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Evolution of Australia's national electricity market

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Abstract

The Australian National Electricity Market commenced in 1998 and spans the longest interconnected AC grid in the world. Most generation is coal-fired, but significant gas-fired capacity has been developed since market start in response to rising peak demand. Until the early 1990s, virtually all electricity was supplied through vertically-integrated state monopolies. These monopolies have now been disaggregated and many of their component businesses privatized. Generation and retailing activities are now largely open to competition, while monopoly transmission and distribution networks are subject to independent economic regulation. The NEM is an energy-only market and prices have generally performed well in encouraging investment where and when it is efficient. However, the mounting cost of climate change policies has offset many of the initial gains. Recent regulatory issues have focused on network 'gold-plating', with some concerns expressed about generator market power and vertical integration. Completion of the reform process requires further privatization and additional retail tariff liberalization.

1 Introduction

The Australian electricity supply industry has undergone substantial pro-competitive reform over the last two decades. In the early 1990s, virtually all electricity was supplied through vertically-integrated state monopolies. Within a decade, the integrated monopolies had been disaggregated into different businesses with the competitive aspects of supply (generation and retailing) reconstituted into dozens of independent firms, many of them privately-owned and the rest 'corporatized' and operating at arm's length from their government owners. Monopoly aspects of supply, transmission and distribution networks, were also in some cases privatized with their prices set by independent economic regulators.

Nevertheless, the process of reform remains incomplete in key areas and certain aspects of market design remain unsettled. The incomplete status of reforms largely reflects political reluctance to engage in further privatization and retail tariff liberalization, while ongoing debates over aspects of market design such as nodal pricing are attributable to policy-makers' self-acknowledged doubts about the benefits of greater sophistication.

Against this background, the Australian electricity sector faces fresh challenges as a result of policies aimed at reducing greenhouse gas emissions. The Federal Government introduced the world's most broadly-based tax on emissions in July 2012. At the same time, consumer costs are

1 The authors would like to thank Liam Blanckenberg of Frontier Economics for helpful comments and feedback on this chapter. However, all errors remain the responsibility of the authors.

increased by a 20% renewable energy target. Renewables also benefit from taxpayer-or customer-financed subsidies.

This chapter commences by describing the most important elements of the Australian electricity supply industry (section 2), before outlining the key structural, institution and regulatory reforms undertaken to date (section 3). The chapter then explains the design and performance of the National Electricity Market (section 4), followed by a brief discussion of outstanding areas of reform (section 5). The chapter goes on to explain the nature and effects of Australian climate change policies on the power industry (section 6) and concludes with some final observations (section 7).

2 The Australian electricity supply industry

2.1 Industry outline

Electricity production across Australia's six states and two territories was approximately 228 TWh in 2010-11.[2] Australian grid-connected generation capacity as at June 2011 was approximately 54 GW, with the bulk of capacity being in the form of coal-fired steam turbines.[3]

Australia's population is concentrated within a narrow strip of land near the eastern, south eastern and south western coastlines (Figure 1).

2 Energy Supply Association of Australia, *Electricity Gas Australia 2012*, Table 2.5, pp.24-25.

3 Energy Supply Association of Australia, *Electricity Gas Australia 2012*, Table 2.1, pp.20-21.

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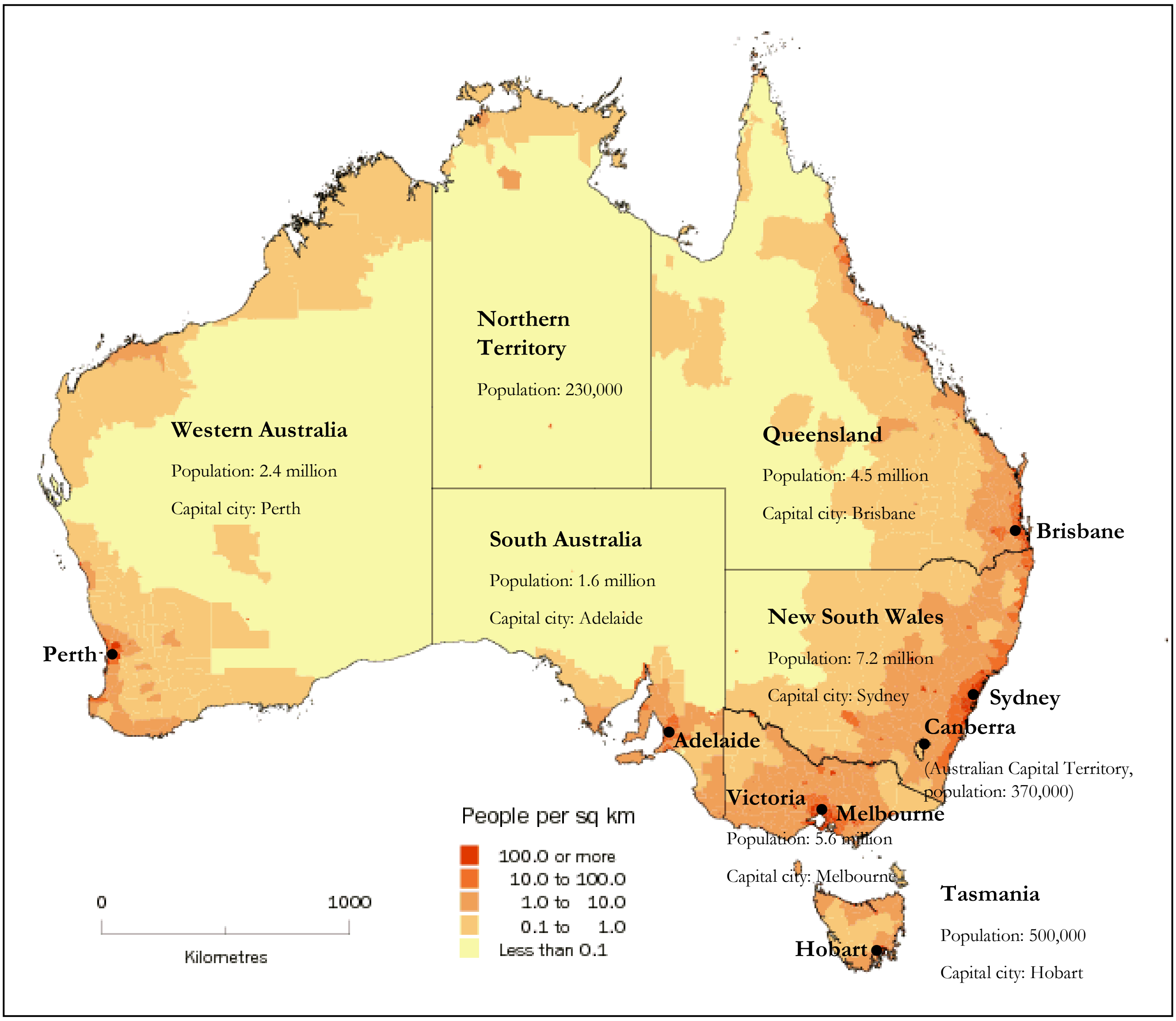


Figure 1 Map of Australia – Population Density
Source: Australian Bureau of Statistics, *Year Book Australia 2012*, Figure 7.14, p.247.

A high-voltage network, rated at 220 kV or higher, connects most consumers and producers of electricity in Queensland, New South Wales (NSW), the Australian Capital Territory (ACT), Victoria, South Australia and (via the undersea Basslink cable) Tasmania (Figure 2). This power system operates within the National Electricity Market (NEM) and it incorporates the longest interconnected AC network in the world, stretching 4,500 kilometres.[4]

4 Australian Energy Regulator, *State of the Energy Market 2011*, p. 25, available at: http://www.aer.gov.au/node/6311.

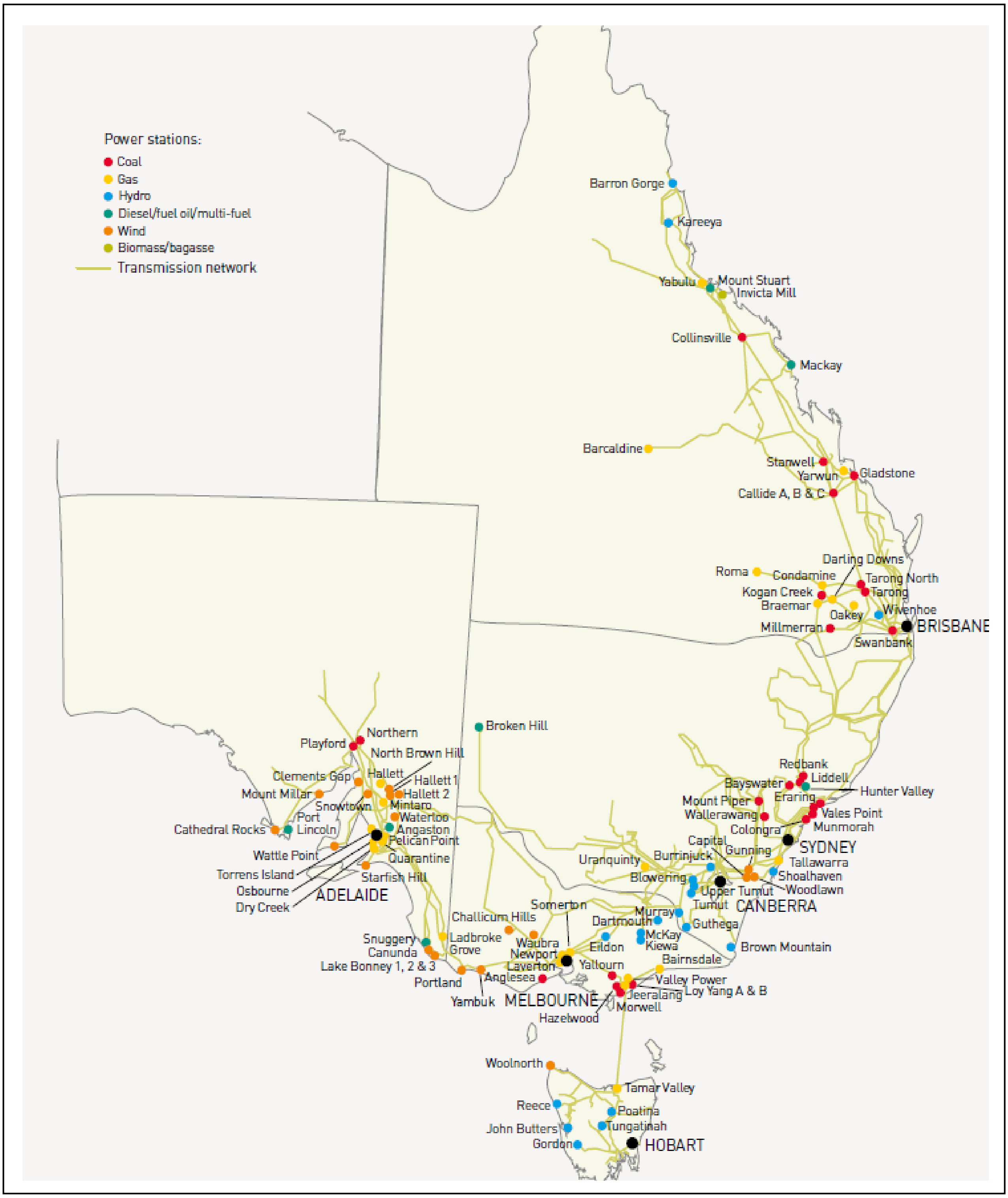


Figure 2 Map of the National Electricity Market
Source: AER, *State of the Energy Market 2011*, Figure 1.2, p.26.

The main power system in Western Australia is known as the South West Interconnected System (SWIS), which operates within the Wholesale Electricity Market (WEM) (Figure 3). Various smaller systems supply consumers in northern parts of Western Australia and the Northern Territory as well as in other isolated areas.

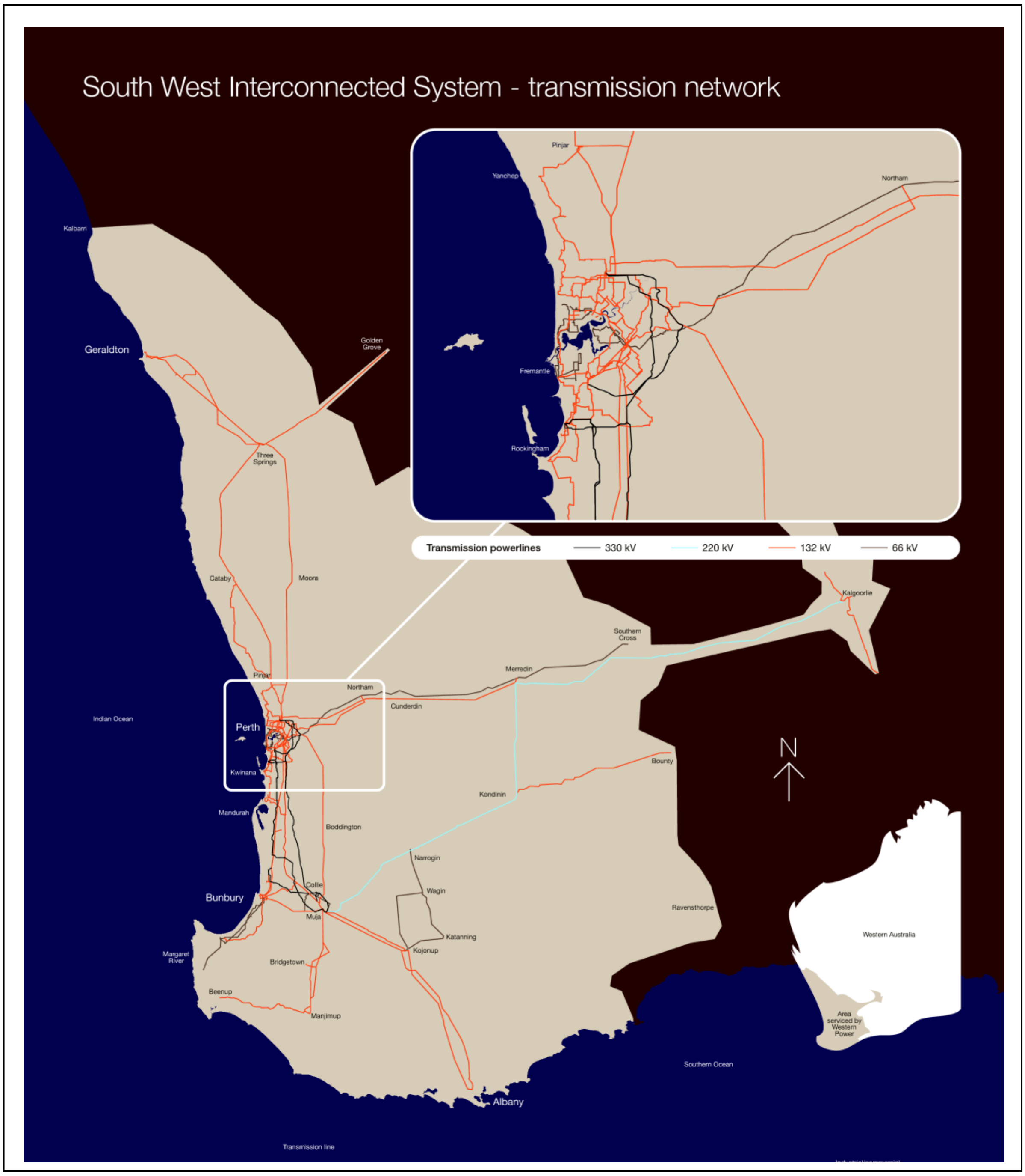


Figure 3 Map of the South West Interconnected System
Source: Western Power

The NEM commenced in December 1998 following the earlier creation of state-based wholesale markets in Victoria, NSW and Queensland. Queensland was interconnected to the southern states in 2000 with the commissioning of the Terranora, formerly Directlink, interconnector and later the Queensland-NSW Interconnector (QNI). Tasmania entered the NEM with the commissioning of Basslink in May 2005.

The NEM supplies approximately nine million end-use customers. Residential households represent approximately 90% of total end-use customers but account for less than 30% of annual electricity consumption, with business, commercial and large industrial customers making up the remainder.

While almost all electricity assets were originally owned and operated by state government instrumentalities, there are now multiple private and government-owned businesses operating as generators and/or retailers in the NEM. Distribution and transmission network businesses in the NEM also reflect a mix of government and private ownership. Table 1 in section 3.1.1 outlines the ownership structure of key participants in each NEM jurisdiction.

All customers in the mainland NEM are now contestable. In Tasmania, only customers with annual consumption levels above 150 MWh are contestable.[5] However, retail tariff controls continue to apply to smaller customers everywhere except Victoria.

In Western Australia, the WEM is dominated by the state-owned generation and retailing businesses, Verve Energy (Verve) and Synergy, respectively. Verve and Synergy were formally the generation and retailing arms of the vertically-integrated state utility Western Power, which was disaggregated in 2006. The SWIS transmission and distribution networks are operated by Western Power, which also remains government-owned. Most energy in the WEM is traded under contracts, but the Independent Market Operator operates a real-time balancing mechanism and a market for capacity credits. Customers in the SWIS with annual consumption levels of 50 MWh or higher are contestable. However, customers consuming between 50 and 160 MWh per annum can choose to be supplied by Synergy at a regulated tariff. The state government approves changes in regulated retail tariffs for both residential and business customers.

2.2 Key supply and demand characteristics

2.2.1 NEM

The majority of Australia's electricity generation capacity is located in the NEM. Registered NEM generation capacity is approximately 48 GW across 305 registered generators and total electricity generated over 2010/11 was 208 TWh.[6]

Most generation in the NEM is coal-fired steam turbine plant, although significant increased gas-fired capacity has been developed over the last decade in response to rising peak demand. Black and brown coal plant are the primary sources of baseload power, with 59% of registered capacity and 78% of output. Gas-fired generation mainly provides intermediate and peaking capacity, with 22% of registered capacity but only 12% of output across the NEM. Hydro-electric generation capacity is relatively small despite the large land area and is nearly fully developed, accounting for 16% of capacity and 8% of output. Scheduled wind now accounts for 4% of capacity and 2.5% of output.

5 Energy Supply Association of Australia, *Electricity Gas Australia 2011*, Table 4.2, p.60.

6 Energy Supply Association of Australia, *Electricity Gas Australia 2012*, Table 2.5, pp.24-25.

Government policies to promote renewable generation have driven the development of wind, particularly since 2001, further described in section 6.2. Liquid and other sources of power are minimal and nuclear power is forbidden by legislation.

As shown in Figure 4, the States of Queensland and New South Wales are dominated by black coal-fired plant, whereas Victoria is mainly supplied by brown coal plant. South Australia has limited coal reserves and has traditionally relied on gas-fired plant. Finally, Tasmania is chiefly supplied by hydro-electric plant. Most wind plant in the NEM has been developed in South Australia and Victoria, where wind capacity factors tend to be highest.

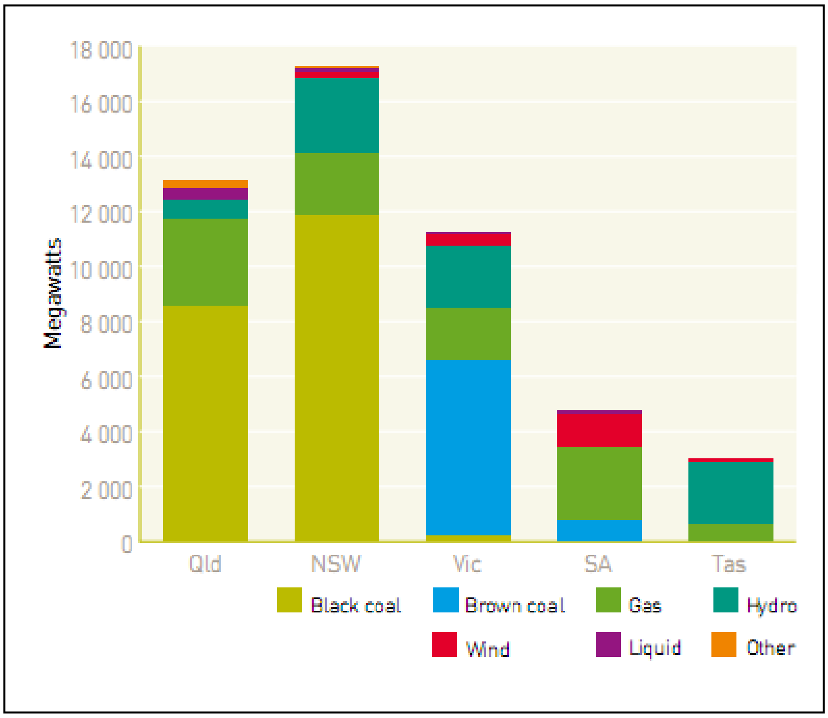


Figure 4 Registered capacity by fuel source 2011
Source: AER, *State of the Energy Market 2011*, Figure 1.4, p.28.

Even though the coal used in Australian power stations is mainly below 'export quality', rising international prices for black coal in recent years as a result of the worldwide commodity boom have increased the fuel costs of a typical NSW black coal plant from $A15/MWh to over $A30/MWh.[7] Gas prices on the Australian east coast are expected to rise towards export parity in response to the development of LNG terminals in Queensland. However, wholesale electricity prices have so far not risen to match these cost increases. This is partly due to the expansion of subsidized renewable generation, which is typically bid into the market at a low or negative marginal cost, in recent years and partly due to demand-side factors.

7 At the time of writing, one Australian dollar was similar in value to one US dollar. For the remainder of this chapter, the notation '$' will be used to refer to Australian dollars.

Peak demand in the NEM occurs during summer, driven by air conditioning load during heatwaves. In recent years, peak summer demand has reached 35 GW (Figure 5), but was only 30.5 GW in the summer of 2012.[8]

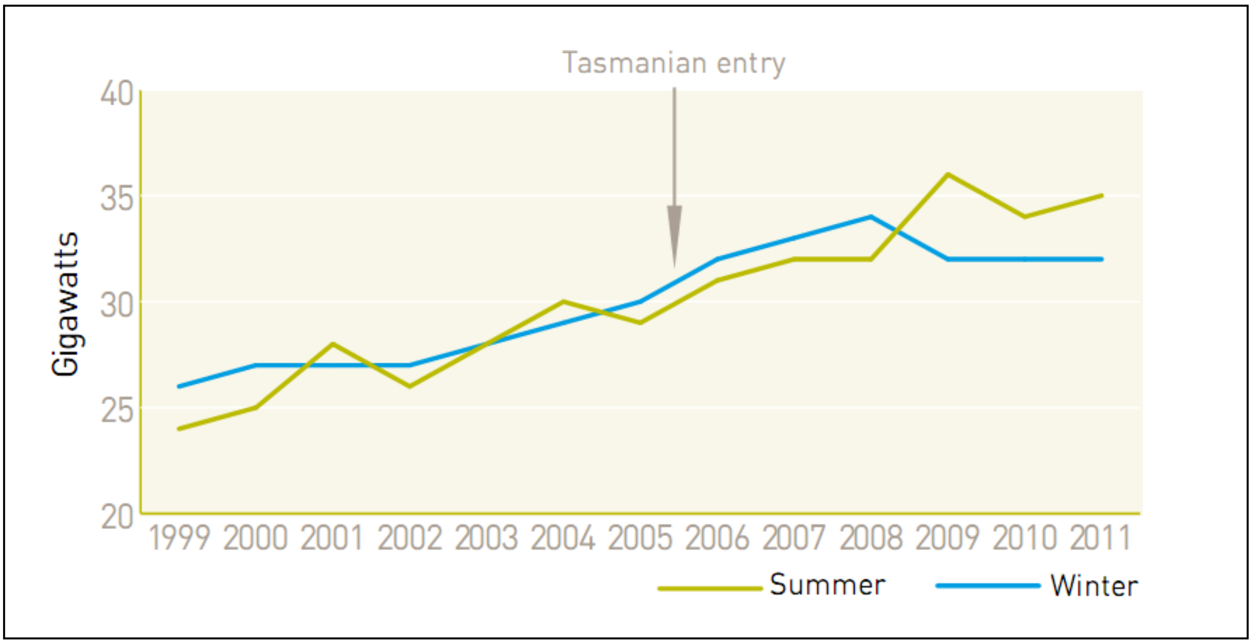


Figure 5 National Electricity Market peak demand
Source: AER, *State of the Energy Market 2011*, Figure 1.1b, p.25.

Total electricity production reached 212 TWh in 2008/09 (Figure 6) but has subsequently tapered off to 208 TWh.[9] The flattening of consumption and to a lesser extent peak demand has been in part attributed to cooler summer weather in recent years as well as being reduced by the installation of domestic solar photo-voltaic (PV) panels encouraged by generous federal and state government subsidies. Total consumption is now forecast to reach only 222 TWh by 2021/22.[10]

Another key factor in slowing electricity consumption has been steadily rising retail tariffs. The principal driver of these increases has been sharply higher network charges. In particular, expenditure on low voltage distribution networks has increased by over 50% in real terms in New South Wales and Queensland over the last decade as investment in the grid has ballooned to meet summer demand peaks. Higher retail tariffs also reflect the costs of renewables subsidies such as the Renewable Energy Targets (RETs) and generous fed-in tariffs (FiTs) for solar PV installations. These schemes and the new carbon pricing mechanism are discussed in section 6.

8 Australian Energy Market Operator, *Energy Update May 2012*, p.3, available at: http://www.aemo.com.au/en/About-AEMO/Publications/~/media/Files/Other/corporate/AEMO_Energy_Update_May_2012.ashx.

9 Energy Supply Association of Australia, *Electricity Gas Australia 2012*, Table 2.5, pp.24-25.

10 Australian Energy Market Operator, *2012 National Electricity Forecasting Report*, Table 3-1, p.3-4, available at: http://www.aemo.com.au/en/Electricity/Forecasting/2012-National-Electricity-Forecasting-Report.

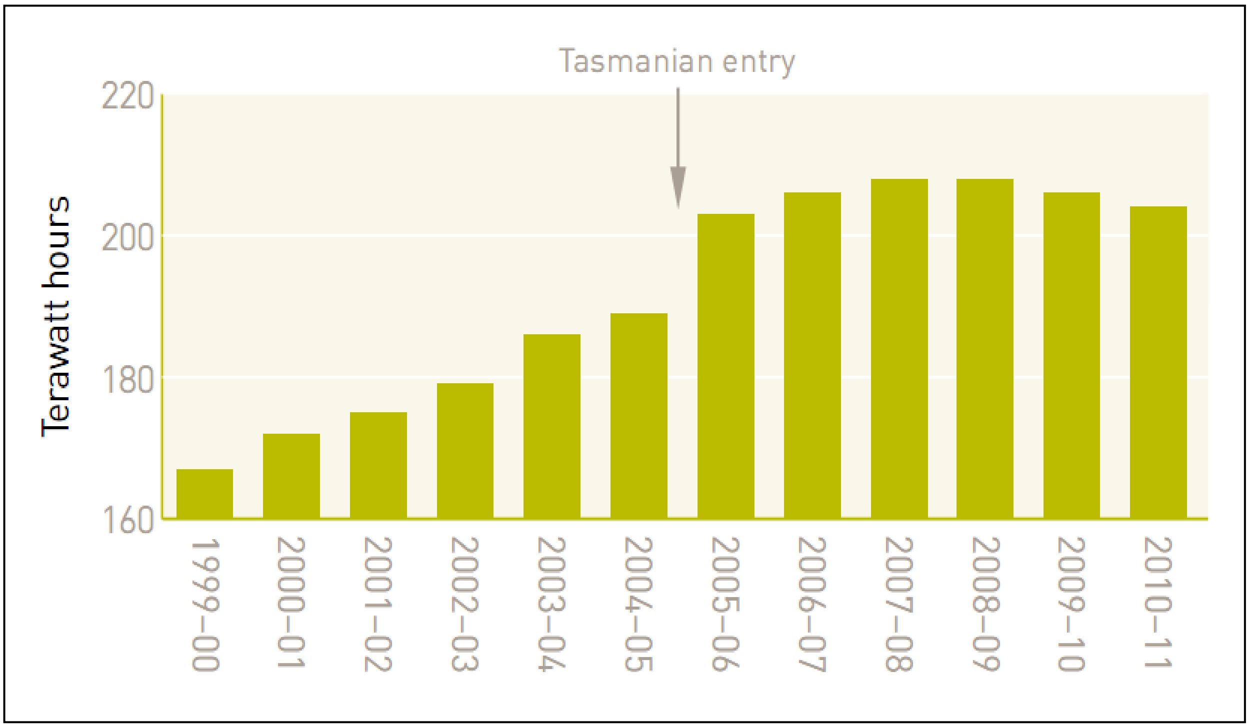


Figure 6 National Electricity Market electricity consumption
Source: AER, *State of the Energy Market 2011*, Figure 1.1a, p.25.

2.2.2 WEM

The WEM incorporates over 6 GW generation capacity.[11] This is dominated by coal, gas and dual-fueled (gas and liquids) generation. Western Australia's heavy reliance on gas for electricity generation was exposed in the winter of 2008, when an explosion at Varanus Island reduced gas supplies to the south-west of the state by 30%, resulting in many forced outages and higher wholesale prices. Significant wind capacity has been developed in recent years, largely due to incentives under the WEM Capacity Mechanism and the Federal Government's RET policy. As a result of new entry since the market commenced, incumbent Verve Energy's share of overall capacity has fallen from over 80% in 2006 to nearly 50% in 2012/13.[12]

Like the NEM, peak demand in the WEM occurs during summer. Presently, peak demand is about 4 GW and total consumption in 2010/11 was approximately 19 TWh.[13] The Independent Market Operator expects peak demand to increase by nearly 2 GW over the next decade, an increase of

11 See Independent Market Operator website at: http://www.imowa.com.au/rc-capacity-in-the-swis.

12 Independent Market Operator, *Wholesale Electricity Market: Request for Expressions of Interest for the 2012 Reserve Capacity Cycle*, February 2012, p.7, available at: http://www.imowa.com.au/f177,2260540/2012_Request_for_EOI.pdf. See also Independent Market Operator website at: http://www.imowa.com.au/rc-capacity-in-the-swis.

13 Independent Market Operator, *Wholesale Electricity Market: Request for Expressions of Interest for the 2012 Reserve Capacity Cycle*, February 2012, p.5.

50%.[14] This compares with NEM peak demand, which is expected to grow by 16% over the same period.[15]

As noted above, retail supply to household customers in Western Australia is not contestable. Regulated retail tariffs have been rising steeply in Western Australia, but from a low base. Residential tariffs did not change for over a decade, from 1997/98 to 2008/09 and business tariffs did not increase between 1991/92 and 2007/08. To help bring tariffs back into line with the costs of supply, the state government approved increases to residential tariffs totalling 25% in 2009, a further 17.5% in 2010 and 5% in 2011. Businesses have seen similar aggregate increases.[16]

3 Structural, institutional and regulatory reforms

3.1 Initial state-based reforms

3.1.1 Disaggregation and privatization[17]

Prior to the 1990s, electricity supply in each state was provided by vertically-integrated, government-owned monopolies. The initial impetus for reform came from:

- the recognition that other countries were achieving considerably greater efficiencies than Australia in electricity supply[18][19];
- the implementation of National Competition Policy, which required a general review of the operations of "essential facilities" and a requirement that they be opened to non-affiliates on reasonable terms; and
- the consequences of poor financial circumstances in the States of Victoria and South Australia, which resulted in new governments that sold energy assets partly in pursuit of a privatization agenda and in part to reduce debt.

Following initial moves to reduce over-manning, Victoria was the first state to undertake vertical and horizontal disaggregation of its electricity business. The Kennett Liberal (conservative) Government, elected in 1992, broke up the State Electricity Commission (SECV) into separate generation, transmission and distribution/retail businesses before proceeding to sell those businesses over the mid-to late-1990s. While the government had a strong philosophical belief in the benefits of privatization, it also wanted to avoid the mistakes made in Britain, where the reforms had resulted in a highly concentrated structure of generation ownership. Great care was taken to establish multiple generation, distribution and retailing firms, with this being given a higher priority than maximising sale proceeds. Notwithstanding these steps to minimize

14 Independent Market Operator, *Wholesale Electricity Market: Request for Expressions of Interest for the 2012 Reserve Capacity Cycle*, February 2012, Figure 4, p.8.

15 Australian Energy Market Operator, *2012 National Electricity Forecasting Report*, Table 3-1, p.3-4.

16 See Western Australian Department of Finance website at: http://www.finance.wa.gov.au/cms/content.aspx?id=15096.

17 For more detail on the history of early reforms, see Moran, A., "The Electricity Industry in Australia: Problems Along the Way to a National Electricity Market", Chapter 6 in Sioshansi, F.P. and Pfaffenberger, W. (Eds), *Electricity Market Reform: An International Perspective* (2006) Elsevier.

18 *Project Victoria: A Rebuilding Strategy for Electricity in Victoria*, Tasman Institute/Institute of Public Affairs, 1991.

19 Industry Commission, *Energy Generation and Distribution Report*, Report No. 11, 17 May 1991, available at: http://www.pc.gov.au/ic/inquiry/11energy.

concentration, the sale process earned $23 billion, far more than the $9-10 billion that had been widely expected. The Kennett Government also set up an independent regulator to set prices for the monopoly network businesses as well as maximum retail tariffs. The regulator gathered performance data that would prove invaluable in defusing claims that privatization had led to higher prices and lower reliability. The setting up of independent regulators was a step followed by all other states as they introduced their reforms.

The Victorian disaggregation and privatization took place as a result of financial pressures and pro-competition/privatization views that were especially prevalent in that state. In the case of other states, the reforms followed on a program of National Competition Policy, agreed to by the state and federal governments in 1996. The competition policy reforms called for natural monopolies to be opened to all users on terms that were fair and reasonable. Regulatory arrangements were put in place to determine where such access was required and, in the event of disputes, the prices at which access was to be made available.

In the late 1990s into 2000, South Australia disaggregated the ETSA Corporation and privatized its component businesses. However, the extent of disaggregation and commitment to competition was not as strong as in Victoria. The government also encouraged the development of a private unregulated interconnector from Victoria (Murraylink) instead of a regulated open access link from NSW.

In Queensland, the Electricity Commission was disaggregated in several steps. By the start of the NEM, the industry comprised two main distributor/retailers, a transmission business and four generation businesses, all in government ownership. In 2007, the retail businesses were separated from their distribution networks and one was sold. New generators were built but most generation capacity remains in government ownership. In 2010, the government re-aggregated its three generation businesses into two in response to falling wholesale prices.

The New South Wales Government's formerly integrated Electricity Commission has undergone several iterations of disaggregation. At NEM start, there were three major generation businesses (excluding the separate Snowy Hydro business, which remains co-owned with the Victorian and Federal Governments), a single transmission company and five distributor/retailers. The three smallest distributor/retailers were merged in 2001. In late 2010 and early 2011, the retail businesses and trading rights to several of the generators were sold under the 'Gentrader' model further described in section 4.4. However, the largest generator, the transmission network and all distribution networks presently remain in government ownership.

Tasmania entered the NEM in 2005, seven years after vertically separating the monopoly Hydro-Electric Corporation into a single generation business, transmission business and combined distribution/retail businesses. All components remain in government ownership at the time of writing, but the government has raised the prospect of a sale of the Aurora retail business. There is no plan to disaggregate or sell the Hydro Tasmania generation business or the networks.

Outside the NEM, the Western Australian Government disaggregated its State Energy Commission to form Western Power in 1996. Western Power was vertically disaggregated in 2006 to form Western Power Networks, Verve (generation) and Synergy (retailing), plus Horizon Energy, which operates outside the SWIS. At the time of writing, the government had proposed re-merging Verve and Synergy.

Table 1 sets out the current ownership status of key participants in the NEM by state.

Queensland							
Generators	**Ownership**	**Retailers**	**Ownership**	**Transmission**	**Ownership**	**Distribution**	**Ownership**
Stanwell	Queensland Government	AGL	Private	Powerlink	Queensland	Energex	Queensland Government
CS Energy	Queensland Government	Origin Energy	Private			Ergon Energy	Queensland Government
Origin	Private	Ergon Energy	Queensland				
InterGen	Private						
Arrow	Private						
Alinta	Private						
New South Wales							
Generators	**Ownership**	**Retailers**	**Ownership**	**Transmission**	**Ownership**	**Distribution**	**Ownership**
Macquarie Generation	NSW Government	AGL	Private	TransGrid	NSW Government	AusGrid	NSW Government
Origin Energy	Private	Origin Energy	Private			Endeavour Energy	NSW Government
TRUenergy	Private	TRUenergy	Private			Essential Energy	NSW Government
Delta Electricity	NSW Government						
Snowy Hydro	Split between the NSW, Victorian and Federal Governments						
Victoria							
Generators	**Ownership**	**Retailers**	**Ownership**	**Transmission**	**Ownership**	**Distribution**	**Ownership**
TRUenergy	Private	AGL	Private	SP AusNet	Private	Powercor	Private
GEAC	Private	Origin	Private			SP AusNet	Private
International Power	Private	TRUenergy	Private			United Energy	Private
Snowy Hydro	Split between the NSW, Victorian and Federal Governments	Momentum Energy	Tasmanian Government			CitiPower	Private
AGL	Private					Jemena	Private

South Australia							
Generators	**Ownership**	**Retailers**	**Ownership**	**Transmission**	**Ownership**	**Distribution**	**Ownership**
AGL	Private	AGL	Private	ElectraNet	Majority owned by Powerlink (Queensland Government)	ETSA Utilities	Private
International Power	Private	Origin	Private				
Alinta	Private	TRUenergy	Private				
Origin	Private	Aurora Energy	Tasmanian Government				
TRUenergy	Private	Momentum Energy	Tasmanian Government				
Infigen	Private						
Infratil	Private						
Tasmania							
Generators	**Ownership**	**Retailers**	**Ownership**	**Transmission**	**Ownership**	**Distribution**	**Ownership**
Hydro Tasmania	Tasmanian Government	Aurora Energy	Tasmanian Government	Transend	Tasmanian Government	Aurora Energy	Tasmanian Government
Aurora Energy (Tamar Valley)	Tasmanian Government						

Table 1: Key participants in the NEM and their ownership

3.1.2 Early productivity gains

The initial state-based reforms yielded substantial productivity gains. Electricity output grew due to better plant management while capital inputs remained flat and employment fell steeply as over-manning was reduced. As a result, output per worker increased from 2 GWh in 1989/90 to 5.5 GWh per employee in 1997/98. Generator productivity continued to increase across all Australian states in the period after 1997. By 2004, after which comparable employment figures are unavailable, all state generation systems were operating at 30-40 GWh per employee with productivity growth highest in the fully privatised systems of Victoria and South Australia[20].

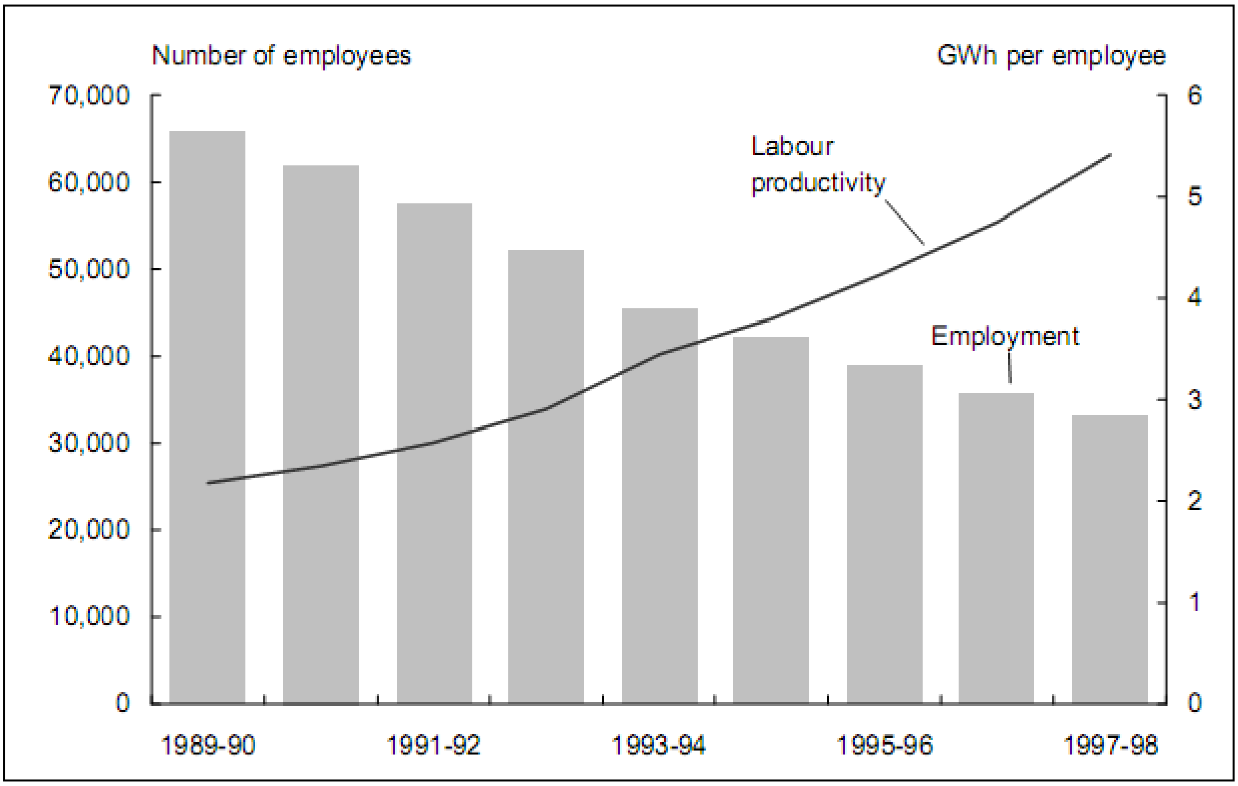


Figure 7 Electricity industry employment and labor productivity
Source: Treasury Economic Roundup Spring 1999, *Developments in Electricity*, Chart 4, p.57.

20 For more detail see Moran, A. and Skinner B., "Resource Adequacy and Efficient Infrastructure Investment", Chapter 11 in Sioshansi, F.P. (Ed), *Competitive Electricity Markets: Design, Implementation, Performance* (2008) Elsevier

Reflecting the lower wholesale prices, retail prices also broadly fell in real terms over this period, especially for commercial and industrial users.

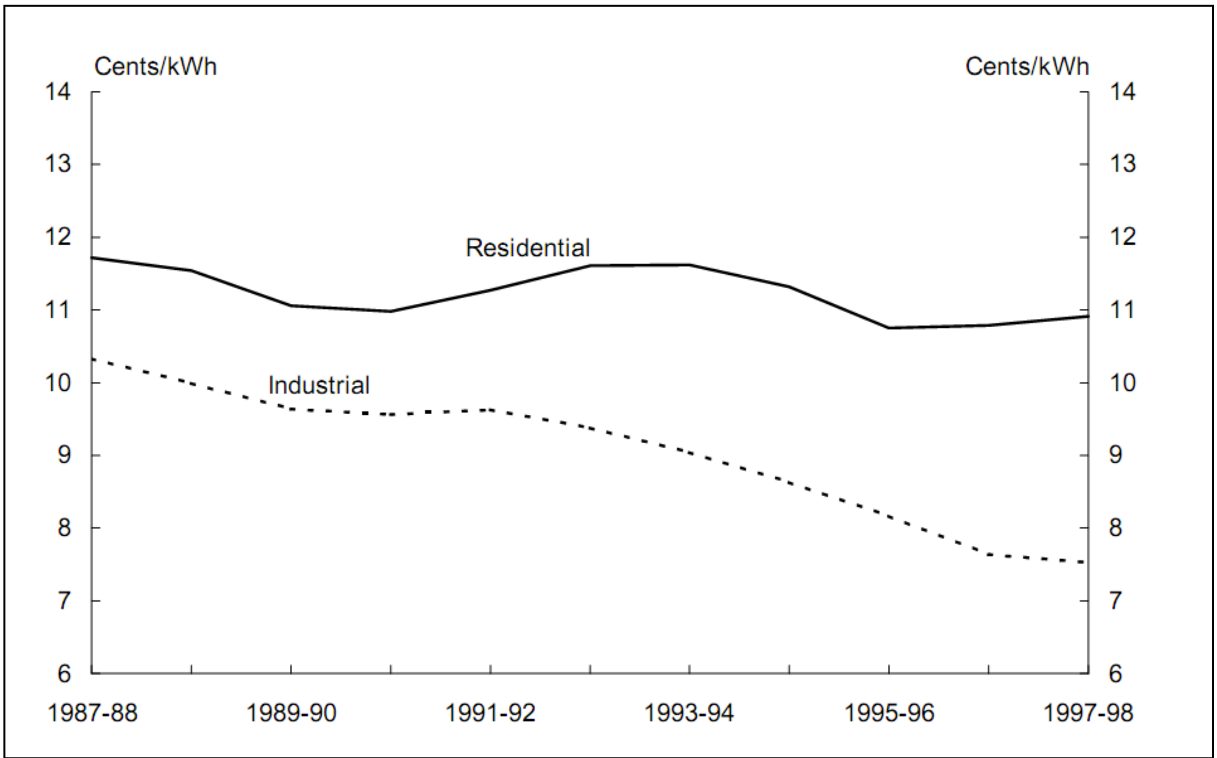


Figure 8 Australian electricity prices (real terms)
Source: Treasury Economic Roundup Spring 1999, *Developments in Electricity*, Chart 5, p.58.

3.1.3 Creation of spot markets

Alongside structural reform, the states were also involved in experimenting with the creation of their own spot markets. The Victorian system operator, VPX, began operating the VicPool in early 1995 and the NSW ELEX market commenced in 1996. Both markets were compulsory spot markets, based on the design of the England & Wales pool. VPX and the NSW system operator, TransGrid, jointly introduced systems to form the NEM1 market in March 1997. The NEM1 market allowed for managed inter-state trade of electricity, but VPX and TransGrid retained responsibility and control over power system security and reliability in their own states.

3.2 Creation of the national market

The NEM was devised jointly by the state and Commonwealth governments and implemented through co-operative mirror legislation known as the National Electricity Law (NEL). The NEL established the NEM and provided for the National Electricity Code (Code), which set out the arrangements for:

- Operation of the wholesale spot market and management of the interconnected power system; and
- Terms of access to the transmission and distribution networks across the NEM jurisdictions.

The NEL also established the NEM governing bodies, the National Electricity Market Management Company (NEMMCO) and the National Electricity Code Administrator (NECA). NEMMCO's role was to operate the market, manage the power system and approve new interconnectors. NECA's role was to administer changes to and enforce the Code. The national regulatory body, the Australian Competition and Consumer Commission (ACCC), was also required to 'authorize' the original Code and any Code changes because of the competitive implications of the provisions dealing with price-setting and terms of network access. The ACCC was also given the job of regulating transmission network revenues using a CPI-X building block methodology.

3.3 Subsequent institutional and regulatory reforms

The autonomous and overlapping style of decision-making practised by NECA and the ACCC led to pressures from a number of sources for an overhaul of their powers. In 2005, the NEM jurisdictions agreed to change the NEM institutional arrangements. The Ministerial Council on Energy (MCE) was set up to provide high-level policy direction to the market institutions. The Code was replaced by the National Electricity Rules (the Rules). NECA was dissolved and replaced by the Australian Energy Market Commission (AEMC), which was given responsibility for making changes to the Rules without ACCC approval and for conducting broader reviews requested by the MCE. At the same time, the Australian Energy Regulator (AER) was set up as a division within the ACCC to monitor and enforce compliance with the Rules as well as to perform the ACCC's transmission revenue regulatory functions. In 2008, the economic regulation of distribution networks was transferred from the jurisdictional regulators to the AER. However, the ACCC maintains its role in approving mergers and acquisitions in the energy industry and elsewhere. In 2011, the MCE was replaced by the Standing Council on Energy and Resources (SCER).

NEMMCO's functions as market and system operator for the NEM were largely untouched by the 2005 reforms. In 2009, a number of state planning bodies and gas market operators were combined with NEMMCO to form the Australian Energy Market Operator (AEMO). In addition to market and system operation across the NEM, AEMO is responsible for transmission network planning in Victoria. This differs from the arrangements in place in other states, where the primary transmission network owner and operator also has responsibility for network planning. In Victoria, planning functions have long been separated from network ownership and operation, which is left to other privately-owned parties.

Table 2 summarizes the current institutional roles in the NEM.

Despite the implementation of full retail contestability across the mainland NEM in the early 2000s, maximum retail tariffs for small customers remain the subject of jurisdictional regulation everywhere apart from Victoria. Non-pricing regulations apply throughout the NEM. Further discussion of retail reforms is contained in section 4.3.

Policy planning and regulatory institutions in the NEM	
Institution	**Role/Function**
Australian Energy Market Operator (AEMO)	Wholesale market operation and settlement Power system operation Transmission planning in Victoria (only)
Australian Energy Market Commission (AEMC)	Making changes to the National Electricity Rules Conducting reviews mandated by the SCER
Australian Energy Regulator (AER)	Enforcement of the National Electricity Rules Economic regulation of transmission and distribution networks
Standing Council on Energy and Resources (SCER)	Overall policy and reform direction

Table 2: NEM institutional responsibilities

4 Design and performance of the National Electricity Market

4.1 Wholesale market

4.1.1 Market design and operation

The NEM is an energy-only gross pool limited-nodal market with security-constrained dispatch. Generators and scheduled loads submit bids on a day-ahead basis in up to ten price bands. Participants can change their bids or 'rebid' up until real time. AEMO, as market and system operator, schedules plant in accordance with their position in the bid-based merit order to minimize the overall costs of dispatch. The final generator bid accepted by AEMO to meet demand sets the spot price. The spot market is cleared on a five minute ('dispatch interval') basis and the simple average of the six dispatch interval prices within a half-hour ('trading interval') is used to settle wholesale transactions.

The energy-only feature of the NEM means that there is no separate capacity market; generators must earn their entire revenues either through spot market transactions or through derivative contracts settled against spot market outcomes. Because of this, spot prices are permitted to reach very high levels – and often do reach such levels at times of peak demand and supply scarcity – to enable generators to earn prices in excess of their operating costs and hence recover a contribution towards their fixed costs. To minimize cash-flow risks, generators hedge most of their output with derivative contracts – further explained below.

The AEMC Reliability Panel is responsible for setting the market price cap at a level designed to encourage sufficient generation capacity to maintain the NEM reliability standard, which is that unserved energy does not exceed 0.002% of total energy in a year. The market price cap in the

NEM is now $12,900/MWh, having risen from $5,000/MWh at NEM start, although typical spot prices are only $30-60/MWh. This is well in excess of the offer caps applying or being contemplated in the energy-only Texas market (chapter 10). If the sum of wholesale prices over the last 336 half-hours (one week) exceeds the Cumulative Pricing Threshold (CPT) - $187,500 indexed from 2012 – an Administered Pricing Cap of $300/MWh applies. This threshold has rarely been reached, as noted in section 4.1.2. AEMO also has the ability to intervene in the market to procure reserves if this standard does not appear likely to be maintained up to nine months in advance. This Reliability and Emergency Reserve Trader function is scheduled to expire on 30 June 2013.

There are no provisions in the Rules or elsewhere preventing generators bidding some or all of their capacity up to the market price cap if they so choose. Spot prices are also permitted to fall to as low as -$1,000/MWh to facilitate generators running at minimum levels at low-load times (such as overnight) or when transmission constraints bind.

The gross pool nature of the NEM means that most sales and purchases of electricity by significant grid-connected participants must be settled at the relevant NEM spot price. Both generator and retailer market participants usually hedge the bulk of their spot market exposures with derivative contracts such as swaps and caps. Over-the-counter contracts have historically been the most common form of hedging tool. However, in recent years, the trading volume of exchange-traded contracts has increased dramatically. In both cases, swap strike prices traditionally incorporate a positive premium over expected spot prices due to the upward skew of spot price outcomes.

There is considerable dispute on question of whether it is necessary to have a market that rewards suppliers with capacity payments as well as for the energy they actually have scheduled[21].

Electricity retailers have to be able constantly to meet a variable demand at a final consumer price that is normally inflexible. The rationale for capacity payments is based on concerns that an energy-only market design might not be able to achieve this or that it would require very high maximum prices to ensure that supplies are continuously available (or to provide a sufficient incentive for demand to back-off where this is possible).

A capacity market seeks to ensure continuous availability by providing a direct reward for suppliers simply for being available to be scheduled. Its rationale is that this is achieved at a lower cost and with greater certainty than is the case in an energy-only market. Adib, Schubert, and Oren[22] express doubt about this taking place when they refer to the "bipolar nature" of capacity markets. They note that capacity prices tend towards zero where capacity is ample and infinity where it is short.

In general it might be argued that if additional payments are made for supplying energy for one set of reasons, compensating reductions will occur in real-time energy prices as firms jockey for revenues that cover their costs.

Other deficiencies of a capacity market include:

- It is a blunt instrument requiring, if it is to work well, bureaucratic judgments on the reliability and dispatchability value of particular types of plant

21 It was addressed in detail in *Resource Adequacy and Efficient Infrastructure Investment* Alan Moran and Ben Skinner Chapter 11 in *Competitive Electricity Markets,* Ed F P Sioshansi, Elsevier 2008

22 *Resource Adequacy, Alternate Perspectives and Divergent Paths* Chapter 9 in Competitive Electricity Markets, Ed F P Sioshansi, Elsevier, 2008

- Typically it has to be administered on a short forward period (sometimes day-ahead, rarely, as with the Western Australian capacity market, more than year ahead) while the requirement is to obtain assurances of capacity some time further into the future.

The Australian NEM has operated very satisfactorily with an energy-only market. This entails retailers constantly searching for lower cost supplies of energy and for a pattern of supply availability that meets their forecast demand. For their part, generators also look at the forward demand in its different time-of-day and seasonal patterns and in the context of the competitive environment they face. Generally this means the parties arrange for contracts of varying lengths – generators need these to offer assurances to their lenders, especially when looking to construct new capacity, while retailers need them to ensure their on-going capabilities to supply.

Another alternative is for a public agency to contract for additional supply where it considers existing supplies to be insufficient. To do so it must either:

- move into the market and contract supplies at a higher price than the supplier was able to get from actual customers; or
- build its own capacity.

If the government agency contracts additional supplies this will encourage firms or demand-side suppliers to hold back offering contracts to the market, hoping that the government will offer them a better price; such an outcome was reported by Joskow (2006)[23]: "In New England, the amount of generating capacity operating subject to special reliability contracts with the ISO has increased from about 500 Mw in 2002 to over 7000 Mw projected for 2005 (ISO-New England (2005), amounting to over 20% of peak demand." Such responses will undermine the commercial market as a whole.

If the reserve power agency were to hold its own capacity to be used only in special circumstances, e.g. when the price exceeds the spot market cap for an agreed period of time, this would simply create an added insurance cost. If the reserve capacity were to be used more liberally than this it would distort investment incentives bringing future supply shortages.

The NEM is a limited-nodal market in that all wholesale transactions are settled at one of five regional reference prices (RRPs), each within a geographically-defined region. Generators and retailers within each region receive and pay, respectively, the relevant RRP for that region adjusted by an annually-set static marginal loss factor based on their precise location within the region. The RRP in each region for a given trading interval is determined by the marginal cost of supply at a point in the region known as the regional reference node (RRN). The marginal cost of power at the RRN is determined on the basis of participants' bids and applicable transmission constraints. RRPs may vary from one another due to transmission constraints that affect flows between regions and dynamically adjusted marginal loss factors. Participants can hedge inter-regional exposures by acquiring inter-regional settlements residue (IRSR) units, which are offered through quarterly auctions run by AEMO. IRSR units are available for each flow direction between adjacent regions and are funded by the rentals accruing from inter-regional power transfers at times of RRP divergences.

23 Competitive Electricity Markets and Investment in New Generating Capacity, By Paul Joskow, 06-009 April 2006

http://dspace.mit.edu/bitstream/handle/1721.1/45055/2006-009.pdf?sequence=1

To the extent that transmission constraints limit flows within a region, they are taken into account in the dispatch process and may affect the RRP. However, such intra-regional constraints are not reflected in more localized settlement prices. This means that when constraints bind, a disjunction can arise – along the lines well documented in the Enron-inspired collapse of the Californian market – between the marginal value of power at a participant's location (the nodal shadow price) and the RRP upon which participants are settled. When this occurs, generators can have incentives to bid in a 'disorderly' manner. For example, generators in a load-rich part of a region, with a higher nodal shadow price than the RRP may have incentives to bid up to the market price cap to avoid being dispatched at a price they find inadequate. Conversely, generators in generation-rich parts of a region may have incentives to bid down to the market floor price in order to be dispatched at an attractively high RRP.

Originally, the NEM had five regions, largely based on state boundaries. This made sense because the historical state-based development of transmission networks meant that the primary points of transmission congestion emerged at state boundaries. NECA proposed expanding the number of regions in the early 2000s to reflect additional points of network congestion. However, state governments' concerns about intra-state price differences, generator market power, inadequate hedging instruments and the lack of clearly demonstrable benefits from more regions stopped NECA from proceeding. The number of regions increased to six when Tasmania joined in the NEM in 2005, but reverted to five in 2008 when the Snowy region was abolished and its area absorbed into the NSW and Victorian regions. The AEMC is presently reviewing the appropriateness of more localized pricing of energy as part of its Transmission Frameworks Review.

In addition to the spot market for energy, the NEM incorporates eight ancillary services markets for frequency control. As generators can trade-off their provision of frequency control against their provision of energy, AEMO's dispatch engine co-optimizes the provision and pricing of FCAS with outcomes in the energy market. Network control and system restart ancillary services are procured by AEMO through contracts with participants.

4.1.2 Pricing and investment outcomes

Spot prices in the NEM have generally remained under $100/MWh for most of the time in most regions (Figure 9).

Following market start, prices in South Australia and Queensland were higher than elsewhere due to relatively tight supply conditions and limited interconnection. This led to new generation investment in both states. Hot summer conditions in early 2001 led to higher prices across the NEM, particularly in South Australia and Victoria, stimulating investment in gas peaking plant in those states. Further interconnector investment was also developed over 2002/03, both between Victoria and South Australia and between Victoria and the Snowy region. These investments combined with milder summer conditions over the next few years led to fairly flat average wholesale prices from 2002 to early 2007.

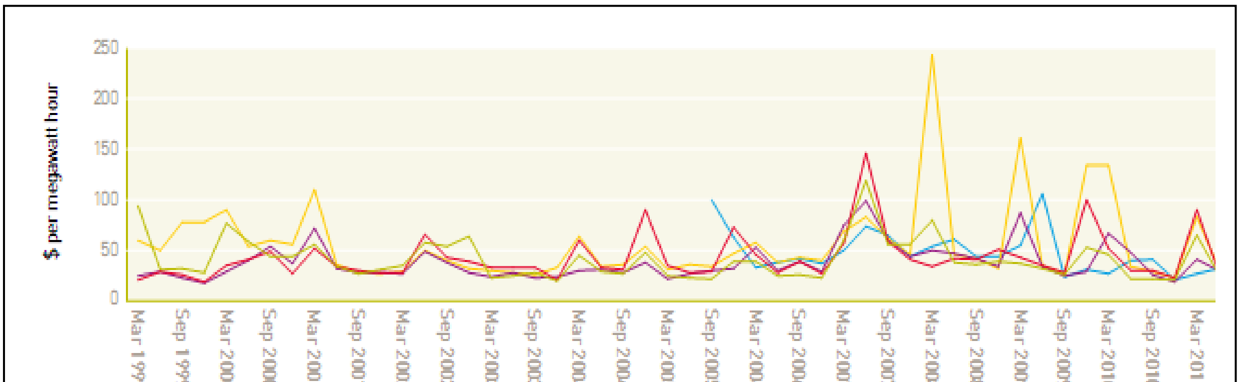


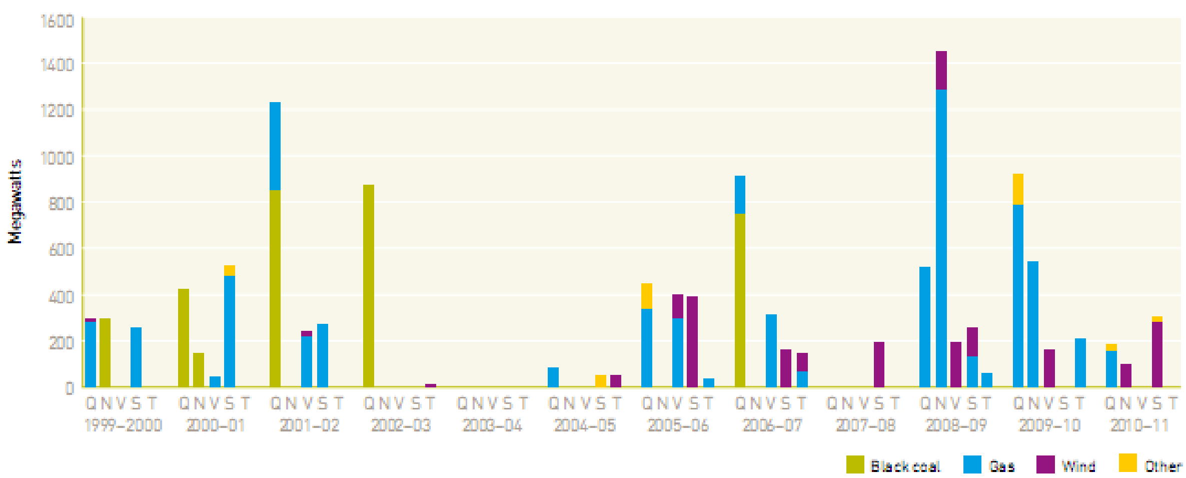
Figure 9 Quarterly spot prices since NEM start
Source: AER, *State of the Energy Market 2011*, Figure 1.7, p.35.

In 2007, an emerging drought over south-eastern Australia constrained the hydro-electric generation capacity in the Snowy, Victorian and Tasmanian regions. The drought also limited the availability of water for cooling in some coal-fired generators, especially in Queensland. These conditions were exacerbated in June 2007 by a number of generator and network outages and generator limitations.[24] As a result of all of these factors, spot prices rose considerably.

South Australian prices spiked in March 2008 due to a record heatwave combined with reduced interconnector capacity from Victoria. The AER also observed that the new owner of the 1,280 MW Torrens Island gas-fired power station, AGL, bid a significant proportion of its capacity near the market price cap. At the time, Torrens Island represented 39% of South Australian electricity capacity. The AER continued to highlight the role of AGL's bidding of Torrens Island when prices spiked again in 2009 and 2010.[25]

The high South Australian spot prices in March 2008 led to the first ever triggering of the CPT and the implementation of administered pricing. At that time, the CPT was $150,000, being 15 times the then prevailing value of the market price cap.

Following the 2003 to 2008 period during which relatively little generation was developed in the NEM, the period since 2008 has seen substantial amounts of new generation gradually became commissioned, particularly in NSW and Queensland. In the three years to June 2011, 4,700 MW of capacity was commissioned, with more than half in 2008/09 alone. Most of new capacity has been in gas-fired plant (Figure 10). The bulk of the remaining generation investment in recent years has been wind plant in Victoria and South Australia in response to the RET.



Q, Queensland; N, New South Wales; V, Victoria; S, South Australia; T, Tasmania.

Note: Data are gross investment estimates that do not account for decommissioned plant.

Figure 10 Annual investment in registered generation capacity
Source: AER, *State of the Energy Market 2011*, Figure 1.13, p.43.

More recently, wholesale prices have been more subdued. The summers of 2010/11 and 2011/12 were much milder than in previous years, leading to fewer price spikes (Figure 11). Another important factor in pushing prices down has been the rapid growth of non-scheduled renewable energy, particularly wind and domestic solar PV units in response to government policies further described in section 6.

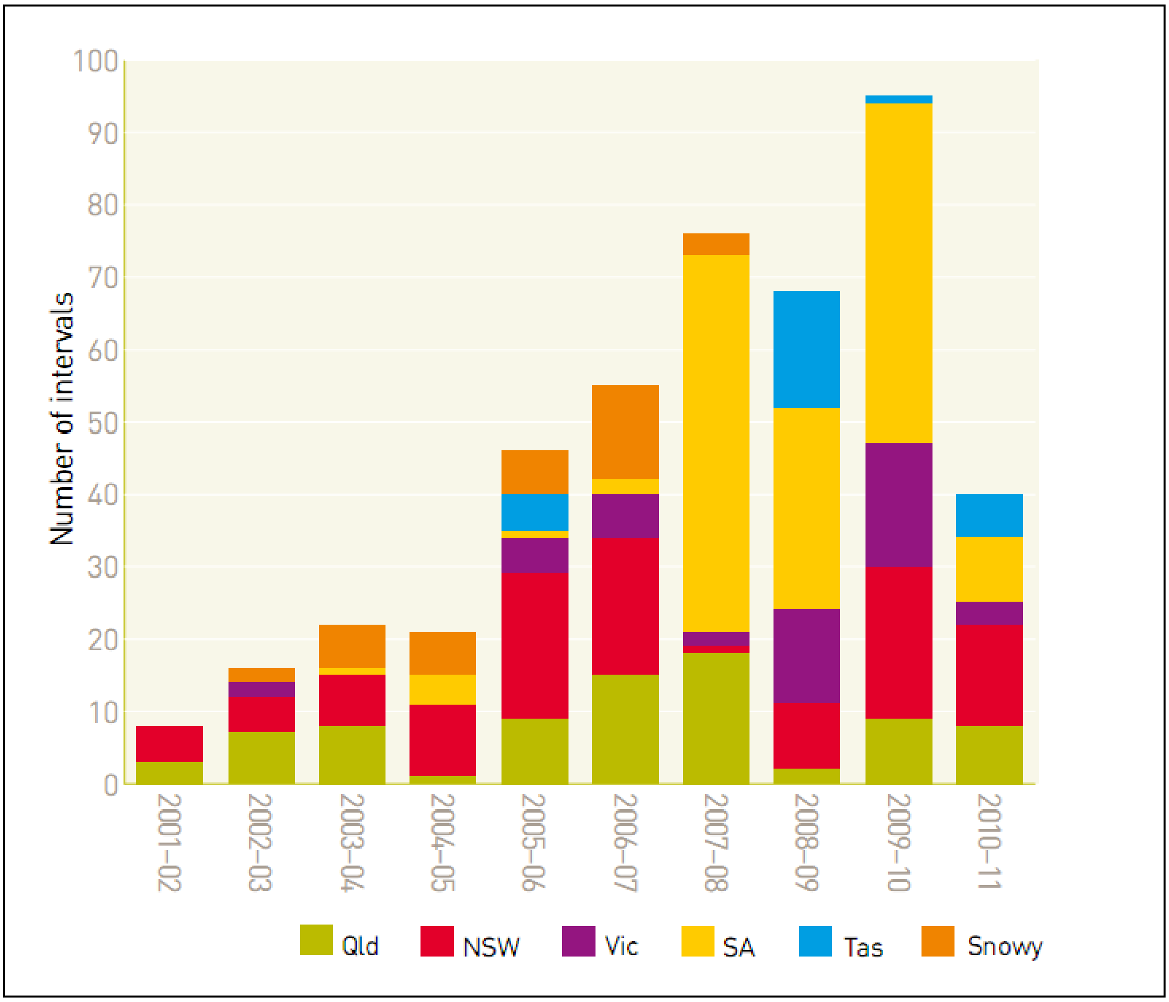


Figure 11 Number of half-hourly trading intervals above $5000/MWh
Source: AER, *State of the Energy Market 2011*, Figure 1.9, p.36.

The result of recent subdued prices is that generation businesses have been earning less than their total levelized costs. Analysis commissioned by the AEMC (Figure 12) shows that prices across the NEM have fallen below estimates of the long-run marginal cost of supply. While some participants have suggested that these outcomes demonstrate the need for capacity mechanisms to support the viability of existing operators, there is as yet little evidence of a generalized shortfall in supply.

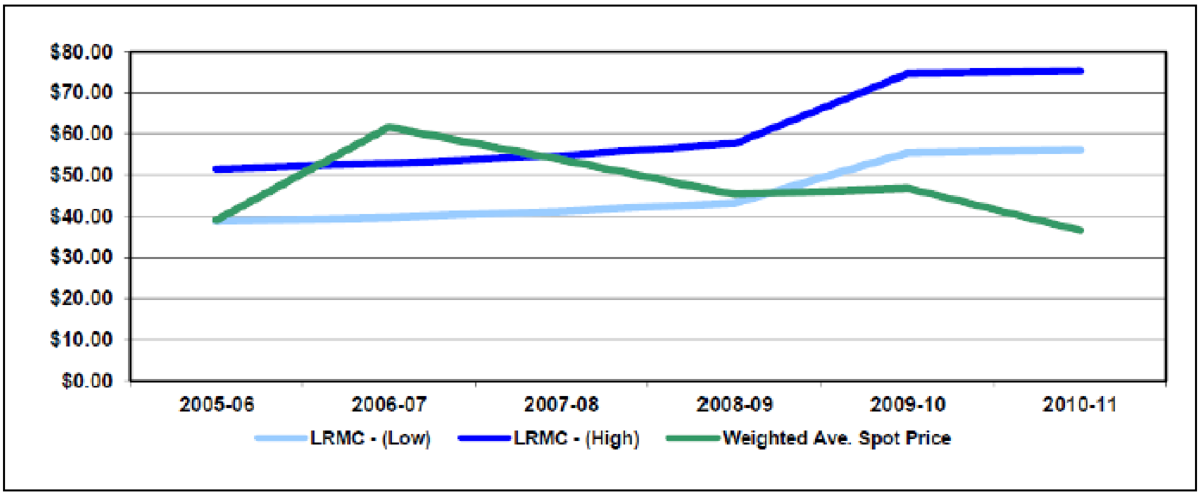


Figure 12 NEM weighted average prices compared with Long Run Marginal Cost
Source: AEMC, *Draft Rule Determination, Potential Generator Market Power in the NEM*, 7 June 2012, Figure 5.1, p.25.

Looking forward, exchange-traded futures prices provide some indication of the market's view of the direction for wholesale prices. In general, futures prices indicate that having risen due to the recent imposition of the carbon tax of $23/t CO2-e, spot prices will gradually fall over the next three years. This is likely a reflection of expected continuing weak demand growth and futures markets pricing in an increasing likelihood of the carbon pricing scheme being repealed should a change of federal government occur in late 2013 as described in section 6.1.

4.1.3 Market power concerns

The NEM design reflects perhaps the most *laissez-faire* attitude to generator bidding behavior of any electricity market in the world. As noted above, despite having a high price cap (essential in an energy-only market design), there is effectively nothing that prevents generators bidding their capacity at high prices as and when they choose. The absence of such constraints combined with the occurrence of occasional price spikes has led to an ongoing debate about the extent of generator market power in the NEM and whether the market design ought to be changed to prevent certain types of bidding behavior.

Under the Rules, the AER is required to publish a report whenever the spot price exceeds $5000/MWh in any region. The AER has often used these reports, as well as its annual *State of the Energy Market* report, to express concerns about the exercise of market power by generators. Typically, the AER focuses on some form of generator withholding behavior at times of high demand and/or curtailed supply, when transmission constraints limit imports into the region experiencing the high price.[26]

In accordance with its Rules enforcement role, the AER has previously launched investigations into bidding behavior by certain generators where that behavior is alleged to breach Rule obligations to bid in 'good faith'. Good faith in this context simply refers to a requirement for generators to submit bids that reflect their honest intention at the time those bids are made. A generator can only be found to breach this provision where it makes an initial bid in an attempt to

26 For example, see the AER's report into the events of 9 November 2011 in NSW, available at: http://www.aer.gov.au/node/11018.

mislead or deceive other parties and follows up with a rebid that exploits the situation created by its initial bid. Although the AER has found *prima facie* grounds for prosecuting a generator for violating the 'good faith' obligation, it has not yet brought a successful prosecution.

Other than the good faith rule and other provisions that similarly require generators to behave honestly, the Rules do not prevent generators from withholding or re-pricing their output at high prices as opportunities arise. In an attempt to address this perceived shortcoming in the market design, the Major Energy Users Inc (MEU) submitted a Rule change proposal seeking to limit the bids of 'dominant generators' in a similar manner to the pivotal generator mitigation measures in place in many north-eastern United States markets. The AEMC published a draft determination in June 2012 provisionally rejecting the change.

The historical lack of constraints on generator bidding behavior in the NEM reflects a preference for structural solutions and a degree of scepticism towards intrusive regulation by the responsible NEM institutions.

Importantly, as evidenced by Figure 12, the lack of constraints on generating bidding has not prevented average spot prices falling below the LRMC of supply in recent years, suggesting that market power has not been exercised in a sustained fashion.

Concerns about market power have also arisen in the context of the ACCC's mergers approval processes, further discussed in section 4.4.

4.2 Network pricing

4.2.1 Form of regulation

Under the original Code, the ACCC was obliged to adopt a CPI-X building block approach to setting revenues for transmission businesses. The ACCC was also obliged to accept the transmission networks' asset valuations prepared by each jurisdictional regulator when determining the appropriate return on capital and depreciation under the building block methodology.

However, the Code otherwise allowed the regulator considerable discretion in how it implemented economic regulation. Originally, the ACCC engaged in *ex post* reviews of transmission investments to determine whether all capital expenditure incurred was efficient and ought to be recoverable through regulated charges. In 2003, the ACCC moved away from *ex post* reviews in favor of a 'lock in and roll forward' approach, which shifted regulatory emphasis to the setting of appropriate expenditure forecasts. While this shift was broadly preferred by transmission companies, they and some jurisdictions were concerned that the ACCC faced so few obstacles to changing its approach to regulation. This was one of the drivers for the 2005 changes to the NEM institutional arrangements and the 'hardwiring' of the network regulatory regime in the Rules in 2006.

Under the Rules, both the methodology and the procedure for setting regulated network revenues are heavily prescribed. Businesses submit a revenue proposal document setting out their calculation of building block revenues for the next five-year control period. The AER, being now the regulator of both transmission and distribution networks, must accept the proposal unless it can demonstrate that a relevant parameter does not 'reasonably reflect' the service provider's efficient costs. This approach effectively reverses the onus for demonstrating that a particular parameter is reasonable from the network business to the AER.

The network regulatory approach in the Rules has arguably led to higher regulated revenues and prices than would have otherwise been the case (see below). In response, the AER has submitted a Rule change proposal that seeks to increase its ability to revise a network business's revenue proposal. As would be expected, the network businesses are staunchly defending the current balance of the regulatory regime. At the time of writing, the AEMC had published a draft determination on the AER Rule change, proposing changes to address concerns about over-investment and excessive regulated returns. The SCER is also considering changes to the scope of merits reviews of regulatory decisions to tilt the balance of regulatory outcomes towards consumers.

4.2.2 Network expenditure and pricing outcomes

Recent regulatory determinations have allowed substantial increases in regulated revenues for transmission and distribution network businesses across the NEM (Figure 13). A key issue for the AEMC in its considerations of the AER Rule change proposal is determining the extent that higher allowable expenditures are the result of necessary investment to meet rising peak demand and the extent to which they reflect inefficient 'gold-plating' by the businesses under the post-2006 regulatory regime.

The data reveal a significant divergence between the expenditures and allowed revenues of privately-owned network businesses (in Victoria and South Australia) and network businesses that remain under government ownership (in NSW and Queensland). Part of this may reflect the incentives on government-owned businesses to maximize revenues via expansion of their asset bases rather than establish savings and take the profits. Part may reflect the cost of satisfying increases in network planning standards that governments in NSW and Queensland have imposed on their businesses in light of high-profile outages. Even if the latter explanation is correct, it is unclear whether the imposition of higher planning standards has brought consumer benefits commensurate with their much higher costs. The AEMC is also currently reviewing distribution reliability standards in the NEM to address this question[27].

27 There is strong evidence that productivity in the privatised networks is considerably higher than in the government owned systems. See Mountain, B., Littlechild, S., *Comparing electricity distribution network revenues and costs in New South Wales, Great Britain and Victoria*. Energy Policy (2010), doi:10.1016/j.enpol.2010.05.027

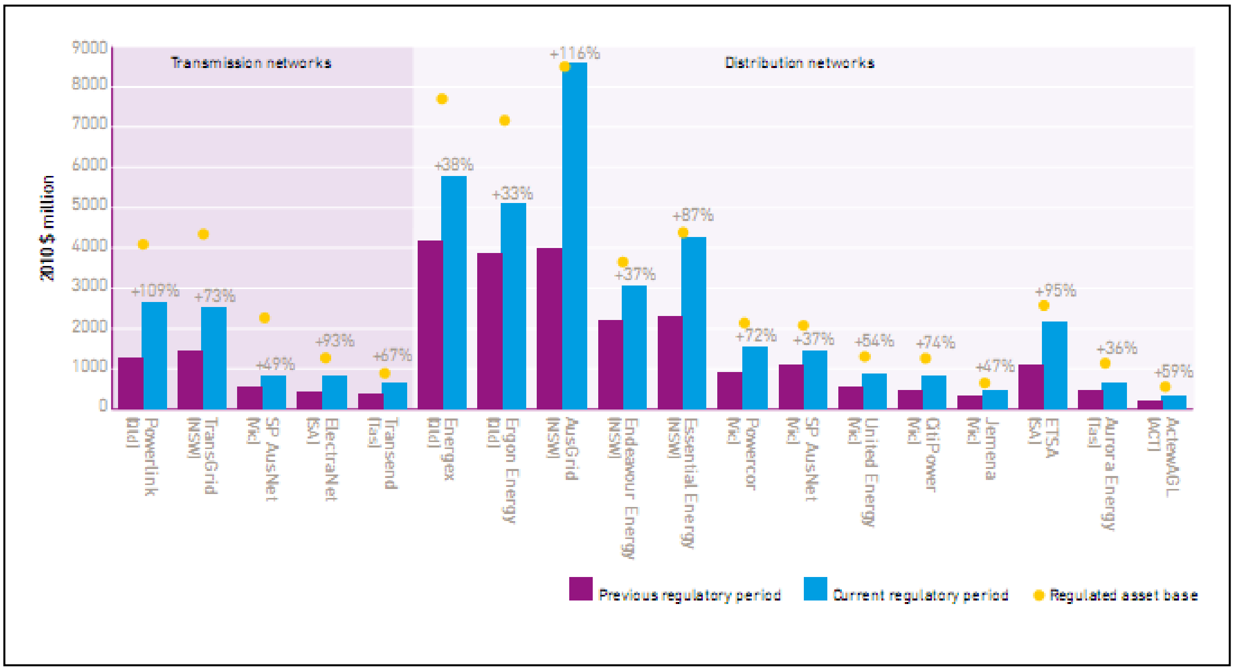


Figure 13 Electricity network investment
Source: AER, *State of the Energy Market 2011*, Figure 2.4, p.62.

4.3 Retail market

4.3.1 Retail price outcomes

As noted in section 3.1.2, Australian retail customers enjoyed falling or flat real tariffs in the 1990s, as the initial reforms promoted large productivity gains. Business customers benefited in particular, due the unwinding of decades-long cross-subsidies to households. However, as wholesale prices rose in the early 2000s, retail prices began to follow (Figure 14). Overall, between 1990/91 and 2005/06, real business tariffs fell by 23% whereas real household tariffs rose by 4%.[28]

Retail prices rose more dramatically from the middle of the last decade as network investment and regulated network charges ballooned. Household electricity bills are now dominated by distribution and transmission network charges (Table 3).

28 AER, *State of the Energy Market 2007*, Figure 6.15, p.191.

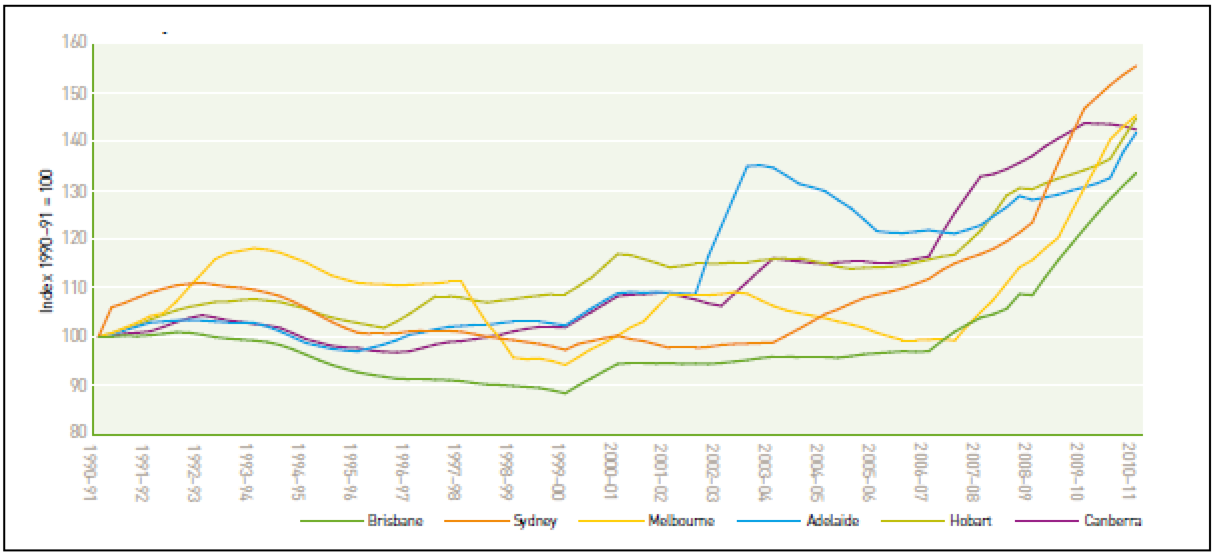


Figure 14 Retail electricity price indexes (inflation adjusted), Australian capital cities
Source: AER, *State of the Energy Market 2011*, Figure 4.5, p.116.

Retail bill proportions				
Wholesale energy costs	Network costs	Retail operating costs	Retail margin	Green costs (excluding carbon)
32-42%	46-51%	4-7%	4-5%	4-8%

Table 3: Retail bill proportions
Source: AER, *State of the Energy Market 2011*, Table 4.2, p.110.

4.3.2 Retail competition

Competition in the retail supply of electricity was gradually introduced in the late 1990s and early 2000s for progressively smaller customers. Contestability timetables varied by jurisdiction, with NSW and Victoria the first to introduce full retail competition ('FRC') in January 2002. By mid-2007, all customers in the mainland NEM were free to choose their electricity retailer. In Tasmania, small customers (those consuming less than 50 MWh per annum) remain non-contestable, with the state government recently announcing an administrative reduction in the rate of increase of regulated retail tariffs.

Victoria is the only state where maximum retail tariffs are not regulated. In this regard, only Victoria has a fully liberalized retail market along the lines of the Texas retail market further described in a companion chapter by Adib et al. All other NEM jurisdictions regulate the default tariffs offered by incumbent ('first tier') retailers to small customers. Regulated tariffs are generally based on the jurisdictional regulator's estimate of the long-run marginal cost of energy of serving small customers – based on their load shape – plus transmission and distribution network charges and other pass-through items.

The retail tariff-setting methodologies applied in most jurisdictions initially failed to provide sufficient 'headroom' to enable non-incumbent ('second tier') retailers to undercut regulated rates.

This curbed customers' incentives to switch retailer. Lack of headroom was primarily due to jurisdictional governments' concern that FRC would become associated with higher prices, coupled with their reluctance to rely on competition to discipline first tier retailers. This has gradually changed and regulated tariffs now allow reasonable scope for second tier retailers to offer attractive deals to customers, with discounts of 10-20% now available to direct debit customers. Customer churn rates have increased in recent years and now exceed 60% in every mainland NEM jurisdiction (Figure 15).

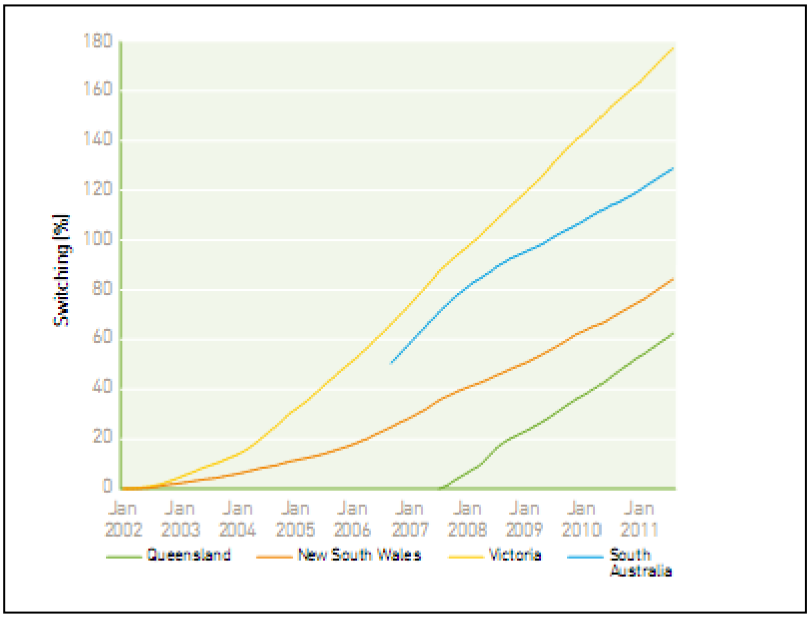


Figure 15 Cumulative customer switching rates
Source: AER, *State of the Energy Market 2011*, Figure 4.4, p.109.

Regulation of non-tariff conditions for retail supply has traditionally been left to individual jurisdictions. In July 2012 the National Energy Retail Law and Rules commenced under the auspices of the National Energy Customer Framework. This established a single regulatory framework for retail supply contracts, including customer protections, to reduce barriers and costs to retailers operating across multiple jurisdictions. However, most states have opted to defer transition to the NECF to maintain their exiting protections.

4.3.3 Tariff innovation

Although originally the poor cousin to wholesale market reform, retailing has received greater attention in recent years due to rising tariffs and growing interest in demand-side response.

Policy-makers are aware that a substantial share of new investment in distribution networks and peaking generation is undertaken to meet system peak demands for just a few hours per year. Yet most end-use consumers do not face the costs that their peak demand calls forward. This is due to the lack of time-sensitive pricing for most small customers, who tend to face flat tariffs based on deemed load profiles. The lack of time-sensitive pricing is largely attributable to the accumulation metering technology at most small customers' premises, which is not capable of recording when during a reading period electricity consumption occurs.

Originally, state governments considered that retail competition would drive the voluntary take-up of interval meters, which are capable of recording the timing of consumption and facilitating more cost-reflective tariffs. However, in the wake of consecutive hot summers and record peak demand in the early 2000s, the Victorian government decided to mandate a rollout of smart meters – interval meters capable of two-way communications including being remotely-read – to all customers. The rollout, which is due to be completed by 2014, has been plagued by substantial cost overruns and a cost-benefit analysis commissioned by the incoming state government in 2011 found that the rollout was not likely to be net beneficial.[29] Other states have observed developments in Victoria and appear unlikely to mandate their own rollouts, although individual businesses often install interval meters on a 'new and replacement' basis. The AEMC is undertaking a 'Power of Choice' review to help promote the installation of smart metering and dynamic tariffs.

Apart from funding the smart meter rollout in Victoria through distribution network charges, retail customers across the NEM are also bearing the cost of a variety of renewable subsidies and other green policies. These policies are discussed in more detail in section 6.

4.4 Structural developments

At the time of the initial structural reforms and later the authorization of the NEM Code, the market arrangements contained no specific long-term measures to prevent re-aggregation in the NEM. This was because there were no firm views as to the most productive structure of the industry, only that the previous state-owned integrated monopolies were not optimal. Regulatory oversight of structural changes was left to the ACCC, to assess in accordance with the general competition protections set out in the *Trade Practices Act*, now the *Competition and Consumer Act* (CCA). Section 50 of the CCA contains the key prohibition against mergers and acquisitions that are likely to lead to a 'substantial lessening of competition' in a relevant market. As discussed below, to date the ACCC has not successfully opposed any electricity merger in the NEM under section 50.

4.4.1 Current market shares

Following from the structural reforms and privatizations discussed in section 3.1, a wide range of investors have entered and exited the NEM. The high prices originally paid for the Victorian electricity generators could not be justified in light of subsequent low wholesale prices and several rounds of restructurings and sales followed. South Australian generators have also been transferred by their original acquirers. The NSW generation sector operates in a hybrid space, with trading rights to several plants held by private participants but the physical assets and the largest generation portfolio (Macquarie Generation) still within government hands at the time of writing. The majority of Queensland and Tasmanian generation assets also remain in state ownership. However, all major electricity retailers outside Tasmania are privately-owned.

Current market shares for each NEM jurisdiction are as set out in Figure 16 (generation) and Figure 17 (retail) below. Leaving aside assets still within government ownership, both figures show that three private firms now dominate generation and retailing activities in the mainland NEM – AGL, Origin and TRUenergy.

29 See Deloitte, *Advanced Metering Infrastructure Cost Benefits Analysis, Final Report*, 2 August 2011, available at the Department of Primary Industries website: http://www.dpi.vic.gov.au/smart-meters/publications/reports-and-consultations/advanced-metering-infrastructure-cost-benefit-analysis.

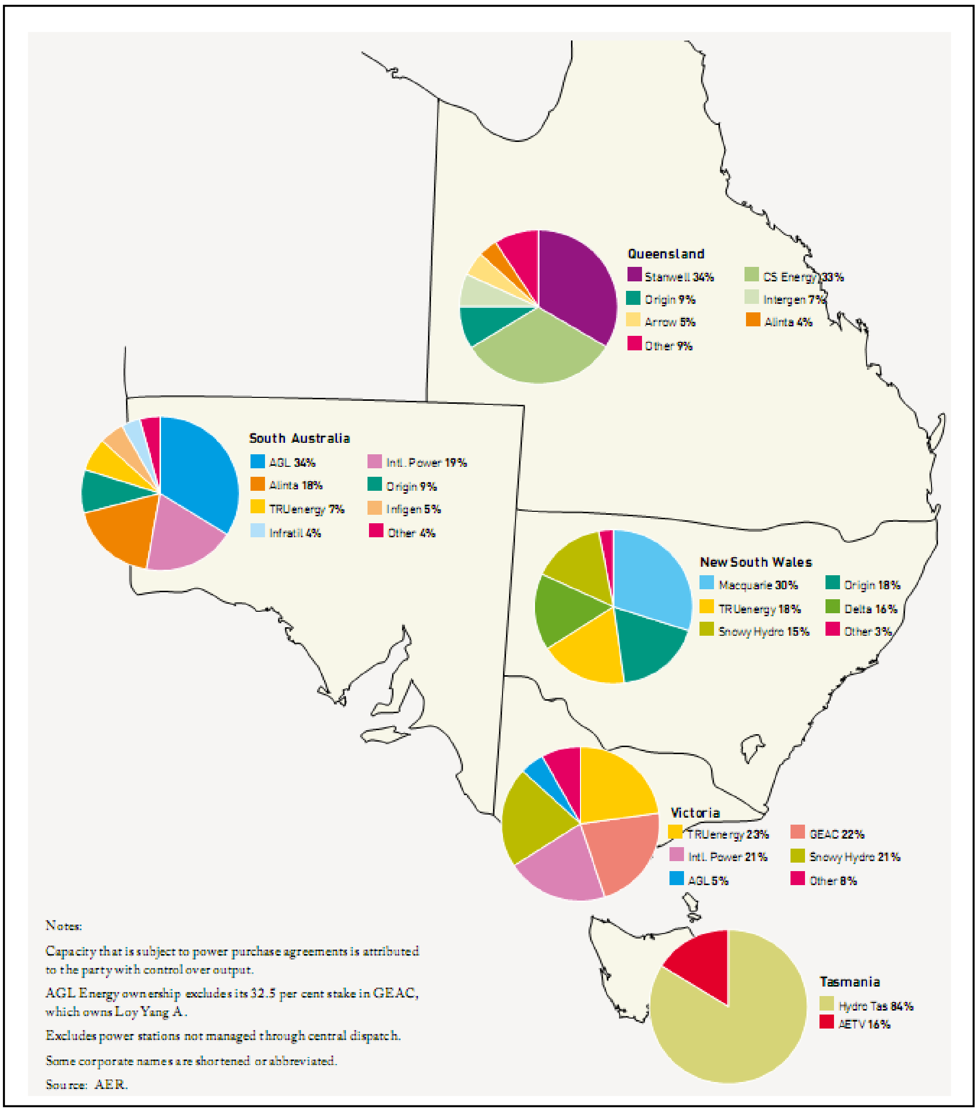


Figure 16 Market shares in electricity generation capacity by region
Source: AER, *State of the Energy Market 2011*, Figure 1.5, p.32.

Since NEM commencement, horizontal aggregation of distribution networks has occurred across NSW, Victoria and South Australia. One consortium now owns two Victorian distribution networks and the single South Australian distribution business, ETSA Utilities. The state-owned Queensland transmission network, Powerlink, is a part-owner of the South Australian transmission network, ElectraNet. All network businesses in Queensland, NSW and Tasmania remain within government ownership.

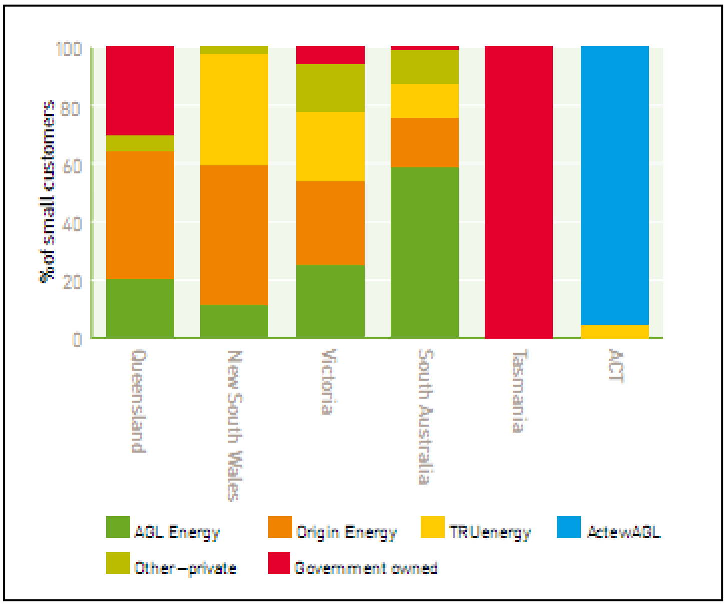


Figure 17 Market shares in electricity retailing to small customers by jurisdiction
Source: AER, *State of the Energy Market 2011*, Figure 4.1, p.103.

4.4.2 Retail-distribution separation

One key structural development since the original reforms has been the unbundling of retail and distribution activities. First tier retailers and distribution networks within a particular geographic area were originally sold as combined entities in Victoria and long operated as combined entities under state government ownership in NSW and Queensland. However, to promote retail entry and competition, the combined entities were 'ring-fenced' to prevent the distribution business favoring its retail affiliate, though the different nature of the businesses, most of which are now totally separate, probably made the statutory requirement unnecessary. Each distribution area has seen considerable second tier entry.

While ring-fencing undoubtedly promoted retail competition, it may have inhibited the rollout of smart meters and dynamic pricing due to the dispersal of the benefits from demand response across more parties. However, the more significant reasons for the lack of take-up of smart meters and dynamic pricing are more likely to have been:

- the high cost of the technology relative to the benefits (section 4.3); and
- the lack of appropriate tariff unbundling to enable retailers interested in offering smart meters to customers to avoid paying regulated network metering charges.

Over the last decade, corporate transactions and further privatizations have led to different owners of retail and distribution businesses throughout the mainland NEM.

This reflects two factors. The first factor is the very different characteristics and requirements of each type of business: Successful retailing is primarily about strong marketing capability, customer handling skills and efficient wholesale market risk management. By contrast, running a distribution business is much more concerned with the planning, procurement, maintenance and operation of physical network assets. The nature of regulation affecting each type of business is also substantially different. Retailers are subject to extensive customer protection regulations regarding marketing, billing, privacy and disconnection. Outside Victoria, a key regulatory issue is the setting of an appropriate level of wholesale energy purchase costs for regulated retail tariffs. Retailers are also the conduit through which the costs of green policies are passed-through to customers. All of this means that retailers need a good understanding of the wholesale market and all schemes and subsidies affecting end-use consumers. On the other hand, distribution networks are subject to periodic regulatory reviews of revenues and prices. These reviews are long and extremely complex processes, typically stretching for over one year, with enormous implications for the financial returns of the business. Distributors are also subject to reliability, safety and other technical standards. For these reasons, ownership of distribution networks typically appeals to investors seeking a relatively steady and secure return, whereas retailing inevitably involves managing wholesale spot market risks.

The second issue is that some state governments have been more reluctant to privatize distribution businesses than retail businesses. Distribution businesses own visible physical assets and employ large numbers of unionized workers. By contrast, retail businesses have few physical assets and provide less visible 'back office' services such as billing.

4.4.3 Vertical integration

A more contentious structural development over the last decade has been vertical integration between retail and generation activities. When the NEM commenced, it was expected that retailers and generators would manage their complementary wholesale risk exposures by entering derivative contracts with one another. However, investors have preferred acquiring physical hedges rather than financial hedges.[30] As noted above, the largest three private energy businesses in the NEM (AGL, Origin and TRUenergy) are all considerably vertically integrated in their retailing and generation assets.

While reduced transactions costs from contracting represents a legitimate rationale for vertical integration, the ACCC has been wary of vertical integration on competition grounds. In 2003 it opposed energy retailer AGL's acquisition of a minority share in the Loy Yang A power station in Victoria. The ACCC was concerned that the transaction would lead to a 'thinning' of the wholesale contract market, which would have the following two detrimental effects:

- encourage generators to withhold output to spike the spot price; and
- make it harder for standalone retailers to obtain hedges, thereby increasing barriers to standalone new entry.

The matter became the subject of litigation and the Federal Court found comprehensively in AGL's favor, noting that:

30 For a discussion of some of the advantages of vertical integration, see Simshauser, P, "Vertical integration, credit ratings and retail price settings in energy-only markets: navigating the Resource Adequacy problem", available at: http://www98.griffith.edu.au/dspace/bitstream/handle/10072/34985/65004_1.pdf?sequence=1.

- A generator's occasional ability to spike to the spot price under particular favorable conditions was not evidence of market power as defined under the precursor to the CCA;
- Barriers to entry in retail and generation were relatively low; and
- Residual demand analysis was not a suitable tool for analysing how real-world generators compete in a market such as the NEM.

A number of other moves towards vertical integration followed the AGL decision. In 2004, Singapore Power, the owner of the Victorian transmission network, sought to acquire TXU's Australian energy assets. These assets included merchant retail and generation interests. The ACCC was concerned about Singapore Power's transmission business favoring its affiliated generators and imposed a number of enforceable undertakings as a condition of its approval for the transaction. These undertakings included an obligation on Singapore Power to divest the former TXU generation assets within 2 years. Those assets were subsequently sold to China Light & Power in 2005, forming the TRUenergy business.

Perhaps the most controversial private transaction since the NEM commenced was the so-called 'asset swap' between AGL and TRUenergy in 2007. This involved TRUenergy selling the 1,280 MW mid-merit Torrens Island power station to AGL in exchange for cash plus AGL's 200 MW Hallett peaking plant. Both plant are located in South Australia. As AGL was and remains the largest retailer in South Australia, the transaction resulted in both AGL and TRUenergy having more vertically balanced portfolios. The ACCC was concerned by the potential for AGL to exploit the market power of the Torrens Island plant, which is the largest generator in South Australia. However, the ACCC were unable to show that AGL would have stronger incentives than TRUenergy to engage in strategic bidding at Torrens Island. Accordingly, the ACCC did not oppose the transaction. Subsequently, a series of hot summers and opportunistic bidding by AGL led to very high prices in South Australia in 2008 and 2009. This resulted in a flurry of investigations by the ACCC to check whether AGL misrepresented its position at the time of the transaction, but ultimately no action was taken against AGL.

By and large, early concerns that retailer and generator amalgamations would lead to monopoly power and market inefficiencies have abated as a result of evidence that competition is bringing lower prices and retail churn. Like other firms that assemble supplies sourced from affiliated and non-affiliated businesses, electricity retailers are forced by market circumstances to ensure that the affiliates are not favored. The risk of high price occurrences are too great for electricity retailers to gamble on fulfilling most of their needs in-house and the costs of alienating potential counterparties by discriminatory behavior far outweigh any short term benefits possible through collusion with in-house suppliers. Indeed, when AGL acquired the entire Loy Yang A power station in 2012, the ACCC focussed only on the horizontal aggregation aspects of the acquisition and cleared the transaction. As such, vertical integration has given way as a regulatory concern in favor of more general concerns about generator market power (section 4.1.3).

4.4.4 NSW Gentrader model

In 2009, after having failed on several occasions to gain the support of trade unions and its political opponents for privatization, the NSW Labor Government embarked on a sale of the trading rights to the state's generation assets. The 'Gentrader model' involved separating the physical power station assets from the rights and obligations associated with the energy trading activity. The former were retained in public ownership, while the latter were sold along with the three incumbent NSW retail businesses through a combinatorial auction process. Similar approaches have been used in Alberta, France and many other European and North American jurisdictions.[31]

The sales process led to Origin Energy acquiring the Eraring power station and TRUenergy acquiring the Mt Piper and Wallerawang power stations. Several generators, including the largest in the state, Macquarie Generation, did not achieve their reserve prices and remained in government ownership. These transactions went ahead following the ACCC's approval, which was somewhat controversial given the horizontal aggregation occurring at the retail level. However, the ACCC's approach was consistent with the reasoning embraced in the Federal Court's original 2003 AGL decision.

Total sales proceeds for the Gentrader rights were just shy of $1.5 billion. While clearly a second-best outcome from a reform perspective, the Gentrader model did not preclude the sale of the remainder of generation or network assets in NSW. In May 2012, the government passed legislation to sell the generation assets. These are expected to fetch another $3 billion, resulting in proceeds of $4.5 billion for the NSW generation system. If achieved, this would be a fraction of the $9 billion achieved for the much smaller Victorian system more than a decade earlier.

5 Unfinished and unresolved areas of reform

While the Australian electricity supply industry has undergone substantial pro-competitive reform over the last two decades, reforms remain incomplete in key areas and certain aspects of market design remain unsettled. These outstanding areas are:

- Ongoing government ownership of electricity assets
- Incomplete retail tariff liberalization
- Uncertainty over transmission pricing and access
- Greenhouse gas mitigation policies

Section 6 is devoted to a discussion of greenhouse gas mitigation policies. The other outstanding areas are addressed below.

5.1 Government ownership

As noted above, many or all generation and network assets in NSW, Queensland, Tasmania and Western Australia remain within government ownership. Apart from the sale of remaining NSW generation assets, no other generation or network assets appear likely candidates for privatization

31 See New South Wales Government, *New South Wales Energy Reform Strategy, Defining an Industry Framework*, March 2009, pp.12-14, available at: http://www.nsw.gov.au/sites/default/files/NSW-Energy-Reform-Strategy.pdf.

in the near term. In particular, the new Queensland and NSW state governments have ruled out privatizing their distribution assets in their respective first terms of office.

Government ownership has been shown to have a multitude of drawbacks

- First, over-staffing and rigid work practices are harder to address than under private ownership, slowing efficiency gains;
- Second, government shareholders tend not to exercise as tight a level of corporate governance as private investors, which can result in wasteful gold-plating and empire-building by the managers of government-owned businesses;
- Third, a government presence in generation deters private investment, as investors face the risk that governments will order their businesses to undertake uneconomic investment to 'keep the lights on'; and
- Fourth, government ownership keeps taxpayers exposed to the risks of owning electricity assets, such as the introduction of carbon pricing and higher fuel costs – both of which were likely responsible for cutting billions of dollars from the sales value of the NSW generation assets.

Many of these issues are evident from a comparison of NSW and Victorian energy businesses, especially distribution network businesses described in section 4.2.2.

These drawbacks combined with state governments' fiscal constraints may eventually bring about further privatization later this decade.

5.2 Retail tariff liberalisation

Outside Victoria, default retail tariffs for small customers are regulated throughout Australia. While regulatory approaches to setting regulated tariffs have become more generous in some states in recent years – encouraging competition – the reverse has occurred in other jurisdictions. For example, the Queensland Government recently announced that default residential tariffs , which cover around half of household customers, the others having accepted a lower cost option, would be frozen for 12 months except for the effect of the carbon price. The Tasmanian Government also announced a reduction in the rate of increase of residential tariffs prior to the introduction of FRC in 2014. Residential and business tariffs in Western Australia did not change for over a decade and have only recently started to approach the real costs of supply.

Avoid parenthesis such as above as a matter of style

For so long as governments regulate retail tariffs, retail competition and innovation is likely to be handicapped. Retailers will remain exposed to risks that governments intervene to reduce default tariffs for political ends, squeezing retailers' margins. An unsupportive environment for innovation and investment by private retailers perpetuates the need for regulation. The result can be an unhealthy cycle of tighter price regulation, less competition and innovation, followed by even tighter regulation.

5.3 Transmission pricing and access

The pricing of transmission access and network congestion have been controversial since the start of the NEM. Presently, loads pay transmission charges that are partly postage-stamped and partly location-specific based on load-flow modeling. Generators only pay 'shallow' connection charges and seldom contribute to the costs of upstream augmentation, which are borne by consumers.

Network congestion is reflected in wholesale price divergences between regions, but prices within regions are kept uniform (subject to the application of static marginal loss factors). The result is that the cost implications of generation and load locational decisions within a region are under-signaled relative to the theoretical ideal.

To date, the jurisdictions and the AEMC have been reluctant to shift transmission costs to generators or to increase the locational granularity of wholesale pricing. The argument against making generators pay higher transmission charges is that generators in the NEM do not 'cause' transmission investment – transmission investment is undertaken by regulated entities when justified through cost-benefit or cost-effectiveness analysis. This means that the test for transmission investment itself sends a signal to generators to locate close to loads and existing network infrastructure. The case against more granular pricing of congestion is partly driven by the need to devise suitable financial risk management instruments and partly driven by political concerns about intra-state wholesale price differentials. The AEMC is currently re-examining these issues in its Transmission Frameworks Review. Whatever this review finds, transmission pricing and access will likely remain unsettled for some time.

6 Greenhouse gas mitigation policies

Greenhouse gas mitigation policies can be neatly split between carbon pricing on the one hand and policies to promote renewable energy on the other. This section discusses both types of policy in turn. You might make the observation that Australia is not alone in this respect as reflected in a number of chapters in this volumed.

6.1 Carbon pricing

The Gillard Labor Government introduced a carbon pricing mechanism on 1 July 2012 as a means of fulfilling a commitment to reduce greenhouse gas emissions by 5% of 2000 levels by 2020.[32] The mechanism commenced with a fixed price of \$23/t CO_2-e imposed on electricity generators and other large emitters. The price is scheduled to rise by 2.5% per annum (real) over the following two years and convert to an emissions trading scheme (ETS) with international linkage on 1 July 2015. The ceiling price for permits under the ETS will be \$20/t CO_2-e above the expected international price.[33] A floor price was originally set at \$15/t CO_2-e in real terms, but abandoned in August 2012, less than two months after the scheme commenced.[34] Given the scope for international trading under the ETS and the current state of the European ETS, Australian permit prices could drop well below \$15//t CO_2-e in 2015. By comparison, a (credible and sustained) permit price of at least \$30/t CO_2-e would be needed to switch investment in new plant from coal to gas, and about \$50/t CO_2-e would be required before existing coal-fired plant began to be significantly displaced by new entrant gas. A carbon price of at least \$80/t CO_2-e would be needed to make renewables cheaper than gas-fired plant.

32 See the website of the Department of Climate Change and Energy Efficiency at: http://www.climatechange.gov.au/government/reduce/national-targets.aspx.

33 See "Securing a clean energy future, The Australian Government's Climate Change Plan" (2011), p.27, available at: http://www.cleanenergyfuture.gov.au/wp-content/uploads/2011/07/Consolidated-Final.pdf.

34 See the website of the Department of Climate Change and Energy Efficiency at: http://www.climatechange.gov.au/government/submissions/closed-consultations/price-floor-carbon-pricing.aspx.

Since its introduction, the carbon price has been close to fully passed-through to wholesale electricity prices. That is, wholesale prices have been (to date) about $23/MWh higher in 2012/13 than they would otherwise have been. Given the current low wholesale prices, this represents an increase of over 50%. Meanwhile, regulated retail prices have risen by 8-10% more than otherwise, with further increases expected. Over time, increases in the carbon price – to the extent they arise – are likely to be less than fully passed-through to wholesale prices due to falling carbon intensity of the marginal plant in the market.

To help offset the costs of the 'carbon tax' (as it is popularly known), the government provided compensation to lower- and middle-income households, energy-intensive trade-exposed industries and private generators. Consequently, the burden of the carbon tax is principally being incurred by higher-income households, less trade-exposed industries and government-owned generators.

Prior to implementation, the Federal Treasury undertook computable general equilibrium modeling of the carbon price and compensation package. Based on extremely optimistic assumptions about the extent of international action to curb emissions, the analysis found that mining, construction and electricity supply would be the hardest-hit sectors and real wages across the economy would be 1.1% lower than otherwise by 2020. Modeling based on more realistic assumptions regarding the extent of international action would likely yield impacts many negative times those tabled by Treasury.

The introduction of carbon pricing in Australia has been highly controversial and the federal opposition has promised to repeal the carbon tax should it win office at the next election. The opposition's present policy for meeting the bipartisan emissions reduction target is called 'Direct Action', and involves government-run and funded tenders for reduced emissions.

6.2 Renewable generation subsidies

Like many other countries, Australia has a slew of policies favoring the development of renewable generation, most of which have been modified over the years as investors have taken advantage of the generous subsidies on offer. The most significant scheme was originally the Mandatory Renewable Energy Target (MRET), which was designed to promote the development of 9,500 GWh of new renewable generation.

In 2009, the Federal Government legislated the Expanded Renewable Energy Target (RET), which was designed to ensure that 20 per cent of Australia's electricity supply will come from renewable sources by 2020 (about 45,000 GWh). The RET obliged 'liable entities' (mainly retailers) to acquire a certain volume of Renewable Energy Certificates (RECs) based on the size of their energy purchases. RECs could be produced by renewable forms of generation. However, the mass installation of domestic solar PV units induced by state schemes led to a collapse in the REC price, discouraging investment in wind and other larger-scale renewable plant. This led the government to replace the RET with a dual set of policies: the Large Scale Renewable Energy Target (LRET) and the Small Scale Renewable Energy Scheme (SRES).[35]

The LRET, which covers large-scale renewable energy projects like wind farms, commercial solar and geothermal, will deliver the majority of the 2020 target. The SRES provides households, small business and community groups $40 for each REC created by small-scale technologies like solar

[35] See the website of the Department of Climate Change and Energy Efficiency at: http://www.climatechange.gov.au/government/initiatives/renewable-target.aspx

panels and solar water heaters. In light of concerns about rising electricity tariffs and falling demand, some participants are now calling for the winding back of these policies.

In addition to the Federal Government's LRET and SRES, each state also has a feed-in tariff (FiT) for energy produced by domestic solar PV units. FiTs were initially extremely generous, causing a 100-fold increase in the installed capacity of domestic solar PV from 10MW in 2007 to more than 1000MW in 2011. The most generous was the NSW FiT, which was originally set at 60c/kWh of energy produced by the unit, including energy consumed by the resident owner. This was reduced to 20c/kWh in late 2010, and further reduced in June 2012 to a range of 8-13c/kWh on net exported energy only.[36] In other states, FiTs were not quite as generous to begin with, but all had reduced rates or tightened eligibility by mid 2012.

Table 4 sets out the key renewable energy policies in Australia.

Key Renewables Policies		
Policy	**State/Federal**	**Objective**
LRET	Federal	Promote large-scale renewable projects (eg wind)
SRES	Federal	Promote small-scale renewable project (eg solar PV, solar hot water)
Solar Feed-in tariffs	State	Promote domestic PV units

Table 4: Key renewable energy policies

Numerous other renewable subsidies are in place or are being set up. For example, the Federal Government is setting up the Clean Energy Finance Corporation to invest up to $10 billion in renewable energy ventures. While the CEFC is meant to be 'commercially orientated', it is likely to become a vehicle of industry policy and as such will probably fail to achieve its modest 4% nominal return target. The Federal Government also has a Solar Flagships Program to support the construction and demonstration of large-scale, grid connected solar power stations. The Victorian Government has previously suggested increasing Victoria's electricity supply from large scale solar power to approximately 5% by 2020 (approximately 2500 GWh) with an interim target for 2014 of 500 GWh. To support this growth, the government is planning a special FiT to promote investment in new large scale solar generation facilities in Victoria.

All of these policies represent extremely expensive means of curbing greenhouse gas emissions. In general, the narrower a scheme in terms of complying technologies, the higher the cost of abatement in $/t CO2-e. For example, the LRET provides the cheapest abatement of the existing policies at about $90/t CO2-e, whereas the cost of abatement under the SRES is about $300/t CO2-e. The abatement cost under most FiTs is over $350/t CO2-e.

Further, the costs of renewable energy plant are not limited to the high cost of energy or greenhouse gas abatement from such plant. Large-scale renewable plant are often developed far

36 See IPART, *Media Release, A Fair and Reasonable Solar Feed-In Tariff for NSW*, Wednesday 27 June 2012, available at: http://www.ipart.nsw.gov.au/Home/Industries/Electricity/Reviews/Retail_Pricing/Solar_feed-in_tariffs_-_2012-2013.

from the existing transmission network, requiring lengthy and expensive network extensions to enable them to inject power into the grid. Another hidden cost of renewable plant arises from their intermittent supply of energy. The average capacity factor of wind plant in the NEM is about 30%, but it may be less than 10% at peak demand times. This means that provision of a firm 100 MW of capacity requires 90 MW of flexible thermal plant such as OCGT for every 100 MW of wind plant. The growing penetration of wind, especially in Western Australia and South Australia, is also creating problems for system operators. In Western Australia, the issue is the unscheduled nature of wind generation, which is leading to coal-fired plant being shut down overnight when demand is low. This is inefficient and may lead to reliability problems the following day when supply is needed quickly. In South Australia, the issue is more about maintaining voltage control in a region with a large and growing stock of wind plant.

Perhaps the best that can be said about Australian policies subsidising renewable energy is that they are less generous than in many other western countries. This has limited the magnitude of the still-substantial costs of these subsidies that are being borne by consumers.

7. Conclusion

The Australian electricity industry has undergone substantial reforms over the last two decades aimed at increasing productive efficiency, consumer choice and decentralized investment decision-making. While different states have moved at different rates, the reforms have for the most part been highly successful. The NEM now represents a not-quite-textbook example of an energy-only gross pool market in operation. In particular, the NEM has shown that if the market price cap is set appropriately and bidding rules are not prescriptive, market forces can provide the right type, quantity and location of new generation in a timely manner. Nevertheless, the true test of the market's robustness and the full benefits of reform will only come when the remaining steps of full privatization and retail tariff liberalization are completed.

The two most unsatisfactory elements of the NEM lie outside the wholesale market design. These elements are the regime for the economic regulation of networks and the impacts of governments' climate change policies.

Economic regulation of networks is often a thorny issue, and regulatory regimes commonly oscillate between emphasising cost efficiency and the provision of adequate reliability. The NEM arrangements now appear to be moving back towards cost efficiency.

Climate change policies, in view of Australia's generous endowment of fossil fuels, represent considerable additional costs to power supplies.

Regulatory and tax matters have led to a major increase in electricity prices since 2007. Network price increases have been considerable caused in part by political insistence on very high reliability standards, and possibly also in part by some catch-up of previous under remuneration of networks and some gold plating, especially in the government owned networks in New South Wales and Queensland. In addition, carbon related policies have had a progressively greater impact.

The combined effects are illustrated for a typical household electricity bill in Table 5

Component of Increased Cost	Increased Cost in Nominal $	Per cent of the increase
Energy	$140	12
Carbon and other green schemes	$248	22
Retail margin	$94	8
Network	$654	58
Total	$1130	100

Source IPART

Table 5 Increased Costs in New South Wales 2007/8-2012/13

The carbon and other green schemes account for 22 per cent of the increase according to these estimates, though the proportion may be slightly understated since a portion of the increased energy costs and the increased retail margin would be indirectly caused by these measures.