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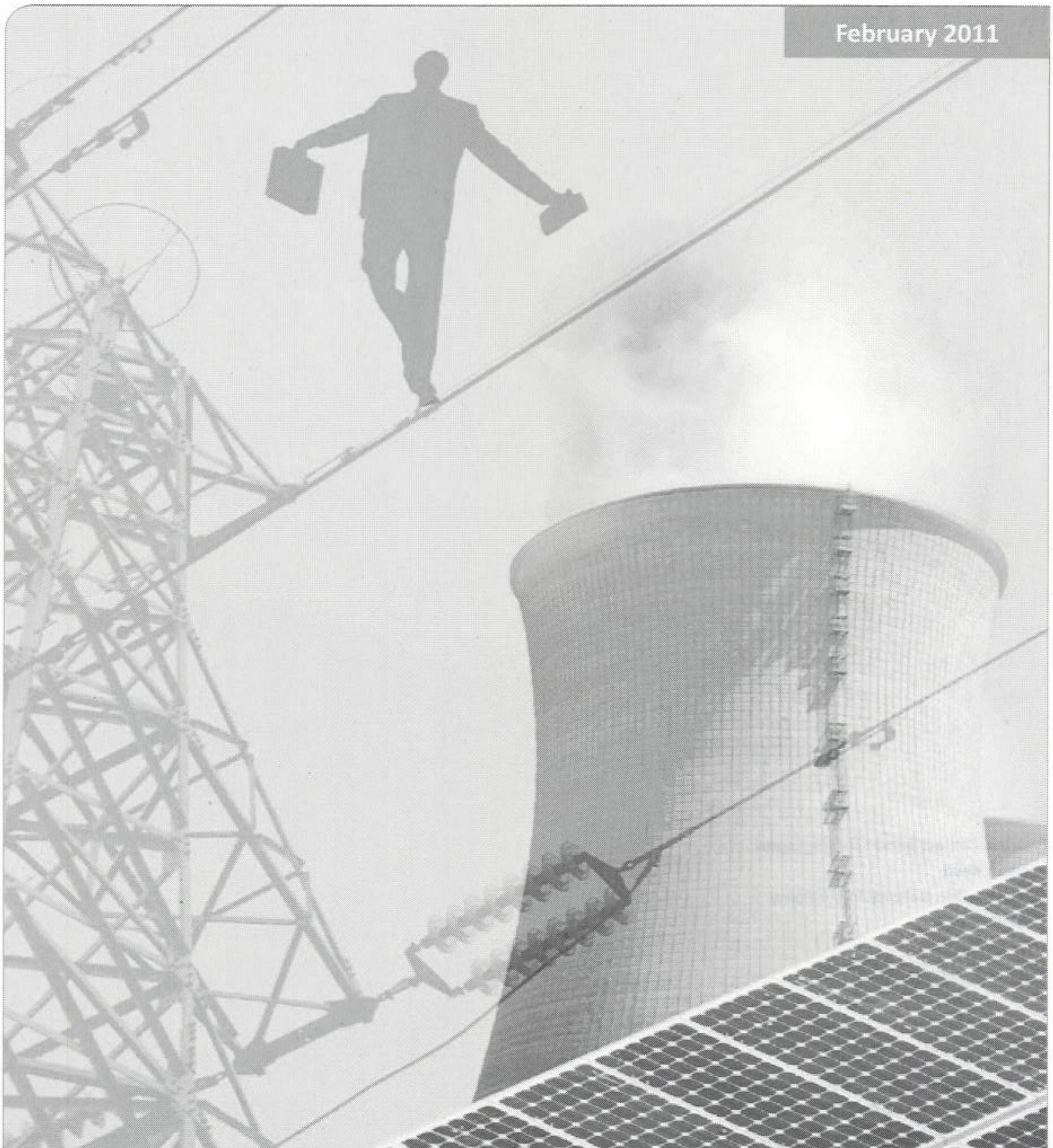
AUSTRALIAN INDUSTRY GROUP

Energy shock: confronting higher prices



AUSTRALIAN INDUSTRY GROUP

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Energy shock: confronting higher prices

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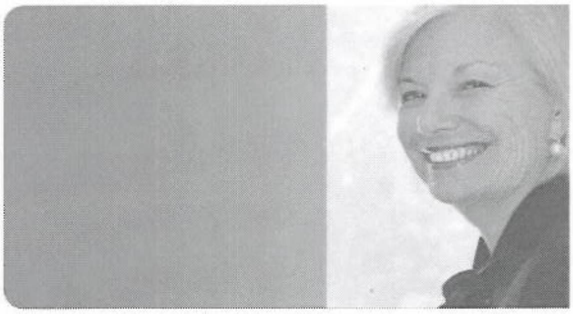
preface

facing up to higher energy prices



challenge

Rising energy prices have been front of mind for industry and the community in recent times – and the issue isn't going away any time soon. The Australian Industry Group has surveyed our members and sifted the evidence to see what has happened to electricity and gas prices, what is likely to happen, and why. As you'll see in Part One of this report (our survey) and Part Two (our analysis), the results are sobering. Energy costs have already risen substantially for most businesses over the past five years, and there is no end in sight. A range of factors point relentlessly upward, from massive network investment to movements in international markets to the increasing role mandated for higher-cost renewable energy. New South Wales' privatisation debate is unlikely to change this much.

Likewise, while much concern has focussed on carbon pricing, energy prices are going up significantly with or without it. Some of those cost drivers could be reduced by a well-designed carbon price. This could eliminate the policy uncertainty that is damaging investment in new electricity generation, and reduce reliance on the high-cost Renewable Energy Target. This would soften the blow of a carbon price, but it would remain a big hit.

Australia is far from alone in confronting rising energy costs, but the challenge is serious given our historic reliance on cheap energy as a competitive advantage. With the right policies, research and investment we may continue to benefit from energy less expensive than that in other countries. But Australian industry will need to learn to live with energy prices higher than we are used to.

response

Adjusting to higher prices will require much greater efforts on energy efficiency than we have seen so far. Large energy-intensive firms focus on efficiency as core business, but in a survey sample dominated by small and medium-sized companies nearly two thirds had not improved their energy efficiency over the past five years, and almost as many did not anticipate improvements in the next two years. The small role of energy in the current cost structure of many businesses may explain this result, along with the barriers to efficiency faced by hard-pressed SMEs. But as higher prices bite, these smaller and less-energy intensive firms will feel the efficiency imperative too. Industry needs to get on the front foot.

Government needs to hold its end up too. Smaller businesses still lack access to the information and capital they need. Gaps and perverse incentives in existing regulation should be fixed – like those that discourage the demand management that could reduce our network investment bill. There may be some role for a national efficiency incentive, though the detail will be difficult. The long-delayed Energy White Paper needs to be completed.

Policy should also be efficient. Reducing network outages or protecting the environment are both worthy ends, but pursuing them has a cost. Without careful balancing we can wind up paying for more substations than we really need. Without clear thinking about the most cost-effective renewables we can get stuck with the equivalent of a Rolls when a hatchback would do. Especially in the environmental arena, where emotion often rules, Australia needs the most efficient policies that we can devise. We can't afford to do otherwise.

H. M. Ridout

Heather Ridout
Chief Executive
Australian Industry Group

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part one – energy input costs survey

An Ai Group online survey in November/December 2010 received 144 valid responses, with most respondents coming from small and medium-sized companies in the manufacturing sector. The responses confirmed that most companies have experienced substantial electricity price rises over the past five years and expect more over the next two years. Gas price rises have been smaller and less widespread so far, and around 35 per cent of respondents did not expect an increase in their gas prices in the next two years. Despite price rises, energy costs are relatively small for many companies – electricity costs are equal to 2 per cent or less of sales revenue at about 65 per cent of respondent companies; for gas costs the figure is about 83 per cent of companies. While some companies have made small-to-significant improvements in their energy efficiency over the past five years, 66 per cent have made no improvement and a small number have gone backwards. 57 per cent of companies expect no improvement over the next two years, and 27 per cent expect a marginal improvement.

part two – factors and futures

Australian retail electricity prices increased by an average of 30 per cent between 2006 and 2010, and by some estimates will have risen by at least 100 per cent from 2008 levels by 2015. These price rises have many causes. Electricity prices break down into the wholesale electricity price, charges for transmission and distribution networks, and retail costs. Government policy also affects prices, for instance through tightened reliability standards that require more network investment (and hence charges) to meet, or through mandates for renewable energy.

While renewable energy-related costs have been higher than necessary, particularly those related to support for small solar PV systems, they are a relatively small part of the price rise story. The biggest role has been played by rises in network charges, which have grown to cover large investment to meet strong growth in peak demand, renew large asset bases, and meet higher reliability requirements. Wholesale prices have also been buffeted by factors including the recent drought and the run-up in resource, construction and maintenance costs. The latter, together with rising prices for internationally traded coal and gas, mean that even with conventional fossil-fuel technologies, new electricity generation will be significantly more expensive than Australia has been accustomed to. A switch from coal plants to efficient gas-fired plants is very likely, driven by regulation or carbon pricing, and will entail a cost premium either way. Indeed, all lower-carbon technologies, from carbon capture and storage to nuclear to renewables, are likely to remain more expensive than conventional coal, though scale and learning effects will help blunt costs over time. Compared to other industrialised countries, Australian electricity prices have been very low for both industrial and residential users; while prices are moving in other countries also, Australian price increases may move us towards the middle of the global pack.

Australian prices for natural gas have also been very low by global standards, underpinned by easily accessible supplies convenient to population centres and by isolation from global gas markets, where prices are much higher and move in sync with oil. Wholesale gas costs are not very transparent outside Victoria, but appear to have lifted during the boom and fallen back somewhat as a result of the global financial crisis. The future direction of gas prices on the east coast is strongly upwards, however, driven by the somewhat higher extraction costs of the unconventional gas that increasingly dominates supply, and especially by the growth of the liquefied natural gas export industry. As has already occurred in Western Australia, LNG investment in Queensland will eventually push east coast prices closer to parity with world prices. Climate policy and carbon pricing will add somewhat to the costs of producing and burning gas, but it will remain a very attractive fuel compared with coal and oil over the medium term under carbon constraints.

The substantial increases in energy prices over the medium term will demand action from both governments and business. Governments should try to meet environmental and other goals as efficiently as possible; the potential introduction of carbon pricing should be an opportunity to trim the thicket of inefficient policies that are currently adding somewhat to energy prices for insufficient benefit. Broader government policy needs to maintain a supportive environment for business to maintain overall competitiveness given pressures from energy prices and the strong dollar. Government also has further scope to encourage and assist energy efficiency through expanded research funding, provision of much more detailed and extensive efficiency information to industry, and reforms to ensure the electricity market does not inhibit efficiency and demand management. A proposed national energy savings incentive offers potential benefits, particularly given the current inconsistent State schemes, but required much detail to be worked through.

Energy efficiency has been core business for the most energy-intensive firms for many years, but for many others it has been a second-order issue. The coming price rises will oblige more businesses to focus on managing and reducing this cost, and to take advantage of the information and assistance on offer. Ai Group is ready to help industry meet this challenge.

part one

energy input costs survey

This chapter highlights the key findings of the Ai Group Energy Input Costs Survey. Additional results are provided in Appendix Three.

survey methodology and sample

The Survey was conducted in November/December 2010, through an internet based survey on the Ai Group website. A copy of the survey questionnaire is provided in Appendix Two.

There were approximately 189 responses of which 45 were 'incomplete' (i.e. did not include responses to any of the questions regarding energy and merely responded to background material such as sector and jurisdiction of operation). The final sample thus consists of 144 respondents. Figure 26 shows the distribution of these respondents by industry sector. Approximately 73 per cent of respondents operate primarily in the manufacturing sector (106 respondents). This was followed by services sector respondents (15 per cent of the final sample, 22 respondents). There were 2 respondents from the energy sector and 1 from resources. 49 per cent were from companies with fewer than 20 employees and 61 per cent from companies with annual turnover of less than $10 million. 43 per cent operated primarily in NSW, 33 per cent in Victoria, and 19 per cent in Queensland.

electricity

company electricity spend as a percentage of sales in 2009-10

Companies identified their electricity expenditure as a percentage of sales in 2009-10. Figure 1 shows the distribution of this ratio across all companies.

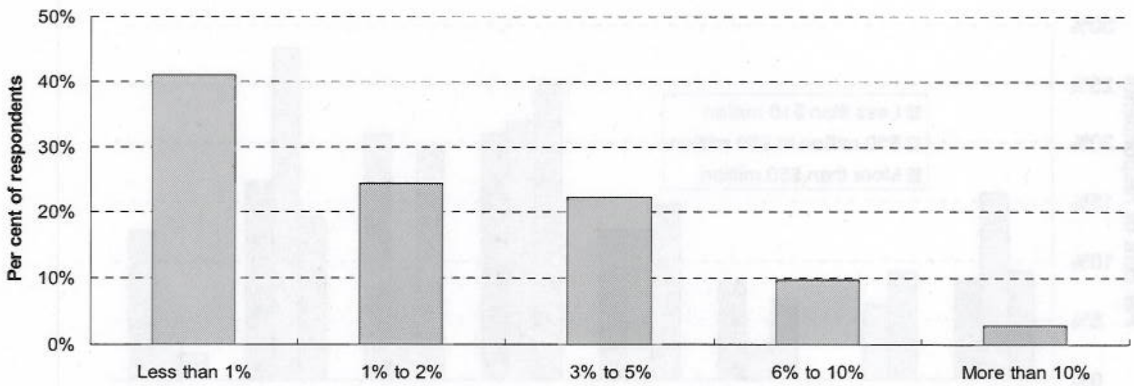

Figure 1 - company electricity spend as a percentage of sales in 2009-10

Figure 1 shows that electricity spend made up a small share of total sales in 2009-10. For 41 per cent of all respondents this equated to less than 1 per cent of their sales. Another 24 per cent spent the equivalent of between 1 to 2 per cent of sales on electricity. Approximately 12 per cent of firms' electricity spend was 6 per cent or greater as a share of their sales.

The relatively small size of electricity spends may help explain the lack of focus on energy efficiency shown in responses to later questions.

change in electricity prices over the last 5 years (including network and retailer charges)

Figure 2 below shows the change in electricity prices over the last 5 years. The most common increase in electricity prices ranged between 11 to 20 per cent. However, 37 per cent of respondents experienced electricity prices increases of 21 per cent or more (including 10 per cent of respondents experienced electricity price increases of more than 50 per cent).

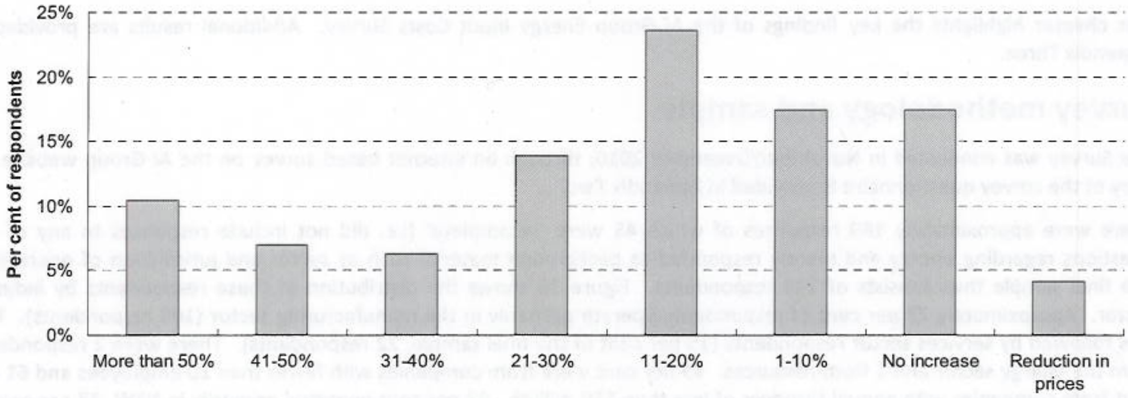

Figure 2 - change in electricity prices over the last 5 years (including network and retailer charges)

Figure 3 below shows the distribution of electricity price changes over the last 5 years by size of company (measured by turnover size). In general we can see that smaller companies experienced larger electricity price increases over the last 5 years. This is evident in the 41 to 50 per cent price increase category, the 21 to 30 per cent category and the 11 to 20 per cent category.

Larger companies were more likely to experience no electricity price increases or reductions in electricity prices, though prices still rose for most such companies, and rose by more than 10 per cent for nearly half of them.

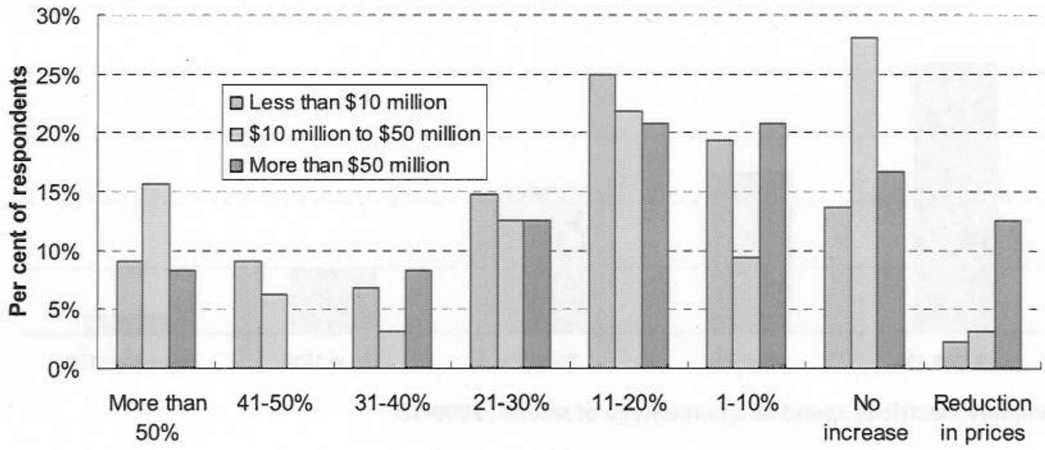

Figure 3 - change in electricity prices over the last 5 years: results by turnover size

expected change in electricity prices over the next 2 years

Figure 4 identifies companies' expectations regarding electricity price changes over the next 2 years. The most common expectation is an increase in electricity prices of between 11 to 20 per cent.

Other companies were more optimistic and expect no increase in electricity prices (20 per cent of respondents – possibly companies in fixed price contracts for the next 2 years). Approximately 35 per cent of respondents expect price increases of 21 per cent or higher.

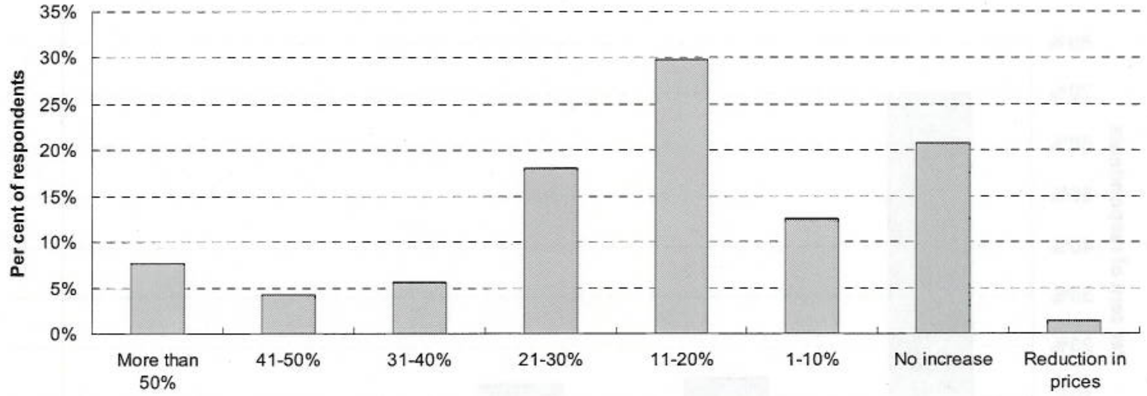

Figure 4 - expected change in electricity prices over the next 2 years

Figure 5 below shows the distribution of the electricity price expectations by company size (turnover basis). We can see that generally smaller companies expect higher electricity price increases in the next 2 years compared to medium and large companies.

For example, approximately 37 per cent of smaller companies expect prices increases of 21 per cent or higher (whether measured as companies with turnover less than $10 million or $50 million and less) whereas only 25 per cent of larger companies (turnover of more than $50 million) expect price increases of 21 per cent or more.

This may reflect the greater role that network charges (which are rising more sharply than wholesale electricity prices or other costs) play in smaller users' bills. However a greater proportion of smaller companies also expect price reductions.

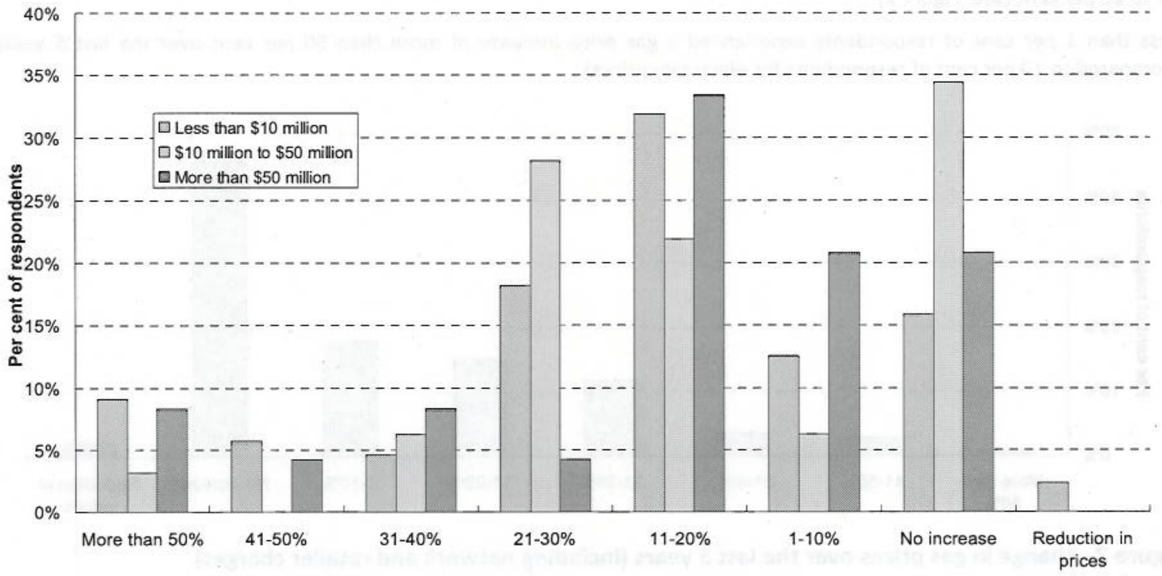

Figure 5 - expected change in electricity prices over the next 2 years: results by turnover size

gas

company gas spend as a percentage of sales in 2009-10

Companies identified their gas expenditure as a percentage of sales in 2009-10. Figure 6 shows the distribution of this ratio across all companies. Companies that responded to the survey generally have a much lower equivalent gas to sales ratio spend compared to electricity to sales (compare Figure 6 with Figure 1). Compared to electricity where 41 per cent of all respondents spent less than 1 per cent of their sales on electricity, for gas the equivalent share is 70 per cent.

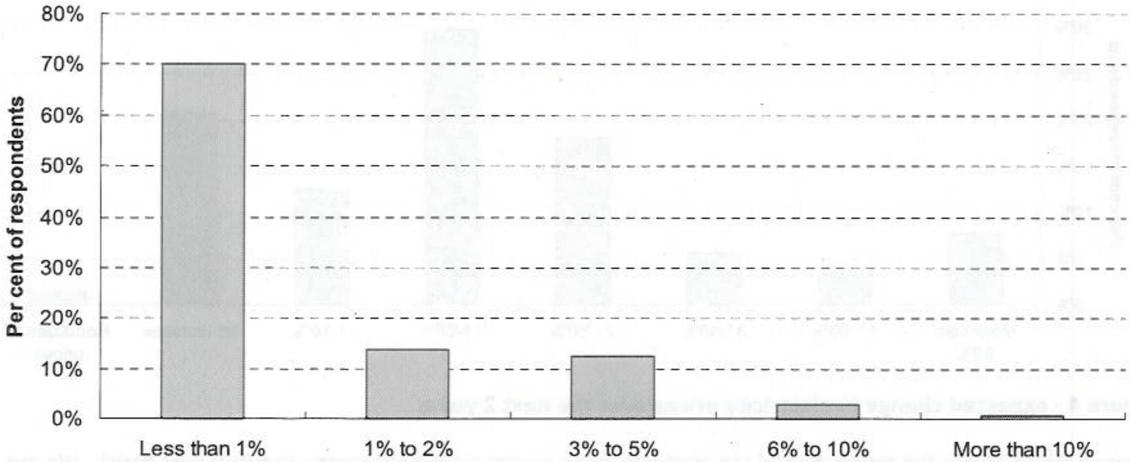

Figure 6 - company gas spend as a percentage of sales in 2009-10

change in gas prices over the last 5 years (including network and retailer charges)

Figure 7 below shows the change in gas prices over the last 5 years. The most common change in gas prices was actually no change (45 per cent of respondents) which is in stark contrast to the most common change in electricity prices of between 11 to 20 per cent (see Figure 2).

Less than 1 per cent of respondents experienced a gas price increase of more than 50 per cent over the last 5 years (compared to 10 per cent of respondents for electricity prices).

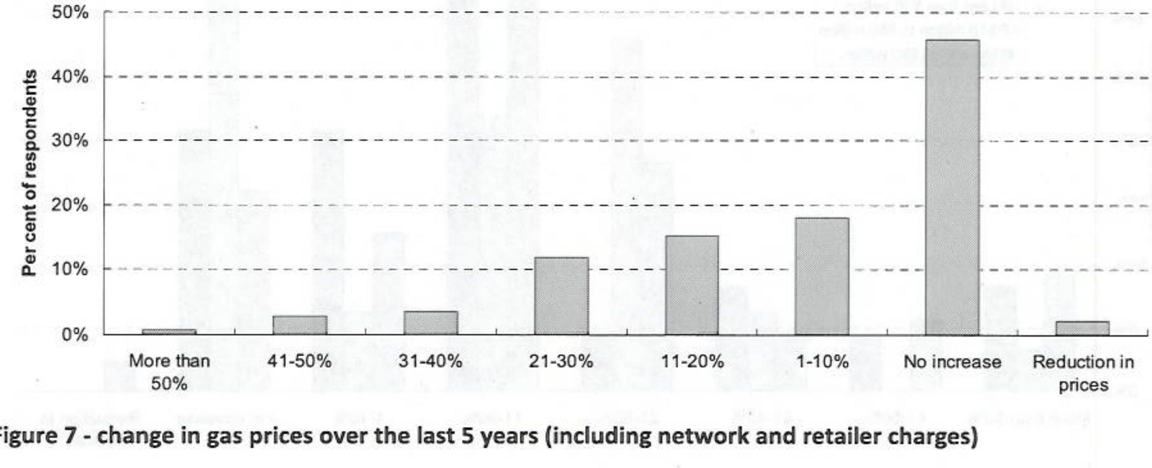

Figure 7 - change in gas prices over the last 5 years (including network and retailer charges)

expected change in gas prices over the next 2 years

Figure 8 below shows the companies' expectations regarding gas price changes over the next 2 years. The most common expectation is no change in gas prices (38 per cent of respondents) which compares favourably to common electricity price expectations (of an increase in electricity prices of between 11 to 20 per cent). Long term gas supply arrangements may play a part in this expectation.

Approximately 17 per cent of respondents expect a gas price increase over the next 2 years of 21 per cent or higher and this compares to 35 per cent of respondents with respect to electricity price increases.

The same proportions of respondents expect a decline in gas prices compared to a decline in electricity prices.

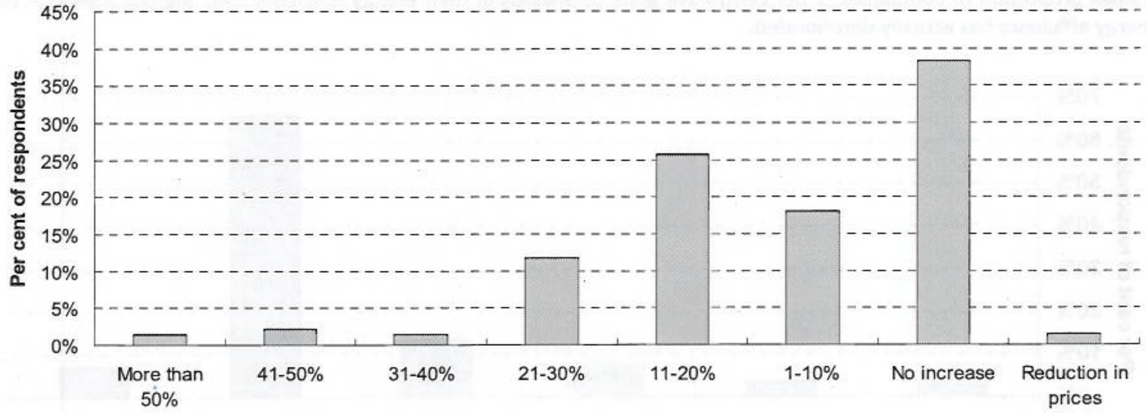

Figure 8 - expected change in gas prices over the next 2 years

Figure 9 below dissects the results for gas price expectations into results by company size on a turnover basis. Larger companies generally expect larger gas price increases. Only smaller companies anticipate experiencing a gas price decline in the next 2 years.

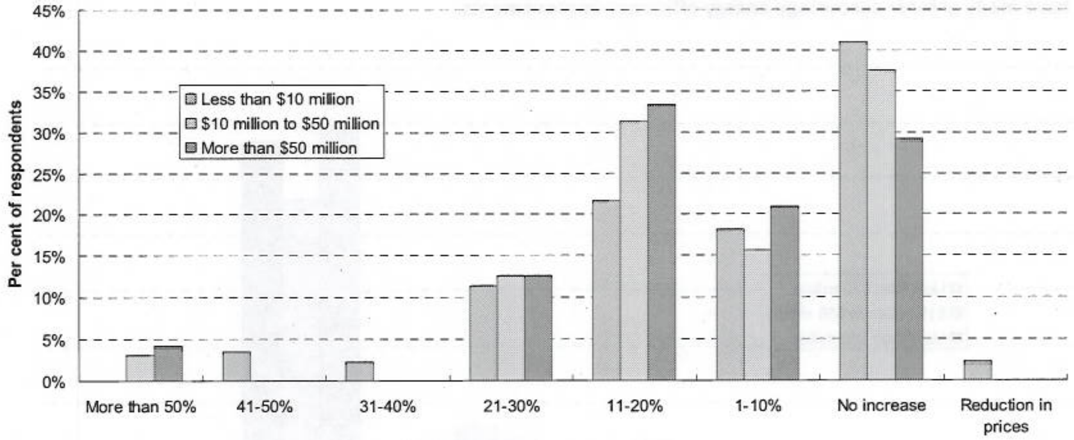

Figure 9 - expected change in gas prices over the next 2 years: results by turnover size

energy efficiency

company energy efficiency improvements over the last 5 years

Companies identified the degree of their energy efficiency improvements over the last 5 years. Figure 10 presents the results. Approximately 66 per cent of companies have made no energy efficiency improvements over the last 5 years, despite the substantial increase in electricity prices over this period. This may reflect the small role of energy costs in overall cost structures for many businesses in low-energy-intensity sectors, or it may be that many businesses either have limited efficiency options or are unable to take up those that exist. If the latter is the case it would be a serious problem given the further energy price rises we are very likely to see.

A small proportion of companies (7 per cent) have gone backwards in their energy efficiency over the last 5 years – their energy efficiency has actually deteriorated.

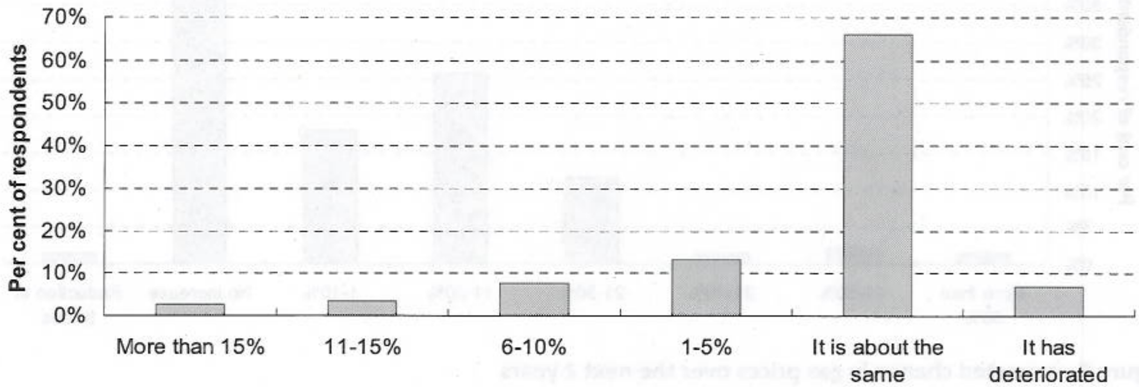

Figure 10 - company energy efficiency improvements over the last 5 years

Figure 11 below compares these results by company size. The smallest and largest companies have made a greater proportion of the largest energy efficiency improvements (i.e. more than 15 per cent). However, generally larger companies have made greater percentage energy efficiency improvements.

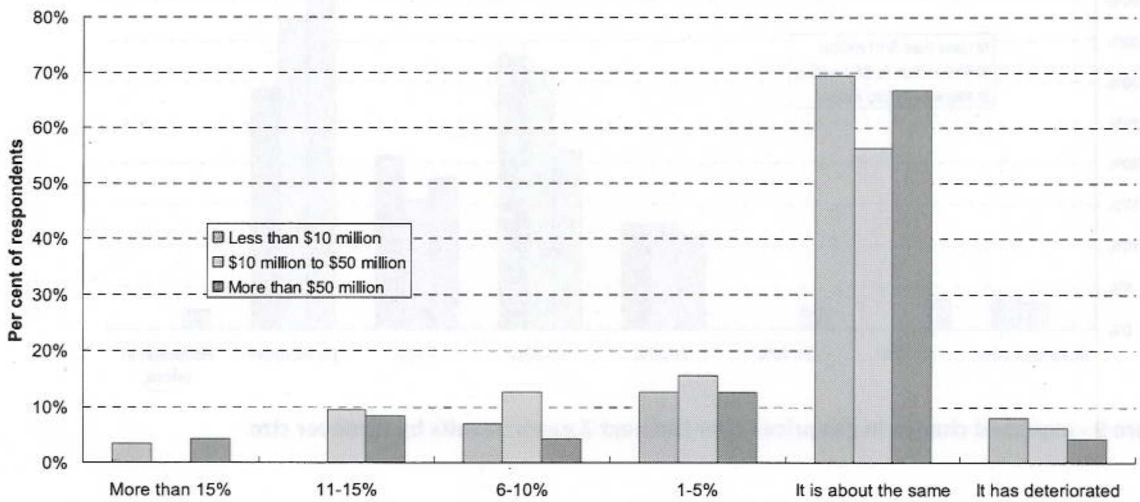

Figure 11- company energy efficiency improvements over the last 5 years: results by turnover size

Figure 12 below shows these results by industry sector. The manufacturing sector has led the way in terms of making substantial energy efficiency improvements. Approximately 15 per cent of manufacturing sector companies made 6 per cent or greater energy efficiency improvements over the last 5 years, compared to 8 per cent for construction sector companies and 14 per cent for services sector companies. This may reflect the greater energy intensity of manufacturing activity, and the higher price rises experienced by the sector (see Figure 33 below).

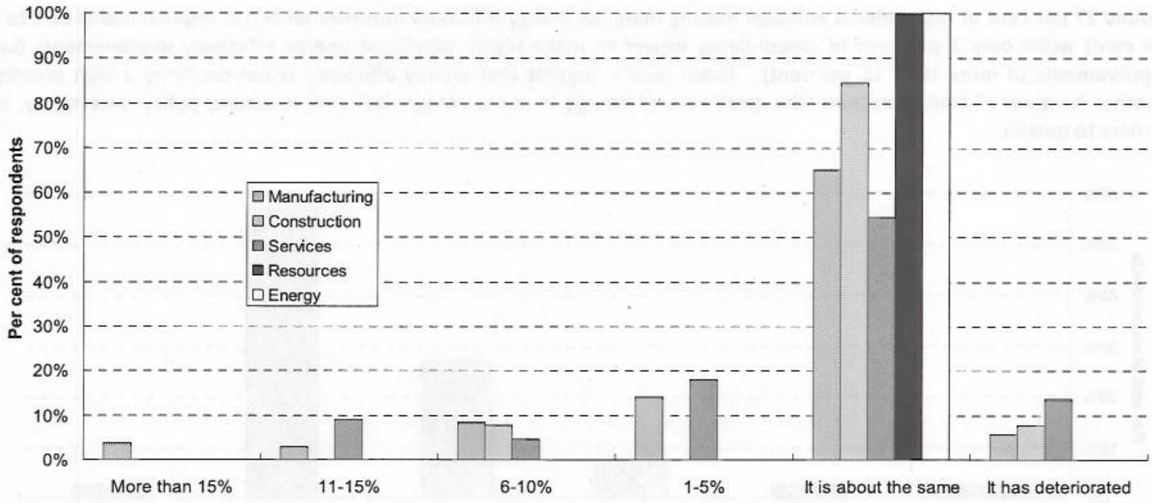

Figure 12 - company energy efficiency improvements over the last 5 years: results by sector

Figure 13 below shows the energy efficiency results by jurisdiction. The results are fairly consistent across jurisdictions. Policies such as New South Wales' Greenhouse Gas Abatement Scheme and Energy Savings Scheme do not appear to have yet had a major impact on energy efficiency in business.

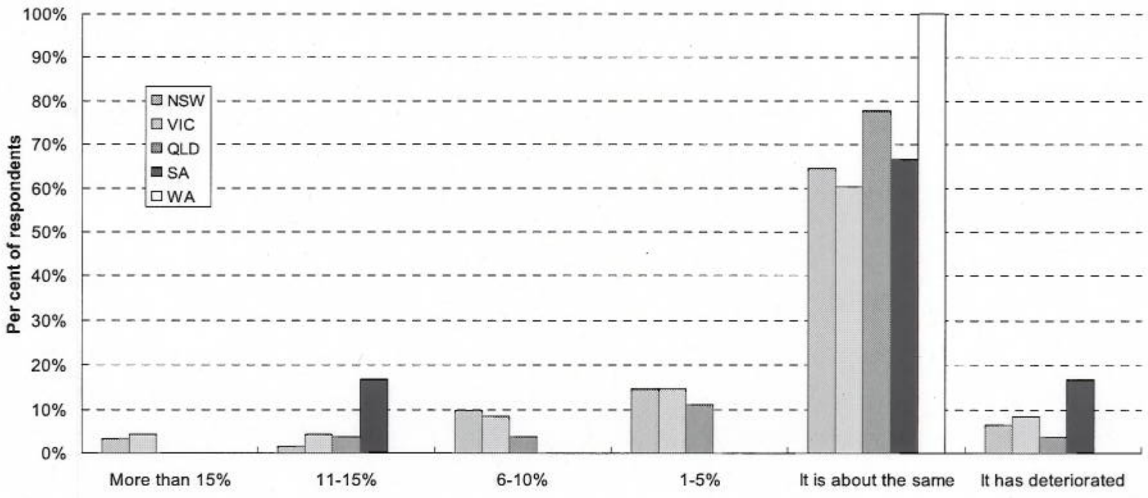

Figure 13 - company energy efficiency improvements over the last 5 years: results by jurisdiction

Expected improvement in company energy efficiency over the next 2 years

Figure 14 below presents the expected improvement in company energy efficiency over the next 2 years.

Over half of all companies surveyed (57 per cent) indicate that their energy efficiency will be about the same over the next 2 years.

Around 27 per cent of respondents envisage making marginal energy efficiency improvements (i.e. improvements of 1 to 5 per cent) while only 3 per cent of respondents expect to make highly significant energy efficiency improvements (i.e. improvements of more than 15 per cent). These results suggest that energy efficiency is not currently a high priority, whether because of limited options, the small role of energy in some companies' cost structure, policy uncertainty, or barriers to uptake.

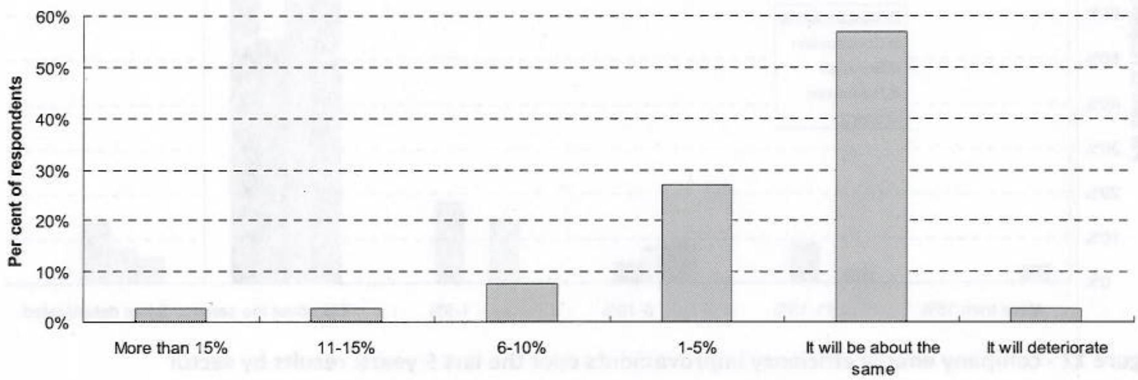

Figure 14 - expected improvement in company energy efficiency over the next 2 years

part two
factors and futures

Energy is a crucial underlying input to almost everything that Australian companies do, whether they smelt aluminium, process food or operate a call centre. Cost structures vary widely, and some businesses can easily manage their energy demand in response to fluctuations in supply. Nonetheless, security of supply is vital for business and relatively cheap energy has been a key source of competitive advantage for many Australian companies. Recent energy worries have usually centred on climate change – whether through concerns over the impact of Australia's exceptionally emissions-intensive energy supply, or through fears that climate policy will radically raise energy prices or reduce reliability.

Climate change and policy are undeniably central to the future of Australia's energy supply and the prices we pay for it, but other important factors are at play. Network maintenance and upgrades are a huge part of electricity price rises in New South Wales and Queensland. The development of the Liquefied Natural Gas export industry has shaped gas prices in Western Australia and will increasingly do so in Queensland and the rest of the east coast. This report seeks to set out the factors that contribute to Australian energy prices, providing context and a sense of scale to assess recent developments and likely future directions.

electricity

Over the past four years Australian retail electricity prices have risen by around 30 per cent in real terms (see Figure 15), and further rises are already locked in.

Electricity prices have three components:

- **wholesale electricity prices**. These are primarily determined through the National Electricity Market (NEM) in all states and territories except Western Australia and the Northern Territory. The price changes constantly, reflecting shifting demand and the price and quantity of supply bid onto the market by generators. Prices are also set through hedge contracts, entered into by generators and retailers or large customers to reduce volatility. Retailers who own some of their own generation capacity will set internal prices based in part on their assessment of the long run marginal cost of building new plant;
- **network charges** for transmission of electricity across long distances and distribution to end users. Since network companies are natural monopolies, their activity and allowable revenue is determined for five-year periods by the Australian Energy Regulator; and
- **retail margins**, which cover costs of retail and customer service. All jurisdictions except Tasmania have now adopted Full Retail Contestability, allowing all users to negotiate contracts at market rates. However, some form of price regulation applies to small customers in all jurisdictions except Victoria, mostly in the form of tariffs set by regulators that customers default to if they do not enter a market contract.

Retail margins have risen somewhat to cover greater risks under full competition, and retailer operating and customer acquisition costs have increased too. Nonetheless, official reviews to date have found that retail competition has been effective, and retail margins comprised only about 5 per cent of a small NSW customer's bill in 2007. It is wholesale prices (currently about 40 per cent) and network charges (about 50 per cent) that determine substantial electricity price movements. Two thirds of the electricity price increase in NSW from 2007-08 to 2012-13 has come from network investment. Figure 16 shows the components of the electricity price paid by a typical Sydney household in 2009-10 and 2012-13.

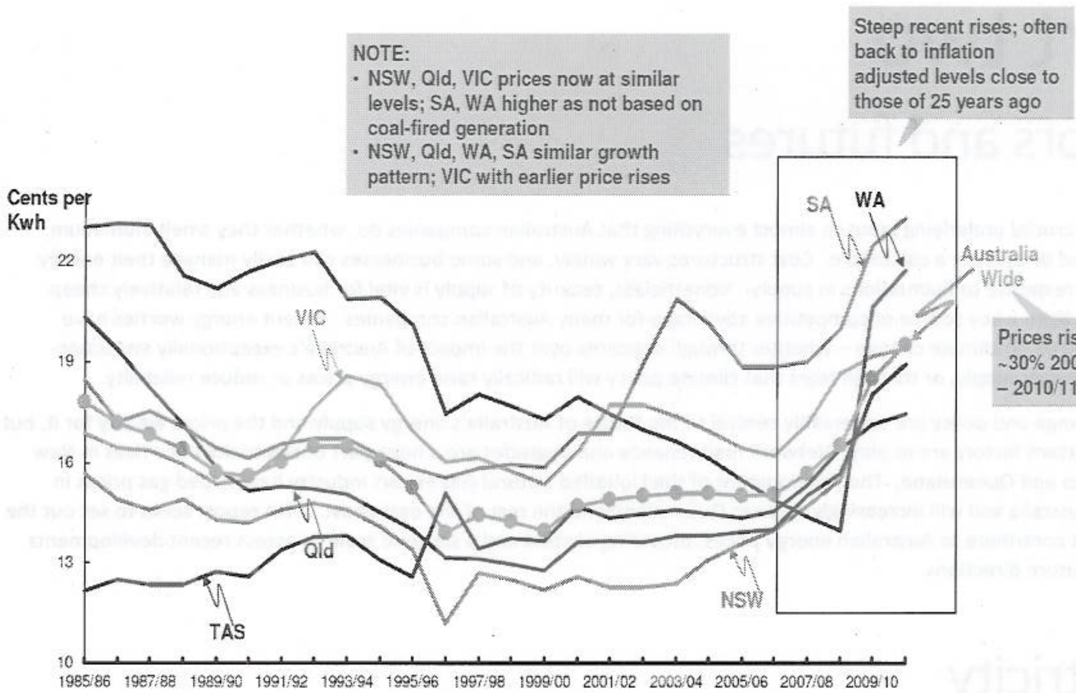

Figure 15 - State electricity prices, inflation adjusted[1]

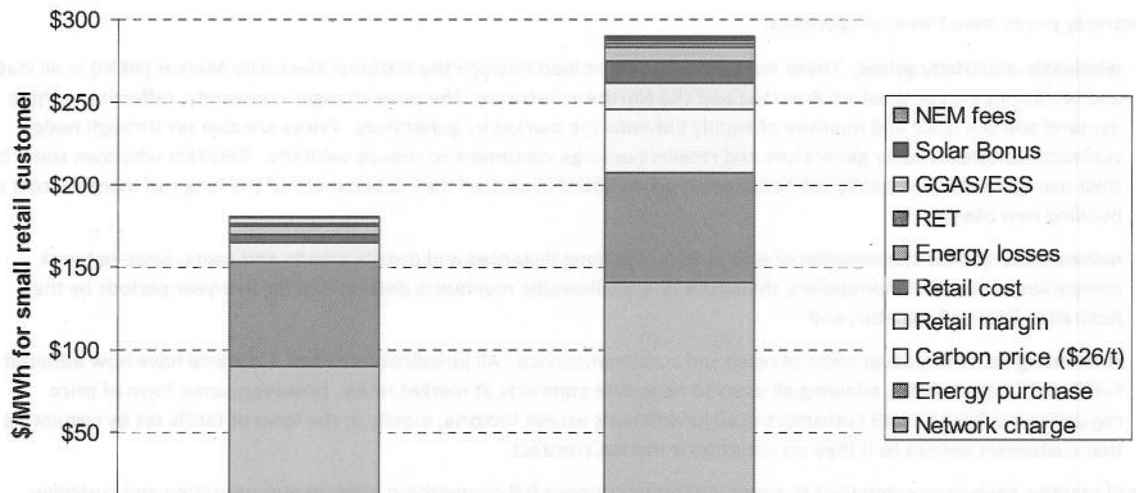

Figure 16 - Components of residential Sydney electricity prices in 2009-10 and 2012-13[2]

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[1] Rod Sims, 'Energy market outlook' (Presentation to the Multi-Party Climate Change Committee, 10 November 2010) 2 <http://www.climatechange.gov.au/government/initiatives/~/media/publications/committee/rod-sims-energy-market-outlook.ashx>. These prices appear to reflect those paid by households and small-to-medium business customers.

[2] Derived from Independent Pricing and Regulatory Tribunal, *Review of regulated retail tariffs and charges for electricity 2010-2013* (Final Report, March 2010) 7 <http://www.ipart.nsw.gov.au/investigation_content.asp?industry=2&sector=3&inquiry=196&doctype=7&doccategory=1&docgroup=1>. An additional estimate has been added for the costs of the NSW Solar Bonus scheme, putting them at $2 per MWh based on the program reaching its cap and costs being spread evenly across all NSW electricity consumption. The chart depicts costs for a household customer of EnergyAustralia with 7,000 kWh annual electricity use and assumes a carbon price of $26 per tonne CO2 – the level

Wholesale electricity prices

Within the NEM, the generators who have bid the lowest prices are called on to supply electricity first, and more expensive generators are brought in as necessary to meet demand. All generators supplying at any one time are paid the same price – the bid of the marginal generator. Thus prices shift over time as more expensive generators are called on or shut out due to variations in: demand; the capacity of the cheaper generators to supply the market; or the prices bid by generators, which might reflect changes in their costs.[3] Each of these has been an important factor in the movement of wholesale prices in recent years (see Figure 17).

Total electricity demand rose strongly through most of the past decade, and peak demand even more so as households installed energy-intensive appliances like air-conditioning amid high average temperatures and more frequent heatwaves. However, the near-recession caused by the Global Financial Crisis depressed demand across the NEM, putting downward pressure on prices in 2008-09.

The ability of low cost generators to supply the market has also been squeezed, largely due to drought and extreme weather. Reduced inflows and water allocations diminished the available capacity from hydro generators and from some coal generators, which require large amounts of water for cooling. During bushfires and extreme heat events, major interconnectors and transmission lines have become congested or inoperable, leading to price spikes in markets temporarily isolated from some cheap generation capacity.

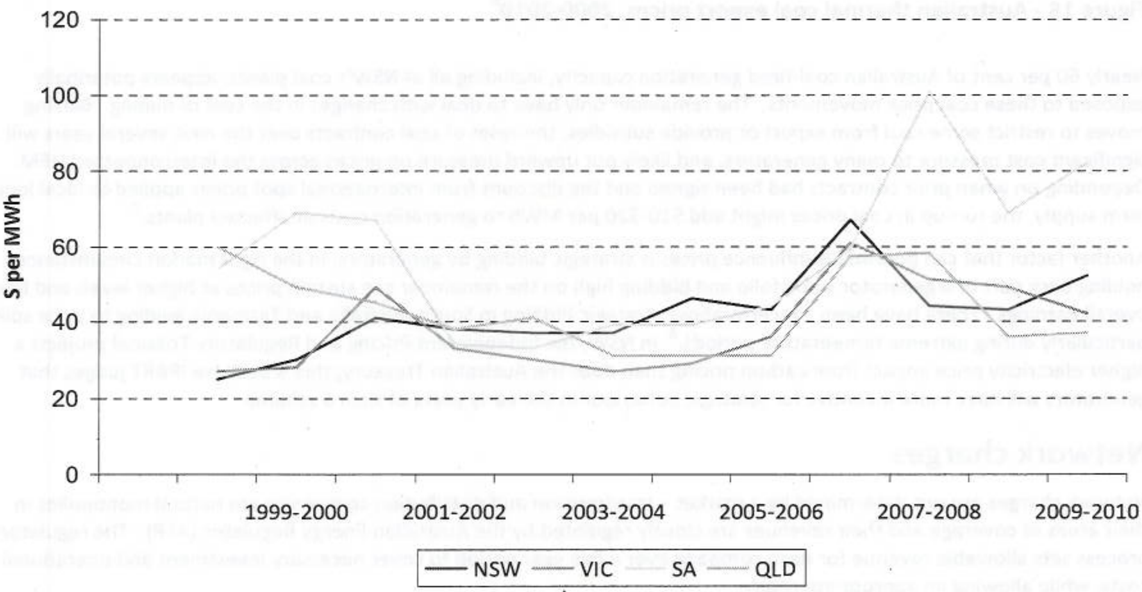

Figure 17 - wholesale electricity prices in the NEM[4]

Generator costs have risen in several ways. The pre-GFC resources boom put pressure on skilled worker wages and materials prices, raising costs for building new plant and operating and maintaining existing ones. The boom also boosted coal production costs and prices for traded steaming coal, which have eased but are likely to remain high by historic

projected for 2012-13 under the CPRS as at late November 2009. RET costs are estimated based on the expanded RET, prior to the split into LRET and SRES; SRES might imaginably add a few dollars in 2012-13, but not enough to substantially change the chart. The total annual bill in 2012-13 would be around $2,000 with a carbon price, or $1,700 without, up from $1,250 in 2009-10. NEM is the National Electricity Market, GGAS is the NSW Greenhouse Gas Abatement Scheme, ESS is the NSW Energy Savings Scheme, RET is the federal Renewable Energy Target.

[3] Bid prices reflect many factors, from the cost of reducing or stopping generation (minimal for an open cycle gas turbine, severe for a coal-fired plant; this can lead to low or negative bids at times, simply to keep a generator going), to the expected bidding of other players, to the presence of unusual market conditions such as constrained supply that enable higher prices.

[4] Australian Energy Regulator, *State of the Energy Market 2010* (Australian Competition and Consumer Commission, 15 December 2010) 28 <http://www.accc.gov.au/content/index.phtml?itemId=961581>.

standards.[5] However, it should be noted that international coal prices will only affect generators who are served by mines also capable of exporting – and only when their long-term supply contracts are renegotiated.

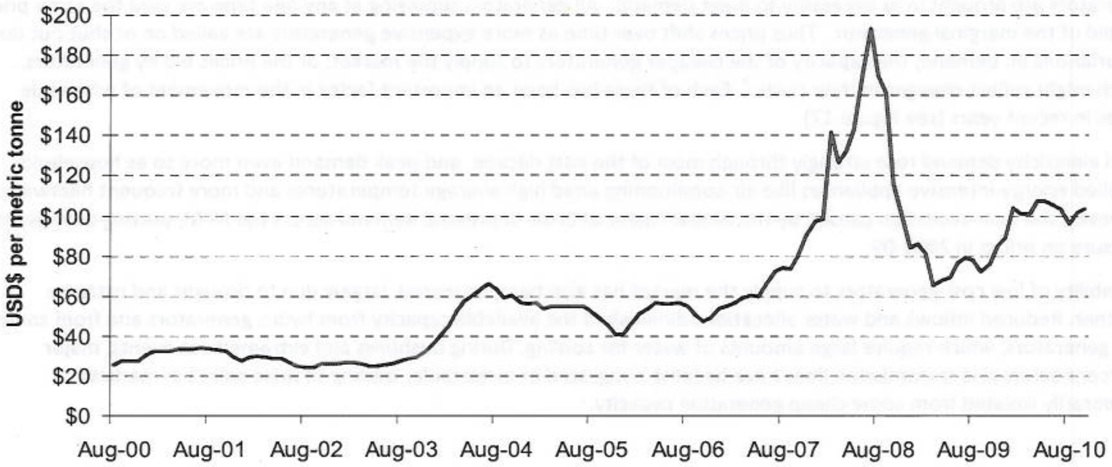

Figure 18 - Australian thermal coal export prices, 2000-2010[6]

Nearly 60 per cent of Australian coal-fired generation capacity, including all of NSW's coal plants, appears potentially exposed to these coal price movements. The remainder only have to deal with changes in the cost of mining. Barring moves to restrict some coal from export or provide subsidies, the reset of coal contracts over the next several years will add significant cost pressure to many generators, and likely put upward pressure on prices across the interconnected NEM. Depending on when prior contracts had been signed and the discount from international spot prices applied to local long-term supply, the run-up in coal prices might add $10-$20 per MWh to generation costs at affected plants.[7]

Another factor that can potentially influence prices is strategic bidding by generators; in the right market circumstances, holding back part of a generator's portfolio and bidding high on the remainder can sustain prices at higher levels and boost overall earnings. There have been concerns about strategic bidding in South Australia and Tasmania leading to price spikes, particularly during extreme temperature periods.[8] In NSW, the Independent Pricing and Regulatory Tribunal projects a higher electricity price impact from carbon pricing than does the Australian Treasury; this is because IPART judges that generators will have more incentive for strategic behaviour in the early years of such a scheme.

Network charges

Network charges are not determined by a market – transmission and distribution companies are natural monopolies in their areas of coverage and their revenues are closely regulated by the Australian Energy Regulator (AER). The regulatory process sets allowable revenue for each company over a five year period to cover necessary investment and operational costs, while allowing an appropriate return.

Recent determinations have locked in large increases in network charges for most states, especially NSW and Queensland. While there has been some increase in operating expenditures, driven by the same pressures on skilled labour and materials as affected the rest of the energy sector during the resources boom, most of the pressure on network charges comes from immense capital investment.

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[5] The strong growth expected from China and India, the role of coal in their energy systems and the extent to which demand has outpaced domestic supply all suggest relatively high coal prices for the foreseeable future, despite the supply growth that higher prices will encourage. Prices would likely be lower if all countries fulfilled their Copenhagen Accord emissions pledges, however.

[6] International Monetary Fund, *Monthly commodity price data for 8 price indices and 49 actual price series* (October 2010) <http://www.imf.org/external/np/res/commod/External_Data-110410.csv>.

[7] Based on a black coal energy content of 27 Gj per tonne and an average thermal efficiency of 0.348 for potentially trade-exposed black coal plants.

[8] See Ed Willett, 'State of the energy market' (Speech delivered at the energy 21C conference, Melbourne, 8 September 2009) 2-6 <http://www.aer.gov.au/content/item.phtml?itemId=730609&nodeId=6ed27686f97df599313b2f08f636f47b&fn=State%20of%20the%20energy%20market.pdf>.

	NSW	QLD	VIC	SA
Net capex	$14.6b	$11.9b	$5.2b	$1.8b
Regulated Asset Base growth	59.1%	50.8%	29.8%	30%
Network charge growth	62.5-93.1%	58.1-60.2%	11.6-19.4%	40.2%
Residential price impact	16.6-37.2%	13-13.9%	10.3-17.8%	14.9%

Table 1 – Cumulative five-year impacts of recent distribution network determinations[9]

This investment is driven by four factors:

- **growing loads and rising peak demand**. Rising populations and expanding cities require more and upgraded poles, wires and substations, especially since they are using more energy per capita. Peak demand is rising particularly fast, while extreme-conditions days and air-conditioner use are more common; assuring supply requires further investment.
- **replacement of ageing and obsolete assets**. Ongoing maintenance and renewal is a significant cost, particularly for regional distribution networks in NSW and Queensland, where networks cover large and lightly populated areas. Another contributing factor, according to some observers, has been past underinvestment; on this view the state governments that own most distributors have required such large dividends that investment has suffered.
- **more rigorous licensing conditions** for network security and reliability. Customers and governments place great importance on security of energy supply, and in recent years this has been reflected in strengthened regulation. Meeting these requirements requires additional investment.
- **the regulatory system**. Network companies generally earn more for carrying higher volumes of electricity, and determinations include an allowance for return on capital invested. There is an incentive to seek higher capital allowances from regulators, while incentives to manage demand are weak.[10] Recent determinations for Victoria and Queensland have included funding or incentives for demand management, but they are modest compared to overall budgets and incentive structures.

Policy costs

Government policies can also contribute to costs at the generation, network or retail stages. The most prominent policies in this context are the Commonwealth's Renewable Energy Target; energy efficiency incentives in NSW, Victoria and South Australia; and proposals for pricing greenhouse gas emissions.

The Large-scale Renewable Energy Target (LRET) requires wholesale purchasers of electricity – mostly retailers, but also some large consumers – to meet growing annual targets for renewable generation. They can do this by producing their own renewable energy, or by purchasing tradable certificates from renewable generators; certificate prices are set by the market at the level necessary to support sufficient generation to meet the target.

The related Small-scale Renewable Energy Scheme (SRES) covers household-scale systems like small solar photovoltaic (PV) panels and solar hot water, and requires wholesale electricity purchasers to buy all the eligible generation that is offered at a fixed certificate price. Certificates are earned on purchase based on the expected generation over the small asset's operating life, and a multiplier is applied to certificates from small PV, wind and hydro systems but not to solar hot water units. This multiplier replaced the former $8,000 PV rebate; it will phase down from 5 to 1 by mid-2014.

The LRET and SRES are intended to raise renewables to about 20 per cent of total generation in 2020, while building industry experience and capacity and driving cost reductions from scale and learning. The costs are ultimately passed on to electricity consumers, though emissions intensive trade exposed industries can get a partial exemption. The additional renewable generation capacity can also put downward pressure on wholesale electricity prices, however. ESCOSA recently put LRET costs at $3.66 per MWh in 2011.[11] Future LRET costs will be substantially higher than currently projected if carbon pricing does not eventuate, as REC prices cover the gap between market returns and the costs of investing in renewables;

[9] Derived from recent determinations available at Australian Energy Regulator, *Electricity distribution revenue regulation* (6 December 2010) <http://www.aer.gov.au/content/index.phtml/itemId/718194>.

[10] There can be strong incentives to underspend the capital expenditure levels determined by the regulator, however, since the company will usually be able to retain the underspend.

[11] Essential Services Commission of South Australia, *2010 Review of Retail Electricity Standing Contract Price Path – Final Inquiry Report & Final Price Determination* (December 2010) 84 <http://www.escosa.sa.gov.au/library/101208-ElectricityStandingContractPrice-FinalPriceDetermination-PartA.pdf>.

by raising wholesale electricity prices, a carbon price narrows this gap.[12] The relatively modest cost projections that preceded introduction of the expanded RET assumed that a carbon price would be in place.

With respect to SRES, falling costs and the combination of State and Federal subsidies have resulted in surging demand for small solar PV systems; combined with the multiplier this will take SRES-related costs to $6 per MWh in 2011. The Government has announced a somewhat accelerated wind-back of the multiplier, and the upfront deeming of certificates means this boom should not have lasting impacts on prices if new installations return to less frothy levels. Furthermore, even the larger-than-anticipated SRES cost impact is small compared to other components of the cost of electricity. Nonetheless, the SRES boomlet is a troubling misallocation of resources. Figure 19 shows how growth in installation of small systems, mostly PV, has increasingly dominated the production of renewable energy certificates in recent years. If the most recent official projections are met, almost as many SRES certificates will be issued in 2011 as for all forms of renewable in 2010, and electricity consumers will pay $1.12 billion in 2011 towards the cost of small-scale systems, mostly PV. Figure 20 shows that the same funds could produce four times as much renewable energy each year if invested in wind farms, and twice as much if invested in innovative large scale solar plants. While solar hot water systems are an excellent option for many Australians and small PV systems are useful in the right context, the current SRES is not offering value for money in terms either of emissions abatement or support for innovation.

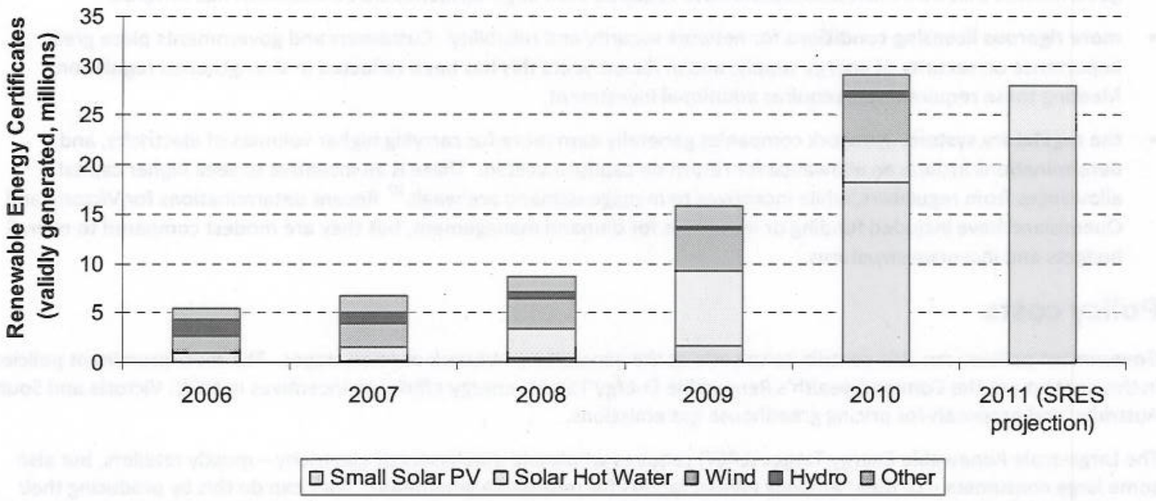

Figure 19 - Renewable energy certificates generated annually by source[13]

The NSW Solar Bonus Scheme is another support for small-scale solar systems and has attracted considerable attention, with uptake dramatically exceeding projections and raising concerns of a large impact on electricity prices. The scheme is a gross feed-in tariff, guaranteeing a premium price for all electricity generated by eligible small solar PV systems; the cost is paid by electricity users. The value of the policy is questionable, but following changes in late 2010 the cost impact should be modest. Total annual costs over the years to 2016, when the tariff expires, should be no more than $163 million; spread over all NSW electricity consumption this would add about $2 per MWh to the cost of electricity.[14] Nonetheless the policy will have directed up to $1 billion to small-scale PV by the time it expires, money that could have reaped greater energy, innovation or carbon benefits if spent elsewhere. Similar feed-in tariffs apply in most other jurisdictions, but they are less generous and have not run out of control.

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[12] See Intelligent Energy Systems, *Scenario modelling for Energy White Paper – modelling results* (6 December 2010) 26, 37 <http://www.aemo.com.au/planning/0400-0022.pdf>.

[13] Derived from data at Office of the Renewable Energy Regulator, *REC Registry* <https://www.rec-registry.gov.au/>. Figures for 2011 are based on the ORER estimate of 28 million SRES certificates to be issued in 2011, and assume the same split between solar hot water and solar PV as in 2010 – see ORER, *Small-scale Technology Percentage* (31 December 2010) <http://www.orer.gov.au/stp/index.html>. 28 million SRES certificates times the fixed $40 certificate price equals $1.12 billion.

[14] Based on the amended scheme, assuming 110MW of capacity earning the 60 cent tariff and 190MW at 20 cents, with an 18% capacity factor and total NSW demand of about 81,200GWh. If all 300MW of scheme capacity qualified for the 60 cent tariff, as is possible but unlikely, the electricity price impact would rise to $3.50 per MWh. See information at *Solar Bonus Scheme for NSW* (Industry & Investment NSW, 13 January 2011) <http://www.industry.nsw.gov.au/energy/sustainable/renewable/solar/solar-scheme>.

Energy efficiency obligation schemes – the Energy Savings Scheme in NSW, Energy Saving Incentive in Victoria, and Residential Energy Efficiency Target in South Australia – generally require retailers to meet an annual target for reduced or avoided energy use, which they do by subsidizing efficiency activities among their customers or buying tradeable certificates from others who have made savings. While these activities should reduce energy bills for participants, and take some pressure off both wholesale prices and network costs for all, they do involve upfront expenditure and the costs are passed through to electricity customers. The net effect is hard to assess, particularly since the schemes have not been in place long; IPART makes a simplified estimate that the upfront costs of the NSW scheme are $0.70 per MWh in 2010-11, rising to $1.40 in 2012-13. ESCOSA estimates a cost of $1.86 per MWh for the SA Residential Energy Efficiency Scheme in 2011. The Prime Minister's Task Group on Energy Efficiency recommended development of a national efficiency scheme.[15]

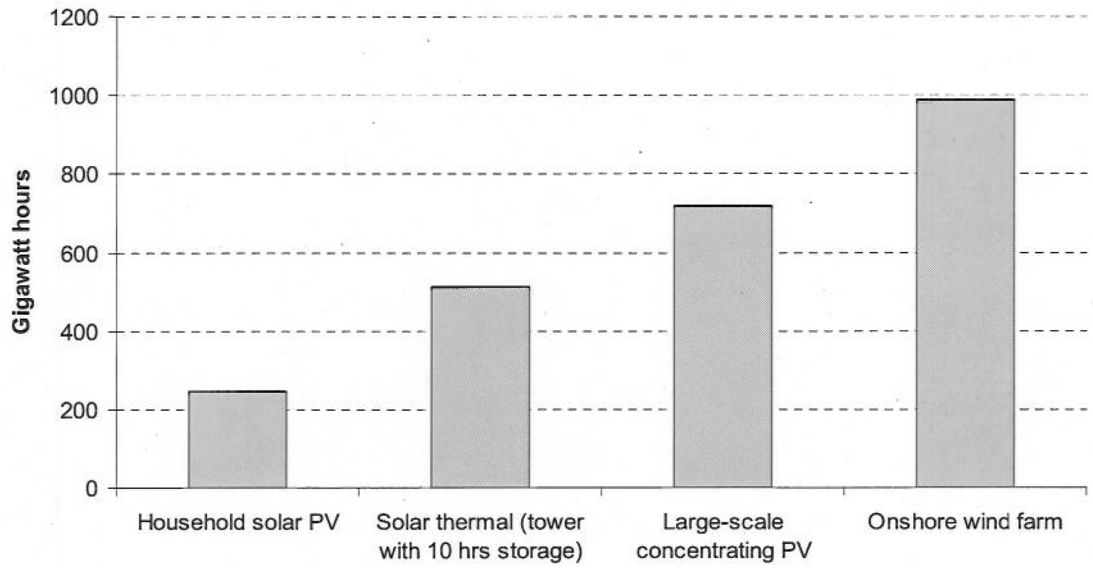

Figure 20 – Potential annual generation from alternate uses of $1.12 billion SRES investment[16]

Pricing carbon can also add to electricity prices, since 75 per cent of Australia's electricity comes from highly-emitting coal-fired power stations. An average current coal-fired generator might emit 1 tonne of carbon dioxide per MWh generated; a $10 carbon price might thus increase wholesale electricity prices by $10 per MWh. However, several factors complicate this.

The ability of generators to pass through their full carbon cost may be constrained, particularly when the marginal generator that sets the market price is less carbon-intensive – like a gas-fired plant. In such cases some of the carbon price would be absorbed in lower margins for the more intensive generators, especially Victorian brown coal-fired generators.

In other cases, market conditions – particularly the dominance of high-emitting generation – may encourage strategic behaviour by generators that could enable them to pass through a higher cost increase than otherwise. On this basis IPART projected a higher pass-through than the Commonwealth Treasury, and hence a larger initial impact on electricity prices. This enhanced pass-through would disappear over time as the generation mix shifted to lower-emitting sources.

[15] *Report of the Prime Minister's Task Group on Energy Efficiency* (DCCEE, 8 October 2010) 49 <http://www.climatechange.gov.au/publications/energy-efficiency/report-prime-ministers-taskforce-energy-efficiency.aspx>.

[16] Comparing capital costs only. Based on: assumptions for household PV costs from McLennan Magasanik Associates, 'Report to Department of Climate Change and Energy Efficiency: Impacts of Changes to the Design of the Expanded Renewable Energy Target' (May 2010) 17 <http://www.climatechange.gov.au/government/initiatives/~/media/publications/renewable-energy/mma-modelling-report.ashx>; data on the SolarReserve Tonopah solar thermal plant from Beyond Zero Emissions, *Zero Carbon Australia Stationary Energy Plan* (University of Melbourne, July 2010) 53, 144 <http://beyondzeroemissions.org/zero-carbon-australia-2020>; information on the proposed Silex concentrating solar PV plant at Mildura from SilexSolar 'Victorian Government launches major solar initiatives at Solar Systems Bridgewater facility' (21 July 2010) <www.silex.com.au> and Adam Morton, 'Big solar project revived', *The Age* (Melbourne), 10 February 2010 <http://www.theage.com.au/business/big-solar-project-revived-20100209-nprg.html>; and onshore wind assumptions from Electric Power Research Institute, *Australian Electricity Generation Technology Costs – Reference Case 2010* (Department of Resources, Energy and Tourism, February 2010) 8-6 <http://www.ret.gov.au/energy/facts/Pages/EnergyFacts.aspx>.

As Rod Sims notes, the impact of carbon pricing should not be judged against projections based on no-climate-policy scenarios.[17] Investors are already reluctant to commit to the coal-fired power stations that such scenarios project;[18] existing inefficient climate policies like the RET will raise electricity prices; and a carbon price can substitute for these policies or reduce their impacts. Thus the net impact on future electricity prices will not be as large as the level of the carbon price would suggest.

[17] Sims, above n 1, 6.

[18] And Australian governments are moving to place legal restrictions of varying stringency on the construction of new coal-fired power plants.

Future directions

The factors that have raised electricity prices in recent years show little sign of retreat.

Much of Australia's current generation capacity is ageing, and all will have to be replaced sooner or later. The capital costs of those replacements will be significantly higher thanks to labour costs and high resource prices, even for conventional fossil-fuel generation technologies.[19] Furthermore, as noted, export prices for Australian thermal coal have risen substantially over the past decade. Future prices depend on the level of global growth, particularly in the major emerging economies, and on the ambition of global climate policy.[20] Weak climate policies would see strongly rising coal demand and high average prices out to 2030.[21] As discussed below, Australian natural gas prices are also likely to rise over the medium term. Both developments would add significantly to operating costs at a large portion of current generators.

Moderate economic growth scenarios over the years to 2020 see average increases in annual electricity demand across the NEM of 2.1 per cent, and increases in summer maximum demand of 2.6 per cent.[22] This will keep upward pressure on wholesale prices and drive further expensive investment in networks.

Demand growth will also require new investment in electricity generation. Installed generation capacity will start to fall below the levels needed to ensure reliability over the next several years. Queensland faces the most immediate pressure, with new investment needed by 2013-14 on medium growth assumptions. If the Low Reserve Condition (LRC) points in Table 2 are reached without additional capacity, the lights will not suddenly go out – but there will be a growing risk of demand exceeding supply during peak times and extreme conditions. The lead time needed to plan, permit and construct new generation means that investment decisions will need to be made soon in many cases. Higher economic growth would make the issue even more urgent.

Region	Low economic growth		Medium economic growth		High economic growth	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
QLD	2015/16	184	2013/14	726	2012/13	716
NSW	2017/18	91	2016/17	27	2016/17	285
VIC	2017/18	135	2015/16	249	2014/15	222
SA	2017/18	11	2015/16	50	2012/13	85
TAS (summer)	>2019/20	NA	>2019/20	NA	>2019/20	NA
TAS (winter)	>2020	NA	>2020	NA	>2020	NA

Table 2 - NEM supply-demand outlook overview[23]

The choice of technologies to meet these needs will impact prices. Figure 21 and Figure 22 show recent estimates of the long term average cost of generation for a range of technologies in 2015 and 2030, and appendix one discusses each option briefly. The somewhat lower projected costs for low-emissions technologies in 2030 reflect estimates of learning effects and economies of scale that depend on continued development, demonstration and deployment in the meantime. If new conventional coal-fired plants are ruled out (whether through regulatory restrictions or through carbon pricing), efficient

[19] The long-run marginal cost of generation from new supercritical black and brown coal plants in Figure 21 is well above the market prices Australia is used to.

[20] Coal suppliers and electricity generators will have to take potential upside and downside risks in traded coal prices (attributable to weaker and stronger global climate policies) into account when negotiating the long-term supply contracts that remain common.

[21] On current policies worldwide, coal demand would rise from around 5 billion tonnes in 2010 to around 7 billion tonnes in 2030 – see International Energy Agency, *World Energy Outlook 2010* (IEA 2010) 200. Regarding coal prices, see the Reference Scenario assumptions on energy prices in IEA, *World Energy Outlook 2009* (IEA 2009) 660.

[22] Australian Energy Market Operator, *2010 Electricity Statement of Opportunities* (2010) 35, 37 <http://www.aemo.com.au/planning/0410-0054.pdf>.

[23] Ibid, 147.

combined-cycle gas turbines (CCGT) are the logical choice over the next decade. CCGT is a mature technology, emits significantly less carbon dioxide than coal-fired plants, and generates at a modest cost premium.

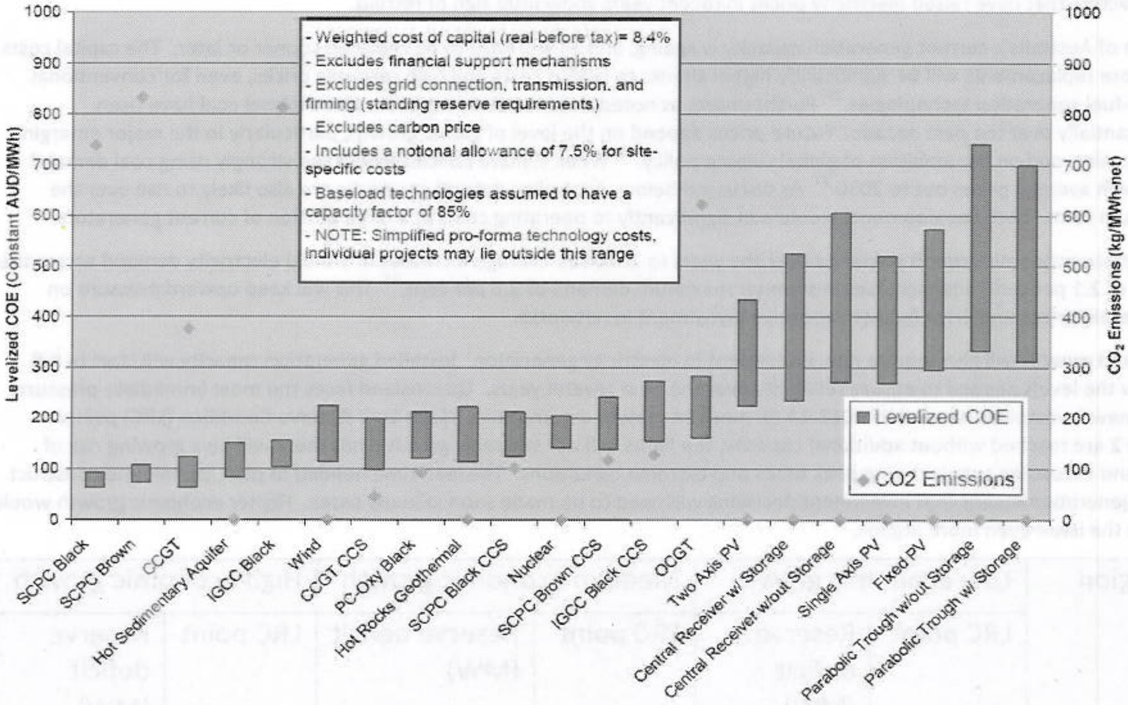

Figure 21 - Cost ranges and CO2 emissions for selected generation technologies in 2015[24]

However, current political uncertainty around carbon pricing presents a serious problem for this shift. Bankers and financial markets largely believe that carbon pricing is inevitable, making it very hard to get approval for substantial new investments in conventional coal-fired power plants. At the same time, since there is no clarity about when or how a carbon price will be introduced, it is very hard to get approval for investment in CCGT. These assets need to supply baseload demand to earn a decent return, and their relatively small price premium is enough to make them a too-risky investment if there is no clarity on if or when coal-fired generation capacity will reduce.

The result has been an investment drought in the electricity sector. As reserve capacity margins erode and investment can no longer be avoided, the investment that is made will be weighted towards Open Cycle Gas Turbines (OCGT) unless there is clarity around carbon pricing. These are a lower investment risk than CCGT, as they are cheaper to build and their rapid startup and shutdown times allow them to be used whenever market prices are high. However, they are also high-emissions than CCGT and produce more costly electricity, as they burn gas less efficiently. Electricity market modelling suggests that uncertainty-driven overinvestment in OCGT would lead to wholesale electricity prices around $8.60 per MWh higher in 2020 than they would be in a scenario with earlier policy certainty and thus more CCGT investment.[25] This increase would mostly be a "deadweight loss" with no associated benefits.

[24] Electric Power Research Institute, *Australian Electricity Generation Technology Costs – Reference Case 2010* (Department of Resources, Energy and Tourism, February 2010) xxi <http://www.ret.gov.au/energy/facts/Pages/EnergyFacts.aspx>. The figure depicts the cost of electricity generation – including capital expenditure, fuel, operations and maintenance – levelised over the whole life of a generic asset of each technology type. Carbon prices are not included, though emissions intensity is indicated. COE is Cost Of Electricity. EPRI excluded fossil-fuel technologies other than open cycle gas from the 2030 estimate unless they incorporated carbon capture.
[25] Tim Nelson, Simon Kelley, Fiona Orton and Paul Simshauser, *Delayed carbon policy certainty and electricity prices in Australia* (March 2010) AGL Blog <http://www.aglblog.com.au/wp-content/uploads/2010/07/Delayed-certainty1.pdf>.

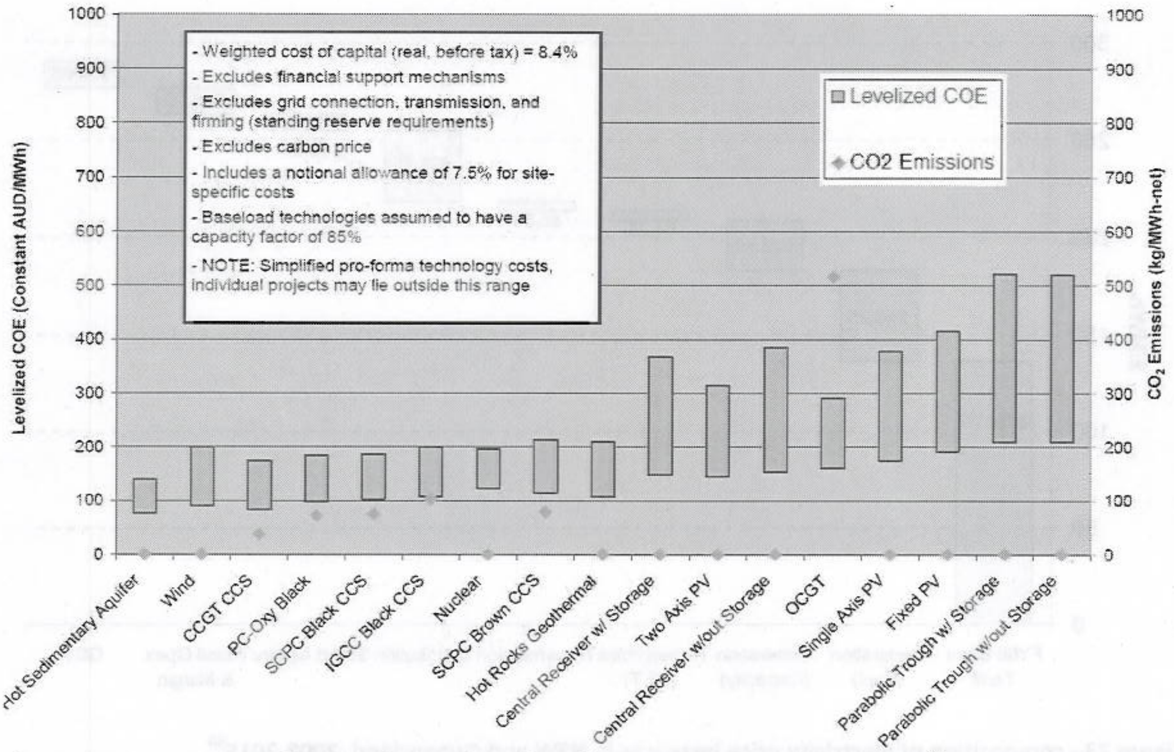

Figure 22 - Cost ranges and CO2 emissions for selected generation technologies, 2030[26]

All these factors suggest strong and sustained electricity price rises over the coming decade. IPART's retail price regulation suggests that from 2009-10 to 2012-13 a typical Sydney household's annual bill will have risen from $1257 to $2012 (with a $26 per tonne carbon price) or to $1705 (without a carbon price).[27] While price rises associated with carbon pricing are likely to be compensated to a substantial degree – at least for lower-income households and emissions-intensive trade-exposed industries – the larger increase from other causes has not been compensated. Looking further ahead, over the period 2008 to 2015 analysts at AGL project price increases in NSW and Queensland of more than 100 per cent in all scenarios for natural gas prices and carbon prices.[28] Figure 23 breaks down the elements that would raise retail electricity prices in NSW and Queensland from an average of $137 per MWh in 2008 to nearly $300 per MWh in 2015, under a scenario without carbon pricing but with natural gas prices converging towards international levels. Under the AGL modelling, a moderate carbon price would add about $15 per MWh to these costs.

Australia has had among the cheapest electricity prices in the world.[29] We are hardly alone in experiencing electricity cost escalation, and we remain blessed with exceptional fossil, nuclear and renewable resources. Nonetheless, on current trends Australia looks set to move towards the middle of the global electricity price pack. This would have significant implications for the competitiveness of many trade-exposed companies.

[26] EPRI, above n 24, xxii. EPRI exclude fossil-fuel technologies from their 2030 analysis unless they incorporate carbon capture and storage, with the exception of open cycle gas turbines for peaking.

[27] IPART, above n 2.

[28] Paul Simshauser, Tim Nelson and Thao Doan, 'The Boomerang Paradox: how a nation's wealth is creating fuel poverty – and how to defuse the cycle' (AGL Working Paper No. 17, April 2010) 19 <http://www.aglblog.com.au/wp-content/uploads/2010/10/No.17-Boomerang-Paradox-Final-Oct-20102.pdf>.

[29] See, eg, New Zealand Ministry of Economic Development, *International comparison of Electricity Prices March Quarter 2008* (18 October 2006) http://www.med.govt.nz/templates/MultipageDocumentTOC 21846.aspx.

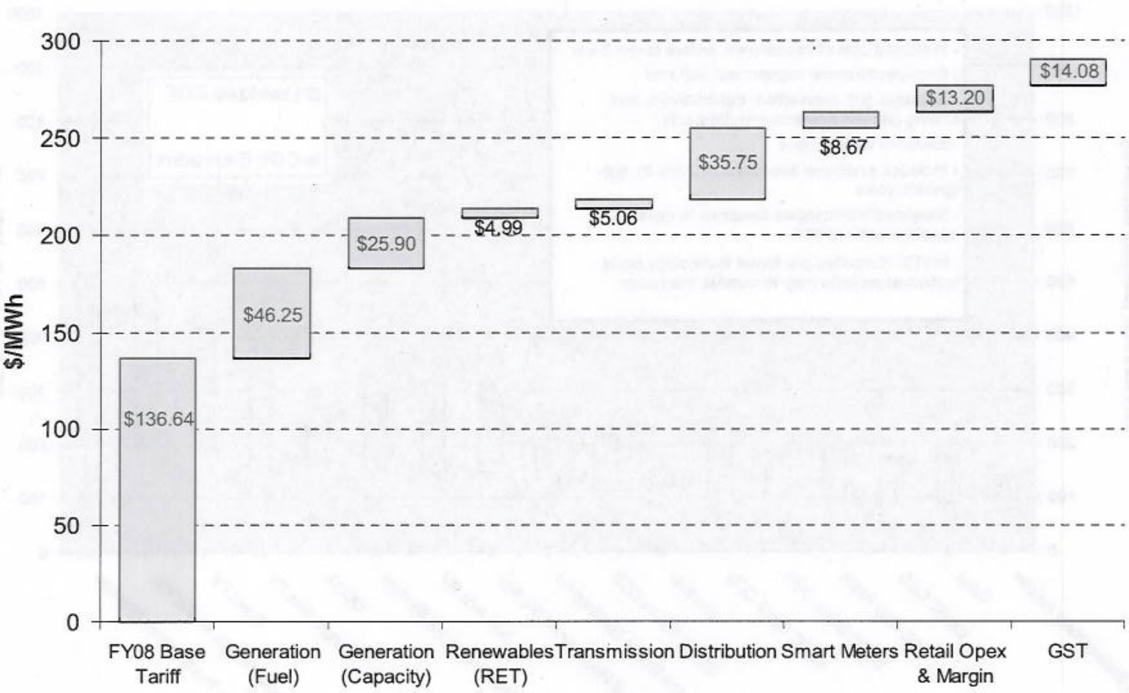

Figure 23 - composition of electricity price increases in NSW and Queensland, 2008-2015[30]

[30] Ibid, 20. This figure depicts a scenario without an explicit carbon price, and with Australian gas prices rising closer to global levels.

Gas

Retail gas prices have risen significantly in real terms over the past decade, but the future picture is complicated. Like electricity, gas prices include wholesale, network and retail components. However, the split differs greatly from electricity and between states. Retail costs and margins account for a larger share of retail gas prices than for electricity – 36 per cent in Queensland and 22 per cent in South Australia for gas, compared to 9 per cent in Queensland and 13 per cent in NSW for electricity.[31] Retail gas prices for small users are regulated in NSW, South Australia and Western Australia. Margins may have to increase in some markets in order to attract further retail entrants,[32] and cost growth will reflect broader employment and operating cost drivers throughout the economy, but network and wholesale prices are more dynamic sources of future price movements.

Wholesale gas prices

Wholesale energy costs can make up as little as 8 per cent of the retail price in Western Australia, or as much as 33 per cent in NSW.[33] The variation is only partly to do with variations in the wholesale price itself; network charges and retail costs are a much larger and more variable factor. As for electricity, wholesale prices depend on the balance of supply and demand and shifts in production costs. The Australian gas market has been much less transparent than the electricity market, however, with most wholesale gas supplied under confidential long-term contracts. Victoria has had a transparent spot market for gas since 1999, which typically accounts for 10-20 per cent of wholesale gas sales volumes, and provides a useful indicator of trends affecting contract prices.[34] The establishment of a similar Short Term Trading Market in Sydney and Adelaide in September 2010 should further improve price transparency. The Victorian data shows a substantial price spike from 2006-07 to 2008-09, and a steep drop in 2009-10 (see Figure 24). The spike was associated with increases in production costs during the mining boom, and with increased demand. A major driver of the latter was increased use of gas-fired electricity generation, a response to surging electricity demand and drought-induced restrictions on the ability of other generators to supply the market. The recent drop in prices is associated with an unusually mild winter, a severe economic slowdown, and the breaking of the drought.

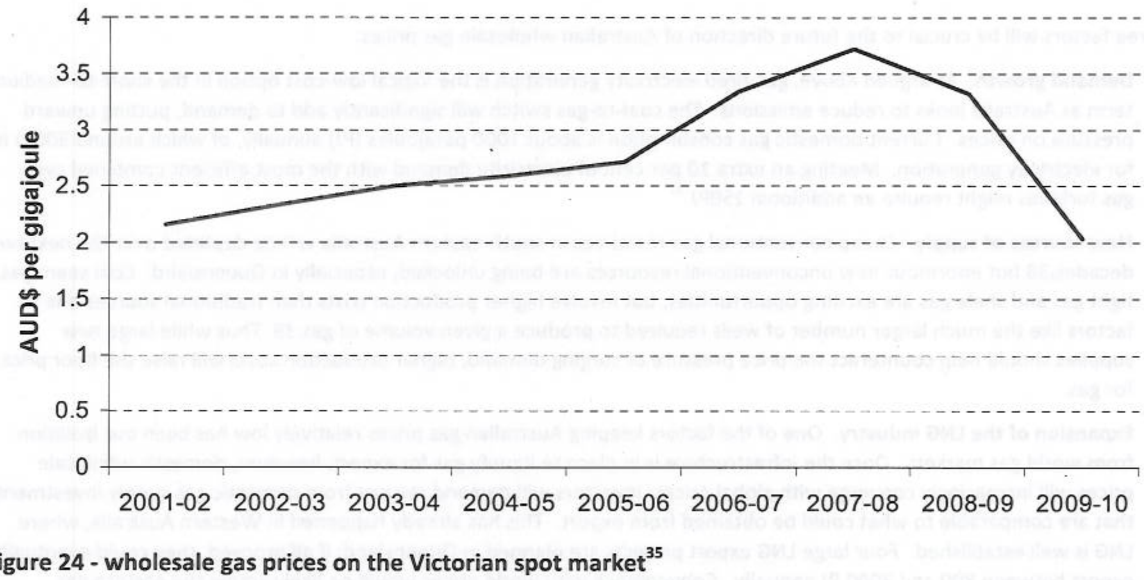

Figure 24 - wholesale gas prices on the Victorian spot market[35]

[31] Australian Energy Regulator, *State of the Energy Market 2009* (Australian Competition and Consumer Commission, December 2009) 206, 305; AER, *State of the Energy Market 2010* (ACCC, December 2010) 99 <http://www.aer.gov.au/content/index.phtml/tag/aerPublications/>.

[32] See, eg, Queensland Competition Authority, *Final report – review of small customer gas pricing and competition in Queensland* (November 2008) 31, 64.

[33] Derived from wholesale and retail prices in AER, above n 31, 244, 308.

[34] AER, above n 33, 245.

[35] Australian Energy Market Operator, *Price & Withdrawals* (13 December 2010) <http://www.aemogas.com.au/index.php?pageID=9922&action=filemanager&folder_id=840&sectionID=9916>.

Details differ between the states. The Western Australian market is completely separate from the eastern one, and prices have been increasingly driven by movements in global gas markets as WA's exports of liquefied natural gas (LNG) have expanded. In the eastern states, production costs differ significantly from region to region, depending on geology and economic conditions. However, the run-up in prices during the mining boom seems to have been national.

While prices have risen, they are coming from a low base. By global standards Australia – and especially Victoria – has enjoyed low gas prices. Plentiful, easily accessible supplies and a mid-sized, globally isolated domestic market have contributed to this.

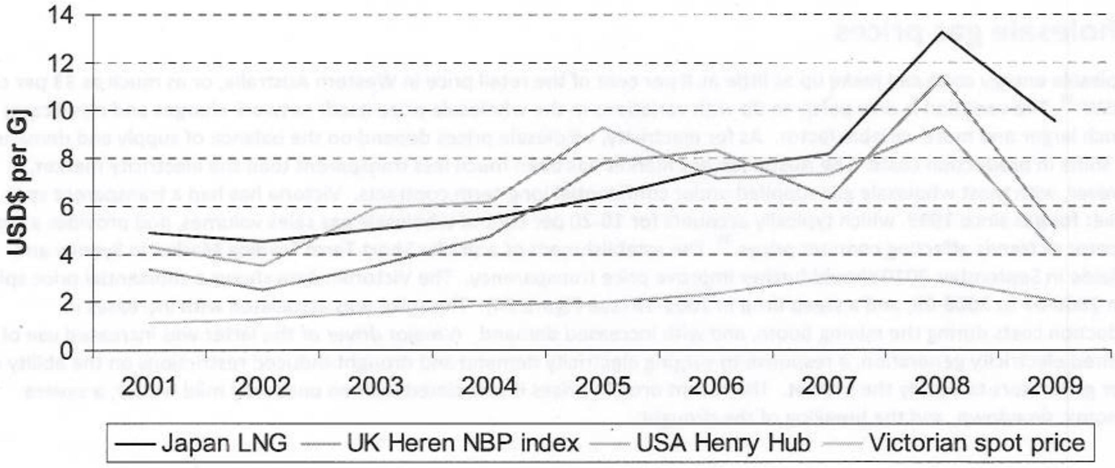

Figure 25 - international gas prices[36]

Three factors will be crucial to the future direction of Australian wholesale gas prices:

- **Demand growth**. As argued above, gas-fired electricity generation is the logical low-cost option in the short-to-medium term as Australia looks to reduce emissions. The coal-to-gas switch will significantly add to demand, putting upward pressure on prices. Current domestic gas consumption is about 1000 petajoules (PJ) annually, of which around 300PJ is for electricity generation. Meeting an extra 10 per cent of electricity demand with the most efficient combined cycle gas turbines might require an additional 150PJ.[37]
- **New sources of supply**. Cheap conventional gas resources in south-eastern Australia will be depleted over the next two decades,38 but enormous new unconventional resources are being unlocked, especially in Queensland. Coal seam gas, tight gas and shale gas are exciting opportunities, but involve higher production costs than traditional sources due to factors like the much larger number of wells required to produce a given volume of gas.39 Thus while large new supplies should help counteract the price pressure of surging demand, higher production costs will raise the floor price for gas.
- **Expansion of the LNG industry**. One of the factors keeping Australian gas prices relatively low has been our isolation from world gas markets. Once the infrastructure is in place to liquefy gas for export, however, domestic wholesale prices will increasingly converge with global prices; investors will demand returns from domestic gas supply investments that are comparable to what could be obtained from export. This has already happened in Western Australia, where LNG is well established. Four large LNG export projects are planned in Queensland; if all proceed, they could eventually export between 800 and 2000 PJ annually. Convergence with world prices would be likely across the eastern gas market. However, construction of the plants will take years, and due to the nature of unconventional gas production there will be a large supply of 'ramp-up gas' on the domestic market as production increases dramatically before the

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[36] Derived from *BP Statistical Review of World Energy 2010* (BP June 2010) 31 <www.bp.com/statisticalreview>, combined with derivatives of the AEMO data above at n 35.

[37] Based on CCGT fuel consumption of around 7.5GJ per MWh sent out, and 2008-09 NEM consumption of 208 terawatt hours.

[38] Treasury, *Australia's Low Pollution Future* (30 October 2008) 242 <www.treasury.gov.au/lowpollutionfuture/>.

[39] See Geoscience Australia and Australian Bureau of Agricultural and Resource Economics, *Australian Energy Resource Assessment* (1 March 2010) 114 <https://www.ga.gov.au/image_cache/GA17052.pdf>.

LNG terminals are complete. Thus while in the medium term LNG exports will raise domestic gas prices, in the short term prices may be depressed substantially.

Gas network charges

As with electricity, network charges account for a large portion of final retail bills – just over half in Queensland and South Australia.[40] Gas transmission and distribution networks are natural monopolies, and gas network companies are regulated (by the Economic Regulation Authority in Western Australia, and by the Australian Energy Regulator in all other jurisdictions). The regulator determines allowable revenue for each company, taking into account its reasonable needs for capital and operating expenditure. These can vary widely depending on the distance from resource to market (very small in Victoria, very large in Western Australia), the size of the customer base to spread fixed costs over, expansion needs and so on. For instance, operating and maintenance expenditure per customer was more than three times higher in Envestra's Queensland distribution network as in its Victorian operations in 2008-09, and expenditure per kilometre of pipeline was twice as high.[41] The next round of determinations is likely to involve significant increases in gas network charges: approved increases in NSW would see distribution tariffs rise by about 30 per cent in real terms over five years, while network companies propose increases of 28.6-47.8 per cent in Queensland and 63.7 per cent in South Australia.[42] Final numbers may well be lower.

Future directions

While gas is a much less emissions-intensive fuel than coal, it would be impacted by a carbon price. Burning a gigajoule of gas produces about 51 kg of CO_2; if fugitive emissions from pipelines and extraction are included, the cost of burning gas might increase by between $0.57 (Victoria) and $0.70 (South Australia) per gigajoule for each $10 of carbon price.[43] However, since the relative cost impact on coal will be much greater, the attractiveness of gas as a fuel for electricity and as a substitute for electricity will increase substantially over the short-to-medium term. The resulting expected coal-to-gas switch will increase gas demand, though the precise impacts on prices remain to be seen.

Climate policy is also likely to see substantial increases in gas use overseas; if met, the emissions reduction and limitation commitments associated with the Copenhagen Accord and the Cancun Agreements would see strong growth in natural gas demand out to 2035 and beyond.[44] World gas prices are currently at very low levels, thanks both to the global financial crisis and to the extremely strong growth of unconventional gas production in the United States. In the longer term, however, strong demand growth is likely to see prices rebound to more normal levels. These trends will affect Australia both as an LNG exporter and as domestic prices more closely track world movements.

Can Australia's gas resources meet likely demand? Proved, probable and possible resources in the eastern states amount to about 50,806PJ; including contingent resources – known accumulations not currently economic to extract, and thus requiring either higher prices or better techniques – brings the total to 93,650PJ; and the total national resource, including inferred but as yet undiscovered accumulations of unknown economic viability, might be 793,400PJ or more.[45] These numbers are the result of substantial upward revisions in recent years as the scale of unconventional resources has become apparent, and further revisions will no doubt follow. While gas production for domestic use and export is set to grow strongly – rising from about 2,000PJ in 2008 to perhaps 8500PJ in 2030 – use of gas will be constrained not by the physical availability of the resource, but by production, distribution and carbon costs that will affect the attractiveness of gas compared to other options.

[40] AER, above n 33, 305.
[41] Ibid, 286.
[42] AER, *Gas distribution by pipeline* (14 December 2010) <http://www.aer.gov.au/content/index.phtml/itemId/721474>.
[43] Based on fugitive emissions estimates in ACIL Tasman, *Final Report – Fuel resource, new entry and generation costs in the NEM* (April 2009) 62 <http://www.aemo.com.au/planning/419-0035.pdf>.
[44] International Energy Agency, *World Energy Outlook 2010* (OECD/IEA 2010) 180.
[45] See AER, above n 31, 33, and GA and ABARE, above n 39, 101. The 793,400PJ figure includes Western Australia's offshore resources.

Responses

It is clear that one way or another, Australian energy prices are headed upwards, driven by network investment, increases in resource and generation costs, trends in world markets, and climate policy. This is a serious issue for Australia, especially given the importance of relatively inexpensive energy to Australian business. While many firms consume little energy because of their size or the nature of their product, Australian business as a whole spent $13 billion on electricity in 2008-09 and $6 billion on natural gas.[46] While the growth of the services sector has moderated the overall energy intensity of the Australian economy, manufacturing remains very energy-intensive. Despite falls in the real energy intensity of manufacturing, especially in the non-metallic minerals and basic non-ferrous metals subsectors,[47] manufacturers purchased half of all electricity and gas bought by business in 2008-09.[48] The price of energy flows through to the competitiveness of trade exposed firms making products whose prices are set on world markets. For firms that are not trade-exposed, higher energy prices will be passed on to their customers, with flow-ons throughout the economy. With energy-intensive products often inputs for other products, there are broad implications for competitiveness and the cost of living. The coming price rises will require a response both from policymakers and from energy users.

The most obvious issue for policy to address is climate policy and carbon pricing. Without decisions in this area over the next couple of years, damaging uncertainty is likely to lead to sub-optimal investments that leave both prices and emissions higher than they need be – with serious and uncompensated impacts on trade-exposed firms. . Policymakers have already instituted a variety of inefficient and costly measures in this space, including the Renewable Energy Target and a range of other subsidies, grants and regulations. A more efficient national policy should be an opportunity to end the expansion of this tangle, and indeed to reduce it.

Carbon policy uncertainty has also been responsible for the delay and eventual halting of the comprehensive Energy White Paper being developed by the Government. This process needs to be completed as soon as practical to give investors a broad view of Australia's energy future. Among other things, the White Paper should address key issues for a national electricity grid as identified by Infrastructure Australia: ensuring efficient investment in regional interconnectors that join the State market segments together, and in potential ambitious transmission proposals to connect major renewables resources to the grid.[49] The recent release of key background papers is a good start.[50]

Governments need to be very conscious of the effects on business competitiveness and household living standards of the energy price increases we are likely to see. Broader policy, including the tax and transfer systems and the range of policies that impact on the ease and cost of doing business, should be used to ensure that Australia remains an attractive place to invest and to live.

While the expansion of LNG exports from the east coast presents challenges, particularly in terms of a convergence with world prices, governments should not be tempted to artificially hold down prices by restricting exports. Such efforts are unlikely to succeed for long, and in any event the impact of higher prices is likely to be outweighed by the benefits of more investment and obtaining the full value of Australia's resources.

Energy efficiency

Whatever the outcome on climate policy, public and private action to improve, encourage and support energy efficiency will be necessary to ease adjustment to likely price increases. Australian studies suggest that reductions of 40-50 per cent in household and commercial building energy use are possible by 2020 with existing technologies,[51] but achieving this will require significant upfront investments and effort to overcome barriers to efficiency like the misalignment of incentives between tenants and landlords. Government can play an important role in overcoming some of these barriers, by providing information, restructuring incentives, or making investments. Intensified effort is needed to improve the regulation of energy networks, which currently encourages investment in infrastructure ahead of efficiency or demand management.

[46] Australian Bureau of Statistics, *Energy, Water and Environment Management, 2009-09* (ABS cat 46600.0, 30 July 2010) http://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/4660.02008-09?OpenDocument.

[47] Australian Bureau of Agricultural and Resource Economics, *Trends in energy intensity in Australian industry* (Research report 08:15, December 2008) 12 <http://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/4660.02008-09?OpenDocument>.

[48] ABS, above n 46.

[49] Infrastructure Australia, *Actions for a National Energy Grid* (November 2009) http://www.infrastructureaustralia.gov.au/files/A_National_Energy%20Grid_WEB.pdf.

[50] Including Geoscience Australia, above n 39, EPRI, above n 24, and Australian Energy Market Operator, *Energy Scenarios Modelling* (24 January 2011) http://www.aemo.com.au/planning/scenarios.html.

[51] Pitt & Sherry, *The Pathway to 2020 for Low-Energy, Low-Carbon Buildings in Australia: Indicative Stringency Study* (Department of Climate Change and Energy Efficiency, July 2010) 55, 69 <http://www.climatechange.gov.au/what-you-need-to-know/~/media/publications/buildings/pathway-to-2020.ashx>.

The difficulties of the former Home Insulation Program highlight the implementation risk that some forms of intervention face, but the need remains for substantial and well-considered government action to encourage and support worthwhile improvements in energy efficiency.

The national efficiency incentive recommended by the Prime Minister's Task Group on Energy Efficiency has important potential benefits, particularly given the proliferation of similar schemes at the State level, but much further development lies ahead to ensure a sound measure that genuinely reduces confusion and compliance costs. Another important recommendation was reform to the national electricity market – broadly defined – to ensure that it does not reduce incentives for energy efficiency. This is a complex task that will require protracted effort involving all jurisdictions and stakeholders – but given the economic benefits, this reform should be a Commonwealth priority. Progress is needed in streamlining the connection process for distributed generation, which currently slows or stops many worthwhile cogeneration projects. Much more work is also needed to ensure that the electricity market incentivises demand-side options (from paying customers to temporarily reduce their load, to more complex demand management, to investments in ongoing efficiencies) when they are cheaper than supply-side options like expanding generation capacity or network infrastructure.

Reforming the energy market and harmonising efficiency incentives between the States will take time. Building on discussions with the Energy Efficiency Council, Ai Group recommends two additional areas for more immediate Commonwealth action on industrial energy efficiency: encouraging innovation, and supporting adoption of existing technologies.

Innovation will be critical to enable Australian industry adjust to and thrive under higher energy prices and a potential carbon constraint. While pure research has an important role, on-site innovation and trialling of alternative technologies at industrial facilities of various sizes and sectors will be critical. While there has been significant investment in research into energy generating technologies, innovation investment in energy use has been substantially lower. Ai Group recommends establishing a well-funded CSIRO National Research Flagship for Industrial Innovation in a Low-Carbon Economy, complementing existing programs in future manufacturing, light metals and energy. In the first years of operation the Flagship should focus on energy efficiency innovation.

Meanwhile, a great deal of existing technology and information is available that can help improve industrial energy efficiency today. Rising energy prices will increase the commercial necessity for companies to adopt existing energy efficiency technologies, but a range of barriers will continue to inhibit takeup, particularly by smaller and medium-sized firms. Government and industry can cooperate to address the barriers to these opportunities, particularly through detailed advice on best practice in energy efficiency technologies. Existing provision of efficiency information by governments tends to be high-level and lacks specificity. What is needed is much more detailed information, drilling down to the level of techniques for optimising the performance of particular models of industrial equipment. This information exists at best-practice operations, and with moderate resources and productive industry-government collaboration it can be captured and made available to industry at large.

For their part, energy users will need to have a closer focus on reducing their exposure to energy price rises. The largest energy users are well aware of their costs and opportunities, and are likely to undertake more efficiency projects as rising prices bring payback periods down. However, many other businesses have not made great progress on efficiency, and are not anticipating imminent improvements. Of the companies responding to the Ai Group survey in Part One, 66 per cent had made no efficiency improvement in the past 5 years, and 57 per cent did not expect improvements over the next 2 years. This lack of focus may have been quite rational in many cases, given the small role of energy in the cost structures of many businesses outside the most energy-intensive sectors. However, unpleasant surprises lie ahead if this situation persists.

There are a range of options open to businesses looking to reduce energy costs. For 24/7 operations with the right mix of heating, steam or cooling needs, cogeneration and trigeneration can offer attractive savings. New equipment that is more efficient or more appropriately sized for use can rapidly pay for itself. Revising production processes is more complex, but can yield major improvements. Efficiency schemes such as NSW's Energy Saving Scheme and Victoria's proposed expansion of the Energy Saving Incentive to small and medium enterprises, as well as innovative financing initiatives such as the Melbourne 1200 Buildings Program, provide potential resources for business to access in overcoming the upfront costs of these opportunities. Ai Group offers a range of advice and assistance to member companies on energy issues, and is committed to helping them meet the challenges to come.

appendix one

electricity generation technologies

A range of technologies for electricity generation are currently available or in development. Below is a brief overview of key issues for each, including cost, scalability, emissions, and level of development.

Coal-fired without Carbon Capture and Storage
Conventional coal-fired power plants are well-understood; while capital-intensive and affected by fuel prices, they can provide very cheap power compared to most other sources. The run-up in resources and construction costs would make generation from new coal-fired plants significantly more expensive than older plants. However, coal plants are also extremely emissions-intensive, and would face substantial cost increases under carbon pricing. Policies in place or under development at the Commonwealth and State levels would ban new conventional coal-fired plants, though a number of 'cleaner coal' technologies might be permitted. These might Integrated Gasification Combined Cycle (IGCC) and Integrated Drying and Gasification Combined Cycle (IDGCC) for black and brown coal respectively. These technologies can reduce emissions somewhat below current levels, but are more expensive and not yet fully mature. More substantial reductions, and competitiveness under high carbon prices, would depend on use of carbon capture and storage.

Open Cycle Gas Turbine (OCGT) and Combined Cycle Gas Turbine (CCGT)
OCGT simply burns gas to run a turbine, comparable to a very large jet engine. The system can start up and shut down very quickly, making it ideal for meeting peaks in demand. A CCGT plant takes the exhaust stream from the gas turbine and recovers the heat from it to run a steam turbine. CCGT thus makes much more efficient use of its fuel than OCGT, with lower operating costs and emissions per MWh. CCGT currently has the best combination of relatively low cost, moderate emissions and technological maturity of any generation technology available to Australia. However it is more capital-intensive than OCGT and represents a greater investment risk.

Wind
Wind turbines are expected to account for most of the renewable generation needed to meet the Large-scale Renewable Energy Target, as they are commercially mature and are lower-cost than other renewables. Australia has excellent wind resources; the limitation on uptake of wind is not availability of good sites, but the difficulties presented by highly variable generation sources.

A wind turbine in a good location would generate at its rated capacity about 30 per cent of the time – that is, when the wind is blowing within useful and safe speeds. A coal-fired power station might generate about 80 per cent of the time – that is, whenever not shut down for maintenance. This difference in *capacity factor* means that much higher amounts of wind capacity have to be built to meet a given level of demand (2.66 times as much in this example). This accounts for much of the expense of wind compared to coal-fired generation, despite the former's lack of fuel costs.

The larger issue with variability is that brief or extended periods of low wind speeds can disrupt generation at many wind farms simultaneously. As use of wind power grows it presents a greater challenge to grid reliability, though there is currently substantial room for further growth in wind generation before this becomes a serious issue. The variability risk can be managed – including by greater dispersion of wind farm locations, higher-capacity interconnectors between NEM regions, more backup OCGT capacity, or potentially energy storage systems like pumped hydro. These solutions require higher private or public investment, however.

Geothermal
Geothermal powerplants use the heat of deep rock formations to drive a steam turbine and generate electricity. While geothermal plants have operated for many years around the world, Australia lacks suitable locations for the well-established form of the technology. Less mature technologies offer great promise, particularly Hot Rock plants; these involve drilling holes between 2 and 10 kilometres deep, fracturing the hot rock formation, and pumping water through it for heating and recovery. This technology may be commercially ready by 2015; the key area for improvement is reliable production of useful fractures. Challenges include the substantial upfront capital costs; cost of transmission from remote locations; potential for groundwater contamination; and the frequent small earthquakes caused by geothermal plants as rock cools. However, a properly managed geothermal plant can provide reliable zero-emissions baseload power for decades.

Nuclear
Nuclear power is widely used overseas and able to provide very large amounts of baseload power. New-generation reactor designs with advanced safety features are beginning to be deployed, though not yet fully mature. Nuclear represents a realistic future option for Australia that should be fully considered.

However, several issues need to be recognised. While a cheaper source of baseload than some immature or intermittent renewables, nuclear power has very high capital costs. It is unlikely ever to be commercially competitive in Australia without very substantial regulatory intervention or a moderate carbon price. Other serious obstacles include strong opposition from parts of the community, associated political nervousness, the need for secure long-term waste storage or processing facilities, and the broader need for a nuclear industrial and skills base that would take some years to develop. At least a decade would elapse between any decision to pursue nuclear power and an operational plant.

Coal or Gas with Carbon Capture and Storage
CCS removes carbon dioxide from the exhaust of a fossil fuel power plant and pumps it deep underground, where it can be permanently stored in appropriate geological formations. The necessary elements of this technology are already in use in various industrial applications, but integrating them in a power plant is new and not yet mature. Where the necessary storage locations are available, CCS can potentially cut emissions from coal- or gas-fired plants by 80 per cent or more. Australia possesses some excellent potential sequestration sites, particularly in the east Bass Strait. However, CCS will never be competitive with conventional coal or gas without substantial regulation or a moderate-to-high carbon price. CCS has a much higher capital cost, and operating costs are inherently higher since a substantial portion of power output must be used to run the capture and storage processes.

Solar Thermal
Solar thermal plants concentrate sunlight with mirrors or lenses to heat a boiler and run a steam turbine. There are many designs, some of which have been operating for decades, and much innovation and learning continues. Heat can be stored, for instance in molten salts, and used to continue generating electricity at night; solar thermal can supply baseload. Solar thermal requires high temperatures, strong sunshine and large areas of cheap land. Australia has enormous potential resources for solar thermal generation, but the technology is presently very expensive and transmission from good inland plant locations would require large new investments.

Solar Photovoltaic
Solar PV generates electricity directly from sunlight. Costs have declined enormously over the past few decades and efficiencies have increased. The past year has seen a steep cost decrease in for PV modules, with a ramped-up supply outpacing demand depressed by economic dislocation and subsidy reductions in Spain and Germany. New materials and techniques are likely to drive costs down further. Nonetheless solar PV remains a very expensive option. Intermittency contributes to this, and makes it challenging to integrate large amounts of PV into the grid.

appendix two

survey questionnaire

1.	How many employees in your company?	
		Less than 20
		20-199
		200+

2.	What is your annual turnover?	
		Less than $10 million
		$10 million to $50 million
		More than $50 million

3.	Which sector are you primarily involved in?	
		Manufacturing
		Construction
		Services
		Resources
		Energy

4.	Which State or Territory does your company primarily operate in?	
		NSW
		VIC
		QLD
		SA
		WA
		TAS
		ACT
		NT

5.	What was your company's electricity spend as a percentage of sales in 2009-10?	
		Less than 1%
		1% to 2%
		3% to 5%
		6% to 10%
		More than 10%

6.	What was your company's gas spend as a percentage of sales in 2009-10?	
		Less than 1%
		1% to 2%
		3% to 5%
		6% to 10%
		More than 10%

7.	How have electricity prices changed over the last 5 years, including network charges and any retailer charges?	
		More than 50%
		41-50%
		31-40%
		21-30%
		11-20%
		1-10%
		No increase

7.	How have electricity prices changed over the last 5 years, including network charges and any retailer charges?	
		Reduction in prices

8.	How have gas prices changed over the last 5 years, including network charges and any retailer charges?	
		More than 50%
		41-50%
		31-40%
		21-30%
		11-20%
		1-10%
		No increase
		Reduction in prices

9.	How has your company's energy efficiency improved over the last 5 years(measured by the amount of energy used per $ of sales revenue)?	
		More than 15%
		11-15%
		6-10%
		1-5%
		It is about the same
		It has deteriorated

10.	How do you expect electricity prices to change over the next 2 years?	
		More than 50%
		41-50%
		31-40%
		21-30%
		11-20%
		1-10%
		No increase
		Reduction in prices

11.	How do you expect gas prices to change over the next 2 years?	
		More than 50%
		41-50%
		31-40%
		21-30%
		11-20%
		1-10%
		No increase
		Reduction in prices

12.	How do you expect your company's energy efficiency to improve in the next 2 years?	
		More than 15%
		11-15%
		6-10%
		1-5%
		It will be about the same
		It will deteriorate

appendix three

additional survey data

Survey sample

Figure 26 breaks down responses by sector, showing the predominance of manufacturing in the sample.

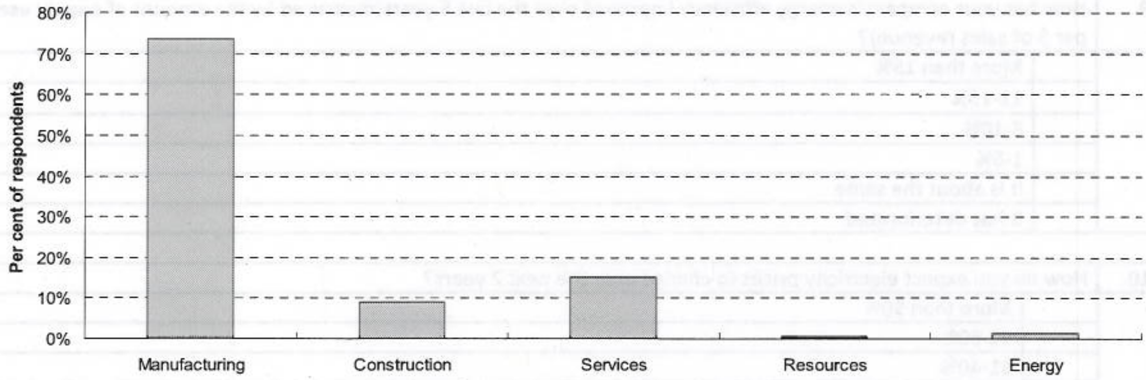


Figure 26 – distribution of respondents by sector

Figure 27 and Figure 28 detail the distribution of respondents by size of company (number of employees or turnover size). On both measures, the greatest number of respondents was from smaller sized companies.

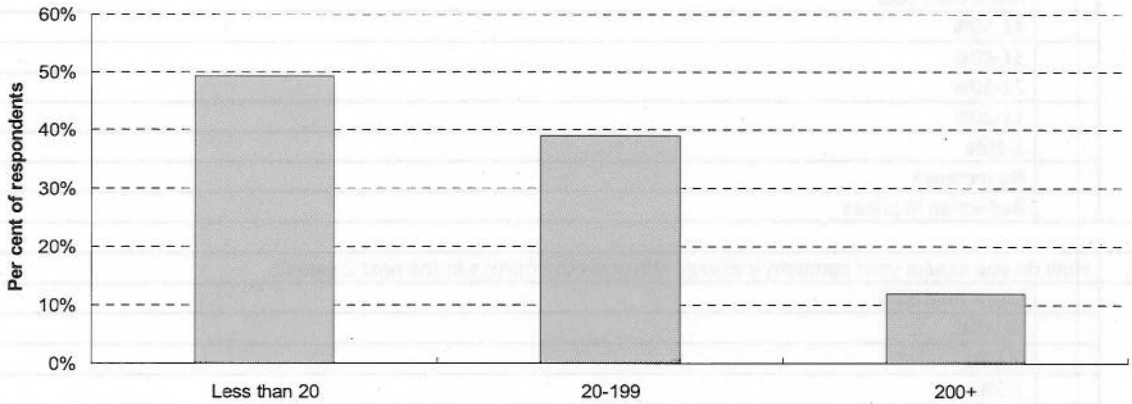


Figure 27 - distribution of respondents by number of employees

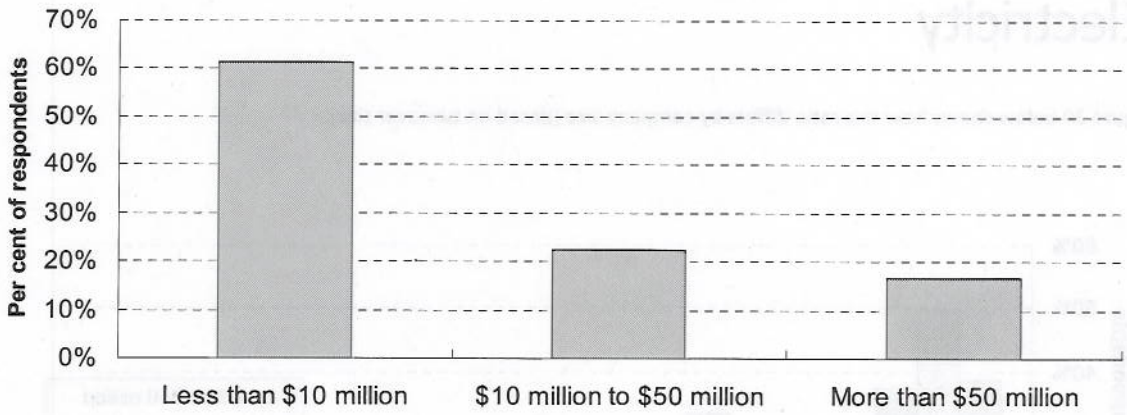


Figure 28 - distribution of respondents: by annual turnover

The distribution of respondents by jurisdiction is provided in Figure 29. The largest numbers of respondent companies primarily operate in NSW (62 of the final 144 sample). This was followed by VIC (48 respondents) and QLD (27 respondents). There was only one respondent from WA and none from TAS, ACT or the NT.

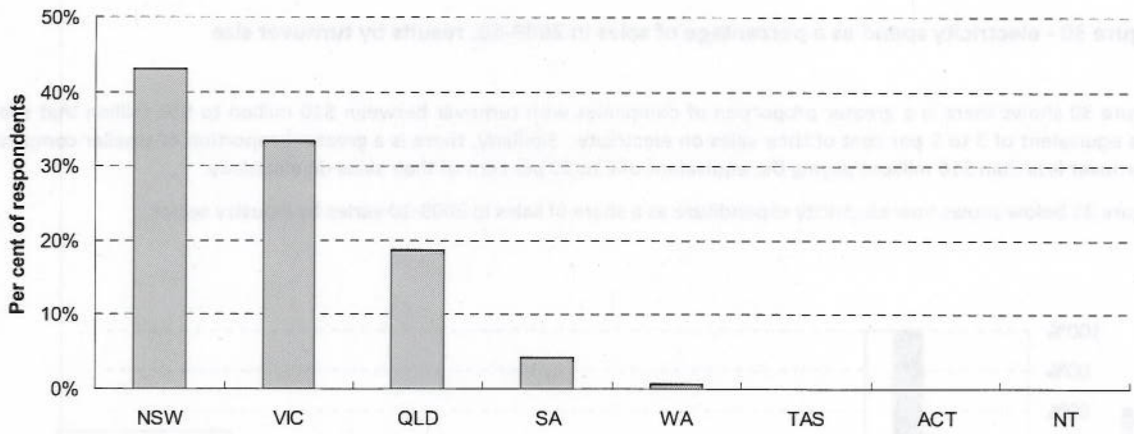


Figure 29 - distribution of respondents by jurisdiction

Electricity

Figure 30 below shows how this ratio differs by company size (based on turnover size).

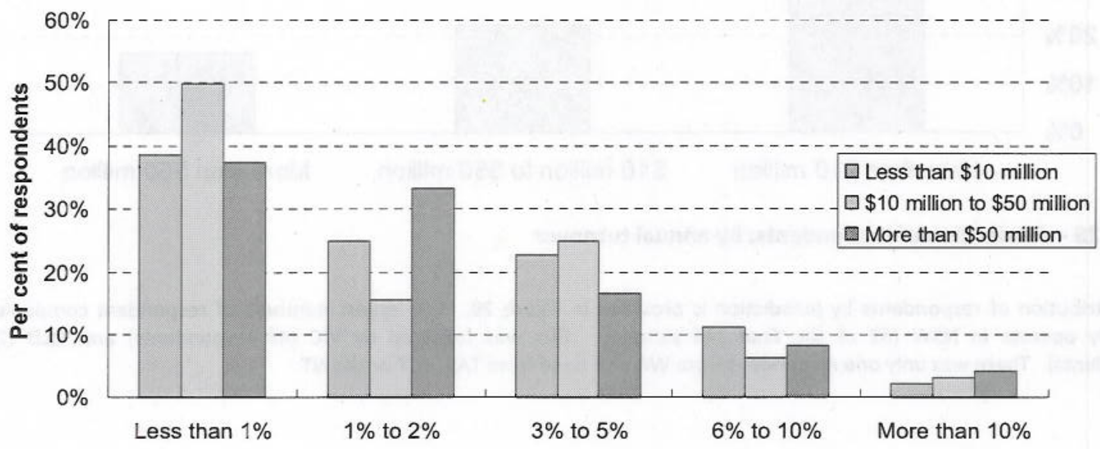


Figure 30 - electricity spend as a percentage of sales in 2009-10: results by turnover size

Figure 30 shows there is a greater proportion of companies with turnover between $10 million to $50 million that spend the equivalent of 3 to 5 per cent of their sales on electricity. Similarly, there is a greater proportion of smaller companies (turnover less than $10 million) paying the equivalent of 6 to 10 per cent of their sales on electricity.

Figure 31 below shows how electricity expenditure as a share of sales in 2009-10 varies by industry sector.

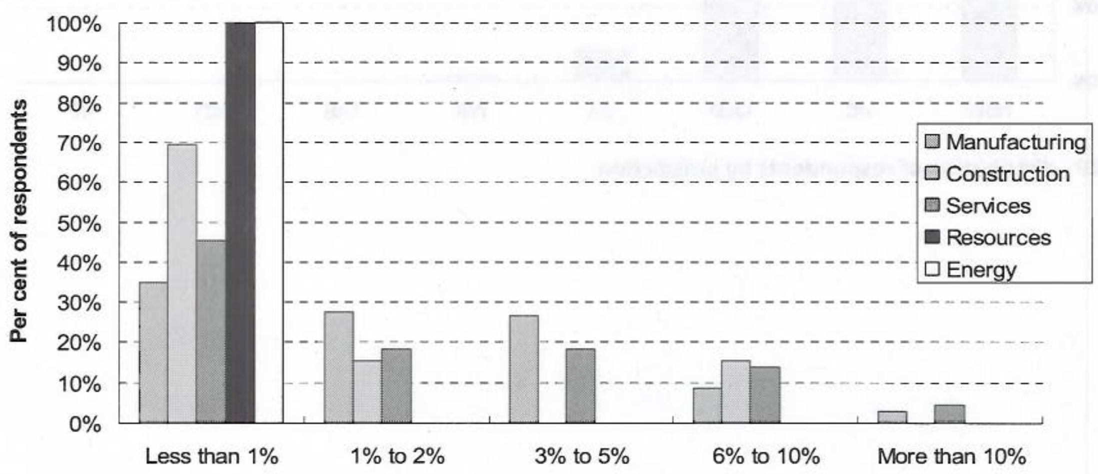


Figure 31 - electricity spend as a percentage of sales in 2009-10: results by sector

We can see from Figure 31 that there is a greater proportion of manufacturing sector companies paying the equivalent of 3 to 5 per cent of their sales in electricity. The same applies to the 1 to 2 per cent category. The less than 1 per cent category consists of the sole resources sector respondent and the 2 energy sector respondents. There is a much greater proportion of construction companies paying the equivalent of less than 1 per cent of their sales on electricity compared to manufacturing and services sector companies.

The distribution of electricity spends as a share of sales across jurisdictions is fairly consistent across jurisdictions (Figure 32) with the exception that the spending share is higher in SA (in the 3 to 5 per cent category and the 6 to 10 per cent category). There is also an outlier in the single respondent from WA in the 6 to 10 per cent category.

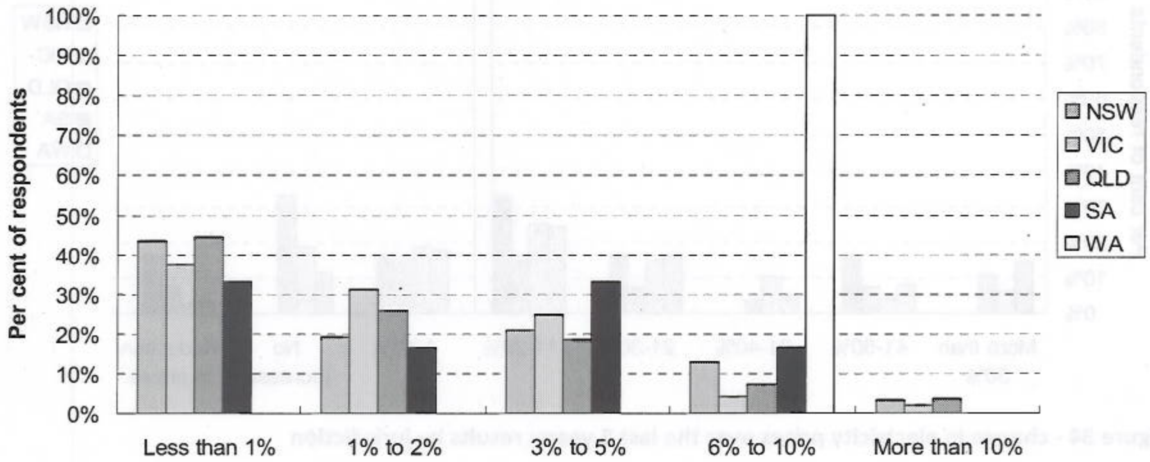


Figure 32 - electricity spend as a percentage of sales in 2009-10: results by jurisdiction

Figure 33 below shows the distribution by industry sector. Manufacturing and services companies tend to have experienced higher electricity prices.

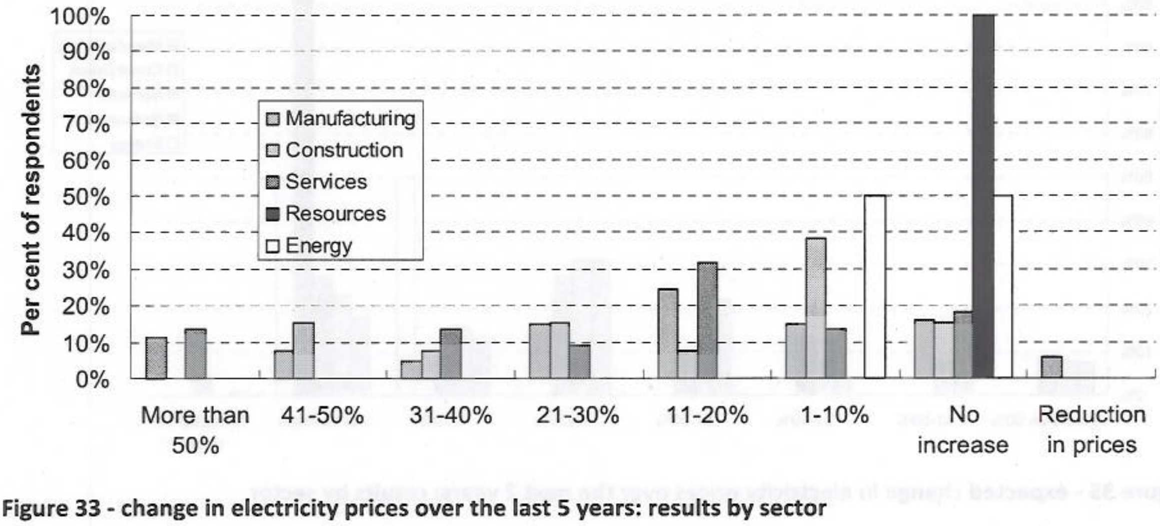


Figure 33 - change in electricity prices over the last 5 years: results by sector

Figure 34 below shows the distribution by jurisdiction. Ignoring the single WA respondent, we can see that electricity prices tended to rise more in NSW and SA (although a greater proportion of SA companies experienced a decline in electricity prices).

For example, 27 per cent of NSW companies experienced electricity prices of 31 per cent or more compared to 20 per cent for VIC and 22 per cent for QLD.

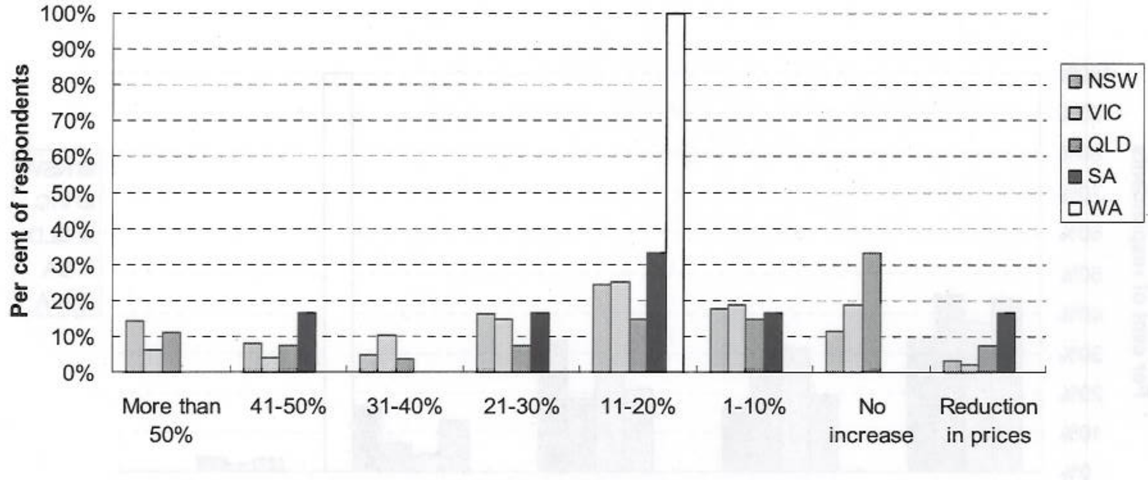


Figure 34 - change in electricity prices over the last 5 years: results by jurisdiction

How do future electricity price expectations differ by sector? Figure 35 shows this distribution. Outside of the small sample of energy and resources companies, generally the distribution is fairly even. However, a greater proportion of manufacturing companies expect a price increase of 21 to 30 per cent.

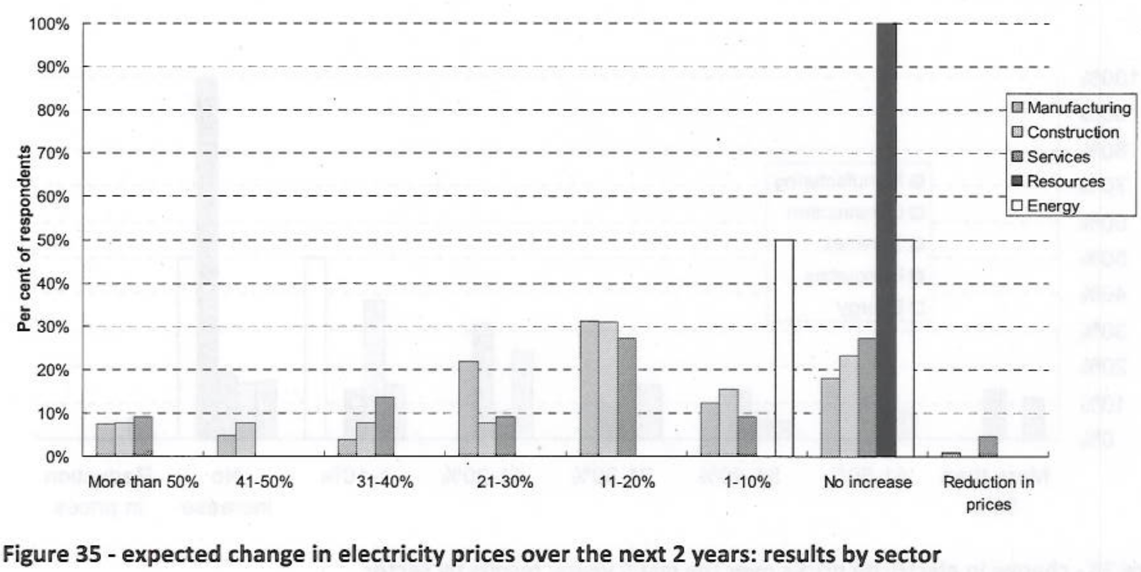


Figure 35 - expected change in electricity prices over the next 2 years: results by sector

Figure 36 below shows electricity price expectations by jurisdiction. We can see that generally companies in NSW and SA are more likely to expect electricity price increases, and to expect relatively larger increases.

Just over 11 per cent of NSW respondents expect electricity price increases of over 50 per cent in the next 2 years. The results for NSW may reflect the public and media interest in the issue following the most recent retail price determination of the Independent Pricing and Regulatory Tribunal.

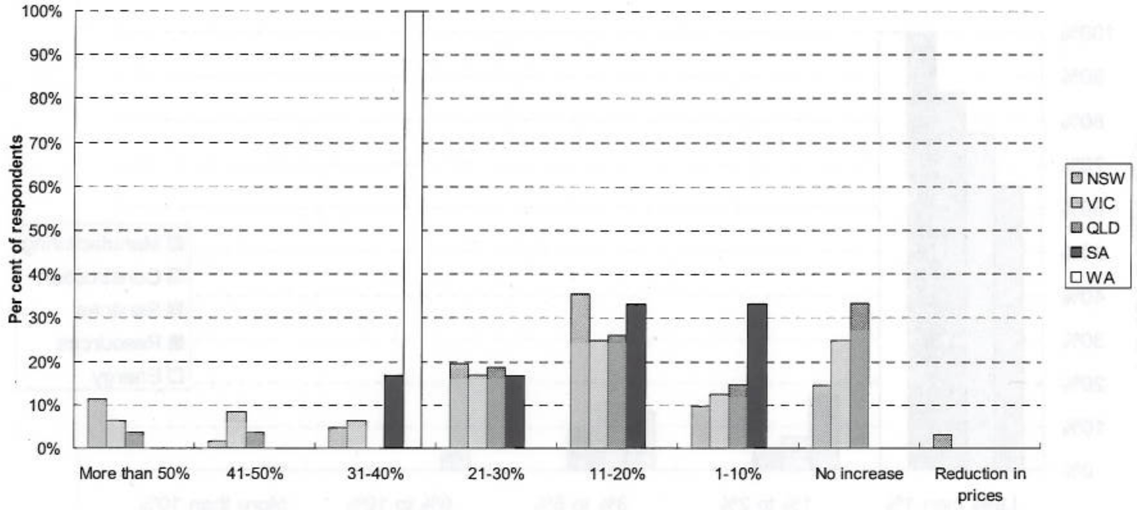


Figure 36- expected change in electricity prices over the next 2 years: results by jurisdiction

Gas

Figure 37 below shows the ratio of gas spend to sales by size of company (turnover size basis). There is a greater proportion of companies with turnover over $50 million that spend the equivalent of 1 to 2 per cent or more than 10 per cent of their sales on gas.

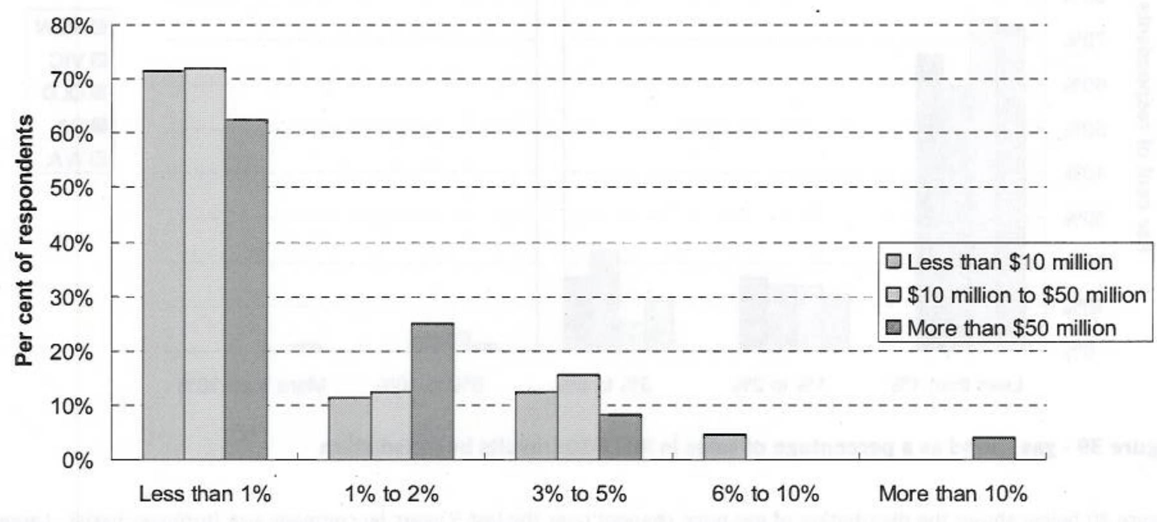


Figure 37 - gas spend as a percentage of sales in 2009-10: results by turnover size

Figure 38 below shows how gas expenditure as a share of sales in 2009-10 varies by industry sector. We can see from this figure that a greater proportion of manufacturing sector companies are spending higher shares on gas expenditure, reflecting the importance of gas as an input to many manufacturing operations. The less than 1 per cent category is influenced by the small number of energy and resources sector respondents.

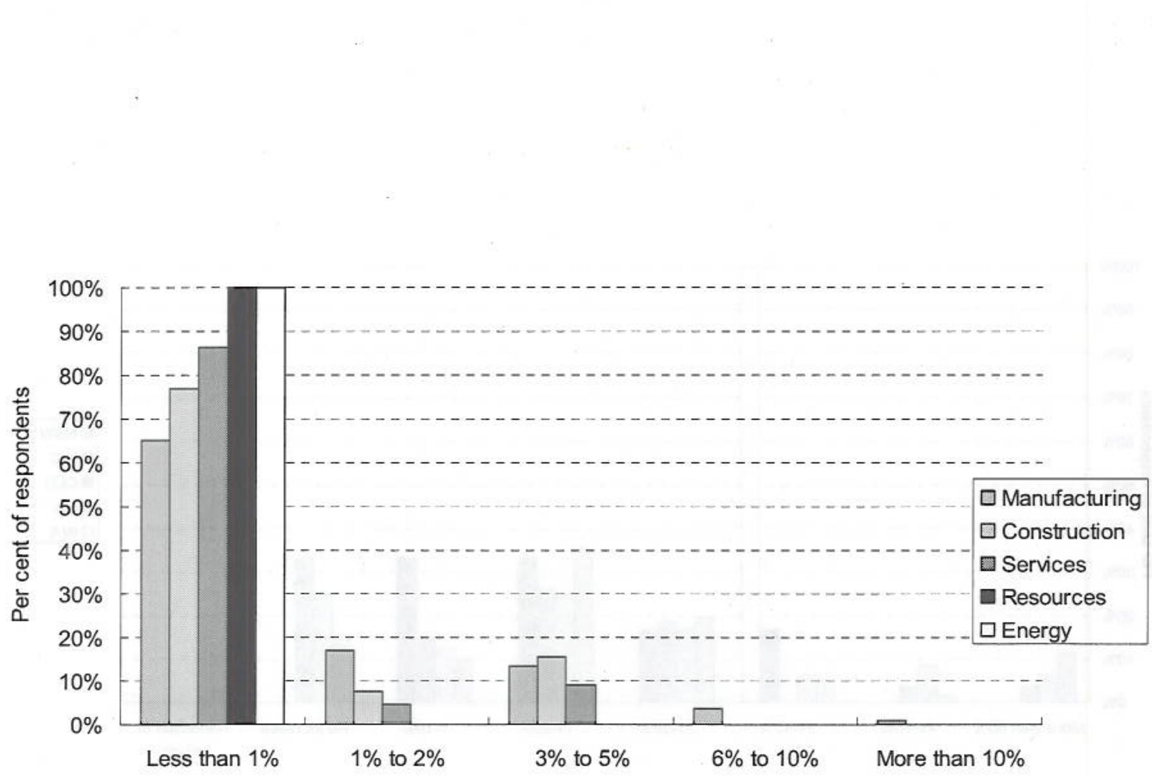


Figure 38 - gas spend as a percentage of sales in 2009-10: results by sector

Figure 39 below displays the results by jurisdiction. Ignoring the single WA respondent, the distribution of gas spend as a percentage of sales is fairly uniform across jurisdictions.

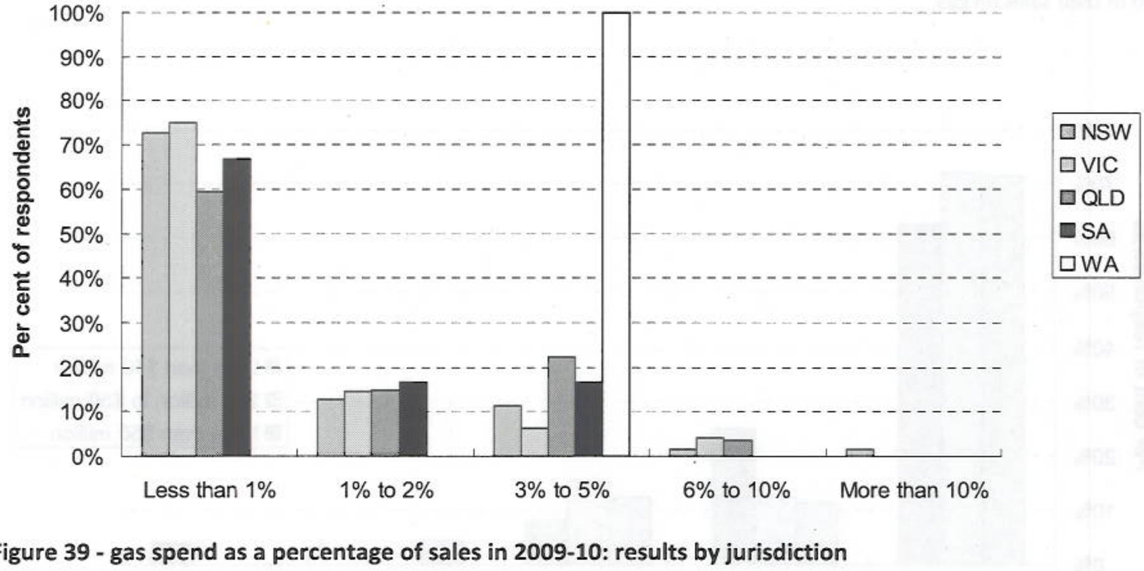


Figure 39 - gas spend as a percentage of sales in 2009-10: results by jurisdiction

Figure 40 below shows the distribution of gas price changes over the last 5 years by company size (turnover basis). Larger companies tended to experience larger price increases (in contrast to electricity price increases) although some larger companies also experienced price decreases.

A large proportion of companies across every size category had no gas price increases over the last 5 years.

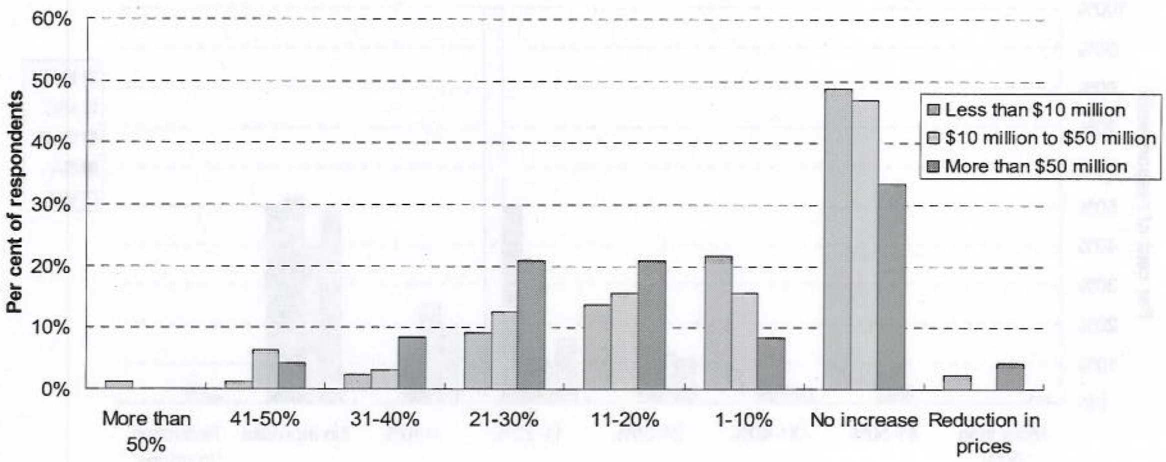


Figure 40- change in gas prices over the last 5 years: results by turnover size

Figure 41 below shows the distribution of gas price changes over the last 5 years across industry sectors. Manufacturing companies were more likely to experience a gas price increase than companies in other sectors.

Approximately 22 per cent of manufacturing companies experienced gas price increases over the last 5 years of 21 per cent or more. This compares to 8 per cent of construction sector companies and 14 per cent of services sector companies.

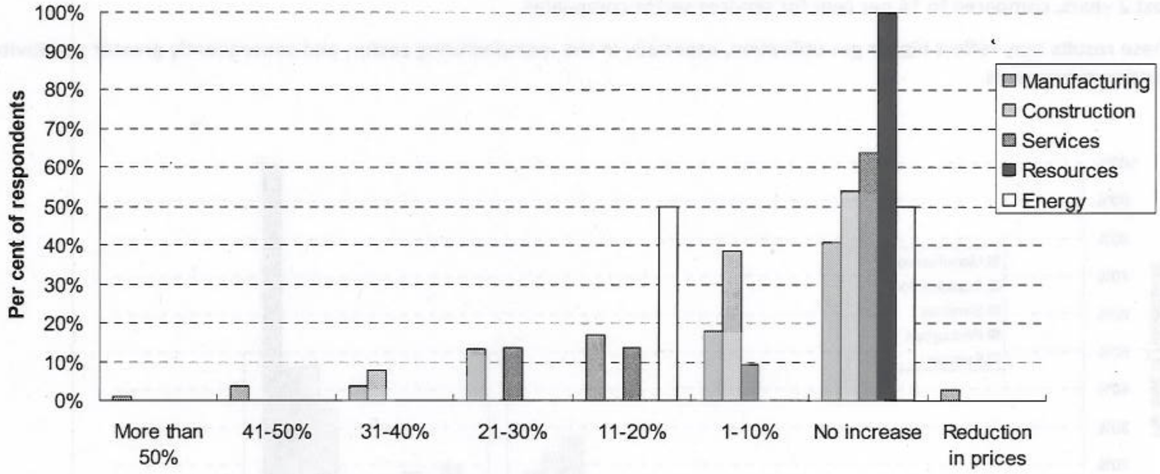


Figure 41 - change in gas prices over the last 5 years: results by sector

Figure 42 below shows the gas price changes across jurisdictions. Again ignoring WA, the distribution is fairly even across jurisdictions.

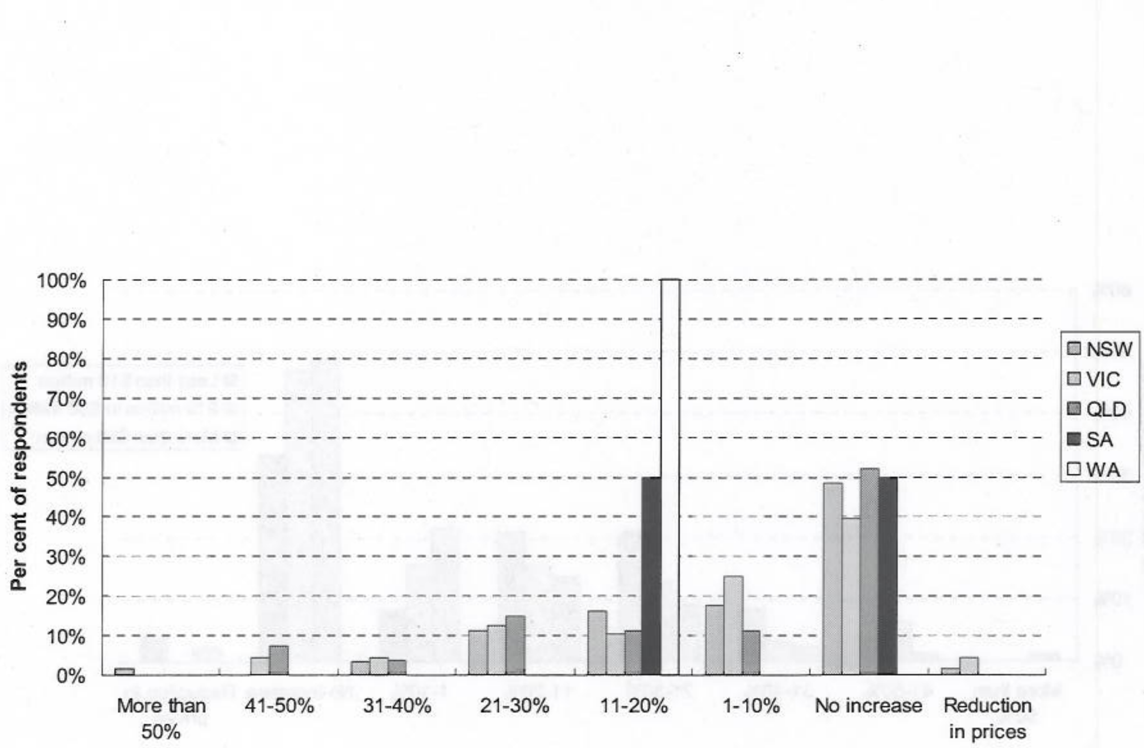


Figure 42 - change in gas prices over the last 5 years: results by jurisdiction

Figure 43 below shows the gas price expectations results by industry sector. It shows that manufacturing and construction sector companies have a higher tendency to expect larger gas price increases.

For example, approximately 23 per cent of construction sector companies expect a gas price increase of 21 per cent or higher in the next 2 years.

Approximately 17 per cent of manufacturing sector companies expect a gas price increase of 21 per cent or higher in the next 2 years, compared to 14 per cent for services sector companies.

These results may reflect higher gas utilisation, especially in the manufacturing sector, and consequently greater sensitivity to price movements.

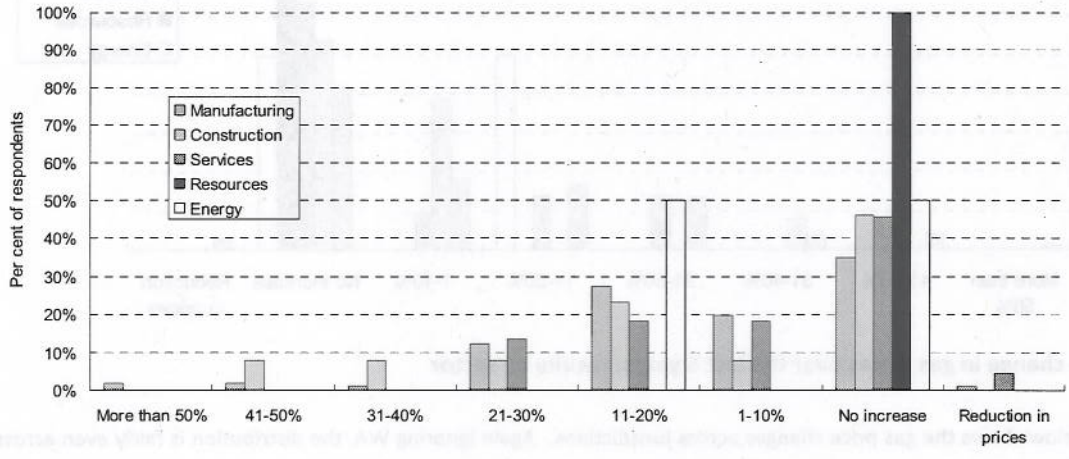


Figure 43 - expected change in gas prices over the next 2 years: results by sector

Figure 44 below shows the results by jurisdiction. The highest price increases are expected by companies operating predominantly in NSW and VIC.

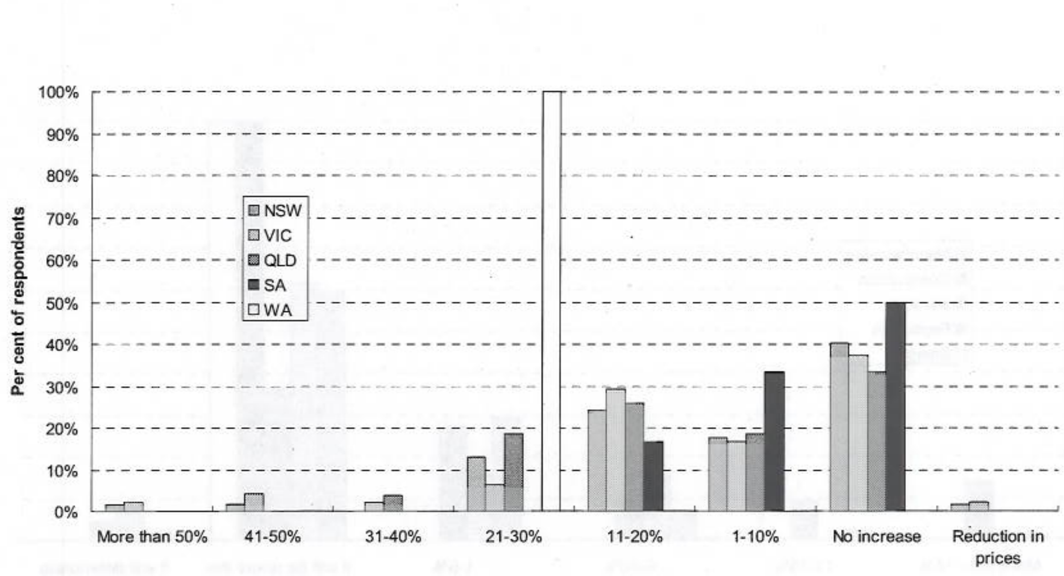


Figure 44 - expected change in gas prices over the next 2 years: results by jurisdiction

Energy efficiency

Figure 45 presents these results by company size (turnover size basis). It shows that the distribution is fairly even. Thus neither the differing levels of staff and investment resources available to these companies, nor the greater exposure of large companies to mandatory energy and efficiency reporting, appears to make a substantial difference to expectations.

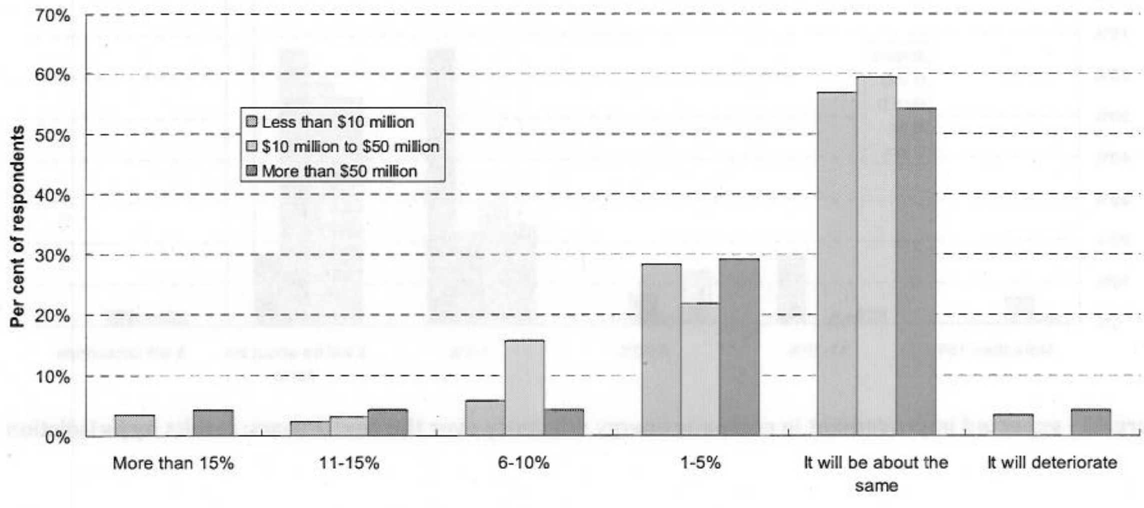


Figure 45 - expected improvement in company energy efficiency over the next 2 years: results by turnover size

Figure 46 below shows the results by industry sector. It shows that services based companies are more likely to undertake more significant energy efficiency improvements. This may reflect greater awareness of efficiency opportunities in the sector, a greater emphasis on efficiency and environmental measures as brand management tools, or a reaction to the somewhat higher electricity price increases reported by the sector over the past 5 years (see Figure 33 above).

Approximately 31 per cent of services sector companies are expecting to make energy efficiency improvements of 6 per cent or greater compared to 9 per cent of manufacturing respondents and 15 per cent of construction respondents.

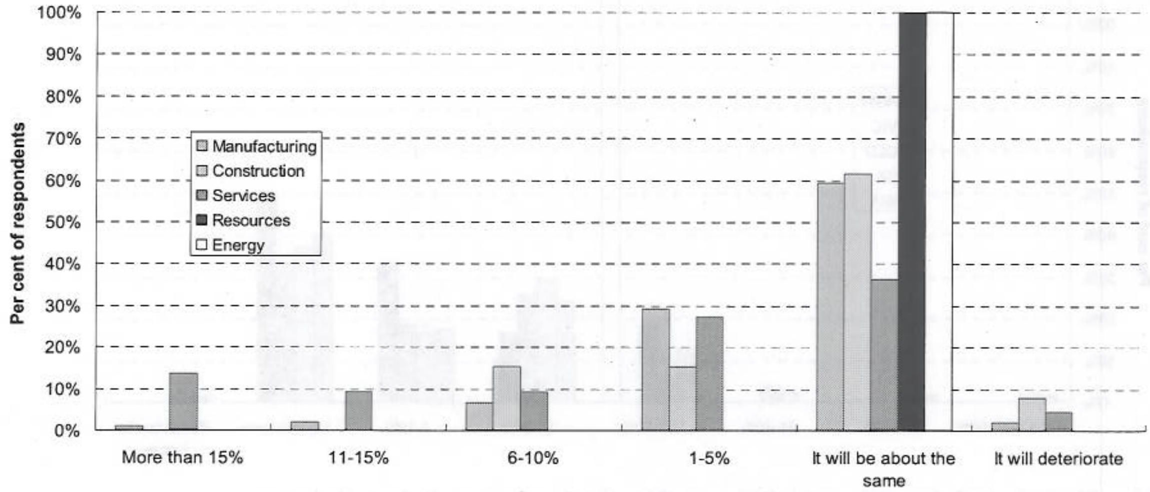


Figure 46 - expected improvement in energy efficiency over the next 2 years: results by sector

Figure 47 below shows fairly even results across jurisdictions, despite significant differences in the nature and level of public policy support for business energy efficiency in each state.

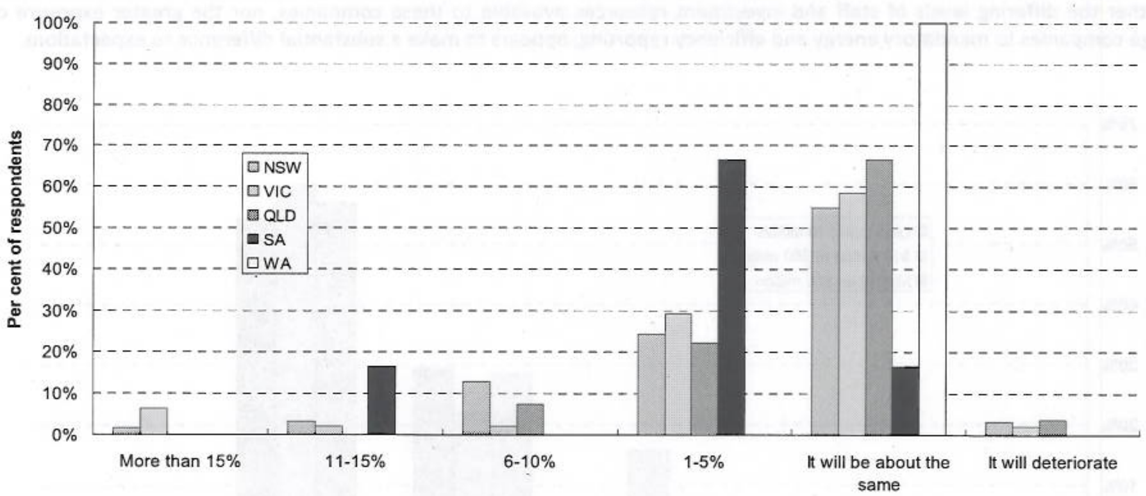
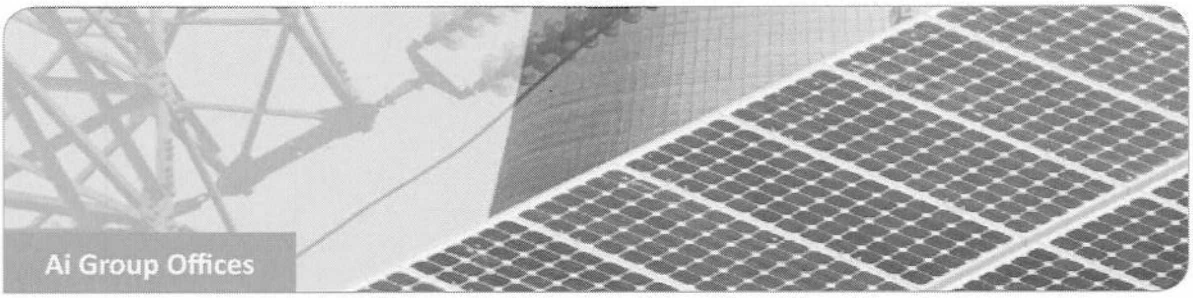


Figure 47 - expected improvement in company energy efficiency over the next 2 years: results by jurisdiction



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Unit Network Costs

Generator Specific Network Costs

Technology	Scaler	Cost ($M/MW/a)
PP_gas	1	0.15
PP__Gas_w__cc	1	0.15
PP_coal_fired	1	0.15
PP_Coal_w__cc	1	0.15
PP_Lignite_fired	1	0.15
PP_Lignite_w__cc	1	0.15
PP_Biomass_and_was	0.75	0.1125
PP_Diesel_generator	0.25	0.0375
PP_Geothermal	1	0.15
PP_Hydro_power	1	0.15
PP_Ocean_energy	1	0.15
PP_PV	0.25	0.0375
PP_solar_thermal	0.75	0.1125
PP_Wind_turbines	0.75	0.1125
CHP_Gas	0.25	0.0375
CHP_Black_Coal	0.25	0.0375
CHP_Lignite	0.25	0.0375
CHP_Biomass_and_wa	0.25	0.0375
CHP_Diesel_Reciproca	0.25	0.0375