STATE OF THE ENERGY MARKET 2010

AUSTRALIAN
ENERGY
REGULATOR

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PREFACE

The Australian Energy Regulator's (AER) fourth *State of the energy market* report provides a high level overview of energy market activity in Australia. The report is intended to meet the needs of a wide audience, including government, industry and the broader community. It supplements the AER's extensive technical and compliance reporting on the energy sector.

The *State of the energy market* consolidates information from various sources into one user friendly publication. The aim is to better inform market participants and assist policy debate on energy market issues.

The 2010 report consists of a market overview, supported by four chapters on the electricity and natural gas sectors. It is more concise than previous editions, and focuses on activity over the past 12–18 months in those jurisdictions and areas in which the AER has regulatory responsibilities. Much of the material excluded from this edition is contextual, and cross-references to the 2009 edition will help readers who require that material.

The *State of the energy market* is an evolving project, and the AER will continue to review its approach. As always, we hope to hear the views of readers. In the meantime, I hope this 2010 edition will provide a valuable resource for market participants, policy makers and the wider community.

Andrew Reeves
Chairman

MARKET OVERVIEW


Getty Images

A feature of energy market reporting in the media in 2010 has been concerns about rising energy charges. While some reporting in this area fails to adequately distinguish between volume and price changes, retail energy charges have risen significantly in most jurisdictions. The increases have been mostly attributed to rising network charges and wholesale energy costs, but retailer costs and climate change policies (including renewable energy targets, incentives for small scale solar generation and energy efficiency schemes) have also contributed.

Recent regulatory decisions have allowed significant increases in capital investment and operating expenditure to enable energy networks to reliably meet greater demand. With network costs accounting for around 50 per cent of a typical electricity bill, rising capital and operating expenditure is flowing through to energy customers.

The continued growth in peak electricity demand, combined with the twin pressures of customer expectations for reliable supply and rising costs of service provision, pose increasingly complex dilemmas for energy customers, network businesses, governments and regulators. This environment presents important responsibilities for ensuring efficient service delivery and customer confidence to participate in the market.

With the transfer of a range of retail regulatory functions to a national framework expected between 2011 and 2013, the Australian Energy Regulator (AER) is consulting with energy customers, consumer advocacy groups, energy retailers, jurisdictional regulators and ombudsmen and government departments to ensure an efficient transition and continuing protections for energy customers.

1 Energy networks

The AER regulates electricity networks and gas pipelines in southern and eastern Australia (and gas pipelines in the Northern Territory). In electricity, this involves the assessment and approval of revenues that network businesses may earn from transporting electricity to customers. The regulatory framework for gas pipelines is similar, but derives prices for reference services set out in access arrangements.

In 2010 the AER completed electricity distribution reviews for the Queensland and South Australian networks (released May 2010) and the Victorian networks (released October 2010). It also approved access arrangements for the Australian Capital Territory (ACT) and New South Wales gas distribution networks (released April and June 2010 respectively).

The AER's recent regulatory decisions have allowed significant increases in capital investment in some networks (figure 1). Key drivers of these increases include:

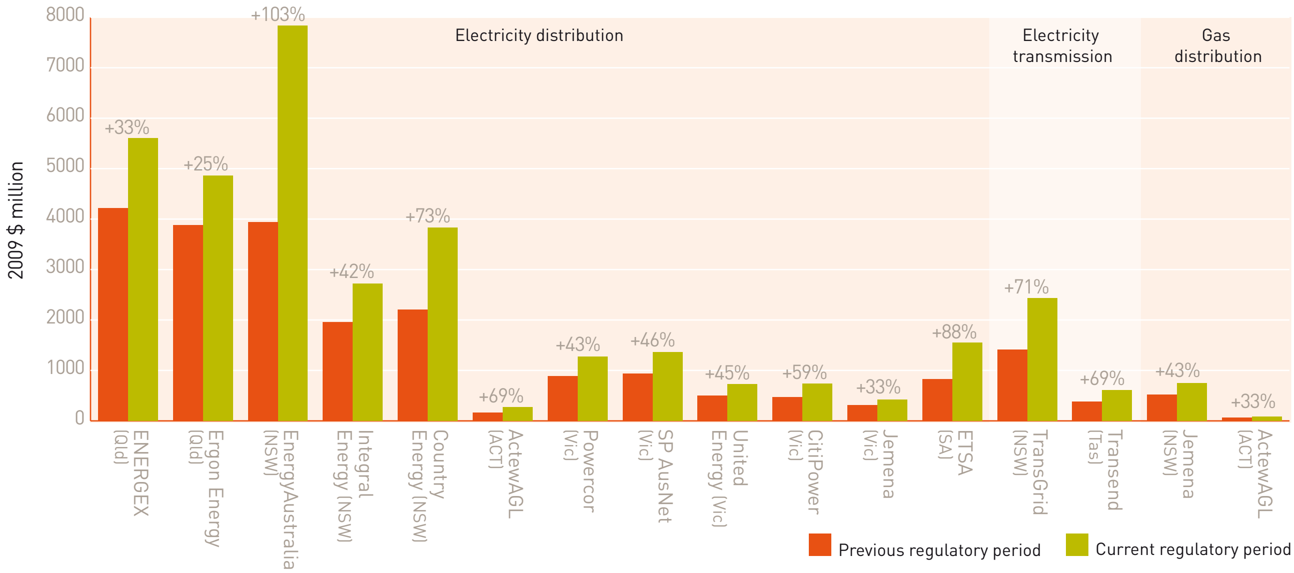
> more rigorous licensing conditions and other obligations for network security, safety and reliability
> load growth and rising peak demand
> new connections
> the need to replace ageing assets, given much of the networks were developed between the 1950s and 1970s.

Other drivers include changes to system operation due to climate change policies and the introduction of smart meters and grids.

While these factors are driving higher levels of investment, each network faces a different blend of challenges—for example, each network has unique issues relating to its age and technology, its load characteristics, the costs of meeting the demand for new connections, and its licensing, reliability and safety requirements. Other issues are common to all network businesses—for example, rising input and finance costs.

Figure 1

Network investment—AER determinations since 2009



Source: AER.

As required by the regulatory regime, the AER accounts for these factors when assessing the needs of each network. Electricity distribution determinations in 2010 reflected that:

> the Queensland networks have pressing capital requirements associated with population growth, new connections and industrial demand, as well as rising demand per customer. The networks are also obliged to improve performance in response to stricter reliability standards
> the South Australian network requires significant investment to meet rising load growth and peak demand driven by the use of air conditioners during summer heatwaves. The network also needs to address reliability risks from ageing assets and new reliability standards for the Adelaide central business district (involving complementary upgrades to transmission and distribution systems). Investment costs in Queensland and South Australia have also been rising as a result of real increases in the cost of labour and materials
> the Victorian distributors operate mostly mature and comparatively reliable networks. While the AER considers past expenditure (in what has been a relatively stable operating environment) provides a good starting point for assessing future needs, it also accounted for the need to replace ageing infrastructure, address Victoria's new bushfire safety standards, and maintain reliability in the face of growing costs and demand. While these considerations led it to approve higher levels of investment, the AER did not accept the full extent of the increases proposed by distribution businesses
> the global financial crisis has significantly increased debt financing costs for all networks. The rate of return on capital in the next regulatory periods has thus increased by more than 100 basis points compared with the rate in previous periods. Recent AER determinations reflected that higher debt costs increased the revenue requirements of distribution businesses by 5–9 per cent from requirements in previous regulatory periods.

The capital drivers for gas distribution networks are broadly similar to those for electricity distribution. The AER's recent determination for the New South Wales gas networks approved higher capital expenditure to meet demand growth and maintain network capacity. The underlying investment drivers included rising connection numbers, the development of renewal and replacement infrastructure to maintain the capacity of ageing networks, and the development of infrastructure to support changes in market operations.

Differences in operating environments can result in significant variations in capital investment requirements. Electricity distribution investment over the current five year regulatory periods is expected to exceed investment in the previous regulatory periods by around 25–33 per cent in Queensland, 42–103 per cent in New South Wales, 33–59 per cent in Victoria, 88 per cent in South Australia and 69 per cent in the ACT (in real terms). Gas distribution investment will increase by around 43 per cent in New South Wales and 33 per cent in the ACT.

Differences in the networks' operating environments also affect operating and maintenance expenditure allowances. In assessing this area, the AER considers relevant cost drivers, including load growth, expected productivity improvements and input costs for labour and materials. The recent Victorian electricity determinations, for example, accounted for an expected increase in regulatory compliance costs for electrical safety, network planning and customer communications, largely stemming from changes associated with the 2009 Victorian bushfires.

With network costs accounting for around 50 per cent of a typical electricity bill, rising capital and operating expenditure are flowing through to energy customers (table 1 and section 3). The retail impacts are greater in networks with substantial capital requirements.

Under the propose–respond model, the AER must accept a regulatory proposal for higher levels of capital and operating expenditure when it represents a reasonable estimate of the efficient costs of a prudent operator. The AER may amend a proposal only to conform with a reasonable estimate. The regulator thus has a substantial evidentiary burden if challenging a proposal.

The AER's decisions are also subject to a merits review by the Australian Competition Tribunal. Since January 2008 network businesses have appealed the determinations on three electricity transmission networks, eight electricity distribution networks and two gas distribution networks (table 2). The decisions on these appeals have increased allowable network revenues by around $2 billion, with substantial flow-on impacts on retail energy charges. Two appeals were continuing in late 2010.

Electricity customers will look to network businesses to make sustained efforts to translate rising investment and operating costs into stable or improving network performance. In light of this, the AER is developing an enhanced national information framework to facilitate its regulatory oversight of network businesses. The framework aims to make the businesses more publicly accountable for the way they spend their regulatory allowances and enhance the transparency of regulated outcomes.

A key performance indicator is network reliability. The average duration of outages per customer in the National Electricity Market (NEM) has generally been 200–250 minutes per year, allowing for regional variations (figure 2). The average duration of outages per customer rose in all mainland jurisdictions in 2008–09. Queensland customers experienced the largest increase, with the average outage duration rising by more than 100 minutes. Annual fluctuations in the data are due largely to climatic variability—for example, tropical storm activity.

Australia' energy markets are operating in an increasingly challenging environment that may impact on network operation and performance. For example, government policy to mitigate climate change may lead to an influx of new low carbon generation plant. The connection framework supporting remote generators—and the transmission network framework more generally—is being reviewed to ensure future network investment is efficient. The issues include how to best coordinate the connection of clusters of new generators (such as wind generators) to the networks.

Table 1 Recent AER decisions—energy networks

SECTOR	LOCATION	ANNOUNCED	PERIOD COVERED (5 YRS TO)	% CHANGE FROM PREVIOUS 5 YEAR PERIOD		ESTIMATED IMPACT ON RETAIL BILL FOR TYPICAL HOUSEHOLD
				CAPEX	OPEX	
Electricity (D)	Vic	October 2010	31 Dec 2015	33–59	8–46	1.8% rise (year 1), then 2.6% per year
Gas (D)	NSW	June 2010	30 Jun 2015	43	8.6	5% rise (year 1), then 2.3% per year
Electricity (D)	SA	May 2010	30 Jun 2015	88	41	6% rise (year 1), then 3.4% per year
Electricity (D)	Qld	May 2010	30 Jun 2015	25–33	19–20	9.2% rise (year 1), then 2.3% per year
Electricity (D)	ACT	April 2009	30 Jun 2014	69	43	4.1% rise (year 1), then 1.3% per year
Electricity (D)	NSW	April 2009	30 Jun 2014	42–103	34–38	9.3–10.4% rise (year 1), then cumulative 16–35% rise (years 2–4)
Electricity (T)	NSW	April 2009	30 Jun 2014	71	23	
Electricity (T)	Tas	April 2009	30 Jun 2014	69	31	2.3% rise (year 1), then 1% per year

Capex, capital expenditure; D, distribution; Opex, operating expenditure; T, transmission.

Notes:

The range of data for some jurisdictions reflects different outcomes across networks.

The Victorian retail impacts are averages across the networks. The range is -1.6 to 5.1 per cent (year 1), then 2.3 to 2.9 per cent per year.

The South Australian retail impact in year 1 will be revised down to reverse over recovery of revenue by the network in 2009–10.

The New South Wales retail impacts cover transmission and distribution. Retail impacts for years 2–4 account for adjustments resulting from a merits review decision.

Capex and opex growth rates are real. Retail impacts are nominal and include inflationary price impacts.

Sources: Regulatory determinations by AER and IPART.

Table 2 Australian Competition Tribunal decisions on AER determinations, June 2008 – November 2010

DECISION DATE	TYPE OF REVIEW	SECTOR	OUTCOME	NETWORKS	REVENUE IMPACT
30 Sep 08	Merits	ET	Increased the opening RAB by $36.1 million	ElectraNet (SA)	$51 million
25 Nov 09	Merits	ET, ED	Nominal vanilla weighted WACC increased from around 8.8% to 10%; EnergyAustralia's controllable operating expenditure allowance increased by $4.5 million; definition of general nominated pass through event amended; AER decision on EnergyAustralia public lighting remitted for redetermination; TransGrid's controllable operating expenditure allowance increased by $14 million	EnergyAustralia (NSW) Integral Energy (NSW) Country Energy (NSW) TransGrid (NSW) Transend (Tas)	$818 million $321 million $411 million $381 million $80 million
18 Jan 10	Merits	ED	Expenditure for related party margins and management fees to be included in budgets for Victorian advanced metering review	Jemena (Vic) United Energy (Vic)	$8.4 million $13.1 million
17 Sep 10	Merits	GD	Debt risk premium calculation method	ActewAGL (ACT)	$5 million
Continuing	Merits	ED	Treatment of imputation credits; opening RAB (ETSA only); capital expenditure allowance, customer service costs, demand forecasts, street lighting, service incentive scheme, labour cost escalators (Ergon only)	ENERGEX (Qld) Ergon Energy (Qld) ETSA (SA)	
Continuing	Merits	GD	Gamma value, DRP value, indemnity clauses in reference services agreement, opening capital base and capital expenditure	Jemena Gas Networks (NSW)	

D, distribution; DRP, debt risk premium; E, electricity; G, gas; T, transmission; WACC, weighted average cost of capital.

Notes:

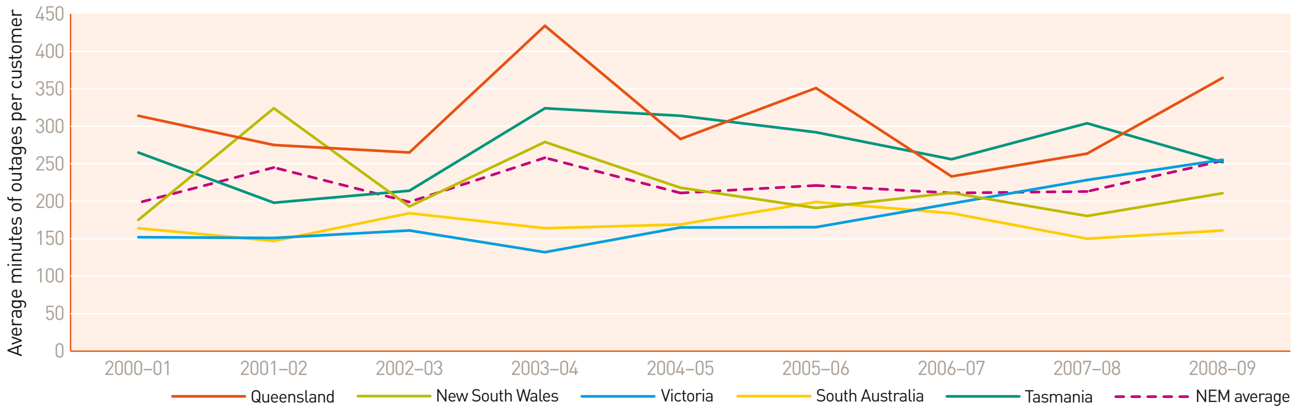
The 18 January 2010 decision on Victorian advanced metering covers a two year period; other revenue impacts are for five year regulatory control periods.

The EnergyAustralia decision (25 November 2009) does not account for increased revenues from public lighting.

The impact of the ElectraNet decision (30 September 2008) accounts for a $30 million increase in revenues from contingent projects.

All data are nominal.

Figure 2
Electricity distribution—reliability of supply



Notes:

The data reflect total outages experienced by distribution customers, including outages resulting from issues in the generation and transmission sectors. In general, the data have not been normalised to exclude outages beyond the network operator's reasonable control. Some data have been adjusted to remove the impact of natural disasters (for example, Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise have severely distorted the data.

The NEM averages are weighted by customer numbers.

Victorian data are for the calendar year beginning in that period.

Data sources: Performance reports by the AER (Victoria), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania), the ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy. Some data are AER estimates derived from official jurisdictional sources. The AER consulted with PB Associates when developing historical data.

Another challenge is finding innovative ways of responding to rising peak demand. When combined with appropriate tariff structures and communications technologies, smart meters are one way to reduce peak and overall demand by giving customers the information needed to manage their consumption more efficiently. Victoria began a rollout of smart meters in 2009.

Smart grids take the concept of smart meters further towards direct control of load, the use of communications technology to rapidly detect and switch around faults to minimise supply disruptions, and the integration of local generation to support the network. The Australian Government has committed $100 million for a trial of smart grid technologies. Ultimately, these innovations should lead to better use and operation of the networks to meet increasingly complex needs.

Regulatory and policy reforms are underway to encourage greater efficiency in network investment. In July 2009 the Australian Energy Market Operator (AEMO) began operating as a single, industry funded national energy market operator for both electricity and gas. It has a National Transmission Planner role, which overlays the traditional jurisdiction based approach to network planning with a more strategic, long term focus on efficiently developing the transmission grid from a national perspective. AEMO expected to publish its first annual national transmission network development plan in December 2010, outlining its view of the efficient development of the power system over the next 20 years.

The AER published a new regulatory investment test in 2010 to require that transmission businesses evaluate the most efficient methods—for example, network augmentation or alternatives such as generation investment—to respond to rising demand for electricity services.

The AER reviewed the compliance of TransGrid (New South Wales) with the regulatory test in relation to a proposed 330 kilovolt (kV) transmission line from Dumaresq to Lismore. It found shortcomings in TransGrid's analysis and decision making process.[1] TransGrid subsequently committed to the AER to improve future processes.

The Australian Energy Market Commission (AEMC) began a comprehensive review in 2010 of the electricity transmission sector. It will consider arrangements for the provision and use of transmission services and implications for the frameworks governing transmission investment. This will include identifying any weaknesses or inefficiencies in how the networks coordinate with generation investment. The final report is expected by November 2011.

2 National Electricity Market

The AER monitors activity in the NEM, which is the wholesale spot market covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. It publishes reports on market activity and the compliance of participants with the National Electricity Rules.

Figure 3 tracks weighted annual average spot electricity prices in the NEM. Average spot prices in 2009–10 rose significantly in South Australia, to $82 per megawatt hour (MWh), and New South Wales, to $52 per MWh. Strategic generator bidding and rebidding to take advantage of opportunities for exceptional prices contributed to these outcomes.

Tasmania recorded its lowest average spot price ($30 per MWh) since joining the NEM in 2005. This reflected more favourable conditions for hydroelectric generation and less evidence of the opportunistic bidding that caused record high prices in 2008–09. Queensland ($37 per MWh) recorded its second consecutive year of average spot prices below $40 per MWh. Victoria ($42 per MWh) was the only mainland region to record a reduction in spot prices in 2009–10.

While conditions were generally benign in most regions in 2009–10, the spot price exceeded $300 per MWh in 330 trading intervals (figure 4) and exceeded $5000 per MWh in 95 intervals (figure 1.9, chapter 1).[2]

Price spikes can have a material impact on market outcomes. If prices approach the market cap of $12 500 per MWh for just three hours in a year, then the average annual spot price may rise by almost 10 per cent.

The bulk of extreme price events in 2009–10 occurred in South Australia and New South Wales. These regions jointly accounted for over 62 per cent of spot prices above $300 per MWh and 71 per cent of spot prices above $5000 per MWh:

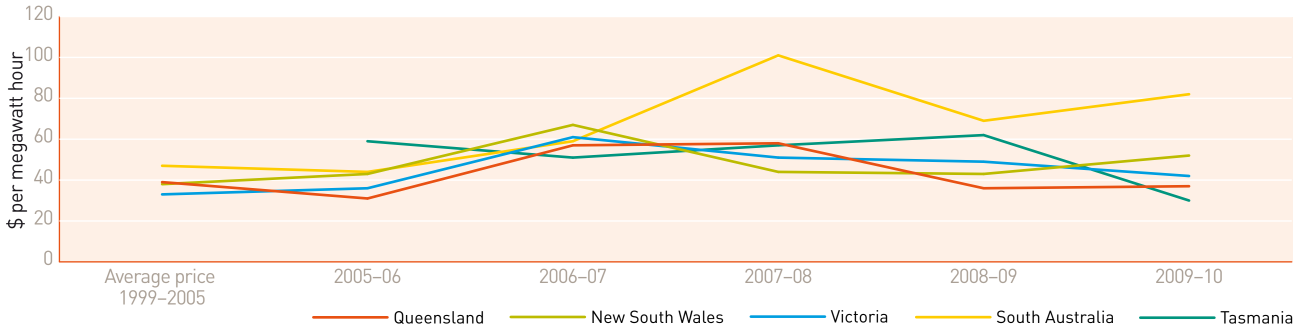
> Spot prices in *South Australia* rose by 20 per cent to $82 per MWh in 2009–10, which was the second highest price for any region since the NEM commenced. Around 50 per cent of NEM prices above $5000 per MWh in 2009–10 occurred in South Australia. Most of the events were associated with opportunistic bidding by AGL Energy, owner of the Torrens Island power station, which accounts for 40 per cent of statewide generation capacity. Transmission limits on importing electricity from Victoria mean AGL Energy can, on days of high electricity demand, bid a significant proportion of its capacity at prices around the market cap and drive up spot prices. A period of prolonged opportunistic bidding and high prices in November 2009 triggered wholesale market controls that capped prices at $300 per MWh.

> Spot prices in *New South Wales* rose by 23 per cent to $52 per MWh in 2009–10, which was the largest regional price increase in that year in the NEM. New South Wales recorded 21 price events above $5000 per MWh. At least 11 of these events featured an interplay of factors in which Delta Electricity and other generators rebid capacity to higher prices to take advantage of a tight market. Generators also rebid their ramp rates, reducing the rates at which plant can vary output in response to dispatch instructions, to prolong the impact. This behaviour caused prices to stay above $300 per MWh for up to eight hours at a time.

1 AER, *Investigation report, Compliance with the planning and network development provisions of the National Electricity Rules—TransGrid*, 2010.
2 A trading interval is 30 minutes. The trading interval price is the average of the five minute dispatch prices during that interval.

Figure 3

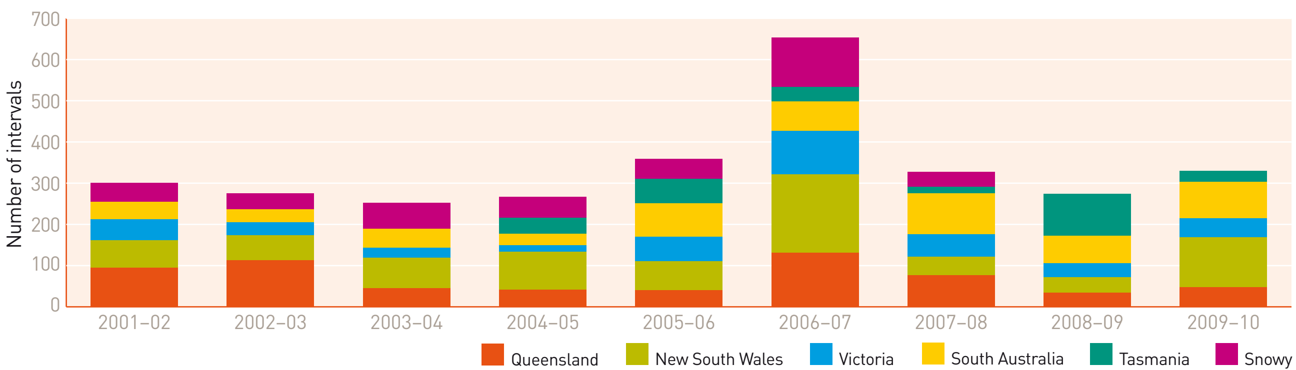
Weighted average spot prices—electricity



Source: AER.

Figure 4

Trading intervals above $300 per megawatt hour—National Electricity Market



Note: Each trading interval is a half hour.

Source: AER.

> While *Tasmania's* wholesale market was relatively stable in 2009–10, concerns about high prices in the frequency control ancillary services market during 2009 led the Office of the Tasmanian Economic Regulator to 'declare' a number of Hydro Tasmania services in December 2009, with a view to setting price caps.

The AER monitors spot market activity to screen for noncompliance with the National Electricity Rules. While bidding capacity at high prices and rebidding prices and ramp rates do not breach the Rules, opportunistic bidding by some generators is a continuing cause of extreme price events. The AER will continue to monitor and report on generator bidding behaviour.

Following an investigation of sustained high electricity prices in Queensland in early 2008, the AER instituted proceedings in 2009 in the Federal Court, Brisbane, against Stanwell Corporation (a Queensland generator) for alleged contraventions of the National Electricity Rules. The AER alleged Stanwell did not make several of its offers to generate electricity on 22 and 23 February 2008 in 'good faith', contrary to clause 3.8.22A of the Rules. The AER sought orders that included declarations, civil penalties, a compliance program and costs. The trial in this matter commenced in Brisbane on 15 June 2010 before Justice Dowsett and concluded on 5 July 2010. In late 2010 the parties were waiting for the judgment.

Generation investment and reliability

Around 1800 megawatts (MW) of new generation capacity was commissioned in the NEM in 2009–10, following 2500 MW in 2008–09. New gas fired plant in Queensland accounted for over 50 per cent of new investment in 2009–10, including Origin Energy's 605 MW power station on the Darling Downs. In New South Wales, Delta Electricity completed a major expansion of its Colongra plant. Investment in wind generation has also been significant, especially in South Australia.

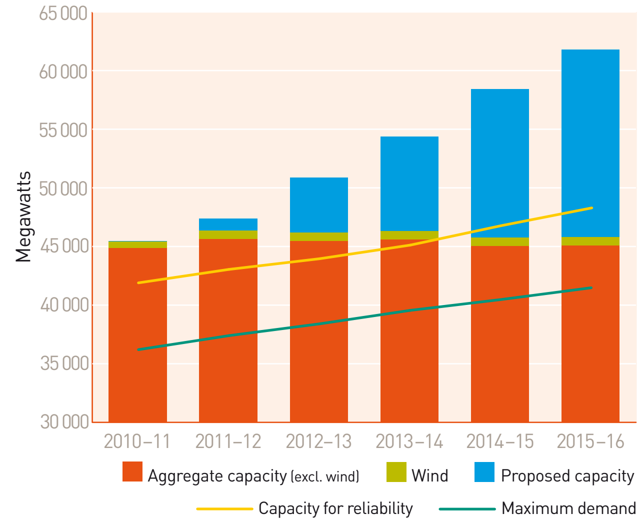
Developers had committed to around 1200 MW of new capacity that was not operational in late 2010. The most significant project is Origin Energy's 518 MW Mortlake power station in Victoria, scheduled for commissioning by the summer of 2010–11.

Generation investment over the past decade generally kept pace with rising demand and provided a safety margin of capacity to maintain the reliability of the power system. While instances of insufficient generation capacity to meet consumer demand are rare, a heatwave in Victoria and South Australia in January 2009 caused unserved energy levels to exceed the reliability standard (when measured on an annual basis) and led the AEMC Reliability Panel to review the reliability settings. The review (completed in April 2010) recommended refinements, including annual increases in the market price cap based on movements in the producer price index. The panel considered this change would improve incentives for efficient investment and was justified given rising capital costs for new entrant gas fired generators and 'peakier' electricity demand.

Recent AEMO assessments found installed and committed capacity (excluding wind) across the NEM as a whole will be sufficient until 2013–14 to meet peak demand projections and reliability requirements (figure 5). Beyond that time, some proposed generation projects may need to come online for the market as a whole to meet reliability requirements.

Figure 5

Electricity demand and supply outlook to 2015–16



Note: Figure 1.17 notes, chapter 1, set out underlying assumptions.

Data source: AEMO, *2010 electricity statement of opportunities for the National Electricity Market*, 2010.

AEMO found, assuming medium economic growth, that Queensland would be the first region in the NEM to require new generation investment (by 2013–14) beyond that already committed. While Queensland has had substantial new investment over the past decade, the region's economic growth is projected to increase electricity demand. Also, installed capacity is expected to fall as the Swanbank B coal fired plant is progressively retired (to be completed by 2012–13).

Victoria and South Australia were projected to require new investment (beyond committed capacity) by 2015–16, and New South Wales by 2016–17. AEMO expected Tasmania to have adequate capacity until at least 2019–20.

AEMO noted climate change policies and the emergence of new technologies would be significant investment drivers over the next few years. In particular, it noted the national renewable energy target would likely shift the generation mix towards less carbon intensive generation sources. It also noted the potential for new technology such as smart meters, smart grids and electric vehicles, combined with an increased focus on energy efficiency, to alter consumption patterns and mitigate the growth in capacity requirements.

The report also considered delays in, and associated uncertainty with, the implementation of an emissions trading scheme may pose risks for investment.[3]

3 Energy retail markets

The legislative package to transfer a range of retail regulatory functions to a national framework was introduced to the South Australian parliament in spring 2010. State and territory governments are expected to implement the framework between 2011 and 2013. The transfer of functions is not expected to occur in Western Australia or the Northern Territory at this time.

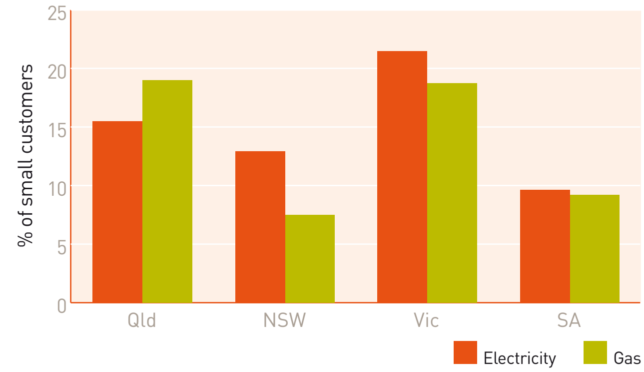
The new framework will transfer several functions to the AER, including:

> monitoring compliance and enforcing breaches of the National Energy Retail Law, Rules and Regulations
> approving the authorisation and exemption of energy retailers
> approving retailers' customer hardship policies
> reporting on performance matters such as customer service and hardship programs, and reporting on energy affordability and retail market activity
> administering a 'retailer of last resort' scheme
> publishing retailers' standing offer prices and an online price comparison service for small customers where required by a jurisdiction.[4]

The states and territories will remain responsible for control of regulated prices.

In preparation for the transition, the AER has been consulting with energy customers, consumer advocacy groups, energy retailers, jurisdictional regulators and ombudsmen, and government departments. In 2010 it ran 11 stakeholder forums on the national arrangements and its proposed approach to retail regulation. It also published issues papers on retail pricing information, retailer authorisations and exemptions, the development of hardship program indicators, performance reporting and a proposed compliance framework. For some processes, it is publishing draft guidelines. The issues papers and draft guidelines are available on the AER website (www.aer.gov.au).

Figure 6
Retail switching by small customers in 2009–10



Note: The customer base is estimated at 30 June 2010.

Sources: Electricity customer switches: AEMO. Gas customer switches: AEMO (Queensland, New South Wales, the ACT, Victoria), REMCo (South Australia). Customer numbers: IPART (New South Wales), ICRC (the ACT), ESCOSA (South Australia), ESC (Victoria), QCA (Queensland).

Retail competition

All NEM jurisdictions except Tasmania have introduced full retail contestability (FRC) in electricity, allowing all customers to enter a contract with their retailer of choice. At 1 July 2009 Tasmania extended contestability to customers using at least 150 MWh per year. Small business customers that consume more than 50 MWh per year are expected to become contestable on 1 July 2011. All jurisdictions have introduced FRC in gas retail markets.

Victoria continues to record high levels of customer switching between retailers (figure 6). While Queensland introduced FRC several years later than other jurisdictions did, customer activity has built momentum. In 2009–10 the state's switching rate in electricity was higher than the rates for New South Wales and South Australia, and was the highest of any jurisdiction for gas. While customer switching in

3 AEMO, *2010 power system adequacy: two year outlook*, 2010; AEMO, *2010 electricity statement of opportunities for the National Electricity Market*, 2010.
4 In New South Wales, Victoria and South Australia, small electricity customers are those consuming less than 160 megawatt hours (MWh) per year. In Queensland and the ACT, the threshold is 100 MWh per year; in Tasmania, it is 150 MWh per year. In gas, small customers are those consuming less than 1 terajoule per year.

South Australia was strong following the introduction of FRC, rates levelled out more recently. New South Wales has the lowest rate of customer switching in gas among the jurisdictions listed.

While most jurisdictions allow customers to choose their energy retailer, jurisdictions other than Victoria apply some form of electricity retail price regulation; New South Wales and South Australia apply similar arrangements in gas. Australian governments agreed to review the continued use of retail price caps and to remove them when effective competition can be demonstrated. The AEMC is assessing the effectiveness of energy retail competition in each jurisdiction, to advise ways to remove retail price caps. State and territory governments make the final decisions on this matter.

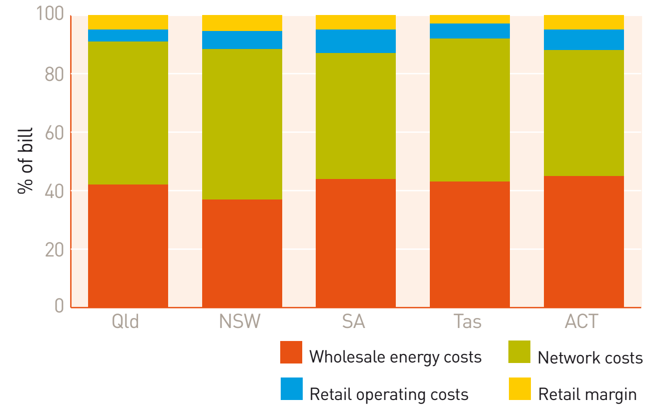
In June 2010 the AEMC released a draft report on the ACT retail electricity market, which found competition in the small customer market was not effective. It considered regulated retail prices were set at levels that did not allow adequate margins to attract new entrants, thus creating barriers to entry. Accordingly, retailer rivalry was limited, as were product choices available to small customers.

The Ministerial Council on Energy and the Council of Australian Governments have agreed to further energy retail market reviews for New South Wales, Queensland and Tasmania (if FRC is introduced).

The New South Wales Government announced plans in 2009 to privatise its state owned energy retailers—EnergyAustralia, Integral Energy and Country Energy—in combination with the electricity trading rights of its nine state owned power stations and seven power station development sites. The 'gentrader' rights will be sold in four bundles.

The government has reserved the option of bundling a number of assets and divesting them through an initial public offering if the sale process does not result in a new entrant. It expected to complete the sale process towards the end of 2010.

Figure 7
Indicative composition of residential electricity bills, 2010



Note: Table 4.2, chapter 4, sets out underlying data.

Sources: Determinations, draft determinations, fact sheets and newsletters by IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (the ACT).

Retail prices

The energy bills paid by retail customers cover the costs of wholesale energy, transport through transmission and distribution networks, and retail services. Figure 7 estimates the composition of a typical *electricity retail* bill for a residential customer in each NEM jurisdiction that regulates prices.

- *Wholesale energy costs* account for around 37–45 per cent of small customer retail electricity bills. This range includes costs associated with government climate change policies which, for example, contribute to around 1 per cent of retail bills in Tasmania and 3 per cent of bills in the ACT. In New South Wales, the renewable energy target scheme accounts for around 0.9 per cent of retail bills; the Energy Savings Scheme accounts for a further 0.4 per cent.
- *Network tariffs* account for 43–51 per cent of retail energy bills. The estimate for New South Wales reflects a significant pass through of distribution network costs that took effect in 2009; the contribution of network costs to retail prices is projected to rise in that jurisdiction from around 47 per cent in 2007 to 57 per cent in 2012.

- *Retailer operating costs* contribute in a range of around 4–8 per cent, and *retail margins* in a range of 3–5 per cent.

The data reflect jurisdictional averages and may vary across distribution networks. The contribution of network charges in New South Wales, for example, ranges from around 47 per cent for Integral Energy distribution customers to 57 per cent for Country Energy distribution customers.

Pipeline charges are the most significant component of *gas retail bills;* they account for around 47 per cent of gas retail bills in New South Wales and 60 per cent in South Australia. Distribution charges account for the bulk of pipeline costs. Wholesale energy costs typically account for a lower share of retail bills in gas than electricity, while retailer operating costs (including margins) account for a higher share. Given the uneven geographic spread of gas producing basins from major markets, the composition of retail prices can vary significantly across jurisdictions and regions.

Figure 8 illustrates indicative movements in *retail electricity prices* in NEM jurisdictions during 2009–10. The data measure regulated prices for those jurisdictions that apply price caps, and unregulated standing offer prices for the deregulated Victorian retail market. A spread is shown for New South Wales and Victoria, in which price movements vary across distribution networks. The percentage change in the electricity component of the consumer price index is also shown, for comparative purposes.

The data indicate that retail electricity prices rose significantly in 2009–10 in most states and territories. At 1 November 2010 further substantial increases had been announced in some jurisdictions:

- In New South Wales, regulated electricity prices rose by up to 21.7 per cent in 2009–10, with further increases of 7–13 per cent expected in 2010–11. The Independent Pricing and Regulatory Tribunal (IPART) found higher network charges accounted for 50 per cent of the 2009–10 price increases and 80 per cent of the 2010–11 increases. Rising wholesale energy costs contributed to around 30 per cent of the 2009–10 retail price rises, but will have a negligible impact in 2010–11.
- The Queensland Competition Authority (QCA) increased regulated electricity prices for 2009–10 by 11.8 per cent, which rose to 15.5 per cent following an appeal by energy retailers. It attributed the rise in roughly equal proportions to rising wholesale energy and network costs. The QCA attributed around 61 per cent of the projected 13.3 per cent rise in 2010–11 retail prices to rising network charges, mainly associated with new investment in distribution networks. The remaining sources of cost pressure were rising wholesale energy costs (contributing 29 per cent) and an increase in retail costs related to customer acquisition and retention.
- Victorian standing offer electricity prices rose by around 12–19 per cent in 2009–10. Given these are unregulated prices, only limited information is available on underlying cost factors. Unlike most jurisdictions, Victoria had relatively flat (or slightly declining) distribution charges, and was the only mainland jurisdiction to record a decrease in spot

Figure 8

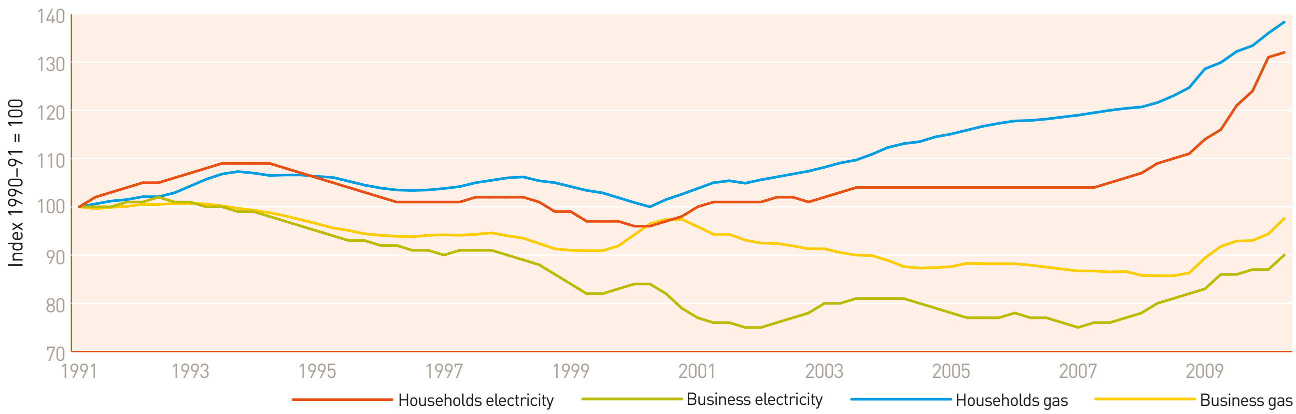
Retail electricity price rises—regulated and standing offers, 2009–10

Note: Victorian prices are based on unregulated standing offer prices published in the Victorian Government Gazette. Price movements in other jurisdictions reflect determinations by jurisdictional regulators.

Sources: Determinations, draft determinations, fact sheets and media releases by IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (the ACT); Victorian Government Gazette; ABS, *Consumer price index*, cat. no. 6401.0.

Figure 9

Electricity and gas retail price index (real)—Australian capital cities



Sources: ABS, *Consumer price index* and *Producer price index*, cat. nos 6401.0 and 6427.0, various years.

electricity prices in 2009–10. Costs associated with the introduction of smart meters would have accounted for retail price increases of around 2.5–7 per cent in 2010. The pass through impact was lowest for United Energy distribution customers and highest for Jemena customers. A pass through of transmission charges would account for retail price increases of up to 2.6 per cent. Higher costs (including compliance costs) associated with government climate change policies also likely contributed.

- South Australian electricity price rises were relatively moderate in 2009–10, but in July 2010 rose by 5.6 per cent in response to rising network charges and pass throughs related to climate change policies. The South Australian regulator's inquiry into regulated prices for 2011–14 foreshadowed in a draft determination that prices may increase by a further 6.9 per cent on 1 January 2011.
- Tasmanian electricity prices rose by around 6 per cent during 2009–10, with a further 6 per cent increase occurring on 1 July 2010 in response to rising network charges. The Office of the Tasmanian Economic Regulator determined that prices would again increase by 8.8 per cent on 1 December 2010. It attributed around half of this increase to rising energy purchase costs.
- The ACT recorded a 6.4 per cent increase in prices in 2009–10 and expects a moderate 2.3 per cent increase in 2010–11.

Customers in most jurisdictions can negotiate discounts against regulated and standing offer prices by entering a market contract. The scope for discounting appears to be greatest in Victoria. A St Vincent de Paul Society analysis (with funding from the Consumer Advocacy Panel) found a price spread of 26–37 per cent across retail offers within Victorian electricity distribution zones.[5]

Recent retail price increases have generally been lower in gas than electricity. South Australia expected a moderate 3.1 per cent increase in regulated gas prices in 2010–11. In New South Wales, IPART attributed price increases of around 3–8 per cent over the same period mainly to higher distribution pipeline charges. In the deregulated Victorian market, gas retail prices rose in 2009–10 by between 6 and 12 per cent.

Retail prices—long term trends

Figure 9 estimates movements in real energy retail prices in major capital cities over time. It illustrates the recent upswing in real electricity and gas retail prices, especially for households. In part, the tendency for household customers to experience larger price rises

5 St Vincent de Paul Society, *Victorian energy prices July 2008 – July 2010: a report from the Victorian tariff-tracking project*, 2010.

than business customers reflects the rebalancing of charges in some jurisdictions to better reflect underlying costs. More generally, it illustrates that household customers are increasingly exposed to prices in wholesale energy markets.

4 Upstream gas

Australia's natural gas industry continues to expand rapidly, driven by buoyant interest in liquefied natural gas (LNG) exports, investment in gas fired electricity generation, and a rapidly expanding resource base of coal seam gas (CSG) in Queensland and New South Wales.

LNG export volumes from Western Australia and the Northern Territory rose in 2009–10 by 7.4 per cent,[6] and major players are continuing to expand capacity:

> Woodside Petroleum's 4.3 million tonne per year Pluto project is nearing completion and will become Australia's third operational LNG project. The first exports are expected in early 2011.
> The $50 billion Gorgon project in Western Australia is scheduled to begin operation in 2015 and produce around 15 million tonnes of LNG per year—almost equal to Australia's current total LNG production. The project partners have signed long term sales agreements with international buyers.

There are emerging issues in Western Australia's domestic gas market. Anecdotal evidence suggests that some long term contracts were written at prices of $8–9 per gigajoule in the 18 months to June 2010. Conversely, weaker demand from mining projects led to reports that short term prices eased in 2010 to around $4.50 per gigajoule.[7]

The Western Australian Department of Mines and Petroleum gave evidence to a parliamentary inquiry into domestic gas prices in September 2010 that Western Australia could face a gas supply shortfall of 300 terajoules per day between 2013 and 2022.[8] To address this shortfall, a number of smaller gas projects focused on the domestic market are expected to come online within the next three years.

On the east coast, long term projections of rising international energy prices, together with rapidly expanding reserves of CSG, have improved the economics of developing LNG export facilities in Queensland. Several export projects that rely on CSG are at an advanced stage of planning. The proposals mostly involve joint ventures between major international and domestic energy businesses.

Existing CSG developments in eastern Australia have reshaped the domestic gas market by providing a new source of gas supply for New South Wales, Victoria and South Australia. CSG production in Queensland and New South Wales rose by 29 per cent in the 12 months to June 2010.[9] New infrastructure, such as the QSN transmission link (commissioned in 2009), is providing the physical capacity to enable gas to flow from Queensland into southern markets.

Rising investment in gas fired power stations is a key driver of natural gas demand in eastern Australia. Output from gas fired electricity generation rose across the NEM jurisdictions by 21 per cent in 2009–10.

While upstream gas is a lightly regulated sector, recent developments significantly enhance transparency. The National Gas Market Bulletin Board, which began in July 2008, provides real time information on the state of the gas market, system constraints and market opportunities. In addition, new spot markets for short term gas trading are being introduced at major hubs to complement a separate market that already operates in Victoria. The first markets, for Sydney and Adelaide, began operation in September 2010. While the new

6 EnergyQuest, *Energy Quarterly*, August 2010, p. 24.
7 EnergyQuest, *Energy Quarterly*, August 2010, p. 89.
8 The findings of the parliamentary inquiry are expected to be released in February 2011.
9 EnergyQuest, *Energy Quarterly*, August 2010, p. 63.

day-ahead market relates to gas for balancing purposes, it is expected to provide transparent price guidance for the market as a whole. The AER, which monitors the short term trading market and enforces the applicable Rules, publishes weekly reports on market activity.

The spot markets in Victoria, Sydney and Adelaide provide the most transparent gas price signals. The Victorian spot market in 2010 was relatively flat, with prices in the first quarter (and the early part of the fourth quarter) typically below $2 per gigajoule. Sydney and Adelaide gas prices moved in a wide range in the first eight weeks of the short term trading market's operation in 2010, which is not uncommon with the establishment of a new market.[10]

Further dynamic change is likely in east coast gas markets with the development of CSG–LNG projects in Queensland in the next few years. While this may increase wholesale gas prices in the longer term, EnergyQuest predicted that domestic prices may ease during the lengthy ramp-up of LNG export capacity.[11]

5 Australian Energy Regulator's role

As the transition to national energy regulation continues, the AER is mindful of its responsibilities in regulating energy infrastructure, monitoring wholesale energy markets for compliance with the underpinning legislation, and reporting on market outcomes, as well as its likely future responsibilities in energy retail regulation. It also has a role in informing debate on policy, including advising on the operation of the market and the regulatory framework.

The AER will continue to work closely with energy customers, industry and jurisdictional agencies in undertaking these roles. It will look to apply consistent and transparent approaches to encourage efficient investment and reliable service delivery. The AER's new retail functions will increase the focus on education and outreach to encourage energy customers to participate actively in the market, and make them aware of and confident in the protections available to them in dealing with service providers.

Across its work program, the AER will continue to work towards best practice regulatory and enforcement outcomes, including the provision of independent, transparent and comprehensive information on market developments.

10 Design differences between the short term trading market and the Victorian spot market limit the validity of price comparisons. The Victorian market is for gas only, while prices in the short term trading market cover gas and transmission pipeline delivery to the hub.

11 EnergyQuest, 'Australia's natural gas markets: connecting with the world', published in AER, *State of the energy market 2009*, 2009.

ABBREVIATIONS

2P	proved plus probable natural gas reserves
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
CCGT	combined cycle gas turbine
CIR	Congestion Information Resource
COAG	Council of Australian Governments
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
CPT	cumulative price threshold
CSG	coal seam gas
DRP	debt risk premium
Electricity Law	National Electricity Law
Electricity Rules	National Electricity Rules
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
FRC	full retail contestability
Gas Law	National Gas Law
Gas Rules	National Gas Rules
GJ	gigajoule
GSL	guaranteed service level
GSOO	Gas Statement of Opportunities
GW	gigawatt

GWh	gigawatt hour
ICRC	Independent Competition and Regulatory Commission
IDGCC	integrated drying gasification combined cycle
IGCC	integrated gasification combined cycle
IPART	Independent Pricing and Regulatory Tribunal
kV	kilovolt
KW	kilowatt
KWh	kilowatt hour
LNG	liquefied natural gas
MCE	Ministerial Council on Energy
MW	megawatt
MWh	megawatt hour
NEM	National Electricity Market
NTP	National Transmission Planner
OCGT	open cycle gas turbine
opex	operating expenditure
OTTER	Office of the Tasmanian Economic Regulator
PJ	petajoule
Q	quarter
QCA	Queensland Competition Authority
QNI	Queensland to New South Wales interconnector
RAB	regulated asset base
RERT	reliability and emergency reserve trader
RET	renewable energy target
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SFE	Sydney Futures Exchange
TJ	terajoule
TJ/d	terajoules per day
TW	terawatt
TWh	terawatt hour
WACC	weighted average cost of capital