanism, a materially steeper capacity payment formula could leave suppliers with payments far below cost if they guessed wrong on the quantity of excess).

Moving to a competitive capacity auction, combined with efficient energy and ancillary services markets, will provide efficient investment incentives to develop the least-cost mix of resources, including baseload, peaking, uprates, demand response, deferred retirements, and new generation. This type of capacity auction must be designed to address the potential exercise of market power, which, as in an energy-only market, is substantial in a small, concentrated capacity market. A less concentrated market structure would substantially alleviate such concerns under either a capacity or energy-only market. Although we have not analyzed exactly what level of market concentration could be effectively addressed by particular monitoring and mitigation measures, we view these problems as generally easier to effectively address in a capacity market than in a similarly-sized and concentrated energy-only market.[87]

Regardless of whether Western Australia opts to pursue an energy-only or capacity market design for resource adequacy, we would recommend building on lessons learned from the NEM and international energy and capacity markets to design a sustainable solution for Western Australia and to implement changes gradually to avoid a sudden shock to the market.

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suddenly from an excess supply to shortage condition with prices at the cap. See additional discussion in Newell and Spees (2014a).

[87] This is because a forward capacity market has far fewer transactions, typically having only one auction per year compared to dozens per day or more in an energy market. Further, a capacity market can operate efficiently and effectively when supplier offer levels and prices are mitigated to individual units' net going forward costs (which is typically zero for most of the generating fleet); in contrast, strict monitoring and mitigation measures can be problematic in an energy-only market since they may also prevent prices from rising high enough to attract investment when needed.

List of Acronyms

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AESO	Alberta Electric System Operator
AUD	Australian Dollars
CAD	Canadian Dollars
CC	Combined Cycle
CONE	Cost of New Entry
CT	Combustion Turbine
DR	Demand Response
EE	Energy Efficiency
ERA	Economic Regulation Authority
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRR	Fixed Resource Requirement
GW	Gigawatt
ICAP	Installed Capacity
IMO	Independent Market Operator
ISO	Independent System Operator
ISO-NE	Independent System Operator-New England
kW	Kilowatt
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MW	Megawatt
MWh	Megawatt Hour
NEM	National Electricity Market
NYISO	New York Independent System Operator
OMIE	OMI-Polo Español S.A
PJM	PJM Interconnection LLC
PUCT	Public Utility Commission of Texas
PUO	Public Utilities Office
RCM	Reserve Capacity Mechanism
RCMWG	Reserve Capacity Mechanism Working Group
RCP	Reserve Capacity Price
RCR	Reserve Capacity Requirement
RM	Reserve Margin
RPM	Reliability Price Model
STEM	Short-Term Energy Market
SWIS	South West Interconnected System
UCAP	Unforced Capacity
USD	United States Dollars
VOLL	Value of Lost Load
WA	Western Australia

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