Retail price review
A report for the Department of Environment, Land, Water and Planning

Final report

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Jacobs Australia Pty Limited
Floor 11, 452 Flinders Street
Melbourne VIC 3000
PO Box 312, Flinders Lane
Melbourne VIC 8009 Australia
T +61 3 8668 3000
F +61 3 8668 3001
www.jacobs.com

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Disclaimer

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### Definitions used in this report

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<td>Large retailers</td>
<td>AGL, Origin Energy and Energy Australia; defined on basis of residential market share in Victoria</td>
</tr>
<tr>
<td>Medium retailers</td>
<td>Red Energy, Lumo, Simply Energy and Momentum; defined on basis of residential market share in Victoria</td>
</tr>
<tr>
<td>Small retailers</td>
<td>All other retailers operating in Victoria and not defined as medium or large retailers</td>
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<td>Residential low usage customer</td>
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<td>Residential medium usage customer</td>
<td>4,000 kWh per annum</td>
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<td>Residential large usage customer</td>
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Executive Summary

An independent retail market review panel (the Panel), supported by The Department of Environment, Land, Water and Planning (DELWP), is examining the operation of the Victorian electricity and gas retail markets to better understand the key drivers underlying increasing retail electricity and gas prices. The aim of the review is to determine whether the electricity and gas retail markets are operating in the interests of consumers, whether there are potential constraints on competitiveness, and to provide options that would improve outcomes for consumers. The scope of the review is restricted to the mass market sector which includes residential and small business customers.

Jacobs’ role in the review has been to assist the Panel in undertaking economic and retail market analysis to inform the review, and also to provide analysis and advice in relation to retail pricing, margins and outcomes for consumers. Jacobs has undertaken research on the wholesale and market costs associated with gas and electricity supply and participated in discussions with retailers led by the Panel, with various outputs of the study feeding into further work undertaken by another consultant for DELWP.

The electricity market cost analysis work underpins longer term analysis of gross margins from Victorian mass market customer retail electricity sales. This margin analysis incorporates the following over an evaluation period from 2009 through to 2017:

- Evaluation of the range of price offers for low usage (2,000 kWh p.a.), medium usage (4,000 kWh p.a.) and high usage (6,000 kWh p.a.) residential electricity customers as well as small business (10,000 kWh p.a.) electricity customers and how these margins differ for large retailers (AGL, Origin Energy and Energy Australia), medium retailers (Lumo and Red Energy, Simply Energy and Momentum) and small retailers (all others).
- Evaluation of the gross retail margins (i.e. retailer’s own costs plus profit) for each customer category and how these margins differ by retailer type.
- Review of trends in retail and network fixed charges and how these have changed over time
- Consideration of historical trends in retailer’s own costs for benchmarking purposes
- Analysis in nominal terms unless specifically mentioned otherwise

The report also provides an overview of the retail market. The report details historical movement in electricity cost of supply, including wholesale and environmental costs which are incurred under market arrangements, and network and metering charges which are regulated. Together, each of these pieces of work supports findings around retail margins and changing retail prices that are the focus of this report.

Overviews of cost stack and average retail prices

Figure 1 overleaf is a key output of the report, because it provides a visual description of how historical costs of supply have built up to form the basis of electricity pricing. Approaches to calculating the costs and prices in the chart are carefully detailed in Part II. The chart reveals how these costs vary for low usage and a medium usage residential customer. In particular:

- Network charges are the largest cost component and are regulated.
- Metering charges formed the fastest growing cost component because of the mandated Advanced Metering Infrastructure (AMI) program. In 2015 this program was no longer mandated and considered to be fully rolled out, leading to a reduction in this charge.
- Wholesale costs have been variable over the time frame, largely due to variations in the supply and demand balance. In 2007 the supply and demand balance was tight because of drought leading to reduced output from hydro-electric plant and because many consumers were increasing use of air-conditioning which increased peak demand. From 2010 the supply and demand balance has widened because of falls in demand including departure of large industries and increased energy efficiency across the market. Larger costs were also evident in 2012/13 and 2013/14 due to the carbon scheme, imposing additional costs on emission intensive generation plant.
• Wholesale costs in 2014 were difficult to adequately assess because of low liquidity in the trading market (following repeal of the carbon scheme) and therefore estimates of wholesale cost in 2014 must be considered with this in mind.

• Average standing offers are overlaid on the chart, and the gap between the total costs and the standing offers are indicative of the level of gross margin that retailers could earn. The chart illustrates a widening gap between costs and retailer standing offers.

Figure 1  Overview of costs of electricity supply – average Victorian energy customer, 4000 kWh pa (excludes retailer own costs)

Figure 2 displays the fixed component of retailer offers for an average Victorian residential customer and Figure 3 presents the difference between the retail and network fixed charges. Both retail and network fixed charges (including metering costs) have exhibited steady growth to 2015. From 2015 fixed charges have remained reasonably steady through to 2017, while network fixed charges have fallen. The variation in fixed charges across all retailers has also increased over time. Figure 3 indicates that for residential customers, fixed charges have grown between 2009 and 2017 by around $148 per customer on average.

1 Two key types of retail offers are discussed in this report – market offers and standing offers. Standing offers are usually used by customers who have not explicitly selected a retailer, and these offers represent the maximum price that a consumer is going to pay. These offers are usually more expensive than market offers which are applicable to the majority of consumers. Market offers are lower in cost and are more competitive to entice customers to purchase their energy from a given supplier. This arrangement enables retailers to contract electricity for their customers and provides some ability to match load to supply.
Gross margin analysis

Gross margins based on standing offers across 3 residential customer usage categories were reviewed. The analysis determined that gross margins based on standing offers for an average usage customer have increased by $328 in nominal terms since deregulation in 2009. However, there exists wide variation in this increase, with cheapest offers to the most expensive offers displaying increases of $178 to $443/medium usage customer. Low usage customer charges increased by $146 on average and high usage customer charges increased by $331 on average over the same period.

Jacobs also compared the results for retailers that hedge one year ahead versus two years ahead, but found little overall difference. However, those that hedge two years ahead seem to be able to manage market fluctuations better (in terms of more stability in costs). For example, the Hazelwood retirement announcement
caused increases in hedge prices quite early on and such retailers would have been better protected from this event.

Review of standing offers demonstrated increasing dispersion in pricing over time. This may be indicative of heavy discounting to support customer acquisition activities while at the same time increasing rates on other customer segments and creating internal market cross subsidies. Based on international experience, this practice is unlikely to improve with additional new market entry and instead could be exacerbated by it (refer to Appendix B).

**Retailer cost benchmarking**

To provide an indication of the level of retailer costs, Jacobs undertook a desktop review of regulated retailer cost-to-serve across Australia in those jurisdictions where regulated pricing applied. The retail costs discovered in that review were compared against AGL and Origin2 reported retail cost-to-serve values (including the cost of customer acquisition and retention). This review indicated that an increasing trend in retailer costs was evident. From 2009, average regulated retailer cost allowances rose by around $47/customer.

A significant part of retailer cost is the cost of customer acquisition. Regulators have typically estimated values of around $40 per existing customer to account for customer acquisition. For comparison, Jacobs also reviewed cost of acquisition information in the AGL and Origin annual reports. Origin have reported ‘cost to grow’ around the range of $22 to $29 per existing customer account between 2011 and 2016, while AGL report cost of acquisition and retention around the range of $35 to $40 per customer account between 2013 and 2016. While these numbers apply to the whole of Australia rather than specifically to Victoria, they imply some direct cost benefit to being a large and/or an incumbent retailer, and that large retailers probably pay less than half the cost of acquisition paid by smaller retailers. From the costs discussed, a gap ranging between $16 and $70 per customer could be inferred as the average incremental cost of acquisition and retention faced by new entrant retailers. It would be reasonable to expect that retailer costs would grow to incorporate the average additional cost of churn, should new market entrants increasingly take market share.

**Conclusions**

The analysis confirmed that fixed charges incorporated into retailer tariffs in Victoria have increased beyond the levels attributable to increasing network fixed charges, with the average increase being around $148 per customer over the period 2009 and 2017.

Retailer gross margins based on average standing offers have also increased by around $328 for a medium usage customer, $146 for a low usage customer and $321 for a high usage customer.

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2 Being Australian listed public companies

3 Some of the regulated costs (Vic/Tas 2007, Tas/NSW/ACT/QLd 2010, ACT 2012, ACT 2015, Tas 2016) did not include cost of customer acquisition. To make the series internally consistent, an assumed customer acquisition cost of $30/customer (spread over entire customer base) was added to these values. This value was derived from the research in Appendix E.
1. **Introduction**

Energy consumers have borne continuing price increases in recent years, with electricity prices most recently increasing of the order of 5 to 24% over the first quarter of 2017. An independent retail market review panel (the Panel), supported by The Department of Environment, Land, Water and Planning (DELWP), is examining the operation of the Victorian electricity and gas retail markets to better understand the key drivers underlying retail pricing and the reasons behind such price increases. The aim of the review is to understand retail costs and margins and determine whether the electricity and gas retail markets are operating in the interests of consumers. The review also seeks to assess the competitiveness of the electricity and gas retail markets and whether there are potential constraints on competitiveness, and provide options that would improve outcomes for consumers. A supplementary objective is to assess whether recent electricity retail price increases truly reflect the market conditions caused by the closure of Hazelwood Power Station. The scope of the review is restricted to the mass market sector which includes residential and small business customers.

Jacobs’ role in the review has been to assist the Panel in undertaking economic and retail market analysis to inform the review, and also to provide analysis and advice in relation to retail pricing, cost of supply and standing offer and margin outcomes for consumers. Jacobs’ has undertaken research on the wholesale and market costs associated with electricity and gas supply and participated in discussions with retailers led by the Panel.

The cost analysis work underpins longer term analysis of Victorian mass market customer retail electricity gross margins. This margin analysis incorporates the following over an evaluation period extending from 2006 through to 2017:

- Evaluation of the range of price offers for low usage (2,000 kWh p.a.), medium usage (4,000 kWh p.a.) and high usage (6,000 kWh p.a.) residential electricity customers as well as small business (10,000 kWh p.a.) electricity customers and how these margins differ for large retailers (AGL, Origin Energy and Energy Australia), medium retailers (Lumo and Red Energy, Simply Energy and Momentum) and small retailers (all others). We also include a review of movement in fixed charges and incorporate consideration of how incumbent retailers price energy in their own areas compared with other non-incumbent retailers. This section describes the methodology used to aggregate and quantify offers.
- Evaluation of the gross retail margins for each customer category and how these margins differ for large, medium and small retailers (section 3.5).
- Review of trends in retail and network fixed charges and how these have changed over time
- Consideration of historical trends in retailer cost of supply for benchmarking purposes

Specific areas of research covered in this report are included in Part I of the work:

- An overview of the characteristics of the electricity and gas retail markets, including customer engagement and market structure (see section 2)
- A summary of outcomes from panel interviews with retailers (see section 3.1)
- A summary of average trends in costs for Victorian consumers (see section 3)
- Analysis of gross margins using an evidence based approach (see section 3.5)
- Overview of retailer cost to serve, and cost of customer acquisition and retention (see section 4)

Part II of the work covers trends in retailer cost of supply:

- Network and metering cost trends (see section 6)
Final report

- Analysis of wholesale electricity and gas market costs, using information available regarding key drivers of costs, market structure, market policies, regulation and retailer pricing practices, and including comparison of Victorian electricity market cost to costs in NSW, South Australia and Queensland (see sections 7 to 8)
- A wholesale market study to support analysis around the impact of the Hazelwood closure on electricity retail prices (included in section 7.2)
- Analysis of environmental costs (section 9)

Additional resources are included in the appendices, including:
- A high level literature review of retail market issues including vertical integration and competition (see the literature reviews in Appendix A and Appendix B)
- Assumptions and methods covering wholesale and gas market research (Appendix C and Appendix D respectively)
- Desktop research on retailer costs based on regulator reports (Appendix E)
- Network area specific results – offers (Appendix F)
- Network area specific results – gross margins (Appendix G)

All retail costs described in this report are in nominal Australian dollars unless otherwise stated.
Part 1: Retail market overview and findings
2. Retail market overview

2.1 Victorian retail energy market

Figure 4 provides an overview of retailer customer share in the Victorian electricity market. The electricity retail sector in Australia is presently dominated by three firms – AGL, Origin Energy and Energy Australia Australia (also known as the ‘Big 3’). However, Red and Lumo (who are both owned by Snowy Hydro), and to a lesser extent Simply Energy, have each made significant increases in market share in Victoria, potentially transforming the retail market to a ‘Big 5’.

The largest retail electricity firms have the largest market shares and also are able to generate all or a significant part of their customers’ load, making them substantially vertically-integrated suppliers. Vertical integration can provide competitive advantages to the supplier in the form of reduced transaction costs and market risk, as well as improved economies of scale (refer to Appendix A for a description of benefits attributable to vertical integration).

The ‘Big 3’ in particular have also built up significant customer intelligence resulting from having been incumbent retailers in their historical franchise areas at the time of market deregulation (in Victoria the consumer market became competitive in 2002). They have been operating in the market for an extensive period of time, invested heavily in marketing and have built up recognizable brands.

Figure 5 displays the evolution of market share changes across the various retailers. In general, the share of the Big 3 has declined as a group and has been displaced by newer market players who also appear to have absorbed growth in the market.
Figure 5  Changing Victorian electricity market shares


Figure 6 provides an overview of existing retailer market share for gas customers. The same ‘Big 5’ retailers also dominate gas mass-market supply.

Figure 6  Retail market shares


2.2 National retailer energy market

Retailer market share by State provides an indication of each retailer’s key areas of focus. In combination, the Big 3 retailers have 60% of small electricity customers in Queensland, more than 90% in NSW, more than 60% in Victoria and nearly 80% in South Australia - approximately 70% of all small customers nationally, as shown in Figure 7. Snowy Hydro and Simply Energy have increased their market shares most strongly in Victoria and South Australia, now together reaching nearly 25% of the Victorian market and nearly 15% of the South Australian market. For sale of gas, the story is similar with the Big 3 dominating gas retail in almost every state except Victoria and South Australia where Snowy Hydro and Simply Energy have also increased market share. In combination, Snowy Hydro and Simply Energy have reached more than 20% of small gas customers in Victoria and nearly 10% of customers in South Australia.

Jacobs has calculated provisional estimates of market share by major retailer for each customer class in the NEM (excluding Tasmania). Of all the major retailers, AGL has grown substantially over the last ten years, and is now Australia’s largest integrated generator and retailer. AGL’s 2016 report stated that generation is actually greater than total consumption (i.e. AGL is now a net generator). Origin is the second largest integrated retailer, especially in NSW and Queensland where its load share dominates all other retailers. However Origin’s 2015/16 annual report indicates that its ownership of generation is not as substantial as that held by AGL, and therefore must, on a net basis, contract for supply of generation from other parties.

The information about Energy Australia is less substantive, as there are few published records of their retail load. The estimates provided in the chart below are partially based on a total load estimates as output from a 2012 report and from estimating mass market load from customer shares. Generation shown is based on AEMO generation data for 2015/16.

Figure 7 Customer market share by retailer

Source: 2015 State of the Energy Market, AER.
https://www.aer.gov.au/system/files/State\%20of\%20the\%20energy\%20market\%202015\%20%28A4%20format%29%20E2%80%93%20last%20updated%20February%202016.pdf

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6 Publicly available information on market share is very difficult to come by as retailers are not obliged to publish their sales data by customer class, and information from other sources can be disparate and difficult to consolidate. As a result SKM cannot validate the accuracy of the estimates, and annotate our work with information on estimation approach, source and potential data consistency issues as these imply a reasonable approach has been undertaken.

2.3 Generation capacity by retailer

Jacobs maintains a database of existing and potential Australian generation, including ownership. Where possible our data was cross-referenced against information found in AEMO and other public reports. Estimated retailer-owned generation capacity for the Big 5 retailers is shown in Figure 8, with totals across the four retailers at 10,306 MW for AGL, 3,200 MW for Energy Australia, 5,386 MW for Origin, 4,350 MW for Snowy Hydro and 1,404 MW for Simply Energy (excludes Hazelwood) respectively. Origin has most of their available capacity in NSW. AGL tends to have most of its generation capacity in Victoria, while Energy Australia tends to have most of its generation capacity in NSW and Victoria. The locations of sources of generation and loads are not required to be exactly matched by State because the presence of regional interconnectors allows generation to travel between States up to inter-regional capacity constraints.

Figure 8 Estimated retailer generation capacity, 2016

Source: Jacobs' analysis of AEMO capacity data, corresponding to 2016

AGL has announced that they are committed to not extending the operating lives of their existing coal-fired assets. This means that these plants may be retired at the age of 50 years\(^8\). Within the timeframe under consideration, Liddell will be decommissioned in 2022, and beyond the timeframe, Bayswater and Loy Yang A will cease operation in the 2030s and 2040s. The retirement of nearly 1,927 MW of coal fired capacity (Liddell) in 2022 would require a number of new generation projects in place to adequately replace the generation output of Liddell, and market responses should be carefully monitored around likely unit retirement periods.

2.4 Retailer net position analysis

Figure 9 shows estimated load and generation from 2015/16 for the big 5 retailers, based on customer numbers, AEMO generation, and AGL and Origin annual reports. Of all the retailers only AGL and Simply Energy (owned by Engie) are net generators; i.e. they have more generation capability than retail load. The decommissioning of Hazelwood and potential sale of Loy Yang B is likely to alter this situation for Simply Energy if they are able to continue growing their market share as they have done in recent years. For the moment, only these two retailers would appear to be able to fully supply their customers without reliance on net contracts with other parties, noting that the nature of supply (with respect to mix of baseload, peaking and intermittent plant) will impact on each company's ability to supply in all time periods.

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\(^8\) "Carbon Constrained Future: AGL's approach to climate change mitigation: a scenario analysis", AGL 2016
Origin and Energy Australia appear to have a net retailing position and are therefore partially reliant on hedging relationships with other parties to provide supply for their customers.

The net position analysis provides background data about the availability of supply contracts to retailers. It does not illustrate the complexities associated with matching supply and demand profiles. For example, a retailer with a large proportion of peaking generation capacity (as Origin has – around 35% of its capacity is in gas fired peaking units) may have a greater ability to manage high price events than other retailers, and less of an ability to manage low cost base load. AGL and Energy Australia by contrast have a much lower share of gas fired peaking capacity (at around 4% and 5% respectively), potentially requiring greater levels of price risk management requiring mitigation from vertically integrated supply. Simply Energy has a 21% share of gas fired peaking capacity, but this will increase to 57% if Loy Yang B is sold, leaving the remainder of generation intermediate gas fired capacity.

Figure 9  Consumption versus generation for AGL, Origin, Energy Australia and Simply Energy, 2015/16

Source: NEFR 2016, AGL and Origin 2016 Annual reports, AER State of the market report 2016, AEMO generation records. Simply Energy generation includes Willogoleche wind farm, which is at this stage proposed. Chart prepared prior to Hazelwood closure, providing a picture of retail net position over recent history.

2.5 Customer engagement

This section describes the present level of engagement between mass market customers and retailers. In a number of past studies, effective competition has been gauged by the rate of churn occurring in the market; that is, the propensity for consumers to switch. However, the market is more complex than that; the market includes consumers who will happily switch to get the best deal, but also includes consumers who are averse to switching, and this section explores why this may be the case.

Reasons given by consumers for switching or remaining with their retailer have been summarised in Table 1, as determined in the 2014 survey undertaken by Newgate Research for the AEMC. The table shows that price is a major reason for switching for those that do switch (see green shaded areas - around 56% of business customers and 67% of residential customers switched to get a better price) whereas price does not materially impact on retention if the consumer is happy with their current retailer and/or is too busy or uninformed to consider switching.

Retailers who can cheaply acquire customers are better able to keep costs down for their entire customer base, while those who can’t may increase operating costs and make it more difficult to remain competitive. Larger retailers might put more effort into advertising and brand, and this may also assist with customer retention and acquiring new customers at lower cost. Economies of scale associated with investment in billing and service
systems may also reduce cost to serve customers. Potentially the cost-to-serve (customers) reported by the largest 3 retailers could provide a lower bound on the cost of service.

Table 1  Summary of reasons customers gave for switching or not switching

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<tr>
<th>Reasons customers did not switch</th>
<th>Reasons customers did switch</th>
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<tr>
<td>Happy with current retailer and arrangements 32%</td>
<td>Wanted a cheaper price 37%</td>
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<td>Too busy/not enough time 22%</td>
<td>Was offered a discount or better price 19% business, 30% residential</td>
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<td>Too much hassle 18%</td>
<td>Moved house 13%</td>
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<td>Would not make a real difference in price 9%</td>
<td>Wanted gas and electricity with the same company 8%</td>
</tr>
<tr>
<td>Feeling pressured by energy companies 8%&lt;sup&gt;9&lt;/sup&gt;</td>
<td>Unhappy with customer service 7% residential and 10% business</td>
</tr>
</tbody>
</table>

Source: AEMC Consumer research for nationwide review of competition in retail energy markets, June 2014, Newgate research

2.6  Retailer cost of supply

Retailer costs of supply include a variety of cost components including:

- Wholesale electricity market costs. See section 3.
- Network service provider costs (these costs are regulated and passed through to consumers as they change). These costs include metering charges. See section 6.
- Wholesale gas market costs. See section 8.
- Costs associated with government environmental policies. These include the cost of the Large Scale Renewable Energy Target (LRET), the cost of the Small Scale Renewable Energy Target (SRET), minimum required feed-in tariffs (FITs) for solar generation and the cost of energy efficiency policies which may be state specific. In Victoria, the Victorian Energy Efficiency Target (VEET) dictates energy efficiency policy cost. In other states, the energy efficiency policies include the NSW Energy Savings Scheme (ESS), the ACT Energy Efficiency Incentive Scheme (EEIS) and the South Australian Residential Energy Efficiency Scheme (REES). See section 9.
- Australian Energy Market Operator (AEMO) market charges and ancillary service charges. See section 7.4.
- Retailer operating costs, including cost of billing, customer service, marketing, and energy procurement costs. See section Appendix E.

<sup>9</sup> Victorian consumer responses in this category were significantly higher than the NEM average
3. Overview of trends in retailer costs and offers

3.1 Outcome of Retailer interviews

The review panelists, Jacobs and DELWP undertook a series of interviews with selected retailers to further inform the review. Retailers interviewed included AGL, Origin, Energy Australia, Powershop, ERM, Red/Lumo, Momentum and Simply Energy. The contents of individual interviews are confidential, but influenced the analysis in the following ways:

- Jacobs has used a conservative, evidence based approach to objectively estimating costs in our margin analysis.
- In the development of wholesale market cost estimates, and in order to employ an evidence based approach, Jacobs:
  - Utilised the value of quarterly and annual peak and cap contracts as part of our estimate of wholesale market cost, using as granular contract data as is publically available, including quarterly peak and flat contract prices as well as calendar year prices.
  - Utilised net system load profile data as well as smart meter data from the AEMO website to assess the value of wholesale energy for mass market customers, including the impact of changing profiles over time.
  - Assumed retailers would be fully hedged.
- Jacobs has undertaken modelling of the electricity market to separate the impact of the Hazelwood closure from increasing gas prices.
- In the development of retailer cost estimates, Jacobs considered the following:
  - The role and responsibilities of retailers is diverse and has expanded over time. The relationship between operating cost and service level is complex.
  - Retailers with a high share of customers with bad debts will face higher costs than others.
  - Because most retailers were unwilling to share their costs with the Panel, alternative sources of cost data were needed. Sources of this data are sparse and generally only available from regulator reviews. As many forms of cost data in these reviewed have been shared across multiple reviews it is difficult to determine with any level of accuracy what the true status of retailer cost is and how these might vary for small, medium and large retailers.
  - It is likely to be difficult to quantify cost to serve adequately as this is variable across type of retailer. Regulated costs are used for benchmarking purposes only.
  - It is likely to be difficult to quantify cost to acquire customers adequately as this is variable across type of retailer. Large retailers with a significant customer base are likely to face lower costs of retaining customers when compared to the cost of acquiring a new customer.
  - Increasing churn rates will impact on profitability of all retailers and may be a cause of price increases to loyal consumers who do not frequently switch retailers.
- A conservative approach to cost estimation is required with respect to contracting load as well as certificates for environmental programs such as the RET and the VEET. Under these programs, retailers can theoretically claim certificates below the market value if they engage in long term hedging. However, if load being matched against certificate requirements for these programs is not secure, retailers will not have the ability to hedge well in advance or secure projects with capital risk. This means that retailers may not be able to apply their sharpest deals to consumers who can easily walk away compared to business customers with fixed term contracts and higher penalty fees for switching before the end of contract expiry.
- Retail offers are presently subject to change for a multitude of reasons, and certainty of these offers with a low exit fee for residential consumers is generally unrealistic. Jacobs' wholesale cost projections recognise that this aspect of the market is difficult if not impossible to monitor. Our approach has been to assume a consistent arrangement where retailer offers reasonably include the cost of hedge contracts a year in
advance of the time the offer has been made. It is recognised that this may be a conservative assumption because some retailers may only include a portion of the future year’s costs in their offers.

3.2 Evaluation of retailer costs and prices

Our approach throughout this project has been to apply an evidence-based approach for estimating and comparing retailer costs and charges. This section describes how the costs described in greater detail later in this report look when stacked up so that readers will appreciate the impact of each charge over time. Figure 10 describes the overall cost impacts for the average Victorian residential consumer using 2,000 kWh per annum and 4,000 kWh per annum respectively (chosen because they represent a typical small and average consumer), excluding retailer own costs.

The chart reveals that the biggest cost element is network charges in both instances. The impact of changes to network prices has had considerable impact on overall cost for both consumers. Some observations include:

- Network charges have remained relatively constant to 2010/11, after which time charges increased at a quicker pace to 2014/15. From 2015/16 charges have reverted to very low growth consistent with growth in inflation.
- The cost element displaying fastest growth over the period was metering charges, largely because of the mandated Advanced Metering Infrastructure (AMI) program. For small consumers this charge approximated the cost of wholesale power over a large number of years. In 2015 this program was no longer mandated and considered to be fully rolled out, leading to reduction in this charge.
- For small consumers the reduction in metering charges in 2015 has been offset by increased wholesale costs.
- For medium consumers the increase in wholesale costs has more than offset any reduction in metering charges.
- Wholesale costs have been variable over the time frame, largely due to variations in the supply and demand balance. In 2007 the supply and demand balance was tight because of drought leading to reduced output from hydro-electric plant and because many consumers were increasing use of air-conditioning which increased peak demand. From 2010 the supply and demand balance has widened because of falls in demand including departure of large industries and increased energy efficiency across many market sectors. Larger costs were also evident in 2012/13 and 2013/14 due to the carbon scheme which imposed additional costs on emission intensive generation plant.
- Overall, the cost of supplying 4,000 kWh pa consumers is not double the cost of supplying 2,000 kWh pa consumers, mainly because network charges include a fixed charge element so only part of the fee would be expected to increase with higher volume of electricity use. Retailer own costs (such as billing, customer retention and acquisition, marketing and customer relations) would also not vary with usage and is expected to be fixed on a per customer basis.
- Average standing offers are overlaid on Figure 10, and the gap between the total costs and standing offers indicates the level of gross margin that retailers could potentially earn. The chart illustrates a widening gap between costs and retailer offers. We note that there is some missing data for standing offers in 2014 so it is not possible to come to any clear conclusions about standing offers in this period.
- The gap between average retail offer and retailer cost is highest in 2014, the year in which the carbon price was repealed on 30th of June. A post analysis adjustment was applied to the retail offer data in this year to account for retailer credits that will have been provided to customers to back out carbon impost on consumers. Nevertheless, the gap remains high and other factors that may have contributed to the larger gap in this year include change in retailer hedging strategy and increasing retailer costs (noting there was a spike in churn rates in June 2014 and there was low market liquidity in hedge contracts during this period).

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10 Network charges for the average Victorian customer were based on a customer number weighted average of charges for each of the five networks.
11 Note that gross margin is not included as a cost element.
12 Standing offers were averaged in each month of availability by retailer and network area. A weighted average of these was taken using customer numbers for each network area and market share for each retailer.
This carbon repeal adjustment was based on data included in the October 2014 ACCC monitoring report\textsuperscript{13}, so that \$28/MWh was deducted from offers for the 12 months following June 2014 to allow for credits on consumer bills resulting from the repeal of the carbon scheme.

Figure 10  Overview of costs of electricity supply – average Victorian energy customer (excludes retailer own costs)

<table>
<thead>
<tr>
<th>Customer using 2,000 kWh pa</th>
<th>Customer using 4,000 kWh pa</th>
</tr>
</thead>
</table>

Source: Jacobs’ analysis.

3.3  Retail standing offers

This section provides a more detailed overview on how retail offers were derived and calculated and how they have changed for the average Victorian Consumer. Further detail about change of offers by distribution area is provided in Appendix F.

Retail offers were provided from the Victorian Energy Compare website from 2014 onwards and from the Essential Services Commission prior to this period. Two key types of retail offers are available – market offers and standing offers. Standing offers are usually used by customers who have not explicitly selected a retailer. For example, those who have moved house and have not yet selected a new retailer will be placed on a standing offer. These offers are usually more expensive than market offers which are applicable to the majority of consumers. Market offers are lower in cost and are more competitive to entice customers to purchase their energy from a given supplier. This arrangement enables retailers to contract electricity for their customers and provides some ability to match load to supply\textsuperscript{14}. Review was only undertaken on the standing offers as these are indicative of the highest price increases to consumers.

\textsuperscript{13} Report to the Minister under s 95ZE of the Competition and Consumer Act 2010: Monitoring of prices, costs and profits to assess the general effect of the carbon tax scheme in Australia, October 2014.  

\textsuperscript{14} Retailers are better able to forecast load for contracted customers than uncontracted customers (for example, those who might switch retailers straight after moving into a new premises or months later and providing no certainty about how long they wish to maintain supply).
A number of offers may be applicable to a given retailer for a period of time. For example, a retailer may offer a single rate\(^{15}\), dual rate\(^{16}\) or time of use\(^{17}\) or demand\(^{18}\) rate for a given period of time. Only single rate offers were compared, and where more than one offer is put out by a retailer for a given month, they have been averaged for the purpose of summarising results. Jacobs’ has assumed that only single rate network charges apply and that the offer applies for the next twelve months.

Since deregulation in 2009, standing offers have grown by 7.4% per annum for standing offers across all retailers and distribution areas\(^{19}\). Average growth in electricity prices by consumer category are provided in Table 2.

Jacobs’ analysis of standing offers was undertaken by comparing small, medium and large retailers (allocated on the basis of market share in Victoria rather than on generation capacity). Offers were assumed to run for a year ahead, and any offers which were based on rate fixing (say, for two years) were excluded to avoid overstating margins in our calculations.

Table 2 Average electricity retail price growth rate, standing offers, 2006 to 2017, % p.a.

<table>
<thead>
<tr>
<th>Customer area</th>
<th>Residential consumer: 2,000 kWh per annum</th>
<th>Residential consumer: 4,000 kWh per annum</th>
<th>Residential consumer: 6,000 kWh per annum</th>
<th>Business consumer: 10,000 kWh per annum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Citipower</td>
<td>7.5%</td>
<td>7.1%</td>
<td>6.8%</td>
<td>2.6%</td>
</tr>
<tr>
<td>Jemena</td>
<td>8.2%</td>
<td>7.3%</td>
<td>7.0%</td>
<td>1.9%</td>
</tr>
<tr>
<td>Powercor</td>
<td>7.6%</td>
<td>6.8%</td>
<td>6.6%</td>
<td>0.6%</td>
</tr>
<tr>
<td>Ausnet services</td>
<td>9.9%</td>
<td>8.7%</td>
<td>8.8%</td>
<td>1.5%</td>
</tr>
<tr>
<td>United Energy</td>
<td>7.6%</td>
<td>7.0%</td>
<td>6.7%</td>
<td>1.3%</td>
</tr>
</tbody>
</table>

Source: Jacobs’ analysis of ESC and Victorian Energy Compare retailer electricity offers

3.4 Trends in fixed costs

The methodology for estimating fixed costs is based on averaging fixed charge in retailer standing offers for each month in the evaluation period. Figure 11 and Figure 13 displays the fixed cost part of retailer offers for a medium usage Victorian residential customer and business customer respectively. Figure 12 displays the difference between the average retail offer fixed charges and the network fixed charges.

For residential customers, annual fixed charges in nominal terms steadily rose from 2009 to 2015, remaining largely constant thereafter. While the growth is largely explained by network tariffs, the differential has consistently grown between 2010 and today, as shown in Figure 11, even in the presence of falling metering costs from 2016. The chart indicates that consumers on standing offers presently are paying around $467 per year to electricity retailers on average on fixed charges, and around $166 of this amount goes to networks.

The range of retailer fixed charges has also widened over the period. At present, some retailers may provide lower fixed retailer charges of $174 per customer above network fixed charges, while others may charge $429 per customer above network fixed charges.

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\(^{15}\) Single rate offers mean that consumers pay a fixed rate for electricity regardless of when it is consumed.

\(^{16}\) Dual rate offers mean that consumers pay a different fixed rate in peak time periods to off-peak time periods, where peak time periods occur between 7am and 11pm on weekdays and off-peak time periods occur at all other times.

\(^{17}\) Time of use offers mean that consumers pay a different fixed rate in peak, off-peak and shoulder time periods. The timing of peak, shoulder and off-peak time periods will depend on the specific tariff chosen.

\(^{18}\) Demand tariffs will include a demand rate in addition to one or more volume based rates. A demand rate applies to the maximum energy demand incurred by a given customer over a billing period. A number of variations exist around how these apply.

\(^{19}\) Assuming average load of 4,000 kWh per annum for a residential customer

\(^{20}\) Average estimated from 2013 as no offer data available prior to this date
Figure 11  Fixed Retail Charges vs Fixed Network Charges (average Victorian customer, residential)

Figure 12  Fixed Retail Charges LESS Fixed Network Charges (average Victorian customer, residential)

Figure 12 indicates that for residential customers, the retailer component of fixed charges have grown by around $148 per customer since 2009 to 2017.

Figure 13 demonstrates that fixed charges and network charges for business customers have also increased throughout 2013 to 2017. The chart indicates that the differential between retailer and network fixed costs has grown from around $272 to around $358 per customer over the period. The dispersion of fixed costs for business customers has also increased.
Figure 13  Fixed Retail Charges vs Fixed Network Charges (average Victorian customer, business)

Figure 14 and Figure 15 display fixed charges by retailer category for residential and business customers respectively. While large retailers have historically charged the highest levels of fixed costs for residential customers (with minor exceptions), this no longer appears to be the case and there is no obvious relationship regarding retailer type and the level of fixed charges.

For business customers a shorter dataset is available, but the results indicate that larger retailers have generally charged lower fixed costs though this may be changing.

Figure 14  Trends in fixed cost by retailer category, average Victorian residential customer
3.5 Gross margin analysis

3.5.1 Residential

A fundamental aim of the review is to better understand retailer margins and costs. Using the assumptions outlined in this report, Jacobs has subtracted estimated costs from retailer standing offers to ascertain the likely range of maximum gross margins received by retailers in each distribution area and for various customer types.

Figure 16 displays the average gross retail margin for an average consumption Victorian residential customer. The chart indicates that small and medium sized retailers have had lower gross margins for much of the time period evaluated, and that up to mid-2012: gross margins have been broadly consistent at around $400 to $500 per customer. After this, the level of standing offers increases and gross margins of $800 per customer are typical at the end of the carbon pricing, reverting slowly to around $600 per customer by May 2017. In addition to the changing level of gross margin, the dispersion in gross margin also increases.

With respect to standing charges, there are no obvious differences between small, medium and large retailer gross margins, at least for an average usage customer. Figure 17 and Figure 18 provides a comparison for low usage customers consuming 2,000 kWh pa and high usage customers consuming 6,000 kWh pa respectively. These charts mirror the effects for the medium usage customer.
Figure 16  Gross retail margins (standing offers), Victorian average consumers: 4,000 kWh pa

Figure 17  Gross retail margins, Victorian average consumers: 2,000 kWh pa
Limitations of the gross margin evaluation approach include that a uniform wholesale price evaluation method has been used across the entire time frame, whereas retailers may have changed their approach to contracting over time. In particular, lesser certainty around cost of wholesale energy exists around the time of the carbon price (2013/14) because fewer trades were executed and there appeared to be undersupply of hedge contracts (see Figure 32 in section 7.1) possibly out of market uncertainty following the announced repeal of the carbon scheme.

Gross margins across 3 residential customer usage categories between 2009 and 2017 were reviewed. The analysis determined that gross margins for standing offers have increased by up to $328 for an average usage customer. However there exists wide variation in this increase, as demonstrated by Figure 19. The change in retailer fixed charges (i.e. exclusive of network fixed charges) is also included in the chart for comparison.
Figure 20 presents gross margin results for the average Victorian small business customer using 10,000 kWh pa. The results show that small and medium size retailer gross margins are consistently cheaper than large retailer’s gross margins. Over the period shown this difference is on average around $359 per customer for the medium sized retailers and $228 per customer for small sized retailers. While the chart shows that the trend has been declining, the dispersion of retail margins has also grown.

**Figure 20  Trends in retailer gross margin for average Victorian business customer - 10,000 kWh pa**

Jacobs also compared the results for retailers that hedge one year ahead or two years ahead, but found little overall difference. Those that hedge two years ahead seem to be able to manage market fluctuations better. For example, the Hazelwood retirement announcement caused increases in hedge prices quite early on and such retailers would have been better protected from this event. The success of any retailer’s hedging strategy will also depend on its ability to adequately forecast load.

For both the residential and business sectors, increasing dispersion in pricing is also evident, in that the gap between the cheapest and most expensive standing offers has grown wider over time.
4. **Retailer cost benchmarking**

To provide an indicative idea around the level of retailer costs, Jacobs undertook a desktop review of regulated retailer cost to serve across Australia and internationally. This is detailed in Appendix E. The retail costs discovered in that review were compared against AGL and Origin reported retail cost to serve (including the cost of customer acquisition and retention\(^{21}\)), and the results plotted in Figure 21 and tabled in Table 3.

Jacobs fitted a trend line through the data. Across the whole set of data, the costs noticeably shift upward.

**Figure 21** Comparison of regulated retailer costs overlaid with reported costs from AGL and Origin

![Graph showing comparison of regulated retailer costs with reported costs from AGL and Origin](image)

*Source: Jacobs’ analysis of regulator reports, AGL and Origin annual reports 2015/16; note all costs include cost of customer acquisition.*

**Table 3** Regulated retailer costs

<table>
<thead>
<tr>
<th></th>
<th>ACT</th>
<th>NSW</th>
<th>Qld</th>
<th>SA</th>
<th>Tas</th>
<th>Vic</th>
<th>WA</th>
</tr>
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<tbody>
<tr>
<td>2003</td>
<td>85</td>
<td></td>
<td></td>
<td>80</td>
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<td></td>
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<td>85</td>
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<tr>
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<td>115</td>
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<tr>
<td>2016</td>
<td>158</td>
<td></td>
<td>150</td>
<td>166</td>
<td>159</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Adjusted for consistency. See footnote below*

\(^{21}\) Some of the regulated costs (Vic/Tas 2008, WA 2009, Tas/NSW/ACT/Qld 2010, Qld 2011, ACT 2012, ACT 2016) did not include cost of customer acquisition. To make the series internally consistent, a conservative assumption of customer acquisition cost of $40/customer (spread over entire customer base) was added to these values. This value was derived from the research in Appendix E.


The reported costs from Origin overlaid on the chart are generally consistent with the range of costs shown, with the exception of 2013 and 2014. Origin’s cost increase in 2013 was the result of a large billing system transformation program following the acquisition of Integral Energy in NSW, and after this time these costs have been settling back down to lower levels consistent with average regulated costs. AGL costs are consistently low, but there is some uncertainty around whether these costs exclude some of the same items considered in the regulation determinations and in the Origin annual report.

From a benchmarking perspective, it would be reasonable to assume that the central trend line approximates the average cost of service (including customer acquisition) for large retailers. It is likely that this cost will be higher for smaller retailers because there may be a lack of economies of scale and because the cost of acquiring new customers will be higher.

Closer examination of the chart reveals that the higher costs apply to states and territories with smaller markets such as the ACT and Tasmania. Review of the Tasmanian data source reveals that these costs were intentionally allowed to be higher on the grounds that these markets do not have the same economies of scale as larger markets such as Victoria hold. With approximately 260,000 customers, the cost of serving Tasmanian customers should be approximately equivalent to the cost faced by a medium sized retailer, noting that high levels of competition and non-incumbency may increase the cost of customer acquisition above the levels implied in the chart.

From the above, we can infer that average costs rose by around $47/customer since deregulation in 2009. This amount is higher than the regulated cost of customer acquisition, notionally around $40/customer. A question around the ability of new entrant retailers to compete with larger retailers on an equivalent basis is often asked because new entrants may not have the same economies of scale as the larger retailers. Ernst and Young concluded that new entrant retailers in the NEM have been able to invest in systems that are not as complex as those of incumbents and improve on efficiency. They quote an Australian Power and Gas report which discusses the former retailer’s outsourcing of essential functions so that the average costs per customer are variable rather than fixed and that this strategy improves a retailer’s operating efficiency.

### 4.1 Cost of customer acquisition

The cost of acquiring new customers in most industries is notionally thought to be around 5 times more than the cost of retaining customers. There does not appear to be any evidence however that this is true in the energy space where customer loyalty may be less than in other industries because energy is seen as a commodity rather than a service.

The difference between the cost of retaining existing customers and acquiring new customers is very material to how a business can keep costs low, as is the average retention time for new customers. If customer acquisition costs are high and annual profits per customer are low, it may take years to make up the cost of new customer acquisition, and operating costs for all customers serviced by a retailer could increase rather than reduce. If the average time of retention is also low, it is possible that retailers may never make up the cost of acquisition.

The retail discussions that Jacobs’ participated in determined that retailers have a number of possible pathways to access new customers and these vary widely in cost. Significantly one of the more expensive pathways included brokerage services which obtain payments from retailers for each new customer win. Increasing use of more expensive pathways such as these could drive costs of service up and consequently retail prices. A number of medium and large retailers indicated that expensive acquisition pathways were not a significant part of their acquisition strategy.

Regulators have typically applied values around the $40 per customer mark for customer acquisition and retention, but these have been applied in areas other than Victoria where churn rates are not as high as here. Such figures are generally applied across the entire customer base, and therefore imply higher numbers in terms of the cost of acquiring one single new customer.

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24 Ernst and Young Retail Price Submission to the Tasmanian department of Treasury and finance, 2013
Churn rates since 2009 are displayed in Figure 22. As regulated cost of acquisition numbers tend to apply to other states with lower churn rates (say 12 to 20% pa if we assume that customers do not switch more than once per year), it is possible to infer that the cost of acquiring a new customer is between $200 and $330$^{25}$ per new customer, depending on each new entrant retailer’s ability to utilise low cost approaches to market.

In Victoria, the numbers imply that 27% of consumers have switched retailers in Victoria over the last year. Based on regulated allowances, this implies that the cost of switching adds around $54 to $90$^{26}$ to the cost of the average bill.

For comparison, Jacobs also reviewed cost of acquisition information in the AGL and Origin annual reports. Origin have reported ‘cost to grow’ around the range of $22 to $29 per customer account between 2011 and 2016, while AGL report cost of acquisition and retention around the range of $35 to $40 per customer account between 2013 and 2016. While these numbers apply to Australia rather than Victoria alone, they imply some direct cost benefit to being a large and/or an incumbent retailer, and that large retailers probably pay less than half the cost of acquisition paid by smaller retailers. From the costs discussed, a gap ranging between $16 and $70 per customer could be inferred as the average incremental cost of acquisition and retention faced by new entrant retailers. As new market entrants increasingly take market share, it would be reasonable to expect that retailer costs would grow to incorporate this additional cost.

In general consumers benefit if costs can be kept low. High levels of switching may not evenly impact all consumers, and new entrant retailers are likely to pay higher customer acquisition costs than incumbent retailers. The high cost of acquiring new customers will generally be paid for by other customers, and these customers are likely to include those least able to recognise that they need to renegotiate their electricity supply arrangements.

Figure 22  Churn rates

$^{25}$Calculated as $40$ divided by the annual churn rate  
$^{26}$Calculated as $330$ multiplied by Victoria’s annual churn rate of 27%
5. Conclusions

The analysis confirmed that fixed charges incorporated into retailer tariffs in Victoria have increased beyond the levels attributable to increasing network fixed charges, with the average increase being around $148 per customer over the period 2009 and 2017.

Retailer gross margins based on standing offers have also increased by around $328 for an average usage customer, $146 for a low usage customer and $321 for a high usage.
Part 2: Methodology for estimating retailer cost of supply
6. Network and metering charges

Network and metering charges together form the largest costs incurred by a retailer to supply electricity. The five Distribution Network Service Providers (DNSPs) and one Transmission Network Service Provider (TNSP) in Victoria are required to submit an annual pricing proposal to the Australian Energy Regulator (AER) detailing the prices proposed for the upcoming regulatory year. These prices are reviewed by the AER to ensure that they conform to the National Electricity Rules (NER) and are consistent with their energy forecasts and regulatory determination. The prices typically are a combination of a fixed charge and a volume charge, as well as a demand charge for large customers (smaller customers may opt in to a demand charge). The transmission and distribution price components are combined to form a Network Use of System (NUoS) charge. Jacobs’ values also include charges for Advanced Metering Infrastructure (AMI).

Growth in network charges between 2006 and 2017 has also been significant. Figure 23 displays the overall growth and composition of the United Energy network charge for a customer using 4,000 kWh per annum and a load profile equivalent to Net System Load Profile prior to 2015 and equivalent to the AEMO published smart meter profile thereafter. The chart shows that both the variable and fixed components of the NUoS charge has grown, and that the impact of metering charges has been significant. Growth in metering charges is largely due to the introduction of Advanced Metering Infrastructure (AMI), also known as smart meters. The rollout of smart meters to all existing customers continued to 2015, leading to reduced metering charges from that date. For any customers that refused to accept a smart meter, distributors are able to recover the cost of running a separate metering service after March 2015.27

Figure 23  Network charges (United Energy, Customer using 4,000 kWh per annum)

Table 4 displays the compound annual growth rate (CAGR) for network charges for each customer category considered between 2006 and 2017. The region displaying the lowest growth rate is CitiPower, and the customer groups with the least impact from network charges is the residential category using 6,000 kWh pa. This is largely due to increases in fixed charges during the time period. The table describes the changes for single rate tariffs and dual rate tariffs. Single rate tariffs are those where there is a single charge for each unit of electricity regardless of when that electricity was consumed. Dual rate tariffs are those where two rates apply; that is, a peak rate for electricity consumed during peak time periods (i.e. 7am to 11pm on weekdays) and an off-peak rate for electricity consumed during off-peak time periods (all other times).

Table 4  Compound annual growth rate (CAGR) for network charges for each customer category considered between 2006 and 2017


27
### Table 4  Average growth rate (2006-2017): All Network Charges

<table>
<thead>
<tr>
<th>DNSP</th>
<th>Residential 2,000 kWh p.a.</th>
<th>Residential 4,000 kWh p.a.</th>
<th>Residential 6,000 kWh p.a.</th>
<th>Small Business 10,000 kWh p.a.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Single rate</td>
<td>Dual rate</td>
<td>Single rate</td>
<td>Dual rate</td>
</tr>
<tr>
<td>CitiPower</td>
<td>8.18%</td>
<td>9.94%</td>
<td>5.81%</td>
<td>9.07%</td>
</tr>
<tr>
<td>Powercor</td>
<td>7.18%</td>
<td>9.50%</td>
<td>5.15%</td>
<td>8.27%</td>
</tr>
<tr>
<td>Jemena</td>
<td>6.36%</td>
<td>7.02%</td>
<td>5.50%</td>
<td>6.08%</td>
</tr>
<tr>
<td>AusNet</td>
<td>10.39%</td>
<td>11.00%</td>
<td>9.04%</td>
<td>10.35%</td>
</tr>
<tr>
<td>United</td>
<td>5.83%</td>
<td>8.66%</td>
<td>4.96%</td>
<td>7.72%</td>
</tr>
</tbody>
</table>

Source: Jacobs’ analysis of published network tariffs from 2006 to 2017.

Figure 24 illustrates the increases to network fixed charges less AMI charges. For AusNet Services and United Energy, the biggest increases commenced in 2011 and in the case of AusNet Services, this has swung back to lower levels from 2016. In other areas price spikes were observed in 2010; Powercor and CitiPower showed price increases in 2016 while Jemena demonstrated a price fall. AusNet Services and Jemena increased growth more slowly than the other three DNSPs, as they increased fixed charges more gradually over a few years rather than a single step-change.

### Figure 24  Fixed charges less AMI charge, Single Rate and Dual Rate

Source: Jacobs’ analysis of published network charges.

### 6.1 Price movement by distribution area

This section discusses network and metering charges in combination. Total costs for CitiPower customers (all residential and business; single and dual rates) were almost flat until 2009, when they grew sharply to 2015, the final year of the regulatory period, before prices declined. Total costs for dual rate customers have increased faster than single rate customers. See Figure 25.

Total costs for Jemena customers grew slowly until 2009, when the growth rate increased sharply to 2015 before prices declined. Total costs for dual rate customers grew in line with single rate customers, at a marginally higher rate. See Figure 26.

Total costs for Powercor customers were almost flat until 2009, when they grew sharply to 2015 before prices declined. The exception to this occurred for dual rate small business customers which peaked in 2014. Total costs for dual rate customers have increased faster than single rate customers. See Figure 27.
Total costs for AusNet Services customers grew slowly until 2009, with more rapid growth from 2010 to 2015 after which prices declined. Total costs for dual rate customers grew in line with single rate customers until 2012, when residential dual rate prices grew faster than the residential single rate prices. Prices for small business single rate customers spiked in 2014 and 2015 before also declining. See Figure 28.

Like other distribution areas, total costs for United Energy customers grew slowly until 2009, when the growth rate increased sharply to 2015 before prices declined. This drop is largely as a result of declining metering charges. Total costs for dual rate customers grew in line with single rate customers, except for a large rise in 2013 which more closely aligned single and dual rate prices.

Figure 25  Movement in network charges by customer type, CitiPower

<table>
<thead>
<tr>
<th>Residential 2,000 kWh p.a.</th>
<th>Residential 4,000 kWh p.a.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential 6,000 kWh p.a.</td>
<td>Business 10,000 kWh p.a.</td>
</tr>
</tbody>
</table>
Figure 26  Movement in network charges by customer type, Jemena

- Residential 2,000 kWh p.a.
- Residential 4,000 kWh p.a.
- Residential 6,000 kWh p.a.
- Business 10,000 kWh p.a.

Figure 27  Movement in network charges by customer type, Powercor

- Residential 2,000 kWh p.a.
- Residential 4,000 kWh p.a.
- Residential 6,000 kWh p.a.
- Business 10,000 kWh p.a.
Figure 28  Movement in network charges by customer type, Ausnet services

- Residential 2,000 kWh p.a.
- Residential 4,000 kWh p.a.
- Residential 6,000 kWh p.a.
- Business 10,000 kWh p.a.

Figure 29  Movement in network charges by customer type, United Energy

- Residential 2,000 kWh p.a.
- Residential 4,000 kWh p.a.
- Residential 6,000 kWh p.a.
- Business 10,000 kWh p.a.
7. **Wholesale cost of electricity supply**

The wholesale cost to retailers of electricity supply is made up of the following components:

- Cost of production from owned power generation sources dedicated to retail sales position for retailers who are integrated with generation
- Spot energy cost as paid to AEMO adjusted by the applicable transmission and distribution loss factors
- Hedging costs around the spot energy price consisting of swaps, caps and floor contracts

We refer to these costs in combination as wholesale costs. Loss factors would also be applied to these costs but these are specific to each consumer. Loss factors have not been applied to the data in this report.

One of the most significant cost elements faced by retailers, and in some respects the least transparent, pertains to wholesale market costs. If small consumers were allowed to trade in the market to consider purchasing energy directly from the spot market, many would be unlikely to do so because price volatility is high (and has been increasing) and many consumers would not be willing to incur the associated financial risks.

Retailers manage this volatility through contracting strategies, and this risk management becomes part of the cost passed through to consumers.

Wholesale market cost risk is generally managed through hedge contracts which can be ‘Over the Counter’ (OTC) with generators, or from the Australian Stock Exchange (ASX). Most retailers purchase the majority of their load through contracts rather than the spot market, and the net impact of such contracting strategies is that retailers effectively only pay spot price for uncovered load. That is, consumption that is higher than their forecasts.

While a range of contract structures can be used, one way and two way hedges are typical:

- One way hedge contracts manage up-side price risk so that a given energy quantity is purchased at a pre-agreed strike price when market spot prices are above a given level. The generator is assured a revenue stream for that quantity of energy and will generate at bids low enough to ensure that spot price payments will offset hedging costs.
- Two way hedge contracts operate in a different way. Retailers typically purchase parcels of peak and flat load in advance (other time slices are available but are less common) from generators at a given strike price for each time slice. Any demand above the parcel load is simply paid at spot price, and any demand below the parcel load is paid for at strike price regardless whether any revenue from the retailer’s customers is received for it.

If a retailer is not vertically integrated with generation, they can purchase options or futures contracts to secure a price at a future given date.

Retailers may have changing load projections depending on their market growth strategy and the intensity of competition, so portions of load may be contracted on a month by month basis depending on each company’s respective risk management strategy. As future periods approach, greater confidence in forecast load is achieved and retailers may seek to address gaps by on selling overcommitted hedging in their contracting approach. Some of the contracts may also be based on sculpted load profiles rather than the flat or peak loads offered by the ASX.

Energy consumption is impacted by weather (so that consumption is higher when it is very hot and very cold, and also may be greater when the sun is not shining and PV systems behind the meter are not operating), and similarly the wholesale price is higher when demand is high. Because mass market load is very weather sensitive, wholesale market prices will be highly correlated with demand and weather, and if a sculpted profile is used in contracting this will be more expensive than a flat contract because it is adjusted to consider the higher market costs in place at peak times.

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28 Consumers are not allowed to trade in the market without a retail license, the cost of which would be prohibitive to small consumers.
Using a Net System Load Profile (NSLP) to assess mass market contracts, the impact on prices has increased monthly average values by a minimum of 5% and up to 20% compared to a flat consumption profile. Changing volatility in the last two years has increased market volatility in the evening peaks but has nevertheless adjusted this range downwards so that monthly average values for the NSLP are now around 0% to 15% higher than a flat consumption profile. This change may be due to the increasing penetration of solar PV systems in the market. See Figure 30.

Consumers with peaky loads will create greater price risk for retailers and will consequently be offered higher prices. Because a number of retailers tend to operate on a portfolio basis, there may be individual customers in a segment that present greater or lesser risk than the average.

Figure 30 Comparison of monthly average wholesale prices on a time weighted and load weighted basis

Wholesale price risk is difficult to quantify, and will largely depend on the predictability of the load being managed. While exposure to wholesale spot prices is minimised using hedge contracts, risk is not completely avoided because of the difficulty in accurately forecasting both the volume and the shape of load. Retailers must formulate a contracting strategy that enables them to manage trading risk according to their own risk management guidelines.

Volume risk is also significant. Retailers who are experiencing heavy competition and having their load base deteriorate may find themselves in the position of being over-contracted and having to offload their hedges. In a rising market this is likely to be at a profit. Retailers who are aggressively trying to increase market share are likely to be under-contracted, and unless they are vertically integrated or have options contracts in the market may have to purchase energy volumes at higher cost if the market is rising. All retailers are likely to need some level of short term trading to manage small parcels of over and under contracting over upcoming hours, days or weeks.

The Net System Load Profile is collected and used by AEMO to assess metered demand for consumers who do not have smart meters or where the smart meter was not operating properly. It is calculated as the total distribution area load less large business loads. From 201...
Contract prices are negotiated between suppliers and retailers who each have a view of future average and peak spot prices. Therefore, while the spot price is highly correlated with contract prices, there may be market conditions where this relationship breaks as a result of market or policy change. An example of this includes the announcement of implementation of the carbon scheme, where contract prices increased beyond levels of increase experienced in the spot market. The announcement of the Hazelwood retirement (indicative announcement in May 2016 and confirmed announcement in November 2016) has also led to significant increases in contract prices, as shown in Figure 31.

The quarterly contracts shown in Figure 31 also demonstrate higher prices for Quarter 1 in almost every year reviewed. Prices are higher in Quarter 1 because of the increased market volatility associated with high temperatures and associated increases in peak demand.

**Figure 31 12 month rolling average\(^{30}\) contract prices in Victoria**

![Graph showing 12 month rolling average contract prices in Victoria](image)

Source: Jacobs’ analysis of ASX contract data; QFlat refers to quarterly flat prices, CalFlat refers to calendar year flat prices, QPeak refers to quarterly peak period prices and Cap refers to the price for one way cap hedges.

### 7.1 Historical Victorian wholesale costs

Our approach to analysing the generation and renewable energy costs assumes initially that all energy is purchased using hedge contracts. That is, there is no self-generation or any self-generation is treated as a profit centre internally. With increasing vertical integration, retailers may depend on its own generation resources which are effectively a long-term swap or cap contract. However, our discussions with retailers indicate that most retailers, even if partially or fully vertically integrated, use a transfer price from the wholesale part of the business and therefore it would be more appropriate to consider the costs for retail as if it were a separate business. Actual retail specific transfer prices and contract prices are commercially confidential. This review will therefore not include specific generator costs, but rather assume that the retailer sources electricity at market prices, even from its own generation.

The actual costs to a retailer for energy depends on its risk management strategy as indicated by how much of its requirements it contracts forward at any particular time. This depends on the load profile of its customers, exposure to the spot market and liquidity in the contract market. Figure 31 presents contract prices based on a 12 month rolling average approach. Our discussions with retailers indicated that the majority started buying contracts for a given period one to two years in advance, so for completeness we will also provide an estimate of wholesale cost assuming a 24 month rolling average basis which may better represent the contracting strategy of a larger retailer.

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\(^{30}\) Prices shown are based on traded volume average calculations for the 12 month period preceding the beginning of the contract period and include any partial contract trades occurring during the contract period.
Raw black energy costs are then assumed to be a combination of (quarterly) peak and (quarterly and calendar) flat contracting, and these are combined with a risk element based on contract difference payments and unhedged residual payments estimated from analysis of half hourly spot price and load data. The process for estimating the risk element is described in the following paragraphs.

Figure 32 displays traded hedge volumes by type against AEMO quarterly loads. The chart shows that for many periods the amount of publically available hedging exceeds market load significantly (implying significant re-trading of hedge contracts), but for some periods where a market constraint might exist (e.g. 2013/14 when the carbon price existed), liquidity is lower. Quarterly and calendar flat contracts are combined using a weighted average approach with actual quarterly and calendar traded volumes determining the weighting to provide an average value for a flat contract.

**Figure 32 Victorian hedge volumes sold**

We further assume that retailers are able to reasonably forecast their load volumes for hedging purposes. Very hot or very cold years could materially impact on a retailer’s ability to adequately hedge their load and may impact on their cost of supply.

The load profiles used for our wholesale cost calculations are based on smart meter loads available on the AEMO web site from 2012 onwards. Net system load profile (NSLP) data was used prior to 2011. In Victoria the available distribution area profiles were summed to obtain a state wide estimate applicable to an ‘average’ Victorian consumer. Load profiles for quarter 1 are shown for selected years in Figure 33, represented as load profile factors. Our analysis used hedging profiles for each respective year except for 2011 where the two data sources were combined and gave spurious results; for 2011 we used 2010 load profiles.

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31 Partial information was available for 2011 but this was excluded because of clear differences in the NSLP and smart meter profiles within that year.
32 Throughout this report load profile factors describe the shape of the load. They are calculated by scaling hourly average load within a quarter with quarterly average load.
Figure 33  Weekday Quarter 1 load profile factors (Average hourly load over average quarterly load ratio)

Source: Jacobs’ analysis of AEMO NSLP and smart meter data

Generation costs will be adjusted by the distribution and average transmission loss factors to reflect the cost of supply at the customer’s meter.

The peak and flat contracts were averaged using the relevant load profile which was specific to each quarter in the historical timeframe of analysis. The contracting levels are demonstrated in Figure 34, which compares the contracting levels to the hourly average profile. The peak hedge was set to the average peak load multiplied by 1.2 less the average off peak load. The flat hedge was set to the average off peak load. This approach will still result in under contracting between 4-9pm and 11-1am, and over contracting in other time periods. Under contracting occurs at a time when the entire market is unable to utilise solar resources and may be constrained. In combination with warm weather conditions, these time periods reflect times of high market cost risk. Over contracting means that retailers are paying for load not being utilised, and if these retailers also have business customers with high energy usage prior to 3pm there may exist opportunities to diversify their portfolio and gain wholesale market cost benefits.

Figure 34  Peak and flat hedging strategy assumption

Source: Jacobs’ analysis. Note that the chart is represented in the form of hourly profile factors; i.e. the average hourly load within the quarter divided by the average quarterly load. In the chart above, average quarterly load is achieved at approximately 7am where the hourly profile factor equals 1.

Peak load was increased by 20% to improve the cost/risk outcome. This was determined by assessing energy purchase costs at 1x, 1.1x, 1.2x and 1.5x peak load and choosing the value resulting in minimum overall costs.

High overnight load may be a result of use of off peak water heating. Some customers will not have these units.
Jacobs has assumed retailers will be fully hedged and purchase cap contracts for all capacity above contracted peak levels as shown above; i.e. the difference between actual peak demand and the peak contracted demand. Jacobs has also estimated the hedging risk associated with over and under contracting using actual pool payments and hedging arrangements as set out above. The resulting contract values are shown in Figure 35 in yellow and blue, before and after risk allowances. The risk allowance is shown in pink and this series is consistent with changing cap contract prices and increasing market volatility.

Figure 35 also shows a ‘forward wholesale price’ which is a load weighted average of the current and following eleven months of the blue series in the chart. It is expected that this series is reflective of the costs retailers may be facing when pricing a retail customer on a forward looking basis. This assumption largely assumes that retailers have been able to hedge most of their load around a year ahead of time. Some retailers may delay hedging larger portions of load in later quarters depending on their risk management strategy.

Figure 36 compares the forward wholesale prices under a one year ahead and a two year ahead contracting strategy, as well as against 12 month historical moving average pool prices. The chart shows that retailers who contract two years ahead achieve contract prices with lower levels of volatility and are less prone to higher prices resulting from market shortages due to drought (as occurred in 2007) or other natural events. This strategy also provides generators greater revenue certainty further out and is likely to reduce market risk for all players. The exception to this seemed to occur in 2013 and 2014 when carbon pricing was in place. In most years the difference in forward wholesale price is within $5/MWh; however our estimate for May 2017 shows a larger difference of around $15/MWh and seems to confirm our assumption that a two year strategy can provide some protection against unforeseen market events.

Another feature of Figure 36 is that the differences between pool prices and contract prices have a gap, or “contract margin”, ranging between $10-20/MWh for most of the time period to the end of 2012/13. This is considered the usual behaviour of the NEM market pricing the transfer of the risk of very high pool prices from retailers (as buyers) to generators (as sellers) when contracting. Generators have a natural hedge against high pool prices (in their generation plant capacity) whereas retailers do not. The data pertaining to 2014 is an anomaly which may have been caused by the removal of the carbon price. It is not possible to ascertain whether contracts that had already been sold were repriced later on under change of law provisions.

The risk component added to the contract price is largely reflective of increasing cap prices and increasing market volatility. Whereas risk was previously highest in the first quarter of each year, the last three years have demonstrated higher risk levels in the other quarters as well.

Throughout the period reviewed, the forward wholesale price ranges from $10 to $20/MWh higher than the average spot price until January of 2014 where the average spot price rose slightly above the forward wholesale price. This appears to be a result of lower contracting levels during this period. From June 2015 the market appears to have returned to a differential of around $10/MWh between the historical spot price and the forward contract price. The differential between the load-weighted average price (LWA) and time-weighted average price (TWA) in the latter half of 2016 appears to be a result of greater price volatility over this period.
Figure 35  Blended monthly contract and risk value

![Blended monthly contract and risk value graph](graph1.png)

Source: Jacobs' analysis

Figure 36 Comparison of 1 and 2 year purchase strategies and pool prices

![Comparison of 1 and 2 year purchase strategies and pool prices graph](graph2.png)

Source: Jacobs’ analysis. Note that Load weighted Averages (LWAs) for 2011 and post September 2016 were based on load data from the previous year.

7.2 Comparison with other states

Figure 37 displays a state by state comparison of Victorian wholesale costs with those of the other states using the same method. The results show that prices have increased in all states and that prices for NSW and Victoria have begun to follow each other much more closely than in the past. The rate of price increase is highest in South Australia where prices have been affected by the closure of Northern Power Station.
7.3 Hazelwood impact analysis

Jacobs was asked to review the price impact resulting from the closure of Hazelwood Power Station, and assess retailers’ response in terms of their price offerings to consumers, and what level of price increase is justifiable.

Electricity wholesale prices are a key building block of electricity retail prices, and they have been modelled in detail for this study for every region of the NEM under two scenarios, which could be described as a Base scenario with and without Hazelwood power station’s presence and supply side contribution. Apart from the availability of Hazelwood, both market scenarios have the same assumptions, which reflect Jacobs’ view of the most likely evolution of the market to 2020. This approach enables an assessment of the increase of retailers’ wholesale market costs due to Hazelwood’s retirement. Jacobs used its PLEXOS simulation model of the NEM to forecast wholesale prices from FY 2017 to FY 2020.

7.3.1 Scenario descriptions

Table 5 summarises the key scenario assumptions used in this modelling study.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Base scenario</th>
<th>Hazelwood stays</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td>2016 NEFR[^25]Neutral economic growth scenario</td>
<td>As per Base scenario</td>
</tr>
<tr>
<td>Renewable targets</td>
<td>LRET: 33TWh by 2020</td>
<td>As per Base scenario</td>
</tr>
<tr>
<td></td>
<td>No VRET or QRET impact prior to 2020</td>
<td></td>
</tr>
<tr>
<td>Exchange rate</td>
<td>1 AUD = 0.75 USD</td>
<td>As per Base scenario</td>
</tr>
<tr>
<td>Gas price</td>
<td>Jacobs’ base gas price forecast (as per Figure 38 below)</td>
<td>As per Base scenario</td>
</tr>
<tr>
<td>Carbon price</td>
<td>No carbon price assumed</td>
<td>As per Base scenario</td>
</tr>
</tbody>
</table>

[^25]: The December 2015 update of the NEFR was used
The assumed gas prices used for this modelling are shown below in Figure 38. These are significantly elevated relative to the history of gas prices in Eastern Australia, which have been low by world standards (in the order of $3/GJ to $4/GJ in nominal terms). The spur for this has been the link to world gas markets brought on by the construction of LNG export terminals in Gladstone. The gas price in Eastern Australia is expected to remain elevated until 2020 due to a supply constraint, because the development of the unconventional coal-seam gas wells has not proceeded as well as originally expected. As a result of this, the retirement of Hazelwood power station is expected to have a larger impact on electricity pool prices in the NEM than would otherwise have been the case.

**Figure 38 Projected gas prices for Eastern Australia by region**

![Projected gas prices](image)

Source: Jacobs

Other high level assumptions and methodology relating to the PLEXOS analysis are provided in Appendix C.

### 7.3.2 Modelling outcomes

Figure 39 shows the PLEXOS pricing outcomes across the two scenarios by region, whereas Figure 40 shows the price differences between the two scenarios by region. Both charts show that the price impact of Hazelwood’s exit over the next three years is relatively large, particularly in Victoria, South Australia and
Tasmania. The price differences in FY2017 are relatively small across all of the regions, as they only include 3 months of difference between the two scenarios.

FY 2018 is the first full year when Hazelwood has exited the market under the Base scenario, and therefore the full brunt of Hazelwood’s absence is felt in this year, particularly in Victoria. The increase in the Victorian price reflects an increase in the dispatch of its gas-fired generation assets, which also tend to be marginal more frequently, thus exerting upward pressure on the average Victorian price. Averaged from FY 2018 to FY 2020, the price impact of Hazelwood’s exit on the Victorian price is $37/MWh.

The impact of Hazelwood’s exit in FY 2018 is lower for South Australia and Tasmania relative to the following years. In the case of both South Australia and Tasmania this is due to transmission congestion, which is relieved in the later years as more renewable capacity is built in Victoria and South Australia. By FY 2019 and FY 2020 the impact of Hazelwood’s retirement in Tasmania and South Australia is similar in magnitude to that of Victoria. Historically, both the Tasmanian and South Australian prices tend to track reasonably close to the Victorian price as Victoria is their largest neighbouring region. Therefore this level of price impact for both of these regions is not unexpected. The average price impact for South Australia and Tasmania respectively, relative to Victoria, from FY 2018 to FY 2020 is 86% and 90%.

New South Wales is also a neighbouring region of Victoria, and this is reflected in the price impact of the Hazelwood exit. However, with the tightening of the supply balance caused by the Hazelwood exit in the southern regions, the modelling is clearly showing New South Wales exporting more frequently to Victoria, and the VIC-NSW interconnector tends to be constrained more frequently, which separates off New South Wales from the southern regions in price terms. This results in lower New South Wales prices and the full impact of Hazelwood’s exit does not translate into the New South Wales price. The average price impact in NSW of Hazelwood’s exit relative to the Victorian price impact from FY 2018 to FY 2020 is 54%, or $20/MWh.

Queensland is the only region in the NEM that is not a neighbour of Victoria, meaning that an additional layer of transmission constraints can separate it from Victoria pricewise. The average impact of Hazelwood’s exit on Queensland from FY 2018 to FY 2020 is $9/MWh, which represents 25% of the impact on the Victorian price.

Figure 41 compares the difference in modelled Victorian prices against the change in blended contract prices from the same period in 2016. The contract market response in 2017 is lower than modelled changes in spot market prices while the contract market increase in 2018 and onward is higher. The contract market response is also less than the actual change in spot prices. The most likely factor to explain the difference are the underlying gas price assumptions.

Contract prices are blended from flat and peak quarterly and calendar year contracts as previously described.
Figure 39 Pricing outcomes by region by scenario, $/MWh

Source: Jacobs’ analysis
Figure 40 Price difference between scenarios by region

![Price difference between scenarios by region](image)

Source: Jacobs’ analysis

Figure 41 Monthly modelled Victorian wholesale price impact due to Hazelwood shut down

![Monthly modelled Victorian wholesale price impact due to Hazelwood shut down](image)

Source: Jacobs’ analysis

7.4 Market operation and ancillary charges

Market fees are regulated to recover the costs of operating the wholesale market, the allocation of customer meters to retailers, and settlement of black energy purchases. These fees, charged by the Australian Energy Market Operator (AEMO) to retailers, are applicable to wholesale black energy purchases and are budgeted at $0.39/MWh in 2017 according to the AEMO 2016 budget. In addition to these fees, AEMO also recovers the costs for Full Retail Contestability ($0.061/MWh), National Transmission Planning ($0.016/MWh) and Energy Consumers Australia, a body which promotes the long term interests of energy consumers ($0.01/MWh).

37 “Electricity final budget and fees: 2016-17”, AEMO, May 2016
Ancillary services charges are also passed through by AEMO to retailers. Retailers are charged ancillary service costs according to load variability. Over the last few years the charges have varied over time and by region, as demonstrated in Figure 42. Due to the volatility of these values, retailers are not able to foresee variations in these costs, and therefore the average values have been applied over the study period as indicative.

These market and ancillary service charges are adjusted by DLFs as the charges are related to the wholesale metered quantity purchased by retailers.

**Figure 42** Ancillary services recovery cost rate, $/MWh

Source: Jacobs’ analysis using AEMO published Ancillary services payments data from 2012 to 2016 and published native energy statistics, accessed 23 March 2017

The final series over the time frame is provided in Figure 43.
Figure 43  Market and ancillary service charges before losses

Source: Jacobs’ analysis of AEMO market reports. Note that ancillary charges prior to 2009 are estimated from 2009 data.
8. Wholesale cost of gas supply

Jacobs undertook gas market research to estimate historical gas costs as well as project gas costs for the Hazelwood analysis provided in the previous section. The assumptions and methodology behind the projection work is provided in Appendix D.

Key findings from Jacobs’ research are:

- 10 to 15% of export feedstock is sourced from third party gas that would otherwise supply the eastern Australian domestic market.
- This has led to supply tightness and rising prices in the domestic gas market. Notwithstanding this price stimulus, gas resource development has failed to keep pace and a supply shortfall appears likely from as early as 2018.
- Falls in global oil and LNG spot prices since 2014 have had multiple impacts on this process: potentially reduced demand for LNG; reduced profitability of LNG suppliers; cuts to exploration budgets reducing mid- to long-term supply.
- Domestic prices are expected to rise sharply in 2017 and 2018 and then moderate. However they are unlikely to fall to historical levels because less expensive resources will become depleted.

Figure 44 illustrates historical contracts for Victorian gas supplying principally Victoria but also NSW, SA and Tasmania. Two features are of note:

- Most of the gas supply up to 2017 has been provided through contracts which started in 2006 or earlier. These contracts were subject to CPI escalation and may have been subject to price renegotiation in the period 2010-2012. Jacobs understands that the initial prices were in the range $4.00/GJ to $4.50/GJ initially in $2016 and that renegotiation may have added 50c/GJ.
- Most of the gas supply after 2017 will be provided through contracts negotiated since 2012, which are most likely to be oil indexed, priced in the range $7.00/GJ to $8.00/GJ at current oil prices.
Historical contract prices are therefore in the range as depicted below. Jacobs considers it unlikely that, given the cost of new contracts since 2014, retail prices since 2014 will simply have reflected these contract prices. It is more likely that retailers holding the historically priced contracts will have priced the commodity components of retail price offers at premiums reflecting the opportunity value of their gas.

**Figure 45  Weighted average prices in existing Victorian contracts ($2016)**

Source: Jacobs’ analysis
9. Environmental schemes

A breakdown of environmental costs per customer is provided below in Figure 46. The method for deriving the costs in this chart is detailed in the following sections.

Figure 46 Elements of environmental scheme costs contributing to a retail bill for a 4,000 kWh pa customer

9.1 Renewable Energy Target

The Renewable Energy Target (RET) is a legislated requirement on electricity retailers to source a given proportion of specified electricity sales from renewable generation sources, ultimately creating material change in the Australian technology mix towards lower carbon alternatives.

Since January 2011 the RET scheme has operated in two parts—the Small-scale Renewable Energy Scheme (SRES) and the Large-scale Renewable Energy Target.

The target mandates that 33 TWh of generation must be derived from renewable sources by 2020, maintaining this level to 2030. Emissions Intensive Trade Exposed (EITE) industry are exempt from the RET.

9.1.1 Large scale Renewable Energy Target (LRET)

The LRET provides a financial incentive to establish or expand renewable energy power stations by legislating demand for large-scale generation certificates (LGCs), where one LGC is equivalent to one MWh of eligible renewable electricity produced by an accredited power station. LGCs are sold to liable entities who must surrender them annually to the Clean Energy Regulator (CER). Revenue earned by renewable power stations is supplementary to revenue received for generated power. The number of LGCs to be surrendered to the CER will ramp up to a final target of 33 TWh in 2020.
9.1.2 Small scale Renewable Energy Target (SRET)

The SRES provides a financial incentive for households, small businesses and community groups to install eligible small-scale renewable energy systems. Systems include solar water heaters, heat pumps, solar photovoltaic (PV) systems, or small-scale hydro systems. The SRES facilitates demand for Small Scale Technology Certificates (STCs), which are created at the time of system installation based on the expected future production of electricity.

9.1.3 Retailer costs

The SRES and LRET impose obligations on retailers. In order to meet the obligations under these schemes, retailers must acquire and surrender renewable energy certificates (LGCs/STCs) each year. The average cost of these retailer obligations can be determined by calculating the following:

\[
\text{Average cost of SRES and LRET} = (RPP \times LGC + STP \times STC) \times DLF
\]

where

- \( RPP \) = Renewable Power Percentage, a mandated value which reflects the proportion of energy sales which must be met by renewable generation under the schemes. Historical RPP values can be obtained from the Clean Energy Regulator website\(^3\), but these are not available for future years. Instead Jacobs has estimated the RPP using current AEMO demand projections, adjusted for energy intensive industrial customers who are exempt.

- \( STP \) = Small scale technology percentage,
- \( LGC \) = Large-scale generation certificate price
- \( STC \) = Small-scale technology certificate price
- \( DLF \) = Distribution loss factor

STCs are expected to range in cost between $39.80 and $40 per certificate in coming months. LGC prices were estimated using forward 12 month moving average spot prices; values for 2017 were projected to remain at penalty rates for the next 12 months. The resulting LGC and STC price series are displayed in Figure 47. Figure 48 displays the impact of the LGCs and STCs on the electricity price, as well as the costs of some now expired schemes including the NSW GGAS scheme, the Queensland GEC scheme and the VRET. This cost is equivalent across all states in Australia.

\(^3\) http://ret.cleanenergyregulator.gov.au/For-Industry/Liable-Entities/Renewable-Power-Percentage/rpp provides the renewable power percentage.
9.2 Energy efficiency schemes

Some states and territories in Australia have implemented energy efficiency policies. Schemes that require retailers to surrender certificates to meet a given energy efficiency target are referred to in this document as white certificates. Energy efficiency scheme impacts require adjustment for the distribution loss factor.

9.2.1 Victorian Energy Efficiency Target

The Victorian Energy Efficiency Target (VEET) Act commenced in January 2009, and the scheme now operates in 3 year phases to 2029. Targets of 2.7 Mt CO$_2$-e per annum applied between 2009 and 2011 and were
doubled to 5.4 Mt CO\textsubscript{2}-e per annum between 2012 and 2015. Targets ramp up from 5.4 Mt CO\textsubscript{2}-e in 2016 to 6.5 Mt CO\textsubscript{2}-e in 2020 (see Table 6). Targets beyond 2020 are not yet known.

Historically, the spot VEET price has been in the range of $10 to $25/t CO\textsubscript{2}-e, which are relatively stable levels though there have been periods of high price volatility as shown in Figure 49. Since 2012, in spite of a doubled target, growth in spot prices has slowed and has been relatively stable until the price spike that occurred in late 2015, around the time the increasing targets were announced.

For this assignment Jacobs has not developed a market based model to project certificate prices, and has instead reviewed historical prices in the context of changing targets. The problem associated with this is that the target since 2012 has been constant, and targets are expected to grow further to 2020. Furthermore, as targets rise and cheaper energy efficiency options saturate the market, more expensive energy efficiency options will be required to meet future targets, and we would therefore expect that certificate prices would be more than likely to rise higher than present levels.

Because of the relatively stable prices over most of the historical period since 2012, we have assumed that prices will grow linearly with an increasing target, and have ignored any possible time trend which may occur as a result of market saturation of low cost activities. This is still a conservative estimate because it is likely that contract prices will be lower than spot prices in any case, and the results are still reasonably consistent with history. The results are provided in Table 6.

**Figure 49 VECC spot prices, $/t CO\textsubscript{2}-e**

<table>
<thead>
<tr>
<th>Calendar Year</th>
<th>Current VEET target</th>
<th>Average annual prices, $/t CO\textsubscript{2}-e</th>
<th>Jacobs projections, $/t CO\textsubscript{2}-e</th>
<th>RE value</th>
<th>VEET impact on retail bill, $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>5.4</td>
<td>15.73</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>5.4</td>
<td>17.43</td>
<td>0.12</td>
<td>2.13</td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>5.4</td>
<td>21.90</td>
<td>0.13637</td>
<td>2.99</td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td>5.4</td>
<td>18.72</td>
<td>0.13111</td>
<td>2.45</td>
<td></td>
</tr>
</tbody>
</table>
9.2.2 NSW Energy Savings Scheme

The NSW Energy Savings Scheme (ESS) commenced in 2009 and is currently legislated to continue to 2020. However in 2014 the NSW Government announced that the ESS will be extended to include gas saving options and extended to 2025. The ESS target is set relative to a percentage of annual NSW electricity sales, as shown in Table 7.

Historically, the spot ESC price has been in the range of $10 to $32/t CO2-e, as shown in Figure 50. Since 2013, in spite of an increased target, spot prices declined up to the end of 2014 when a reversal of trend occurred and prices started increasing again. The price peaked in early 2016 and has trended downwards again since then.

<table>
<thead>
<tr>
<th>Year</th>
<th>Energy Savings Target</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>1.0%</td>
</tr>
<tr>
<td>2010</td>
<td>1.5%</td>
</tr>
<tr>
<td>2011</td>
<td>2.5%</td>
</tr>
<tr>
<td>2012</td>
<td>3.5%</td>
</tr>
<tr>
<td>2013</td>
<td>4.5%</td>
</tr>
<tr>
<td>2014</td>
<td>5.0%</td>
</tr>
<tr>
<td>2015</td>
<td>5.0%</td>
</tr>
<tr>
<td>2016</td>
<td>7.0%</td>
</tr>
<tr>
<td>2017</td>
<td>7.5%</td>
</tr>
<tr>
<td>2018</td>
<td>8.0%</td>
</tr>
<tr>
<td>2019-2025</td>
<td>8.5%</td>
</tr>
</tbody>
</table>
Retail price pass through impacts were estimated by the OEH (Office of Environment and Heritage, NSW Government) in 2015. These are shown in Figure 51, and are used in this study.

Figure 51 OEH retail price pass through impacts of the ESS, $/MWh

9.2.3 SA REES

The Residential Energy Efficiency Scheme operated from 2009 to 2014, and has been rebadged as the Retailer Energy Efficiency Scheme (REES) from 1 January 2015. It was expanded to include the small business sector and converted from an emissions savings target to an energy savings target. The scheme requires that larger energy retailers help households and businesses save energy, and provides a separate target for low income households in particular, as well as a target for annual energy audits. According to a review of the scheme, it saved 4.1 PJ of energy between 2009 and 2014, though it is not clear how much of this saving is attributed to gas and electricity, and this value could also be applicable to anticipated savings in future years as the target ramps up. The scheme is administered by the Essential Services Commission of South Australia (ESCOSA). Targets for 2015, 2016 and 2017 are 1.2 PJ, 1.7 PJ and 2.3 PJ respectively, with 19.2% of these savings to be made in low income households. Retailers must also undertake 5,667 energy efficiency audits annually. The scheme has been extended to 2020, although targets have not yet been announced. We assume a 2.3 PJ target for 2018 to 2020.

The REES is not a certificate-based scheme, so there is no price transparency for REES activities and audits so that contracting parties do not know whether terms reflect supply and demand and regulation may be cumbersome. This also means that the method to estimate retail price impacts is not immediately apparent and some further consideration is needed.

9.2.4 Energy efficiency scheme cost estimates

Resulting white scheme cost estimates over the historical period for Victoria and NSW are shown in Figure 52.

Figure 52 White scheme cost estimates

Source: Jacobs' analysis of scheme targets and certificate prices

9.3 Feed-in tariffs

Feed-in tariffs are equivalent to payments for exported electricity. Feed-in tariff schemes have been scaled back in most jurisdictions so that the value of exported energy does not provide a significant incentive to increase uptake of solar PV systems.

Between 2008 and 2012, state governments in most states mandated feed-in tariff payments to be made by distributors to owners of generation systems (usually solar PV). A list of such schemes is provided in Table 8. Following a commitment by the Council of Australian Governments in 2012 to phase out feed-in tariffs that are in excess of the fair and reasonable value of exported electricity, most of these schemes are now discontinued and have been replaced with feed-in tariff schemes with much lower rates.

However, the costs of paying feed-in tariffs from those schemes to customers must still be recouped as eligible systems continue to receive payments over a period that could be as long as twenty years. Network service providers provide credits to customers who are eligible to receive feed-in payments, and recover the cost through a jurisdictional scheme component of network tariffs. Networks are able to estimate the required payments each year and include these amounts in their tariff determinations adjusting estimated future tariffs for over and underpayments annually as needed. Where this has occurred, it would be reasonable to assume that cost recovery components are included in the distribution tariffs under ‘jurisdictional’ charges, so no additional amounts are included in the Jacobs’ estimates of retail price. In all cases where distributors are responsible for providing feed-in tariff payments, the distributors would have been aware of the feed-in tariffs prior to the latest tariff determination, so it is reasonably safe to assume inclusion.

Retailers may also offer market feed-in tariffs, and the amount is set and paid by retailers. Where such an amount has been mandated, the value has been set to represent the benefit the retailer receives from avoided wholesale costs including losses, so theoretically no subsidy is required from government or other electricity customers. In a voluntary feed-in tariff situation, no subsidy should be required from government or other electricity customers. Nevertheless, Jacobs’ wholesale price projections are based on a post-scheme generation profile which incorporates new solar PV, and therefore may underestimate the cost compared to what may have been the case had the schemes not been implemented. Therefore we suggest that retailer feed-in tariffs be added back to wholesale prices by adding back the quantities shown in Figure 53 to the wholesale price.

![Figure 53 Impact of FITs on electricity price](image-url)
### Table 8  Summary of mandated feed-in tariff arrangements since 2008

<table>
<thead>
<tr>
<th>State or territory</th>
<th>Feed-in tariff</th>
<th>Cost recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>Queensland</td>
<td><em>Queensland solar bonus scheme (legacy)</em>&lt;br&gt;The Queensland solar bonus scheme provides a 44 c/kWh feed-in tariff for customers who applied before 10 July 2012 and maintain their eligibility. The scheme was replaced with an 8 c/kWh feed-in tariff which applied to 30 June 2014. The scheme is now closed to new solar customers. The tariff provided to existing solar customers is recovered through an impost in the network tariffs of Ergon Energy, Energex and Essential Energy. These networks must apply annually to the AER for a pass through of these costs which are expected to diminish over time.</td>
<td>Network tariffs include provision for legacy payments</td>
</tr>
<tr>
<td></td>
<td><em>Regional mandated feed-in tariffs</em>&lt;br&gt;From 1 July 2014, retailers in regional Queensland are mandated to offer market feed-in tariffs that represent the benefit the retailer receives from exporting solar energy, ensuring that no subsidy is required from government or other electricity customers. The feed-in tariff is paid by Ergon Energy, and by Origin Energy for customers in the Essential Energy network in south west Queensland. The amount set in 2016/17 is 7.447 c/kWh.</td>
<td>Assume 7.447 c/kWh over projection period.</td>
</tr>
<tr>
<td>NSW</td>
<td><em>NSW Solar Bonus scheme</em>&lt;br&gt;This scheme began in 2009 offering payment of 60 c/kWh on a gross basis, reduced to 20 c/kWh after October 2010. The scheme closed in December 2016 when legacy payments made by distributors and are recovered through network tariffs ended. IPART now regulates a fair and reasonable rate range for new customers who are not part of the SBS, where the minimum rates in 2011/12 were 5.2 c/kWh, 6.6 c/kWh for 2013/14, 5.1 c/kWh for 2014/15, and 4.7 c/kWh for 2015/16, and 5.5 c/kWh for 2016/17. However offering the minimum rate is optional.</td>
<td>Network tariffs include some provision for legacy payments which is topped up by retailer contribution. Assume 5.5 c/kWh over projection period to cover retailer benefit.</td>
</tr>
<tr>
<td>ACT</td>
<td><em>ACT feed-in tariff (large scale)</em>&lt;br&gt;ACT feed-in tariff (large scale) supports the development of up to 210 MW of large-scale renewable energy generation capacity for the ACT. This scheme has been declared to be a jurisdictional scheme under the National Electricity Rules, and is therefore recovered in network charges. <em>ACT feed-in tariff (small scale, legacy)</em>&lt;br&gt;ACT feed-in tariff (small scale), is already declared to be a jurisdictional scheme under the National Electricity Rules, and is therefore recovered in network charges. In July 2008 the feed-in tariff was 50.05 c/kWh for systems up to 10 kW in capacity for 20 years, and 45.7 c/kWh for systems up to 30 kW in capacity for 20 years. The feed-in tariff scheme closed on 13 July 2011.</td>
<td>Network tariffs include provision for feed-in tariffs. Assume 5.5 c/kWh over projection period to cover retailer benefit. (based on NSW estimates)</td>
</tr>
<tr>
<td>Victoria</td>
<td><em>Premium and transitional feed-in tariff scheme (legacy)</em>&lt;br&gt;The Victorian Government introduced the premium feed-in tariff of 60 c/kWh in 2009 and closed it to new applicants in 2011. Consumers eligible for the premium rate are able to continue benefiting from the rates until 2024 if they remain eligible to do so. The Transitional Feed-in Tariff was then introduced with a feed-in rate of 25 c/kWh. The transitional and premium feed-in tariffs are cost recovered through distribution network tariffs. <em>Minimum feed-in tariffs</em>&lt;br&gt;The Essential Services Commission (ESC) in Victoria is required to determine the minimum electricity feed-in tariff that is paid to small renewable energy generators for electricity they produce and feed back into the grid. The minimum feed-in tariff is determined by considering wholesale electricity market prices, distribution and transmission losses avoided through the supply of distributed energy, avoided market fees and charges, and avoided social cost of carbon. These payments are made by retailers and have shifted to a financial year basis. The ESC has determined that the minimum energy value of feed-in electricity for 2017/18 is 11.3 c/kWh, compared with a January 2016 to July 2017 value of 5 c/kWh, a 2015 value of 6.2 c/kWh.</td>
<td>Network tariffs include provision for feed-in tariffs Assume a feed-in tariff of 11.3 c/kWh, to recover likely retailer rates</td>
</tr>
<tr>
<td>State or territory</td>
<td>Feed-in tariff</td>
<td>Cost recovery</td>
</tr>
<tr>
<td>--------------------</td>
<td>----------------</td>
<td>--------------</td>
</tr>
<tr>
<td>South Australia</td>
<td>Premium feed-in tariff scheme (legacy)</td>
<td>Network tariffs include provision for feed-in tariffs</td>
</tr>
<tr>
<td></td>
<td>In July 2008 the South Australian government introduced a feed-in tariff scheme providing 44 c/kWh for 20 years until 2028. In 2011, this amount was reduced to 16 c/kWh for 5 years until 2016. This scheme was closed to new customers in September 2013.</td>
<td>Assume a feed-in tariff of 6.8 c/kWh over the projection period</td>
</tr>
<tr>
<td></td>
<td>Premium feed-in tariff scheme (legacy)</td>
<td>Assume a feed-in tariff of 6.8 c/kWh over the projection period</td>
</tr>
<tr>
<td></td>
<td>Retailer feed-in tariff / Premium feed-in tariff bonus</td>
<td>Assume a feed-in tariff of 6.8 c/kWh over the projection period</td>
</tr>
<tr>
<td></td>
<td>A retailer contribution is also available, as set by the SA regulator (Essential Service Commission of South Australia or ESCOSA), where the minimum tariff is set to 6.8 c/kWh in 2016. For 2017, ESCOSA has not set a minimum amount for the retailer feed-in tariff (R-FiT) scheme. Each retailer will determine its own R-FiT amount and structures, and publicly demonstrate the benefits to solar customers. ESCOSA is monitoring R-FiT prices and will reset a minimum price if in the best interest of consumers.</td>
<td>Assume a feed-in tariff of 6.8 c/kWh over the projection period</td>
</tr>
<tr>
<td>Tasmania</td>
<td>Metering buyback scheme (legacy)</td>
<td>Network tariffs include provision for feed-in tariffs</td>
</tr>
<tr>
<td></td>
<td>In Tasmania, Aurora (TasNetworks) offered a feed-in tariff which offered customers a one-for-one feed-in tariff at the regulated light and power tariff for residential customers or general supply tariff for small business customers for their net exported electricity. This program was closed to new customers in August 2013 and replaced with a transitional feed-in tariff of 20 c/kWh for residential customers and a similar blocked feed-in tariff for commercial customers.</td>
<td>Assume a retailer tariff of 6.67 c/kWh to recover retailer costs</td>
</tr>
<tr>
<td></td>
<td>Post reform</td>
<td>Assume a retailer tariff of 6.67 c/kWh to recover retailer costs</td>
</tr>
<tr>
<td></td>
<td>The Tasmanian regulator has now stipulated smaller rates which are now 6.67 c/kWh for 2016/17, compared with 5.5 c/kWh for 2015/16, 5.551 c/kWh in 2014/15 and 8.282 c/kWh for the first half of 2014. These rates are now a component of standing offer tariffs provided by retailers.</td>
<td>Assume a retailer tariff of 6.67 c/kWh to recover retailer costs</td>
</tr>
</tbody>
</table>
Appendix A. Literature review: Vertical integration in electricity markets

Jacobs have reviewed the literature covering the advantages and disadvantages of vertical integration in electricity markets where forward contracting is also available.

Older economic theory saw vertical integration as a tool that a monopolist could use to extract profit from competitive activities. However, in a competitive environment (as opposed to a regulated one), vertical integration can be a positive feature of electricity markets and lead to better risk management and cost advantages for retailers, and possibly enhancing competition overall. These cost advantages are based on improved information and transaction cost management, as well as benefitting from different boom and bust cycles particular to the very different environments of the retail and generation supply chain elements.

One of the main questions asked about vertical integration is the extent of any cost advantage of vertically integrated retailers vs partially vertically integrated or separated retailers. Hogan and Meade found that retail prices are higher in markets with vertical separation than in markets with balanced separation (i.e. generation similar to electricity load for most participants) or markets that are fully vertically integrated. Furthermore, Lopez found that the capacity factor of plant in vertically integrated retailers could be around 4.6% higher than for other types of retailers, strengthening the argument that electricity businesses can more efficiently find supply for their load when integrated than other retailers. It is therefore possible that cost savings from initial deregulation could have more to do with privatisation than separation of retail and generation activities.

Nevertheless, good alternatives to vertical integration exist as retailers could alternatively invest in options to hedge future generation rather than invest in ownership of generation plant, as long as the market for options is sufficiently liquid. Low liquidity can occur when peak reserve margins have narrowed significantly. When such narrowing occurs it can be a good argument for a vertically separated retailer to invest in generation capacity to hedge against high prices. Alternatively, market participants who are able to fully focus on one part of the value chain may outperform their diversified peers.

Impact of market reforms

Shen and Yang undertook a literature review to assess the impact of market reforms such as ownership separation of retail, distribution and generation activities on energy markets. Their review revealed mixed impacts. Ownership separation can:

- Stimulate innovation and efficiency in distribution and retail sectors, eliminate cross subsidies and limit need for regulation
- Result in loss of economies of scope from integration, which can result in an increase of transaction costs between activities at different levels of operation and reduce the adequacy of investment.

The deregulation that originally separated parts of the value chain in electricity and gas utilities in many parts of the world including Australia has appeared to make significant reductions in electricity prices for consumers. However,

In many countries an unintended output of ownership separation is the re-integration of generation and retailing activities after the initial unbundling. This has also occurred in Australia, especially with respect to the larger retailers AGL, Energy Australia and Origin significantly increasing their operations base to include significantly larger generation and retail activities over time.

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43 Michaels, R. “Rethinking vertical integration in electricity”, California State University, Fullerton, May 2005
Re-integration benefits the risk profile of generation and retail businesses as it provides a natural hedge against price volatility and prevents supply risk associated with the generation asset. Standalone generation and retail businesses are more susceptible to volatile wholesale prices. Unfortunately it can also give certain generation businesses market power that is advantageous their retail businesses. When contract markets become thin, non-integrated retailers are exposed to extreme price volatility, which can be highly detrimental to those businesses and inhibit market entry; Worse, it can make it difficult for existing competitors who may have previously had sufficient working capital to obtain and retain market share, but under thinning contract markets could easily go out of business.

Theoretically speaking, there would appear to be a balance of vertical integration which increases market efficiency and consequently reduces cost. Hogan and Meade (2007) undertook modelling that showed that vertical integration in and of itself does not create an incentive to exercise market power. However, a mismatch between generation and retailer share can, with the result that net sellers of electricity are more likely to over report wholesale prices and net buyers of electricity are more likely to under report wholesale prices. The implication is that balanced vertical integration is a desirable thing, and that vertical separation will have the effect of increasing costs altogether.

Reforms have put in place a strict separation between operation of generation and network businesses. Steiner (2001) showed that separation of transmission and generation can provide higher capacity utilisation, but is not associated with lower prices. Furthermore, a number of studies have shown that a network business without generation assets is less efficient than a network business with generation assets, possibly from reduced transaction costs and better co-ordination. Reform in New Zealand has recommended that in areas where there is weak competition (such as remote and rural areas), that network businesses be allowed to become retailers, subject to certain conditions.

The deregulation that originally separated parts of the value chain in electricity and gas utilities in many parts of the world including Australia has appeared to make significant reductions in electricity prices for consumers. The empirical evidence reviewed has shown that competition in retail and wholesale markets has provided efficiency, service quality and consequently reduced prices immediately after the unbundling. However, the impact of unbundling and competition was in many cases temporary, as some countries have witnessed rising retail prices, falls in productivity and drops in service quality. In the retail sector in particular, prices for residential consumers in particular have increased. Some of the empirical research studies are summarised in Table 9 below.

Table 9  Comparison of empirical studies

<table>
<thead>
<tr>
<th>Study</th>
<th>Findings</th>
</tr>
</thead>
<tbody>
<tr>
<td>United Kingdom, Davies and Price (2007)</td>
<td>Market share of vertically integrated businesses tended to be 8% higher than their non-integrated counterparts all else being equal.</td>
</tr>
<tr>
<td>Joskow (2006b)</td>
<td>Competitive wholesale and retail prices have reduced prices for residential customers by 5-10% and for industrial customers by 5%</td>
</tr>
<tr>
<td>Pennsylvania, New Jersey and Maryland, Bushnell et al (2008)</td>
<td>Generators tend to overstate their wholesale prices when there is unbundling resulting in higher retail prices</td>
</tr>
<tr>
<td>Pennsylvania, New Jersey and Maryland, Bushnell et al (2008)</td>
<td>Complete unbundling would raise retail prices as a result of production inefficiencies</td>
</tr>
</tbody>
</table>

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<table>
<thead>
<tr>
<th>Study</th>
<th>Findings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pennsylvania, New Jersey and Maryland, Mansur 2007</td>
<td>Two large net wholesalers increased anti-competitive behaviour through wealth transfer. Vertical integration can counter this however.</td>
</tr>
</tbody>
</table>
| EU market reform, Pollitt 2009a | **Pros associated with market reforms**  
Increased EU cross border trade  
Improved labour productivity  
Reduced prices  
**Cons associated with market reforms**  
Competition concerns  
Rising prices  
Exercising of market power by incumbents |
| United States, Joskow 2006a | **Pros associated with market reforms**  
Performance improvements  
Lower retail prices overall  
**Cons associated with market reforms**  
Less successful for smaller customers |

**Hedging and vertical integration**

Forward hedging and vertical integration are two separate risk management mechanisms that can be employed by electricity retailers. Aid et al (2010) argue that both lead to reduced retail prices and can lead to increased retailer market shares. However, vertical integration is superior to forward hedging in the presence of highly risk averse retailers. Even in the absence of market power, a non-integrated retailer can only obtain significant market share of the retail market if the forward hedging market is well developed and their risk aversion is limited. The availability of forward hedging therefore underpins the competitiveness of the Australian electricity market.

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Appendix B. Literature review: Benefits and costs of competition

Jacobs’ also undertook a literature review exploring the benefits and costs of competition, mainly to understand what market factors may point to a situation in which competition was ineffective or was creating an overheated market.

Why is effective competition valued? Competition has long been seen as beneficial to society. The presence of effective competition promotes learning and innovation and consequently advances society. It forces companies to be more competitive by trying new things, which can lead to a combination of lowered costs, improved service and a motivated and engaged workforce. This benefits everyone.

B.1 Signs that retail markets are uncompetitive

However, there exist circumstances in which competition does not work effectively. If a small number of firms with large market share (i.e. an oligopoly) create barriers to market entry for smaller new entrant firms, effective competition can be hampered. It is possible for large firms to move in tandem to set prices and consequently increase profit margins above what a truly competitive market would allow, or alternatively undercut a new market entrant and force it out of business. Barriers to entry can also take the form of significant investment in capital expenditure or high leasing costs to use existing infrastructure.

An example of the above is provided by a study undertaken by Melbourne University and the University of Sydney on 17 January 2017, focussing on tacit co-ordination of petrol prices by major retailers in Western Australia. The study demonstrated that collusion can occur over an evolving process where dominant firms engage in price leadership to create focal points that coordinate market prices, soften competition and enhance margins. The margins achieved in the Western Australian market increased from around 5% to an average of 15% over the period, generally above margin increases in the eastern states. Furthermore, the dispersion in individual retailer margins reduced over time, and in periods where price wars appeared to break out, they lasted for a much shorter time period than has occurred historically (3 weeks versus 6 months), signalling improved conflict resolution.

The Western Australia petrol price study was made possible by the availability of detailed data sets for an extended period of 15 years. The complexity of the electricity and gas retail markets, as well as the lack of transparency and availability of an existing data set around actual retailer margins, makes it unlikely that collusive patterns of behaviour could ever be detected in these markets. This is problematic for the energy industry as lack of transparency will reduce consumer trust and create barriers to suppliers attempting to provide fair and reasonable prices. Furthermore, electricity and gas are essential services and high prices are likely to have a disproportionate impact on vulnerable consumers, so improved transparency will provide some assurance that these customer sectors have their interests protected.

B.2 Signs that retail markets are overheated

The literature has shown that there are some particular scenarios where competition delivers suboptimal results.

- **Behavioural exploitation.** Competition benefits society when firms compete to help consumers obtain or find solutions for their bounded rationality and willpower. However, when firms compete to exploit this, and it becomes the norm in an industry, firms instead compete to devise better or new ways to exploit consumers. In energy retail markets, some forms of behavioural exploitation include:
  - Using framing effects and changing the reference point so that the price change is viewed as a discount rather than a surcharge; this is known to have occurred in the retail electricity market through providing a new discount at the end of a consumer’s benefit period that is claimed against a standing

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 tariff rather than the consumer’s existing offer. This would result in a price increase rather than a price reduction for the consumer.

- Anchoring consumers to an artificially high suggested retail price from which consumers can negotiate from. This has occurred in the electricity market through discounting practices and use of standing offers as a means for obtaining the relevant discount. For example, a pay on time discount is equivalent to a surcharge for consumers that do not pay on time (noting that pay on time discounts are a valid means of keeping working capital costs down).

- Using sunk costs as a means to remind consumers that they have already made a commitment to them to induce them to continue paying for items whose value is less than the remainder of the payments, as may be the case for retailers who tie the purchase or lease of solar products to a consumer’s energy offer.

With respect to the above, the literature indicates that more competitors can intensify rather than improve the situation. This is more likely if some consumers have difficulties judging quality and prices, so firms have lesser incentive to compete by offering better deals, and may make price comparisons and search harder to obscure product quality or offering complex pricing. The increased intensity of behavioural exploitation under greater competition is dependent on the payoff for new firms to continue what is being done by their competitors rather than educate consumers.

- **Competitive escalation** is where two firms overbid for another firm or product because neither can afford for their competitor to obtain access to that firm or product. With sufficient market regulatory oversight, this may be avoided. This could occur if retailers bid for a market asset that neither wants other retailers to have access to.

- **When individual and group interests diverge** describes the situation where individual and society interests are not aligned. An example of this is when a firm engages in unethical or criminal behaviour to gain a relative competitive advantage. For energy retailers, increased competition may potentially encourage firms to do any of the following:
  - invest less in legal compliance and more likely violate the law
  - pay kickbacks to secure business
  - underreport profits to avoid taxes
  - invest in less sustainable forms of generation to obtain a price advantage, leaving society to bear the brunt of the cost of externalities attributed to those choices (e.g. carbon costs)
  - Take part in greater levels of risk taking behaviour to gain a competitive advantage. For example, a decision to hedge lesser proportions of energy consumption by one retailer may increase financial risk for generators and consequently increase spot prices which will have an impact on uncovered load for all retailers. As a result generation retirements could occur, or at least hedging costs could increase, and eventually this will lead to higher prices for consumers.
  - Underprice rates to achieve greater market share, increasing the fiscal risk associated with trading energy and on-selling to consumers, and increasing consumer expectations on low prices to unrealistic levels
  - Engage in agreements with buyers who have market power to provide favourable, least-cost, prices which will not be above the sellers’ lowest price. Provided these prices are not predatory and not below the sellers incremental cost, such agreements may not be a bad thing. However, buyers collectively could be worse off as a result and wide spread use of such agreements could turn a number of buyers into free riders and consequently make prices more uniform and consequently anti-competitive.

- **Competition among intermediaries reduces accuracy.** As competition increases in the intermediary’s market, more will be willing to distort their product and reduce accuracy, which may appeal to the individual customers, but harms society overall. In energy retail, this could occur if comparator websites chose a different way to present energy bill comparisons that somehow aligned with their goal to increase commissions from retailers, or, as has already happened, retailers present their price offering in a simplified format to increase understanding and gain market share, without educating consumers about
how to keep their costs down. The consequence could be a proliferation of tariffs that are not accurately presented to consumers and/or do not provide the best market signals to reduce costs to society as a whole. For example, single rate tariffs are widely used yet do not adequately send signals to consumers to reduce demand in peak periods. This could have the direct consequence of increased investment in network and generation infrastructure that ultimately increases prices to customers overall. Because of the proliferation of single rate tariffs being adopted, there are very few Time-of-use or demand tariffs being adopted and this may ultimately have a negative effect on society as a whole. A recent example has already occurred in Victoria as one retailer has offered an ‘all you can eat’ style of tariff based on a fixed annual price with no requirement to limit energy use in peak periods in summer for example.

The above scenarios do not provide an argument against competition, but provide guidelines as to when more competition will not help a given situation. Evidence of any of the above could signal overheating competition rather than effective competition.

A number of approaches have been used to assess the effectiveness of retail energy competition in a number of jurisdictions. Some of these include:

- Consideration of the proportion of customers on market vs standing offers and the degree of switching in the market
- Review of standing and market offers, particularly tracking the divergence between these
- Movement in retailer pricing margins

A large number of reviews have looked to high switching rates in Victoria in particular as evidence that competition is effective. However, high switching rates could also mask market inefficiencies. For example:

- Retailers are more likely to make a profit on customers who stay around for a while because the cost of customer acquisition is relatively high and may eat through any profits made in the first year.
- The transaction costs alone on switching may not cover the savings made by very small customers. If such customers are also frequent switchers then their profit margin might never recover this cost and retailers will need to recover it from other customers.

A study undertaken by the UK Competition and Markets Authority found that there was significant variation in prices for different customer/tariff arrangements as follows:

- Average revenue for customers of the six large energy firms was around 10% higher for electricity and 13% higher for gas than average revenue earned from customers on other tariffs.
- Small business faced significantly higher prices than average in the following circumstances:
  - Customers on rollover tariffs (i.e. tariffs that customers would pay if they took no action at the end of an existing fixed term contract) paid 29 to 36% higher than retention tariffs (i.e. customers that actively renegotiate with their existing supplier at the end of an existing contract) for electricity and 25 to 28% higher for gas.
  - Customers on deemed tariffs (i.e. a tariff paid until a customer, typically in new premises, contacts its supplier to enter into its first contract) paid 66 to 82% higher than retention tariffs for electricity and 70 to 116% higher for gas.
- The EBIT margin was 8% for this group compared much lesser rates for residential or large business customers.
Appendix C. PLEXOS modelling assumptions and method

C.1 Key high level assumptions

The key assumptions underlying the wholesale electricity market modelling are presented in this section.

Key assumptions used in the electricity market modelling include:

- The various demand growth projections with annual demand shapes consistent with the median growth in summer and winter peak demand as projected by AEMO. The load shape was based on 2010/11 load profile for the NEM regions.
- Wind power in the NEM is based on the chronological profile of wind generation for each generator from the 2010/11 financial year, and is therefore accurately correlated to the demand profile.
- Capacity is installed to meet the target reserve margin for the NEM in each region. Some of this peaking capacity may represent demand side response rather than physical generation assets.
- Infrequently used peaking resources are bid near Market Price Cap (MPC) or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low.
- Generators behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry. This is a conservative assumption as there have been periods when prices have exceeded new entry costs when averaged over 12 months.
- Implementation of the LRET and Small-scale Renewable Energy Scheme (SRES) schemes. The LRET target is for 33,000GWh of renewable generation by 2020.
- Additional renewable energy is included for expected Greenpower and desalination purposes.
- The assessed demand side management (DSM) for emissions abatement or otherwise economic responses throughout the NEM is assumed to be included in the NEM demand forecast.

C.2 Jacobs' PLEXOS model

The PLEXOS market simulation model is used to forecast the evolution of the wholesale price and generation levels. It determines dispatch (and resulting price levels) by co-optimising energy and FCAS markets.

PLEXOS is a sophisticated stochastic mathematical model developed by Energy Exemplar which can be used to project electricity generation, pricing, and associated costs for the NEM. This model optimises dispatch using the same techniques that are used by AEMO to clear the NEM, and incorporates Monte-Carlo forced outage modelling. It also uses mixed integer linear programming to determine an optimal long-term generation capacity expansion plan.

Detailed modelling simulations using PLEXOS are typically run one year at a time to more accurately model system dispatch and pricing. Prior to optimising dispatch in any given year, PLEXOS schedules planned maintenance and randomly pre-computes a user-specified number of forced outage scenarios for Monte Carlo simulation. Dispatch is then optimised on a half hourly basis for each forced outage sequence, given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, variable operating costs including fuel costs, inter-connector constraints and any other operating restrictions that may be specified.

Expected half-hourly electricity prices for the NEM are produced as output, calculated by modelling strategic behaviour, based on gaming models. In this particular case we have employed the Nash-Cournot equilibrium model. Jacobs uses a combination of user-defined bids and the Nash Cournot equilibrium model to produce the price forecasts, and has benchmarked its NEM database to market outcomes that have been achieved over the last twelve months (May 2016 to April 2017) using this algorithm to ensure that the bidding strategies employed produce price and dispatch outcomes commensurate with historical outcomes.
There are four key tasks performed by PLEXOS:

- Forecast demand over the planning horizon, given a historical load profile, expected energy generation and peak loads.
- Schedule maintenance and pre-compute forced outage scenarios.
- Model strategic behaviour based on dynamic gaming models.
- Calculate half-hourly unit dispatch given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, other operating restrictions (such as spinning reserve requirements) and variable operating costs including fuel costs and price impacts of abatement schemes.

One of the key advantages of this model is the detail in which the transmission constraints of electricity grids can be modelled. The PLEXOS model includes 5 regions: Tasmania, South Australia, Victoria, New South Wales, and South Australia. Inter-regional transmission constraints and the dispatch impacts of intra-regional transmission constraints are modelled using the constraint set provided by AEMO as used in the 2016 ESOO.\(^\text{60}\) These constraints are dynamic with the limits typically being a function of regional demand, flows on other lines, inertia, number of units generating, and generation levels of relevant units.

### C.3 Modelling methodology

Jacobs’ PLEXOS model was calibrated to reproduce price outcomes for each NEM region over the last 12 months with actual gas prices, grid demand and plant availability as model inputs. The calibration involved tuning the elasticity of demand parameters for each NEM region until the required pricing outcome was replicated. These are the key parameters that define the Nash-Cournot game, which PLEXOS plays over the course of one year to emulate the bidding behaviour of all generators, grouped into their portfolio structures, in the NEM. These parameters were then fixed for the projection period, and formed the basis for the projected prices produced by the model.

As a check on the modelling outcomes, we also ran the same modelling scenarios with marginal cost bidding, which in effect switches off generator bidding in the model. This was done as a check to ensure that the emulated bidding behaviour of the model was not unduly skewing pricing outcomes and exaggerating the price impact of Hazelwood’s exit. The price differentials between the Base and Hazelwood stays scenarios were broadly in line with the same scenarios run under marginal cost bidding, thus giving us more confidence in the modelling outcomes.

Appendix D. Gas market modelling

D.1 The eastern Australian gas market

Jacobs prepares gas price forecasts based on projected demand-supply balances in eastern Australia. The gas resources and delivery infrastructure in this region are illustrated in Figure 54. This chapter presents in detail Jacobs’ gas market modelling methodology and assumptions.

Eastern Australia (New South Wales, Victoria, Queensland, South Australia, Tasmania and the ACT) has substantial gas resources that support both domestic and export markets. Total reserves at the end of 2015 comprised 44,239 PJ of coal seam gas, almost all in Queensland, and 4,999 PJ of conventional gas mainly in Victoria and SA. Total demand of 1662 PJ in 2016 comprised 603 PJ in domestic markets and 1,059 PJ of exports, all from three export projects at Gladstone in Queensland. Regional breakdowns of these figures are shown in Table 10. Background information on reserves definitions is provided in 0.

Table 10 Gas demand and reserves by state (PJ)

<table>
<thead>
<tr>
<th></th>
<th>NSW</th>
<th>Victoria</th>
<th>SA</th>
<th>Tasmania</th>
<th>Queensland Domestic</th>
<th>Total Domestic</th>
<th>Queensland Export</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand (2016)</td>
<td>126</td>
<td>206</td>
<td>75</td>
<td>6</td>
<td>189</td>
<td>603</td>
<td>1,059</td>
<td>1,662</td>
</tr>
<tr>
<td>2P Reserves (as at 31/12/2015)</td>
<td>40</td>
<td>3,568</td>
<td>1,266</td>
<td>99</td>
<td>44,265</td>
<td>49,237</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>


Export demand is a recent phenomenon driven by growth of CSG reserves since 2005, to levels in excess of foreseeable domestic demand. This led to construction of three LNG export projects, the first of which shipped its first cargo in January 2015. All three projects completed their construction programs in 2016 and are moving towards their target output levels. LNG exports have substantially changed the domestic market, both in terms of the demand-supply dynamics and the nature of the participants, who now include global energy companies such as BG Group, Conoco Phillips, Petronas and Shell, and large offshore gas purchasers such as China Petroleum Corporation, Kogas and PetroChina.

All Eastern States sub-markets except Northern Queensland are now served by multiple basins and/or pipelines. Plans for a pipeline between Moranbah and Gladstone, which would link Townsville to other supplies, have been advanced but construction appears to be contingent upon further LNG development in Gladstone using gas from the Moranbah area. The Northern Territory pipeline from Tennant Creek to Mt Isa is scheduled to start construction in 2017.

Gas production history

Figure 55 illustrates historical gas production by basin. For many years production was dominated by the Cooper and Gippsland basins. After growing to supply the Queensland market in the 1990s, Cooper Basin production declined and was replaced by Surat/Bowen CSG in Queensland and Otway Basin gas in southern Australia. Surat/Bowen CSG production has recently expanded fivefold to meet export commitments.

Market transactions

The dominant transactions in the Eastern Australian gas market are long-term gas sales agreements (GSAs) between gas producers and buyers such as retailers, large industrial users and generators. Over time the duration of long-term contracts has covered a wide range, running from 3 years to 15 years in contracts entered over the last decade. There is limited public information on gas contracts but the basic details such as term and average volumes are known for the majority of the significant contracts. Contract prices are less well known but can often be estimated – until recently most contract prices were CPI indexed and underwent periodic reviews to ensure they remain at market levels, though without a recognised market price, reviews can be prolonged.
Some recent contracts however, have been indexed to oil prices, which is also the basis for most Australian LNG export contracts.

Shorter-term bi-lateral contracts are also used but there is almost no public information about them. In particular, short-term markets appear to have insufficient participants and depth of trading to support a price index, in contrast to short-term markets in the US and Europe, where many trading hubs have associated benchmark prices, the best known being the Henry Hub in Louisiana. Many longer term contracts in the US are
now indexed to the Henry Hub price, overcoming the difficulty of setting long-term prices that remain in line with the market.

**Figure 55: Eastern Australian gas production by basin**

[Image of a graph showing Eastern Australian gas production by basin]

Organised spot markets are operated by the Australian Energy Market Operator (AEMO) in Victoria, Adelaide, Brisbane and Sydney for the primary purpose of balancing the transmission/distribution system – the pool price is used to settle injection/withdrawal imbalances. Bidding into the pool is compulsory for all transmission/distribution system users, most of whom are retailers buying gas from producers under GSAs. In general, the pool prices are determined by the prices set in the GSAs rather than vice versa. AEMO has also established trading hubs at Wallumbilla (near Roma), which has seen a rapid increase in volumes associated with LNG developments, and at Moomba.

The level of gas producer competition has until recently been sufficient to maintain price levels for new GSAs in the south-east and to reduce prices in some Queensland sub-markets. Supply pressures resulting from development of resources for export have already led to higher prices in new contracts and this is widely expected to continue.

**D.2 Outlook for gas reserves**

**Reserves and resources estimates**

Recent trends in gas reserves and contingent resources are presented in Table 11. It is notable that while Queensland’s CSG reserves proved up for export have been static, 2P reserves in Southern States have declined significantly due to both production without replacement (Gippsland, Otway and Cooper Basins declined by 1,417 PJ) and declassification (NSW CSG declined by 2,186 PJ, as 2P reserves were reclassified as 2C resources owing to uncertainties regarding NSW regulation and disappointing production test results).

In addition to the decline in Southern States 2P reserves, Southern States 2C Contingent Resources, which would be expected to be converted into reserves in the medium term, have also declined significantly. Of the 2C estimates for 2017, 75% is for Cooper Basin Shale, 15% is for NSW CSG and only 10% is for conventional gas in Victoria.
Individual joint venture reserves and resources are interpreted on an operating basis, i.e. they include reserves and resources in all fields operated by the JV, even when some are part owned by parties outside the JV.

Table 11  Recent trends in Gas Reserves and Contingent Resources (PJ)

<table>
<thead>
<tr>
<th>GSOO Date</th>
<th>2P Reserves</th>
<th>2C Contingent Resources</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Queensland</td>
<td>Southern</td>
</tr>
<tr>
<td>2014</td>
<td>43,075</td>
<td>8,719</td>
</tr>
<tr>
<td>2015</td>
<td>40,315</td>
<td>8,401</td>
</tr>
<tr>
<td>2016</td>
<td>42,417</td>
<td>7,166</td>
</tr>
<tr>
<td>2017</td>
<td>44,265</td>
<td>5,052</td>
</tr>
</tbody>
</table>

Source: AEMO Gas Statement of Opportunities. The reserve date is usually in the year prior to the GSOO date.

Table 12 Remaining conventional gas reserves and resources as at 31st December 2015 (PJ)

<table>
<thead>
<tr>
<th>Basin</th>
<th>Joint venture</th>
<th>2P</th>
<th>2C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gippsland - Longford</td>
<td>BHPB, Exxon</td>
<td>3,056</td>
<td>686</td>
</tr>
<tr>
<td>Gippsland - Orbost</td>
<td>Cooper Energy</td>
<td>106</td>
<td>313</td>
</tr>
<tr>
<td>Bass</td>
<td>Origin, AWE</td>
<td>99</td>
<td>99</td>
</tr>
<tr>
<td>Otway - Minerva</td>
<td>BHPB, Cooper Energy</td>
<td>17</td>
<td>0</td>
</tr>
<tr>
<td>Otway - Geographe</td>
<td>Origin, Others</td>
<td>236</td>
<td>0</td>
</tr>
<tr>
<td>Otway - Casino</td>
<td>Cooper Energy, Others</td>
<td>153</td>
<td>30</td>
</tr>
<tr>
<td>Cooper - Eromanga</td>
<td>Santos, Beach, Origin</td>
<td>1,266</td>
<td>0</td>
</tr>
<tr>
<td>Cooper - Eromanga</td>
<td>Others</td>
<td>0</td>
<td>7,497</td>
</tr>
<tr>
<td>Surat/Bowen</td>
<td>All producers</td>
<td>66</td>
<td>Minor</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>4,999</td>
<td>8,625</td>
</tr>
</tbody>
</table>

1 Mainly unconventional

**Future 2P reserves growth**

2P reserves are not static and have generally grown over time but can decline if they become uneconomic due to changing market prices. In the MMAGas model, growth in 2P gas reserves for each of the producers is estimated as follows:

- Starting at current 2P levels, a proportion of 2C resources are assumed to be convertible to 2P reserves each year.
- Ultimate 2P reserves projections for existing acreage are set at the current 2P + 2C level
- In the longer term, 2C conversion to 2P is assumed to be controlled so that total remaining reserves remain steady, as defined by the reserves production (R/P) ratio. The R/P ratio used in this study is 25.

In each modelling scenario some known resources may be assumed not to be developed. The scenario assumptions are described in section D.9.

D.3  Gas production costs
Cost trends

Gas production costs have recently been trending upwards under the combined effects of higher materials costs, labor costs and development of lower grade resources\(^61\). With the end of the resources boom the first two factors are in retreat though the third may continue to have an impact given the extent of resource development undertaken for the LNG export projects. For this study, we have estimated costs of production, being the breakeven cost of earning a benchmark rate of return for a production project, on a project basis, assuming costs are fixed in real terms for each resource but with a strong difference between the cost of developing 2P reserves and 2C resources.

Table 13 Remaining CSG reserves and resources as at 31\(^{st}\) December 2015 (PJ)

<table>
<thead>
<tr>
<th>Basin</th>
<th>Joint venture</th>
<th>2P</th>
<th>2C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sydney</td>
<td>AGL</td>
<td>40</td>
<td>0</td>
</tr>
<tr>
<td>Gunnedah</td>
<td>Santos</td>
<td>0</td>
<td>971</td>
</tr>
<tr>
<td>Bowen</td>
<td>AGL/Arrow</td>
<td>3,285</td>
<td>5,548</td>
</tr>
<tr>
<td>Surat</td>
<td>APLNG</td>
<td>10,542</td>
<td>3,030</td>
</tr>
<tr>
<td>Surat</td>
<td>QCLNG</td>
<td>12,579</td>
<td>13,700</td>
</tr>
<tr>
<td>Surat/Bowen</td>
<td>GLNG</td>
<td>6,578</td>
<td>1,328</td>
</tr>
<tr>
<td>Surat/Bowen</td>
<td>Arrow Energy</td>
<td>9,824</td>
<td>17,923</td>
</tr>
<tr>
<td>Surat/Bowen</td>
<td>Second Tier</td>
<td>1,391</td>
<td>5,186</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>44,239</td>
<td>47,686</td>
</tr>
</tbody>
</table>

Estimates based on LNG project costs

In 2013 McKinsey and Company released a detailed study of LNG costs in Australia and elsewhere\(^62\). Their estimate of CSG production costs is $4.75/GJ in $2016 terms, for a typical LNG project, which compares to Jacobs’ estimate of $4.00/GJ in $2016 terms for the GLNG project prior to cost blowouts. Costs for LNG supply are higher than for domestic supply owing to the need to drill wells over a period of 2-3 years in advance of first production of LNG.

Well productivity

A key factor in determining CSG costs is the rate of production per well. The above costs are typical of wells that produce 0.6 TJ/day to 1.0 TJ/day. Table 14, based on CSG production data released by Queensland Department of Resources and Mines, shows that the three producers committed to LNG exports, APLNG, GLNG and QCLNG, have the most productive wells, with others operating well below the optimum rate. APLNG has stated\(^63\) that some of its fields are operating below capacity and their outputs could be increased by 50%. Jacobs believes this could also apply to GLNG and QCLNG because in 2013 and 2014 they did not need all of the output from wells drilled for their LNG projects. We used this information to fine tune our estimates of relative production costs.

D.3.1 AEMO Estimates

AEMO provides estimates of gas production costs as part of its annual Gas Statement of Opportunities. Jacobs has compared its estimates with AEMO’s and found them to be in general agreement.

---

\(^{63}\) APLNG CSG Production, May 2013. www.originenergy.com.au
### Table 14 CSG well productivity (TJ/day)

<table>
<thead>
<tr>
<th>Producer</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>APLNG</td>
<td>0.73</td>
<td>0.73</td>
<td>0.80</td>
<td>0.90</td>
<td>0.93</td>
<td>0.71</td>
<td>0.35</td>
</tr>
<tr>
<td>Arrow Energy</td>
<td>0.25</td>
<td>0.24</td>
<td>0.29</td>
<td>0.26</td>
<td>0.26</td>
<td>0.28</td>
<td>0.30</td>
</tr>
<tr>
<td>GLNG</td>
<td>0.75</td>
<td>0.77</td>
<td>0.94</td>
<td>1.00</td>
<td>0.92</td>
<td>0.64</td>
<td></td>
</tr>
<tr>
<td>Molopo</td>
<td>0.07</td>
<td>0.14</td>
<td>0.26</td>
<td>0.17</td>
<td>0.08</td>
<td>0.05</td>
<td>0.04</td>
</tr>
<tr>
<td>QCLNG</td>
<td>0.68</td>
<td>0.78</td>
<td>0.84</td>
<td>0.74</td>
<td>0.76</td>
<td>0.56</td>
<td>0.25</td>
</tr>
<tr>
<td>Westside Corporation</td>
<td>0.17</td>
<td>0.15</td>
<td>0.15</td>
<td>0.14</td>
<td>0.17</td>
<td>0.13</td>
<td>0.14</td>
</tr>
</tbody>
</table>

### D.3.2 Production cost assumptions

For the purposes of this study for the Base Scenario we have assumed gas production costs excluding carbon costs as listed in Table 15. The costs of 2C resources are set higher than the costs of 2P reserves. All the costs are assumed to be constant in real terms.

In any scenario costs of production will increase when more costly resources are brought into production. Carbon costs are added on a scenario basis, based on the scenario carbon costs and producer specific estimates of CO₂ content and gas used in production.

The modelling did not assume that resources will be developed in strict cost order, as in a least cost of supply approach. Instead, each producer develops its most competitive option in any basin, subject to its competitiveness relative to other producers. Thus if the market price is above $6/GJ at any time, all resources with costs below $6/GJ will be developed to the extent necessary to meet demand at that time.

### Table 15 Jacobs’ estimates of gas production breakeven costs, Base Scenario ($2016)

<table>
<thead>
<tr>
<th>Basin</th>
<th>Joint venture</th>
<th>2P</th>
<th>2C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gippsland, Longford</td>
<td>BHPB, Exxon</td>
<td>$4.00</td>
<td>$5.00</td>
</tr>
<tr>
<td>Gippsland, Orbost</td>
<td>Cooper Energy</td>
<td>$5.00</td>
<td>$6.00</td>
</tr>
<tr>
<td>Bass</td>
<td>Origin, AWE</td>
<td>$4.50</td>
<td>$6.50</td>
</tr>
<tr>
<td>Otway, Minerva</td>
<td>BHPB, Cooper Energy</td>
<td>$4.50</td>
<td>$6.50</td>
</tr>
<tr>
<td>Otway, Geographe</td>
<td>Origin, Others</td>
<td>$4.50</td>
<td>$6.50</td>
</tr>
<tr>
<td>Otway, Casino</td>
<td>Cooper Energy, Others</td>
<td>$4.50</td>
<td>$6.50</td>
</tr>
<tr>
<td>Cooper Eromanga</td>
<td>Santos, Beach, Origin</td>
<td>$4.90</td>
<td>$6.50</td>
</tr>
<tr>
<td>Cooper Eromanga</td>
<td>Others (Unconventional)</td>
<td>$6.50</td>
<td>$6.50</td>
</tr>
<tr>
<td>Sydney</td>
<td>AGL</td>
<td>$6.00</td>
<td>$8.00</td>
</tr>
<tr>
<td>Gunnedah</td>
<td>Santos</td>
<td>$7.00</td>
<td>$7.00</td>
</tr>
<tr>
<td>Bowen</td>
<td>AGL/Arrow</td>
<td>$5.00</td>
<td>$5.00</td>
</tr>
<tr>
<td>Surat</td>
<td>APLNG</td>
<td>$4.00</td>
<td>$6.00</td>
</tr>
<tr>
<td>Surat</td>
<td>QCLNG</td>
<td>$4.00</td>
<td>$6.00</td>
</tr>
<tr>
<td>Surat/Bowen</td>
<td>GLNG</td>
<td>$4.50</td>
<td>$7.00</td>
</tr>
<tr>
<td>Surat</td>
<td>Arrow Energy</td>
<td>$5.00</td>
<td>$5.00</td>
</tr>
<tr>
<td>Surat/Bowen</td>
<td>Second Tier</td>
<td>$5.50</td>
<td>$6.50</td>
</tr>
<tr>
<td>NT Basins</td>
<td></td>
<td>$5.00</td>
<td>$5.00</td>
</tr>
</tbody>
</table>

Source: Jacobs’ analysis

### D.4 Gas transmission
The existing network of transmission pipelines, depicted in Figure 54, in principle enables gas to be transported from any production centre to any major market centre, with the exception of Townsville. Of course in practice there are capacity constraints and difficulties in arranging backhaul but these can generally be overcome where there is sufficient commercial incentive.

Figure 56 illustrates historical gas transmission volumes in South Eastern Australia. These volumes add up to the total demand in South Eastern Australia less the volume supplied from the Sydney Basin, which is not transported on a transmission pipeline.

![Historical transmission volumes South Eastern Australia](image)

As the cost of gas delivered to the city gate or transmission customer meter is made up of approximately 75% wellhead price and 25% transmission price, when matching demand and supply, our focus is more on the wellhead component of supply than transmission and our assumptions regarding pipelines are as follows:

- Existing pipelines are unconstrained, that is, capacity can be added by further compression or duplication.
- Pipeline tariffs continue at current levels and escalation rates.
- Uncommitted new pipelines can be added to the model but their projected throughputs are tested to ensure commercial viability.

For this study uncommitted new pipelines have been included as follows:

- A pipeline to convey CSG from the Gunnedah Basin south to Wilton to compete in the broader NSW market. Owing to the delays to CSG development caused by local opposition in NSW, pipeline start-up is assumed to be 2020 at the earliest. At throughput rates of 50 PJ/annum the tariff is estimated at $1.15/GJ escalating at CPI. As the developers have undertaken not to export this gas if its development goes ahead, there is no “Hunter Pipeline” from Gunnedah to Wallumbilla.
- The NT pipeline linking Carpentaria Basin gas resources with Mt Isa from 2019. The location of these resources is assumed to result in transmission tariffs of $1.00/GJ.
D.5  Overview of gas demand

D.5.1  LNG exports

Worldwide, the preferred technology for utilising excess gas\(^64\) is LNG production. LNG is a global product that saw rapid growth and high prices during the oil price surge from 2003 to 2008. Three large LNG export projects have been constructed on Curtis Island, near Gladstone: Queensland Curtis LNG (QCLNG); Gladstone LNG (GLNG); and Australia Pacific LNG (APLNG) to utilise Queensland CSG. QCLNG commenced exports from its first LNG train in January 2015 and the sixth train, APLNG’s second, came on line in October 2016.

The six LNG trains are each capable of delivering about 3.9 to 4.5 million tonnes of LNG per year when operating at their nameplate capacities. A fourth major project from Arrow Energy was cancelled as a stand-alone project in 2015 and Arrow has yet to indicate how it will try to monetise the value of its gas reserves. Using the gas in a third train at one of the existing projects or another, smaller, project is a widely canvased option. Arrow’s 50% owner, Shell, is in the process of taking over BG Group, the majority owner of QCLNG. Other proposed eastern Australian export projects are no longer under consideration.

Jacobs uses base, low and high projections as published by AEMO in the 2016 NGFR (AEMO labels these scenarios neutral, weak and strong). The scenarios reflect the following assumptions:

- **Base Scenario** – exports reach contracted levels by 2020, no additional projects
- **Low Scenario** – exports at contract take-or-pay levels of the three projects, no additional projects, projects contract after 2030
- **High scenario** - exports rise to the full capacities of the three projects and one additional train starts up in 2028

APLNG has proved up sufficient reserves to meet its export requirements for two trains. However GLNG, and to a lesser extent QCLNG, still require additional reserves to meet their second train requirements despite the fact that they have purchased gas under third-party contracts in competition with domestic gas buyers. This has sustained the relative lack of reserves available to support new domestic gas contracts.

Note: the low and high scenarios are not used in this study.

D.5.2  Domestic demand

For this study Jacobs has used a single domestic demand forecast, so that the impact of different scenario price outcomes can be measured directly by the demand outputs from modelling. If different scenarios were used it would be necessary to associate low domestic demand with high LNG demand and vice versa.

Domestic demand projections are those put forward by AEMO in the 2016 National Gas Forecasting Report (NGFR), presented in Figure 57 and Figure 58.

\(^{64}\) Gas that cannot reach a market by pipeline. LNG is preferred to conversion technologies such as Gas-To-Liquids
The projections imply that domestic gas demand will decline up to 2020 and then grow with increasing strength for the remainder of the period. There are several causes of this:

1) a general decline in manufacturing accentuated by higher gas prices;

2) flat residential and small business load with increasing customers offset by declining domestic use per household owing to:
   a) increasing efficiency of housing stock and appliances
   b) competition from solar water heating and reverse cycle electric heating

3) relatively strong growth in electricity demand

D.5.3 Hazelwood Scenario
The AEMO Base Case forecast includes estimates of additional gas usage due to the closure of the Hazelwood Power Station in 2017. To determine the effect of this on gas prices a scenario that assumes Hazelwood continues to operate until 2022, the Hazelwood 2022 Scenario, is included in the study.

Jacobs has estimated the following reductions in gas used for generation in this scenario. 98% of the variation occurs in 2017 and only the 2017 reductions are used in this scenario. The total reduction represents 2.3% of domestic demand and 0.8% of total demand.

Table 16  Hazelwood 2022 Scenario, Reductions in Gas Demand in 2017 (PJ)

<table>
<thead>
<tr>
<th></th>
<th>NSW</th>
<th>Victoria</th>
<th>SA</th>
<th>Tasmania</th>
<th>Queensland</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0.6</td>
<td>7.1</td>
<td>3.7</td>
<td>1.0</td>
<td>1.2</td>
<td>13.6</td>
</tr>
</tbody>
</table>

D.6  Levels of Upstream Contracting

As noted in section 0, the Australian gas market is based on long-term contracts between buyers and sellers. At present the domestic market is in the unusual position of demand not being fully covered by contracts for a number of years to come, in fact supply appears to be short in 2017, with a wider gap in 2018 and thereafter (Figure 59). In contrast, export demand is understood to be almost fully contracted for the next twenty years.

Notes:
1) This is interpreted as meaning that the reserves have been dedicated to exports but in many dedicated areas wells have yet to be drilled to bring gas into production. Under some circumstances, such as very low global oil and LNG prices, it may be uneconomic to drill the wells.
2) Domestic supply contracts are defined as those contracted by producers to parties other than exporters, such as retailers, traders and end users. However, some gas purchased by retailers and traders has been resold to LNG projects (refer to sales by AGL, Origin and Stanwell in Table 17) and are no longer available to domestic users. Jacobs has estimated the contract volume committed or available to domestic users and this is used for price modelling.

a)  Gas Available for Contracting

The gaps between domestic demand and contracts can be filled by new contracts, provided there is sufficient supply available. Supply availability is determined largely by gas reserves and the capacity they can support.

For CSG it is well known that gas production from each well will decline over time, with the result that to maintain a steady output, new wells must be continuously drilled and connected to processing plants. For each export project the CSG production profile has the form of that in Figure 60, with a short ramp up phase (which is now past), a twenty-year export phase and a long ramp down phase during which the output of the wells required to support full production in the final year of export declines to zero. Jacobs estimates that the volume of gas produced during ramp down is approximately eight times the annual export volume, so the volume of CSG reserves initially committed is 28 times annual exports rather than just 20 times.
How strictly the export projects reserve gas for the ramp down phase is not known, however if they are developed for other users or to expand exports the project runs the risk that exports during the final years will fall below contracted levels, if no further gas is available.

Conventional gas fields exhibit similar behaviour though it is understood that the ramp down volume is lower, namely about four times plateau production. For all fields ramp down gas is assumed to be sold at the appropriate time.

Total reserves required to support LNG exports plus domestic gas contracts (with replacement contracts on five year terms) is compared with the estimated maximum possible 2P reserves available in Figure 61. The reserves required decline over the initial terms of the LNG projects but would flatten out if the projects were extended beyond 2035. Reserves potentially available grow slowly over the next four years but can then grow more rapidly if new projects are initiated. For the next two to three years there appears to be a deficit of reserves, though this is largely confined to the GLNG project. It is nevertheless clear that 2P reserves availability is and will be very tight over the medium term.
D.7 Recent contract prices

New gas supply availability across eastern Australia is strongly influenced by the export of significant volumes of LNG from Gladstone.

D.7.1 LNG third party contracts

While the LNG projects will source most gas from their associated producers there are also a growing number of third party contracts between suppliers and LNG projects, all of which have been entered at prices linked to oil prices.

D.7.2 Domestic upstream contracts

Tight domestic supply is expected to prevail until at least 2017, by which time the three LNG projects under construction will be operating. The position beyond 2017 will depend primarily upon whether the Arrow Energy LNG or other LNG projects proceed or not and the rate of development of additional gas reserves, including shale gas.

A growing number of domestic buyers have recently secured new wholesale gas supply contracts, however the prices reflect market tightness and are considerably higher than the $4/GJ typical of contracts entered before 2010 (Table 18). Some of the new contracts also link the gas price to oil prices, which is a feature of the LNG export market. This price level is expected to continue at least until 2018 and possibly beyond if additional reserves are more costly to develop.

Table 17 LNG project contracts with third party suppliers

<table>
<thead>
<tr>
<th>Seller</th>
<th>Operator</th>
<th>Buyer</th>
<th>Source</th>
<th>Delivery point</th>
<th>Term (years)</th>
<th>Total volume (PJ)</th>
<th>Annual volume (PJ)</th>
</tr>
</thead>
<tbody>
<tr>
<td>APLNG</td>
<td>QCLNG</td>
<td>QCLNG</td>
<td>Surat CSG Field</td>
<td></td>
<td>20</td>
<td>640</td>
<td>95 falling to 25 after 2016</td>
</tr>
<tr>
<td>Santos</td>
<td>Santos</td>
<td>GLNG</td>
<td>Cooper primarily</td>
<td>Wallumbilla?</td>
<td>15</td>
<td>750</td>
<td>50</td>
</tr>
<tr>
<td>AGL</td>
<td>QCLNG</td>
<td>QCLNG</td>
<td>Surat CSG Field</td>
<td></td>
<td>3</td>
<td>75</td>
<td>25</td>
</tr>
<tr>
<td>Origin</td>
<td>Unknown</td>
<td>GLNG</td>
<td>OE Portfolio</td>
<td>Wallumbilla</td>
<td>10</td>
<td>365</td>
<td>36.5</td>
</tr>
<tr>
<td>Origin</td>
<td>Unknown</td>
<td>QCLNG</td>
<td>OE Portfolio</td>
<td>Wallumbilla</td>
<td>2</td>
<td>30</td>
<td>15</td>
</tr>
<tr>
<td>Origin</td>
<td>Unknown</td>
<td>GLNG</td>
<td>OE Portfolio</td>
<td>Wallumbilla</td>
<td>5</td>
<td>100 Firm 94 Sellers option</td>
<td>20-39</td>
</tr>
</tbody>
</table>
Increasing contract prices are accompanied by increasing uncertainty about what current and future prices are or should be. This has been and will continue to be reflected in increasing differences between contract negotiation outcomes for different participants.

### Table 18 Recent domestic gas supply contracts

<table>
<thead>
<tr>
<th>Buyer</th>
<th>Seller</th>
<th>Date Entered</th>
<th>Wellhead Price</th>
<th>Annual Volume</th>
<th>Term</th>
<th>Indexation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Xstrata</td>
<td>AGL</td>
<td>Nov 11</td>
<td>$6/GJ</td>
<td>13 PJ</td>
<td>2013-23</td>
<td>CPI</td>
</tr>
<tr>
<td>Unknown</td>
<td>Santos</td>
<td>Feb 13</td>
<td>Towards $9/GJ</td>
<td>Low</td>
<td>2015-18</td>
<td>Unknown</td>
</tr>
<tr>
<td>Origin</td>
<td>Beach Petroleum</td>
<td>April 13</td>
<td>$6-9/GJ</td>
<td>17 PJ</td>
<td>2015-22</td>
<td>Oil price linked</td>
</tr>
<tr>
<td>Lumo</td>
<td>BHPB-Esso</td>
<td>May 13</td>
<td>Unknown</td>
<td>7 PJ</td>
<td>2016-18</td>
<td>Oil price linked</td>
</tr>
<tr>
<td>Origin</td>
<td>BHPB-Esso</td>
<td>Sep 13</td>
<td>$6-7/GJ</td>
<td>48 PJ</td>
<td>2014-22</td>
<td>Transitions to an oil link</td>
</tr>
<tr>
<td>Orica</td>
<td>BHPB-Esso</td>
<td>Nov 13</td>
<td>$6/GJ</td>
<td>14 PJ</td>
<td>2017-19</td>
<td>N/a</td>
</tr>
<tr>
<td>Santos</td>
<td>Nexus</td>
<td>Oct 13</td>
<td>$6/GJ</td>
<td>15 PJ</td>
<td>2013-18</td>
<td>N/a</td>
</tr>
<tr>
<td>Incitec Pivot</td>
<td>AGL?</td>
<td>Dec 13</td>
<td>$10/GJ</td>
<td>8.5 PJ</td>
<td>2015-16</td>
<td>CPI</td>
</tr>
<tr>
<td>Orica</td>
<td>Strike Energy</td>
<td>Mar 14</td>
<td>$6.00</td>
<td>17.5 PJ</td>
<td>2019-37</td>
<td>N/a</td>
</tr>
<tr>
<td>Orora</td>
<td>Strike Energy</td>
<td>Jun 14</td>
<td>$6.00</td>
<td>4.5 PJ</td>
<td>2019-27</td>
<td>N/a</td>
</tr>
<tr>
<td>Dow Chemical</td>
<td>Lakes Oil</td>
<td>Jul 14</td>
<td>n/a</td>
<td>Unknown</td>
<td>Unknown</td>
<td>N/a</td>
</tr>
<tr>
<td>Simplot Australia</td>
<td>Lakes Oil</td>
<td>Jul 14</td>
<td>n/a</td>
<td>Unknown</td>
<td>Unknown</td>
<td>N/a</td>
</tr>
<tr>
<td>AGL</td>
<td>Benarlis</td>
<td>Aug 14</td>
<td>n/a</td>
<td>17.25 PJ</td>
<td>2018-21</td>
<td>N/a</td>
</tr>
<tr>
<td>AGL</td>
<td>BHPB-Esso</td>
<td>Apr 15</td>
<td>n/a</td>
<td>66 PJ</td>
<td>2018-20</td>
<td>Oil price linked</td>
</tr>
<tr>
<td>AGL</td>
<td>Cooper Energy</td>
<td>Oct 16</td>
<td>n/a</td>
<td>12 PJ</td>
<td>2019-26</td>
<td>N/a</td>
</tr>
<tr>
<td>AGL</td>
<td>Cooper Energy</td>
<td>Oct 16</td>
<td>n/a</td>
<td>2 PJ</td>
<td>2019-26</td>
<td>N/a</td>
</tr>
<tr>
<td>Oil Australia</td>
<td>Cooper Energy</td>
<td>Oct 16</td>
<td>n/a</td>
<td>1 PJ</td>
<td>2019-26</td>
<td>N/a</td>
</tr>
<tr>
<td>EA</td>
<td>Cooper Energy</td>
<td>Dec 16</td>
<td>n/a</td>
<td>5 PJ</td>
<td>2019-26</td>
<td>N/a</td>
</tr>
</tbody>
</table>

Source: Media releases

In response to the price rises reflected in the above and parallel claims by industrial gas users that they are encountering difficulty obtaining price quotes, the Federal Government commissioned the ACCC to undertake the East Coast Gas Inquiry, which reported in April 2016. Key findings by the Inquiry are reproduced in Appendix D.11.

### D.8 Demand-supply and pricing methodology
The demand-supply balance and price projections for this study have been derived using Jacobs’ MMAGas (Market Model Australia – Gas) model which replicates the essential features of Australian wholesale gas markets:

- A limited number of gas producers, with opportunities to exercise market power
- Dominance of long term contracting and limited short term trading
- A developing network of regulated and competitive transmission pipelines
- Domestic demand driven by gas-fired generation and large industrial projects.
- Strong influence of LNG exports on supply availability for the domestic market.

MMAGas has been developed over a period of twelve years, to provide assessments of long term outcomes in the Australian gas market, including gas pricing and quantities produced and transported to each regional market including LNG:

- The gas market in MMAGas is the market for contracts between producers and buyers such as retailers or generators. Contracts durations can range from 1 to 20 years
- MMAGas combines information on gas demand and committed contracts to estimate the demand for new contracts as described above
- The PJ per year capacity of each producer to supply new contracts from its available uncontracted 2P reserves is based simply on reserves available divided by the timeframe for developing a gas resource plus the allowance for rundown gas described in section a). 2P reserves are assumed to grow limited by current 2C estimates.
- Allocation of new GSAs in each market zone to gas producers is based on the assumption that each producer seeks to control its volumes and prices to maximise its profit (revenue less cost of production) subject to constraints imposed by its competitors and its capacity to produce
- This competition between producers is represented as a Nash-Cournot game with the role of buyers replicated by modelling the activities of an arbitrage agent. Transmission costs are treated as production cost inputs, so the profit in each market zone is the volume times delivered price less delivered cost.
- A gas producer in MMAGas is generally a joint venture controlling major resources, such as the Cooper Basin JV (Santos, Beach and Origin Energy). Some resources effectively controlled by a JV but not part of it are added to the JV’s resources, such as the Kipper field in Gippsland, 35% owned by Mitsui, which is outside the BHPB-Exxon JV. This is consistent with the definition of gas reserves.

Gas producers are assumed to make joint sales and to compete fully with other JVs, even when the JVs have some common ownership. This may overstate the level of competition, however in practice this is offset by additional competition created by separate selling within some JVs.

MMAGas outputs have been benchmarked against gas production and transmission flows reported by AEMO on the “Bulletin Board” and against new GSA prices wherever such information is available. Historical contract prices have covered a narrow range relative to potential future prices and MMAGas’ ability to accurately project results outside of its development data range is not guaranteed. The projections made under any specific set of assumptions should not be regarded as absolutely precise, even though they are expressed as a single set of numbers.

The current implementation of MMAGas represents the eastern states market as up to twenty separate producers competing in nine separate domestic market zones plus one LNG export zone.

**D.8.1 LNG contract demand function**

The influence of LNG prices on domestic prices is specified via the LNG contract function, which specifies the value available to producers from supplying LNG projects. Gas supplied from the projects own reserves are considered pre-contracted and only the incremental project requirements are competed for (where project JV reserves are insufficient), such as the contracts supplied by Santos and Origin to GLNG.
The LNG demand function assumes that gas producers and liquefaction owners share in the LNG netback value at Gladstone. The netback value is the delivered price of LNG less the costs of liquefaction and shipping. Netback value can be calculated using short or long-run costs and the appropriate value depends on the status of the LNG plants. During the planning phase, when none of the project costs have been committed, long-run costs are appropriate but during operations, short-run costs should be used. Consequently, in this study, where no new LNG trains are constructed, short-run costs are used.

In reality netback value will also vary between LNG projects, however as we are unable to differentiate between the costs/revenue of the various projects, a single value is used in this study. We have used Gladstone as the netback point rather than a gas field because gas for LNG is sourced from more than one field and because Gladstone is the relevant point of competition for supply between LNG and other demand.

The delivered price of LNG from Gladstone depends primarily on the price of crude oil (using the Japan Customs-cleared Crude (JCC) measure) and the $US/$A conversion rate, and secondarily on the link between LNG prices in $US/mmbtu and the JCC price in $US/bbl. For this study we have used a direct linkage without a cap or floor, namely LNG Price = 1 + 0.14 * JCC price. This formula is believed to apply to GLNG contracts and implies that at $US100/bbl oil, the LNG price is $US15/mmbtu.

Jacobs has used a fixed oil price of $US55/bbl for this study, combined with an Australian $ value of $0.75 $US/$A. This results in an LNG netback value of $A9.50/GJ at Wallumbilla. Jacobs estimates that short-run liquefaction plus shipping costs are approximately $A1.25/GJ.

For the purposes of constructing the LNG demand function it is assumed that the purchaser will not be prepared to pay more than the netback value at Gladstone for gas delivered to Gladstone, because a higher price would render the LNG project uneconomic. GSA sellers are assumed to be unwilling to sell at a price below their cost of production plus transmission to Gladstone, which for typical CSG producers would be in the range $4.50/GJ to $5.50/GJ. A value of $5/GJ is assumed in all modelling. The LNG demand function used in the Nash-Cournot model assumes that forecast demand is met at a price mid-way between these extremes, as illustrated in Figure 62. Only the medium price is used in this study.

**Figure 62 LNG contract demand functions**

![LNG Contract Price vs. LNG Contract Price](image)

*Source: Jacobs’ analysis; refer to text for explanation*

**D.8.2 Further assumptions**

---

65 GLNG Project FID, 13 January 2011, and Santos Investor Presentation, March 2011, both available at www.Santos.com
A key assumption is the number of competing gas producers and the gas resources available to them. The number of producers competing in the Eastern Australian gas market is currently modelled as the 18 joint ventures represented in Table 12 and Table 13. Up to now transmission costs have presented a barrier to producers competing in all nine zonal markets, however higher gas prices may enable low cost producers to compete in all markets.

Future reserve additions and changes in uncontracted reserves of the producers are projected using MMAGas. MMAGas can also accommodate changes in industry structure such as gas reserve additions in new provinces, market entry by new producers and reductions in the number of producers due to mergers or takeovers. However these changes are not calculated within the model but must be input as data – our base case assumption is that the number of producers remains static and only their resources and costs change.

The modelling assumes that all producers with uncontracted reserves will compete to sell to the domestic market. In view of the difficulties currently being experienced by domestic buyers in engaging producers in discussions about long-term domestic gas contracting it is legitimate to question when producer interest in the domestic market will return.

### D.9 Gas wholesale market scenario summary

The key parameters in the two scenarios are summarised in the table below.

#### Table 19 Key scenario parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Base Scenario</th>
<th>Hazelwood 2022 Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas resources</td>
<td>Arrow resources available progressively</td>
<td>Arrow resources available progressively</td>
</tr>
<tr>
<td>Gas Production costs</td>
<td>As per Table 15</td>
<td>As per Table 15</td>
</tr>
<tr>
<td>Oil prices</td>
<td>Ave $US55/bbl</td>
<td>Ave $US55/bbl</td>
</tr>
<tr>
<td>Exchange rates$^{66}$</td>
<td>Ave $US0.75$/A</td>
<td>Ave $US0.75$/A</td>
</tr>
</tbody>
</table>

Source: Jacobs’ analysis

### D.10 Gas Market Projections

#### D.10.1 Gas Supply

The chief characteristics of the Base Case (Base price) projected eastern Australian gas supply over the next twenty years are, as shown in Figure 63:

- Gippsland Basin – declines rapidly after 2017 owing to the very limited 2C resources available for further development
- Otway and Bass basins – similar pattern to Gippsland
- Cooper Basin – very limited from 2017 to 2020, then grows back to 60 PJ/yr, due to development of unconventional resources.
- NSW CSG – very limited development after 2020
- Queensland CSG – declines slightly until early 2020s then expands with development of resources additional to LNG requirements. Accounts for 50% of supply by 2030s

$^{66}$ The average exchange rate across the modelling horizon is presented here
• NT Gas – enters the market in 2019 and grows to 50 PJ/.

• Price Effect – This is the price induced reduction in demand compared to the demand forecast. In other studies, such as the GSOO, this is depicted as a shortfall.

Supply in the Hazelwood Late Scenario is the same apart from 2017.

Figure 63: Projected gas supply, eastern Australia domestic market, Base Scenario

![Projected gas supply, eastern Australia domestic market, Base Scenario](source)

Source: Jacobs’ analysis

Figure 64  Projected gas supply, Victoria, Base Scenario

![Projected gas supply, Victoria, Base Scenario](source)

Victorian gas supply is projected to include non-Victorian sources after 2020. Victoria moves from having a price advantage over other states due to local supply, to having a price disadvantage owing to longer transmission distances and higher transmission costs for all non-Victorian sources. This price disadvantage translates into Victoria bearing a higher proportion of the price induced reduction in demand.
Remaining Victoria gas reserves are shown in Figure 65. Reserves are projected to decline steadily through the period.

**Figure 65: Remaining Victorian 2P gas reserves**

![Graph showing remaining Victorian 2P gas reserves](image)

*Source: Jacobs' analysis*

### D.10.2 Upstream gas price projections

Gas price projections for Victoria and Wallumbilla, the CSG Benchmark, are presented in Figure 66 and Figure 67. All prices are for gas delivered to zonal hubs (i.e. include transmission costs) and are expressed in real $2017 terms. Two prices are presented for each point:

- The estimated price of new 5-year gas contracts starting in a particular year (Figure 66)
- The estimated average price over all gas contracts delivering gas in any year (Figure 67)

In each market a single price is estimated for both new contracts and for the average price, whereas the prices in actual contracts in the same market may differ from one another (refer to section 0). It is expected that these differences would be most pronounced during periods of rapid price change, that is, 2016 to 2020 based on the projections presented below.

At both delivery points, new contract prices are expected to rise sharply for several years, to almost $9/GJ at Wallumbilla and over $10/GJ in Victoria. Prices at Wallumbilla then fall, eventually to $7.50/GJ, under the influence of increasing CSG availability. However, prices in Victoria remain high owing to the transition in Victorian supply from local reserves to non-Victorian reserves.

Average contract prices reflect the progressive addition of new contracts to the aggregate contract portfolio, at higher prices. The sharp rise in 2018 reflects the substantial re-contracting that occurs in that year.

Differences between the Base and Hazelwood scenarios are relatively limited, as may be expected given the small volume differences between them. The volume change in 2017 has repercussions in later years, with both positive and negative price changes (Hazelwood minus Base). It is difficult to trace through the precise reasons for these though it is clear that changes in new contract prices give rise to the changes in average prices.
Average price differences between the scenarios over the period 2016-2035 are approximately 10c/GJ in Victoria and 20c/GJ at Wallumbilla.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>New Contract Price</th>
<th>Average Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Victoria</td>
<td>-$0.11/GJ</td>
<td>-$0.10/GJ</td>
</tr>
<tr>
<td>Wallumbilla</td>
<td>-$0.20/GJ</td>
<td>-$0.14/GJ</td>
</tr>
</tbody>
</table>

D.11  ACCC East Coast Gas Inquiry Key Findings

Gas supply
1) Domestic purchasers of gas, particularly industrial users, experienced an unprecedented change in their ability to obtain gas, especially in the period from about 2012 to the end of 2014 for gas to be supplied in 2016 and beyond. When seeking gas they received few, if any, real offers. Offers received were high priced, with limited volumes over shorter periods of time, had more restrictive terms and conditions and some were on ‘take it or leave it’ terms.

2) More gas supply offers are now available, but at higher prices, for shorter durations and with more restrictive non-price terms and conditions. Domestic industrial users may have seen margin reductions of 0.6–6.0 percentage points, depending on the industry and the wholesale gas price increases. Household gas bills may increase by 5 per cent in New South Wales and 11 per cent in Victoria with wholesale gas price increases of, for example, $2/GJ.

3) The reliability of future gas supply is affected by three significant factors coinciding:
   a. Significant demand from the LNG projects, which has diverted gas from traditional sources of domestic supply.
   b. Low oil prices reducing the ability and incentive of producers across the entire east coast gas market to explore for and develop gas.
   c. Moratoria on onshore gas exploration and development and other regulatory restrictions in New South Wales, Victoria and Tasmania, and potentially the Northern Territory, prohibiting new gas supply.

4) The future supply outlook is uncertain. Future domestic and LNG demand will require extensive development of undeveloped gas reserves. Sufficient gas is currently forecast to be produced in the east coast gas market to meet domestic demand and existing LNG contract commitments until at least 2025, but there is uncertainty over the timing of some developments, particularly due to low oil prices.

5) There is a need for more sources of gas supply, particularly in the southern states. The gas users in these states are becoming overly dependent on the jointly marketed GBJV gas. If their alternative to dealing with the GBJV is to transport gas from Queensland, southern users may have to pay considerably more for gas than they are otherwise likely to pay in a competitive market. This is exacerbated by the high cost of transportation. Increasing the level and diversity of supply, located close to southern demand centres, will improve the competitive dynamics in the south and is likely to lead to better pricing outcomes for domestic users.

Gas transportation

1) Pipeline operators have responded to the changes underway in the market. There is, however, evidence that a large number of pipeline operators have been engaging in monopoly pricing. This gives rise to higher delivered gas prices and is having an adverse effect on the economic efficiency of the east coast gas market and upstream and downstream markets, the costs of which will ultimately be borne by consumers. There is also evidence that the ability and incentive of existing pipeline operators to engage in this behaviour is not being effectively constrained by competition from other pipelines, competition from alternative energy sources, the risk of stranding, the countervailing power of shippers, regulation or the threat of regulation.

2) The current gas access regime is not imposing an effective constraint on the behaviour of a number of unregulated pipelines. The current test for regulation under the National Gas Law (NGL) (the coverage criteria) is not designed to address the market failure that has been observed in this Inquiry, that is, monopoly pricing that results in economic inefficiencies with little or no effect on the level of competition in dependent markets. Other gaps in the regulatory framework are also allowing pipelines that are subject to regulation to continue to engage in monopoly pricing. Information asymmetries are limiting the ability of shippers to identify any exercise of market power and to negotiate effectively with pipeline operators.

3) Less than 20 per cent of the transmission pipelines on the east coast are currently subject to regulation under the NGL and National Gas Rules (NGR). This is in direct contrast to other comparable jurisdictions, such as the United States, the European Union and New Zealand, where the vast majority of transmission pipelines are regulated. It is well recognised in these jurisdictions that pipelines can wield substantial market power even where producers and users have a number of transportation options.
Market operation and the level of market transparency

1) The gas specification required by the LNG projects is different to the specification required by other gas users. This difference has the potential to impede the free flow of gas across the east coast gas market and impose additional costs on some market participants, potentially bifurcating the market, and reducing liquidity and opportunities for trading and arbitrage.

2) Lack of transparency and information about the level of reserves, and commodity and transport prices are hindering efficient market responses to the changing conditions and are not signalling expected supply problems effectively.

3) Trading of longer-term capacity held by shippers is occurring across the east coast. Shorter-term capacity trades are also occurring but not on all pipelines. There is no evidence of withholding of capacity by shippers on major east coast pipelines.

4) However, there is evidence that capacity is being withheld by incumbents on some regional pipelines, which is restricting competition for supply from other retailers.

5) APA has taken steps, in conjunction with AEMO, to improve transparency around gas flows into the Wallumbilla compound which services the Wallumbilla GSH. Some concerns remain as to the transparency of actual hub services being delivered and the pricing of those services.

6) Risk management mechanisms are becoming more important for buyers, and especially industrial users, as the terms and conditions of supply are tightened by suppliers. These include storage and gas trading mechanisms such as the STTMs. The liquidity of gas trading mechanisms is currently limited. In the long-run, liquidity will be best supported by an increase in the diversity of gas market participants and the volume of gas supply in the market overall. At present, there is no evidence that access to storage capacity on reasonable terms is a significant barrier to entry by smaller retailers in the east coast gas market. This may become a more significant issue in the future if the volume of gas available for supply into the market increases.

D.12 Natural gas

Natural gas is a blend of hydrocarbons, principally methane, and inert gases found in sandstone, carbonate and shale reservoirs and in coal seams, at depth in the earth’s crust. Sometimes the term natural gas is reserved for processed gas while gas in a field is called raw gas. Gas is frequently categorised as conventional (sandstone and carbonate reservoirs with good porosity and permeability and therefore free flowing) or unconventional (low permeability reservoirs or tight gas, shale gas and coal seam gas or CSG and needing additional stimulation to flow to the surface in commercial quantities67). In Australia CSG is currently the dominant unconventional gas though shale gas commenced production in 2012. Figure 68 illustrates typical accumulation structures.

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67 Also known as coal seam methane (CSM) and coal bed methane (CBM). CSG, CSM and CBM are terms used for gas recovered by drilling into coal seams from the surface. The term coal mine methane (CMM) is generally used to refer to gas recovered from coal seams in association with coal mining.
From a discovery and production perspective conventional and unconventional gases are different – a single well can discover or confirm a large conventional field but unconventional fields are more extensive and need to be tested at regular intervals. After removal of liquids and inert gases in the processing plant to meet quality standards for pipelines, in transmission, distribution and end-use, there is little distinction other than small differences in heating value and so the two are virtually interchangeable.

Liquid hydrocarbons such as oil and condensates are found in the same types of reservoirs as natural gas, sometimes in association in the same reservoir - the term petroleum is used to cover all naturally occurring mixtures of hydrocarbons in the gaseous, liquid, or solid phase. This has had a very material impact on gas discovery as much conventional gas has been discovered in the search for more valuable oil. However there are no liquid hydrocarbons with CSG and all CSG is found by deliberately searching for coal seams from which it can be extracted economically. Other forms of unconventional gas however can be liquids rich and the liquids content affects the exploration effort.

D.13 The exploration and production sector

Exploration and production (E&P) sector participants seek to discover, market, and produce hydrocarbons. Apart from some involved solely with CSG, most are multi-product firms and many sector decisions are based upon multi-product considerations. Many of the products, including natural gas, are sold into both domestic and export markets.

Petroleum results from geological processes and is found in underground reservoirs or coal seams at depths ranging from several hundred metres for the latter up to several thousand metres for the former. Rights to underground resources vest in the relevant jurisdictional government, or the Commonwealth where they are in Australian territorial waters.

The jurisdictions generate or collect pre-competitive geological information regarding potential petroleum resources and regularly call for bids from participants for permits to explore defined exploration lease areas. Permits are awarded on the basis of participant commitments to explore by means of seismic surveys and by drilling wells. A hydrocarbon discovery may be converted into either a production lease, if development is to proceed immediately, or a retention lease, if production is not at that time commercially viable but is expected to become so within 15 years. Retention leases are granted for periods of 5 years, after which they can be

Queensland does not have separate retention leases. Retention is managed under the Authority to Prospect (a potential commercial area). However, the concepts of retention are the same as other States.
renewed, and authorities can require lessees to re-evaluate the commercial viability of petroleum production in a lease area once during the term of a lease. Permits that are unsuccessful are relinquished and may be tendered.

The above aspects of offshore E&P are governed by the Offshore Petroleum and Greenhouse Gas Storage Act (OPGGS, Commonwealth), with similar jurisdictional legislation governing onshore E&P. National policy is determined by the Standing Council on Energy and Resources (SCER). Resource extraction in Australia is generally subject to royalty payments in addition to income tax – offshore petroleum resources are subject to the Petroleum Resources Rent Tax (PRRT) and onshore resources are subject to both jurisdictional royalty regimes and PRRT - royalty payments are deductible expenses under the onshore PRRT.

Producers market gas domestically to buyers such as retailers, generators and large industrial users. The structure of these transactions is determined by the participants, with almost all being long-term arrangements that lock-in prices and quantities with limited flexibility for a number of years.

Once petroleum has been discovered, the scale and quality of the resource must be estimated. Resource evaluations focus on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

The Society of Petroleum Engineers (SPE) resources classification system evolved out of international efforts to standardize the definitions of petroleum resources and how they are estimated. The system is now in common use internationally within the petroleum industry.

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. Interpretation considers both technical and commercial factors that impact the project’s economic feasibility, its productive life and its related cash flows. For these reasons, estimates of reserves can vary significantly depending on the interpreter. Further, the category in which resources are placed can vary between interpreters.

The term “resources” is intended to encompass all quantities of petroleum naturally occurring on or within the Earth’s crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered “conventional” or “unconventional.”

Figure 69 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production; Reserves; Contingent Resources; and Prospective Resources, as well as Unrecoverable petroleum.

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69 Victorian onshore retention leases are granted for a single term of up to 15 years
70 Geoscience Australia uses the McKelvey reserves classification system which uses demonstrated, inferred and undiscovered resources. The US Energy Information Administration uses proved and probable categories which can be related to the SPE classification.
The “Range of Uncertainty” reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the “Chance of Commerciality”, that is, the chance that the project that will be developed and reach commercial producing status.

Resources and reserves estimates for newly discovered fields are based on the geological and geophysical information gathered during the discovery process, combined with engineering and economic factors relating to commerciality. For fields in production, reserves are re-estimated using production data. While there are some variations in approach, there are generally accepted methods of estimating discovered resources. The undiscovered resource potential of a region is a quantitative assessment of the potential to discover a stated level of new reserves if (further) exploration were to take place in the region. In contrast to assessment of discovered resources, there are no universally accepted methods of assessing undiscovered resource potential.

From a commercial perspective the 2P reserve category is crucial, because it is generally the level of reserve security required to underwrite long-term gas sales contracts that provide sales volume and revenue security for reserve developments. For this reason 2P reserves estimates receive more scrutiny than other figures and 2P data is more readily available than data for other classifications.

Gas reserves are often quoted as volumes, particularly in the early stages. However, gas supplied under contract has a particular energy value when burnt and contracts are stated in energy values (typically PJ). 1 billion cubic feet (Bcf) of methane has an energy value of 1.055 PJ. However, domestic gas is not pure methane as it contains a proportion of higher hydrocarbons and inert gases. For example, for typical Gippsland gas 1 Bcf has an energy value of 1.0987 PJ.
Appendix E. Retail operating costs

E.1 Retail costs and margins in other jurisdictions

This literature review was to look for evidence of the difference between net and gross margins for gas and electricity retailers and the size of internal company costs. Jacobs’ also had limited, confidential, access to information for some retailer’s operating costs for the purpose of understanding context.

Retail operating costs (costs an electricity retailer must undertake to supply energy to its customers) are generally considered to consist of:

- Billing and revenue collection costs;
- Call centre costs;
- Customer information costs;
- IT systems;
- Corporate overheads;
- Energy trading costs;
- Regulatory compliance costs; and
- Other costs – including depreciation, customer acquisition costs and retention costs FRC-related costs.

The cost categories described above are typically either fixed costs or costs that are driven by the number of customers. Some costs which are considered to be fixed (such as IT systems costs), can grow when customer numbers hit a given threshold and systems require upgrade. These types of costs provide benefits to growing retailers for a period of time as increasing customer numbers provide economies of scale and a larger customer base to enable cost recovery.

Customer acquisition and retention costs include marketing campaigns, discounts and other incentives for customers to switch retailers or offers, or to encourage retention if an existing customer. Depending on the sales channel chosen, costs of customer acquisition can be expensive and create a significant cost burden on the business overall, sometimes being almost as much as a retailer’s net margin. The implication is that such costs need to be recovered over the remaining customer base.

The cost of acquiring new customers in most industries is notionally thought to be around 5 times more than the cost of retaining customers. There does not appear to be any evidence however that this is true in the energy space where customer loyalty may be less than in other industries because energy is seen as a commodity rather than a service.

The difference between the cost of retaining existing customers and acquiring new customers is very material to how a business can keep costs low, as is the average retention time for new customers. If customer acquisition costs are high and annual profits per customer are low, it may take years to make up the cost of new customer acquisition, and operating costs for all customers serviced by a retailer could increase rather than reduce. If the average time of retention is also low, it is possible that retailers may never make up the cost of acquisition.

E.2 Current estimates of retail costs and margins

Regulators in Australia have tended to determine an appropriate allowance for retail operating costs using one or both of the following approaches:

- Assessment of the actual retail operating costs of existing retailers; and
- Benchmarking against allowances for retail operating costs in other regulatory decisions and against public information on these costs.

The approach used and the weight of each approach (if both are used), are driven largely by practical considerations, such as access to useful data on actual retail operating costs and the need to determine
efficient costs through benchmarking\textsuperscript{71}. Table 21 provides a summary of regulated costs and margins across Australian jurisdictions in 2015-16.

Table 21 Summary of regulated costs and margins in Australia in 2015-16, $/customer

<table>
<thead>
<tr>
<th>Jurisdiction</th>
<th>Retail margin</th>
<th>Cost to serve excluding customer acquisition and retention costs, $/customer</th>
<th>Cost to serve including customer acquisition, $/customer</th>
</tr>
</thead>
<tbody>
<tr>
<td>NSW</td>
<td>5.7%</td>
<td>$150</td>
<td></td>
</tr>
<tr>
<td>ACT</td>
<td>5.7%</td>
<td>$117.53</td>
<td>$169.67</td>
</tr>
<tr>
<td>Queensland</td>
<td>5.7%</td>
<td>$169.67</td>
<td></td>
</tr>
<tr>
<td>Tasmania</td>
<td></td>
<td></td>
<td>$159.14</td>
</tr>
</tbody>
</table>

As comparison to the regulated costs outlined above, AGL had cost-to-serve for the consumer market of $108/customer in 2015-16, while Origin Energy had a cost-to-serve of $148/customer\textsuperscript{72}. Both retailers reported cost of customer acquisition and retention, but the data appear to have been calculated over different bases (one cost is spread over the entire customer base while the other appears to be on a per acquisition basis), so these are not comparable. Furthermore it is not clear whether the AGL and Origin estimates include the same types of costs considered in the regulated retail cost allowances based on the descriptions provided in these companies’ annual reports.

E.3 Australian jurisdictions

E.3.1 NSW – IPART

Electricity

New South Wales ceased regulating standing offer retail electricity prices as of 1 July 2016, but it undertook a thorough review of what regulated prices should be in 2013.

In its 2013 review of standing offer prices, the authority determined a Retail Operating Cost (ROC) allowance of $110.00 per customer (with an adjustment to remove costs recovered through late payment fees of $3.80 per customer) and a customer acquisition and retention cost of $40.00 per customer for 2015-16. It represented the mid-point of their estimated range for the NSW Standard Retailer’s efficient retail operating costs, and was consistent with the ROC incurred by publicly listed companies and other regulators’ decisions. Information on NSW Standard Retailers came from businesses’ historic, current and forecast ROC, and adjusting the results to remove costs recovered elsewhere in the regulatory package and any inefficient costs. This allowance was held constant in real terms through the determination period to incorporate an increase in productivity\textsuperscript{73}.

As part of its 2013 investigation, IPART engaged Strategic Finance Group (SFG) consulting to undertake a retail margin analysis and IPART’s determination of the retail margin was based on the mid-point of the reasonable range recommended by SFG. SFG derived this range by using 3 alternative approaches for estimating the margin (as it did for the 2010 and 2007 determinations): expected returns, benchmarking and bottom-up. IPART set the margin as a fixed percentage of total costs over the determination period\textsuperscript{74}.


\textsuperscript{73} AGL and Origin annual reports for financial year ending June 2016; The Origin report is available from https://www.originenergy.com.au/content/dam/origin/about/investors-media/senate-submission-carbon-risk-disclosure-160331/Origin_Annual_Report_2016.pdf

\textsuperscript{74} OTTER, 2016; IPART, 2013

\textsuperscript{75} IPART, 2013
The expected returns approach resulted in a range of retail margin from 2.7% to 3.6%. The expected returns approach involves estimating the expected cash flows that a retailer will earn from small customers and the systematic risk associated with these cash flows, and then determining a retail margin that will compensate investors for this systematic risk\(^75\).

SFG analysed a sample of 692 listed retailers from 1980 to 2012 in its benchmarking exercise, which comprises 7,990 annual observations. Firms were from the United States, United Kingdom, Australia, Canada and New Zealand classified by FTSE as “Retail” and for which data was available, but excluding the sector Specialised Consumer Services. SFG excluded observations in which ratios were above the 99th percentile or below the 1st percentile so conclusions were not based upon extreme outcomes. The range was 5.1% to 5.4%. SFG also did a bottom-up analysis, based on 12 transactions of electricity and gas retailers over the 12 year period from 1999 to 2010. The reasonable range was 4.4% to 5.7%.

IPART determined the CARC allowance based on the desired regulated retail prices needing to be $22/MWh above the efficient short-term cost of supply to promote a level of competition that is in the long-term interests of customers, as well as promote efficient cost recovery. It found a CARC allowance from $8 to $13/MWh nominally was sufficient for the level of regulated prices to be $22/MWh above the forecast short-term efficient cost of supply in 2013-14. The estimates are also based on bottom-up analysis, based on actual costs incurred by retailers.

**Gas**

IPART considered in its 2013 review of regulated retail prices and charges for gas that a range for retail operating costs in 2013/14 was $91 to $106 per customer. Its range is based on bottom up analysis based on retailers’ forecast ROC per customer and benchmarking from regulated electricity prices\(^76\).

Information provided by the Standard Retailers suggests that their estimated ROC is in the range of $91 to $106 nominally per gas customer, with a mid-point of $99 per customer in 2013/14. Its range does not include customer acquisition and retention costs as competition for gas customers tends to focus on dual fuel customers, so that some of the costs associated with customer acquisition and retention costs are shared across electricity customers too.

The benchmarking showed gas retail operating costs are in the order of $17 per customer lower than for electricity retail operating costs and this is consistent with the information from gas Standard Retailers. The most significant differences is that electricity bills are higher than gas bills, so electricity companies have about twice as high bad debt costs than gas retailers.

IPART engaged SFG to assist in estimating an appropriate range for the retail margin of gas retail suppliers. SFG’s final advice was that this range is 6.3% to 7.3% of earnings before interest, tax, depreciation and amortisation (EBITDA). This is lower than the range IPART determined to be reasonable as part of the 2010 determination, which was 7.3% to 8.3% of EBITDA. The recommendations were based on an expected returns approach (4.7% to 6.0%), the benchmarking approach (6.2% to 6.4%) and a bottom-up approach (8.1% to 9.6%)\(^77\).

**E.3.2 Queensland – Queensland Competition Authority**

**Electricity**

The QCA regulated a retail operating costs allowance of $169.67 per customer in 2015-16, with $123.07 per customer for retail operating costs and $46.60 per customer for customer acquisition and retention costs\(^78\). This

\(^75\) IPART (2013)


determination maintained the allowance from the 2013-14 determination, based largely on IPART’s 2013 decision\textsuperscript{79}.

\textbf{E.3.3 ACT - ICRC}

In June 2015, the ICRC approved a retail margin of 6.04\% for 2015-16 (6.04 per cent in ex ante terms is the equivalent of a retail margin of 5.7 per cent applied ex post). This margin was applied to all cost components, excluding the retail margin allowance itself. This resulted in a retail margin allowance of $10.15 per MWh for 2015-16\textsuperscript{80}. The Commission adopted IPART’s retail operating cost allowance of $110 per customer\textsuperscript{81}.

\textbf{E.3.4 Tasmania - Office of the Tasmanian Economic Regulator (OTTER)}

Electricity

Tasmania has a partially regulated retail electricity market. It undertakes pricing investigations to make its determinations of maximum prices that Aurora Energy may charge small customers under standard retail contracts for electricity services on mainland Tasmania. The maximum prices are set based on a notional tariff base and notional maximum revenue. The notional maximum revenue includes costs to supply standard retail services to small customers and a retail margin allowance\textsuperscript{82}.

In 2016 OTTER undertook a price determination for the period 1 July 2016 to 30 June 2019. It determined a retail margin of 5.7\% for 2016-19, based on comparing the level of risk facing Aurora Energy with the risks facing electricity retailers in other Australian jurisdictions. It determined a cost-to-serve allowance of $138.56 per customer, based on an operating cost build up from Aurora Energy and benchmarking from other jurisdictions\textsuperscript{83}. See Table 22.

Table 22  Aurora retail price determination summary data

<table>
<thead>
<tr>
<th></th>
<th>2015-16</th>
<th>Aurora Energy Preliminary Submission</th>
<th>Final report (2016-17)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Retail margin ($m)</td>
<td>25.584</td>
<td>25.039</td>
<td>25.899</td>
</tr>
<tr>
<td>Number of customers</td>
<td>228,951</td>
<td>226,878</td>
<td>239,446</td>
</tr>
<tr>
<td>Cost-to-serve ($m)</td>
<td>36.436</td>
<td>34.059</td>
<td>33.151</td>
</tr>
<tr>
<td>Cost-to-serve ($/customer)</td>
<td>159.14</td>
<td>150.12</td>
<td>138.45</td>
</tr>
</tbody>
</table>

The Tasmanian Government engaged Ernst and Young in 2013 to recommend a Notional Maximum Revenue requirement for retail electricity services to small customers in Tasmania for 1 January 2014 to 30 June 2016. It recommended a cost to serve of $108 per customer per annum in 2014 (in 2011-12 dollars) and a CARC of $42 per customer. It used data from Aurora and Australian regulation benchmarks to determine this, with the estimates at the higher end of the range due to Aurora needing to serve customers in isolated regions and lots of customers that require more service time. It recommended a retail margin of 6.9\%, at the top of the SFG report’s international benchmark range, to encourage greater competition into the retail market\textsuperscript{84}.

As part of this report, Aurora Energy stated that its actual retail operating costs for an average small customer in 2012-13 was $119 and $123.62 in 2011-12 (in 2011-12 dollars), with an allocation of its common costs to customers based on the number of bill accounts. The report also includes a chart that breaks down Aurora’s


\textsuperscript{82} OTTER, 2016

\textsuperscript{83} OTTER, 2016

\textsuperscript{84} Ernst and Young (2013) Retail Price Submission to Tasmanian Department of Treasury and Finance. Available from http://www.energyregulator.tas.gov.au/domino/otter.nsf/LookupFiles/132014_Ernst_and_Young_revised_Retail_Price_Submission_18_June_2013.PDF?openfile/132014_Ernst_and_Young_revised_Retail_Price_Submission_18_June_2013.PDF
costs in 2012-13 (business as usual and under TSA) into components - management (roughly $0.8 m under business as usual), call centre ($6.5 m), billing ($2.5 m), credit ($4 m), connections and data ($3 m), commercial analysis ($2 m), and regulatory, in 2012-13 dollars\textsuperscript{85}.

E.3.5 South Australia – ESCOSA

The South Australian Government deregulated electricity and gas retail prices on 1 February 2013. The Commission no longer has responsibilities in the setting of gas or electricity standing contract prices or electricity reselling prices\textsuperscript{86}.

Gas

The Commission’s final determination of gas retail operating cost allowances in 2011 is shown below. The base costs were subject to a 2% annual efficiency target, while other components received annual CPI escalation. The cost allowances were based on benchmarking with the electricity determination, Origin Energy’s actual cost structure and testing a weighted average ROC allowance for electricity and gas against actuals provided by Origin\textsuperscript{87}. The ROC and CARC amounts are shown in Table 23.

Table 23 Final determination on ROC allowance, 2011/12 to 2013/14, $/customer, $Dec11

<table>
<thead>
<tr>
<th></th>
<th>2011/12</th>
<th>2012/13</th>
<th>2013/14</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base ROC</td>
<td>$79.05</td>
<td>$77.47</td>
<td>$75.92</td>
</tr>
<tr>
<td>REES</td>
<td>$2.62</td>
<td>$2.62</td>
<td>$2.62</td>
</tr>
<tr>
<td>Total ROC allowance</td>
<td>$108.04</td>
<td>$106.46</td>
<td>$104.81</td>
</tr>
</tbody>
</table>

9.3.1 Western Australia – Economic Regulation Authority

Frontier Economics undertook a study for the Economic Regulation Authority of Western Australia on the actual retail operating costs reported and forecast by Synergy and the efficient level of retail operating costs in Western Australia for the period of 2012-13 to 2015-16. The commercial information on Synergy’s prices was redacted. Frontier economics did provide a survey of regulated cost-to-serve determinations, shown below\textsuperscript{88}. The results reveal values ranging from $65/customer to $115/customer. See Figure 70.

\textsuperscript{85} Ernst and Young, 2013
\textsuperscript{86} ESCOSA (no date) Pricing and access. Available from \url{http://www.escosa.sa.gov.au/industry/gas/pricing-access}
\textsuperscript{87} ICRC, 2011
\textsuperscript{88} Frontier Economics (2012)
E.3.6 AGL 2016 annual report

AGL provides data by consumer market and business market, including a breakdown of net operating costs in the consumer market. In 2015/16, EBIT was reported as $108/customer for the consumer mass market part of the business (i.e. residential and small business retail arm of AGL).

E.4 New Zealand comparison

New Zealand does not have regulated prices for retail electricity. There is only a legislative role under the Commerce Act for the Commerce Commission to regulate markets where there is little or no competition. The Commerce Commission regulates transmission and distribution services.

Pulse energy is a community owned energy retailer providing electricity and gas, servicing over 58,000 customers throughout New Zealand. Pulse energy was taken over by Buller Electricity in early 2016.

The operating results for Pulse are displayed in Table 24. These results may be useful for understanding the scale of costs in a retailer, particularly as no similar data is available for retailers in Australia. Notably, when comparing the ratios of costs to total costs, bad debts were highly significant, around 8% of all retailer costs (not including network or wholesale costs). AGL reported that bad debts were around 14% of total retailer operating costs.

<table>
<thead>
<tr>
<th>Year to March 2015 results</th>
<th>Pulse energy ($NZ* and $A)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Retail energy revenue</td>
<td>99,406,946 ($A92,064,086)</td>
</tr>
<tr>
<td>Meter services revenue</td>
<td>294,264 ($A272,528)</td>
</tr>
<tr>
<td>Interest income</td>
<td>394,494 ($A365,354)</td>
</tr>
<tr>
<td>Bad debts recovered</td>
<td>430,500 ($A398,700)</td>
</tr>
</tbody>
</table>

---

91 It is possible that overheads, customer acquisition and computing costs have been excluded from the total.
<table>
<thead>
<tr>
<th>Year to March 2015 results</th>
<th>Pulse energy (€NZ$ and $A)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Other income</td>
<td>1,247,754 ($A1,155,587)</td>
</tr>
<tr>
<td>Total revenue</td>
<td>101,773,958 ($A94,256,255)</td>
</tr>
<tr>
<td>Electricity, gas, line and meter expenses</td>
<td>90,476,116 ($A83,792,947)</td>
</tr>
<tr>
<td>Employee benefits expenses</td>
<td>5,948,502 ($A5,509,106)</td>
</tr>
<tr>
<td>Bad and doubtful debts</td>
<td>984,812 ($A912,067)</td>
</tr>
<tr>
<td>Computers and communication</td>
<td>480,752 ($A445,240)</td>
</tr>
<tr>
<td>Sales and marketing</td>
<td>909,905 ($A842,693)</td>
</tr>
<tr>
<td>Professional services fees</td>
<td>503,959 ($A466,733)</td>
</tr>
<tr>
<td>Other expenses</td>
<td>3,140,103 ($A2,908,154)</td>
</tr>
<tr>
<td>Total operating expenses</td>
<td>102,444,149 ($A94,876,941)</td>
</tr>
<tr>
<td>Profit/(Loss) before Finance Costs, Tax,</td>
<td>(670,191) (-$A620,686)</td>
</tr>
<tr>
<td>Depreciation, Amortisation, Fair value Movements</td>
<td></td>
</tr>
<tr>
<td>and Other items</td>
<td></td>
</tr>
<tr>
<td>Profit/(Loss) before Income Tax</td>
<td>(38,602) (-$A35,751)</td>
</tr>
<tr>
<td>Customers</td>
<td>54,761</td>
</tr>
</tbody>
</table>

*Converted using the average exchange rate for the year to March 2015 from monthly exchange rates from http://www.rbnz.govt.nz/statistics/b1
Appendix F. Offer results by network

F.1 Standing offers

These charts show, by distribution area, the trends in retail standing charges overlaid against the least and highest cost retail offers.

Figure 71 through to Figure 75 describes changes in standing offers for each area. The charts each indicate that the dispersion between cheapest and most expensive offers has grown over time and that trends have generally been increasing for residential consumers until 2013 levelling thereafter. Standing offer prices have remained quite level for business consumers.

Figure 71 Movement in standing offers, Ausnet services

Residential 2,000 kWh p.a.  
Residential 4,000 kWh p.a.  
Residential 6,000 kWh p.a.  
Business 10,000 kWh p.a.
Figure 72  Movement in standing offers by customer type, CitiPower

Residential 2,000 kWh p.a.  Residential 4,000 kWh p.a.

Residential 6,000 kWh p.a.  Business 10,000 kWh p.a.
Figure 73  Movement in standing offers by customer type, Jemena

Residential 2,000 kWh p.a.  
Residential 4,000 kWh p.a.

Residential 6,000 kWh p.a.  
Business 10,000 kWh p.a.

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Min  Max  Average
Figure 74 Movement in standing offers by customer type, Powercor

- Residential 2,000 kWh p.a.
- Residential 4,000 kWh p.a.
- Residential 6,000 kWh p.a.
- Business 10,000 kWh p.a.
Figure 75  Movement in standing offers by customer type, United Energy

- Residential 2,000 kWh p.a.
- Residential 4,000 kWh p.a.
- Residential 6,000 kWh p.a.
- Business 10,000 kWh p.a.
Appendix G. Gross margin analysis by distribution area

G.1 Residential

This section presents residential standing offer gross margins received by retailers in each distribution area and for various customer usage classes. For the various distribution services area, these are displayed in Figure 76 to Figure 80. All charts are indicative of one-year-ahead retail hedging strategies, and do not include any carbon repeal adjustment.

G.2 Business

Figure 76 to Figure 80 present gross margin results for small business customer standing offers. The diversity of price offerings is wide, and appears to be much wider than for the residential sector. Note the particularly high increase in the maximum prices following the Hazelwood retirement announcement.
Figure 76  Gross retail margin in Ausnet services area
Figure 77  Gross retail margin in CitiPower area
Figure 78  Gross retail margin in Jemena area
Figure 79  Gross retail margin in Powercor area

Gross retail margin in Powercor area for 2,000 kWh, 4,000 kWh, and 6,000 kWh over the period from May 2009 to May 2017.
Figure 80  Gross retail margin in United Energy area

2,000 kWh

4,000 kWh

6,000 kWh
Figure 81  Trends in retailer gross margin for other distribution areas: Business 10,000 kWh pa

Ausnet

CitiPower

Jemena

Powercor

United Energy