



The Australian Industry Group

# FROM WORSE TO BAD

## Eastern Australian Energy Prices

July 2018



The Australian Industry Group

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## About Ai Group

The Australian Industry Group (Ai Group) is a peak employer association which together with partner organisations represents the interests of 60,000 businesses employing more than 1 million Australians.

Ai Group members are from a broad range of industry sectors including manufacturing; engineering; construction; food and beverage processing; transport and logistics; information technology; telecommunications; labour hire; and defence.

Ai Group is also the employer shareholder in the Trustee of AustralianSuper - a leading Australian superannuation fund.

With more than 250 staff in offices across NSW, QLD, SA, VIC and WA, we have the resources and the expertise to meet the changing needs of our members. We provide the practical information, advice and assistance to help members run their businesses more effectively.

Ai Group also offers members a voice at all levels of government through our policy leadership and influence. Our deep experience of industrial relations and workplace law positions Ai Group as the leading advocate on behalf of enterprises large and small across Australia.

We intrinsically appreciate the challenges facing industry and remain at the cutting edge of policy debate and legislative change – and strategic business management advice.

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*Cover: 'The Destruction of Pompeii and Herculaneum', by John Martin (1822); and 'Christ's Descent Into Hell', by a follower of Hieronymus Bosch (16<sup>th</sup> century)*

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# Foreword



Energy should be boring. Like many technically complex goods and services that underpin our lives and work, we only pay attention when something has gone wrong. The prominence of energy in political debate is a very bad sign.

Ai Group played a leading role in warning of the gas and electricity price surge that buffeted Eastern Australian businesses and households over the past year. Building on our earlier research, our 2017 report, *Energy shock: no gas, no power, no future?* put into stark terms the scale of the challenge created by an

export-led gas price rise and a much tighter electricity market dependent on gas generation.

Over time, warnings from industry were heeded: the Federal Government and the States, the energy market authorities, the gas and electricity industries, and industrial energy users themselves have taken action and produced results. The Australian Domestic Gas Security Mechanism led to agreement with the gas exporters to alleviate a looming gas shortage. Mothballed gas generators came back online, industry committed to provide demand response, big batteries materialised with extraordinary speed, and the 2017-18 summer passed without major supply problems.

The improvement goes beyond supply security: prices for electricity and gas in 2018 are significantly down from 2017. But as this report outlines, the improvement is strictly relative. We've gone from worse to bad. Energy prices are set to remain well above their historic average, sapping the competitiveness of many industries and putting households under pressure. Can we go from bad to good?

The future of gas prices looks bleak for gas users: supply costs are high and exports have permanently transformed the market. New supply is essential to avert a return to the scarcity pricing of 2017, but gas users will likely have to economise, fuel switch, or leave Eastern Australia in search of cheaper gas.

The future of electricity prices could be much brighter for users, given the rapidly falling cost of key technologies. But there are two big barriers to overcome:

- Gas generation is currently essential, but if gas prices are going to stay high, its role must shrink.
- Over a decade of political warfare on climate creates immense uncertainty for energy investment.

The National Energy Guarantee is a technology-neutral approach to cutting emissions, maintaining reliability and improving affordability. It can be a durable mechanism for investors to plan around. The COAG Energy Council and Federal Parliament need to find compromises, and make energy boring again.

Innes Willox

A handwritten signature in black ink that reads "Innes Willox". The signature is written in a cursive, slightly slanted style. Below the signature is a long, thin horizontal line.

Chief Executive

Australian Industry Group

# Executive Summary

Eastern Australia faces a severe energy cost challenge.<sup>1</sup> Gas and electricity prices increased to extraordinary levels in 2017, before recovering significantly in 2018. However, prices are expected to remain far above their historic averages for the foreseeable future. Businesses, particularly those in energy intensive industries, are under pressure. Steep energy price rises are proving difficult to pass on to customers and are squeezing margins across a wide range of industries. All else being equal, rising energy costs make Australian industry less competitive compared to overseas firms. Hard decisions must be made to ensure Australia's energy system will be secure and affordable into the future. This report seeks to answer three key questions about the Eastern Australia energy cost challenge and provide recommendations for a lower cost energy future.

## What is going on with energy prices?

- In 2017, wholesale electricity prices more than doubled from their 2015 levels across the National Electricity Market and gas prices offered to industry were as much as six times their recent levels. So far in 2018, spot electricity prices have dipped in New South Wales, Queensland and Tasmania, while holding slightly higher in South Australia and Victoria; electricity futures prices decline significantly over the next two years. Wholesale gas prices have fallen from their extreme peaks. Both gas and electricity prices remain far above the historical average.
- Business expects their energy prices to worsen. When surveyed in late 2017, almost three quarters (71%) of businesses expected price increases in 2018. In the past year, 65% of businesses had retail energy price increases, while 8% had price decreases. Most businesses commit to energy contracts of more than one year, and price increases take time to filter through.

## Who is affected by recent energy price rises?

- Energy is a fundamental input to production and the living standards of households. Wholesale price rises are the main factor contributing to energy price rises in recent years and industrial businesses are generally more exposed to the wholesale prices for gas and electricity than households.
- Once fully passed through, the recent electricity and gas price increases will cost energy users \$9.4-\$11.7 billion per year. Households will pay up to an extra \$3.4 billion a year, and business up to \$8.4 billion a year. Within business, more energy intensive manufacturers will be particularly hard hit, paying up to \$3.9 billion a year. This will worsen margin pressures for business, with some manufacturers questioning their ongoing viability as a result.
- Companies in primary metals manufacturing, refining, basic chemicals and non-metallic mineral products (including building products) are particularly exposed to a double hit to their profitability from steep electricity and gas price increases.

## What is driving energy prices?

- Gas prices have risen because of the massive rapid expansion of Liquefied Natural Gas (LNG) exports from Eastern Australia (which has driven up production costs, linked local prices to international markets, and driven a shortage of contractable gas); and to a lesser extent the restriction by several states and territories on development of new gas supplies.
- Electricity prices have risen because fuel costs for gas fired generators have increased. These generators play a key role in setting prices, and this role has grown with the closure of several old coal-fired generators.

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<sup>1</sup> Western Australia and the Northern Territory have separate electricity and gas markets from the East Coast (though the Northern Gas Pipeline will shortly bring some Northern Territory gas East) and have not been subject to the same pressures in recent years. This report focusses on Eastern issues.

# Recommendations

## **Increase the supply of gas**

There is limited potential to further reduce wholesale gas prices. Federal Government pressure has seen gas exporters make more gas available to the domestic market in the near term, easing scarcity-induced extremes. More supply from undeveloped Queensland reserves, LNG imports, Northern Territory shale and potentially New South Wales and Victorian onshore resources is essential to help avoid future scarcity. However, production and transport costs for these options, combined with international price pressures, suggest prices will remain well above historical levels.

## **Reduce the role of gas**

Gas generation currently plays a critical role in meeting electricity demand and setting electricity prices. But if this role persists, the high cost of gas will keep electricity prices high. Reducing the volume of gas generation is achievable with cheap variable renewables but displacing gas as the key source of dispatchable and flexible capacity would be more complex. We need to remove barriers to all the many potential sources of dispatchable capacity to achieve globally competitive electricity prices in the longer term. Beyond the electricity sector, industrial, commercial and residential gas users may have growing opportunities to switch away from gas.

## **Agreement on the National Energy Guarantee**

Electricity futures prices fall moderately over the next two years as more supply is brought in by the Renewable Energy Target (RET). Low costs for new generators mean further supply should be able to sustain this reduction, but deep uncertainty over energy and climate policy beyond 2020 is holding back investment. A durable negotiated agreement over the National Energy Guarantee will unblock necessary investment. Full implementation of the Finkel reforms, including the Integrated System Plan and a mechanism to reward demand response, will also contribute to unblocking investment.

## **Implementation of new technologies and reforms to support energy efficiency**

If wholesale energy prices remain elevated, other sources of price and cost reduction are needed. Pro-competitive reforms to gas markets and networks remain a high priority. Electricity network cost growth has paused or slightly reversed in most places, but continuing pressure is needed for cost efficiency and the use of demand management where it is cheaper than new infrastructure. Above all, improvements to energy efficiency and productivity are essential. As energy users in countries with a longer history of high prices demonstrate, overall energy costs can be moderated by new technologies, improved practices, and upgrades and improvements to existing equipment and processes that significantly reduce the energy required to do business.

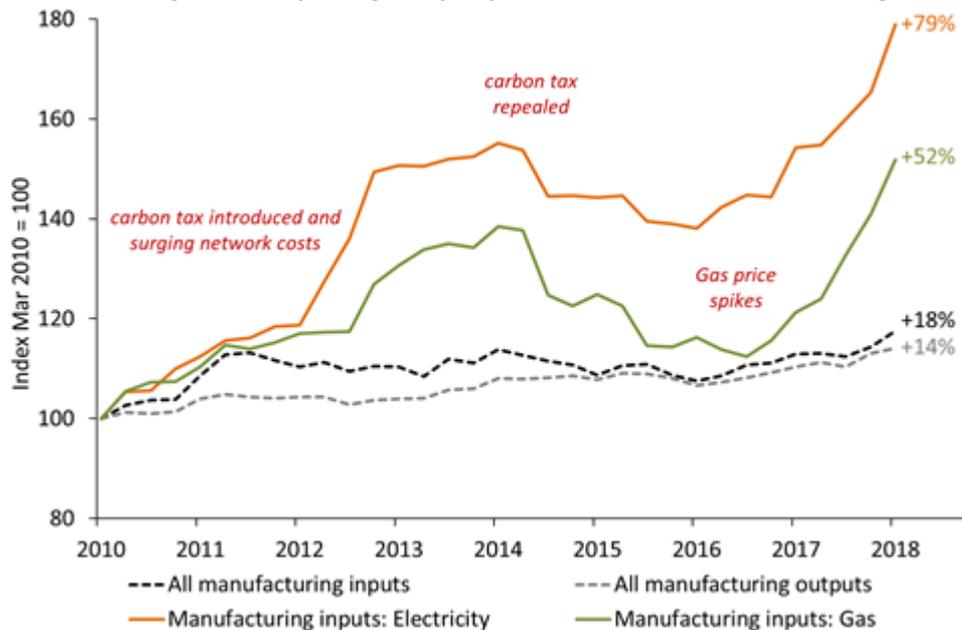
PART ONE

## What is going on with energy prices?

Recent data from the Australian Bureau of Statistics (ABS) confirm widespread reports of outsized energy price rises in Ai Group’s monthly Australian PMI®, Australian PSI® and Australian PCI® throughout 2017-18 and in the 2018 National CEO Survey. Among businesses, Australia’s producer price index (PPI) indicate that energy price rises are a major input cost pressure across all industries, but particularly for many manufacturers.

ABS data continues to demonstrate the cumulative impact of energy price rises. Electricity input prices for manufacturers are at a new high and 79% higher than prices paid at the start of the decade. Gas prices have increased 52% over the same period (Chart 1). This has contributed to manufacturing input prices rising faster than output prices. As set out in Part Two, energy intensive manufacturers are the businesses hardest hit by rising energy prices and their high trade exposure leaves little ability to pass on cost increases to customers.

**Chart 1: Manufacturing electricity and gas input prices indexes, cumulative change\*, 2010 to 2018**



\* producer price indexes rebased to March Quarter 2000 = 100.  
 Source: ABS, *Producer Price Index*, Mar 2018.

### Wholesale electricity prices have surged and partly abated

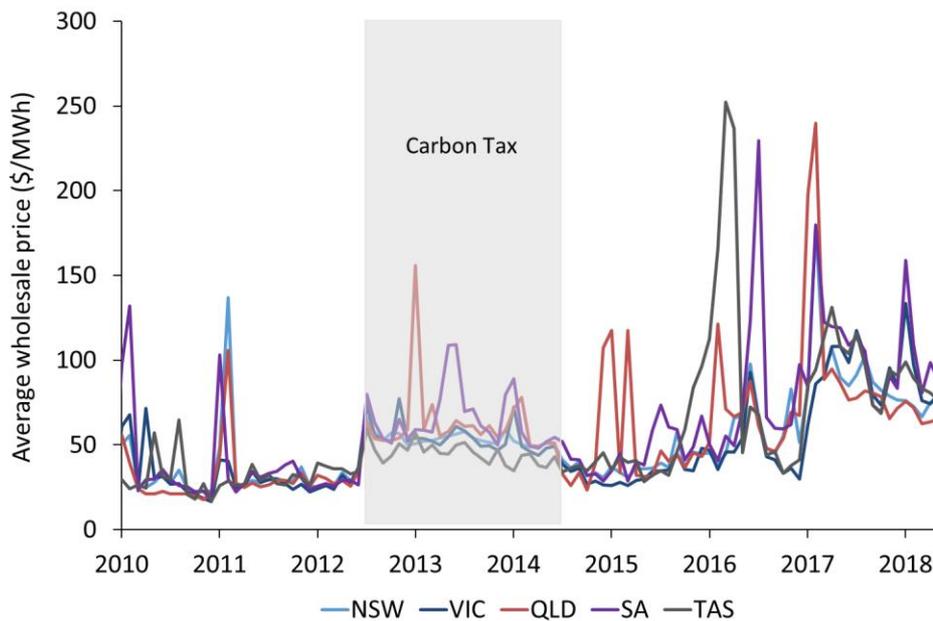
In 2016, some forecasters expected retail electricity prices to decline over the next few years<sup>2</sup>, as network costs eased and wholesale electricity prices were expected to remain low to 2020 because of a loose market with significant amounts of renewable generation added under the RET. Instead, electricity prices have surged, driven mainly by wholesale prices.

Short price spikes are a common occurrence in the electricity market, but as Chart 2 illustrates, the level and the volatility of wholesale electricity prices increased through 2016 and the start of 2017. This means higher retail prices, particularly for larger business users. Over 2017, average wholesale electricity prices increased 57% in New South Wales, 44% in Victoria, 55% in Queensland and 76% in South Australia. This follows substantial price increases in 2016. Large energy intensive businesses signing contracts in 2014 and 2015 faced exceptionally low prices, with the removal of the carbon price coinciding with weak demand and strong oversupply. Those same users coming off these low-priced contracts are now dealing with a

<sup>2</sup> Retail electricity price history and projections, Jacobs, May 2016

new, much higher level of wholesale electricity prices. The cumulative increase across 2016 and 2017 in average wholesale electricity prices was 131% in New South Wales, 119% in Victoria, 77% in Queensland and 176% in South Australia.

**Chart 2: Average monthly wholesale electricity prices**



Source: AEMO

While wholesale spot prices have increased dramatically over the past two years, spot market data for 2018 and base futures prices<sup>3</sup> for 2018 and beyond indicate that prices have peaked and will decline over the next few years as set out in Table 1 and Chart 3. While there are regional factors, overall this decrease reflects the loosening of the supply-demand balance as substantial amounts of generation capacity enter the market, largely driven by the RET. This decrease is significant and is benefitting energy users now, since futures prices directly influence the contract prices retailers offer industry. However, it is important to note that despite the looming fall, wholesale prices still look set to remain well above historic levels. Furthermore, futures for 2021 currently show a small uptick from 2020 levels, though the longest-dated futures are relatively thinly traded and may simply be taking longer to reflect the falling trend in earlier contracts.

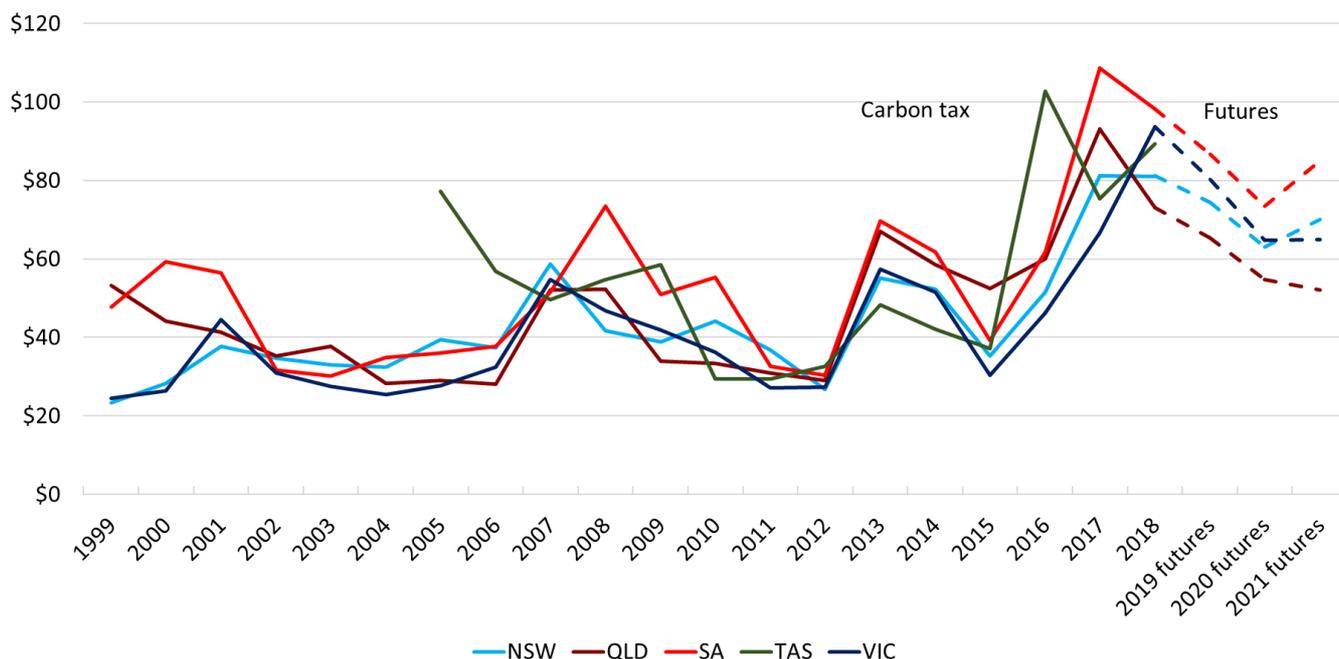
**Table 1: Wholesale electricity price reductions**

Region	Base futures 2020 (\$/MWh)	Reduction from peak (%)	Notes
NSW	\$60	26%	Prices partly track QLD
QLD	\$53	43%	Changes in state-owned generator bidding suppress prices
SA	\$74	32%	Most gas dependent state
VIC	\$61	35%	Returning to alignment with NSW

Source: AEMO, ASX Energy; futures prices are as at 20 June 2018

<sup>3</sup> Futures prices are financial contracts for a specified amount of electricity at a forward date. These represent the prices that can be contracted by retailers, generators, large users of electricity and financial market participants. Note that base futures prices are not directly comparable to historical electricity prices. Cap prices are usually added to the base futures price to reflect the total cost of wholesale electricity to the retailer. Caps are financial products designed to protect retailers from periods of very high prices in the wholesale market.

Chart 3: Average wholesale electricity prices – historical and futures



Source: AEMO, ASX Energy. Prices depicted are nominal.

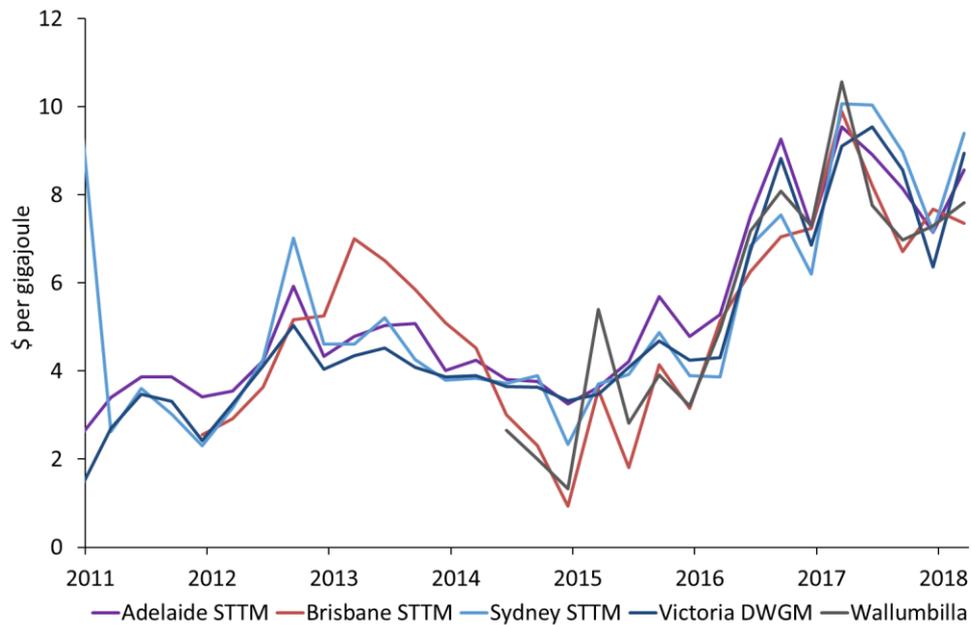
### Gas prices have fallen from their peak but remain elevated

The Australian natural gas industry is separated into three distinct markets: the East Coast, Western Australia and Northern Territory<sup>4</sup>. The location of gas basins and pipeline networks geographically separate the markets.

As outlined in Part Two, business gas users (particularly large ones) are heavily exposed to wholesale gas prices. The gas market is less transparent than the electricity market and pricing is often difficult to determine because gas is sold through confidential bilateral contracts. However, the Australian Energy Market Operator (AEMO) operates several balancing markets in Sydney, Brisbane, Adelaide and across Victoria, as well as a gas trading hub at Wallumbilla (Queensland). This allows some observation of trends in wholesale gas prices through recent years. Prices rose steeply in the first half of 2017 and averaged around \$10 per GJ in Q1 2017, before dropping to average between \$6.00 and \$7.50 per GJ in Q4 of 2017. This is approximately double the \$3 to \$4 per GJ range previously experienced in the domestic wholesale gas market before it was exposed to the international market.

<sup>4</sup> The Northern Territory and Western Australian markets have different pricing dynamics to the East Coast market and are not the focus of this report. The Northern Territory is currently the smallest market and largely produces LNG for export purpose. A pipeline project to link the Northern Territory to the East Coast market is due for completion in 2018. Western Australia has the largest gas reserves in Australia and primarily converts natural gas to LNG for export. The state first started shipping LNG in 1989 from the North-West Shelf.

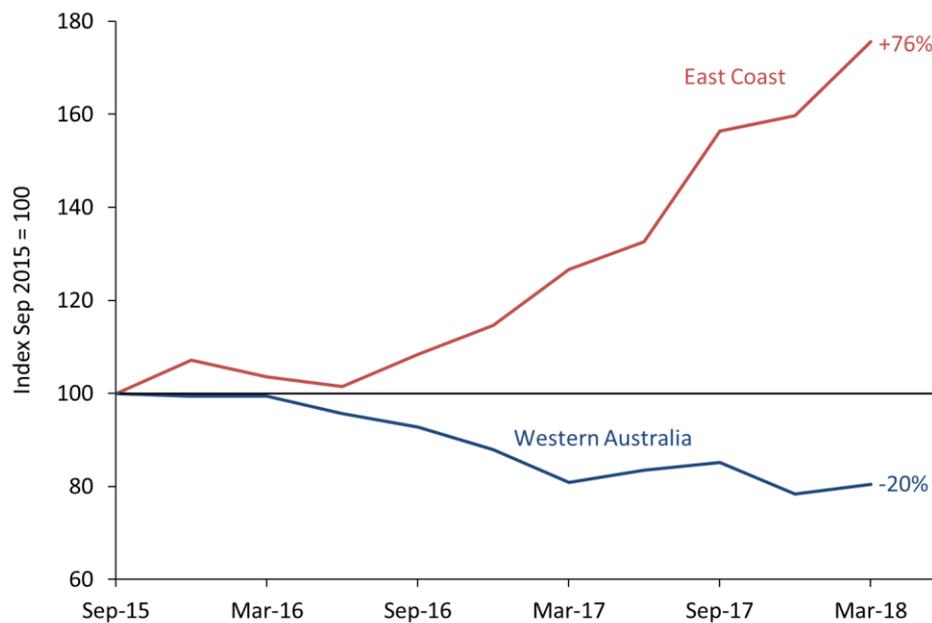
Chart 4: Quarterly average wholesale gas prices



Notes: STTM stands for Short Term Trading Market. DWGM stands for Declared Wholesale Gas Market. STTM prices are ex-post. DWGM is the average daily weighted imbalance price.  
Source: Australian Energy Regulator

In response to the significant expansion of the Australian natural gas market, the ABS recently began publishing data to measure price changes in the domestic natural gas industry. The new series measure change in the prices received by producers of natural gas on the domestic market<sup>5</sup>. Since September 2015, prices received by producers on the domestic East Coast market have jumped 76%, while the equivalent prices in the domestic Western Australian market were down 20%.

Chart 5: Change in prices received by natural gas producers on the domestic market



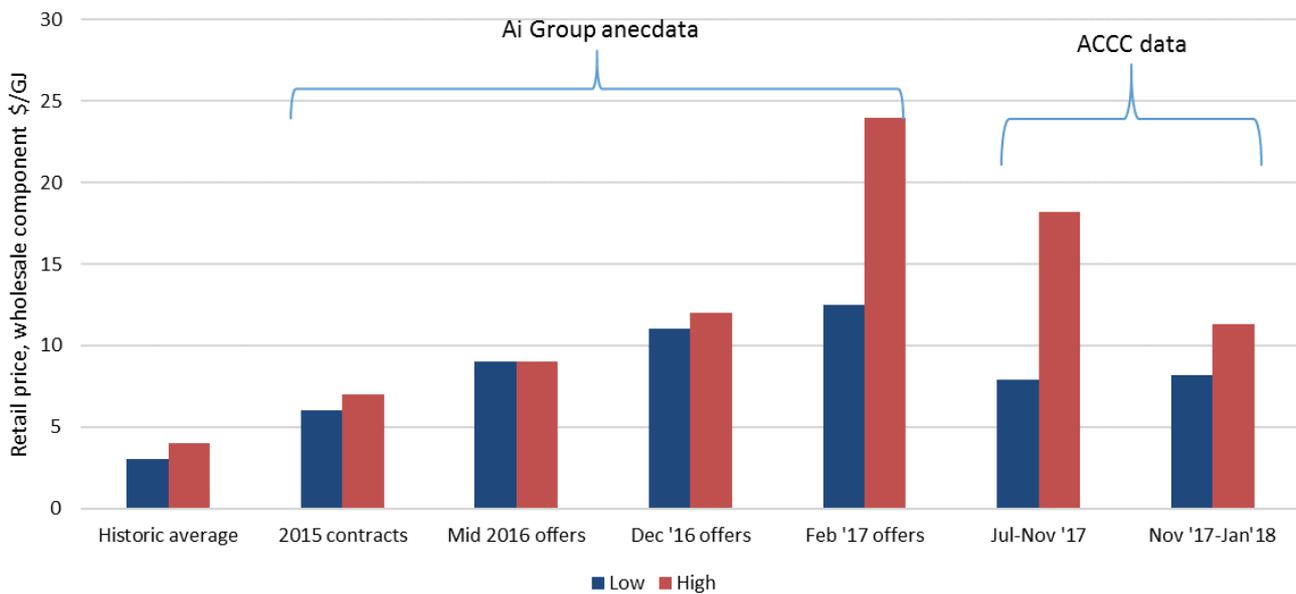
Source: ABS, *Producer Price Index*, Mar 2018.

<sup>5</sup> Prices are measured at basic prices, which exclude taxes and subsidies, transport costs and trade margins. The new series intends to measure price change of all market transactions. Sampled prices reflect a representative mix of market transactions, with the dominant mechanism in the market for the sale of natural gas currently being medium-to-long term bilateral contracts (ABS, 2017).

The prevalence of bilateral contracts has made the gas market very opaque, with little direct connection between the prices visible in spot or balancing markets and the outcomes facing consumers. Ai Group has heard from a range of members over the past few years about their historical, current and offered gas prices. Since mid-2017 the ACCC has been tasked with reporting on the state of the gas market, drawing on their investigatory powers to compel provision of information by suppliers and users. Putting the data and anecdotes together gives the picture in Chart 6 below.

Historically, industrial gas customers often paid \$3-4 per gigajoule; contracts signed around 2015 were often for around \$6/GJ; in late 2016 prices offered to industrial customers began to rise rapidly, peaking above \$20/GJ in the first half of 2017. Since that time the prices offered have roughly halved from the most extreme levels of 2017, to around \$10/GJ. Although much better than 2017, these price levels are still dramatically higher than the historic average, and present a substantial challenge to more gas-intensive businesses.

**Chart 6: Rapid rise and partial fall of industrial retail gas price offers**

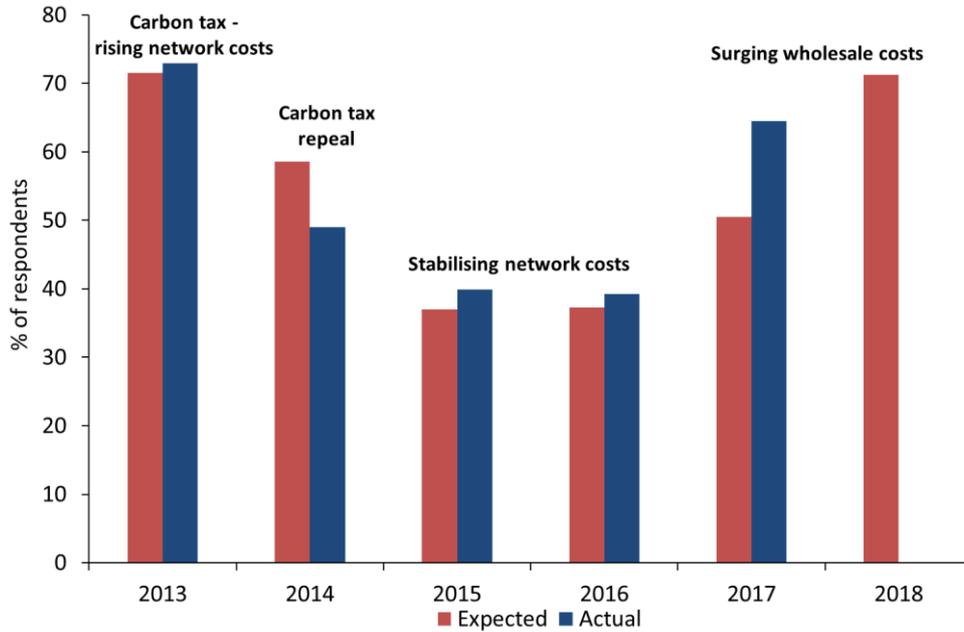


Source: Ai Group, ACCC

**Businesses expect prices to get worse**

Ai Group’s 2018 National CEO Survey shows energy prices are one of the biggest headwinds identified by otherwise optimistic businesses for 2018. Energy prices remain elevated compared to historical levels for Australian businesses, with many increasingly concerned about the unnecessary strain high energy prices are putting on profit margins. Energy costs have been a persistent issue over the much of the last decade, with enduring price hikes caused by surging network costs, a brief spike from the former carbon tax and now changes in wholesale markets are bringing fresh pressure to energy prices.

**Chart 7: Percentage of businesses with increasing energy prices – actual and expected**



Source: Ai Group

Rising energy prices (and reliability of energy supply) are a key risk for Australian businesses. Price rises were larger than expected in 2017. At the start of the 2017, 50% of businesses expected energy prices to increase, compared to 65% of businesses at the end of 2017 that reported higher energy prices. Energy costs are expected to get worse in 2018, with almost three quarter of CEOs (71%) expecting energy costs for their businesses to rise further.

Prices are rising for a broad range of businesses, although manufacturers seem to be feeling the most pain:

- 80% of manufacturers experienced price hikes in 2017. Of those with increased prices, the average increase was 31%.
- 63% of services businesses experienced increasing prices in 2017. Of those with increased prices, the average increase was 9%.
- 63% of construction businesses experienced price increases in 2017. Of those with increased prices, the average increase was 9%.

Expectations for energy prices in 2018 are also pessimistic, with almost three quarter of CEOs (71%) expecting energy input costs for their businesses to rise further in 2018 and less than 1% expecting a decrease. Around 29% of businesses expect no change, which may reflect that their supply contracts are not due for renewal in 2018, or that their energy prices are already elevated. Increasing costs appear to be a common theme across industries for 2018:

- A large 85% of manufacturers expect an increase energy prices, with only 3% expecting reductions.
- 68% of services businesses expect an increase in energy prices and 0% expect a decline in prices.
- 80% of construction businesses expect an increase in energy costs while 0% expect a decrease.

Although the majority (67%) of CEOs expect their total turnover to grow in 2018, gross profit margins are expected to grow in only 41% of businesses in 2018. The low expectations of margin growth relative to expectations of sales growth is related to expectations of rising input prices and especially rising energy prices for the majority of businesses.

## Reliability and security developments

Aside from pricing pressures, the adequacy and reliability of energy supply has come into question. Significant amounts of valuable industrial production have been at risk (or lost in some recent cases). Reliability of energy supply is valuable to manufacturers, although an excessive level of reliability can easily cost more to achieve than it is worth.

Following the closure of several other coal-fired power plants, the sudden retirement of Hazelwood in 2017 raised fears that supply might be inadequate over the 2017-18 summer, particularly in South Australia and Victoria, if weather were extreme and output from variable renewables was low. However, in the end, the system avoided major incidents during this time. There were localized failures in the distribution network in Victoria because of hot weather, but this did not affect the wider market.

This outcome was due to a combination of actions by the market operator, Federal and State Governments, energy users and generators to make available both extra generation capacity and ‘demand response’, or users willing to be paid to reduce their load or turn on their own generation when conditions are tight. Furthermore, while average temperatures in late summer and early autumn have been unusually high, this summer passed without the sort of multi-state extreme temperature events that most challenge the electricity system.

The latest reliability assessment for the Australian Energy Market Commission projects that the current reliability standard (no more than 0.002% unserved energy, or at least 99.998% of annual demand being met) will be well and truly met in all regions of the National Electricity Market through 2023<sup>6</sup>. This includes a base scenario where the announced closure of the Liddell power plant in NSW goes ahead and no additional uncommitted capacity is added to replace it.

There should now be greater confidence that the immediate threat to reliability has greatly reduced. However, in the longer term, further closure of old assets will require timely reaction and investment by the market to maintain reliability. The National Energy Guarantee (see Recommendations and Part Four) is an opportunity to help ensure this market response occurs. It is important to note that increasing reliability comes at a cost; energy retailers have recently begun passing through the costs of the Reliability and Emergency Reserve Trader (RERT) mechanism, which helped deliver reliability through the recent summer. There is no evidence of an appetite from energy users to pay the significant additional costs that would be entailed by raising the existing reliability standards to ‘zero tolerance’ levels.

With respect to gas, 2017 saw grave fears of a substantial gap between gas demand and contractable gas supply emerging as a result of the rapid growth of exports and the slower growth of production. Eastern Australian domestic gas demand was around 700 petajoules (PJ) until recently, including demand from industry, households and the power sector. LNG exports have added around 1400PJ of demand. Left unresolved, a supply gap might have constrained output from gas fired electricity generators and manufacturers. However, action by the Federal Government through the Australian Domestic Gas Security Mechanism led to a commitment by the gas exporters to supply (on commercial terms) as much gas to the domestic market as necessary to avert a shortfall. This has had a positive but limited effect on price (see Part Three) and has greatly eased near term shortfall concerns. AEMO no longer projects a risk of supply shortfall.<sup>7</sup>

Over the longer term current gas resources will decline, particularly the conventional offshore oil and gas production in the Gippsland Basin. A range of new medium or long-term supply options to offset this decline are available, likely to go ahead, or are already going ahead. These and other resource options should mean that Eastern Australia can avoid absolute scarcity of gas supply. They include:

- further Queensland coal seam gas (CSG) development, particularly Shell’s Arrow reserves (close to final investment decision (FID), 240PJ per year from around 2021);
- LNG import terminals proposed by Australian Industrial Energy and AGL (FID 2018-19, potentially ~100PJ per year each

<sup>6</sup> AEMC, Reliability Panel Final Report, 30 April 2018.

<sup>7</sup> AEMO, 2018 Gas Statement of Opportunities (June 2018) <https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities>.

from 2020-21);

- New South Wales CSG development at Narrabri (FID unknown, regulatory approvals uncertain, could deliver 50PJ/year from early 2020s);
- shale gas development in the Northern Territory along with new pipeline capacity to the eastern market (supply volumes undetermined but potentially very large, must comply with strong new regulatory regime, plausibly at large scale from mid-2020s); and
- onshore conventional gas development in Victoria, if current geological investigations are favourable and the ban on conventional drilling is lifted (volumes completely unknown; potential production from mid-2020s).

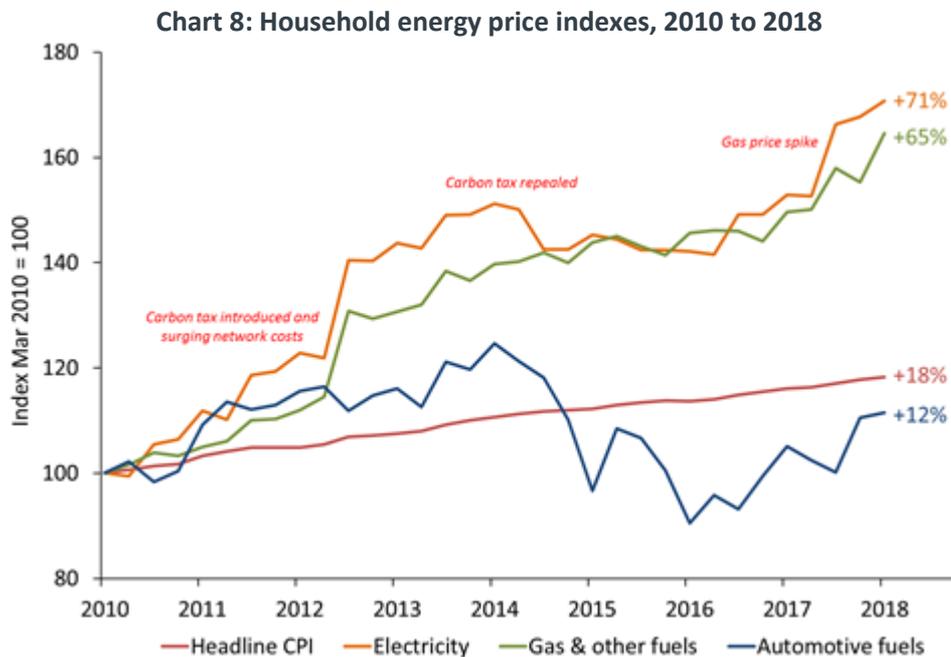
PART TWO

## Who is affected by the recent energy price rises?

### Households were hit hard by rising network costs in 2012

Energy is a fundamental input to produce output for businesses and to sustain the living standards of households. Prices for electricity and gas are made up of wholesale costs for the energy; charges for the networks that bring the energy to users; fees for retailers' costs; and costs related to government policies and levies. The mix of these elements in an energy bill and the total price paid varies dramatically for different energy users (see Table 2 below).

As can be seen in Chart 8, electricity and gas prices increased sharply for households around 2012. This coincided with the introduction of the former carbon tax, but most of the increase was due to surging electricity network investments. Only a small portion of the increase was reversed when the carbon tax was repealed, and prices have since increased due to recent wholesale cost increases being passed onto consumers. From 2010 to 2014, household electricity prices increased by 51% compared to 12% between 2014 to 2018.



Source: ABS, Consumer Price Index, Mar 2018.

### Wholesale energy price rises particularly hurt industrial users

Recently wholesale costs (the costs of the energy itself, rather than the costs of transporting it or retailing it) have been the main driver of increasing prices. Businesses vary from small operations with a low energy intensity and prices similar in level and structure to households, all the way through to large energy-intensive industrial facilities with big bills and low prices.

Industrial businesses are generally more exposed to wholesale prices for gas and electricity than households because:

1. energy is a relatively minor expense for most households compared to rent or other input costs<sup>8</sup> (although rising energy costs do impact vulnerable households, and the economy through reduced household consumption); and
2. wholesale prices make up more of the electricity bill for large industrial users, with network costs a smaller share.

<sup>8</sup> Domestic fuel and power, including electricity and gas, was 2.9% of average household weekly expenditure in 2015-16; see ABS Household Expenditure Survey 2015-16.

Businesses face various and complex pricing structures from retailers that differ by the size and characteristics of their energy use, as well as the distribution area that the business is in. Table 2 shows how this variation plays out by industry. Despite this variation, wholesale price increases are typically passed entirely to business energy users when they enter new contracts. If wholesale electricity prices are indeed becoming more volatile, retailers' costs to hedge and manage their price risk will increase with costs likely passed on to customers.

These increases can take time to filter through, as very few energy users are directly exposed to movements in the spot price. Households typically contract for one year at a time, while most businesses contract for one to three years. Some of the largest users contract for five to ten years or more. Thus, even though energy prices offered in 2018 are lower than 2017, most business users looking for contracts will still experience painful increases from their previous contracts. While the effects extend to all sectors, the impacts of rising energy prices on manufacturers are particularly large.

In the eastern energy markets (which exclude Western Australia and the Northern Territory), the impacts from expected price increases will be large. It can reasonably be expected that any wholesale price increases will be passed on in full by energy retailers and these increased costs will likely run into the millions for consumers and billions for business.

**Table 2: Industry electricity and gas prices, 2014-15**

Industry	Electricity (\$/MWh)	Gas (\$/GJ)
Construction	292.16	15.89
Administrative and Support Services	256.45	24.73
Other Services	246.53	20.24
Furniture and Other Manufacturing	242.69	18.01
Professional, Scientific and Technical Services	228.27	17.17
Accommodation and food services	224.73	24.95
Agriculture, Forestry and Fishing	216.25	26.40
Machinery and Equipment Manufacturing	208.90	15.23
Wholesale trade	205.63	8.77
Public Administration and Safety (Private)	202.26	15.18
Financial and Insurance Services	198.41	23.05
Renting, Hiring and Real Estate Services	197.18	16.91
Textile, Leather, Clothing and Footwear Manufacturing	196.33	10.96
Education and Training (Private)	193.41	15.66
Wood Product Manufacturing	192.83	9.35
Retail trade	190.87	18.51
Printing (including the Reproduction of Recorded Media)	190.65	9.59
Arts and Recreation Services	190.33	15.38
Health Care and Social Assistance (Private)	175.74	14.14
Information Media and Telecommunications	170.55	23.32
Fabricated Metal Product Manufacturing	160.77	10.84

Transport, Postal and Warehousing	157.82	3.70
Beverage and Tobacco Product Manufacturing	155.07	10.57
Transport Equipment Manufacturing	144.76	11.32
Polymer Product and Rubber Product Manufacturing	142.76	13.17
Food Product Manufacturing	136.39	9.43
Basic Chemical and Chemical Product Manufacturing	116.14	4.91
Electricity, gas, water and waste services	105.45	3.95
Non-Metallic Mineral Product Manufacturing	96.17	6.53
Mining	91.67	8.56
Petroleum and Coal Product Manufacturing	81.91	5.53
Pulp, Paper and Converted Paper Product Manufacturing	75.29	8.25
Primary Metal and Metal Product Manufacturing	50.04	5.10

Notes: Derived by dividing industry spend on energy by energy consumption. Captures, wholesale, network and retail costs. May understate costs where an industry has substantial self-generation that shows up in consumption but not purchases.

Source: ABS, Energy Use, Electricity Generation and Environmental Management 2014-15.

For electricity, wholesale prices have increased from a long-term average of \$30-\$40/MWh to levels in 2017 and 2018 of \$70-\$80/MWh. This \$40-\$50/MWh increase may translate into \$5.5 to \$6.9 billion per year in extra costs<sup>9</sup> for all businesses in eastern energy markets, including between \$2.1 to \$2.7 billion per year in extra costs for manufacturers. Households in these regions may also face substantial cost increases (\$2.1 to \$2.7 billion per year).

For gas, prices in the eastern markets have increased from around \$3-\$4/GJ to \$7-\$9/GJ since the east coast became exposed to international prices. This \$4-\$5/GJ price impact costs businesses about \$1.1 to \$1.4 billion per year on aggregate. Manufacturers bear the brunt of this increase, with additional costs of around \$1.0 to \$1.2 billion per year. Households are relatively less affected, although still likely to face significant increases of \$600 to \$800 million in extra costs per year.

**Table 3: Estimated energy price impacts**

	\$40-\$50/MWh electricity price impact (\$bn)	\$4-\$5/GJ gas price impact (\$bn)	Total (\$bn)
Manufacturing	2.1 – 2.7	1.0 – 1.2	3.1 – 3.9
Non-manufacturing	3.2 – 4.2	0.2 – 0.2	3.6 – 4.4
Total business	5.5 – 6.9	1.1 – 1.4	6.7 – 8.4
Residential	2.1 – 2.6	0.6 – 0.8	2.7 – 3.4
<b>Total</b>	<b>7.6 – 9.5</b>	<b>1.8 – 2.2</b>	<b>9.4 – 11.7</b>

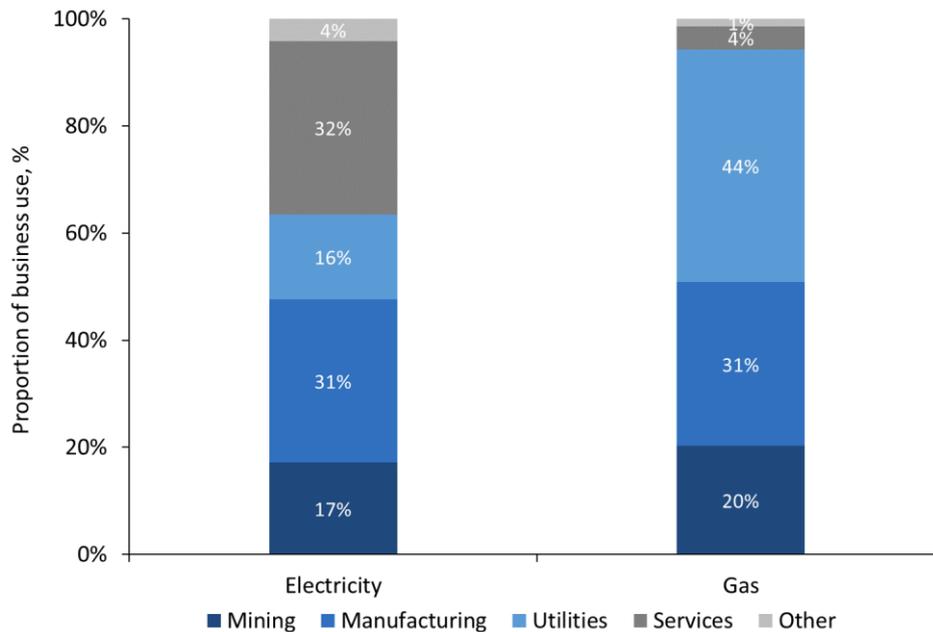
Note: Price impacts are based on 2015-16 energy demand in NSW, Vic, QLD, SA and Tas and the assumption of 100% wholesale price increase pass-through

Source: Department of Environment and Energy, *Australian Energy Statistics 2015-16*; Ai Group estimates.

<sup>9</sup> Estimates are derived from 2015-16 electricity demand for NSW, Vic, QLD, SA and Tas. Department of Environment and Energy, *Australian Energy Statistics 2015-16*.

For 2015-16, manufacturers used 31% of all electricity consumed by businesses and 31% of all gas consumed by business. While most manufacturers are not energy intensive,<sup>10</sup> there are many significant activities for which energy is a significant portion of input costs. This includes some, like chemical manufacturers, for whom gas is also a feedstock. Manufacturers (particularly machinery and equipment and petroleum, coal and chemical manufacturers) are typically highly trade exposed with little ability to pass through cost increases to customers.

**Chart 9: Proportion of business electricity and gas use by industry, volumes, 2015-16**



Note: Other includes agriculture, construction and transport.  
 Source: Department of Environment and Energy, *Australian Energy Statistics 2015-16*.

ABS data on energy use and industry value add (IVA) are combined in Chart 10, which illustrates the diverse impacts of recent energy price rises. For agricultural businesses, which pay relatively high prices for energy to start with but use very little, the recent rise is equivalent to just 0.05% of IVA. At the other end of the spectrum, if primary metal manufacturers with their enormous consumption at very low base prices were fully exposed to the increases (in practice some have longer contract terms that delay the impacts), the additional cost would be equivalent to 24% of their IVA. Other industries with particularly severe impacts include: fuel refining (7.0% of IVA); the pulp and paper sector (5.9% of IVA); chemicals (4.7% of IVA); cement, glass and other non-metallic mineral products (3.9% of IVA); and food processing (1.7% of IVA). Some sectors of manufacturing are less exposed, including machinery and equipment and furniture products (both 0.3% of IVA). However, with trade exposure limiting their ability to charge higher prices to consumers, and generally tight margins, these businesses face a significant loss of profitability and severe consequences for reinvestment, employment and ultimately continuity.

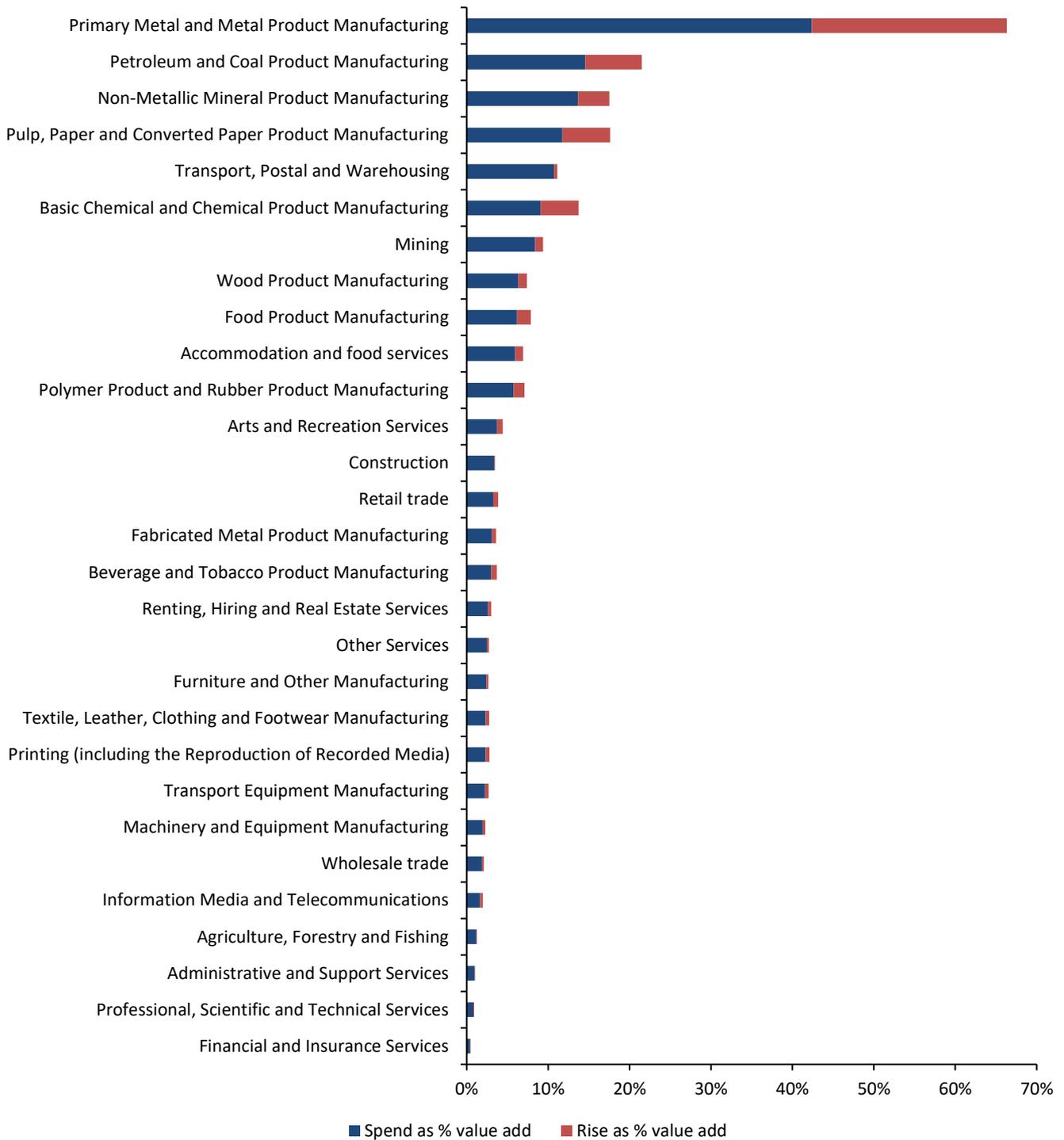
For those least affected, adjustments to other cost centres may be adequate to maintain viability. For other businesses, particularly in manufacturing, survival will depend either on:

- policies and market developments that achieve and sustain lower prices; and/or
- business strategies that limit the impact of energy prices on costs, through greater energy productivity, smarter contracting, self-generation, fuel switching and more flexible and agile use of energy.

The remainder of this report will consider the price outlook and prospects for responses.

<sup>10</sup> Ai Group, Energy shock: pressure mounts for efficiency action (July 2012) p12

Chart 10: Energy spend and price rise as proportion of IVA



Notes: Shows total energy spend by sector in 2014-15 as a percentage of total industry value added, including electricity, gas, LPG, diesel, petrol and coal products; and the incremental increase in spending if electricity prices rise by \$40/MWh and gas by \$4/GJ over 2014-15 levels while all other factors remain constant. Data is national and has not been corrected for uneven distribution of industries between Eastern States and other jurisdictions.  
 Source: Ai Group, derived from ABS, Energy Use Electricity Generation and Environmental Management 2014-15 and ABS, Australian Industry 2015-16.

PART THREE

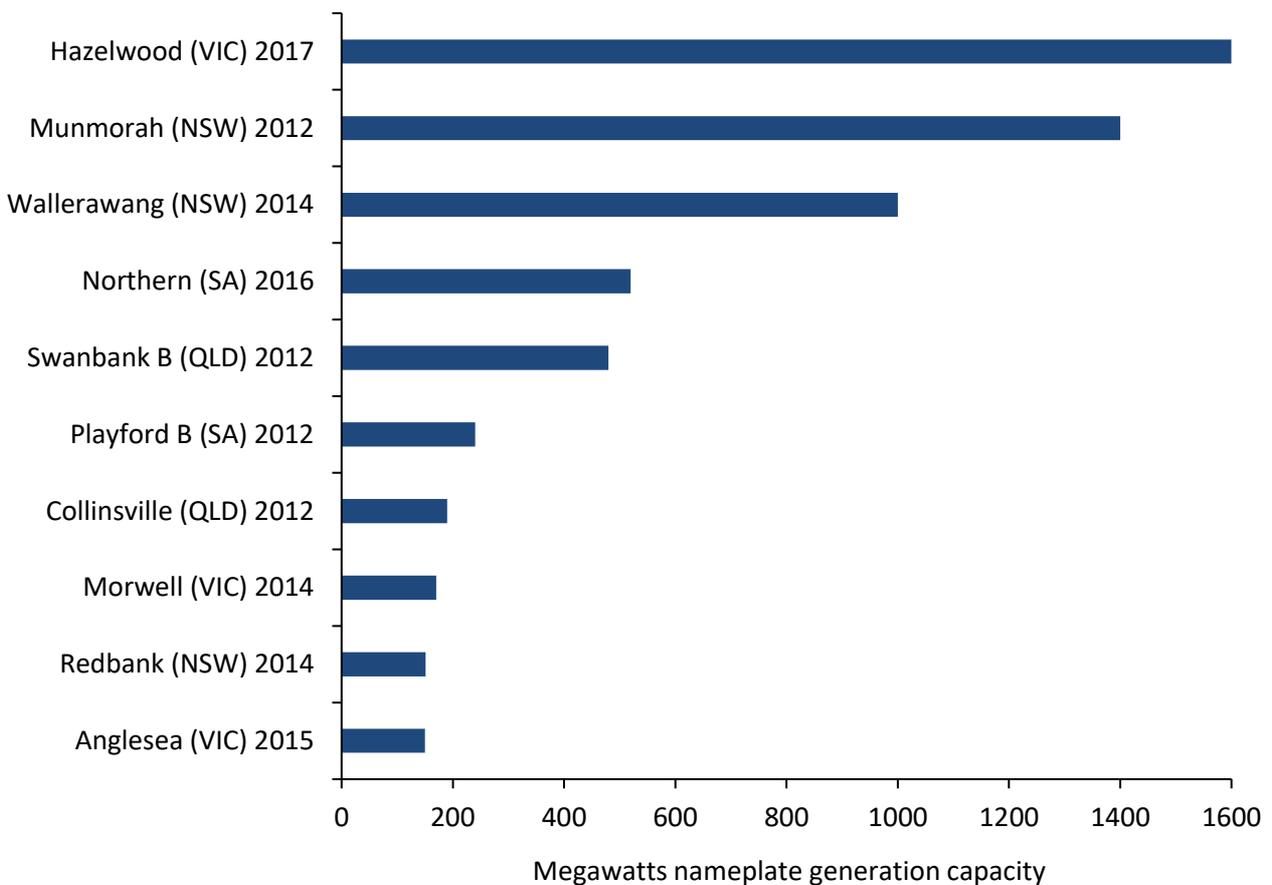
## What is driving energy prices?

### Electricity price drivers

Retail electricity prices are made up of charges for wholesale energy, use of networks and retail management. Earlier this decade, most of the price pressure resulted from overinvestment in the network. However, over the past two years nearly all the pressure on electricity prices has come from wholesale energy. The rise in wholesale electricity prices has two primary drivers.

First, the market has become much tighter as a result of the closure of old coal-fired generation capacity (see Chart 11). Victoria’s Hazelwood plant closed in March 2017 and attracted significant attention, as a large and controversial facility. However, Hazelwood only accounts for 27% of the nameplate capacity closed since 2012. Plant operators’ decisions to close these facilities varied in specifics but were broadly made on the basis that they were ageing, inefficient, physically inflexible, increasingly dangerous to run, would require significant reinvestment to continue, faced substantial risks from future carbon constraints and expected to be part of an oversupplied market with declining demand, increasing competition from renewables and low wholesale prices. The total volume of closures, together with a leveling-off of previously falling electricity demand, helped push the market from oversupply to tightness by 2017.

**Chart 11: Coal generator closures since 2012**



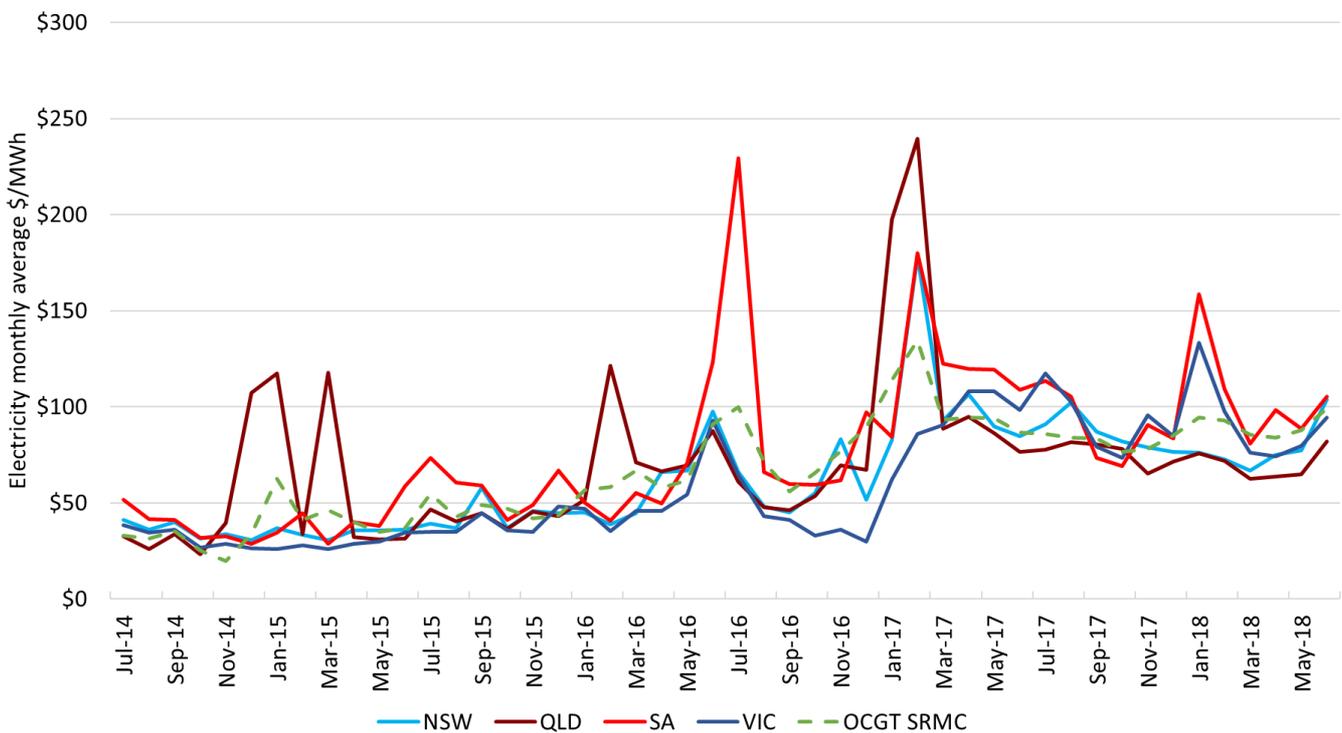
Source: Ai Group

Secondly, gas-fired electricity generators play a critical role in the electricity market and that role has grown with the closure of coal generators. The increase in gas prices has substantially increased the running costs of these generators and these higher costs have directly translated into higher spot prices. This last point may require some unpacking.

The prices any generator earns in the National Electricity Market at any given moment reflect the price bid by the marginal generator – the market operator stacks up the bids from cheapest to most expensive, calls on just as much supply as it needs to meet demand, and pays all called-on generators the price bid by the marginal bidder. The intention is to ensure the price is adequate to meet immediate demand, while ensuring that the cheapest generators make the highest returns. This incentivises existing generators to maximise their daily availability and encourages investors to build the cheapest new assets. However, if a low-bidding generator closes, or the operating costs for the marginal bidder increase, the market price all suppliers receive may increase.

Chart 12 shows the strong correlation between the monthly average price of electricity in different regions and the short run marginal costs of gas fired generators, as represented by an efficient open cycle generator with fuel costs reflecting spot prices at the Wallumbilla trading hub.

**Chart 12: Correlation of electricity prices and gas generator costs**



Source: AEMO (monthly average prices), Ai Group (estimated Open Cycle Gas Turbine Short Run Marginal Cost).

Higher spot prices should inspire more investment in capacity with lower costs, which in turn stabilises prices at a lower but sustainable level. To some extent this is happening, with a surge in large-scale wind and solar capacity coming online in 2018-19. However, these renewables projects are to a significant extent underpinned by the RET which provides a high degree of policy certainty and a reduction in market risk. Potential investments outside the RET are widely agreed to be inhibited by deep uncertainty on post-2020 energy and climate policy.

The 2017 price surge was plausibly exacerbated by the mere six months’ notice of the closure of Hazelwood which left other market participants very little time to respond. The delay in construction of RET capacity, resulting from sustained policy uncertainty in 2014-15, was also unhelpful.

**Gas price drivers**

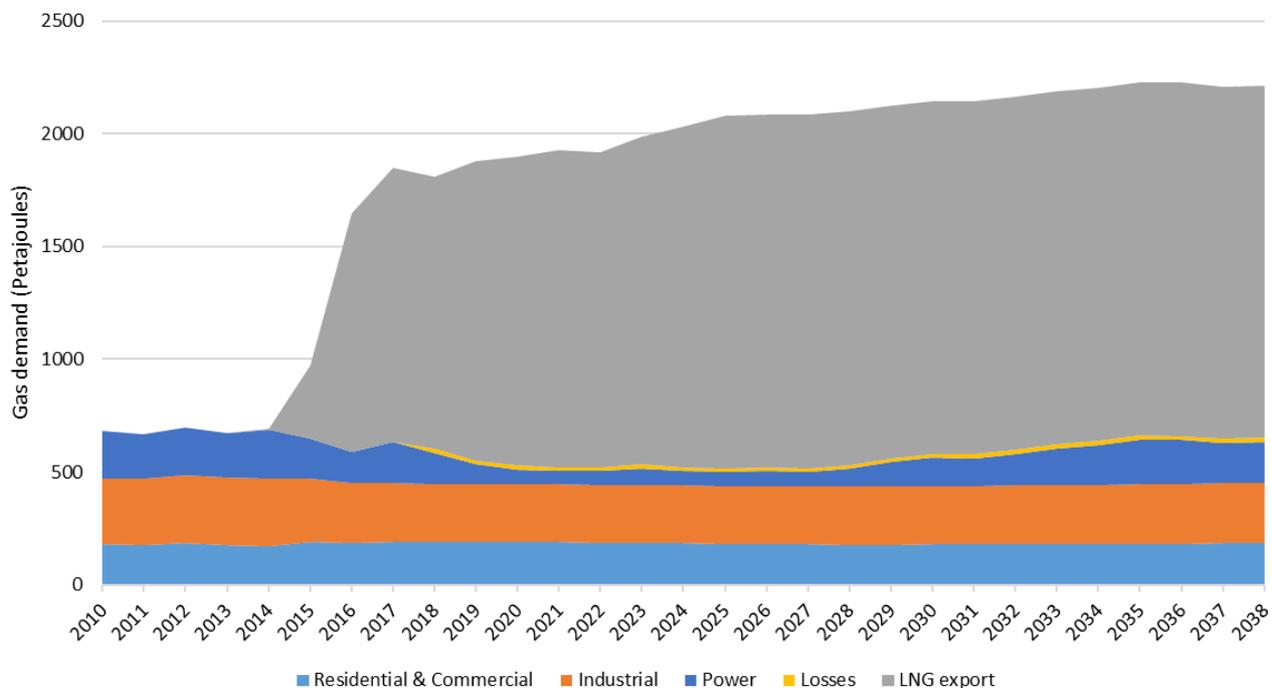
Wholesale gas prices in Eastern Australia have been opaque as discussed above, but the drivers were relatively straightforward. Gas resources off Gippsland and in the Cooper Basin were developed, along with substantial amounts of oil, through conventional techniques at low unit cost. This supply was isolated from global markets and serviced a slowly growing domestic market. Prices were very low and shaped by local supply, demand and production cost.

The recent growth of LNG exports from Queensland has fundamentally transformed the gas market. As three large liquefaction facilities came on line between January 2015 and the end of 2016, the East Coast gas market transitioned from

mainly producing gas for domestic consumption, to increasingly become a major exporter of LNG. In the process, eastern gas demand has tripled (see Chart 13 below), with three major downstream effects on supply and prices across the local market:

- *Production costs.* The size of export contracts both underpinned and necessitated development of new coal seam gas (CSG) resources, mostly in Queensland, since existing conventional resources are much smaller and are in decline. While CSG production costs vary, they are generally higher than for conventional gas because to produce a given volume of gas more wells must be sunk and replaced more frequently. Conventional gas production has historically been a sideline of oil production, with oil revenue underpinning the development and demand sought at low prices for gas that would otherwise be a waste product. CSG wells do not produce oil and must recover their costs from gas revenue alone. Production costs serve as a floor under long-term prices, and the floor is higher than it used to be.
- *Export parity pricing.* The availability of an export channel has ended the isolation of the eastern market. The export terminals have large contracted commitments, but also significant capacity to process and ship additional volumes of gas beyond these contracted commitments. Thus, producers supplying domestic customers have an export alternative, and will generally expect prices at least at ‘export parity’ (the export price minus export-related costs). East Asian gas prices have historically been linked to oil prices and as long as this relationship holds, Eastern Australian gas export parity pricing will reflect movements in international oil prices.
- *Scarcity.* Export demand for Eastern gas grew very rapidly over a couple of years from zero to twice the size of all domestic demand. Production growth does not appear to have kept pace, resulting in a period in late 2016 through mid-2017 when there was a scarcity of contractable gas and industrial gas price offers surged far above any benchmark for export parity. The existence and scale of a shortfall between existing demand and supply has been debated, though market authorities repeatedly projected a shortfall in 2017. Also debatable are the relative contributions to the shortfall of under-investment by producers, over-commitment by exporters, slower rollout of new wells than expected, lower productivity in new wells than desired, or faster decline in existing conventional resources than previously projected. Scarcity can drive prices above export parity.

**Chart 13: Total annual gas consumption by sector 2010 to 2038**

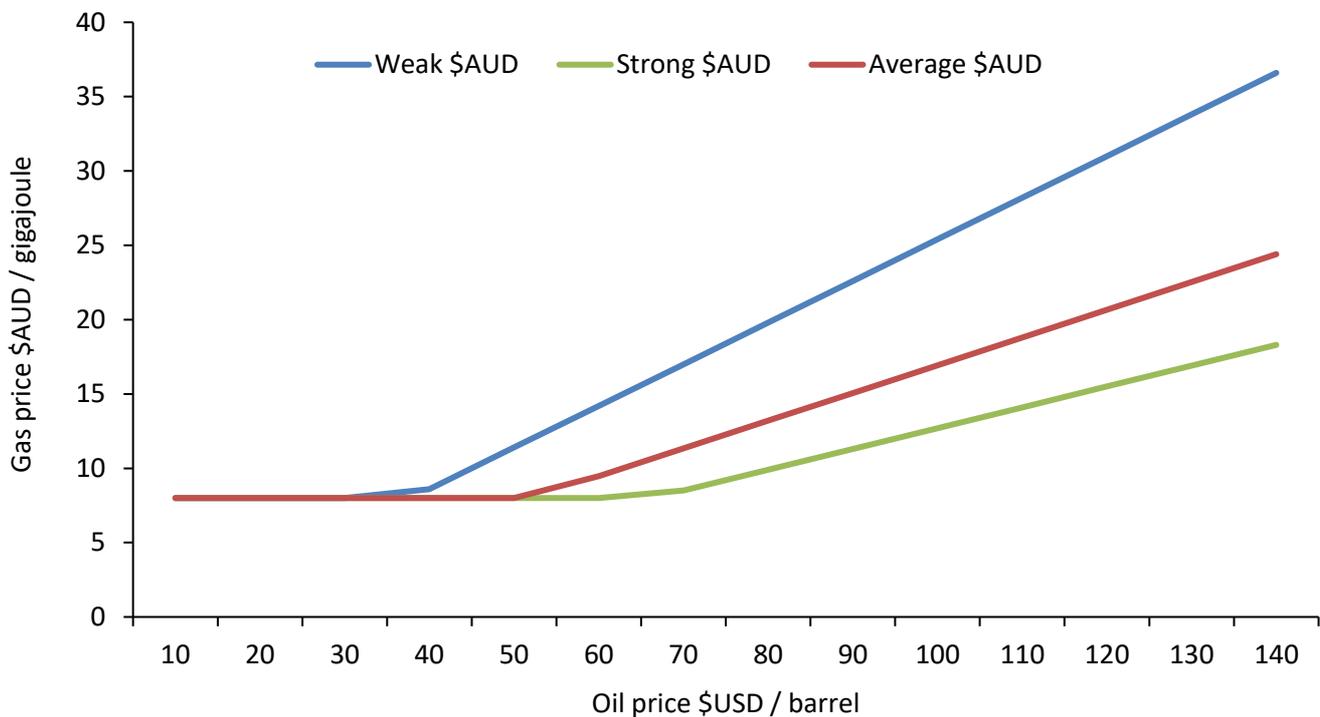


Source: AEMO. LNG is Liquefied Natural Gas.

The Australian Government’s Australian Domestic Gas Security Mechanism (ADGSM) and the commitments made by gas exporters in exchange for the non-invocation of this mechanism for 2018, appear to have eliminated the immediate risks of scarcity and reined in the most extreme gas prices. The range of new supply options considered in Part One will help avoid a return to scarcity as existing reserves deplete. However, a combination of production costs, transportation costs and international market linkage makes it unlikely that these resources will push generally available gas prices below the range of international price parity.

Chart 14 illustrates a simple relationship between international oil prices and oil-linked Eastern Australian gas prices. The lower bound is set by domestic production and transportation costs – assumed to be around \$8/GJ for generally available marginal supply – and the relationship is depicted according to three illustrative exchange rates to the US dollar: weak (50 US cents to the dollar, a low point touched in 2001), average (75 US cents to the dollar, around the current level) and strong (parity, exceeded in 2011-13).

**Chart 14: Indicative oil/gas price relationship**



Note: Gas price reflects that 1mmbtu of gas has around 0.14 of the energy content of 1bbl oil.  
Source: Ai Group.

Chart 15 shows the gas prices implied by this simple oil link since 2010. While oil prices collapsed in 2014 and bottomed out in early 2016, over the past two years oil prices have ranged from USD\$40-\$80 per barrel. This would imply local parity prices of AUD\$8-\$13 per gigajoule.

**Chart 15: Simple oil-linked gas prices - historical**



Source: Ai Group, US Energy Information Administration.

The future course of oil prices, and hence linked gas prices, is highly uncertain:

- Prices need to be sufficient over the long term to bring on new oil production to replace depleting supplies or meet demand growth; many growth resources, such as deepwater or North American shale oil, have costs around USD\$40 or more, though technological improvement could reduce these.<sup>11</sup>
- Geopolitical events could raise prices by pulling out supply (e.g. from Iran or Venezuela).
- Disciplined action by OPEC and other producers could raise prices by constraining supply, while lack of discipline could lower prices by raising production from the lowest-cost existing supplies. High US shale oil production coupled with strong OPEC production pushed prices as low as USD\$26 in 2016.
- Growing use of efficient, hybrid or pure electric vehicles could reduce oil demand and prices.

It seems likely that oil prices will remain volatile, but it would be prudent to plan around a base assumption that international price pressures will keep generally available Eastern Australian domestic gas prices far above their historic \$3-\$4/GJ level.

<sup>11</sup> BP, [BP Technology Outlook 2018](#), 23.

## What should we do?

Easing energy cost pressures will aid business and households. Going beyond immediate relief, building a new energy cost advantage would bring significant long term economic benefits. Success is not guaranteed, but there are some straightforward steps to take.

### Electricity prices

Since the rise in electricity prices is largely due to a reduction in supply and a lasting increase in the price of gas, the most obvious responses are to increase supply and to reduce dependency on gas-fired generation. Smarter planning of the grid, greater energy efficiency and a voluntary revaluation of State-owned electricity networks should also help.

#### Electricity: more supply

More electricity supply is needed. High prices in the electricity market should signal to investors to build more electricity generation. Over the long term, this should moderate wholesale prices and ensure that, on average, they reflect no more than the long-run costs of the marginal sources of new supply. In practice, the volatility of the market design and the revolutionary changes affecting the electricity sector globally mean investors face significant risks. Beyond these factors, however, electricity investors face immense policy uncertainty.

The national RET currently acts to ensure that a large volume of new supply – largely from wind and solar – will enter the market over the next two years. This expected additional supply is likely to be largely responsible for the reduction in futures prices over the same period. However, the RET flatlines in 2020 and expires in 2030. What will follow it?

At the national level, and in many of the States, every election since 2007 has featured the prospect of a complete reversal of energy and climate policies. Between elections, governments have frequently considered or made further fundamental changes. As of June 2018, there is no clear, durable, credible and national policy framework in place for addressing climate change within the electricity sector. Yet climate policy makes an immense difference to the sector. Most existing supply comes from emissions-intensive black and brown coal assets. While many of these generators are ageing and all will eventually retire, their retirement date, and hence the emergence of an investment opportunity for new assets, can be heavily affected by carbon constraints. The specific design features of those carbon constraints can greatly change the potential returns for different low or zero-emissions technologies, and from new assets versus existing assets or upgraded facilities. Despite market fundamentals for investment growing stronger as the retirement of further assets like the Liddell Power Station draws closer, policy chaos is a significant disincentive for the new supply needed.

#### Electricity: Settling the National Energy Guarantee

The National Energy Guarantee (the Guarantee) represents the best available chance to resolve this chaos. Proposed by the Energy Security Board and championed by the Commonwealth Government, the Guarantee is now under intense development ahead of consideration by the States in August. The basic model is to place two obligations on retailers:

1. to achieve specified reductions in emissions intensity; and
2. to support the dispatchable capacity needed to maintain a reliable electricity system – and give retailers sufficient operational and contractual flexibility to achieve the minimum overall cost of supply.

Considerable work is being done to flesh out the detail and meet the needs of all stakeholders. The positions of the Commonwealth and the States on matters like the appropriate level of emissions reduction ambition remain far apart. Nonetheless, the proposal is extremely promising and there is unlikely to be a better opportunity to cement a workable and scalable mechanism for emissions and reliability. Nobody will win from further failure. All sides should work to achieve agreement on the Guarantee's emissions and reliability mechanisms in 2018. That would be a dramatic advance, even if

political debate over the scale of emissions cuts continues.

### Electricity: How could we decrease our reliance on gas generation?

Resolving a durable climate policy would help to ease electricity prices by unblocking investment in new supply and reinvestment in existing assets. Even so, the role of gas presents a big challenge. If the long-term price of gas is likely to remain high (as argued in Part Three), Eastern Australia cannot achieve low electricity prices unless it decreases the electricity system's reliance on gas generators.

This is not straightforward. Supply from gas generators is sorely needed at present to meet overall demand. Gas generators are also flexible, dispatchable and (mostly) reliable, making them very useful for balancing the grid as demand and other sources of supply swing up and down. High-efficiency combined cycle gas generators have about half the emissions of the most efficient new coal generators, and emerging designs may enable full carbon capture and storage at a lower cost than previously expected over the next two decades.<sup>12</sup>

If the role of gas needs to shrink to achieve affordable power, the main alternative would seem to be wind and solar photovoltaic (PV) power. These sources are growing fast in Australia and around the world – much faster than other low emissions options – because the combination of production scale and learning effects has slashed their costs below alternatives. Continuing innovation and experience will deliver further cost reductions. They are likely to meet an increasing share of the annual energy demand currently served by coal and gas, while producing zero direct emissions. The combination of falling generation costs with Australia's exceptionally large and high-quality solar and wind potential raises the possibility of a new global competitive advantage in electricity prices over the long term. AEMO's latest gas demand forecasts do project that overall gas demand for power will contract substantially over the next few years, largely due to growth in renewables.

But wind and PV are variable resources, subject to daily and seasonal cycles and weather. On their own they cannot play the flexible role that gas does. Displacing gas as the main source of daily flexibility will be important for lower long-term prices, as long as the alternatives are themselves cost-competitive. Some alternative sources of flexibility include:

- Coal generation is dispatchable, though existing generators have been built and financially structured around continuous operation and are not very flexible. New coal generators could be more flexible – at a significant wear and tear penalty – but are unlikely to be built given high costs, high emissions and high risks of being stranded, and the extreme controversy and cost to the public purse of the public funding or guarantees needed to ignore these risks.<sup>13</sup> Upgrading existing coal generators for more flexibility is also possible,<sup>14</sup> and may be more financially attractive, especially given their likely retirement timetable as carbon constraints bite.
- Pumped hydro stores grid energy by pumping water from a lower dam to a higher dam, then releases that water on demand via a hydro generator in between the dams. It is a flexible, dispatchable storage technology and Australia has some very large water storage options that could fill big gaps in supply for long periods. These options include not just Snowy 2.0 and potential upgrades to Tasmania's hydro assets, but also an emerging set of medium-scale projects using old mining pits for water storage.
- Batteries are rapidly falling in cost and are becoming attractive in more applications. The Hornsdale Power Reserve has cut costs for frequency control in South Australia, and renewables projects are increasingly integrating some battery storage to firm their output over short periods. However, batteries are likely to remain a relatively expensive way to fill longer-duration gaps in energy supply.
- Diversifying the location and technology of renewables can significantly improve confidence in overall expected output

<sup>12</sup> See for example the Allam Cycle-based NET Power prototype now under testing in the United States: <https://www.nature.com/articles/d41586-018-05247-1/>.

<sup>13</sup> See further discussion in Ai Group, *Will contracts make the difference?* (September 2017) [http://cdn.aigroup.com.au/Reports/2017/Working\\_paper\\_Will\\_contracts\\_make\\_the\\_difference\\_Sept2017.pdf](http://cdn.aigroup.com.au/Reports/2017/Working_paper_Will_contracts_make_the_difference_Sept2017.pdf).

<sup>14</sup> See Agora Energiewende, *Flexibility in thermal power plants – with a focus on existing coal-fired power plants* (June 2017) [https://www.agora-energiewende.de/fileadmin/Projekte/2017/Flexibility\\_in\\_thermal\\_plants/115\\_flexibility-report-WEB.pdf](https://www.agora-energiewende.de/fileadmin/Projekte/2017/Flexibility_in_thermal_plants/115_flexibility-report-WEB.pdf).

and reduce the requirement for firming resources. Options include:

- mixing wind and solar, which have different generation profiles;
  - getting more solar generation from further west, to spread generation into the eastern evening peak, and further north, to reduce seasonal variation;
  - spreading wind generation to reduce correlation of weather conditions and hence output;
  - greater use of solar thermal, such as the Port August power plant under development, which can store heat and operate dispatchably; and
  - greater use of offshore wind farms, which can access steadier winds and offer more constant power.
- Demand response – energy users shifting or reducing their demand, or increasing or redirecting their own generation – can be cheaper than supply-side options, especially for dealing with more extreme and infrequent circumstances. Demand response is dispatchable, though more capacity is available with a day’s notice (to ease shift changes, for instance) than with 5 minutes’ notice.
  - Many other forms of dispatchable capacity exist, including nuclear energy, geothermal power and more. They appear unlikely to be as significant in the Australian context as the resources above.

There is no shortage of non-gas options for supply, reliability and low emissions. Technology-neutral policy and market settings – including the National Energy Guarantee – would be expected to bring forward non-gas capacity if gas really does remain as expensive as expected. We should not expect chronic reliability challenges, but it is not yet clear which mix of the options above will be most efficient or what the achievable long-term costs may be. Policy makers should try to ensure the costs of dispatchable capacity are as low as possible, including by lowering barriers to all options:

- regulating unconventional gas production rather than banning it;
- developing a mechanism to reward demand response within the wholesale electricity market, as recommended by the Finkel Review; and
- resolving a climate policy framework to clarify the investment case for all technologies, including upgraded coal plants.

### Electricity: Strategic grid development

To ease the entry of new energy resources of all sorts, and in particular to minimise the long-term costs of renewables and storage, a more strategic approach to the grid is needed, particularly in regard to planning and approval of generation and transmission developments. Much of our existing transmission networks were built to connect major population centres with the most cost-effective places to locate coal generators. New lines that are sized and routed to unlock the most promising new resources are likely to be more cost effective than incremental additions of generation and storage along the existing network. The Integrated System Plan currently under development may be a big step in this direction.

### Electricity: energy efficiency and productivity

While there is greater prospect of lowering electricity prices than gas prices, improving energy efficiency and productivity in electricity use will remain important. Many businesses can still benefit from basic steps such as lighting upgrades, turning major equipment off when not in use and plugging leaks in compressed air systems. New options are also opening up for more sophisticated energy users, including:

- better and more accessible data analytics to identify opportunities to cut peak demand or overall consumption;
- use of batteries and other energy storage to cut peak demand, improve power quality or offer services to the grid;

- self-generation, particularly with solar but in some cases waste biomass, primarily to displace grid demand rather than export; and
- financial contracting with large energy projects to guarantee a price level that is lower and more stable than the wholesale market.

Energy costs are ultimately price multiplied by usage. Producing more economic value with a given volume of energy will make energy-intensive businesses more competitive, even if prices were to remain high.

### Electricity: Network asset bases

A final area for potential cost reduction has had much recent discussion, but raises very difficult issues: electricity network asset bases. While the most recent retail electricity price increases have been driven by wholesale electricity prices, much of the substantial cost growth of the past decade has come from increasing costs for electricity networks, particularly the ‘poles and wires’ – distribution networks.<sup>15</sup> These increases reflected excessive projections of demand growth (demand actually fell); planning standards in NSW and Queensland that mandated rigid levels of redundancy in over-reaction to high-profile blackouts; and a relatively weak regulatory system in which successful network appeals repeatedly overturned constraining elements of regulatory decision. Arguably, State ownership of the NSW and Queensland networks worsened things. These networks were regulated as commercial entities with a commercial cost of capital. However, the States access finance at a lower cost than this. While the States levied ‘competitive neutrality’ payments on the finance they provided to their networks, the real rate of return to these States on capital spending by their networks was much higher than the regulator assumed and the incentive to overbuild was immense.

Whatever the reasons, the total regulatory asset base (RAB) of Australia’s electricity networks grew enormously. While demand forecasts have been revised down, planning standards have been made more efficient and risk-based, and limited merits review of regulatory decisions has been abolished, the high RAB remains and energy users will continue to pay for the multi-decade life of the assets involved.

If the asset base includes far more assets than we have turned out to need, and resulted from broken processes, should the value of the RAB be written down to spare energy users from further costs? This is a difficult issue. Many of Australia’s energy networks are privately owned; NSW partially privatized its networks in 2016-17, after the RAB had already surged. Retrospective involuntary revaluation of assets that were built under a regulator- or court-approved plan would be massively controversial, raising concerns about sovereign risk and calls for just-terms compensation for their owners (which include, indirectly, many members of Australian superannuation funds).

On the other hand, the bulk of the growth in asset bases occurred in Queensland and NSW; Queensland still fully owns its networks, and NSW holds a partial interest. The Grattan Institute recently proposed that these governments voluntarily write down the regulated value of their assets without impacting private investments.<sup>16</sup> This would avoid the risks of an involuntary write-down, but would still have consequences: revenue from State-owned networks helps support State budgets, and a reduction in this revenue would entail either a reduction in State services, an increase in borrowing, or most likely the raising of replacement revenue through other measures. The benefits to energy users of lower bills would need to be weighed against the impacts of these fiscal consequences. Ai Group has urged the Queensland Government to develop options for both a write-down and alternate revenue, in the belief that there are more efficient and equitable ways to fund services than a de facto tax on energy users.

Regardless of the treatment of the existing asset base, Australia will see continuing investment in networks to accommodate growth and changes in the way we use electricity, including the expected uptake of electric vehicles. It will be essential to ensure that this investment is efficient. Networks are increasingly willing to use approaches like demand response to maintain reliability without adding to the asset base, but the adequacy of current incentives for this efficiency will need to be monitored and alternatives – like treating operating and capital expenditure as a single fungible regulated figure – will need

<sup>15</sup> Rod Sims, ‘Shining a light: Australia’s gas and electricity affordability problem’ – Address to the National Press Club (20 September 2017) <https://www.accc.gov.au/speech/shining-a-light-australia%E2%80%99s-gas-and-electricity-affordability-problem>.

<sup>16</sup> Tony Wood, David Blowers and Kate Griffiths, *Down to the wire: A sustainable electricity network for Australia* (March 2018) <https://grattan.edu.au/report/down-to-the-wire/>.

consideration. It will also be important to give more energy users the information, decision support and financial incentives to use network capacity efficiently. This will help moderate spending on network augmentation while maintaining reliability.

## Gas prices

There are several approaches that can help limit the final cost of gas to energy users: increasing supply to avert a return to scarcity; continued pro-competitive reform; interventions to ensure local supply is not threatened; relocation of gas intensive activities; and increasing gas efficiency or switching to different fuels.

### Gas: Increasing supply

Supply has an important role to play. More supply is, on its own, unlikely to drive generally available prices sustainably below export parity. Investors can be expected to maximise returns and gas supply is increasingly dependent on unconventional resources that require ongoing reinvestment to sustain production, limiting the window for strong development to strand gas in the domestic market. Prices will certainly not be sustained below production costs. However, new sources of supply can eliminate the risk that export commitments and declining existing resources lead to domestic scarcity and prices *above* export parity.

All gas supply options should be available for development with appropriately strong regulatory protection for vital community interests. The recent decision by the Northern Territory to partially lift its moratorium on hydraulic fracturing in favour of a stringent regime to ensure environmental, agricultural and community values, should inspire New South Wales and Victoria to follow suit.

Emerging proposals for LNG import terminals in Victoria (AGL) and New South Wales (AIE) should likewise receive fair and timely consideration, and not just in planning and approvals processes. Import options make considerable sense at this point: they provide substantial and flexible supply to avert future shortages; involve modest investment; help ensure that international pricing serves as a ceiling on domestic prices, and not just an export-driven floor under them; and inject additional competitive pressures to upstream, transport and retail markets.

### Gas: Competition and transparency

Competition and transparency is also vital to improved outcomes for energy users. The gas market has historically lacked transparency, dominated by confidential long-term bilateral contracts. A range of helpful reforms are now in place or taking shape to make it easier for energy users to understand the market and get the best deals they can. The ACCC's scrutiny since mid-2017, backed by investigatory powers, has shone a brighter light on actual prices in the market, and this level of transparency should become permanent. The indicative LNG netback price metrics being developed by the ACCC will be very helpful when available. A separate push to develop a European-style market for trading pipeline capacity is positive, despite some concerns from the pipeline sector about compliance costs. However, while this approach can lead to more efficient short-term reallocation of otherwise idle capacity, significant new energy use or supply options will need more secure pipeline access.

### Gas: Interventions

Interventions in the gas market have been widely discussed, given the intensity of gas supply concern in 2017 and the serious impacts on energy users of the changes brought by exports. Three forms of intervention are particularly relevant: export controls; national interest assessment; and domestic gas reservation.

The Federal Government's ADGSM threatens LNG producers with export controls in the event of a projected shortfall in domestic supply, with projections made based on export-parity pricing (rather than scarcity-driven pricing). As noted above, the gas industry made significant two-year commitments to domestic supply adequacy to avert the invocation of the ADGSM, and this is bringing prices back down to export parity. The measure has been a success on its own terms. However, its further impact is limited: it is explicitly temporary, sunseting in January 2023; it is reactive, invoked in response to an emerging shortfall, rather than strategic; and it is aimed at ensuring prices are no higher than export parity, rather than pushing prices below parity. The ADGSM should be retained through at least 2023 and its invocation should continue to be considered in the light of supply adequacy and exporters' commitments.

Ai Group and others have long advocated national interest assessment before further expansions of gas export infrastructure are approved. The United States and Canada have had formal assessment processes in place that considered and approved export expansion while identifying and avoiding risks to the domestic market. Recent Australian experience demonstrates the importance of understanding the impacts of major step changes in demand and the risks of simply assuming everything will be fine. It makes sense to run a preemptive independent assessment of the implications for domestic supply adequacy of a potential new LNG liquefaction train or other market-significant export infrastructure. While the enormous loss of shareholder value associated with the current Queensland LNG facilities would seem to make further investment unlikely, resource markets are very cyclical and investors often have short memories when the excitement of the next boom takes hold. We should get a national interest assessment process in place well ahead of a potential return to expansion of the LNG sector.

The concept of reserving gas for the domestic market has been intensely controversial, with advocates saying it is the only way to preserve affordable gas prices, and critics declaring it neo-protectionism. More recently, however, the debate appears to have shifted: Queensland has experimented with a limited form of forward-looking reservation to a warm response from resources sector representatives; Western Australia's long-standing (albeit ambiguous) reservation policy has seemed more functional than the East Coast's open slather; both sides of politics in Victoria advocate forms of reservation for new undeveloped resources; and the CEO of Santos, one of Australia's largest gas producers, has suggested reservation could help underpin community support for development of fracked gas in the Northern Territory.

Reservation remains a difficult and slippery subject. Retrospective reservation of already-developed reserves would be a massive intervention involving major sovereign risk and likely enormous compensation bills, but forward-looking reservation of undeveloped resources would take many years to have an effect. Reserving particular fields for domestic use can enable specific highly visible supply deals with individual large energy users, but provides no guarantee of a net increase in domestic supply: unreserved fields that might otherwise have contributed to domestic supply may be developed for export instead, or left undeveloped. Reserving a proportion of all new fields for domestic supply is less circumventable, but reduces the returns from developing gas resources and hence likely reduces activity – unless the reservation carries no obligation to supply on uncommercial terms, in which case the reservation may bolster security but will have little impact on price. Federalism complicates things further: restrictions on trade between the States are unconstitutional; the Commonwealth must step carefully to avoid discriminating between the States; and States have little incentive to consider the interests of energy users beyond their borders in operating any reservation. The frequent reinvestment required to maintain production levels from unconventional gas resources limits the potential to 'strand' large volumes of gas in the domestic market. Further, the increase in production costs for unconventional over conventional resources limits the potential for sustainable price reduction.

In short, the discussion over securing adequate domestic supply needs to be very clear about the ends that are being pursued: it would be quite possible to wind up with a reservation that achieved nothing or that simply inhibited new investment. The recent willingness of the gas sector to tolerate or even propose prospective reservation seems to be driven by concerns over gas prices and reliability of supply and the widespread community discomfort with unconventional gas development and the acceptance of a need to re-earn a social license to operate.

The Eastern States and the Commonwealth should develop an intergovernmental approach to securing domestic supply through the COAG Energy Council that addresses new development and the Eastern Australian domestic market in a coordinated way. Any agreed policy should be applied prospectively. Decisions would be needed on whether to ensure that associated gas is offered to the domestic market on fully commercial terms, which would support security and resource development but have limited effect on price, or whether an obligation to supply the associated gas come what may, which could suppress domestic prices but would also suppress resource development.

If, as seems likely, generally available gas prices in Eastern Australia remain high by historical standards, energy users have two options.

#### Gas: Relocating gas intensive activities

One is to relocate gas-intensive activities like basic and advanced chemicals, fertilizer, explosives or alumina refining. The United States seems to have geological and market structure advantages that will support very low gas prices for decades to come, and there are also opportunities for low-priced industrial gas supply in the Middle East. The offshore loss of this

industrial activity and its associated value adding, employment and taxes would be a bad outcome for Australia and impose avoidable adjustment costs. If the different market and policy contexts in Western Australia or the Northern Territory can support lower prices over the longer term, it may be possible for Australia to retain these industries by relocating them west or north. While adjustment costs would still be incurred, more of the benefits of relocation would be realised within Australia. The Northern Territory has demonstrated great interest in diversifying its economy with downstream industrial development, and may have a strong case to make, particularly for gas intensive activities focused on export to Asia.

### Gas: Energy efficiency and fuel switching

For many gas users the answer will not be to move, but to use less gas through energy efficiency or fuel switching:

- For many industries gas is a clean and efficient source of high-grade process heat, steam and hot water, but there are often practical options for businesses to do more with less: better insulation, careful tuning of boiler settings, pre-heating of inputs, rearrangement of thermal loads and much more. Cost effective opportunities are also emerging to replace or reduce gas in some industrial applications with heat pumps, induction heating, solar thermal and other technologies.
- In the chemicals sector, where gas is a feedstock, the main alternative in widespread use is oil – in which Australia cannot offer a cost advantage. It is possible to produce various feedstocks and chemical precursors from coal processing, biomass, or renewables-powered processes. However, these alternatives involve various problems of environmental impact, material availability, technical readiness and cost. All alternatives, including oil, would involve substantially upgrading or replacing existing facilities. Australia’s chemicals sector – which supports wider supply chains and valuable activities across the economy, particularly agriculture and mining – may be uniquely exposed to the future of gas prices.
- Household gas use is entirely substitutable, for instance with heat pump water systems, reverse cycle air conditioning and modern induction cooktops. Recent research suggests all new Australian homes and many existing homes would save money by going all-electric, even at the household electricity prices prevailing in late 2017.<sup>17</sup> However, the turnover and upgrade of the housing stock is a slow process. Mass switching of heating requirements to the electricity system would also require significant new generation and supply infrastructure, and intensify the need for careful management of seasonal supply and demand: for instance, solar generation is weakest in the southern winter when heating needs are highest.
- In the power sector, gas generation plays two key roles: as a source of bulk energy (megawatt hours) and as a reliable and dispatchable source of capacity to meet changing demand (megawatts). As will be considered further below, there are alternatives for both roles, though gas may remain a highly competitive source of capacity for a long time.

AEMO’s most recent projections anticipate basically flat demand for gas from residential, commercial and industrial customers. This outlook could change radically if the opportunities above are seized – or if we fail to seize them, and high gas prices lead to the exit of gas intensive industry.

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<sup>17</sup> See Alternative Technology Association, *Household fuel choice in the NEM* (May 2018) [http://www.ata.org.au/wp-content/projects/Household\\_fuel\\_choice\\_in\\_the\\_NEM.pdf](http://www.ata.org.au/wp-content/projects/Household_fuel_choice_in_the_NEM.pdf).

## Appendix: CEO Business Prospects survey 2018 participants

Responses were received from the CEOs of 269 private-sector businesses across Australia in October and November 2017. Together, these businesses employed around 43,000 people (170 people each on average) and had an aggregate annual turnover of around \$20 billion in 2017.

All Australian states, and all major non-farm private-sector industries are represented in this year's CEO survey. The manufacturing sector contributed the highest proportion of respondents (69%). Manufacturing's share of this sample is higher than its share of national production (5.8%). Victoria was somewhat over-represented in the sample, relative to other states.

The data presented in the summary section of this report were weighted by industry (based on ABS estimates of their value-added contribution to GDP in 2016-17) in order to adjust for these characteristics of the sample. The analysis for each of the industry groups is not affected by the sample composition.

**Table 4: CEO Business Prospects survey 2018 participants**

CEO Survey: Business Prospects 2018			ABS data (2016-17)
Industry	Number of respondents	% of respondents	Value-added output (% of GDP)
Manufacturing	186	69.1	5.8
Services	51	19.0	54.7
Construction and mining services	32	11.9	7.4*
<b>Total</b>	<b>269</b>	<b>100</b>	<b>67.9**</b>
CEO Survey: Business Prospects 2018			ABS data (2016-17)
State	Number of respondents	% of respondents	Value-added output (% of GDP)
NSW	75	27.9	33.0
VIC	128	47.6	22.6
QLD	40	14.9	18.2
WA	3	1.1	13.8
SA	22	8.2	6.0
TAS	1	0.4	1.7
<b>Total</b>	<b>269</b>	<b>100</b>	<b>96.3</b>

\*only includes construction value added output.

\*\* These industries do not sum to GDP due to the exclusion of utilities (2.4% of GDP), public administration and safety services (5.5%), agriculture (2.4%), mining other than mining services (5.8% of GDP), ownership of dwellings (8.7% of GDP) and other additional statistical items that are included in GDP.

The services sectors represented in this sample include: IT, communications and media services; transport, post and storage services; wholesale trade; retail trade; finance and insurance; real estate and property services; professional services; administrative services; health and welfare services; education; hospitality (food and accommodation services); arts and recreation services; and personal services.

