NERA
ECONOMIC CONSULTING

Review of Alternative Approaches to setting a Wholesale Electricity Market Price Cap

A Report for the AEMC

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Contents

1.	**Introduction**	**1**
2.	**Overview of Electricity Markets Considered**	**3**
2.1.	**Price caps in wholesale electricity markets**	**3**
2.2.	**Electricity markets reviewed**	**4**
3.	**New Zealand**	**9**
3.1.	**Overview of the New Zealand wholesale electricity market**	**9**
3.2.	**Do market price caps reflect consumer values of reliable electricity supply?**	**11**
3.3.	**Uses of estimates of the VCR**	**14**
3.4.	**Methodology for estimating the VCR**	**15**
3.5.	**General observations**	**18**
4.	**ERCOT, United States**	**20**
4.1.	**Overview of the ERCOT wholesale electricity market**	**20**
4.2.	**Do market price caps reflect consumer values of reliable electricity supply?**	**22**
4.3.	**Approach to setting the price cap**	**27**
4.4.	**Methodology for estimating the VCR**	**27**
4.5.	**General observations**	**28**
5.	**Singapore**	**29**
5.1.	**Overview of the Singapore wholesale electricity market**	**29**
5.2.	**Do market price caps reflect consumer values of reliable electricity supply?**	**31**
5.3.	**Approach to setting the price caps**	**32**
5.4.	**Methodology for estimating the VCR**	**33**
5.5.	**General observations**	**35**
6.	**Alberta, Canada**	**37**
6.1.	**Overview of the Alberta wholesale electricity market**	**37**
6.2.	**Do market price caps reflect consumer values of reliable electricity supply?**	**41**
6.3.	**Methodology for estimating VCR**	**45**
6.4.	**General observations**	**45**
7.	**MISO, United States**	**47**
7.1.	**Overview of the MISO wholesale electricity market**	**47**
7.2.	**Do market price caps reflect consumer values of reliable electricity supply?**	**51**
7.3.	**Approach to setting the price cap**	**52**

7.4. General observations 53

8. PJM, United States 55
8.1. Overview of the PJM wholesale electricity market 55
8.2. Do market price caps reflect consumer values of reliable electricity supply? 58
8.3. Approach to setting the price cap 61
8.4. General observations 62

9. Great Britain 63
9.1. Overview of the wholesale electricity market in Great Britain 63
9.2. Do market price caps reflect consumer values of reliable electricity supply? 66
9.3. Methodology for estimating VCR 67
9.4. General observations 71

10. The Netherlands 73
10.1. Overview of the wholesale electricity market in the Netherlands 73
10.2. Do market price caps reflect consumer values of reliable electricity supply? 76
10.3. General observations 77

11. Conclusions 79

Appendix A. Correspondence with local organisations 81

List of Tables

Table 2.1 Considerations taken into account in setting the market price cap(s) 5
Table 2.2 Summary of the wholesale electricity markets considered 6
Table 3.1 Non-load weighted VCR for all respondents from direct measurement survey (NZ$/MWh, approximate AU$/MWh denoted in parenthesis) 17
Table 5.1 Violation penalties and price ceilings, expressed in multiples of VCR and S$/MWh (approximate AU$/MWh expressed in parenthesis) 33
Table 5.2 EMC VCR estimates using revised GDP and total energy consumed estimates (approximate AU$ expressed in parenthesis) 34
Table 7.1 Residential consumers WTP (US$ 2005, approximately current AU$ denoted in parenthesis) 53
Table 8.1 Installed capacity by fuel type (MW) 55
Table 8.2 Average hourly load for 2012 (MW) 56
Table A.1 Correspondence with local organisations 81

List of Figures

Figure 3.1 Grid connected generation capacity by fuel type (MWh) 9
Figure 3.2 Average daily electricity consumption by month in 2012 (GWh) 10
Figure 4.1 ERCOT energy use 2011 by fuel type (Per cent) 20
Figure 4.2 Weekly generation output 21
Figure 4.3 ERCOT system-wide offer cap 24
Figure 4.4 ERCOT seasonal ORDC 3p.m. to 6p.m. 26
Figure 4.5 ERCOT seasonal ORDC 3a.m. to 6a.m. 26
Figure 5.1 Peak demand by month (MW) 30
Figure 6.1 Installed generation capacity by fuel type (MW) 37
Figure 6.2 Mean hourly electricity consumption by month for 2012 (MW) 38
Figure 6.3 Average hourly generation for 2011 (MWh) 39
Figure 6.4 On-peak offers at or near the price cap by asset type in 2008 42
Figure 6.5 Off-peak offers near or at the price cap by asset type in 2008 43
Figure 7.1 MISO geographical market 48
Figure 7.2 MISO geographical reliability market 48
Figure 7.3 MISO generation mix 49
Figure 7.4 MISO Planning Resources 50
Figure 7.5 Median VCR estimates for I&C consumers (US$ 2005, 1 hour outage) 52
Figure 9.1 Electricity generation by fuel type 2012 (GWh) 63
Figure 9.2 United Kingdom electricity generation by quarter in 2012 (GWh) 64
Figure 9.3 Sell offers in the Balancing Mechanism (2012/13, £/MWh) 66
Figure 10.1 Installed generation capacity by fuel type 2013 (MW) 74
Figure 10.2 Expected maximum load (MW) 75

1. Introduction

NERA Economic Consulting (NERA) has been asked by the Australian Energy Market Commission (AEMC) to conduct an international review of approaches to setting wholesale electricity market price caps that reflect consumer expectations for reliable electricity supply. We understand that this advice will be used in the development of the AEMC's response to the Standing Council on Energy and Resources' (SCER) investigation on linking the National Electricity Market (NEM) reliability requirements to the value of customer reliability (VCR).

Our principal task in this project has been to investigate approaches used to determine the market price cap (if present) in a number of wholesale electricity markets, and to assess the extent that these approaches reflect consumer values for reliable electricity supply. The markets we considered include:

- the New Zealand electricity market;
- the Texan electricity market in the United States, operated by the Electric Reliability Council of Texas (ERCOT);
- the Singaporean electricity market;
- the Albertan electricity market in Canada;
- the Midcontinent electricity market in the United States;
- the PJM Interconnection in the United States;
- the Great Britain electricity market; and
- the electricity market in the Netherlands.

For each market we provide:

- a brief overview of the principal features of the market;
- explain to what extent consumer values of reliable electricity supply are taken into account the approach to setting market price caps; and
- where available information on the methodology used to estimate the VCR.[1]

We also provide our own observations as to the lessons learned from each market, as relevant to the AEMC's consideration on how best to link estimates of the market price cap in the NEM to the VCR.

Our research has been greatly informed by interviews with relevant organisations within each market.[2] That said, our analysis is necessarily high-level reflecting the breadth of markets considered.

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[1] While we refer to the VCR in this report, some jurisdictions refer to the 'value of lost load' or 'VOLL'. We note that these terms can be used interchangeably.

[2] Appendix A lists the organisations that participated in an interview with us, and so assisted with the development of our conclusions.

This remainder of this report is structured as follows:

- Section 2 provides a high-level overview of each of the jurisdictions considered in our investigation;
- Section 3 outlines the arrangements currently in place in New Zealand;
- Section 4 outlines the arrangements currently in place in ERCOT, United States;
- Section 5 outlines the arrangements currently in place in Singapore;
- Section 6 outlines the arrangements currently in place in Alberta, Canada;
- Section 7 outlines the arrangements current in place in MISO, United States;
- Section 8 outlines the arrangements currently in place in the PJM, United States;
- Section 9 outlines the arrangements currently in place in Great Britain;
- Section 10 outlines the arrangements currently in place in the Netherlands; and
- Section 11 draws out the key conclusions from our research.

Appendix A provides a list of organisations that were interviewed over the course of our research.

2. Overview of Electricity Markets Considered

In this section we describe the rationale for establishing price caps in wholesale electricity markets and outline the two primary approaches to estimating market price caps, ie, demand-side approaches and supply-side approaches. We also provide a summary of the markets that have been included in this review, including the considerations taken into account in setting the market price cap(s).

2.1. Price caps in wholesale electricity markets

In theory, the efficient price level during emergency conditions when electricity load must be shed is the value that customers place on receiving electricity supply, ie, the price that would make customers indifferent between experiencing an interruption in service and paying a very high price for delivered electricity. However, in most wholesale electricity markets, consumers do not respond directly to real-time prices and so wholesale market price caps are often established to act as an effective ‘risk cap’ for market participants.

In addition to the limited real-time demand behaviour, the fact consumers do not experience frequent blackouts means that there is almost no market information available on the value that customers place on receiving electricity supply. Therefore, a number of different approaches have been developed to estimate this value in the context of setting a wholesale electricity market price cap. Specifically, there are two primary approaches that have been adopted, namely:

1. demand-side approaches: estimating the VCR explicitly and basing the market price cap on this estimate; and
2. supply-side approaches: deriving a market price cap based on an estimate of the price levels needed to attract a desired level of generation investment.

The most common demand-side approach to estimating the value that consumers place on receiving electricity supply involves surveying consumers’ preferences. These surveys generally seek to ascertain both the ‘willingness to accept’ and ‘willingness to pay’ for electricity outages and usually investigate a number of hypothetical outage scenarios, for example:

- differing lengths of time for the outage;
- the time of day;
- the day of the week; and
- whether the outage was in a particular season.

However, in some markets it may not be possible to obtain sensible estimates of the value that consumers place on receiving electricity supply. For example, in some markets a high proportion of electricity demand is from industrial, commercial and service related industries. As a consequence, estimating the value that consumers place on receiving electricity supply can be practically challenging given the likely different range of estimates across these industries and by individual consumers within each market segment.

An alternative demand-side approach that has been used, involves developing an estimate of the value that consumers place on electricity supply by dividing the industry's contribution to gross domestic product by its total electricity consumption. This approach essentially provides an estimate of the average value of electricity to consumers within each industry.

In a number of wholesale electricity markets, a lack of information on the costs of electricity supply disruptions and poor (or a lack of) estimates of the VCR have given rise to supply-side approaches to estimating the relevant price cap being undertaken. These approaches are typically based on reliability standards (ie, are undertaken from an engineering perspective as opposed to an economic perspective).

Supply-side approaches generally estimate the costs required to encourage a level of investment that reduces expected load shedding to some pre-determined level of reliability. Under these approaches, the market price cap is typically set high enough to allow a new entrant peaking plant to recover its total costs if it were to operate at the price cap for the number of hours of load shed.

2.2. Electricity markets reviewed

In selecting electricity markets to examine as part of this study, our focus was mostly on selecting 'energy only' markets,[3] to ensure direct comparability to the NEM.

While we have focused our study on 'energy only' markets, we have also included two markets that have some form of capacity market in addition to a market for energy (ie, PJM and MISO). The market price cap in the energy component of these markets does not need to be sufficiently high to encourage new generation investment, because those costs can be expected to be recovered directly through capacity market payments. The market price cap in these markets therefore only provides a limit to marginal dispatched demand response, which has a typically higher marginal cost compared with traditional thermal generation.

A summary of the considerations taken into account in setting the market price cap(s) in each of the jurisdictions reviewed is provided in Table 2.1 below. In addition, a summary of key characteristics of each of the jurisdictions included in this review are provided in Table 2.2 below. In both tables, dollar values are stated in local currency, with the approximately Australian dollar value denoted in parentheses.[4]

[3] We note that many of these markets are not currently *pure* energy-only markets because of 'backstop' mechanisms, as well as administratively-determined scarcity pricing arrangements.

[4] Throughout our report, we give approximate Australian dollar conversions using exchange rates at 26 September 2013.

Table 2.1
Considerations taken into account in setting the market price cap(s)

Jurisdiction	Price cap(s)*	Considerations
New Zealand	NA	During limited supply emergencies, scarcity pricing is triggered, which involves a market price range of NZ$10,000/MWh to NZ$20,000/MWh (AU$8,850/MWh to AU$17,690/MWh). The lower bound was set with reference to the costs of a peaking gas-fired generator. The upper bound was set with reference to the value of forgone consumption to consumers during emergency load shed.
ERCOT	US$5,000 increasing to US$9,000 in 2015 (AU$5,320 to AU$9,570)	Increases in the market price cap have been in response to concerns about a slowing of generation investment and have been designed to increase the revenues available for the marginal generating unit. The market price cap has also been set to limit the scope for generators to exercise market power given stakeholder concern.
Singapore	S$4,500 (AU$4,240)	A recent proposal to double the VCR was rejected because of concerns that: it would provide an inadequate incentive for investment in peaking plants; there is no need to incentivise investment in base load plants; it may raise risks of generators exercising market power; and consumers may become more vulnerable to extreme price spikes in the spot market because of high market concentration and low demand response.
Alberta	CA$1,000 (AU$1,060)	A number of market characteristics (high industrial load, flat load profile and large degree of interconnectedness) mean that the relatively low price cap is considered to be sufficient to encourage new investment. Further, the price cap has been maintained in part to limit generator opportunities to exercise market power.
Great Britain	NA	Estimated VCR is intended to be used to procure capacity as part of the proposed capacity market and for setting network reliability standards. VCR may also be used to price involuntary consumer disconnections that may arise from the balancing market (not currently priced).
MISO	US$3,500 (AU$3,720)	The scope for both supply-side and demand-side entities to bid into energy and capacity markets means there is less of a need for a market price cap to incentivise generation investment.
PJM	US$1,800, increasing to US$2,700 in 2015 (AU$1,910 to AU$2,870)	Increase in the market price cap is to accommodate demand side bidding. The ability of both supply-side and demand-side entities to bid into the capacity market means there is less of a need for a market price cap to incentivise generation investment.
The Netherlands	€3,000 day-ahead auction and strips market (AU$4,330) €99,999.90- intraday market (AU$144,333)	Price caps have not been set with reference to an estimate of the VCR. Rather, they have been set in collaboration with market parties and exchanges in interconnected countries with the intention of harmonising across the markets. The Netherlands has a binding forward market that places significant risk on participants that price imbalance energy at very high levels, which reduces the importance of price caps.

** Price caps are all expressed in $/MWh*

Table 2.2
Summary of the wholesale electricity markets considered

Jurisdiction	Level of VCR*	Methodology for Estimating VCR	Market Price Cap*	Market similarities to the NEM	Market differences to the NEM
New Zealand	NZ$20,000 (AU$17,690)	Survey in 2010 of approximately 14,000 electricity customers as well as smaller follow-up surveys in 2012	No official market price cap (in most operating circumstances) Price range of between NZ$10,000 (AU$8,850) to NZ$20,000 (AU$17,690) when scarcity pricing arrangements are triggered	Energy-only market, rural/urban population split	Higher population density, less variable temperatures, lower GDP per capita, lower peak demand, winter peaking
ERCOT	NA	Neither the current market cap nor the proposed market cap increases are based on an analysis of customers' VCR or an analysis of the price cap needed to sustain investments	Currently US$5,000 (AU$5,320) but increasing to US$9,000 (AU$9,570) over the next two years	Energy-only market, large land size, GDP per capita, summer peaking	Higher population density, peak demand, rural population percentage and less variation in temperature
Singapore	S$5,000 (AU$4,240)	Singaporean GDP divided by total energy consumed	Market price caps are defined as portions of the VCR Current energy price cap is S$4,500 (AU$3,810), ie, 0.9 of VCR	Energy-only market	Much higher portion of commercial and industrial customers, less variable temperatures, higher population density, higher proportion of urban customers, higher GDP per capita

Jurisdiction	Level of VCR*	Methodology for Estimating VCR	Market Price Cap*	Market similarities to the NEM	Market differences to the NEM
Alberta	NA	There has been no explicit consideration of the value that customers place on reliable electricity supply in setting the current price cap	US$1,000 (AU$1,060)	Energy-only market, increasing wind penetration	Much higher portion of commercial and industrial customers, large degree of interconnectedness with neighbouring jurisdictions, low natural gas prices, large degree of Power Purchase Agreements set to expire by 2020 (5,000MW)
Great Britain	GB£16,940 (AU$28,880) for domestic and SME users GB£1,400 (AU$2,386) for industrial and commercial consumers	Used stated preference choice experiments (small and medium sized businesses) and value-at-risk approach and econometric techniques (commercial and industrial)	No price cap	Energy-only market – however, introducing a capacity market with the first capacity auction to be held in 2014, peak demand is falling	Winter peaking, higher peak demand, higher total annual consumption
MISO	US$3,500 (AU$3,720)	Used previously conducted studies conducted between 1989 and 2002, using MISO-specific values for the independent variables	US$3,500 (AU$3,720)	GDP per capita, summer peaking, market price cap is set to VOLL	Voluntary capacity market, higher population density, less variable temperatures, connected to another network (ie, PJM), higher peak demand, greater proportion of rural customers

Jurisdiction	Level of VCR*	Methodology for Estimating VCR	Market Price Cap*	Market similarities to the NEM	Market differences to the NEM
PJM	NA	Price caps in the energy markets are based on negotiations between entities from both the demand and supply side of the PJM, not VCR.	Historically been US$1,000 (AU$1060) but a price cap of US$2,700 (AU$2,870) is being phased in over four years. Currently US$1,800 (AU$1,910)	Large area covered (largest centrally dispatched grid in North America), summer peaking	Forward capacity market, generators face significant scrutiny with regard to their market offers, higher peak demand, high degree of demand response
The Netherlands	NA	NA	€3,000 (day-ahead auction and strips market) €99,999.90 (intraday market)	-	Large amount of interconnectedness with neighbouring countries, binding forward market, large degree of vertical integration, winter peaking

** VCR and price caps are all expressed in $/MWh*

3. New Zealand

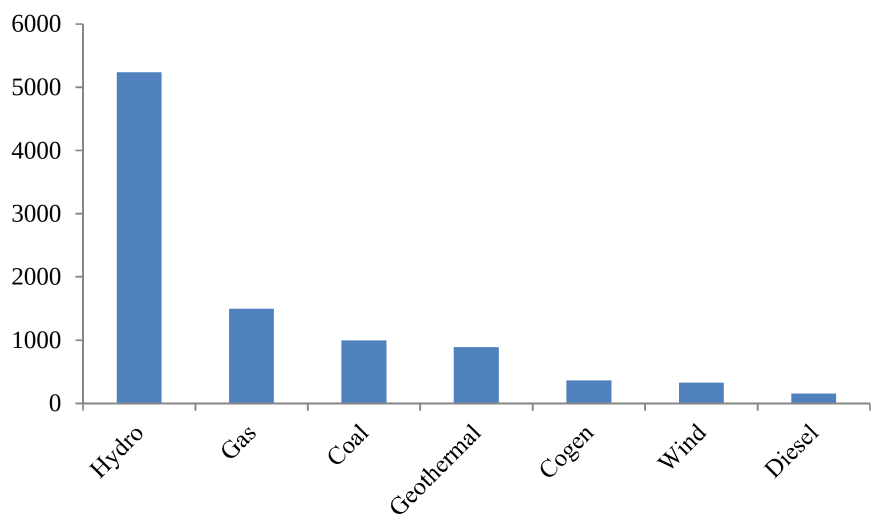
In this section we provide an overview of the New Zealand 'energy-only' wholesale electricity market that is overseen by the Electricity Authority, and set out its principal characteristics so as to highlight similarities and differences between New Zealand's electricity market and the NEM.

3.1. Overview of the New Zealand wholesale electricity market

New Zealand has over 200 power stations and generated 43,138 GWh of electricity in 2011, of which 76.7 per cent was from renewable sources.[5]

Figure 3.1 shows grid connected generating capacity by fuel type in New Zealand in 2013.

Figure 3.1
Grid connected generation capacity by fuel type (MWh)



Source: Transpower, 2013 Annual planning report, March 2013.

The New Zealand electricity market serves 1.7 million households, 165,000 commercial businesses, 70,000 agriculture forestry and fishing businesses and 40,000 industrial customers.[6] Approximately 34 per cent of total electricity is purchased by residential consumers, 36 per cent by industrial consumers, 25 per cent by commercial consumers and 5 per cent by agricultural, forestry and fishing consumers.[7]

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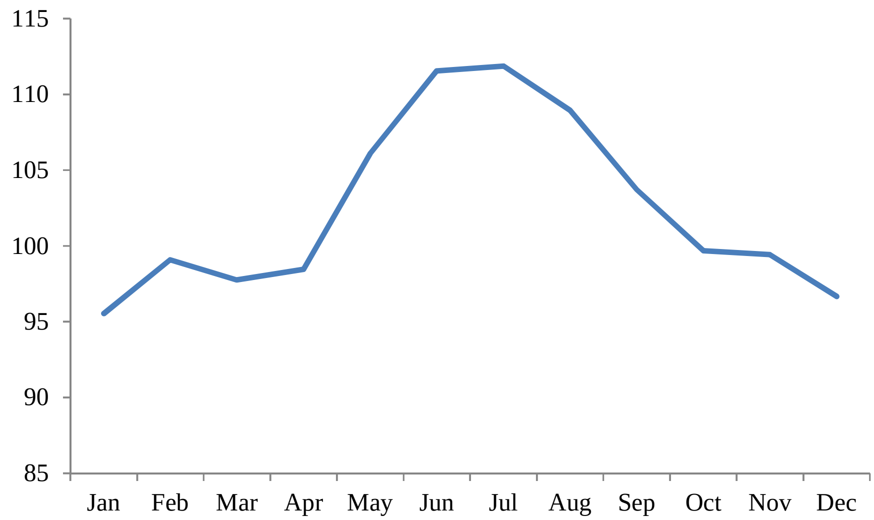
5 New Zealand Ministry of Business, Innovation and Employment, New Zealand Energy Data File 2012.

6 Ibid.

7 Energy Authority website available at: http://www.ea.govt.nz/consumer/industry-overview/ accessed 2/9/2013.

Demand is winter peaking, with the highest recorded peak being 6,654 MW recorded on the 15th August 2011.[8] Figure 3.2 shows the average daily electricity consumption in New Zealand by month during 2012.

Figure 3.2
Average daily electricity consumption by month in 2012 (GWh)



Source: Data from the Electricity Authority.

The New Zealand wholesale electricity market is 'energy-only' whereby the recovery of costs comes from energy and operating reserves, not capacity. The system operator, Transpower, matches generators offers and purchasers bids together with other factors such as the state of the electricity grid and plant outages. Transpower schedules generation profiles for each generator and calculates prices for each of the 11 nodes for every half hour trading period up to 36 hours ahead.

Five minute indicative prices, known as 'real-time prices' are calculated at the end of each five minute period for every node.[9] Final prices are generally available 'ex-post', at 2pm following the day's trading unless delayed for correction to metering and grid data.[10]

New Zealand had 835,000 smart meters installed at the end of 2012 and an estimated 1 million will be installed by the end of 2013 with a further 600,000 installed by April 2015. There is no regulatory requirement for retailers to install or use smart meters.[11]

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8 Electricity Authority, Peak Electricity Demand Nationally data file.

9 Electricity Authority website available at: https://www.ea.govt.nz/industry/market/wholesale-pricing/ & http://www.ea.govt.nz/footer-elements/faqs/market/ accessed 10/9/2013.

10 WITS website, available at: http://www.electricityinfo.co.nz/comitFta/ftaPage.pricesMain accessed 11/9/2013.

11 Electricity Authority, (2013), *Smart Meters fact sheet*, February, Wellington.

We understand from discussions with Electricity Authority staff that large consumers typically respond well to price signals in the market. However, ex-post pricing distorts consumers' ability to respond to actual prices.

During a period of shortage, Transpower, which in addition to its role as system operator is also the state owned transmission service provider, can call an official conservation campaign to encourage New Zealanders to use less electricity. Consumers in the affected area(s) are compensated for reducing demand by their electricity retailer. In severe shortages, Transpower can also implement rolling blackouts.[12]

3.2. Do market price caps reflect consumer values of reliable electricity supply?

New Zealand has two price caps, namely:

- a cap of NZ$20,000/MWh (approximately AU$17,690/MWh) when scarcity pricing conditions are met; and
- a de facto generator offer cap of NZ$3,000/MWh (approximately AU$2,650/MWh) due to a High Court ruling.

In addition, New Zealand introduced 'stress testing' to ensure retailers are aware of their exposure to spot prices and to manage risks accordingly.

These three features of the New Zealand market were not set with reference to each other and have evolved to address different market problems. Nonetheless, each has an impact on the price of electricity in the New Zealand market. We discuss each of these three features below.

3.2.1. Scarcity pricing

In October 2011, the Electricity Authority of New Zealand amended the Electricity Code to allow 'scarcity pricing' to provide more certainty about spot prices during instances of widespread emergency load shedding.[13] Scarcity pricing has been available since 1 June 2013, and effectively sets a market price band, with an associated cap in certain limited circumstances.

If a situation of widespread energy load shedding arises then scarcity pricing is triggered with the generation weighted average spot price (GWAP) being first calculated for the affected network area(s) (ie, island(s)) based on existing pricing processes. However:

- if the GWAP is less than NZ$10,000/MWh (approximately AU$8,850/MWh), all prices within the affected island(s) are scaled up to NZ$10,000/MWh;

[12] Electricity Authority, (2012), *Reliability electricity supply fact sheet*, October, Wellington.

[13] Emergency load shedding, or rolling outage framework is outlined in the System Operator Rolling Outage Plan (SOROP). According to the SOROP issued by the Electricity Commission in 2010, rolling outages are triggered if hydro storage falls to or below a level at which, in the system operator's view, it is more likely than not that shortage will occur; or an 'immediate event' has occurred which, in the system operator's view, creates a situation such that it is more likely than not that shortages will occur.

- if the GWAP is more than NZ$20,000/MWh (approximately AU$17,690/MWh), all prices within the affected island (s) are scaled down to NZ$20,000/MWh.

In other words the scarcity pricing arrangements guarantees that the GWAP will fall within the range of NZ$10,000 to NZ$20,000/MWh.

We understand that the lower bound of the scarcity price band (ie, NZ$10,000/MWh) was set with reference to the costs of a peaking gas-fired generator. The upper bound (ie, NZ$20,000/MWh) was set with reference to the value of forgone consumption to consumers during instances of emergency load shedding, consistent with the Electricity Authority's analysis of the value of electricity to consumers affected by forced power cuts.[14] The NZ$20,000/MWh upper limit of the scarcity pricing arrangements effectively acts as a market price cap during scarcity pricing periods.

New Zealand's scarcity pricing arrangements also have a 'stop-loss' provision that halts the application of scarcity pricing if the average price over any rolling seven day period is greater than NZ$1,000/MWh (approximately AU$885/MWh). If the average price exceeds this threshold, normal pricing processes apply. Irrespective of this provision, scarcity pricing arrangements end once the need for emergency load shedding ceases.

Scarcity pricing was introduced to address the problem of low wholesale market prices in circumstances when a part of the network is isolated from the remainder of the network. The low prices create perverse incentives on the use of electricity by consumers.

Significantly, scarcity pricing and consequently, the price cap is only invoked when an electricity supply emergency causes forced power cuts, or emergency load shedding throughout the entirety of one or both islands, which occurs infrequently. The Electricity Authority found that this provides an appropriate balance between providing the desired signals for generation and demand-response to avert widespread shortages, while narrowing the scope for unintended adverse effects. The Electricity Authority will review the scarcity pricing threshold over time and apply it to a more localised area if it is consistent with the Authority's objective.[15]

The Electricity Authority's rationale for adopting an upper scarcity pricing cap was to address consumer concerns that simply imposing a price floor for emergency load shedding situations could lead to providers of last-resort plant charging prices above what would arise in a workably competitive market.

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[14] Electricity Authority, (2011), *Scarcity pricing questions and answers*, October, Wellington.

[15] Electricity Authority, (2011), Scarcity pricing and related measures – proposed amendments to the Code, Consultation paper, 13 July, Wellington, p 23-24.

3.2.2. Stress testing

Stress testing was introduced in New Zealand due to the growing public dissatisfaction with the electricity conservation campaigns that were implemented during periods of low rainfall, and consequently low generation from hydro sources.[16]

Retailers benefited from the conservation – through reduced demand, limiting exposure to the payment of higher prices. The Electricity Authority found there was a need to remove the incentives retailers had to request electricity conservation campaigns to reduce their exposure to high spot market prices. Further, to improve the incentives for retailers to better manage spot market price risks, the Electricity Authority introduced a requirement that retailers pay residential consumers NZ$10.50 (approximately AU$9) per week in compensation during a public conservation campaign.[17]

In addition, the Electricity Authority now requires retailers and high demand consumers to conduct standard ‘stress test’ price scenarios and provide the results to an independent registrar. This ensures that retailers are aware of the risks of being exposed to spot prices.

The stress test disclosure statement provided to the registrar must outline the retailers:[18]

- annual net operating cash flow;
- shareholders equity;
- the estimated value of electricity that it expects to sell to the clearing manager during the period that the stress test is applied, minus the estimated value of that electricity when a base case is applied;
- the estimated value of electricity that it expects to purchase from the clearing manager during the period that the stress test is applied, minus the estimated value of that electricity when a base case is applied;
- the estimated projected net cash flows from operating activities when the stress test is applied, minus the estimated value of those cash flows when a base case is applied; and
- a statement of any explicit risk management policy in respect of exposure to the wholesale market and if so, the target cover ratio for each stress test calculated in accordance with a method public by the Electricity Authority.

3.2.3. De facto price cap

Although New Zealand does not have a formal market price cap, our understanding based on conversations with Electricity Authority staff is that the High Court’s decision with regard to

16 Communication with Electricity Authority, 6/9/2013.

17 Electricity Authority, (2011), Customer compensation scheme during public conservation campaigns, summary sheet, March, Wellington.

18 Electricity Authority website available at: http://www.ea.govt.nz/industry/security-of-supply/stress-testing-regime/ accessed 11/9/2013.

the Electricity Authority's finding of an Undesirable Trading Situation (UTS) on 26 March 2011 acts as an implicit market price cap.

During the UTS, the Genesis owned Huntly power station offer price was approximately NZ$19,000/MWh (approximately AU$16,800/MWh). However, wholesale electricity purchasers were unaware of the exceptionally high prices. The Electricity Authority retrospectively set a maximum price of NZ$3,000/MWh (approximately AU$2,650/MWh) to correct the UTS. The revised offer prices were intended to reflect the prices wholesale electricity market purchasers would have incurred with their own demand response or would have paid for demand-side response had they been aware of the exceptionally high prices.[19]

Electricity Authority staff identified that following the High Court decision, maximum generation offers have tended to be around NZ$3,000/MWh during supply shortages.[20]

3.3. Uses of estimates of the VCR

While estimates of the VCR have been used to inform the upper bound of the scarcity pricing band, they are also used for transmission planning and regulatory purposes.

The Electricity Industry Participation Code (the Code) sets out the circumstances where estimates of the VCR are used, specifically:

- to benchmark transmission agreements such as when Transpower is assessing whether a transmission connection asset should be replaced or enhanced;[21]
- to assess increased services and reliability, or decrease services and reliability under a transmission agreement;[22]
- when Transpower applies the net benefits test specified in Part 12 of the Code when assessing whether to remove or reconfigure shared connection assets or permanently remove interconnection assets;[23] and
- when Transpower applies the net benefits test specified in the outage protocol to assess proposed planned outages, connection asset variations and interconnection asset variations.[24]

The VCR is also used by the Electricity Authority in its regulatory duties. Specifically, the Electricity Authority states that:[25]

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19 Electricity Authority, (2011), *Summary of decision on actions to correct 26 March 2011 UTS*, 4 July, Wellington.

20 Personal communication with Electricity Authority,, 6/9/2013.

21 Clause 40.2 of the benchmark agreement incorporated by reference into the Code.

22 Clauses 12.35 to 12.37 and 12.39 of the Code.

23 Clauses 12.41, 12.42, 12.43 and 12.117 of the Code.

24 Refer to the outage protocol incorporated by reference into the Code.

25 Electricity Authority, (2013), *Investigation into the Value of Lost Load in New Zealand*, Report on methodology and key findings, 23 July, Wellington, p 6.

> In order to regulate the reliable supply of electricity and efficient operation of the industry … the Authority must understand the value that consumers place on the reliable supply of electricity to them, and the costs incurred by those consumers if their demand for electricity is not met due to a power outage.

Beyond the functions set out by the Code, the VCR plays a limited role in investment decisions. However, the Electricity Authority stated that the substantial cost of transmission and distribution network investments emphasises the need to estimate, as accurately as practical, the economic value of network reliability.[26] The Electricity Authority will consider amending the Code to require the use of VCR for other purposes (eg to guide investment and reliability decisions).[27]

3.4. Methodology for estimating the VCR

Schedule 12.2(4)(1) of the Electricity Industry Participation Code 2010 provides:

> The value of expected unserved energy is –
>
> (a) $20,000 per MWh; or
>
> (b) Such other value as the Authority may determine.

The currently used estimates of VCR were determined in December 2004 by the former Electricity Commission.

In 2008, the Electricity Commission commenced a project to investigate if the current VCR is appropriate.[28] The Electricity Authority which subsumed the Electricity Commission is progressing the review. [29]

The project has involved stated preference surveying of electricity consumers so as to elicit New Zealand electricity consumer's value of reliability.[30] Two survey techniques were used, namely:[31]

- face-to-face interviews with 33 large industrial consumers who account for a significant proportion of New Zealand's electricity consumption; and

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26 Ibid, p 6-7.

27 Electricity Authority website available at http://www.ea.govt.nz/our-work/programmes/transmission-work/investigation-of-the-value-of-lost-load/ accessed 2/9/2013.

28 The final phase of the study is to assess whether the VCR as set in the Rules should be updated and whether the VCR should be used to inform decisions such as reliability and investment standards. To date, the Electricity Authority has not commented on the appropriateness of the current VCR.

29 Electricity Authority website available at http://www.ea.govt.nz/our-work/programmes/transmission-work/investigation-of-the-value-of-lost-load/#stage2 accessed 2/9/2013.

30 Electricity Authority website available at http://www.ea.govt.nz/our-work/programmes/transmission-work/investigation-of-the-value-of-lost-load/#stage2 accessed 2/9/2013.

31 Ibid, p 33.

- a written survey mailed-out to approximately 13,000 randomly selected electricity consumers, with responses received from 24 per cent (3,203 electricity users).[32]

The survey sample was broken into four customer categories, namely: residential, non-residential (small), non-residential (medium), and non-residential (large).[33] A specific stated choice survey was designed for each customer category based on attributes most relevant to each category.

The stated choice question variables included:[34]

- the number of outages per year;
- the length of the outage;
- the seasons of the outage; and
- the time of day.

In addition, residential customers were asked to provide an estimate of the minimum amount they would accept ('willingness to accept' (WTA) questions) as compensation for an eight hour outage at the most inconvenient time. Non-residential consumers were also asked to provide an estimate of the personal cost of a ten minute, one hour and eight hour outage at the most inconvenient time.[35] The WTA questions informed the determination of the VCR for most inconvenient times, while the stated choice questions were used to identify changes in the VCR for various levels of attributes (eg. seasonality effects).[36]

The Electricity Authority published a guideline for conducting a VCR survey in 2013.

3.4.1. Estimates of the VCR

Table 3.1 sets out the non-load weighted VCR estimates based on all responses to the stated choice survey.

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32 The response rate to the mailed survey was 24 per cent.

33 Electricity Authority, (2013), *Investigation into the Value of Lost Load in New Zealand*, Report on methodology and key findings, 23 July, Wellington, p 25.

34 Ibid, p 28.

35 Ibid, p 7.

36 Ibid, p 72.

Table 3.1
Non-load weighted VCR for all respondents from direct measurement survey (NZ$/MWh, approximate AU$/MWh denoted in parenthesis)

	10 minute outage	1 hour outage	3 hour outage	8 hour outage
Maximum	2,215,569	370,000	290,667	109,000
	(1,961,890)	(327,640)	(257,130)	(96,420)
Minimum	0	286	190	159
		(250)	(170)	(140)
Mean	152,269	30,547	28,321	16,798
	(134,700)	(27,020)	(25,050)	(14,560)
Median	19,960	6,439	5,042	4,167
	(17,660)	(5,700)	(4,460)	(3,690)
Upper Quartile	86,228	16,320	21,642	16,304
	(76,280)	(14,450)	(19,140)	(14,440)
Lower Quartile	4,196	3,256	2,381	1,875
	(3,710)	(2,880)	(2,110)	(1,660)
Standard Deviation	401,590	67,183	56,292	27,917
	(355,610)	(59,430)	(49,850)	(24,700)

Source: Electricity Authority, Investigation into the Value of Lost Load in New Zealand, Report on methodology and key findings, 23 July 2013.

Based on these results, the VCR was estimated to be:[37]

- NZ$47,842/MWh (approximately AU$42,360), for an 8 hour outage at the least convenient time possible for consumers using a non-load weighted approach[38]; and
- NZ$50,031/MWh (approximately AU$44,560), for an 8 hour outage at least convenient time possible for consumers using a load weighted approach.

Following this analysis, the Electricity Authority conducted further internet-based surveys to validate and clarify the study findings, particularly in certain geographical regions. The Electricity Authority included willingness-to-pay questions in the follow up study. However, the Electricity Authority has not made any conclusions regarding the appropriateness of the WTP and WTA approaches. The follow up reaffirmed the Electricity Authority's findings that a single VCR figure cannot capture variation across time or across different consumer groups.

37 Ibid, p 56.

38 The *non-load-weighted* values give each survey respondent equal weighting regardless of the quantity (size) of the respondent's electricity consumption. In effect each respondent is given a single 'vote'. The *load-weighted* values adjust the responses to reflect respondent electricity consumption.

3.4.2. Methodological insights

The Electricity Authority's findings arising from its analysis of VCR include:[39]

- a single VCR figure is an 'inappropriate' measure of the value that New Zealand electricity consumer place on reliability because:
  - the actual VCR likely varies considerably across and within consumer categories;
  - the actual VCR likely varies across regions;
  - an individual consumer's VCR is likely to be dependent on the duration of a specific power outage; and
- a carefully designed survey-based approach to estimating the VCR will most likely produce reasonably robust estimates.

These findings will inform the Electricity Authority's consideration about the practicality of using the VCR to inform its decisions in the future.[40]

3.5. General observations

The New Zealand wholesale electricity market is an 'energy-only' market for which there is no official market price cap. That said:

- when an electricity supply emergency causes forced power cuts, or emergency load shedding throughout the entirety of one or both islands, scarcity pricing arrangements are triggered, which involves a market price range of between NZ$10,000/MWh and NZ$20,000/MWh; and.
- a recent High Court decision regarding Genesis owned Huntly generator's power offer prices during a UTS, has led to generators bidding around NZ$3,000/MWh during periods of high demand, which can therefore be considered a de-facto market price cap.

The lower bound of the scarcity pricing arrangement (ie, NZ$10,000/MWh) was set with reference to the costs of a peaking gas-fired generator. In contrast the upper bound (ie, NZ$20,000/MWh) was set with reference to the value of forgone consumption to consumers during instances of emergency load shedding. As a consequence, estimates of the VCR are relevant to the setting of the upper bound of the scarcity pricing arrangement.

The most recent investigation of the VCR was undertaken by the Electricity Authority in 2013. The study had two primary applications to the NEM, namely:

- the importance of estimating the VCR using a number of methodologies, given the likely large variation in values across and within consumer categories, as well as across regions; and

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39 Ibid, p 9-10.

40 Electricity Authority website available at http://www.ea.govt.nz/our-work/programmes/transmission-work/investigation-of-the-value-of-lost-load/#stage2 accessed 2/9/2013.

- that the survey design needs to be appropriate framed for the audience, within the jurisdiction being considered.

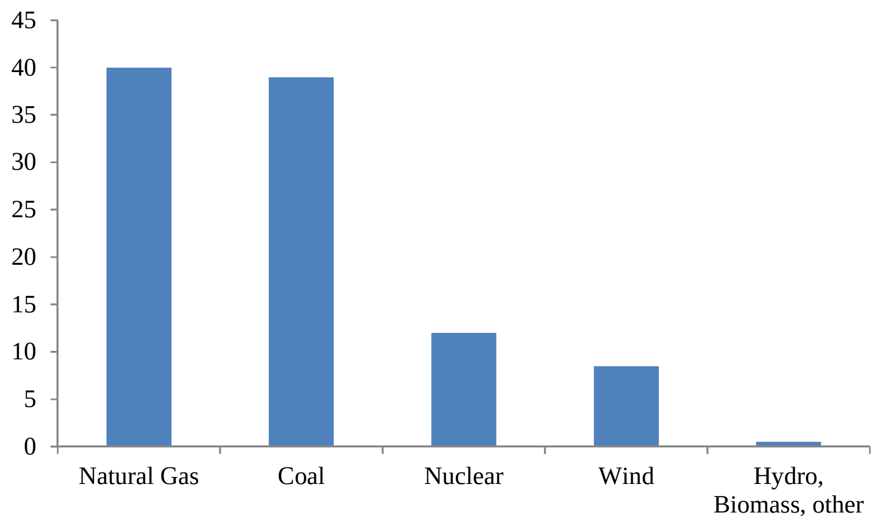
4. ERCOT, United States

In this section we provide an overview of the 'energy-only' electricity market that is operated by the Electric Reliability Council of Texas (ERCOT), and set out its principal characteristics so as to highlight similarities and differences between ERCOT's electricity market and the NEM. We explore ERCOT's objective and approach to determining the level of the market price cap with reference to the VCR.

4.1. Overview of the ERCOT wholesale electricity market

The ERCOT wholesale electricity market, which covers approximately 75 per cent of Texas' landmass and 85 per cent of its electricity load, had capacity of 74,000 MW in 2010. Generation in 2010 was approximately 95 TWh with 1.3 per cent generated from renewable sources – Figure 4.1.[41]

Figure 4.1
ERCOT energy use 2011 by fuel type (Per cent)



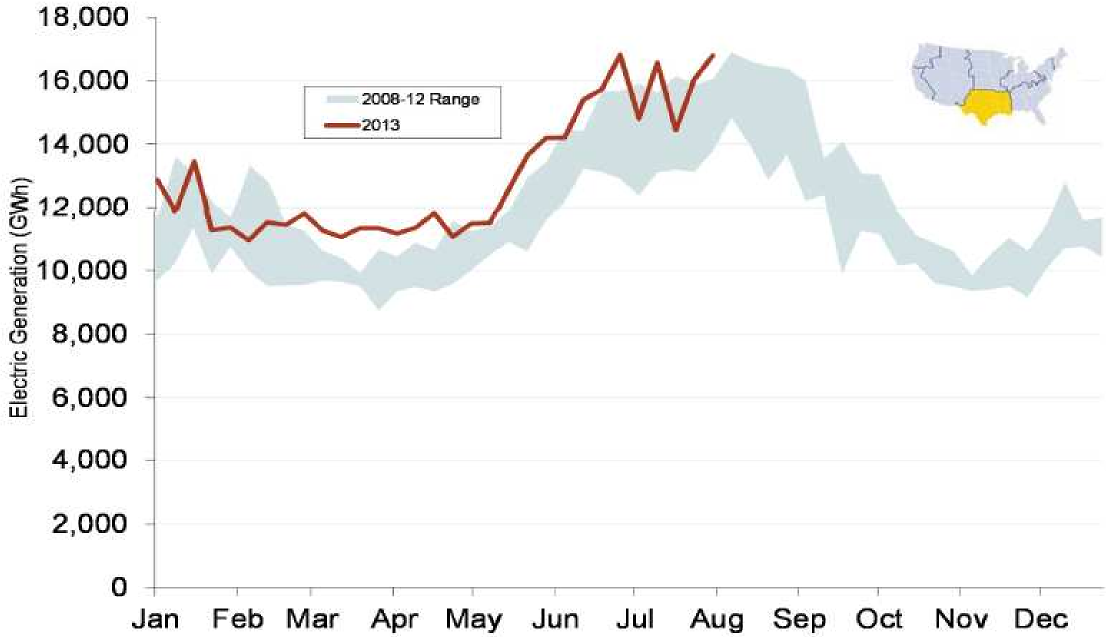
Source: ERCOT, State of the Grid 2013.

The highest demand for electricity occurs in July and August in the afternoon. The peak demand record of 68,305MW was set on the 3 August 2011 between 4pm and 5pm[42]

41 ERCOT, (2012), *2012 State of the Grid*, p. 21.

42 ERCOT, ECOT breaks peak demand record third time (update), news release, available at: http://www.ercot.com/news/press_releases/show/416 viewed 28/8/2013.

Figure 4.2
Weekly generation output



Source: FERC.

Texas had approximately 11.1 million retail electricity customers in 2010.[43] 44 per cent of ERCOT's consumers are in urban locations and the break down between residential, commercial and industrial is 38, 24 and 28 per cent respectively.[44] Residential sales accounted for 57.8 per cent of retail sales in Texas in 2010.[45] By November 2012, 5.8 million advanced meters had been installed.[46]

The key source of demand response is in the reserves market. ERCOT has 1,800 MW in demand response resources including approximately:[47]

- 1,200 MW in load resources mostly from large industrial consumers;
- 430 MW of emergency response service from commercial and industrial consumers; and
- utility load management programs.

According to ERCOT staff, ERCOT anticipates that there is in excess of 10,000 MW of load that would be available if conditions conducive to demand response were developed.[48]

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[43] Data from U.S. Department of Energy, State Electricity Profiles 2010, January 2012.

[44] London Economics, (2013), *Estimating the value of lost load, Report for ERCOT*, 17 June, Boston, p 31.

[45] Data from U.S. Department of Energy, State Electricity Profiles 2010, January 2012.

[46] ERCOT, (2012), *State of the grid*, p 17.

[47] Ibid, p 6.

During periods of supply shortages, ERCOT can begin a public electricity conservation campaign and implement 'rolling blackouts'.[49]There are two commercially operated interconnections between ERCOT and the Eastern Interconnection; the Northern Interconnector, 220 MW and the East Interconnector, 600 MW. There are also three interconnections between ERCOT and the Federal Electricity Commission in Mexico[50]; Eagle Pass, 36 MW, Railroad, 150 MW and Laredo, 100 MW.

ERCOT operates an 'energy-only market', which means power producers are paid only for the energy they provide. In this type of market structure, the scope to receive higher prices for electric power when supplies are scarce encourages generators to provide power to serve peak demand.

ERCOT implemented a nodal market in December 2010 that enabled ERCOT to dispatch resources on a five-minute interval using its Security Constrained Economic Dispatch (SCED) system. ERCOT staff identified that the introduction of the nodal market has allowed them to address localised congestion more effectively.

Within the SCED system, ERCOT operates a day-ahead market that provides market participants with opportunities to buy and sell energy prior to the operating day. Most of the wholesale energy that is bought or sold through the ERCOT market is sold in this centralised, voluntary day-ahead market and the results are factored into ERCOT's operating plans for the following day. Day-ahead prices in 2011 averaged about US$46/MWh (approximately AU$49), compared to US$43/MWh (approximately AU$46) for real-time prices. This reflects the premium buyers place on reduced volatility.[51]

ERCOT operates a congestion revenue rights (CRR) market. This market allows market participants to hedge differences in node prices resulting from transmission network congestion in the day-ahead market.[52]

4.2. Do market price caps reflect consumer values of reliable electricity supply?

The wholesale electricity price cap is determined by the Texas Public Utility Commission of Texas (PUCT), taking into account recommendations made by ERCOT. The initial offer cap of US$1,000/MWh (approximately AU$1,060) was approved by PUCT in 2001.

In May 2003, after experiencing generator bidding consistent with physical or economic withholding of supply (and consequent extreme market prices), the PUCT ordered ERCOT to implement a mitigation procedure called the Modified Competitive Solution Method (MCSM), which aimed to limit the impact of such bidding. However, the MCSM was

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48 Conversation with ERCOT staff, 13 September 2013.

49 ERCOT, ERCOT emergency interruptible load service presentation, AEIC load research workshop, 28 February 2008.

50 The electricity sector in Mexico is federally owned.

51 ERCOT, *2012 State of the Grid*, p. 11.

52 ERCOT website available at: http://www.ercot.com/mktinfo/crr/ accessed 11/9/2013.

terminated in 2006, as it resulted in unpredictable adjustments in prices and undermined the incentive of high prices in the balancing energy market.

The MCSM was replaced with a new approach to market power mitigation and resource adequacy, including:[53]

- publishing resource specific offers;
- a scarcity pricing mechanism;
- the idea of 'small fish swim free';[54] and
- a voluntary mitigation plan.

In addition, PUCT relaxed the US$1,000/MWh offer cap in light of the new approach to addressing resource adequacy and market power concerns. Specifically the offer cap was increased to US$1,500/MWh on 1 March 2007 and again to US$2,250/MWh (approximately AU$2,390) on 1 March 2008.[55] In addition, the system wide-offer cap was again raised to US$3,000/MWh (approximately AU$3,190) two months after ERCOT implemented a nodal market design (ie, in December 2010) and again to US$4,500/MWh (approximately AU$4,780) in August 2012.[56] More recently, PUCT has recently agreed to double the current wholesale electricity system-wide offer cap from US$4,500 /MWh to US$9,000/MWh (approximately AU$9,960) over a three year period as follows:[57]

- US$5,000/MWh (approximately AU$5,310) beginning 1 June, 2013;
- US$7,000/MWh (approximately AU$7,440) beginning 1 June, 2014; and
- US$9,000/MWh beginning 1 June, 2015.

The history of the recent increases to the ERCOT system wide-offer cap is shown in Figure 4.3 below.

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53 AESO, (2009), *Alberta Wholesale Market Price Cap*, Discussion paper, 23 June, pp. 29-30.

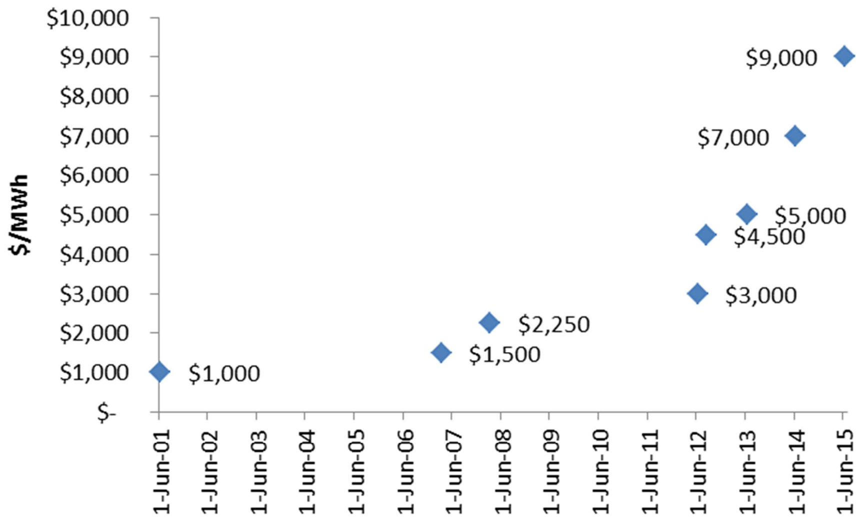
54 It is illegal in Texas for an entity that has market power to withhold production. If an entity holds less than 5 per cent of the total installed capacity in ERCOT, it is thought to not hold market power (ie, a small fish) and thus would not be prosecuted if it withholds capacity from the market.

55 AESO, (2009), *Alberta Wholesale Market Price Cap*, Discussion paper, 23 June, p. 30.

56 ERCOT, (2012), *2012 State of the Grid*, p. 11.

57 Ibid, p. 8.

Figure 4.3
ERCOT system-wide offer cap



Source: ERCOT, 2012 State of the Grid, p. 8.

The most recent increases were motivated by concern about a slowdown in generation investment.[58] ERCOT estimated that the revenue likely to be earned by a new combined cycle, gas-fired plant in 2012 was about US$42 per kilowatt-year. This amount is far below the US$105-US$135 (approximately AU$110-AU$145) per kilowatt-year needed to support new investment to keep pace with economic growth.[59]

Importantly, neither the current market cap nor the proposed market cap increases are based on an analysis of customers' VCR or an analysis of the price cap needed to sustain investments.[60]

The PUCT has faced increasing pressure from the Texas Industrial Electric Consumers, who represent the state's largest oil, chemical and steel companies, not to increase the market price cap.[61] Our conversation with ERCOT staff identified that although increasing the cap has been contested by large industrial and commercial consumers, these consumers consider increasing the market cap preferable to introducing a capacity market, which has been done in other markets in the United States. The large industrial and commercial consumers often have on site generation capacity and can implement voluntary demand curtailment, so do not want to pay for capacity in the market.

In light of this resistance amongst other things, the PUCT is progressing with a model to increase the market price to reflect scarcity in electricity reserves and so, increase generation

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58 Public Utility Commission of Texas, (2012), *Annual Service Quality Report*, May, Item Number 106.

59 E. O'Grady, Big users in Texas oppose major change to stretched power market, Reuters, 8/8/2013.

60 The Brattle Group, *ERCOT Investment Incentives and Resource Adequacy*, 1 June 2012, p. 77

61 E. O'Grady, Big users in Texas oppose major change to stretched power market, Reuters, 8/8/2013.

capacity in the wholesale market. The Operating Reserve Demand Curve (ORDC) will allow ERCOT to value reserves in real-time as they are consumed. The price yielded by the ORDC curve will be ‘added’ to the price in the spot price in the market. The ORDC is expected to be operational by June 2014.

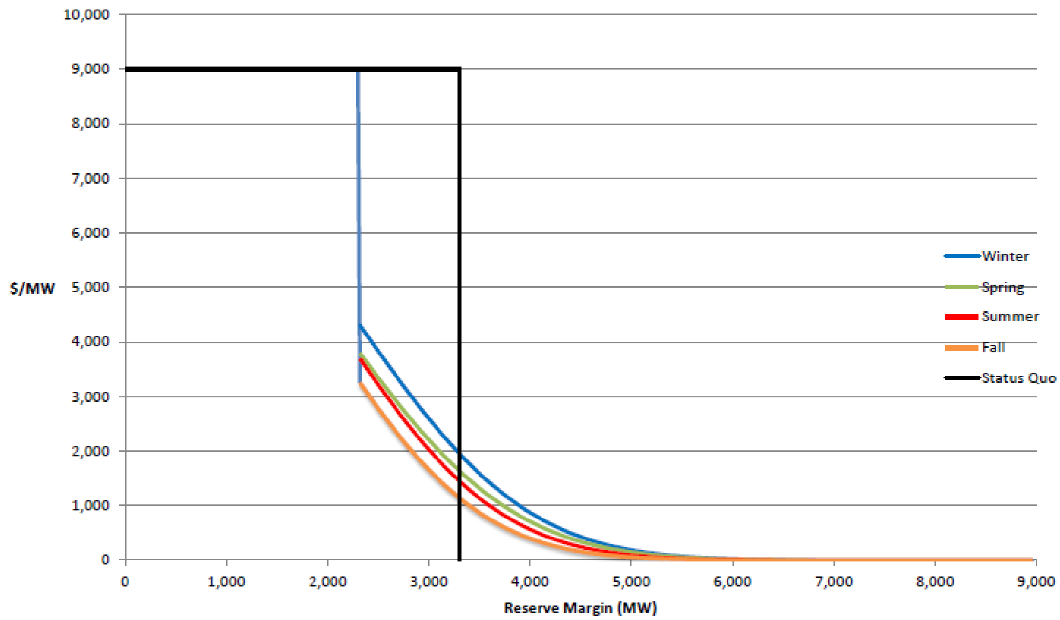
The PUCT has identified the following benefits of implementing an ORDC:[62]

- an ORDC sets reliability incentives because it places an explicit and transparent value on operating reserves. ERCOT’s experience has demonstrated that installed capacity does not guarantee reliability;
- an ORDC is tied to the principle of ‘pay for performance’;
- it is self-correcting;
- an ORDC allows participants to hedge against increases in the price of electricity and it can be incorporated into forward and secondary market pricing models;
- an ORCD will improve market efficiency because it smooths out transitory price spikes that may not occur due to true scarcity conditions, thereby improving price signals;
- an ORDC is technology neutral and will price signals regarding desired load and resource behaviour; and
- an ORDC improves resource adequacy at minimum cost.

The PUCT has included indicative examples of the ORDC with a minimum contingency of 2,300 MW. These are set out in Figure 4.4 and Figure 4.5.

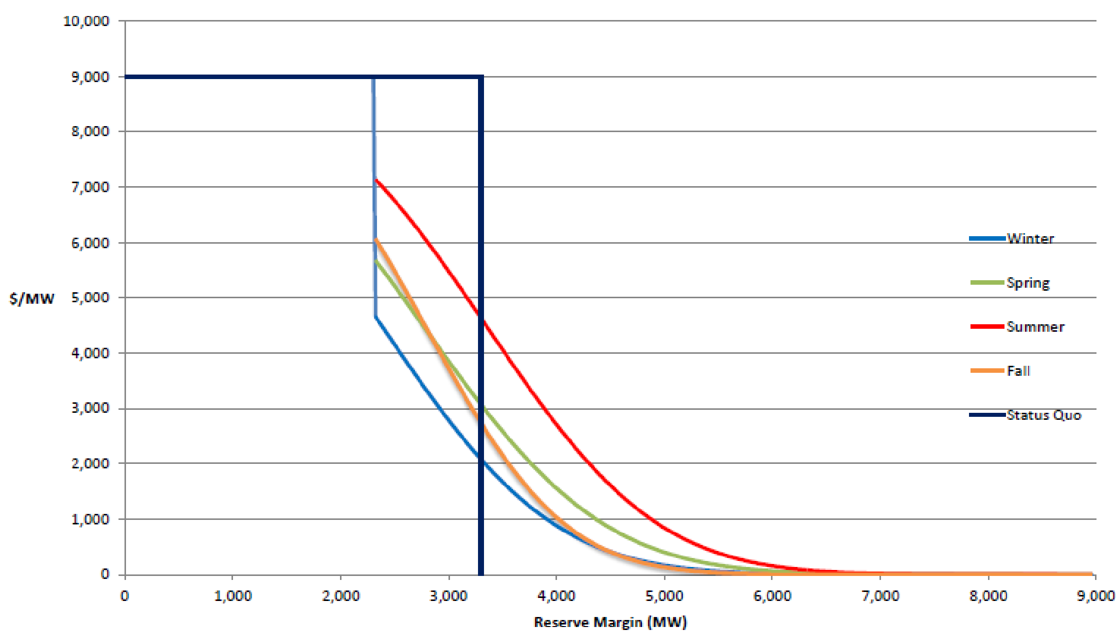
[62] PUCT, Memorandum regarding the open meeting of August 29, 2013, Agenda Item No. 20, Project 40000 ‘Commission proceeding to ensure resource adequacy in Texas’, 28 August 2013.

Figure 4.4
ERCOT seasonal ORDC 3p.m. to 6p.m.



Source: PUCT, Memorandum regarding the open meeting of August 29, 2013, Agenda Item No. 20, Project 40000 'Commission proceeding to ensure resource adequacy in Texas'.

Figure 4.5
ERCOT seasonal ORDC 3a.m. to 6a.m.



Source: PUCT, Memorandum regarding the open meeting of August 29, 2013, Agenda Item No. 20, Project 40000 'Commission proceeding to ensure resource adequacy in Texas'.

We understand that ERCOT has historically set a reserve target of around 12 to14 per cent. However, reports have indicated that a reserve capacity of around 16 per cent is required to meet ERCOT's current reliability target of one lost load event every ten years. ERCOT has commissioned a report due to be released this year, on the economically efficient operating reserve in Texas. ERCOT is anticipating that the economically efficient reserve margin will be below the reserve required to establish a target of one lost load event every ten years.

4.3. Approach to setting the price cap

In addition to the system-wide offer cap outlined above (also referred to as the high system-wide offer cap (HCAP)), ERCOT has a lower offer cap (known as LCAP) which is set on a daily basis as the higher of US$2,000/MWh (approximately AU$2,120) or 50 times the daily Houston Ship Channel gas price index of the previous business day.[63]

Furthermore, during an 'annual resource adequacy cycle', ERCOT sets the peaker net margin at a level less than or equal to a threshold of US$300,000/MW (approximately AU$318,640) in 2012 and 2013. In subsequent years, ERCOT shall set peaker net margin at not less than three times the cost of construction of a new peaking generation facility, and considering other relevant factors, if any.[64]

The process surrounding revisions to the system-wide offer caps and the SPM requires that the ERCOT Technical Advisory Committee approve the revisions and then ERCOT will post the revised offer caps and SPM Methodology to the ERCOT website within three business days.[65]

4.4. Methodology for estimating the VCR

Neither the current market cap nor the proposed market cap increases are based on an analysis of customers' VCR or an analysis of the price cap needed to sustain investments.[66] However, ERCOT commissioned a report from London Economic International, released in June 2013, on estimating the VCR, in aggregate and by customer class as it relates to rotating outages caused by insufficient operating reserves in ERCOT's jurisdiction.

The report presented a literature review of VCR studies as well as macroeconomic analysis, which estimated the VCR for ERCOT commercial and industrial customers of between US$5,645/MWh and US$6,468/MWh (approximately AU$6,000 and AU$6,870).[67] According to ERCOT staff, the PUCT wanted to conduct an analysis of VCR for residential consumers. This has been delayed because the PUCT wanted to progress increases in the market price cap sooner than the analysis could be undertaken. ERCOT staffed identified the

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63 Energy Choice Matters website, available at: http://www.energychoicematters.com/stories/20121026a.html

64 Energy Choice Matters website, available at: http://www.energychoicematters.com/stories/20121026a.html

65 ERCOT, *Business Practice - System-Wide Offer Cap and Scarcity Pricing Mechanism Methodology*, Effective 15 November 2012

66 The Brattle Group, *ERCOT Investment Incentives and Resource Adequacy*, 1 June 2012, p. 77

67 London Economics *Briefing paper prepared for the Electric Reliability Council of Texas, Inc*, 17 June 2013, p. 64.

new cap of US$9,000 MWh is congruent with their expectations of the market VCR as well as with other VCR studies.

4.5. General observations

The ERCOT wholesale electricity market is an energy-only market with a current system wide offer cap of US$5,000/MWh, which will increase to US$9,000 MWh in 2015. The current cap was recommended by ERCOT following discussions with both electricity generators and consumers. It follows that it has not been set with reference to the VCR.

The impetus for the increase in the market price cap was a slowing of generation investment. Consequently, the new market price cap has been designed to increase the revenues available for the marginal generating unit.

Some stakeholders have objected to the price cap increases due to concern regarding the potential for generators to exercise market power. Therefore, the market price cap has also been set to limit the scope for generators to exercise market power.

5. Singapore

In this section, we provide an overview of the Singaporean ‘energy-only’ wholesale electricity market, and draw upon market characteristics to highlight similarities and differences between the National Electricity Market of Singapore (NEMS) and Australia’s NEM. We explore the electricity wholesale market operator, the Energy Markey Company’s (EMC’s) objective and approach to determining the market price caps and provide a discussion of the evaluation and incorporation of VCR into these caps.

5.1. Overview of the Singapore wholesale electricity market

Singapore generated 46,936 GWh of electricity in 2012. Natural gas accounted for 84.3 per cent of the fuel used; petroleum products accounted for 12.3 per cent. [68]

Installed capacity was 11,615MW in July 2013.[69] PV solar installed capacity was 5,256 kW at the end of 2011.[70]

Industrial consumers accounted for 40.2 per cent of Singapore’s electricity consumption, commerce and service related industries accounted for 37.5 per cent. The remainder being consumed by households and transport related sectors; 15.7 and 5.5 per cent respectively. Consumption peaks in May to July which coincides with the ‘dry’ season.[71] Monthly peak demand is depicted in Figure 5.1.

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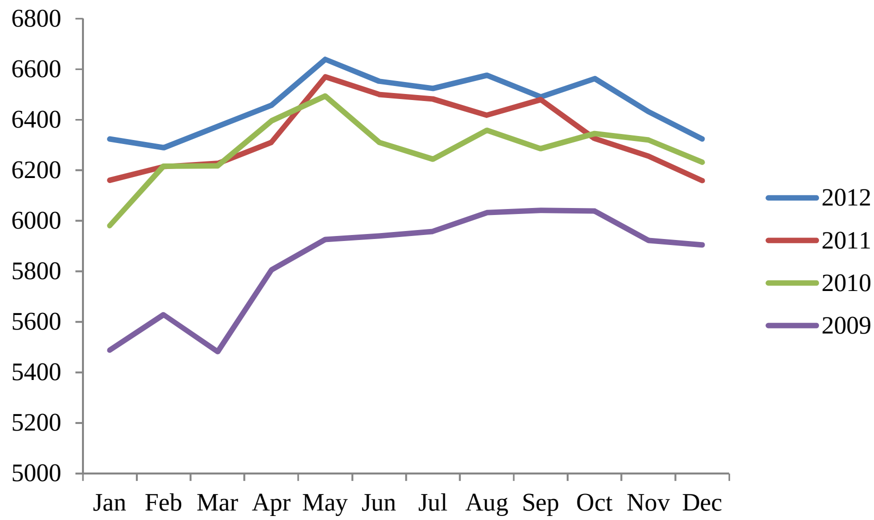
[68] Data from the EMA.

[69] Data from the EMA.

[70] EMA, (2012), *Energising out nation: Singapore energy statistics 2012*, October.

[71] Ibid.

Figure 5.1
Peak demand by month (MW)



Source: EMA data.

The NEMS commenced in 2003 following the separation of electricity generation and retail businesses from electricity transmission businesses. The NEMS is a real-time electricity trading pool with operating reserves trading on a half hourly basis.

The NEMS is an 'energy only' market and is operated and administered by the EMC who also schedules generating units and settles accounts of market participants. There are no capacity payments in the wholesale market and so all generation facilities recover their fixed costs exclusively through revenue from energy and ancillary services earned during periods when the clearing price is above their marginal costs.[72] Consumers in the NEMS can choose to buy electricity from the wholesale market at pool prices, which have historically been volatile. However, consumers who wish to mitigate pool price volatility risks can buy electricity packages from electricity retailers.[73]

Vesting contracts were introduced to the NEMS on 1 January 2004 with the objective of curbing market power of electricity generators. The vesting contracts in the NEMS are bilateral electricity contracts between generation companies and SP Services – the 'market support services licensee' responsible for metering and billing services to the electricity market. The vesting contracts require that generators sell a specified amount of electricity (the 'vesting contract level') at a specified price (the 'vesting contract price'),which removes

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72 Note this assumes an un-contracted generator. For contracted generators, they will recover their fixed costs from the contract strike price that is above its marginal costs. See: EMC, (2012), *Review of the value of lost load*, decision, 13 March, Singapore, p 7.

73 EMA website, available at: http://www.ema.gov.sg/page/16/id:40/

the incentives for generation companies to exercise their market power by withholding their generation capacity to push up spot prices in the wholesale electricity market.[74]

The Electricity Market Authority (EMA), which regulates Singapore's electricity and natural gas industries, reviews both the vesting contract level and the parameters used to set the vesting price every two years. The vesting price is currently set using the long run marginal cost of the most efficient generation technology that accounts for more than 25 per cent of the total electricity demand. The vesting contract level is set to effectively curb the exercise of market power based using projections of electricity supply and demand.[75]

Current interconnection between Singapore and its neighbouring countries is limited to a 400 MW interconnector with Malaysia on the Johor-Singapore causeway. The interconnector is currently used to provide regulation/frequency support, and for mutual emergency assistance between Malaysia and Singapore. There is no explicit trading or sale of electricity over this link. Importantly, the existing interconnector capacity is not included by the Power System Operator (PSO) in determining the reserve margin for the NEMS.

However, the PSO and the EMA are actively looking at the possibility of importing electricity. Although the EMA is confident of Singapore's domestic generation capacity, it acknowledges that there are potential benefits to consumers of importing electricity, from lower electricity costs.[76]

Singapore currently has an interruptible load scheme where load can be offered for the provision of reserves, with consumers being compensated for any load provided. In addition, the EMA is currently reviewing the implementation of a demand response programme in the NEMS. The two mechanisms proposed are demand side bidding and incentive payments to demand response loads.[77]

5.2. Do market price caps reflect consumer values of reliable electricity supply?

All market price caps in the NEMS are tied to the current estimate of VCR (S$5,000/MWh or approximately AU$4,240). However, the VCR in Singapore is estimated using an 'economic estimate' approach (ie, as opposed to using consumer surveys or undertaking supply-side calculation). Specifically, the EMC states the following in regard to the how the current VCR was estimated:[78]

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74 EMA website, available at: http://www.ema.gov.sg/page/91/id:134/

75 EMA website, available at: http://www.ema.gov.sg/page/91/id:134/

76 EMA replies to forum letters, EMA recognises potential for electricity imports, 5 October 2012.

77 See EMA, (2012), *Implementing demand response in the national electricity market of Singapore*, Consultation Paper, 19 November, Singapore.

78 EMC, (2012), *Review of the value of lost load, decision*, 13 March, Singapore, p 3.

> "A rule-of-thumb estimate of VOLL is derived by dividing the country's gross domestic product (GDP) by its total energy consumed, which proxies the costs of lost production due to power supply interruption."

The exact approach taken to estimating the current VCR is outlined in Section 5.4.

Further, a report released by Cybele Capital in conjunction with the 2012 EMA Consultation Paper regarding the implementation of a demand response program in Singapore noted that the existing market price cap was likely to be below the true VCR, which creates an impediment to effective demand response developing 'organically'.[79]

5.3. Approach to setting the price caps

Singapore uses the VCR as an estimate of the average consumer's valuation of energy, beyond which the market clearing engine would incur an energy deficit and schedule load shedding.[80] Under Singapore's Electricity Market Rules, the price ceilings and violation penalties are set out relative to the estimated VCR.[81] These are listed below in Table 5.1 along with the equivalent price cap, or 'ceiling'.

79 Cybele Capital, *Demand Response Implementation,* p. 14.

80 EMC, (2012), *Review of the value of lost load*, 13 March, Singapore, p 3.

81 See EMA, (2013), *Singapore Electricity Market Rules*, Appendix 6J, 1 January, Singapore.

Table 5.1
Violation penalties and price ceilings, expressed in multiples of VCR and S$/MWh (approximate AU$/MWh expressed in parenthesis)

	Price ceiling (x VCR)	Price ceiling ($/MWh)	Violation penalty (x VCR)	Violation penalty ($/MWh)
Energy price	0.9	4,500 (3,820)	1	5,000 (4,240)
Primary reserve	0.85	4,250 (3,610)	0.9	4,500 (3,820)
Secondary reserve	0.75	3,750 (3,178)	0.8	4,000 (3,390)
Contingency reserve	0.65	3,250 (2,760)	0.7	3,500 (2,970)
Regulation	0.06	300 (250)	0.6	3,000 (2,540)
Line constraint	-	-	2.2	11,000 (9,330)
Security Constraint	-	-	6	30,000 (27,990)
Facility constraint	-	-	20	100,000 (84,830)

Source: EMC, Review of the value of lost load, decision, 13 March 2012.

5.4. Methodology for estimating the VCR

The electricity wholesale market operator in Singapore (ie, EMC) acknowledges that the VCR is highly variable and influenced by many factors. However, it expects that the most reflective VCR will be the aggregate of all its possible values across a mix of consumer types and outage circumstances.[82]

The VCR has been estimated in Singapore by dividing gross domestic product (GDP) by total energy consumed, measured by load settled through NEMS. The result was assumed to be the cost of lost production due to power supply interruption. Using this method, the VCR was set to S$5,000/MWh in 2003.[83]

[82] EMC, (2012), *Review of the value of lost load, decision*, 13 March, Singapore, p 3.

[83] Ibid, p 3-4.

In 2012, the EMC conducted a review of VCR, which had not been revised or inflated since its inclusion in the Rules in 2003. The EMC estimated the VCR using the previous methodology (ie, the 'economic estimate' approach) using revised economic estimates of GDP and total energy consumed for the period 2004 to 2010, as shown in Table 5.2.[84]

Table 5.2
EMC VCR estimates using revised GDP and total energy consumed estimates (approximate AU$ expressed in parenthesis)

Year	GDP at current market price (S$m)	Load settled through SWEM (GWh)	Embedded load (GWh)	VCR (S$/MWh)
2004	190,484	32,805	2,976	5,324
	(162,150)			(4,530)
2005	208,764	35,628	2,976	5,408
	(177,780)			(4,600)
2006	230,923	36,724	2,976	5,817
	(196,570)			(4,950)
2007	267,254	38,311	2,514	6,546
	(227,500)			(5,570)
2008	267,952	38,900	2,184	6,522
	(228,090)			(5,550)
2009	266,659	39,040	2,184	6,469
	(226,990)			(5,500)
2010	303,652	42,522	2,184	6,792
	(258,480)			(5,780)

Source: EMC, Review of the value of lost load, decision, 13 March 2012.

Consequently, the EMC considered increasing the VCR to S$6,500/MWh (approximately AU$5,530) by assessing the following factors:[85]

- the incentives provided for investment in base and peaking generating plants;
- the risks in the market;
- generator concentration in the market; and
- the potential and scope for demand response.

The EMC found that a higher VCR was not warranted because:[86]

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84 Ibid, p 7.

85 Ibid, p 7-10.

86 Ibid, p 10.

- raising the VCR to the current economic estimate provides an inadequate incentive for investment in peaking plants;
- there is currently no compelling need to incentivise investment in base load generation plants, so increasing the VCR is not currently required;
- a higher VCR could raise risks of generators exercising market power and so increase retailers risk premiums; and
- the market is expected to remain fairly concentrated in the foreseeable future and coupled with weak demand responsiveness, a higher VCR/price ceiling could lead to consumers becoming more vulnerable to extreme price spikes in the spot market.

The EMA supported the EMC's decision. The EMA found that a change in the market price cap was likely to have a minimal effect on prices and contracting risk. Further, the EMA report found that the current price cap results in appropriate signals for investment in new plants and supports the sustainability of the NEMS.[87]

The EMC has therefore proposed to hold increases in the VCR in abeyance until there is:[88]

- a lower level of generation market concentration;
- more demand response initiatives; and/or
- better risk management mechanisms that could mitigate the effect of a higher VCR.

5.5. General observations

The wholesale electricity market in Singapore is an energy-only market with a market price cap of S$5,000/MWh (approximately AU$4,240). The level of the price cap is tied to a fixed proportion of estimates of the VCR, which are periodically updated by the EMA.

Importantly, a high proportion of total annual electricity demand is from industrial, commercial and service related industries (approximately 80 per cent). As a consequence, estimating the VCR via state-preference or contingent value surveying is practically challenging. This reflects the likely different range of estimates of the value of avoiding outages across specific industries.

As a consequence, the EMA estimates VCR by dividing Singapore's GDP by total energy consumed as a proxy for the costs of lost production due to power supply interruption. This approach essentially provides an estimate of the average value of electricity to consumers within each industry.

A proposal to double the current VCR from S$5,000/MWh to S$10,000/MWh (from approximately AU$4,240 to AU$8,480) was rejected by the EMA in 2012 because of concerns that:

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[87] Ibid, p 11.

[88] Ibid, p 10.

- raising the VCR to the current economic estimate provides an inadequate incentive for investment in peaking plants;
- there is currently no need to incentivise investment in base load generation plants, so increasing the VCR is not currently required;
- a higher VCR could raise risks of generators exercising market power and so increase retailers risk premiums; and
- the market is expected to remain fairly concentrated in the foreseeable future and coupled with weak demand responsiveness, a higher VCR/price ceiling could lead to consumers becoming more vulnerable to extreme price spikes in the spot market.

Finally, a key advantage of the methodology adopted by Singapore to update estimates of the VCR (and so ultimately the market price cap), is its relative simplicity and flexibility. This allows the cap to be updated frequently to reflect changes in the value of electricity to consumers over time.

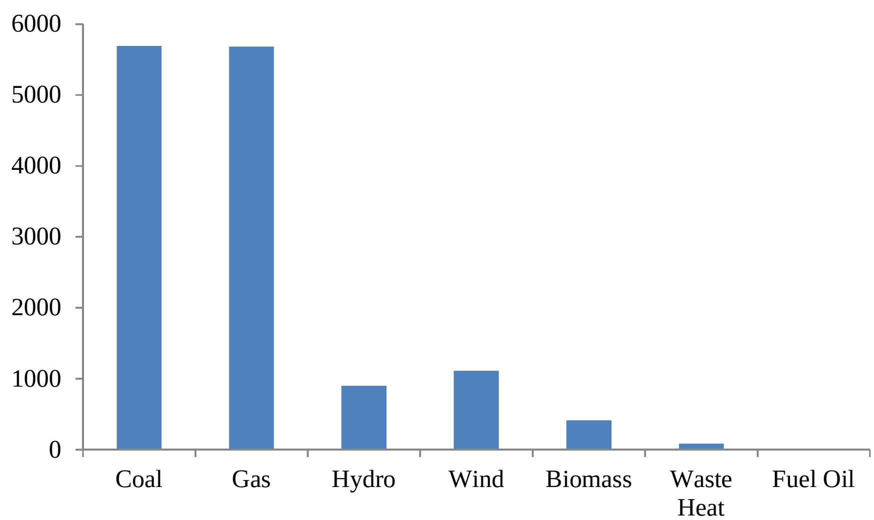
6. Alberta, Canada

In this section, we provide an overview of Alberta's 'energy-only' electricity market, and draw upon market characteristics to highlight similarities and differences between Alberta's electricity market and Australia's NEM. We explore Alberta's Electric System Operator's (AESO) objective and approach to determining the level of the market price cap with reference to the VCR.

6.1. Overview of the Alberta wholesale electricity market

The Albertan wholesale electricity system had installed generation capacity of 13,898 MW at June 2013 of which approximately 17.5 per cent was from renewable sources – Figure 6.1.[89] Total energy consumption was 75,574GWh in 2012.[90]

Figure 6.1
Installed generation capacity by fuel type (MW)



Source: Data from Alberta Energy.

5,400MW of capacity operates under Power Purchasing Agreements (PPAs). 4,300 MW of coal and 780 MW of hydro PPAs will expire on December 31, 2020, which represents approximately 39 per cent of current capacity.

New peak demand records of 10,609 MW and 9,885 MW were set for winter and summer in 2012, respectively. In winter, demand typically peaks between 5 pm and 6 pm. The 2012 winter record peak occurred during these hours when the temperature reached -28 degrees Celsius. Peak demand during summer months is typically driven by sustained periods of high

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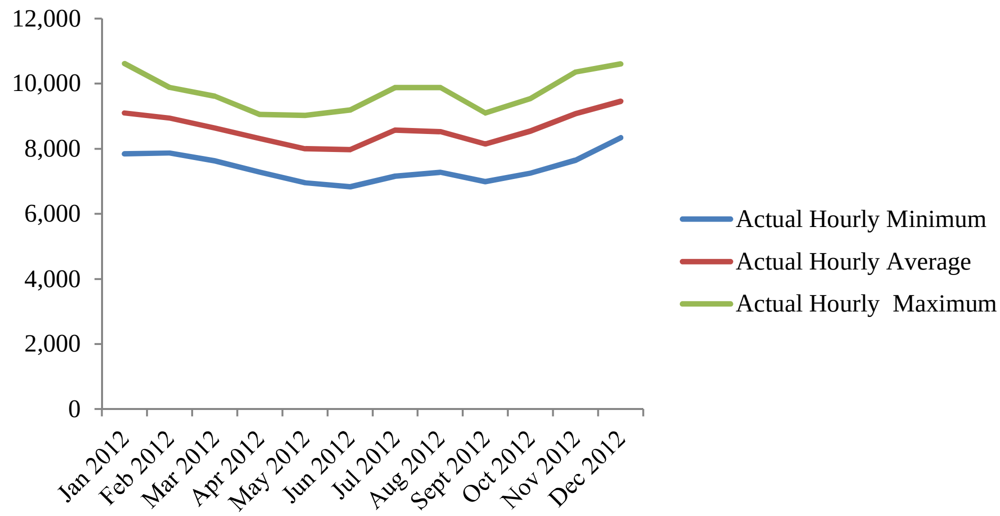
[89] Alberta Energy website, available at: http://www.energy.alberta.ca/Electricity/682.asp accessed on 28/8/2013.

[90] AESO, (2012), *Annual Market Statistics 2012*, p 6.

temperatures. The 2012 summer peak occurred on 9 July 2012 between 2 pm and 3 pm when the average temperature was 29 degrees Celsius.[91] The mean hourly minimum, maximum and average consumption for each month in 2012 is set out in Figure 6.2.

Figure 6.2
Mean hourly electricity consumption by month for 2012 (MW)



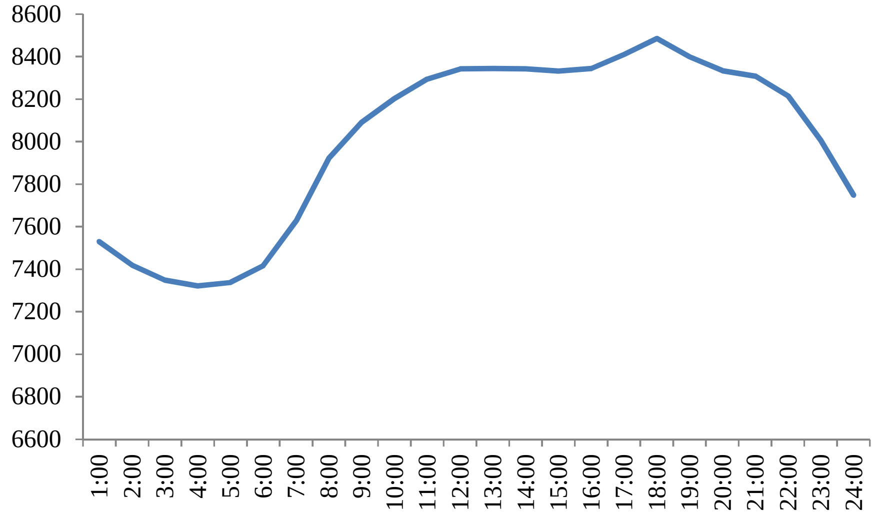
Source: Data from AESO Annual Market Statistics Data file, 2012.

AESO identified that average and peak demand has been increasing by around 2.5 to 3 per cent annually with the exception of a lag during the Global Financial Crisis. Industrial consumers account for approximately 60 to 70 per cent of total electricity demand. Given the relatively flat load profile of industrial consumers, the difference between peak and average demand, or on-peak and off-peak load in Alberta is also relatively small. In addition, we understand that some oil and sand businesses have installed cogeneration units to use excess steam and so have become less reliant on electricity sourced from the grid.

The average hourly generation in Alberta for 2011 is shown in Figure 6.3.

[91] AESO, (2012), *Annual Market Statistics*, p 7.

Figure 6.3
Average hourly generation for 2011 (MWh)



Source: Data from AESO Data Requests.

The population of Alberta was approximately 3.6 million in 2011.[92] There are 1.6 million sites supplied by retail electricity providers in Alberta, including 1.3 million households (81 per cent), 107,000 farms (7 per cent), 179,000 small businesses (11 per cent) and 17,000 large industrial sites (1 per cent, largely oil and sand companies). Although households and farm account for 88 per cent of the sites served by retailers, they account for only 16 per cent of the electricity sold in the province.[93]

Albertan's can purchase electricity from a regulated service or a competitive retailer. There is one regulated retailer per geographic region, with monthly regulated rates set by the Alberta Utilities Commission. The monthly prices change in response to changing prices in the forward market for electricity. Competitive retailers typically provide a broad selection of service agreements including contracts that provide fixed prices at rates that can be lower than the default rate. The Regulated Rate Option (RRO) Regulation, which governs the current default rate is due to expire in 2014.[94] However, in contrast to the recommendations of the retail market review committee, the RRO will not be eliminated as the majority of Albertans pay the default rate.[95]

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92 Statistics Canada website available at: http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/demo02a-eng.htm accessed 28/8/2013.

93 Retail Market Review Committee, (2012), *Power for the people*, Report for the Minister of Energy, Goevernment of Alberta, September, p 7.

94 Ibid, p 6-7.

95 Alberta Energy website, available at: http://www.energy.alberta.ca/Electricity/682.asp accessed on 28/8/2013.

Smart meters are widely deployed for industrial and large commercial customers and are being increasingly deployed to smaller commercial customers. According to AESO staff, some industrial consumers are price sensitive and voluntarily curtail load when prices reach approximately between CA$200/MWh to CA$500/MWh (approximately AU$210 to AU$520).

Under the Independent System Operator Rule 6.8, the AESO system controller may direct involuntary curtailment of demand by some or all wire owners when the Alberta interconnected electric system demand and regulating reserve cannot be met. Further, AESO can make a public appeal for Albertan's to voluntarily reduce their electricity consumption.[96] AESO has a variety of frequency load shed agreements with consumers, who are financially compensated should frequency load shedding be required.

The wholesale, energy-only electricity market in Alberta operates on an hourly basis and is facilitated by AESO who are also accountable for the administration and regulation of load settlements.[97] AESO establishes the hourly pool price according to the following process:[98]

3. Entities submit their bids to AESO, namely:
   - power producers and importers submit electricity supply offers;
   - exporters submit bids to purchase supply generated in Alberta to export to neighbouring jurisdictions; and
   - consumers submit demand bids to purchase electricity at or below a specific price, indicating an intention not to purchase if the electricity price reaches a specific point.
4. Supply offers and demand bids are sorted from the lowest to the highest for each hour of the day, ie, a merit order for dispatch is created.
5. AESO keeps supply and demand in balance throughout the day and maintains reliability of the system by dispatching from the merit order (both up and down the merit order depending on demand).
6. The System Marginal Price (SMP) is set every minute according to the last eligible electricity block dispatched by AESO.
7. The hourly pool price is set at the end of each hour and is calculated as the time-weighted average of the 60 one-minute SMPs. Wholesale electricity is financially settled at this real-time pool price.

Alberta is linked to other jurisdictions through its interconnection with British Columbia (BC) and Saskatchewan. The BC interconnector has capacity of 750 MW and the interconnector to Saskatchewan has capacity of 150 MW.[99] Significantly, the BC

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96 For example, see AESO issued Electricity load shed directive, 2 July 2013 available at http://www.marketwire.com/press-release/aeso-issues-electricity-load-shed-directive-1807997.htm viewed 29/8/2013.

97 AESO website, available at: http://www.aeso.ca/market/153.html

98 AESO, *Determining the Wholesale Market Price for Electricity*, Fact Sheet, p. 1.

99 Alberta Energy website, available at: http://www.energy.alberta.ca/Electricity/682.asp accessed on 28/8/2013.

interconnection links Alberta to the Western Interconnection, ie, the electricity grid involving Western Canada south to Baja California in Mexico and stretching eastward over the Rocky Mountains to the Great Plains.[100] A third interconnection to Montana is currently under construction and will add approximately 300 MW of additional supply capacity.[101] Overall, current interconnectors provide Alberta with an installed generation and interconnection capacity of 14,798 MW.[102]

Alberta is currently a net importer of electricity and the interconnections are essential to the Albertan market as they facilitate energy imports during times of tight supply.[103] Although both BC and Alberta have winter peaking markets, the major demand centres in each market have different demand profiles. Further, the climatic differences between the regions of the Western Interconnection result in demand peaking at different times of the year, and the different time zones mean that demand peaks are not synchronised. Importantly, the BC interconnection is not readily constrained.

We understand that Alberta is considered by market participants as a 'premium market' in the Western Interconnection, due to its relatively high average electricity prices given strong demand and a high value of electricity to industrial consumers. The cost of generation in other regions of the Western Interconnection, particularly in the United States is typically lower than in Alberta due to lower gas prices and low capital and labour costs. Other regions have also experienced lower load growth than in Alberta.

6.2. Do market price caps reflect consumer values of reliable electricity supply?

Since its inception in 1996, Alberta's wholesale electricity market has had a price cap of CA$1,000/MWh (approximately AU$1,030). Under ISO Rule 3.9(a) the system marginal price is set at the highest dispatched block and offers and bids must be CA$0/MWh or greater and less than CA$1,000/MWh. ISO Rule 6.3.9.1(a) provides the price setting mechanism that translates the offer cap into a CA$999.99 price cap for normal operations.

Increasing the market price cap has been an increasingly topical issue in Alberta.[104] Although the price did not reach the cap in the first years of operation, price cap events have occurred with increasing frequency in the last three years. According to AESO, the increase in price cap events appears to be driven by an energy shortfall requiring the use of prescribed procedures by the system controller when there is insufficient energy offered in the energy

[100] US Department of Energy website, available at: http://energy.gov/oe/recovery-act/recovery-act-interconnection-transmission-planning/learn-more-about-interconnections

[101] Market Surveillance Administrator, (2012), *State of the Market report 2012*, 10 December, p 17.

[102] Alberta Energy website, available at: http://www.energy.alberta.ca/Electricity/682.asp accessed on 28/8/2013.

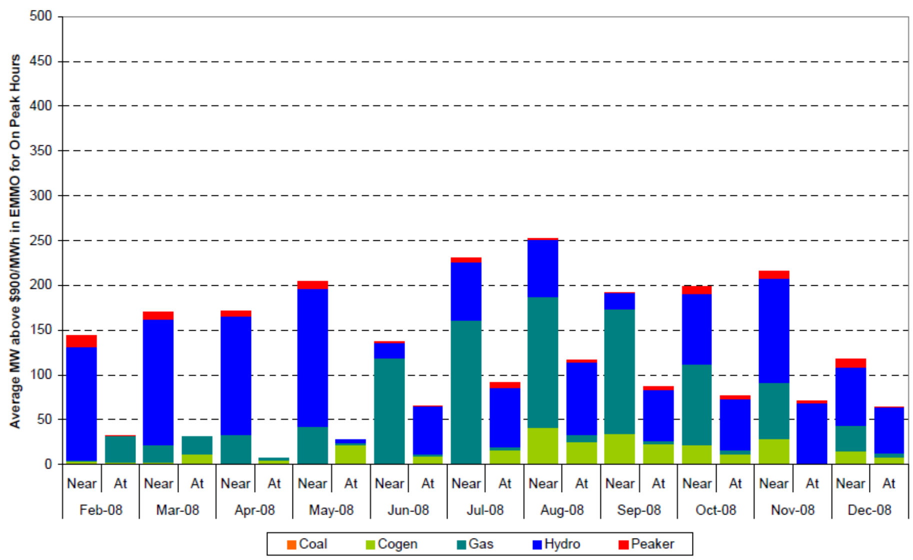
[103] AESO, 2006 Annual Report.

[104] AESO released a discussion paper on the wholesale market price cap in 2009. AESO also commissioned reports from the Brattle Group in 2011 and 2013 which, among other issues, analyzed the market cap. See J. P. Pfeifenberger & K. Spees, Evaluation of market fundamentals and challenges to long term system adequacy in Alberta's electricity market, The Brattle Group, April 2011; J. P. Pfeifenberger, K. Spees & M. DeLucia, Evaluation of market Fundamentals and challenges to long term system adequacy in Alberta's Electricity market: 2013 update, The Brattle Group, March 2013.

market to meet the Alberta Internal Load.[105] Supply shortfalls could ultimately require curtailment of firm loads in order to maintain system reliability and could be triggered by events such as generation and/or transmission contingencies, energy market deficiencies, or unexpected demand levels.

Figure 6.4 and Figure 6.5 below summarise AESO collected data on the on-peak and off-peak offers near or at the current price cap by asset type during 2008.

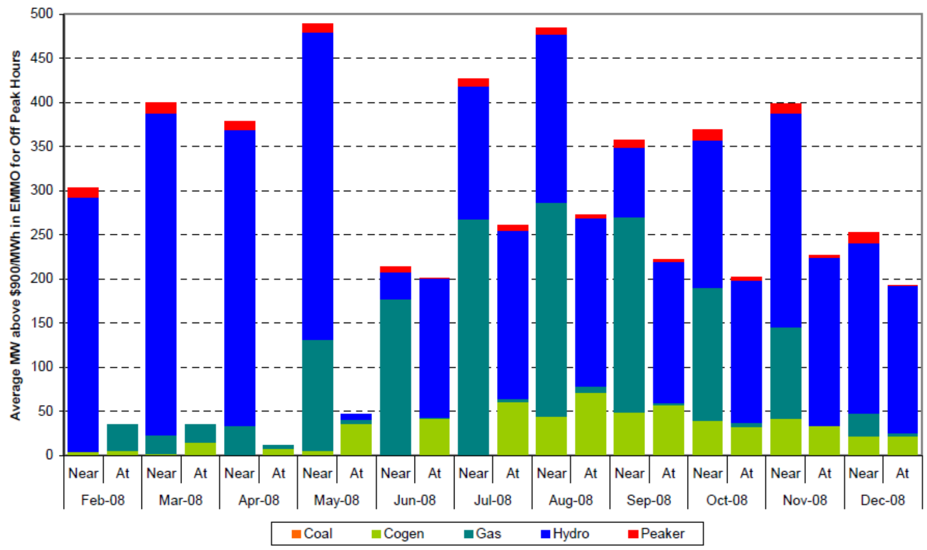
Figure 6.4
On-peak offers at or near the price cap by asset type in 2008



Source: AESO, Alberta wholesale market price cap, discussion paper, 23 June 2009.
Notes: 'Near' refers to offers between $900/MWh and $999.98/MWh. 'At' refers to offers at the $999.99/MWh price cap.

105 AESO, *801 Supply Shortfall*, Issued 2012-08-07.

Figure 6.5
Off-peak offers near or at the price cap by asset type in 2008



Source: AESO, Alberta wholesale market price cap, discussion paper, 23 June 2009.
Notes: 'Near' refers to offers between $900/MWh and $999.98/MWh. 'At' refers to offers at the $999.99/MWh price cap.

Scarcity pricing is important in Alberta as less than one per cent of the hours contributed to almost ten per cent of the total revenue earned by the industry. However, even for peaking units, the majority of revenue comes from hours when the price is below CA$900/MWh (approximately AU$930).[106]

AESO found in its review of the market price cap in 2009 that there was no strong evidence to suggest that the price cap has been an impediment to generation investment. Importantly, generation investment was found to have kept pace with demand growth. We note that in 2012 AESO note that more than 2,500 MW of generation capacity has been added to the system since 2007 and has come from a variety of technologies including:[107]

- gas-fired (1,304 MW);
- coal-fired (697 MW);
- wind (503 MW); and
- other technologies (60 MW).

That said, AESO did indicate a concern that if the price cap was set too low, then generators that may not deliver all available capacity into the system during periods of shortage as they

106 AESO, (2009), *Alberta wholesale market price cap*, discussion paper, 23 June, p 12.

107 AESO, *2012 Long-Term Outlook*, p. 4.

might not expect to recover both the start-up and operating costs. However, further analysis led AESO concluded that this concern was unfounded.[108]

In addition AESO concluded that the price cap was not:[109]

- excessively interfering with generation offers;
- limiting the interconnectors; and
- acting as an impediment to demand response.

Overall, AESO concluded that ‘the price cap level and other market design features as currently set out in the ISO rules have achieved the balance necessary to allow the market to reflect scarcity without creating artificial issues.’[110]

Further, AESO monitors the long term adequacy of generation capacity and expectations of new generation investment, amongst other metrics to determine whether the price cap should be increased. We understand that AESO’s approach is to ensure that the price cap:

- allows demand response to be triggered; and
- allows prices to reflect scarcity conditions and so, signal the need for new generation investment.

In addition, AESO seeks to ensure that the market price cap prevents generation scarcity from impacting on annual electricity prices by a significant amount. [111]

AESO also takes account of the principles set out in Alberta’s electricity policy framework. Specifically:

> ‘[T]he price cap must balance a number of competing objectives:
>
> - Prices must be able to rise substantially above the cost of new generation for a time in order to signal the need for new investment.
> - Prices must be allowed to rise high enough to ensure short term adequacy. This means the cap should be high enough to allow all generators to profitably enter the market, flexible demand to profitably curtail and import capability to be maximized.
> - Small changes in the number of scarcity hours are unpredictable, largely based on the timing of forced outages. If these basically random hours have too much influence, the market signals are neither predictable nor understandable.
> - Sustainability requires both sufficient generation and reasonable prices reflecting market economics. If prices rise too quickly in response to relatively limited instances of scarcity, the market structure will come under public pressure.’[112]

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[108] AESO, (2009), *Alberta wholesale market price cap*, discussion paper, 23 June, p 15-16.

[109] AESO, Alberta wholesale market price cap, discussion paper, 23 June 2009.

[110] Ibid, p 6.

[111] Ibid, p 5-6.

While the current approach to increasing the price cap is based on the exercise of discretion by the AESO, we understand that there has been some consideration given to indexing the price cap. In essence the AESO's approach ensures that the price cap is sufficient to fund new generation capacity investments in the market.

It follows that the price cap therefore does not necessary reflect the VCR, and so likely does not lead to efficient use of electricity by consumers.[113]

6.3. Methodology for estimating VCR

We understand that the current market price cap of CA$1,000/MWh was set without explicit consideration of the VCR or the costs of new generation investment.

To date, there has been no consideration of the VCR in setting the market cap. According to AESO staff, if the price cap was found to be 'too low' then the AESO might give consideration to the VCR in determining a higher level of the price cap. However, it was reiterated that VCR figures tend to be far in excess of the current cap and that introducing a higher cap would require consideration of a number of competing concerns, particularly the potential for higher prices to consumers, and the possibility that a higher cap might create greater opportunities for generators to exercise market power and so inappropriately increase market prices.

6.4. General observations

Alberta's wholesale electricity market is an energy-only market with a market price cap of CA$1,000/MWh (approximately AU$1,030). The current price cap has remained unchanged since the market's inception in 1996.

Relevant to our study, the current market price cap was determined without any explicit consideration of the value that customers place on reliable electricity supply.

Regardless, the current market price cap has been sufficient to ensure that adequate electricity supplies is available to satisfy consumer demands. That said there are a number of characteristics of this market that mean that the relatively low price cap is considered by AESO to be sufficient to encourage new investment, namely:

- industrial consumers account for approximately 60 to 70 per cent of total electricity demand and contribute to the Albertan wholesale electricity market having a relatively flat load profile; and
- the wholesale electricity market in Alberta has significant interconnectedness with neighbouring markets. While these adjacent markets are typically also winter peaking, peak periods occur at sufficiently different times of the day and year.

[112] Ibid, p 5.

[113] J. P. Pfeifenberger, K. Spees & M. DeLucia, Evaluation of market Fundamentals and challenges to long term system adequacy in Alberta's Electricity market: 2013 update, The Brattle Group, March 2013, p 44-45.

Finally, we understand that the level of the price cap has been maintained at CA$1,000/MWh in part because of concerns that a higher cap might create greater opportunities for generators to exercise market power and so inappropriately increase market prices.

7. MISO, United States

In this section we provide an overview of the electricity market that is operated by the Midcontinent Independent System Operator (MISO), and set out its principal characteristics so as to highlight similarities and differences between MISO's electricity market and the NEM. We explore MISO's objective and approach to determining the market price cap and discuss how the levels of the various price caps are set.

7.1. Overview of the MISO wholesale electricity market

MISO provides regional grid management and open access to its transmission facilities across all or parts of 15 states in the U.S. and the Canadian province of Manitoba. These jurisdictions form MISO's reliability grid. MISO introduced competitive wholesale electricity markets in 2005. 11 of the 15 jurisdictions that MISO coordinates participate in the wholesale electricity markets. MISO is interconnected with the Independent Electricity System Operator of Ontario, the Mid-continent Area Power Pool, PJM, Southwest Power Pool and the Tennessee Valley Authority.[114]

MISO has total generation capacity of 131,522 MW, with 205,759 MW available in the reliability market. The highest historic peak load occurred on the 23 July 2012, when 98,576 MW was traded in the market and 133,368 MW was traded in the reliability market.[115] The MISO market is summer peaking.

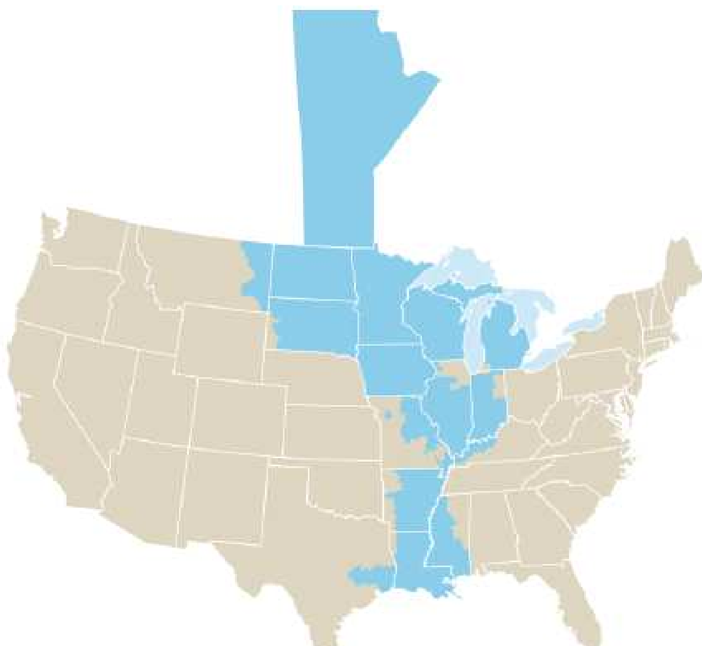
[114] MISO, *Corporate fact sheet*, June 2013.

[115] MISO, *Corporate fact sheet*, June 2013.

Figure 7.1
MISO geographical market

Source: MISO, Corporate fact sheet, June 2013.

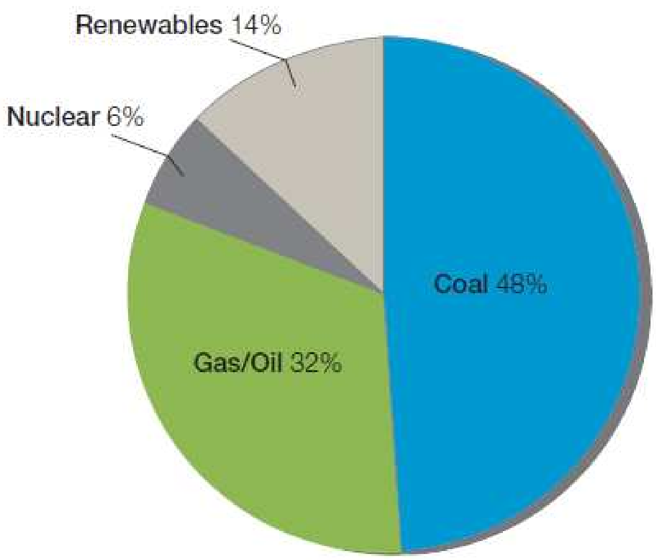
Figure 7.2
MISO geographical reliability market



Source: MISO, Corporate fact sheet, June 2013.

The mix of generation by fuel type in MISO is depicted in Figure 7.3 below.

Figure 7.3
MISO generation mix



Source: Potomac Economics, State of the energy market 2011, Prepared for the MISO electricity markets, June 2012.

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Approximately 48 million people are served by the MISO market, with a population density of approximately 37 people per square kilometre.[116] The market has 34, 32 and 34 per cent residential, commercial and industrial consumers, respectively. 34 per cent of MISO consumers are located in urban regions.[117]

MISO operates two energy and operating reserve markets, namely:

- the day-ahead energy and operating reserve market and
- the real-time energy and operating reserve market.

The day-ahead energy and operating reserve market is a forward market in which energy and operating reserves are cleared on a simultaneous co-optimised basis for each hour. The real-time energy and operating reserve market operates in a similar manner to the day-ahead market, but with energy and operating reserves cleared every five minutes.[118] We understand that demand-side resources are available in each of these markets.

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[116] MISO website available at: https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/SmartGrid.aspx accessed 9/9/13; London Economic, (2013), Estimating the value of lost load, prepared for ERCOT, 17 June.

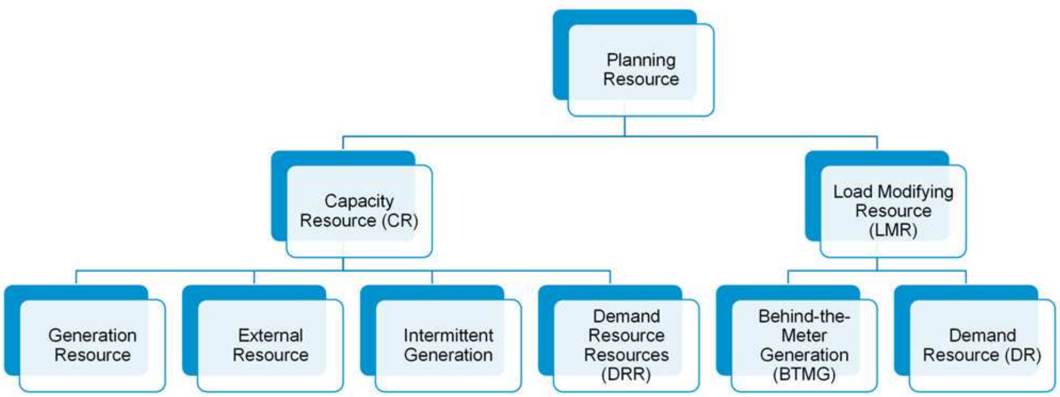
[117] London Economics, (2013), Estimating the value of lost load, Report for ERCOT, 17 June, p 31.

[118] MISO, (2013), Energy and operating reserve markets business practice manual, 6 February, pp 20-21.

MISO also operates a financial transmission rights market that auctions revenue rights (ARR) on an annual and monthly basis. ARRs are financial instruments that entitle the holder to a share of the revenue generated in the annual FTR auction. The value of FTRs is determined by the transmission congestion charges that occur in the day-ahead market. FTRs can be used to hedge against congestion charges.

In addition to the energy and operating reserve markets, the MISO operates a capacity auction. In 2013, MISO held its first annual voluntary capacity auction, which replaced the monthly auction process.[119] It allows participants with insufficient capacity to satisfy their resource adequacy requirements with planning resources acquired from market participants with excess planning resources. The resources included under 'planning resources' are shown in Figure 7.4 below and includes demand-side resources.

Figure 7.4
MISO Planning Resources



Source: MISO, (2012), MISO Integration Training – Resource Adequacy, February, p. 8.

For entities that continue to hold insufficient capacity, a financial settlement charge is paid based on the cost of a new entity (CONE), which includes the annual capital, operating and other costs that would be incurred to develop capacity in the market.[120] The current CONE is set at approximately US$90,000 MW/year (approximately AU$96,100).[121]

MISO has developed market mechanisms to facilitate demand response, including:[122]

- by end consumers where it is economic;
- for regulation or contingency reserves;
- to reduce demand during system emergencies; and

119 Carmel, I. *MISO clears first annual capacity auction*, PR Newswire, 5 April, 2013.

120 FERC (2012), *Order on annual cost of new entry recalculation filing*, 24 May. Docket number ER10-2090-000.

121 MISO (2013), *Letter to Secretary Bose Re: Filing of LRZ CONE calculation*, 3 September.

122 MISO, Operations frequently asked questions fact sheet.

- to substitute for generating capacity.

From June 2012, end consumers have been allowed to bid into the wholesale market though an aggregator.[123]

Demand response can also occur through:[124]

- direct load control, which allows load serving entities (LSEs) to curtail specific end uses; and
- interruptible load which allows LSEs to curtail a preset amount of load.

7.2. Do market price caps reflect consumer values of reliable electricity supply?

MISO has a number of price caps in its energy and ancillary services markets, namely:[125]

- an energy Offer Price Cap of $1,000/MWh (approximately AU$1,060);
- an energy Offer Price Floor of -$500/MWh (approximately -AU$530);
- a regulating Reserve Total Cost Price Cap of $500/MW/Hour (approximately AU$530);
- a regulating Reserve Total Cost Price Floor of -$500/MW/Hour (approximately -U$530);
- a contingency Reserve Offer Price Cap of $100/MW/Hour (approximately AU$110); and
- a contingency Reserve Offer Price Floor of -$100/MW/Hour (approximately -AU$110).

During times of operating reserve scarcity when operating reserves decrease and load shedding becomes more likely prices are affected by scarcity prices that are determined by reserve demand curves.[126] Under these circumstances, the price depends on the amount of operating reserve available relative to the operating reserve requirement, with the maximum price capped at the estimated VCR of $3,500/MWh (approximately AU$3,740 – outlined below).[127]

Relevantly, to date the energy price cap in the MISO has never been reached. Although regions have had periods of transient scarcity, there has not been a period of sustained scarcity conditions where operating reserves have been sufficiently short so as to trigger energy shortage conditions. According to MISO staff, a transient shortage typically results in wholesale prices around US$1,100 MWh (approximately AU$1,170). MISO does not envisage conducting another VCR study or updating the VCR figure in the near future.

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[123] MISO, Operations frequently asked questions fact sheet.

[124] MISO, Operations frequently asked questions fact sheet.

[125] MISO, (2013), *Energy and Operating Reserve Markets Business Practices Manual*, Manual No. 002.February, pp. 93 & 183.

[126] MISO, (2013), *Energy and Operating Reserve Markets Business Practices Manual*, Manual No. 002.February, p. 179.

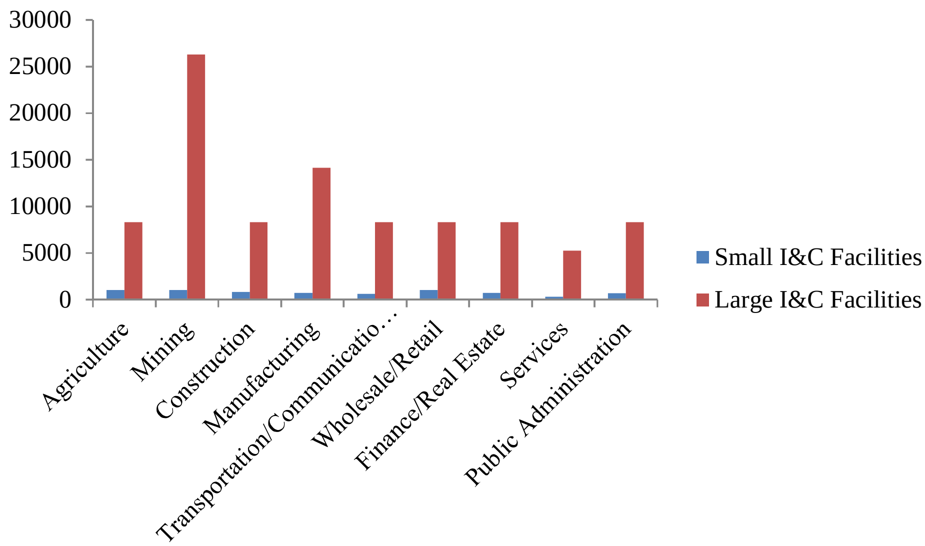
[127] MISO (2009), FERC Electric Tariff, Volume 1, Schedule 28, 22 January.

7.3. Approach to setting the price cap

The VCR that MISO uses is US$3,500/MWh and was set in 2006 on the basis of a meta-analysis of other VCR studies. The meta-analysis was conducted using a statistical model based on 24 studies conducted by eight electric utilities between 1989 and 2002. The analysis was designed to make available a ready source for outage cost estimates that could be readily adapted to the MISO electricity market using MISO-specific macroeconomic variables, ie, household income data. The MISO review found that VCR estimates vary widely according to customer class, business sector, duration of outage, and the extent of advanced warning of an outage.[128]

The VCR for a one hour outage in during peak time for small and large industrial and commercial (I&C) consumers is depicted in Figure 7.5.

Figure 7.5
Median VCR estimates for I&C consumers (US$ 2005, 1 hour outage)



Source: Data from Centolella, P., (2006) Estimates of the Value of Uninterrupted Service for theMidWest Independent System Operator, Science Applications International Corporation.

The willingness-to-pay for residential consumers during peak time to avoid outages of one, two and three hours (normalised to a per kW basis), respectively is set out in Table 7.1.

[128] Data from Centolella, P., (2006) *Estimates of the Value of Uninterrupted Service for the Mid West Independent System Operator*, Science Applications International Corporation.

Table 7.1
Residential consumers WTP to avoid outages (US$ 2005, approximately current AU$ denoted in parenthesis)

	Median	Mean	Standard Deviation	Minimum	Maximum
1 Hour Outage	3.76	4.06	1.62	0	20.17
	(4.00)	(4.35)	(1.75)		(21.55)
2 Hour Outage	4.55	4.96	2.15	0	31.71
	(4.85)	(5.30)	(2.30)		(33.85)
3 Hour Outage	5.41	6.02	2.92	0	38.74
	(5.80)	(6.45)	(3.10)		(41.35)

Source: Data from Centolella, P., (2006) Estimates of the Value of Uninterrupted Service for the Mid West Independent System Operator, Science Applications International Corporation.
Note: It is implicit that these estimates are incremental to the value of consumption.

The analysis concluded that median values provide a better indicator than mean values, which implicitly take into account some very high outliers. Although other reports tended to use mean estimates, the analysis found that the median values of the estimates for MISO are within the range observed in other studies.[129]

To determine a single VCR figure, the median VCR values were taken for residential and small I&C from each of the studies reviewed, with weights of 0.18 and 0.15 respectively applied. Therefore, the MISO's VCR estimate of US$3,500 is lower than an average across all sectors because 'it represents an estimate for the market segment that values uninterrupted electrical service the least.'[130]

7.4. General observations

The MISO wholesale electricity market includes a day-ahead and a real-time market for both energy and operating reserves. In addition, MISO operates an annual capacity auction. Both supply-side and demand-side entities can bid into these markets meaning that there is less of a need for a market price cap to be sufficiently high so as to create sufficient revenue to fund generation investment.

MISO currently has a number of price caps in the energy and ancillary services markets. However, during times of scarcity, the energy price rises gradually to the estimated VCR of US$3,500/MWh as operating reserves decrease and load shedding becomes more likely. The estimated VCR of US$3,500/MWh is based on a 2006 meta-analysis MISO commissioned that assessed various studies conducted between 1989 and 2002, using MISO-specific values

[129] Centolella, P., (2006) *Estimates of the Value of Uninterrupted Service for the Mid West Independent System Operator*, Science Applications International Corporation, p 14.

[130] Testimony of Roy Jones found in: MISO (2007), *Electric tariff filing to reflect ancillary services markets*, Filed with the FERC, 15 February. Docket ER 07-550-000.

for the independent variables. The review found that VCR estimates vary widely according to customer class, business sector, and duration of outage, and advanced warning of the outage.

Interestingly, the US$3,500/MWh price cap in the MISO has never been reached. Although regions have had periods of transient scarcity, there has not been a period of sustained scarcity conditions where operating reserves have been sufficiently short so as to trigger energy shortage conditions.

In addition, during 2013 MISO held its first annual voluntary capacity auction, replacing the monthly auction process. This auction process includes a de-facto price cap set on the basis of the cost of a new marginal entity and is currently set at approximately US$90,000 MW/year.

8. PJM, United States

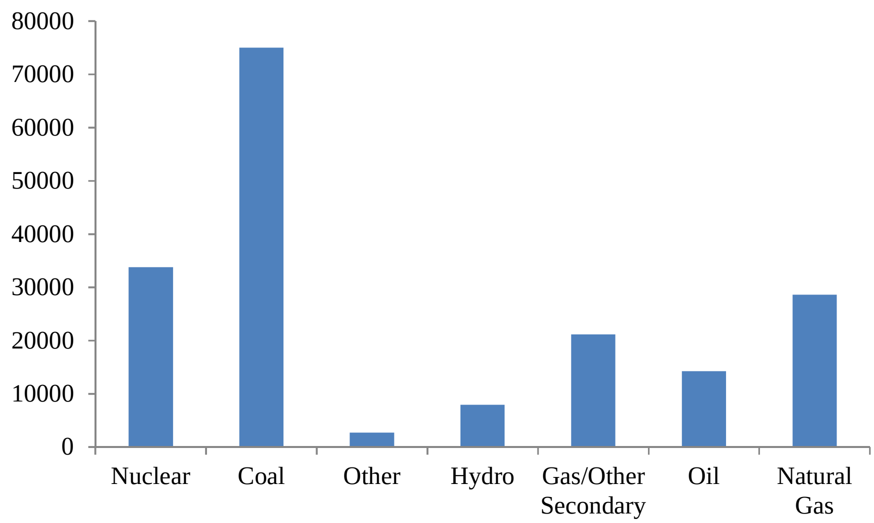
In this section we provide an overview of the wholesale electricity market that is operated by the PJM Interconnection (PJM), and set out its principal characteristics so as to highlight similarities and differences between PJM's electricity market and the NEM. We explore PJM's objective and approach to determining the market price cap and discuss how the level the various price caps are set.

8.1. Overview of the PJM wholesale electricity market

PJM is part of the Eastern Interconnection and coordinates the transmission of wholesale electricity in all or part of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM is also developing complementary system operations with MISO to create a single wholesale market across both jurisdictions.[131]

PJM has generating capacity of approximately 184,000 MW with annual energy delivery of 832 TWh. In 2011, renewable generation provided 3.5 per cent of total electricity consumed in the PJM.[132]

Table 8.1
Installed capacity by fuel type (MW)



Source: PJM data.
Note: Data effective 1/7/2013 based on capacity of 183,534 MW.

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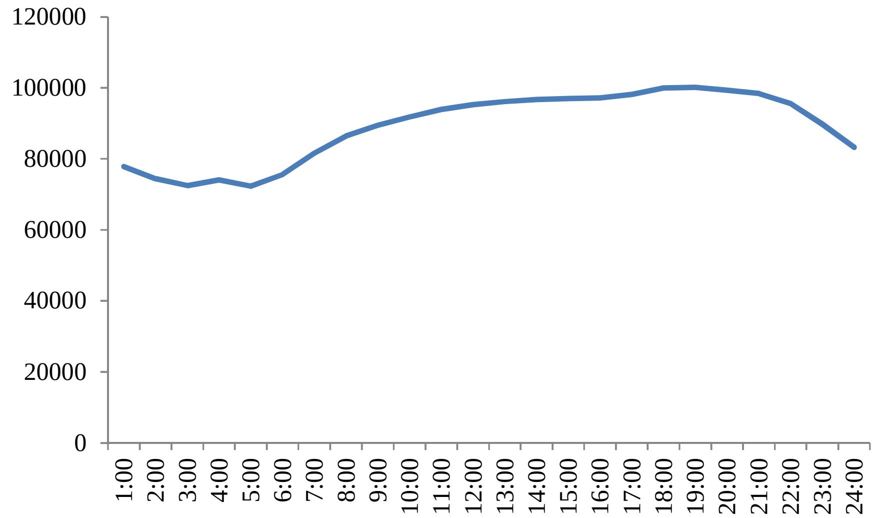
131 MISO PJM interconnection website available at http://www.miso-pjm.com/ accessed 30/8/2013.

132 PJM website available at: http://www.pjm.com/about-pjm/learning-center/renewable-resources/renewable-energy-in-pjm-overview.aspx?faq={77120078-6DD2-48C2-BFCE-D3B057CE0071}#qa accessed: 28/8/2013.

The PJM has been historically a summer peaking market, with the highest peak recorded being approximately 165 GW.[133]

Table 8.2
Average hourly load for 2012 (MW)



Source: PJM hourly load data.

The PJM has both a day-ahead energy market as well as a real-time energy market. Specifically:[134]

- the day-ahead market is a forward market in which hourly locational marginal prices (LMPs) are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions; and
- the real-time market is a spot market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions.

PJM settles transactions hourly and issues invoices to market participants monthly.[135]

The PJM also has a forward capacity market referred to as the 'Reliability Pricing Model' (RPM). Implemented in 2007, the RPM, based on making capacity commitments three years ahead, is designed to create long-term price signals to attract needed investments in reliability

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[133] PJM Statistics dated February 2013 available at http://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/pjm-statistics.ashx accessed 28/8/2013.

[134] PJM website available at http://www.pjm.com/markets-and-operations/energy.aspx accessed 30/8/2013.

[135] PJM website available at http://www.pjm.com/markets-and-operations/energy.aspx accessed 30/8/2013.

in the PJM region.[136] From our discussions with PJM staff, we understand that both the supply side and the demand side of the market participate in the forward capacity market.

Based on discussions with PJM staff, we understand that the current market code applying to PJM's energy markets (ie, both the day-ahead market and the real-time market) require that every generator submits two offers, namely:[137]

- a 'market based' offer; and
- a 'cost based' offer.

When electricity supply is scarce in both the day-ahead and real-time, PJM investigates whether generators have potential market power. To ensure that any such power is not exercised, PJM will use the cost-based offer, so as to stabilise prices at reasonable levels. In all other circumstances, the market-based offer is used.

We understand from discussions with PJM does not apply cost-based offers often – in practice it occurs approximately 2.5 per cent of all hours, across all generators. Further, we understand that generator market based offers do not typically vary significantly from cost-based offers.

Further, there is a significant degree of demand response in PJM's markets for energy, day-ahead scheduling reserve, capacity, synchronised reserve and regulation. In these markets, demand response can compete equally with generation and can set the price of energy.[138]

End-use retail customers participate in demand response in PJM through agents that are PJM members, known as curtailment service providers (CSPs). The CSP identifies demand response opportunities for customers and implements the necessary equipment, such as by installing a smart meter.[139] The CSP can be separate to retail providers and currently there are 78 CSPs that are active in some (or all) States in which PJM operates.[140] A number of retailers in PJM have announced plans for large-scale advanced meter installations, and state

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136 PJM website available at http://www.pjm.com/markets-and-operations/rpm.aspx accessed 30/8/2013.

137 Also see PJM, Market based offers training workshop available at: http://www.pjm.com/~/media/etools/emkt/mktbid.ashx accessed 6/9/2013.

138 The energy markets include the day ahead and real time markets. The day ahead scheduling reserve market is a market based mechanism to procure day ahead supplemental 30 minute reserves pm the PJM system. The synchronised reserve service supplies electricity if the grid has a supply shortfall without much notice. The capacity market procures capacity by auction. The majority of capacity is contracted three years ahead. The regulation service corrects for short term changes in electricity use that might affect the stability of the power system by matching generation and load and adjust generation output to maintain the desired frequency. For further information on PJM markets, see the PJM website available at: http://www.pjm.com/about-pjm/learning-center/markets-and-operations.aspx

PJM, (2013), *Shortage Pricing,* Fact Sheet, 15 April.

139 PJM, (2013), *Shortage Pricing,* Fact Sheet, 15 April.

140 PJM website, available at: http://www.pjm.com/markets-and-operations/demand-response/csps.aspx

regulatory authorities have authorised the installation of more than 12 million smart meters across PJM by 2022.[141]

8.2. Do market price caps reflect consumer values of reliable electricity supply?

On November 16, 2005, PJM filed a settlement agreement with FERC following negotiations between generators and load serving entities regarding the implementation of shortage pricing in PJM. The settlement was uncontested by FERC in December 2005 and an implementation plan for shortage pricing in PJM was established.

Shortage pricing is declared in PJM when energy consumption increases to the point where generation supply is limited (either across the entire system or within one of the predefined major load centres) and the system operators must take emergency actions in order to prevent the system from collapsing. This can include calling on generation that has limited-run hours due to machinery problems or emissions controls, implementing system voltage reductions (‘brownouts’) or implementing manual load reductions (‘rolling blackouts’).

These emergency actions are typically expensive and result in higher prices. Prior to the settlement in late 2005, more expensive generators that were called online during these periods were prevented from submitting offers significantly above cost by market power mitigation rules. Following the 2005 settlement, once any of the above conditions are met, the normal rules for determining energy market prices were to be suspended and the scarcity pricing rules would be triggered, ie, there will be no generator mitigation and prices can rise to the then US$1,000/MWh (approximately AU$1,070) price cap.

We note that the price cap applying to the energy market has historically been set at US$1,000/MWh but a price cap totalling US$2,700/MWh (approximately AU$2,880) for energy during a reserve shortage is being phased in over four years.[142] In proposing an increase in the energy price caps, PJM cited four reasons why limiting the price to US$2,700/MWh was appropriate, namely:[143]

- political sustainability considerations;
- the maximum energy prices would never have risen about US$2,700/MWh in the worst shortage conditions to date;
- discriminatory considerations between different sub-zones; and
- the figure is within the range of the FERC’s approved set of implied maximum prices in other RTO’s.

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[141] PJM, (2013), *Shortage Pricing,* Fact Sheet, 15 April.

[142] This is discussed further in section 8.3 below.

[143] PJM Interconnection,. L.L.C., Affidavit of Paul, M. Sotkiewicz, Ph.D., 18 June 2010 Proposal, p. 26.

PJM indicated to FERC that the shortage pricing mechanism operating at that time did not satisfy the six criteria for shortage pricing outlined in Order No. 719,[144] namely:[145]

1. improve reliability by reducing demand and increasing generation during periods of operating reserve shortage;
2. make it more worthwhile for customers to invest in demand response technologies;
3. encourage existing generation and demand resources to continue to be relied upon during an operating reserve shortage;
4. encourage entry of new generation and demand resources;
5. ensure that the principle of comparability in treatment of and compensation to all resources is not discarded during periods of operating reserve shortage; and
6. ensure market power is mitigated and gaming behaviour is deterred during periods of operating reserve shortages including, but not limited to, showing how demand resources discipline bidding behaviour to competitive levels.

For example, it was stated that:[146]

- the suspending of market power mitigation and offer capping is not consistent with the FERC criterion to ensure market power is mitigated;
- the inability of resources outside of the ‘scarcity pricing region’ providing energy into the that region to set prices during scarcity is not consistent with the FERC criterion regarding comparable treatment of resources; and
- near zero synchronized reserve prices during reserve shortage conditions is not consistent with the FERC criteria regarding improving reliability and encouraging existing resources to be relied upon during reserve shortage conditions.

Further, PJM argued that its proposal will allow existing demand resources to convey its willingness to respond during shortage conditions, whether through its commitment in RPM or through its participation in PJM’s economic load response program in the real-time energy market.[147] PJM further argued that the proposed overall energy-reserve price cap of US$2,700/MWh is ‘well-supported’ and quotes a range of studies that have estimated the value to consumers of lost load during reserve shortage conditions and the cost of unserved energy in other jurisdictions.[148]

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144 FERC Order No. 719 amends FERC’s regulations under the Federal Power Act to improve the operation of organised wholesale electric markets in the areas of: (1) demand response and market pricing during periods of operating reserve shortage; (2) long-term power contracting; (3) market-monitoring policies; and (4) the responsiveness of regional transmission organizations and independent system operators to their customers and other stakeholders, and ultimately to the consumers who benefit from and pay for electricity services.

145 PJM Interconnection,. L.L.C., Affidavit of Paul, M. Sotkiewicz, Ph.D., 18 June 2010 Proposal, p. 17

146 Ibid, p. 17

147 Ibid, p. 26

148 PJM interconnection, L.L.C., Letter to Honourable Kimberley D. Bose, Secretary, FERC, 18 June 2010, pp. 25-26.

The revised shortage pricing arrangements in PJM created a new market to price primary reserves, ie, reserves that can be activated within 10 minutes. Other elements of the shortage pricing arrangements include:[149]

- energy and reserves are priced jointly in real-time every five minutes to improve their price consistency and ensure that a shortage of reserves is reflected in energy prices;
- during a reserve shortage, a demand curve establishes prices for reserves;
- a new market for non-synchronized reserve (reserves that are not electrically synchronized to the system but can be brought online within 10 minutes) was implemented to supplement the existing synchronized reserve market;
- emergency demand response, emergency generation and purchases, and demand resources with bids in excess of US$1,000/MWh can set the price of energy; and
- the market power screening and mitigation remain in effect during shortage conditions.

Finally, PJM states:[150]

> "At times when reserves are short (i.e., less than the largest generating unit on line), accurate pricing is important to provide the correct price incentives for resources like generation and demand response to respond to help alleviate the shortage."

We understand that resources with the highest probability of setting the market price during periods when shortage pricing is in effect are demand side resources, ie, as compared to generation resources. We understand this is largely due to the scrutiny that generators face with regard to their market offers, ie, the litigation that generators may face for withholding capacity or price fixing and the ability of PJM to mitigate their market based offers. Further, we understand that during periods of shortage pricing, demand side resources typically bid at the market price cap.

Our discussions with PJM outlined that the primary objective of the market price cap in PJM energy markets is to encourage demand side resources. The high degree of scrutiny that generators face largely negates the need for shortage pricing arrangements from a generation point of view. We note that by having a market price cap targeting the involvement of demand side resources and at a level that is above what generators offer, is in effect having electricity customers reveal the real-time (and day-ahead) value to them of having electrical supply.

As noted above, the PJM is not an 'energy only' market as it includes a forward capacity market. From our discussions with PJM staff, we understand that the objective of the price cap in the forward capacity market is to encourage supply-side investment and mimic the cost of the marginal generator. The approach to estimating this market price cap is outlined in section 8.3 below.

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149 PJM, (2013), *Shortage Pricing,* Fact Sheet, 15 April.

150 PJM, (2013), *Shortage Pricing,* Fact Sheet, 15 April.

8.3. Approach to setting the price cap

We understand that the price cap in the forward capacity market is set with reference to the cost of constructing the most inexpensive capacity, which is currently the cost of a peaking gas generator. Analysis of the 20 year levelised cost of electricity of these generators is undertaken every four years by PJM. The price cap is reset for each year between these reviews using the 'Handy Whitman' index (an index of the construction costs of public utilities). The results of this analysis are included in a proposal, which the PJM submits to FERC who then approves the price cap.

Further, the price caps applying in the day-ahead energy market and in the real-time balancing energy market are not based on specific analysis. Rather, the price caps in these markets are a result of negotiations between entities from both the demand and supply side of the PJM.

Following the last of these negotiations, PJM submitted a proposal to FERC in June 2010 that included a price cap totalling US$2,700/MWh for energy during a reserve shortage to be phased in annual over the period out to mid-2014.[151] Specifically, the PJM proposed phased in approach to increasing the market price cap was as follows:[152]

- US$1,500 per MWh in the first year (approximately AU$1,600);
- US$1,800 per MWh in the second year (approximately AU$1,920);
- US$2,100 per MWh in the third year (approximately AU$2,240); and
- US$2,700 per MWh in the fourth year and thereafter (approximately AU$2,880).

In April 2012, the FERC accepted PJM's proposed price cap increases and we understand that PJM is currently in the second year of this phase, ie, the US$1,800/MWh price cap applied during the 2013 summer. We understand that the process for altering the level of these price caps after the US$2,700/MWh is in place would involve PJM submitting a proposal to FERC outlining reasons for the change.

As part of the market price cap increase proposal submitted to FERC, PJM states that the proposed overall energy-reserve price cap of US$2,700/MWh is 'well-supported' and quotes a range of studies that have estimated the value to consumers of lost load during reserve shortage conditions and the cost of unserved energy in other jurisdictions.[153] Overall, PJM stated that:[154]

> "Accordingly, PJM's proposed maximum level of $2700/MWh is reasonable, and will put the PJM Region on a comparable basis with its neighboring RTOs."

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151 PJM Interconnection,. L.L.C., 139FERC 61,057 (2009), Order on Compliance filing, Issues 19 April 2012.

152 Ibid.

153 PJM interconnection, L.L.C., Letter to Honourable Kimberley D. Bose, Secretary, FERC, 18 June 2010, pp. 25-26.

154 Ibid, p. 26.

8.4. General observations

The PJM wholesale electricity market includes both a forward capacity market, which both supply-side and demand-side entities can bid into, and a day-ahead energy market. As a consequence, there is less of a need for a market price cap to be sufficiently high so as to create sufficient revenue to fund generation investment.

The price cap in the forward capacity market is set with reference to the cost of constructing the most inexpensive capacity, which is currently the cost of a peaking gas generator. It follows that the capacity market price cap is not based on estimates of the VCR.

The price caps applying in the day-ahead energy market and in the real-time balancing energy market (currently US$1,800/MWh, with it being scheduled to increase to US$2,700/MWh in 2015) are not based on any specific analysis. Rather, the price caps in these markets are a result of negotiations between entities from both the demand and supply side of the PJM.

The increase in the energy market price cap in PJM is to accommodate demand side bidding into the market, particularly during periods of high demand and insufficient conventional generation capacity. Higher prices in the energy market (ie, prices close to the market price cap) therefore generally reflect the actual value to customers of reliable electricity supply. This is because demand side bids reflect a market estimate of the amount consumers would be willing to accept to not be supplied with electricity.

9. Great Britain

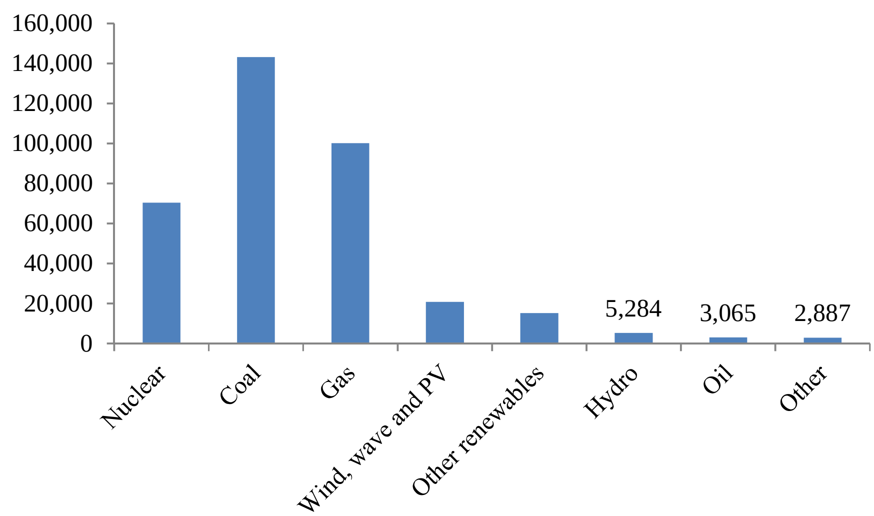
In this section we provide an overview of the electricity market in Great Britain, and set out its principal characteristics so as to highlight similarities and differences between Great Britain's electricity market and the NEM. In addition, we explore the Office of Gas and Electricity Markets' (Ofgem) recently commissioned study of VCR and discuss the absence of a market price cap in the balancing market.

9.1. Overview of the wholesale electricity market in Great Britain

Great Britain's domestic production of electricity in 2012 was approximately 364 TWh. Great Britain is currently a net importer of electricity and had total consumption of approximately 376 TWh in 2012. Renewable generation accounted for 11.3 per cent of total generation. Total installed generation capacity connected to the United Kingdom transmission network was almost 84 GW at the end of December 2012. [155]

Figure 9.1 shows electricity generation by fuel type in Great Britain.

Figure 9.1
Electricity generation by fuel type 2012 (GWh)

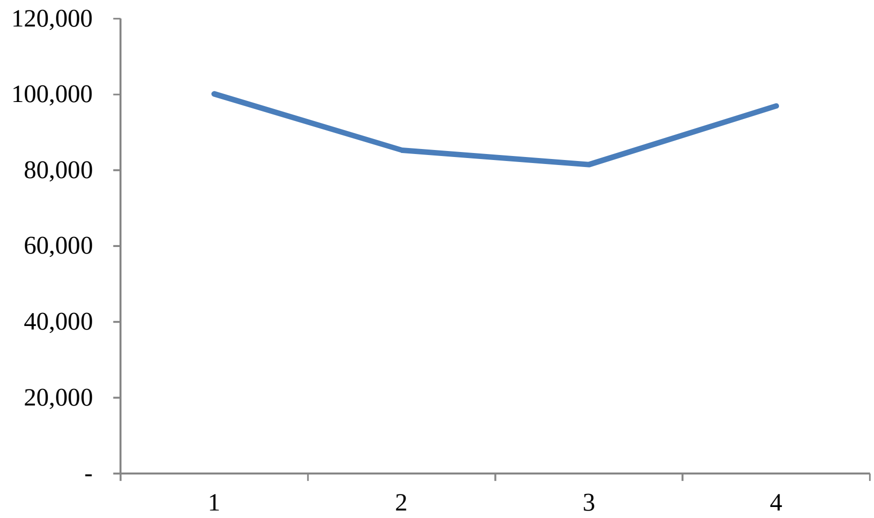


Source: DECC, Digest of United Kingdom Energy Statistics (DUKES): Electricity, 25 July 2013.

Figure 9.2 below shows electricity generation by quarter in 2012.

[155] Data from DECC.

Figure 9.2
United Kingdom electricity generation by quarter in 2012 (GWh)



Source: DECC data.

Wholesale trading usually occurs on a bilateral basis with contracts spanning a variety of time periods from on-the-day trades to several years ahead. The National Grid Electricity Transmission (NGET) operates the residual balancing market, known as the Balancing Mechanism. If a market participant generates or consumes more electricity than they are contracted for, they are exposed to a 'cash out' which is based on NGET's cost of balancing the system in each half hour. The payment acts as an incentive for market participants to minimise reliance on the balancing mechanism.

The current design of the wholesale electricity market in Great Britain is as an 'energy-only' market. However, concern regarding low generation investment has resulted in mechanisms being introduced to allow capacity to be separately purchased, with the first capacity auction to be held in 2014 for delivery of generation capacity in 2018/19.[156]

There is considerable uncertainty about future electricity generating capacity in Great Britain due to a significant reduction in generation from existing coal and oil plants, coupled with limited investment in new plants. More than 2 GW of installed generation capacity is to be retired from the market in the near future. Ofgem is expecting further retirements, in part due to regulatory and price uncertainty.[157] Ofgem does not expect any new conventional generation plants to be built before 2016.[158]

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156 Ofgem, Letter to market participants: Consultation on the potential requirement for new balancing services by National Grid Electricity Transmission PLC (NGET) to support an uncertain mid-decade electricity security of supply outlook, 27 June 2013.

157 Ofgem, (2013), *Electricity Capacity Assessment Report 2013*, 27 June, p 4.

158 Ibid, p 4.

Peak demand has fallen by around 5 GW over the last seven years in part due to the economic downturn experienced in Great Britain, and overall improvements in energy efficiency. NGET is projecting peak demand to fall a further 3 to 4 GW by 2018, in part due to anticipated higher levels of demand side response within the market.[159]

Currently, only large non-domestic consumers provide demand response in the wholesale electricity market. Smart meters are being rolled out across Great Britain and 53 million meters are expected to be installed by 2020.[160] Consequently, in part demand response is expected to reduce peak demand by 1 GW in the non-domestic sector and 0.4 GW in the domestic sector by 2018-19.[161]

Ofgem has a long term goal to increase the role of demand in the market. Our discussion with Ofgem staff identified that demand will be able to bid into the capacity market but the mechanism by which this will occur within the market design has not been finalised yet. We also understand that demand-side aggregators are playing an increasingly important role in the market.

There are currently interconnectors between Great Britain and France, the Netherlands and Ireland (both the Republic of and Northern). The mean and median of annual, winter wholesale electricity prices show no large differences between the four interconnected regions. Great Britain's wholesale electricity prices are generally lower than Irish prices, with the exception of 2008 when there were plant outages in Great Britain. The price difference between France and the Netherlands varies between years, potentially due to changes in gas and carbon prices.[162]

We understand that Ofgem is anticipating continuing investment in interconnectors, with an interconnection between Great Britain and Belgium expected to become active in the near future.[163] Under the European Electricity Target Model,[164] which is expected to come into force in 2014, a large number of binding new network codes will be implemented. The codes seek to harmonise key elements of the various electricity markets to facilitate trade across Europe. Ofgem expects that from November 2013 there will be full coupling on day-ahead electricity trade across North-West Europe. Within the next 18 months, Ofgem anticipates a move to continuous intraday trading across the region.

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[159] Ibid, p 4.

[160] Morales, A., U.K. prefers Telefonica for biggest smart meter deal, Bloomberg, 15/8/2013.

[161] Ofgem, (2013), *Electricity capacity assessment report 2013*, 27 June, p 39. Based on analysis by NGET.

[162] Poyry, Comparison of electricity prices between GB and interconnected systems, a presentation for Ofgem, 12 March 2013.

[163] Conversation with Ofgem staff, 4 September 2013.

[164] The European Electricity Target Model has developed from interactions between Great Britain and the European Union. It model sets out the functioning of a single electricity market between the regions.

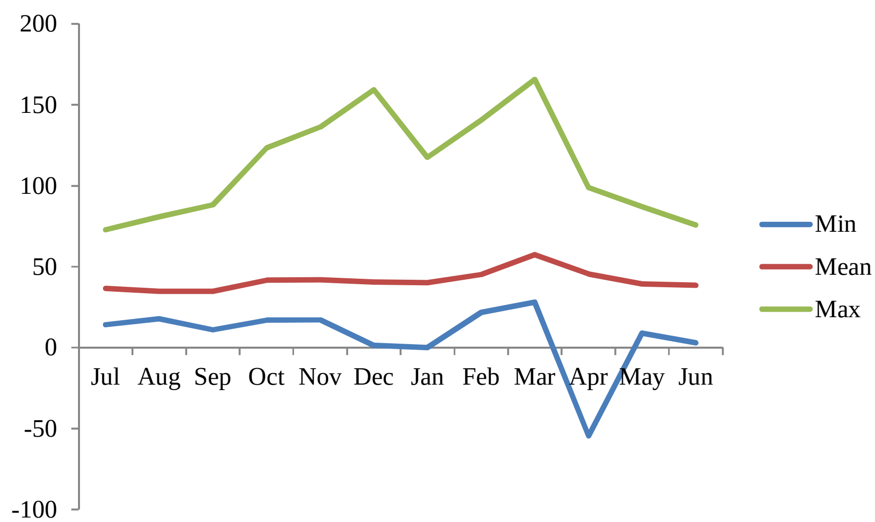
9.2. Do market price caps reflect consumer values of reliable electricity supply?

Currently, there is no market cap in the wholesale electricity market in Great Britain. However, Ofgem staff identified that the government has 'left the door open' to adjust the volume procured in the capacity market if the prices are too high.

It follows that market prices reflect the out workings of the balancing market arrangements.

Figure 9.3 sets out the average daily offer price in the balancing market in for the 2012/13 financial year.

Figure 9.3
Sell offers in the Balancing Mechanism (2012/13, £/MWh)



Source: Elexon Trading Operations Reports.

While values of reliable electricity supply are not currently used as the basis for setting a market price cap, Ofgem has conducted a recent study of VCR. These estimates are intended to be used to inform decisions about the quantum of capacity to purchase as part of the proposed capacity market, [165] and for the purpose of setting network reliability standards. In addition, estimates of VCR could be used to price involuntary consumer disconnections (ie, load shedding) that might arise from the out-workings of the balancing market.[166] Presently, disconnections are not currently priced in at all.

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[165] London Economics, (2013), *The value of lost load (VOLL) for electricity in Great Britain*, Final report for Ofgem and DECC, July, p x.

[166] London Economics, (2013), *The value of lost load (VOLL) for electricity in Great Britain*, Final report for Ofgem and DECC, July, p x.

From our discussion with Ofgem staff, we understand that estimates of the VCR will also be used to inform the quantum of penalty charged to generators who have received a capacity payment but fail to generate at time of system stress.

9.3. Methodology for estimating VCR

While there is no formal market price cap in the Great Britain market, estimates of the VCR have recently been estimated for Ofgem and the Department of Energy and Climate Change (DECC) for domestic, small and medium sized businesses (SME) and industrial and commercial electricity consumers in Great Britain.[167]

The context for the report was a change in generation mix towards renewables and new rules for European electricity market integration coming into effect. Further, Ofgem and DECC are reviewing some aspects of energy policy, including the legislation for the introduction of a capacity market. In particular, the amount of electricity generating capacity that will be contracted through the capacity market is likely to be informed by the VCR.[168]

The Competition Commission in the United Kingdom commissioned Accent, in association with RAND Europe, to conduct a review of stated preference and willingness to pay methods in conducting surveys.

The report recommends the use of discrete choice questions when carrying out WTP research. However, contingent valuation methods can be effective when there are time pressures. The report recommends:[169]

- including additional information to allow respondent to indicate any changes in behavior from the change (as opposed to discrete) price;
- introducing a choice valuation task by personalizing and setting context for the issue (ie imagine you face this situation);
- including diagnostic questions to assess whether respondents understood the task;
- using qualitative research to identify marginal consumers;
- having a sample size of at least 400; and
- minimising the length of the study; 10 minutes is recommended.

In 2011, Ofgem undertook a VCR review in the gas market to review system emergency arrangements. We understand that Ofgem intended to apply the results of this study to the gas ‘cash-out’ arrangements[170] by setting disconnection cash-out equal to domestic consumers

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[167] London Economics, (2013), *The value of lost load (VOLL) for electricity in Great Britain*, Final report for Ofgem and DECC, July.

[168] Ibid, p x.

[169] Competition Commission, (2010), *Review of state preference and willingness to pay methods*, Introductory note by the Commission, April.

[170] In the United Kingdom ‘cash-out’ arrangements are operated in both the gas and electricity markets and are designed to address the cost of energy balancing incurred by National Grid to the parties who created those costs (ie, those parties

VCR. However, Ofgem concluded that this approach led to domestic consumers capturing nearly all of the industrial and commercial customer VCRs, which was considered too high. This would send a strong signal to gas shippers to enter into interruptible contracts with industrial and commercial customers, who can then reveal their true VCR is in negotiations with shippers. However, we understand that Ofgem received significant resistance from industry which has argued that it is methodologically incorrect to use residential VCR's for industrial and commercial customers.

In addition, we understand that it was argued that because industrial and commercial gas customers are metered on a daily basis, and can interact with the market, it is possible to hold a tender to reveal a more accurate estimate of VCR. Ofgem are now proposing to hold a demand side response tender for industrial and commercial gas customers to better estimate the VCR for these customers. Ofgem proposes to use the marginal VCR to set the cash-out price.

The approach recently used to estimate the VCR for residential electricity customers in Great Britain used a combination of stated choice and contingent valuation techniques to estimate both the willingness to accept (WTA) and willingness to pay (WTP) for electricity outages. The specific attributes investigated include:

- differing lengths of time for the outage;
- the time of day;
- the day of the week; and
- whether the outage was in a particular season.

In addition, the survey included a 'don't know' option. Around 11 per cent of respondents selected this option for WTP choices whilst around 5 per cent selected this option for WTA questions. These answers were excluded from the results.[171]

The stated choice questionnaires also contained general survey questions relating to electricity usage, availability of substitutes (eg gas heating) and general household and business characteristics. The contingent valuation questions required respondents to state their value for an outage in both WTP and WTA terms. By using both approaches, the results were able to be cross-checked for internal consistency.[172]

The residential online survey had a representative sample of 1,524 respondents. A face-to-face survey was also undertaken with 150 vulnerable domestic electricity consumers.

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who do not balance their inputs and outputs within the relevant balancing period). As such, parties who are not in balance incur charges that reflect the costs incurred by National Grid in addressing the imbalance, which are known as cash-out prices. See: Ofgem website, available at: https://www.ofgem.gov.uk/gas/wholesale-market/market-efficiency-review-and-reform/cash-out-arrangements

[171] London Economics, (2013), *The value of lost load (VOLL) for electricity in Great Britain*, Final report for Ofgem and DECC, July, p 8-9.

[172] Ibid, p x.

In contrast, VCR for industrial and commercial customers was estimated using a combination of ‘value at risk’, gross value added and production function approaches.

The business survey was conducted as a computer assisted telephone interview due to the low response rate of businesses to online surveys in previous research.[173]

9.3.1. Estimates of VCR

The results for residential consumers and small and medium sized businesses are summarised in Table 9.1 and Table 9.2 respectively.

Table 9.1
(£/MWh, approximately AU$ given in parenthesis)

	Not Winter Not Peak, Weekend	Not Winter, Not Peak, Weekday	Not Winter, Peak, Weekday	Not Winter, Peak, Weekend	Winter, Not Peak, Weekend	Winter, Not Peak, Weekday	Winter, Peak, Weekday	Winter, Peak, Weekend
WTA	9,550	6,957	9,257	11,145	10,982	9,100	10,289	11,820
	(16,390)	(11,940)	(15,900)	(19,130)	(18,850)	(15,630)	(17,670)	(20,300)
WTP	2,766	(101)	(105)	1,805	2,240	315	208	1,651
	(4,750)	((170))	((180))	(3,100)	(3,840)	(540)	(360)	(2,840)

Source: London Economics, The value of lost load (VOLL) for electricity in Great Britain, Final report for Ofgem and DECC, July 2013.
Note: Figures based on a one hour outage. Adjusted for different demands. Peak is 3pm-9pm.

Table 9.2
Comparison of WTA and WTP for SME’s (£/MWh, approximately AU$ given in parenthesis)

	Not Winter Not Peak, Weekend	Not Winter, Not Peak, Weekday	Not Winter, Peak, Weekday	Not Winter, Peak, Weekend	Winter, Not Peak, Weekend	Winter, Not Peak, Weekday	Winter, Peak, Weekday	Winter, Peak, Weekend
WTA	37,944	36,887	33,358	34,195	44,149	39,213	35,488	39,863
	(65,120)	(63,290)	(57,250)	(58,690)	(75,770)	(67,340)	(60,890)	(68,390)
WTP	21,864	19,271	20,048	24,175	26,346	21,325	21,685	27,859
	(37,510)	(33,070)	(34,410)	(41,490)	(45,220)	(36,590)	(37,240)	(47,810)

Source: London Economics, The value of lost load (VOLL) for electricity in Great Britain, Final report for Ofgem and DECC, July 2013.
Note: Figures based on a one hour outage. Adjusted for different demands. Peak is 3pm-9pm.

173 Ibid, p 9-10.

The results for industrial and commercial consumers was based on readily available secondary data sources rather than surveys due to the difficultly of organizing surveys with these consumers. According to Ofgem staff, not surveying industrial and commercial consumers also assisted in reducing the cost of the study.

The VCR for industrial and commercial consumer was significantly lower than for SMEs. This was expected as large consumers use more electricity per unit of GVA than small business, which impacts the VCR/MWh. Further, large consumers may have back up generating equipment in case load is curtailed. The average VCR for industrial and commercial consumers was approximately £1,400/MWh (approximately AU$2,400).[174]

As the demand side response becomes more sophisticated, Ofgem and DECC expect that large customers, mainly industrial and commercial consumers, will become increasingly capable of responding to wholesale price signals. Therefore, Ofgem and DECC have focused their VCR analysis on residential and SME's.[175]

Ofgem has identified that the inclusion of industrial and commercial VCR was important in the study as it assisted in identifying the costs incurred when disconnecting large consumers in a 'largest first' manner. It also revealed the potential for benefits to be gained by interrupting demand in by consumers that have the lowest VCR first.

The marginal impact on reliability of supply was set by reference to a one hour peak winter electricity outage. There is a downwards bias in WTP figures due to consumers having a sense of entitlement for services they pay for. Use of such figures would result in setting reliability standards too low. Therefore, Ofgem and DECC use WTA figures, which were also more robust then WTP figures.[176]

The VCR was valued at £16,940/MWh (approximately AU$29,070) using the WTA stated choice results, as a load-share[177] weighted average across domestic and SME users for winter peak weekday figures.

The analysis also considered the value of voltage reductions. However, the statutory requirement implies that a loss of voltage would be unlikely to affect domestic consumers and SME's.

9.3.2. Methodological insights

Ofgem, acknowledges that VCR estimates produced from almost any methodology are likely to be highly uncertain due to the practical difficulties of eliciting values for outages from consumers.

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174 Ibid, p 41.

175 Ibid.

176 Ibid, p 53-54.

177 The share is 74:26 ratio of domestic to SME consumers.

Ofgem considered how the estimates of VCR should be applied, given the variation in the estimates, ie, by consumer type, season and time of day. Ofgem found that with the currently available technology, it is not possible to identify the type of consumer that has been disconnected. Therefore, differentiating VCR by customer type is not possible. Although it is possible to apply different VCR levels depending on the season/time of day, Ofgem's Technical Working Group recommended that the benefits of improved accuracy do not outweigh the added complexity of using several VCR estimates. It would also increase the complexity of hedging against the costs associated with disconnection.[178]

Ofgem also considered whether it is the marginal or average VCR that should be applied. Ofgem noted that, in theory, to maximise the balancing incentive for market participants the marginal VCR would be applied. However, Ofgem was also of the view that the wide range of VCR estimates provided in the London Economics' VCR study meant that adopting a marginal VCR would likely place too great of a risk on market participants (Ofgem also noted that it appears particularly high compared to VCR in other countries). Ofgem therefore decided to select an administrative VCR based on an average of the study's VCR estimates.[179] Specifically, Ofgem stated:[180]

> Although the research provided VoLL estimates for domestic, small business and large I&C consumers we have only used an average of the domestic and small business results in our administrative VoLL. I&C consumers are most likely to have the capability to reveal their 'true' VoLL through demand side response/ interruptible contracts. VoLL figures per MWh for I&C consumers are generally significantly lower than for domestic and small business consumers, as I&Cs use more electricity which impacts on the value they put on each MWh. Also, they have the potential to use back-up equipment when production is load-critical, which limits their VoLL. An administrative VoLL based on an average of domestic and small business VoLL and hence above the true' VoLL of I&C consumers should therefore provide appropriate incentive for I&C consumers to voluntarily enter into arrangements to reduce load at times of system stress.

In considering VCR for cash-out arrangements, Ofgem indicates that they are most concerned with ensuring that the cash-out price reflects scarcity at times of system stress and provides the strongest incentive for market participants.[181] Ofgem therefore based the administrative VCR figure on the estimates of VCR at typical winter peak periods and stated that by doing so they were ensuring that the greatest incentives are in place to encourage participants to reveal their true value of VCR through demand side response/interruptible contracts.[182]

9.4. General observations

The wholesale electricity market operating in Great Britain is an energy only balancing market. However, concern regarding a lack of generation investment has led to mechanisms

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[178] Ofgem, (2013), *Electricity balancing significant code review*, draft policy decision, 22 October, p 56 - 57.

[179] Ibid, p 56.

[180] Ibid, p 56 & 57.

[181] Ibid, p 57.

[182] Ibid, p 56 & 57.

being introduced to allow capacity to be separately purchased, with the first capacity auction planned to be held in 2014 for delivery of generation capacity in 2018/19.

Relevant to our study, the wholesale market in Great Britain does not currently have a market price cap.

While values of reliable electricity supply are not currently used as the basis for setting a market price cap in Great Britain, Ofgem recently commissioned a study to estimate VCR. The study estimated :

- a load-share weighted average VCR of £16,940/MWh (approximately AU$29,070) for domestic and SME users; and
- an average VCR for industrial and commercial consumers of approximately £1,400/MWh (approximately AU$2,400).

The VCR estimate for domestic and SME users used a combination of stated choice and contingent valuation techniques to estimate both the ‘willingness to accept’ and ‘willingness to pay’ for electricity outages. The study found that the ‘willingness to accept’ approach is the more robust estimate.

The data from industrial and commercial consumers was based on readily available secondary data sources rather than surveys due to the difficultly of organising surveys to collect sufficiently robust data with these consumers.

10. The Netherlands

In this section we provide an overview of the electricity market in the Netherlands, and set out its principal characteristics so as to highlight similarities and differences between the electricity market in the Netherlands and the NEM. In addition, we discuss the market price cap in the spot and adjustment markets in the Netherlands.

10.1. Overview of the wholesale electricity market in the Netherlands

The electricity market in the Netherlands began to de-regulate in 1998 with the establishment of both a regulatory body (DTe) and a transmission system operator (TenneT). The retail market underwent a staged opening, with large customers being able to choose a supplier in 1998, with the smallest customers following in 2004.[183]

TenneT has a number of additional responsibilities that cannot be performed by other grid operators, for example:[184]

- system services (eg, maintaining the balance between electricity supply and demand);
- ensuring the security of supply; and
- granting access to foreign wholesale markets to market participants and maintaining the ‘programme responsibility system’.

The ‘programme responsibility system’ in the Netherlands refers to the system that settles any differences between the transactions and the actual generation or consumption of electricity. TenneT determines the differences and ensures that they are settled. Parties inform TenneT on a daily basis about the transactions with other parties on a day-ahead basis. After day-ahead approval, parties are permitted to update their transactions, as follows:

- cross-border transactions: up until 1 hour prior to delivery; and
- within border: until 10am the next day, ie, post-delivery.

The regional grid administrators notify TenneT of the amount of electricity that each party has actually consumed and/or supplied. The difference between the amounts recorded and the total of the actual measured values of each party is called the imbalance.

In January 2010, TenneT bought the German extra high voltage grid of ‘Transpower’, which made TenneT Europe’s first cross-border transmission service operator.[185] However, the two transmission service operator functions of TenneT operate independently, as they fall under different regulatory authorities.

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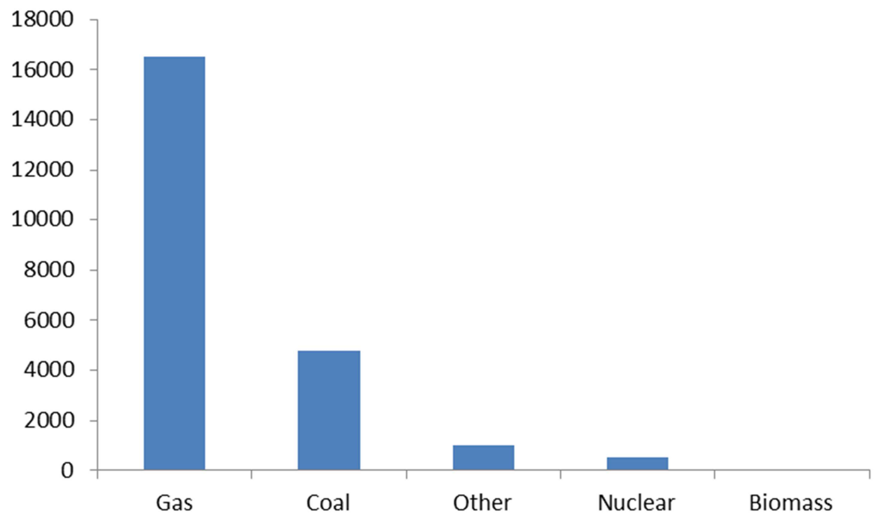
[183] AESO, *Alberta wholesale market price cap, discussion paper*, 23 June 2009.

[184] TenneT website, available at: http://www.tennet.eu/nl/about-tennet/about-the-electricity-sector.html

[185] TenneT, (2010), *Market integration – Coupling of the European electricity markets*, December, p. 3.

In the Netherlands, electricity is primarily generated from natural gas, coal and petroleum. However, some electricity is generated from renewable sources such as wind and solar as well as sustainable sources such as biomass and ambient heat.[186] The installed generation capacity in 2013 by fuel type is shown in Figure 10.1 below.

Figure 10.1
Installed generation capacity by fuel type 2013 (MW)



Source: Tennet Energyinfo website, available at: http://energieinfo.tennet.org/Production/index.aspx

Installed capacity on the TenneT grid, which covers the Netherlands and a large part of Germany, was 82,000 MW in 2010 including 11,800 MW of wind capacity.[187] Peak demand occurs in winter and dropped during the Global Financial Crisis. However, TenneT has projected 2 per cent growth in annual electricity consumption until 2016.[188]

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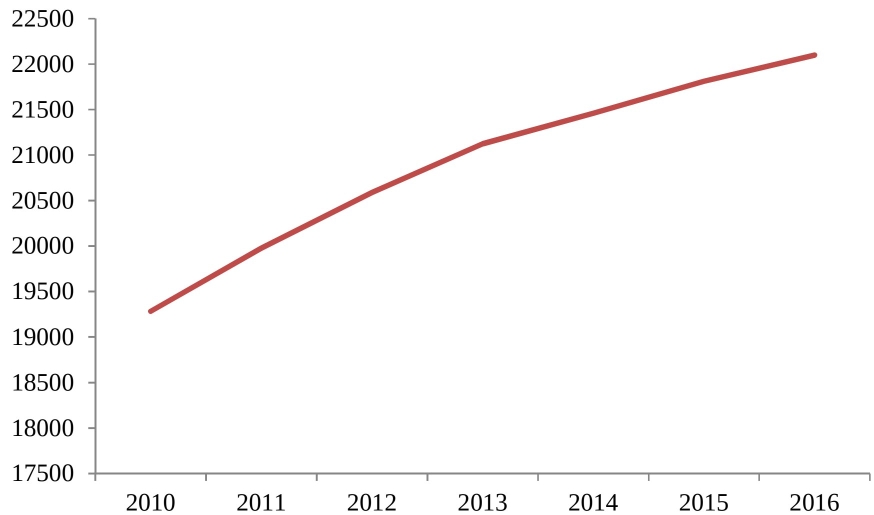
186 TenneT website, available at: http://www.tennet.eu/nl/about-tennet/about-the-electricity-sector/electricity-producers.html

187 TenneT (2010), *Taking power further*, Corporate Brochure, November.

188 TenneT (2009), Quality and Capacity Plan 2010-2016, 30 November, pp 27-28.

Figure 10.2
Expected maximum load (MW)



Source: TenneT (2009), Quality and Capacity Plan 2010-2016, 30 November.

A key characteristic of the electricity market in the Netherlands is the high degree of interconnectedness it has with neighbouring countries. Since 2006, TenneT has been working with other European transmission service operators and power exchanges on 'coupling' the electricity markets in Northwest Europe with the aim of establishing a single market.[189] We understand that this coupling involves the implicit day-ahead auctioning of cross-border transfer capacity. The Netherlands was a large net importer of electricity following deregulation as it has a relatively high cost of generation compared to its neighbours.[190]

For a long time the Netherlands had only two interconnections with Belgium and three with Germany. However, TenneT has expanded this capacity to now include additional interconnections with the United Kingdom (via the 1,000 MW BritNed cable) and with Norway (via the 700 MW NorNed cable). TenneT is also currently in the process of investigating the following interconnectors:[191]

- interconnector linking Doetinchem in the Netherlands to Wesel in Germany (scheduled for completion in 2014);
- a second cable link to Norway (study phase); and
- a 700MW interconnector to Denmark (the 'COBRAcable'). The COBRAcable's objective is to advance the integration of more sustainable energy (particularly wind energy) into

[189] TenneT website, available at: http://www.tennet.eu/nl/grid-projects/international-projects/market-coupling.html

[190] AESO, *Alberta wholesale market price cap, discussion paper*, 23 June 2009.

[191] TenneT website, available at: http://www.tennet.eu/nl/grid-projects/international-projects.html

the Dutch and Danish electricity markets.[192] The feasibility study for the COBRAcable is expected to result in a final investment decision in late 2014.[193]

Interconnection with Norway allows for better capacity utilisation because of the non-coincident peak demand periods of the two countries. Specifically, electricity consumption in Norway is relatively high at night time and so the Netherlands typically exports electricity to Norway during the night as it is cheaper and also allows Norway to save the water in its reservoirs for use during the day. In turn, Norway exports electricity to the Netherlands during the daytime peak hours, when electricity is expensive. Importantly, Dutch market parties are able to import renewable hydropower from Norway via the NorNed cable.[194]

TenneT has also worked with its international partners to complete the following system improvements:[195]

- market coupling between Belgium, France and the Netherlands (2008);
- market coupling between Germany, Belgium, France and the Netherlands (2010);
- cross-border intraday trading (2011);
- intraday trading with Norway (March 2012) and the United Kingdom (May 2012); and
- European market coupling between Scandinavia, the United Kingdom and Northwest Europe (2014).

The wholesale electricity market in the Netherlands is a two part market and comprises a firm forward market as well as a real-time balancing market. The forward market schedules flows over the interconnectors and trades between market participants. The design is such that market participants balance schedules prior to real-time with the balancing market then used to correct small imbalances as a result of forecast errors.

We understand that the requirement to operate balanced schedules has resulted in very small volumes exchanged in the imbalance market, and the tendency has been for market participants to over schedule electricity such that the imbalance market often sheds excess electricity.

10.2. Do market price caps reflect consumer values of reliable electricity supply?

The APX power exchange operates the day-ahead auction. All market participants can be active as a buyer or supplier and include entities such as generation and distribution companies, large consumers, industrial end-users, brokers and traders. The day-ahead auction operates on an hourly trading basis but also allows flexible block contracts to be traded. The

192 TenneT website, available at: http://www.tennet.eu/nl/grid-projects/international-projects/cobracable.html

193 TenneT website, available at: http://www.tennet.eu/nl/grid-projects/international-projects/cobracable.html

194 TenneT website, available at: http://www.tennet.eu/nl/grid-projects/international-projects/norned.html

195 TenneT website, available at: http://www.tennet.eu/nl/grid-projects/international-projects.html

minimum price for any day-ahead market instrument is -€3,000/MWh and the maximum price is €3,000/MWh (approximately +/-AU$4,330).[196]

The APX power exchange also operates the continuous intraday and strips market (referred to as the 'adjustment' markets). These markets have been linked to the Belgium power exchange, Belpex intraday market and the Nord Pool Spot Elbas[197] intraday market since February 2011 and March 2013, respectively. On the intraday market, electricity is traded in hourly intervals as well as freely definable block orders up to five minutes prior to delivery. The strip market allows continuous trade up to two business day-ahead on standardised blocks of hours; base load, peak load and off peak load. The intraday market has a minimum price of -€99,999.90/MWh (approximately -AU$144,320) and maximum price of €99,999.90/MWh.[198]While the price cap is set at approximately €100,000/MWh, we understand that the highest price actually realised has been around €1,200/MWh.

Importantly, the market design in the Netherlands provides market participants with a disincentive to make high balancing offers as each market participant is responsible for its own imbalances at the prevailing spot price. For example, if an entity submits a very high offer price and then unexpectedly becomes short, it is required to purchase electricity on the adjustment market to account for its imbalance.

We understand that the various market price caps in the Netherlands were set in collaboration with market parties and exchanges in interconnected jurisdictions and included considerations such as:

- the harmonisation between countries involved in market coupling;
- placing minimal restrictions on market prices;
- the technical price limitation required for the matching algorithm; and
- limitations for prices in other Central Western European markets.

Overall, we understand that the price caps in the Netherlands have not been set with reference to an estimate of the VCR.

10.3. General observations

The Dutch electricity market has become interconnected with neighbouring European countries since it began to de-regulate in 1998, which led to the Netherlands becoming a large net importer of electricity given its relatively high cost of generation.

While price caps do exist in the Dutch wholesale electricity market, we understand that these have not been set with reference to an estimate of the VCR. Rather, they have been set in

196 APX website, available at: http://www.apxgroup.com/trading-clearing/day-ahead-auction/

197 NordPool operates in Norway, Denmark, Sweden, Finland, Estonia and Lithuania.

198 APX website available at: http://www.apxgroup.com/trading-clearing/continuous-markets-intraday-strips/ accessed 24 September 2013.

collaboration with market parties and exchanges in interconnected jurisdictions with the intention of harmonising across the markets.

The market design in the Netherlands (ie, the binding forward market) places significant risks on participants that price energy in the imbalance market at very high levels, which reduces the usefulness of price caps to place downward pressure on prices. Revealingly, we understand that actual market prices have not reached levels near the defined price caps.

11. Conclusions

Our review of a number of wholesale electricity markets highlights that there are a mixture of methodologies used to determine the market price cap. In general the methodologies can be split into four broad categories, namely markets where:

- there is no formal market price cap (Great Britain, New Zealand (under ordinary operating conditions));
- the market price cap is set with reference to the cost of a marginal generating unit (ERCOT, Alberta, PJM forward capacity market, the MISO annual voluntary capacity auction, New Zealand (lower price bound when scarcity pricing in place));
- the market price cap is set with reference to an amount obtained through direct negotiation between market participants (PJM energy markets, the Netherlands); and
- the market price cap is set with reference to the VCR (Singapore, MISO, New Zealand (upper price bound when scarcity pricing in place)).

In a number of markets the relevant agency was mindful to recommend market price cap that limits opportunities for generators to exercise market power. In these circumstances the market price cap (and in particular a relatively low cap) was considered to be one mechanism by which scope for generator market power could be limited.

That said, the motivation for recent increases in the market price cap in some markets in part, reflected concerns about the lack of new generation investment.

Separately, Alberta has the lowest market price cap in the markets we investigated. Despite extensive analysis surrounding the market price cap, it is not expected to be increased. In our opinion, this reflects the relatively flat load profile in the Albertan market combined with decreasing demand and significant interconnection with adjacent markets, which means that generation capacity is not currently a concern.

Although most of the price caps in the wholesale electricity markets we investigated were not set with reference to the VCR, estimates of VCR were often used for other purposes. For example, in New Zealand a scarcity pricing mechanism imposes a market price band, with the lower bound reflecting the cost of marginal generating unit, and the upper band an estimate of VCR. Estimates of VCR are also commonly used for transmission investment planning and decision making purposes. In addition, Ofgem in Great Britain have recently estimated VCR to inform decisions about the procurement of capacity in light of the proposed energy market reforms.

The methodological approaches to estimate VCR typically involve:

- stated preference or contingent value surveying, mostly for residential or small domestic consumers; and/or
- using estimates of industry gross value add and electricity consumption to input the value of electricity to large industry and/or commercial consumers.

The common theme from the VCR studies that we have considered is that obtaining reliable estimates of the VCR is challenging. This reflects the variability of likely values by individual consumers, time of day, etc. A number of the more recent studies have addressed this by using a number of difference methodologies as a cross check (eg, both stated preference and contingent valuation techniques), including estimating both the willingness to pay and willingness to accept to both avoid an outage, or to not consume. Ultimately, how the VCR appropriately translates to the market price cap is likely to be a matter of judgement, given all of the contextual circumstances.

Finally, markets that allow demand response to be bid into the market provide interesting insights into the VCR. In markets such as the MISO and the Netherlands, demand-side resources can set the market price during times of shortage and as a result essentially reveal the value of outages to marginal consumers. Importantly, the market price caps in these markets are set at a level that has not been reached (to date), suggesting the current price cap is above the underlying VCR. On the other hand, while the price in the PJM energy market is essentially set with reference to demand response behaviour, we understand that both the current and future market price caps may not be sufficiently high so as to ensure that sufficient demand response is bid into the market to balance the market during periods of high demand.

Importantly, any market revelations regarding the VCR gleaned from the observed price in such markets depends on how representative the demand-side activity is of the overall customer base. For example, if only large industrial customers are active in providing demand response in the market then the observed market price may not reflect the underlying value that residential customers place on having reliable electricity supply. The extent of competition in the market for demand-side resources (eg, the demand aggregators market) will also affect the extent that observed market prices actually reflect the underlying VCR.

Emerging demand response mechanisms might therefore provide useful insights on the VCR of a market into the future.

Appendix A. Correspondence with local organisations

Table A.1 below outlines the correspondence we had with local organisations in each of the jurisdictions included in this report.

Table A.1
Correspondence with local organisations

Organisation	Local Contact	Correspondence
PJM, United States	Executive Vice President, Markets	Phone interview conducted 2 September 2013
AESO, Canada	Kevin Dawson, Director of Market Design	Phone interview conducted 4 September 2013
Ofgem, United Kingdom	Rachel Fletcher, Interim Senior Partner, Markets	Phone interview conducted 4 September 2013
Electricity Authority, New Zealand	Tim Street, Manager Wholesale Markets, Greg Williams, Senior Adviser Wholesale, Markets	Phone interview conducted 6 September 2013
ERCOT, United States	Ken McIntyre, Vice President Grid Planning and Operations Brad Jones, Vice President Commercial Operations	Phone interview conducted 13 September 2013

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