SOUTH AUSTRALIAN SUPPLY AND DEMAND OUTLOOK

2010

AUSTRALIAN ENERGY MARKET OPERATOR

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Acknowledgment

AEMO acknowledges the support, co-operation and contribution of all participants in providing the data and information used in this SASDO.

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Abbreviations

The following abbreviations are used throughout this report:

AC	Alternating Current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator Limited
AER	Australian Energy Regulator
APR	Annual Planning Report
AWEFS	Australian Wind Energy Forecasting System
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CO_2e	Carbon Dioxide Equivalent
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DC	Direct Current
DNSP	Distribution Network Service Provider
DSP	Demand Side Participation
DTEI	Department of Transport, Energy and infrastructure (South Australia)
EITE	Emissions Intensive Trade Exposed
ESCOSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities
ETS	Emissions Trading Scheme
GDP	Gross Domestic Product
GJ	Gigajoules
GPG	Gas-fired Power Generation
GSP	Gross State Product
GWh	Gigawatt hours
Km	Kilometres
kV	Kilovolts
kW	Kilowatts
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
MAE	Mean Absolute Error
MAPE	Mean Absolute Percentage Error
MCE	Ministerial Council on Energy

MD	Maximum Demand
MLF	Marginal Loss Factor
MRET	Mandatory Renewable Energy Target
MRL	Minimum Reserve Level
MTPASA	Medium-term Projected Assessment of System Adequacy
MVA	Mega-volt-amperes
MVAr	Mega-volt-amperes-reactive
MW	Megawatts
MWh	Megawatt hours
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEMMCO	National Electricity Market Management Company
NEL	National Electricity Law
NER	National Electricity Rules
NSP	Network Service Provider
NTNDP	National Transmission Network Development Plan
PJ	Petajoules
POE	Probability of Exceedence
RET	Renewable Energy Target
SAEDC	South Australian Electricity Distribution Code
SAETC	South Australian Electricity Transmission Code
SASDO	South Australian Supply and Demand Outlook
SRES	Small-scale Renewable Energy Scheme
TJ	Terajoules
TNSP	Transmission Network Service Provider
USE	Unserved Energy
V	Volts

Executive Summary

The South Australian Supply and Demand Outlook (SASDO) is a report prepared by the Australian Energy Market Operator Limited (AEMO) in accordance with Division 2, Subdivision 2, Section 50B of the National Electricity Law, for the South Australian jurisdiction.

Advisory functions for the South Australian jurisdiction are delivered by AEMO across a number of its publications including the SASDO, Electricity Statement of Opportunities (ESOO), Power System Adequacy - Two Year Operational Assessment, and the National Transmission Network Development Plan (NTNDP).

The SASDO describes the current state of South Australia's electricity supply, and is published by 30 June to align with production of ElectraNet's South Australian Annual Planning Report (SAAPR).

The 2010 SASDO, the first produced by AEMO, addresses the following advisory functions:

- Historical and forecast future demand for electricity including peak and aggregate energy usage.
- Existing and potential future electricity supply options.
- Historical fuel usage and estimated greenhouse gas emissions.

The SASDO has been prepared prior to the Australian Government announcements regarding the Henry Review of Taxation and the Resource Rent Tax, as such issues relating to these policies have not been considered.

Energy and demand forecasts

South Australia experienced prolonged heatwave conditions throughout November 2009, as well as a number of consecutive peak demand days in early February 2010. The peak level of electricity supplied during the 2009/10 summer occurred on Monday, 11 January 2010 when electricity demand peaked at 3,321 MW, and Adelaide's temperatures reached a maximum of 42.8°C following an overnight minimum of 28.9°C. This level of demand did not exceed the previous summer's record demand of 3,413 MW, which occurred on Thursday, 29 January 2009.

Energy consumption in South Australia continues to increase, with the expected economic downturn in 2009 failing to reduce electricity consumption. Actual energy consumption increased by 0.5% from 14,576 GWh in 2008/09 to an estimated 14,656 GWh in 2009/10.

Energy forecasts are now expected to increase from 15,002 GWh in 2010/11 to 16,265 GWh in 2019/20, at an average projected growth of 0.9% per annum over the next decade.

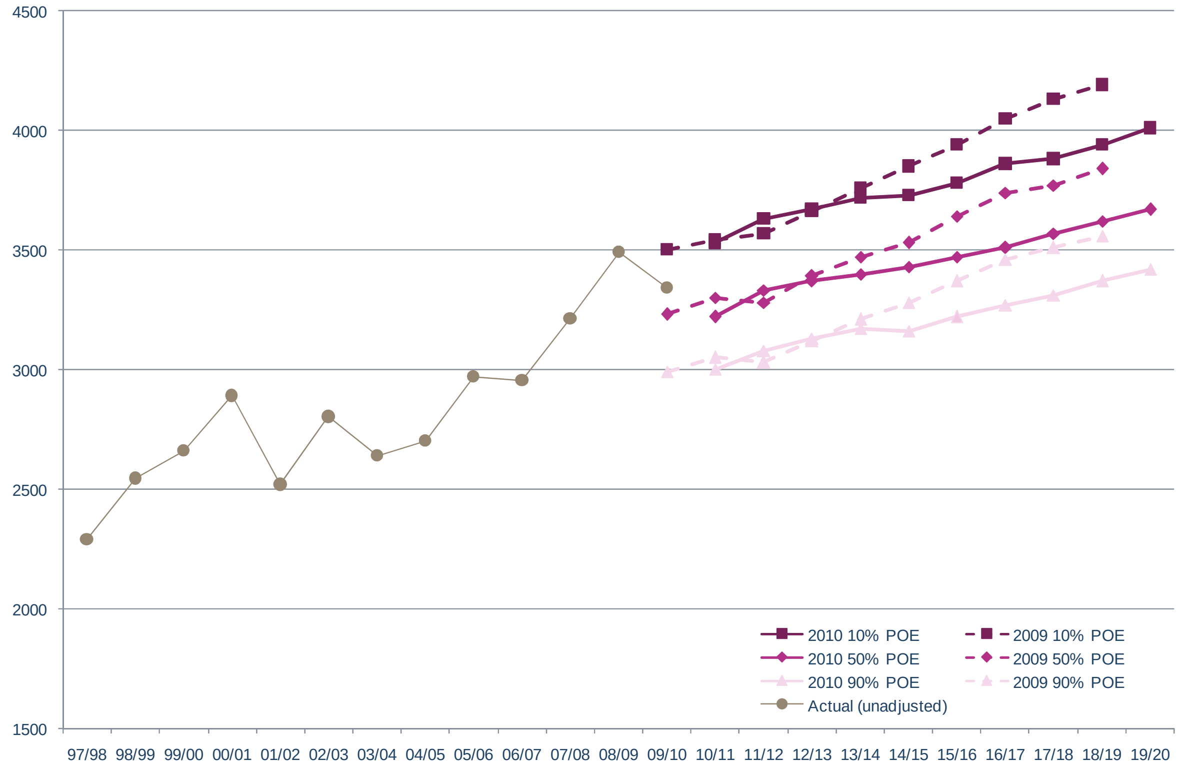
The 10% probability of exceedence (POE), 1-in-10 year summer maximum demand (MD) forecast increases from 3,530 MW in 2010/11 to 4,010 MW in 2019/20, with an average projected growth of 1.4% per annum over the forecast period.

Table 1 lists the 10% POE summer MD and energy forecasts for the forecast period. Figure 1 presents both last years and this years 10% POE summer MD forecasts.

Table 1 – Electricity summer MD and energy forecasts (medium economic growth scenario)

2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Average Annual Growth 2010-2019
10% POE SUMMER MD FORECAST (MW)										
3,530	3,630	3,670	3,720	3,730	3,780	3,860	3,880	3,940	4,010	1.4%
ENERGY FORECAST, MEDIUM GROWTH SCENARIO (GWh)										
15,002	15,544	15,710	15,750	15,506	15,717	15,853	15,979	16,102	16,265	0.9%

Figure 1 – Comparison of 2009 and 2010 electricity maximum demand forecasts



In preparing energy and MD forecasts, AEMO cannot provide a single definitive view of the future. The SASDO and supporting documentation on AEMO's website provides information on methodologies, assumptions and the range of sensitivities tested. This information is provided to allow readers to consider the issues and form their own views of the future.

The demand forecasting process relies on the accuracy of the forecasts of economic variables such as gross state product (GSP) and future electricity prices. Changed assumptions may lead to different outcomes, requiring the use of sensitivities to assess the impact of different economic growth and pricing assumptions.

Energy and MD consumption growth is lower than forecast in 2009, primarily as a result of updated forecasts of electricity demand drivers, and specifically an increase in projected forward electricity prices, and a slight decrease in projected economic growth for South Australia over the next 10 years.

Average retail electricity prices are an important driver of electricity sales and MD levels in South Australia. The price elasticity of annual sales is estimated to be -0.25, with slightly less than half of this elasticity applying to peak demand levels; a 4% real rise in prices is expected to lead to a 1% reduction in sales and a 0.5% reduction in peak demand.

Table 2 compares the 2009 and 2010 forecasts.

Table 2 – Comparison of the 2009 and 2010 forecasts

	AEMO 2010 SASDO	ESIPC 2009 SA APR	Change
Summer 2010/11 10% POE MD	3,530 MW	3,540 MW	-10 MW (-0.3%)
Winter 2010 10% POE MD	2,660 MW	2,720 MW	-60 MW (-2.2%)
2010/11 Energy Consumption	15,002 GWh	15,380 GWh	-378 GWh (-2.5%)
2010/11 Australian GDP Growth	3.6%	4.0%	-0.4%
2010/11 South Australian GSP Growth	3.1%	3.9%	-0.8%

Economic forecasts developed by KPMG in April 2010 assume implementation of the Australian Government's carbon policy from July 2011. Following recently announced changes, the peak demand and energy forecasts presented in the SASDO assume this policy commences in 2013.

Supply

Investments in renewable generation over the last 12 months have further increased the generation capacity in South Australia. Wind farm projects completed since 2008/09 include a 71 MW wind farm at Hallett Hill and a 56.7 MW wind farm at Clements Gap, increasing South Australia's installed wind capacity to 868 MW.

Projects currently under construction include:

- AGL's 132 MW North Brown Hill Wind Farm
- Infigen Energy's 39 MW Lake Bonney Stage 3 Wind Farm
- Roaring 40s' 111 MW Waterloo Wind Farm, and
- International Power's expansion of the Port Lincoln Power Plant by 23 MW.

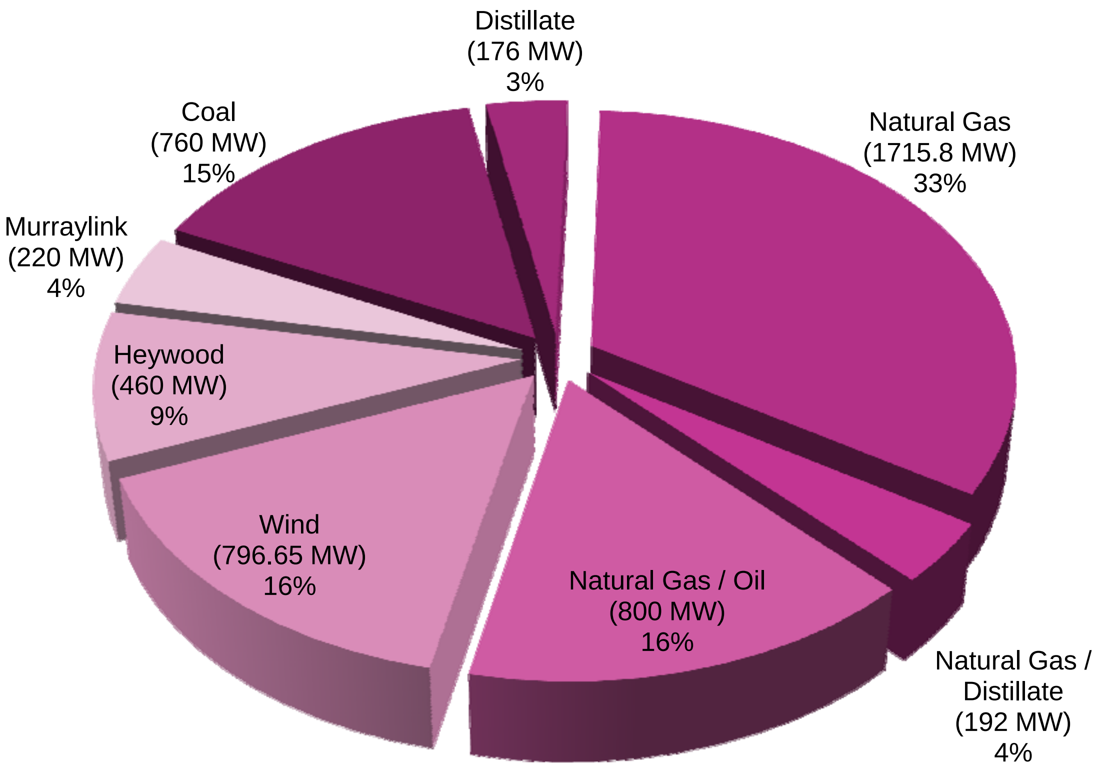
Industry response to higher renewable energy targets and the possible introduction of a carbon policy will likely lead to further investment in wind power, especially in South Australia with its significant wind resource. The capacity of wind generation in South Australia continues to grow and is now amongst the highest in the world relative to customer sales. The wind generation projects currently under construction will increase the installed capacity of wind generation in South Australia to more than 1,000 MW.

South Australia's available summer capacity for 2010/11 is expected to be 3,482 MW, and is likely to continue to increase due to a large number of possible developments, including additional wind and gas powered generation (GPG).

Fuel usage

Figure 2 presents South Australia's electricity supply by fuel source.

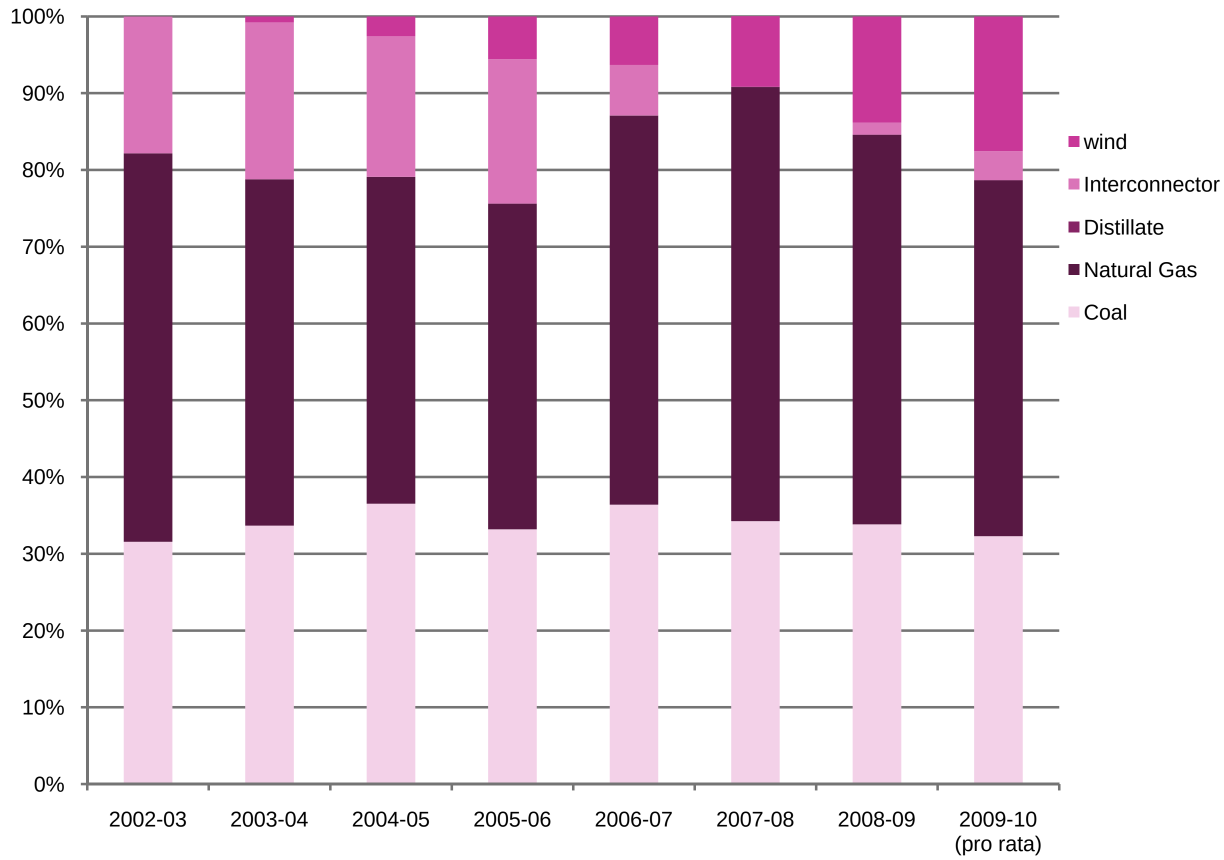
Figure 2 – South Australian installed capacity by fuel source, 2009-10



The steady growth of wind energy as a component of South Australian generation, combined with the easing of the drought in Australia's eastern states, has resulted in a reduction in the contribution from energy imports and the use of GPG. Use of coal has remained consistent and is likely to remain so until the introduction of an Australian carbon policy.

Figure 3 presents South Australia's energy contribution by fuel source.

Figure 3 – Percentage of South Australian energy contribution by fuel source



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1 Introduction

The South Australian Supply and Demand Outlook (SASDO) describes the current state of South Australia's electricity supply, and is published by 30 June to align it with production of ElectraNet's South Australian Annual Planning Report (SAAPR).

The SASDO is a report prepared by AEMO in accordance with Division 2, Subdivision 2, Section 50B of the National Electricity Law, whereby the South Australian Minister for Energy wrote to AEMO outlining additional advisory functions required for South Australia.

The additional advisory functions for the South Australian jurisdiction are delivered by AEMO across a number of its publications including the SASDO, Electricity Statement of Opportunities (ESOO), Power System Adequacy Report, and National Transmission Network Development Plan (NTNDP).

The SASDO addresses the following advisory services requirements:

- Historical and forecast future demand for electricity (peak usage and aggregate energy usage);
- Existing and potential future electricity supply options; and
- Historical fuel used and estimated greenhouse gas emissions associated the electricity usage.

The SASDO has been prepared prior to the Federal Government announcements on the Henry Review of Taxation and Resource Rent Tax in May 2010. Issues related to these policies have not been considered in the SASDO.

1.1 Contents of the SASDO

Table 1-1 summarises the contents of each of the SASDO chapters.

Table 1-1 – SASDO chapter overview

Chapter	Contents
2 – Energy and Demand Forecasts	Forecasts of South Australia's annual and seasonal peak electrical energy requirements, including: • Review of electricity demand during the 2009-10 summer; • Economic outlook; • Peak demand forecasts to 2019-20; and • Annual energy forecasts to 2019-20.
3 – Supply	Current and prospective electricity supply developments in South Australia, including: • Existing generating capacity; • New plant developments; • Historic levels of performance; and • Wind generation performance study.
4 – Fuel Usage	Sources and volume of fuel required to support the forecast generation levels, including: • Fuel use history; • Use of gas, coal and liquid fuels in South Australia; • Fuel prices; and • Greenhouse gas emissions.

1.2 AEMO's planning documents

In 2010, AEMO will publish six planning documents, some originally published by AEMO's predecessor organisations, and some altogether new publications. While individually satisfying unique demands for energy market information from AEMO's various planning roles, a key aim has been to ensure that their common elements provide a consistent and coherent message.

The VAPR satisfies AEMO's Victorian gas and electricity transmission planning roles. AEMO will also publish the South Australian Supply and Demand Outlook (SASDO), outlining South Australian electricity supply, demand and fuel information, at the same time as the VAPR.

In August AEMO will publish the Electricity Statement of Opportunities (ESOO), which provides an outlook for electricity supply and demand in the National Electricity Market (NEM) for the next 10 years. The ESOO will provide a 10-year outlook again this year, but focus on years 3-10. This year AEMO will also produce the Power System Adequacy Report, which is a new publication focussing on electricity supply and demand for the next two years.

In November AEMO will publish the VAPR update, and by the end of the calendar year will also be publishing its second Gas Statement of Opportunities (GSOO) and the inaugural National Transmission Network Development Plan (NTNDP).

Table 1-2 lists the planning documents produced by AEMO in 2010, and the unique and common elements of each.

Table 1-2 – AEMO's planning documents

	Victorian Annual Planning Report (VAPR)	South Australian Supply and Demand Outlook (SASDO)	Power System Adequacy Report	Electricity Statement of Opportunities (ESOO)	Victorian Annual Planning Report Update (VAPR Update)	National Transmission Network Development Plan (NTNDP)	Gas Statement of Opportunities (GSOO)
Published	30 June	30 June	31 August	31 August	30 November	31 December	31 December
Focus	Victorian Gas and Electricity	South Australian Electricity	NEM Electricity	NEM Electricity	Victorian Gas	NEM Electricity	Eastern Australian Gas
Outlook	10 years	10 years	2 years	10 years	5 years	20 years	20 years
Gas Forecasts	✓	n/a	n/a	n/a	✓	n/a	✓
Electricity Forecasts	✓	✓	✓	✓	n/a	✓	n/a
Scenario Planning	✓	✓	n/a	✓	n/a	✓	✓
Network & Modelling	✓	n/a	n/a	n/a	n/a	✓	n/a
Market Modelling	n/a	n/a	n/a	✓	n/a	✓	n/a

2 Energy and Demand Forecasts

South Australia's annual electrical energy requirements and probability of exceedence (POE) levels for summer and winter peak demand are described in this section. The material presented covers the following topics:

- Review of electricity demand during the 2009-10 summer
- Economic outlook
- Peak and annual demand forecasts to 2019-20

Native Demand – unless otherwise indicated, demand and energy values refer to demand for scheduled generation, including imports, and semi and non-scheduled generation greater than 1 MW in capacity and connected to the South Australian grid.

Peak demand forecasts are reported according to POE levels. A 10% POE forecast has a 1-in-10 chance of being exceeded. A 50% POE forecast has a 1-in-2 chance of being exceeded. Demand and energy is reported on an 'as generated' basis and includes generator internal use of electricity.

2.1 Review of electricity demand during the 2009-10 summer

Daily maximum demand (MD) against average daily temperature, for the extended 2009/10 summer period, 1 November 2009 to 31 March 2010, is shown in Figures 2-1 and 2-2. This figure demonstrates the volatility of demand and its dependency on average daily temperature.

Figure 2-1 – MD and Average Temperature from November 2009 to March 2010

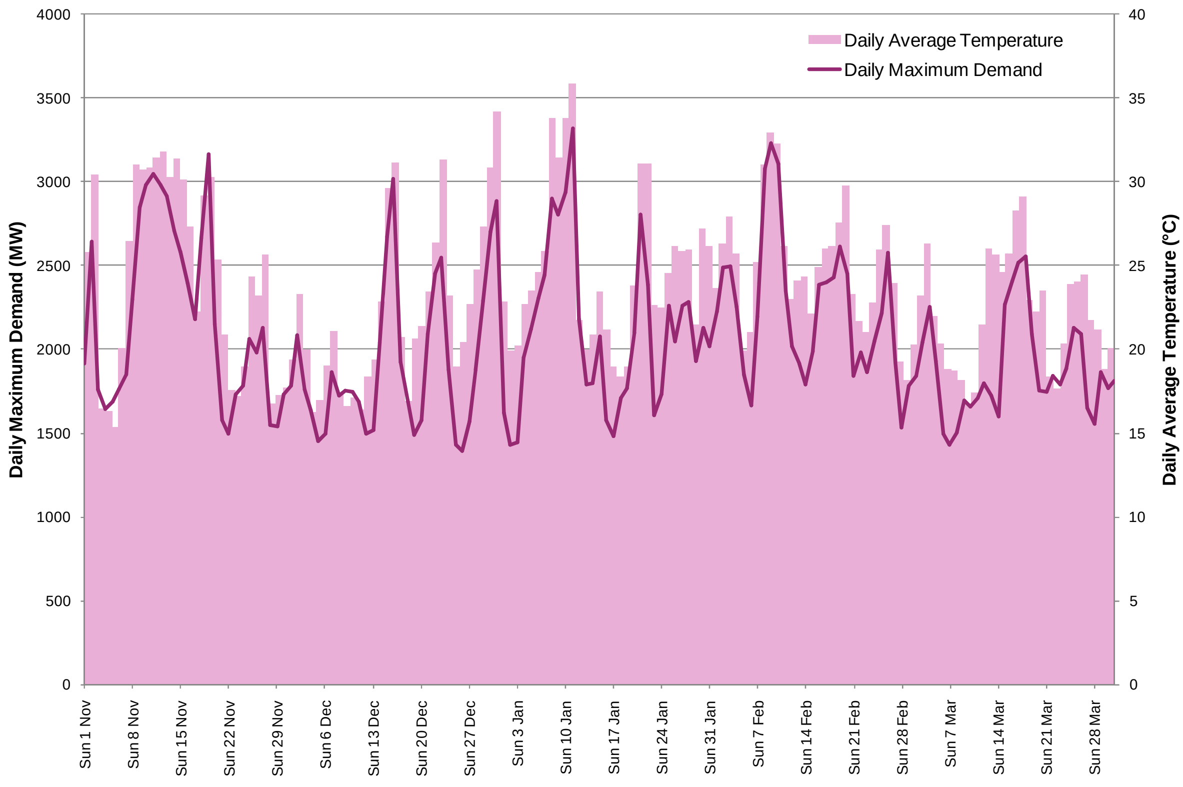
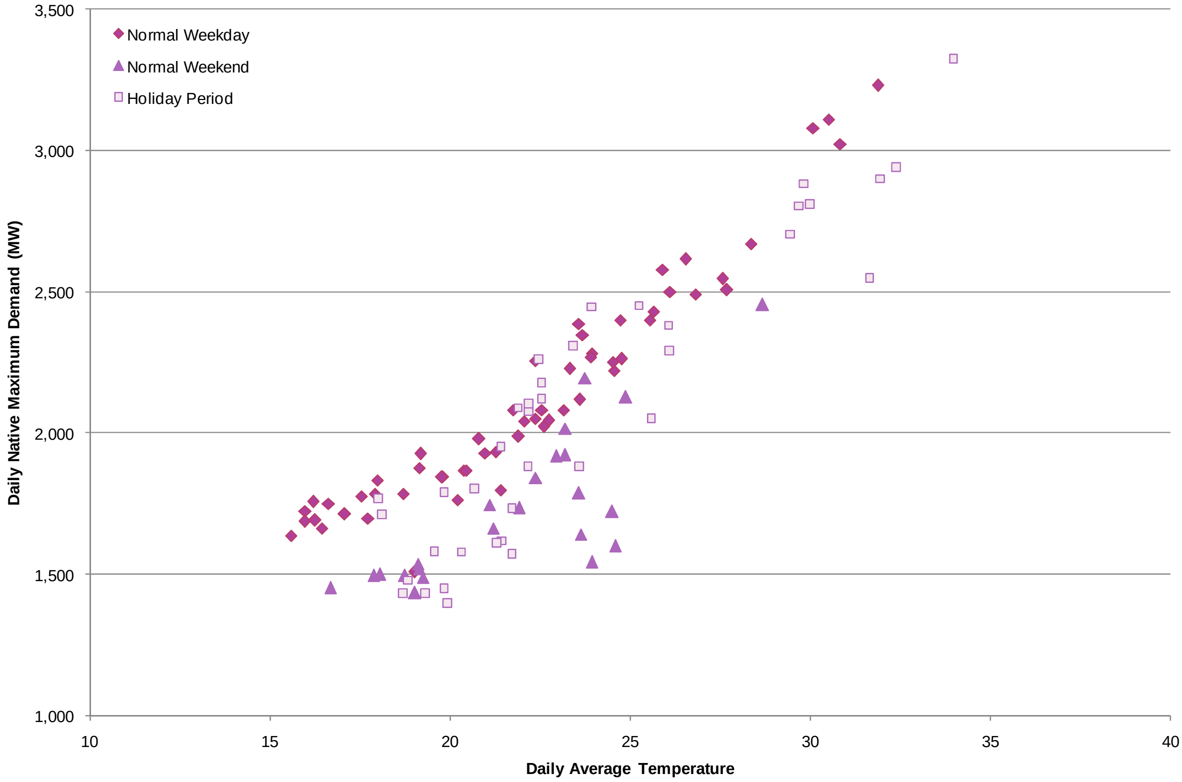


Figure 2-2 – Daily MDs for summer 2009/10



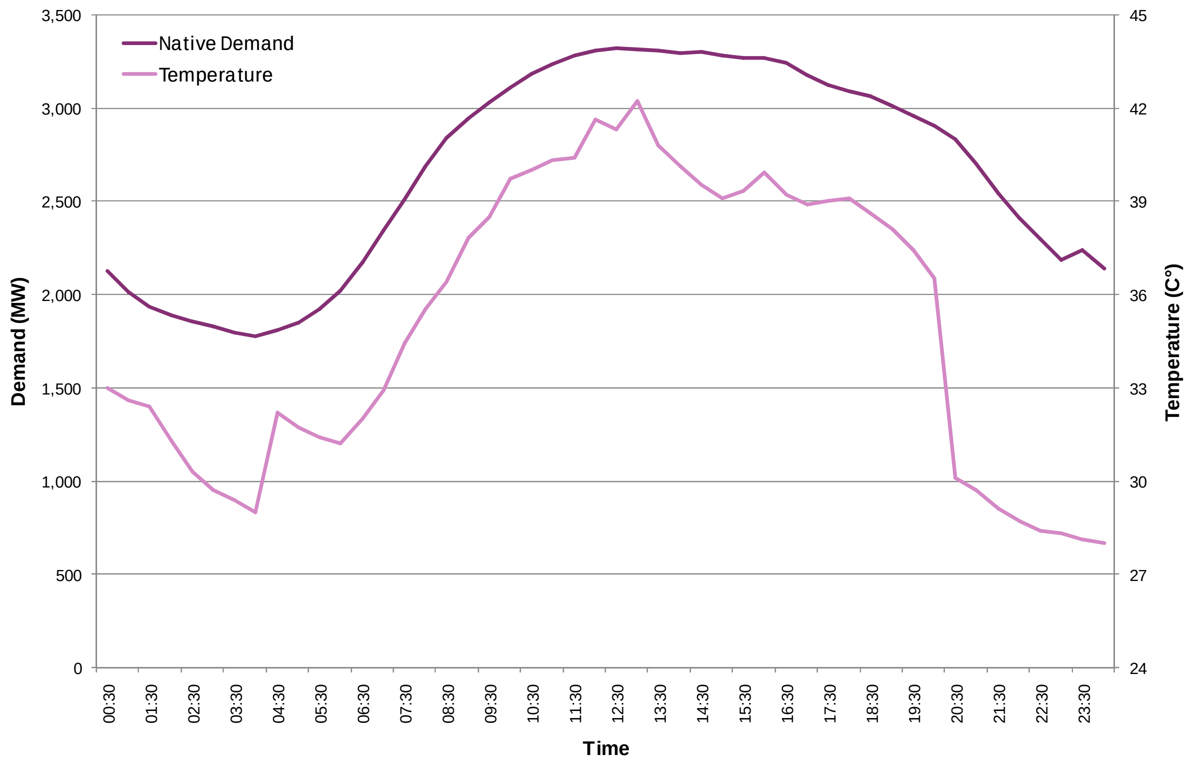
The highest recorded demand for summer 2009/10 was 3,321 MW, and occurred at 12:30 pm on Monday, 11 January 2010. This is 92 MW lower than the South Australia's record demand of 3,413 MW, which occurred during the 2008/09 summer.

The scheduled, semi-scheduled, non-scheduled and maximum demands for the five highest summer demand days are shown in Table 2-1. Figure 2-3 presents the half-hourly demand and temperatures on Monday, 11 January 2010.

Table 2-1 – Summer 2009/10 Maximum demands and Temperatures

Date & Time (AEST)	Maximum Temp (°C)	Minimum Temp (°C)	Average Daily Temp (°C)	Scheduled Demand (MW)	Semi Scheduled Generation (MW)	Non Scheduled Generation (MW)	Maximum Demand (MW)
12:30 pm Monday 11 January 2010	42.2	28.1	35.2	3,056	188	265	3,321
4:00 pm Tuesday 9 February 2010	38.6	26.8	32.7	3,103	19	126	3,229
2:00 pm Wednesday 10 February 2010	38.3	26.2	32.3	2,912	15	196	3,108
4:00 pm Monday 8 February 2010	37.7	25.4	31.6	2,973	34	107	3,080
4:00 pm Wednesday 16 December 2010	40.4	21.7	31.1	2,862	165	159	3,021

Figure 2-3 – Demand and Temperature in South Australia on Monday, 11 January 2010



2.2 Economic outlook

AEMO's economic consultant, KPMG Econtech, prepared economic forecasts in April 2010 which are used to update each NEM region's electricity forecasts, published in their Annual Planning Reports (APRs), and collated in AEMO's 2010 Electricity Statement of Opportunities (ESOO).

KPMG has also prepared the projections of average retail electricity prices and new investment in wind farms that underlie AEMO's electricity demand and energy forecasts.

Assumptions regarding Australia's future Carbon and Renewable Energy Policies

Australian energy policies, such as the previously announced Carbon Pollution Reduction Scheme (CPRS) and the expanded Renewable Energy Target (RET) are likely to have a direct effect on electricity consumption. This impact occurs as consumers respond to changes in electricity price and indirectly through their effect on particular industries and the economy more generally. In April 2010 the Australian government announced that implementation of an Australian carbon policy could be delayed beyond the 2013 election as its legislation would depend on action by the end of 2012 from major emitters: China, the United States of America, and India.

As a result of this announcement, the 2010 energy and peak demand forecasts assume that the CPRS is introduced in 2013 with a permit price of \$10 per tonne CO_2 equivalent. Table 2-2 presents the permit prices assumed.

Table 2-2 – Carbon permit prices ($/tonne C02 equivalent)

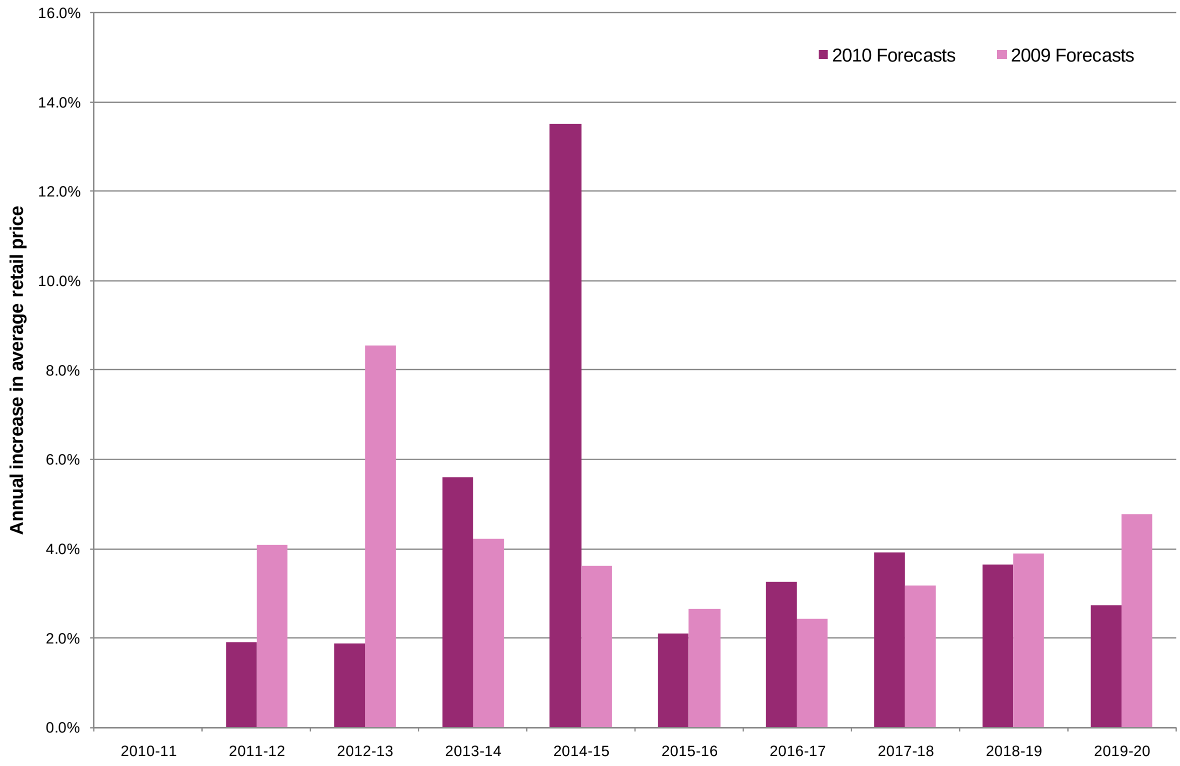
Year	Assumed Trajectory
2011/12	0.0
2012/13	0.0
2013/14	10.0
2014/15	34.3
2015/16	35.7
2016/17	37.1
2017/18	38.6

Considerable uncertainty surrounds the future of Australian carbon policy. The assumptions used in this 2010 SASDO present a significant impact on energy and peak demand electricity consumption in South Australia, at the time a carbon policy is introduced, due to the forecast increase of average electricity retail price.

Average retail electricity prices are an important driver of electricity sales and MD levels in South Australia. The price elasticity of annual sales is estimated to be -0.25, with slightly less than half of this elasticity applying to peak demand levels; a 4% real rise in prices is expected to lead to a 1% reduction in sales and a 0.5% reduction in peak demand.

Figure 2-4 presents the assumed annual percentage increases of average electricity retail price for South Australia, for both the 2010 and 2009 forecasts.

Figure 2-4 – Annual increase in average electricity retail price



In 2009, the Council of Australian Governments (COAG) announced an agreement on the design of a Renewable Energy Target (RET) scheme to achieve a 20 per cent share of renewables, or 45,000 GWh, in Australia's electricity mix by 2020. Changes in this agreement have since included:

- 45,000 GWh target will now be extended from 2020 until 2030 when the scheme ends
- REC penalty price will be increased from the current price of $40/MWh to $65/MWh

On 20 August 2009, the expanded RET scheme legislation was passed.

The RET legislation has since had further amendments, involving the separation of large-scale projects from small-scale projects such as installation of solar hot water and solar photovoltaic panels. The Renewable Energy (Electricity) Amendment Bill 2010 was passed by the Parliament on Thursday, 24 June 2010. As of 1 January 2011, the RET will be separated into the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). This change to the expanded RET scheme is largely consistent with the modelling in these forecasts.

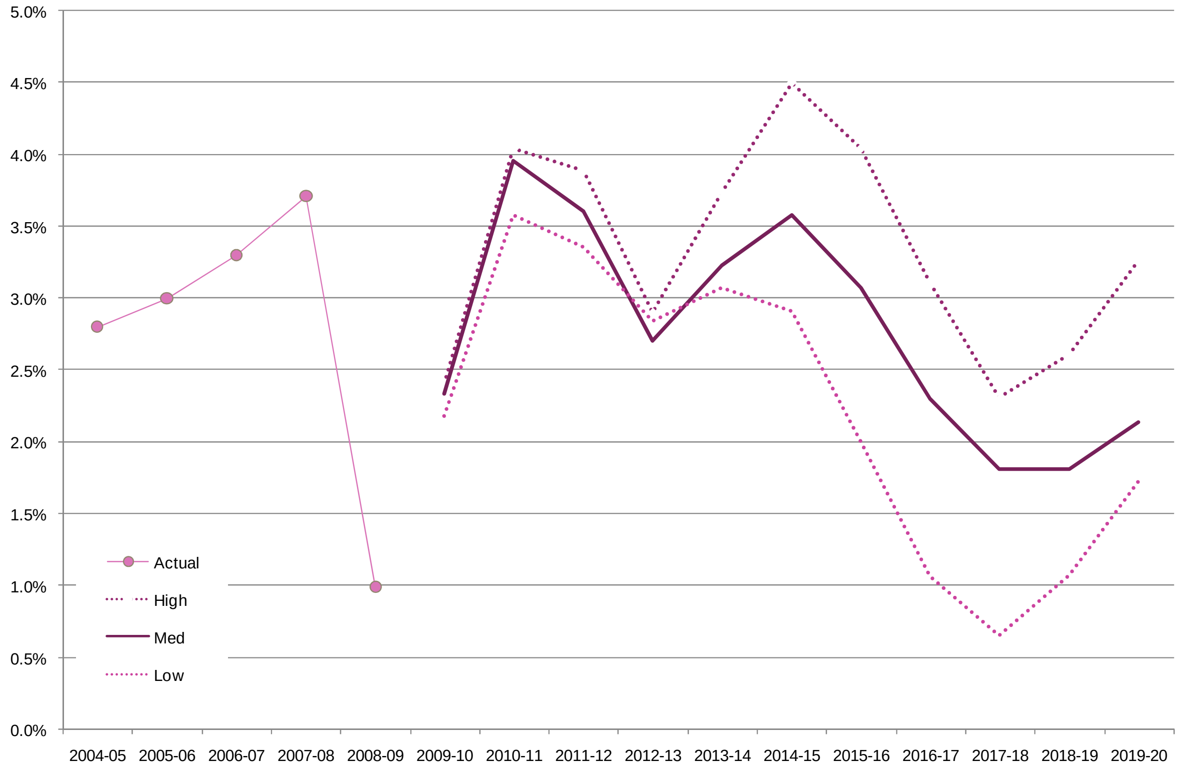
Outlook for the Australian economy

The Australian economy has continued to surprise over the last few quarters, exceeding the expectations of both markets and policy makers. The rapid recovery in the domestic economy can be attributed to a range of factors, including the strong performance of Asian trading partners, resilient consumer spending and a sooner than expected recovery in dwelling investment. With domestic business and consumer sentiment bouncing back to pre-crisis levels, overall economic growth should pick up in 2009/10. A full-fledged recovery is expected in 2010/11 as the economy gathers pace in late 2010.

KPMG's forecasts show Australian GDP increases in 2009-10, with real growth of 2.3%, and further increase in real terms by 4.0% in 2010-11. Growth is projected at an average of 2.7% over the remainder of the 10 year forecast horizon.

KPMG's growth projections for the Australian economy are shown in Figure 2-5.

Figure 2-5 – Projected real growth of Australian GDP



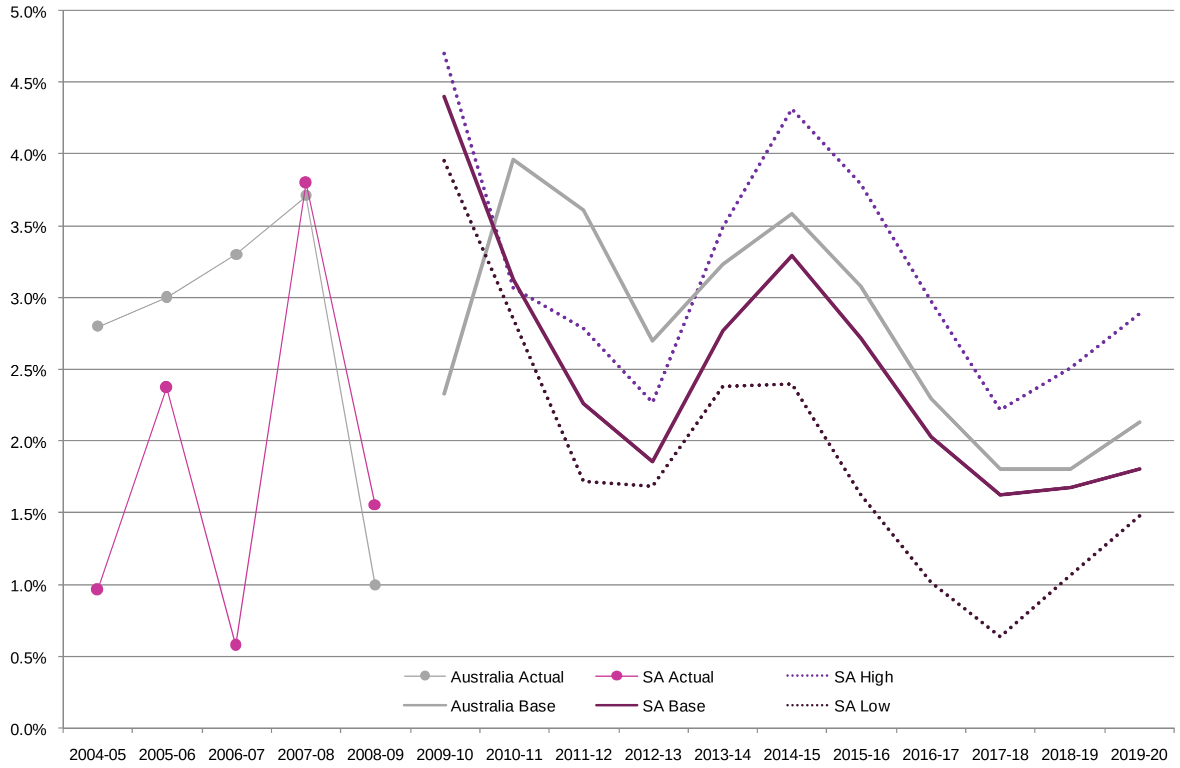
Outlook for the South Australian economy

The South Australian economy outperformed the national economy in 2008/09, with strong growth in state final demand contributing positively to an expansion in GSP. Unlike the rest of the country, high levels of dwelling and business investment were sustained in South Australia, reflecting strong demand for housing as a result of gains in net overseas migration. Consumer demand also continued to grow at a comparatively fast pace. In response to a growing need for public transport within and around Adelaide, the South Australian government began a program of infrastructure upgrades in 2008/09 worth an estimated $2 billion. The program is expected to continue supporting growth over the medium term.

KPMG expect strong growth in 2009/10 followed by healthy but more moderate growth in 2010/11. GSP growth in then expected to moderate sharply in 2011/12. Over the longer term, net outflows of interstate migrants will see SA underperform compared to the wider economy. Comparatively weak population growth will have a strong impact on the construction sector, which is expected to exhibit slow growth over the forecast period.

Figure 2-6 compares KPMG's projected GSP growth for South Australia with the base case forecasts for Australia as a whole.

Figure 2-6 – Projected real growth of South Australian GSP



Assumptions regarding major industrial load growth

AEMO's 2010 energy and peak demand forecasts for South Australian electricity consumption make the following assumptions regarding major industrial load growth.

Desalination Plant – low, medium and high growth forecasts assume commissioning of the Lonsdale 100 GL/year desalination plant to service Adelaide's water requirements. A desalination plant of this size is estimated to consume 500 GWh per annum and have a maximum demand of 80 MW. Whilst first water is expected to be delivered by the end of 2010, impact on South Australia's energy and peak demand consumption is not expected to be seen until 2011 in the high growth scenario, 2012 in the medium growth scenario and 2013 in the low growth scenario.

Penola Pulp Mill – only high growth scenario forecasts have included the construction of the Pulp Mill at Penola. The high growth scenario assumes completion of the project in 2012/13, with the mill reaching full output in 2014/15.

Mining Expansion – expansion of BHP Billiton's Olympic Dam Mine has only been included in the high growth scenario forecasts.

Both the Pulp Mill and Mining expansion have been excluded from the medium and low growth forecasts as they are not yet regarded as committed projects.

2.3 Peak and annual demand forecasts to 2019-20

2.3.1 Summer native maximum demand forecasts

Table 2-3 lists the forecast summer 10%, 50%, and 90% POE native MDs. From the start of the forecast period, the summer 10% POE native MD is projected to grow each year by:

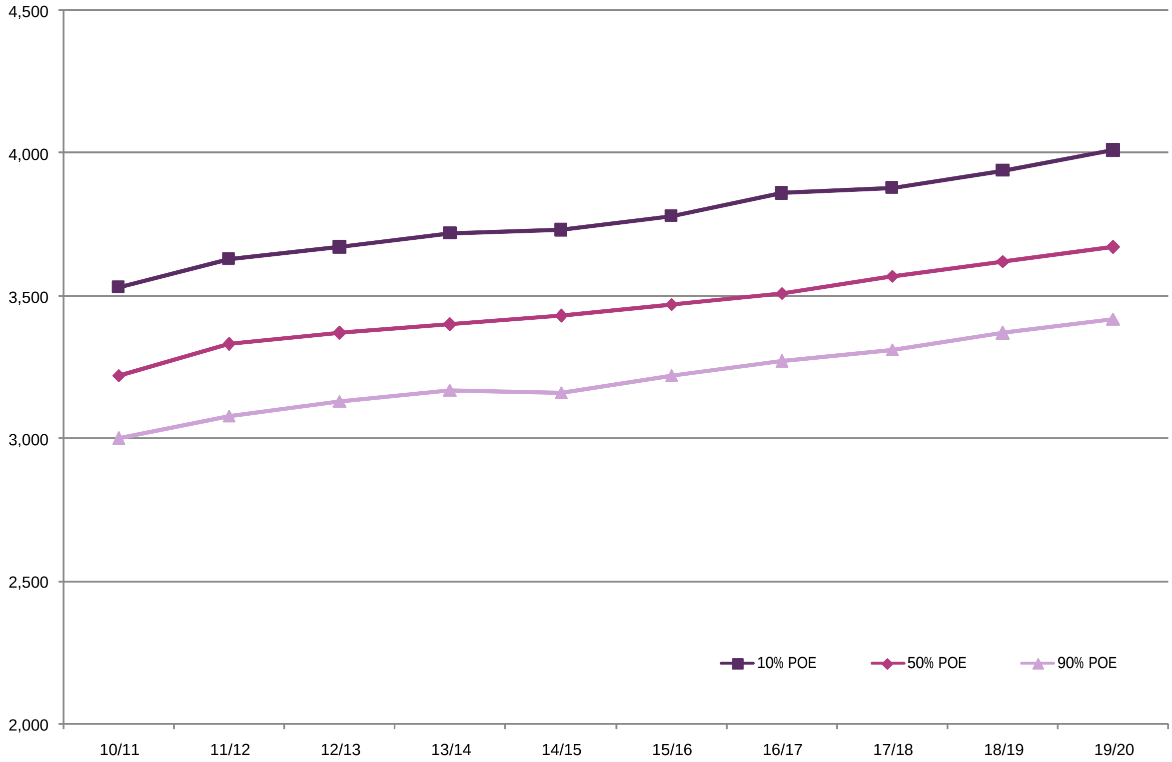
- 1.4% under the medium growth scenario;
- 3.0% under the high growth scenario; and
- 0.9% under the low growth scenario.

Table 2-3 - Summer native maximum demand forecasts (MW)

Scenario	POE	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
High	10%	3,520	3,630	3,810	3,910	4,080	4,200	4,320	4,400	4,520	4,610
	50%	3,230	3,340	3,510	3,620	3,760	3,880	3,990	4,070	4,180	4,250
	90%	3,000	3,110	3,260	3,370	3,490	3,610	3,740	3,790	3,910	3,980
Medium	10%	3,530	3,630	3,670	3,720	3,730	3,780	3,860	3,880	3,940	4,010
	50%	3,220	3,330	3,370	3,400	3,430	3,470	3,510	3,570	3,620	3,670
	90%	3,000	3,080	3,130	3,170	3,160	3,220	3,270	3,310	3,370	3,420
Low	10%	3,520	3,560	3,600	3,630	3,670	3,690	3,700	3,740	3,780	3,830
	50%	3,210	3,250	3,290	3,300	3,350	3,380	3,400	3,420	3,460	3,510
	90%	2,980	3,030	3,050	3,070	3,100	3,140	3,160	3,190	3,220	3,250

Figure 2-7 shows the summer 10%, 50%, and 90% POE native MD forecasts under the medium growth scenario for the forecast period.

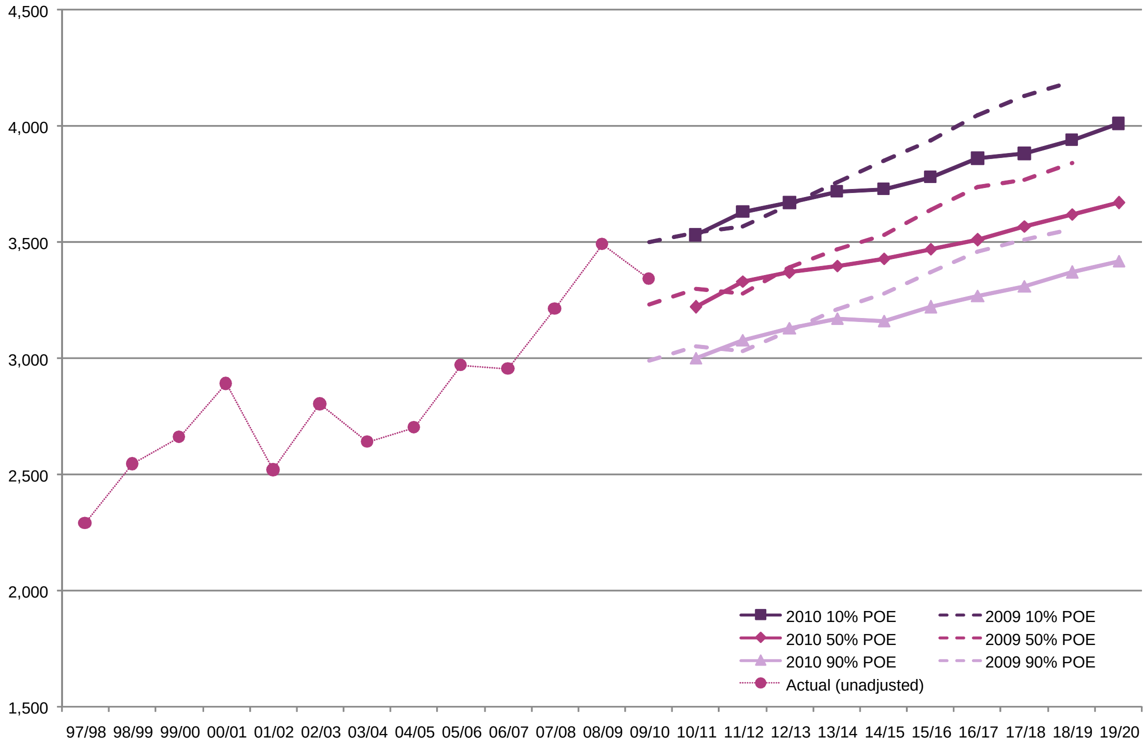
Figure 2-7 – Summer native maximum demand forecasts (medium growth scenario)



Forecast comparison (summer native maximum demand)

Figure 2-8 compares the 2009 and 2010 summer native MD forecasts. Compared to the 2009 forecasts, the current forecasts for the medium growth 10% POE summer demand are 10 MW lower, 120 MW lower and 250 MW lower for 2010/11, 2014/15 and 2018/19 respectively.

Figure 2-8 – Comparison of summer native maximum demand forecasts (MW)



2.3.2 Winter native maximum demand forecasts

Table 2-4 lists the forecast winter 10%, 50%, and 90% POE native MDs. From the start of the forecast period, the forecast 10% POE winter native MD is projected to grow each year by:

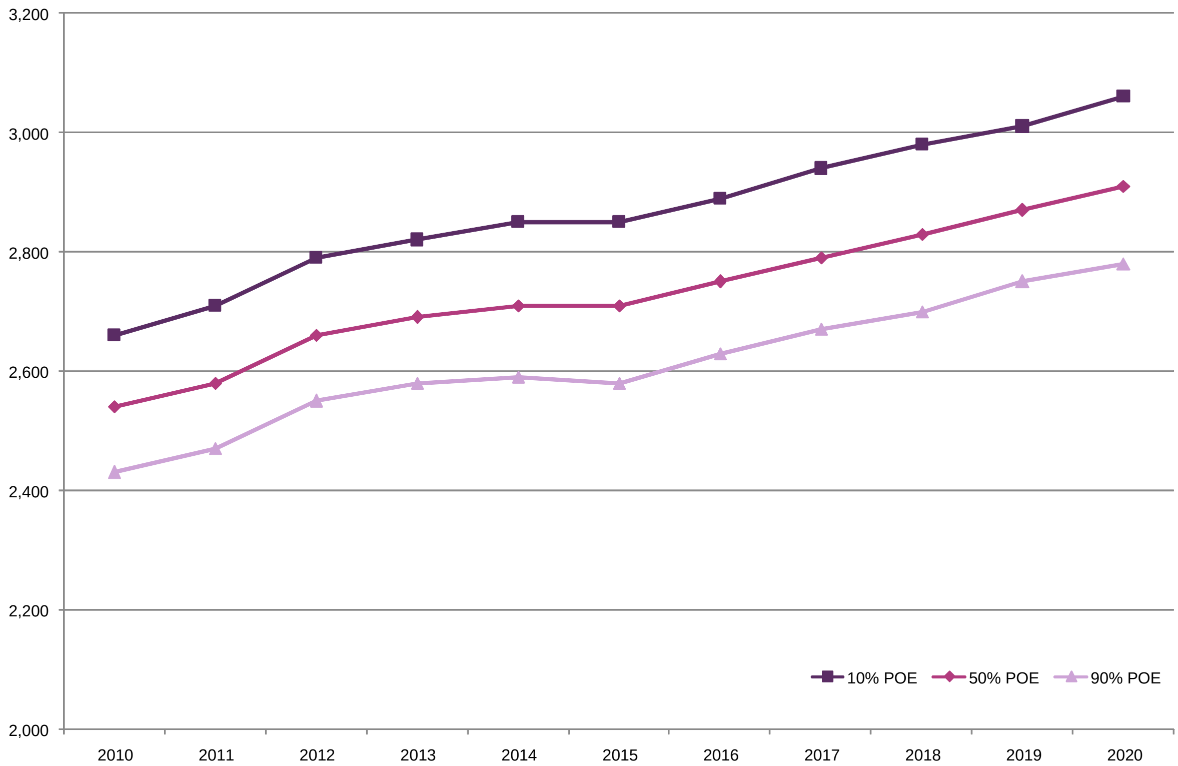
- 1.4% under the medium growth scenario;
- 3.3% under the high growth scenario; and
- 0.9% under the low growth scenario.

Table 2-4 – Winter native maximum demand forecasts (MW)

Year	POE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High	10%	2,660	2,730	2,820	2,970	3,060	3,200	3,300	3,400	3,470	3,570
	50%	2,530	2,580	2,680	2,830	2,920	3,040	3,150	3,250	3,320	3,420
	90%	2,430	2,480	2,570	2,720	2,810	2,910	3,030	3,130	3,190	3,290
Medium	10%	2,660	2,710	2,790	2,820	2,850	2,850	2,890	2,940	2,980	3,010
	50%	2,540	2,580	2,660	2,690	2,710	2,710	2,750	2,790	2,830	2,870
	90%	2,430	2,470	2,550	2,580	2,590	2,580	2,630	2,670	2,700	2,750
Low	10%	2,670	2,700	2,730	2,750	2,770	2,810	2,830	2,850	2,880	2,900
	50%	2,540	2,580	2,600	2,630	2,650	2,680	2,700	2,720	2,740	2,760
	90%	2,420	2,460	2,490	2,510	2,530	2,550	2,580	2,600	2,620	2,650

Figure 2-9 shows the winter native MD forecasts under the medium-growth scenario for the forecast period.

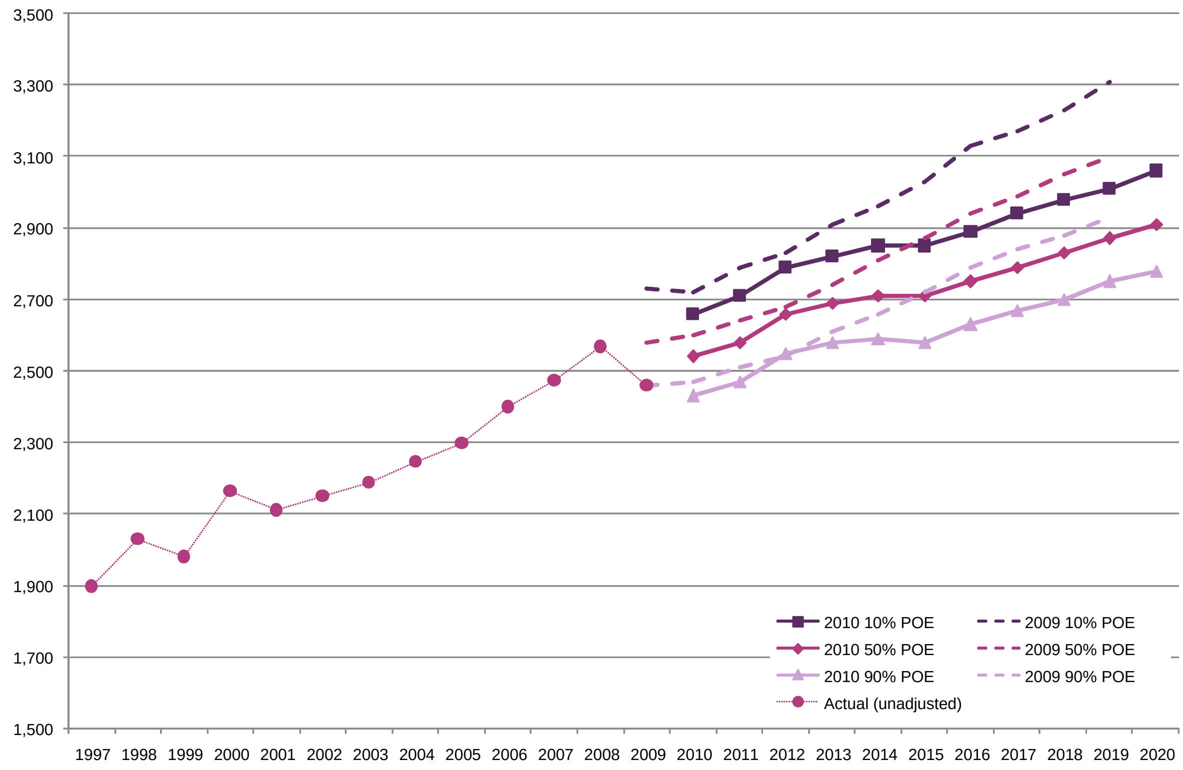
Figure 2-9 – Winter native maximum demand forecasts (MW) (medium-growth scenario)



Forecast comparison (winter native maximum demand)

Figure 2-10 compares the 2009 and 2010 winter native MD forecasts. Compared to the 2009 forecasts, the current forecasts for the medium growth winter 10% POE MD are 60 MW lower, 110 MW lower and 250 MW lower for 2010, 2014 and 2018 respectively.

Figure 2-10 – Comparison of winter native MD forecasts (MW)



2.3.3 Native energy forecasts

Ten-year forecasts

Table 2-5 lists the native energy forecasts, which are projected to grow each year, from the start of the forecast period commencing 1 July 2010, by:

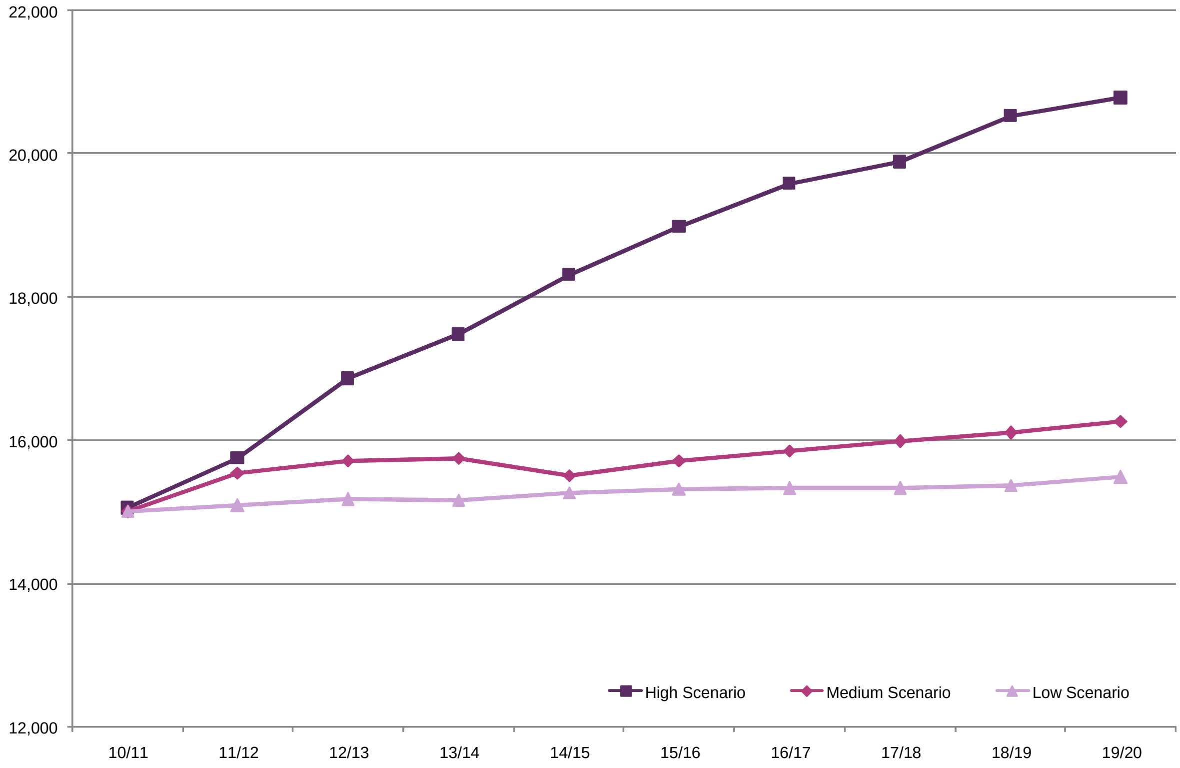
- 0.9% under the medium growth scenario;
- 3.6% under the high growth scenario; and
- 0.3% under the low growth scenario.

Table 2-5 – Native energy forecasts (GWh)

Year	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
High	15,055	15,751	16,858	17,478	18,313	18,983	19,584	19,883	20,524	20,779
Medium	15,002	15,544	15,710	15,750	15,506	15,717	15,853	15,979	16,102	16,265
Low	15,012	15,089	15,173	15,160	15,267	15,321	15,330	15,326	15,374	15,485

Figure 2-11 shows the native energy forecasts for the high, medium and low-growth scenarios for the forecast period.

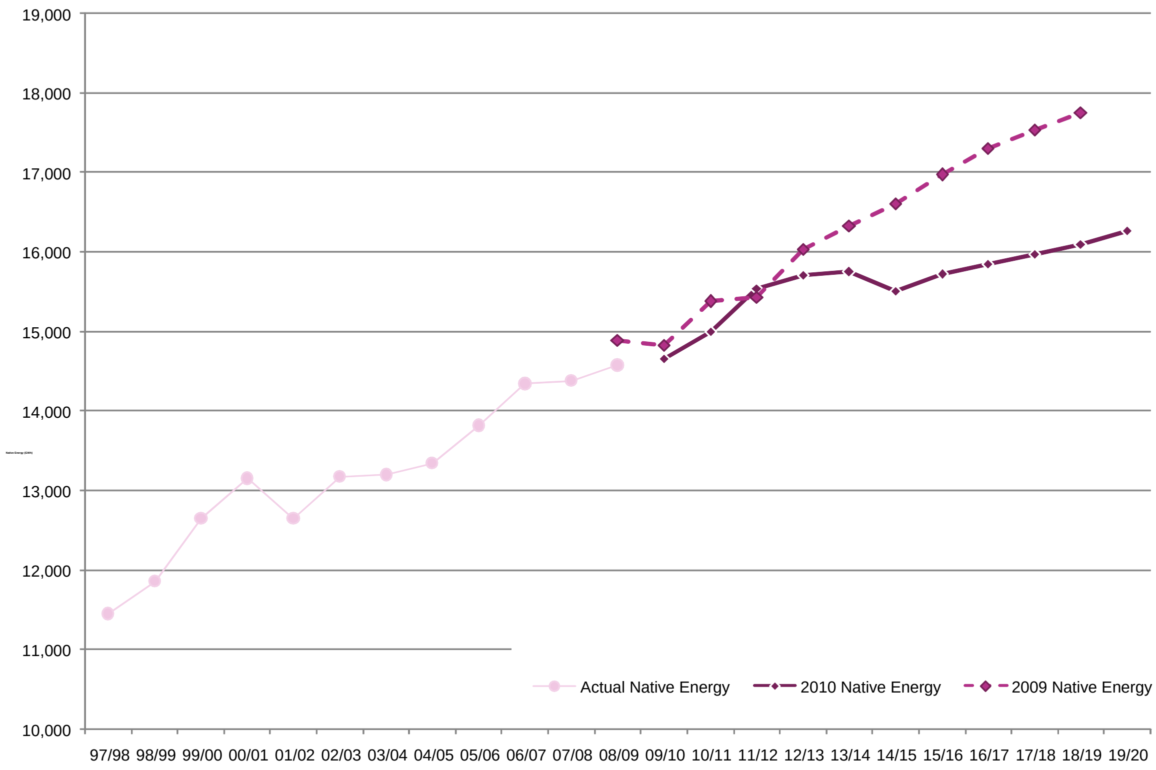
Figure 2-11 – Native energy forecasts (GWh)



Forecast comparison (native energy)

Figure 2-12 compares the 2009 and 2010 native energy forecasts. Compared to the 2009 forecasts, the current forecasts follow a similar trajectory from 2009/10 to 2012/13 before consumption reduces with a step change to average retail price following the introduction of a carbon price, before then continues at a slower rate of growth from 2014/15 onwards.

Figure 2-12 – Comparison of native energy forecasts (medium growth scenario)



The 2010 native energy forecasts are lower due to lower economic growth projections and higher assumed impact of government efficiency policies. The reduction to the 2010 energy forecasts from 2013/14 is predominantly due to carbon price assumptions.

2.3.4 Comparison of the 2009 and 2010 SA forecasts

Table 2-6 compares the 2009 and 2010 forecasts for the 2010/11 year.

Table 2-6 – Comparison of 2010/11 forecasts (2010 compared with 2009)

	AEMO 2010 SASDO	ESIPC 2009 SA APR	Change
Summer 2010/11 10% POE MD	3,530 MW	3,540 MW	-10 MW (-0.3%)
Winter 2010 10% POE MD	2,660 MW	2,720 MW	-60 MW (-2.2%)
2010/11 Energy Consumption	15,002 GWh	15,380 GWh	-378 GWh (-2.5%)
2010/11 Australian GDP Growth	3.6%	4.0%	-0.4%
2010/11 South Australian GSP Growth	3.1%	3.9%	-0.8%

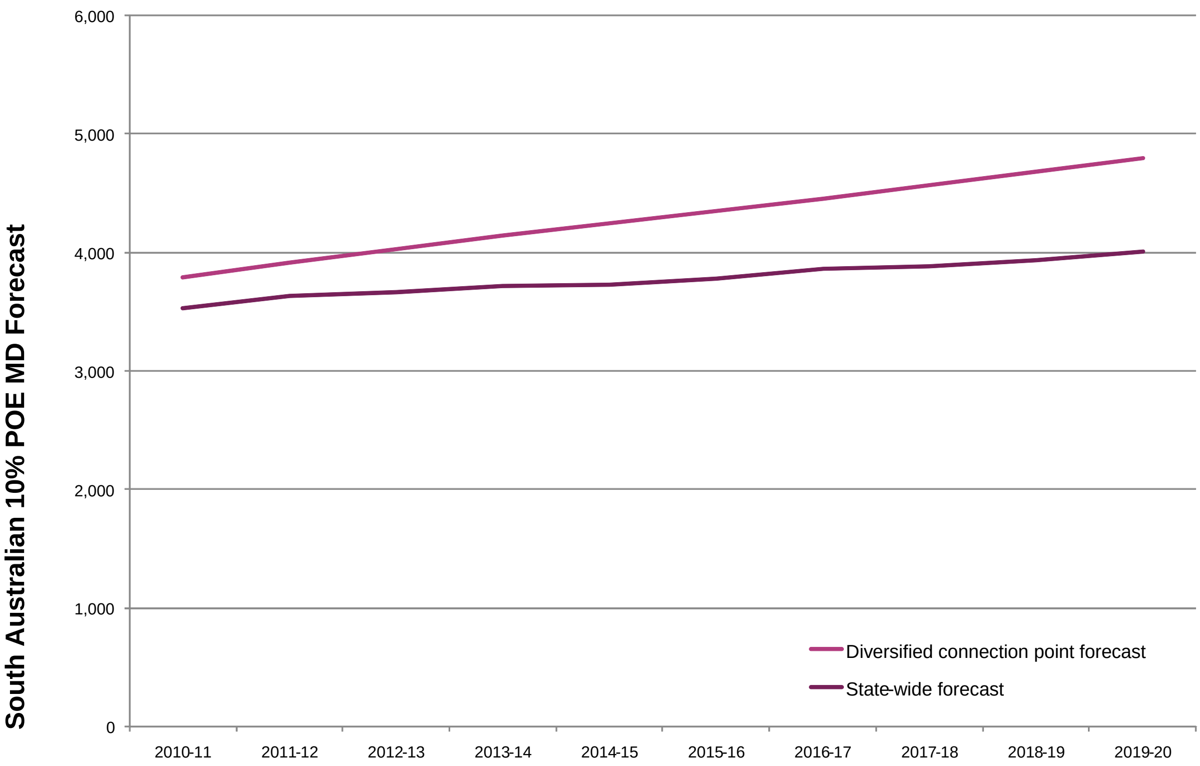
2.3.5 Comparison of SA state-wide and connection point forecasts

Each year ElectraNet and ETSA Utilities prepare peak demand forecasts over the ten year horizon for each transmission connection point on the South Australian network. Although there is not a formal link between state-wide and connection point forecasts, AEMO reconciles the two sets of forecasts to ensure network planning is done on a consistent basis.

The reconciliation process requires adjusting the connection point forecasts to place them on a comparable basis with the state-wide forecasts. This involves combining diversified connection point forecasts and then scaling up this aggregate to reflect transmission losses and generator auxiliary loads. These adjustments have been based on actual diversities observed during the recent summers.

Figure 2-13 presents the adjusted connection point forecasts and compares these against AEMO's updated summer 10% POE peak demand forecasts.

Figure 2-13 – Comparison of state-wide and connection point demand forecasts



The diversified connection point forecasts show higher growth in peak demand across the ten year horizon. The state-wide forecast is lower than the diversified connection point forecast largely due to the assumed impact of higher electricity prices associated with a carbon price and a reduced economic growth forecast.

2.3.6 Semi-scheduled and non-scheduled generation forecasts

From 2010/11 to 2019/20, native energy is forecast to grow by 0.9% under the medium scenario. Using the projections of semi-scheduled and non-scheduled generation supplied by KPMG Econtech, and AEMO's wind generation projections, the annual electricity load supplied by:

- semi-scheduled generation is forecast to grow by an average of 12.5% per annum
- non-scheduled generation is forecast to grow by an average of 0.0% per annum, and
- scheduled generation is forecast to decline by an average of approximately -2.3% per annum.

Figure 2-14 shows projections of future wind farm capacity based on KPMG Econtech's projections. The projections assume that all future wind developments with an aggregate nameplate rating of 30 MW or greater will be classified as semi-scheduled.

Figure 2-14 – Installed wind capacity projection (MW)

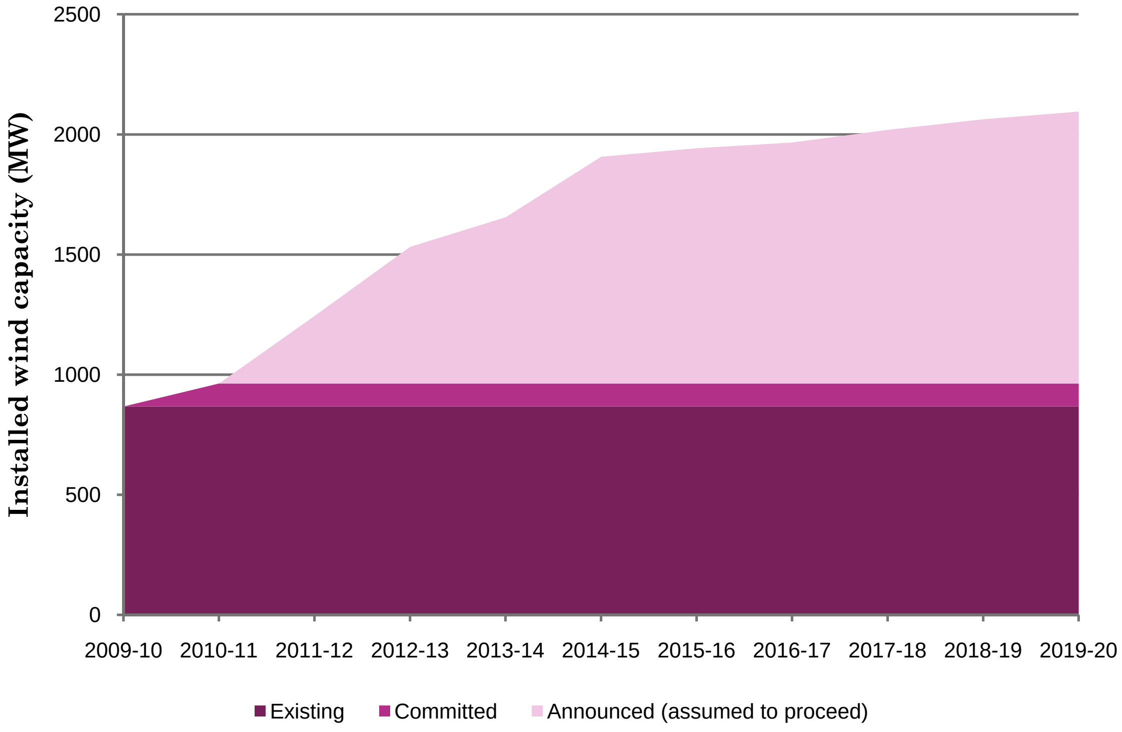


Figure 2-15 shows a breakdown of generation types contributing to the medium scenario native energy projections.

Figure 2-15 – Energy contribution projection (GWh)

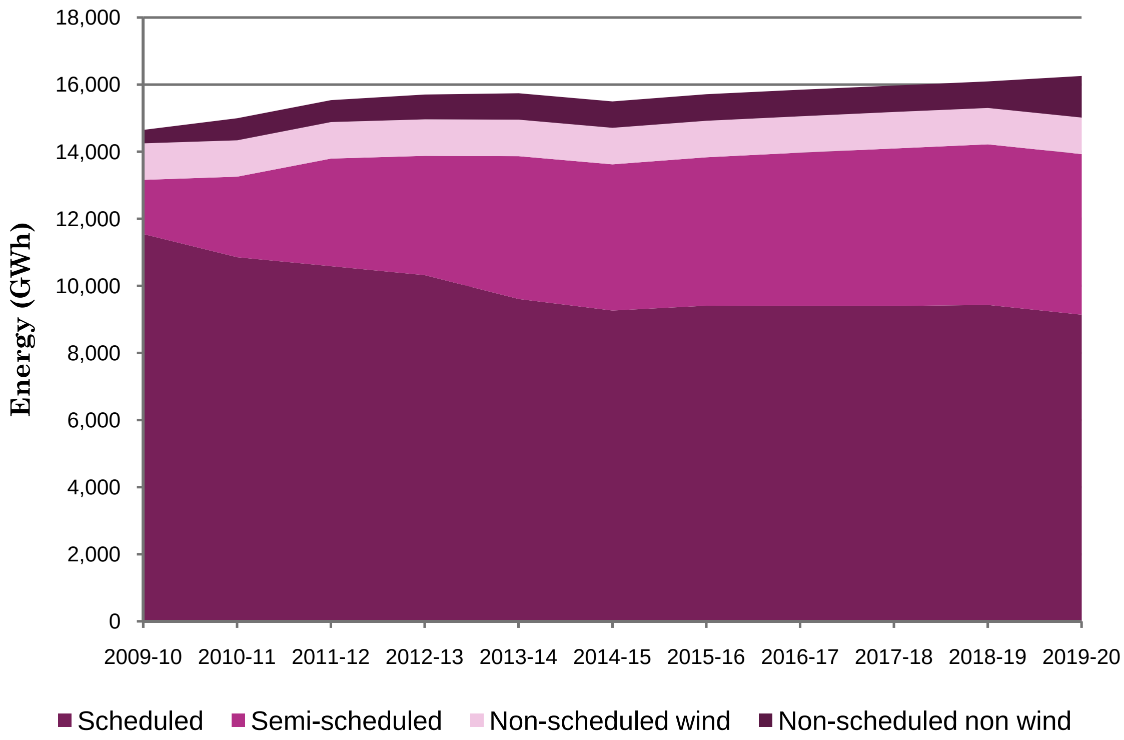


Table 2-7 lists the projections of non-scheduled generation capacity, energy contribution (i.e. annual generation) and contribution to the summer and winter MD (i.e. generation level).

Table 2-7 – Projections of non-scheduled and exempt generation

Year	Capacity (MW)	Energy Contribution (GWh)	Summer MD Contribution (MW)	Winter MD Contribution (MW)
2010/11	604	1,742	77	69
2011/12	604	1,742	77	69
2012/13	624	1,829	83	75
2013/14	635	1,878	86	78
2014/15	635	1,878	86	78
2015/16	635	1,878	86	78
2016/17	635	1,878	86	78
2017/18	635	1,878	86	78
2018/19	635	1,878	86	78
2019/20	739	2,332	117	109

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3 Supply

3.1 Summary

This chapter outlines current and prospective electricity supply developments in South Australia.

Table 3-1 – South Australian Generating Capacity Summary

Period	Summer (MW) 2010-11	Winter (MW) 2011
Conventional Thermal Generation	3,421	3,712
Scheduled/Semi-Scheduled Wind Generation (total/firm)	630/19	763/19
Current Installed Wind Generation (total/firm)	868/26	868/9
Total for the Supply Demand balance	3,440	3,719

Completed projects since 2008-09:

- AGL's 71 MW Hallett Stage 2 – Hallett Hill Wind Farm in the Mid North South Australia
- Pacific Hydro's 56.7 MW Clements Gap Wind Farm

Projects under construction:

- AGL's 132 MW Hallett Stage 4 – North Brown Hill Wind Farm is under construction, this project should be completed before mid-2011
- Infigen Energy's 39 MW Lake Bonney Stage 3 Wind Farm has undergone substantial construction. The company is also pursuing registration and licensing for the project
- International Power is expanding Port Lincoln Power Plant by 23 MW. The project is current under development with completion expected mid 2010
- Roaring 40s' 111 MW Waterloo Wind Farm is currently under construction, with expected completion later in 2010

Drought conditions in the past few years have affected electricity generation capabilities, reducing water levels available for hydro energy and for generators which rely on water for cooling. Recent heavy rains in the eastern states have eased generation restrictions, however, overall annual rainfall has not significantly increased and dam levels remain low.

3.2 Existing South Australian Generating Capacity

Scheduled generation in South Australia currently consists of two sub-bituminous coal, three distillate, seven natural gas and two dual-fuel capable power stations Together these generators have a total name-plate capacity of 3,640 MW. South Australia also has 11 operating wind farms with a total installed capacity of 868 MW. The name-plate ratings and other details of the generators that are currently operating in South Australia are provided in Table 3-2 and Table 3-3 with their locations shown in Figure 3-1.

Table 3-2 – Existing Conventional Thermal Generation Capacity

Registered NEM Participant	Power Station	# Units and Name-Plate Rating	Station Capacity (MW)	Plant Type	Fuel
AGL Energy	Torrens A	4 x 120	480	Conventional Steam	Natural Gas
AGL Energy	Torrens B	4 x 200	800	Conventional Steam	Natural Gas / Oil
Infratil	Angaston	30 x 1.67	50	Reciprocating Diesel	Distillate
International Power	Dry Creek	3 x 52	156	Gas Turbine	Natural Gas
International Power	Mintaro	1 x 90	90	Gas Turbine	Natural Gas
International Power	Pelican Point	1 x 487	487	Combined	Natural Gas
International Power	Port Lincoln	2 x 24	48	Gas Turbine	Distillate
International Power	Snuggery	3 x 26	78	Gas Turbine	Distillate
Origin Energy	Ladbroke Grove	2 x 46	92	Gas Turbine	Natural Gas
Flinders Operating Services	Northern	2 x 260	520	Conventional Steam	Coal
Flinders Operating Services	Osborne	1 x 180	180	Cogeneration	Natural Gas
Flinders Operating Services	Playford	4 x 60	240	Conventional Steam	Coal
Origin Energy	Quarantine	4 x 24.6 1 x 128.4	226.8	Gas Turbine	Natural Gas
TRUenergy	Hallett	11 units	192	Gas Turbine	Natural Gas / Distillate
Total Name-plate Capacity			3,640		

Table 3-3 – Existing Wind Generation Capacity

Registered NEM Participant	Wind Farm Name	# Units and Turbine Rating (MW)	Farm Capacity (MW)	Dispatch Type
AGL Energy	Hallett Stage 1- Brown Hill	45 x 2.1	94.5	Semi-Scheduled
AGL Energy	Hallett Stage 2- Hallett Hill	34 x 2.1	71.4	Semi-Scheduled
AGL Hydro	Wattle Point	55 x 1.65	90.75	Non-Scheduled
Pacific Hydro	Clements Gap	27 x 2.1	56.7	Semi-Scheduled
Infigen Energy	Lake Bonney Stage 1	46 x 1.75	80.5	Non-Scheduled
Infigen Energy	Lake Bonney Stage 2	53 x 3	159	Scheduled
Roaring 40s	Cathedral Rocks	33 x 2	66	Non-Scheduled
International Power	Canunda	23 x 2	46	Non-Scheduled
Transfield Services	Mt Millar	35 x 2	70	Non-Scheduled
Transfield Services	Starfish Hill	23 x 1.5	34.5	Non-Scheduled
TrustPower Ltd	Snowtown Stage 1	47 x 2.1	98.7	Scheduled
Total			867.65	

Figure 3-1 – Generator Locations around South Australia

3.3 Summer and Winter Scheduled Generation Capacity

While the name-plate rating of the generators provides some indication of their realisable capacity, the actual level of generation available at any particular time will depend on a range of factors. Factors such as age, outages and wear will affect the maximum capacity of every thermal generator, but the dominant factor with respect to its output will be the reduction in thermal efficiency with increasing temperature. Table 3-4 and Table 3-5, list the latest advised summer and winter ratings of the South Australian generators. Summer conditions relate to their statistically predicted peak demand contribution at 10% POE conditions. Due to the intermittent nature of wind generation, wind generation capacities have been de-rated to account for firm contribution to peak generation. Details on the analysis for this is described in further detail in Section 3.8.2.

For summer, wind generator capacities have been de-rated to 3% of their installed capacity to account for the level that would be available during times of peak demand. Similarly, in winter, they have been de-rated to 1% of installed capacity. Figures in Table 3-4 and Table 3-5 are rounded to the nearest whole number.

It is worth noting that South Australia has a number of large non-scheduled generators such as the wind generators listed in Table 3-4.

Table 3-4 – Summer Scheduled and Semi Scheduled Capacity by Station

Power station	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	Class[1]
Angaston	49	49	49	49	49	49	49	49	49	49	S
Dry Creek	115	115	116	117	118	118	118	118	118	118	S
Hallett Power Station	176	199	199	199	199	199	199	199	199	199	S+CP
Ladbroke Grove	70	70	70	70	70	70	70	70	70	70	S
Mintaro	67	68	68	68	68	68	68	68	68	68	S
Northern	542	542	542	542	542	542	542	542	542	542	S
Osborne	175	175	175	175	175	175	175	175	175	175	S
Pelican Point	448	448	448	448	448	448	448	448	448	448	S
Playford	200	240	240	240	240	240	240	240	240	240	S
Port Lincoln	57	57	57	57	57	57	57	57	57	57	S
Quarantine	191	191	191	191	191	191	191	191	191	191	S
Snuggery	51	51	51	51	51	51	51	51	51	51	S
Torrens Island A	480	480	480	480	480	480	480	480	480	480	S
Torrens Island B	800	800	800	800	800	800	800	800	800	800	S
Clements Gap WF	2	2	2	2	2	2	2	2	2	2	SS
Hallett WF S1 (Brown Hill)	3	3	3	3	3	3	3	3	3	3	SS
Hallett WF S2 (Hallett Hill)	2	2	2	2	2	2	2	2	2	2	SS
Lake Bonney WF S2	5	5	5	5	5	5	5	5	5	5	S
Snowtown WF	3	3	3	3	3	3	3	3	3	3	S
Hallett WF S4 (Nth Brown Hill)	2	2	2	2	2	2	2	2	2	2	CP
Hallett WF S5 (The Bluff)	1	1	1	1	1	1	1	1	1	1	CP
Lake Bonney WF S3	1	1	1	1	1	1	1	1	1	1	CP
Waterloo WF	3	3	3	3	3	3	3	3	3	3	CP
TOTAL	**3440**	**3508**	**3510**	**3511**	**3512**	**3512**	**3512**	**3512**	**3512**	**3512**	

[1] S = Scheduled, SS = Semi Scheduled, CP = Committed Project

Table 3-5 – Winter Scheduled and Semi Scheduled Capacity by Station

Power station	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Status
Angaston	49	49	49	49	49	49	49	49	49	49	S
Dry Creek	146	146	147	148	148	148	148	148	148	148	S
Hallett Power Station	203	203	203	203	203	203	203	203	203	203	S+CP
Ladbroke Grove	86	86	86	86	86	86	86	86	86	86	S
Mintaro	90	90	90	90	90	90	90	90	90	90	S
Northern	546	546	546	546	546	546	546	546	546	546	S
Osborne	192	192	192	192	192	192	192	192	192	192	S
Pelican Point	474	474	474	474	474	474	474	474	474	474	S
Playford	240	240	240	240	240	240	240	240	240	240	S
Port Lincoln	73	73	73	73	73	73	73	73	73	73	S
Quarantine	223	223	223	223	223	223	223	223	223	223	S
Snuggery	66	66	66	66	66	66	66	66	66	66	S
Torrens Island A	504	504	504	504	504	504	504	504	504	504	S
Torrens Island B	820	820	820	820	820	820	820	820	820	820	S
Clements Gap WF	1	1	1	1	1	1	1	1	1	1	SS
HallettWF S1 (Brown Hill)	1	1	1	1	1	1	1	1	1	1	SS
Hallett WF S2 (Hallett Hill)	1	1	1	1	1	1	1	1	1	1	SS
Snowtown WF	2	2	2	2	2	2	2	2	2	2	S
Lake Bonney WF S2	1	1	1	1	1	1	1	1	1	1	S
Hallett WF S4 (Nth Brown Hill)	1	1	1	1	1	1	1	1	1	1	CP
Hallett WF S5 (The Bluff)	1	1	1	1	1	1	1	1	1	1	CP
Lake Bonney WF S3	0	0	0	0	0	0	0	0	0	0	CP
Waterloo WF	1	1	1	1	1	1	1	1	1	1	CP
TOTAL	**3719**	**3720**	**3720**	**3721**	**3722**	**3722**	**3722**	**3722**	**3722**	**3722**	

3.4 Retirements / Refurbishment / Relocations

Hallett Gas Turbine summer capacity was enhanced by around 25 MW during 2009 with the installation of "fogging" capability on the existing units. Improved information on the station has led to a minor degradation in winter by 8 MW.

AEMO is not aware of any currently proposed retirements before the end of the ten year planning horizon.

3.5 New Plant Developments

3.5.1 Completed Projects

Over the past financial year, two generation projects were completed in South Australia:

AGL Energy completed its 71 MW Hallett Stage 2 – Hallett Hill Wind Farm in the State's Mid North in December 2009.

Pacific Hydro completed its 56.7 MW Clements Gap Wind Farm in early 2010.

3.5.2 Commitment Criteria

AEMO has sought information from the proponent of each known new project to enable it to determine whether the project should be classified as - "Committed", "Advanced", or "Publicly Announced". The information obtained from proponents is assessed against the following criteria:

- The proponent has purchased/settled/acquired land[2] (or legal proceedings have commenced) for the construction of the proposed development.
- Contracts for the supply and construction of the major components of plant or equipment (such as generators, turbines, boilers, transmission towers, conductors, terminal station equipment) should be finalised and executed, including any provisions for cancellation payments.
- The proponent has obtained all required planning consents, construction approvals and licences, including completion and acceptance of any necessary environmental impact statements.
- The financing arrangements for the proposal, including any debt plans, must have been concluded and contracts executed.
- Construction of the proposal must either have commenced or a firm commencement date must have been set.

Projects which meet five of the commitment criteria are considered "committed", those that meet at least three criteria are considered "advanced" and those that meet less than three criteria are classified as "publicly announced". For the purposes of this report, a further project classification of "Under Construction" has been included.

3.5.3 New Projects – "Under Construction"

Table 3-6 shows the list of projects that are currently under construction.

[2] Purchase of land or acquisition of easements, if required, do not imply by themselves a binding financial commitment but are a pre-requisite for commitment.

Table 3-6 – Generation Projects "Under Construction"

Developer	Power Station	Capacity[3] (MW)	Plant & Fuel Type / Dispatch Type	Completion Targets
AGL Energy	Hallett (Nth Brown Hill) WF	63 x 2.1 = 132.3	Wind Turbines	Under Construction Complete: Q2/2011
Infigen	Lake Bonney 3	13 x 3.0 = 39	Wind Turbines	Advanced but Under Construction: Operational 2010
International Power	Port Lincoln	1 x 23	OCGT Distillate Scheduled	Under Construction Complete: mid 2010
Roaring 40s	Waterloo	37 x 3 = 111	Wind Turbines	Under Construction Complete: 2010
TRUenergy	Hallett Power Station GT 2-3	1 x 23	Gas Turbine	Under Construction Complete: Q1/2011

AGL Energy has announced plans to continue with its wind farm developments in the Hallett area in stages. Hallett 4 located at North Brown Hill, is currently under construction and is expected to be completed around May 2011.

Infigen Energy is developing a third stage at Lake Bonney in the State's South East. While significant construction has already been undertaken, AEMO notes that registration with AEMO is still under negotiation, and output from the wind farm is currently limited to below 5 MW by licence conditions. This project is difficult to classify as it has started construction but has not yet satisfied the commitment criteria.

International Power has advised that a third distillate fired Frame 5 open cycle gas turbine is currently under construction adjacent the existing generation facilities in Port Lincoln by International Power. This additional unit should be complete mid 2010 and will increase the name plate capacity at that installation to 71 MW.

Roaring 40s has commenced construction of its 111 MW Waterloo Wind Farm located near the Clare Valley in South Australia, about 30 km south-east of the township of Clare. Roaring 40's has entered a long term contract with Vestas who will supply and maintain 37, 3 MW, V90 turbines and with CLP (through its subsidiary TRUenergy) and Hydro Tasmania to purchase renewable energy certificates and hedge electricity prices for the first 10 years of production.

TRUenergy has commenced work at Hallett Power Station with the addition of a new 23 MW gas turbine. The project is expected to operational from January 2011.

3.5.4 New Projects - "Committed" And "Advanced"

Table 3-7 shows the list of projects that are either under construction, committed or advanced, with Figure 3-2 presenting the locations of those generators.

[3] Capacity here refers to the Name-Plate of the units rather than their potential output during peak demand periods.

Table 3-7 – Generation Projects "Committed" and "Advanced"

Developer	Power Station	Capacity[4] (MW)	Plant & Fuel Type / Dispatch Type	Completion Targets
AGL Energy	Hallett WF (The Bluff)	25 x 2.1 = 52.5	Wind Turbines	Committed Complete: Q4/2011
Origin Energy	Quarantine	1 x 125	Gas Turbine	Advanced Project No Firm Date
Trust Power	Snowtown 2	98 x 2.1 = 205.8	Wind Turbines	Advanced Project Complete: 2011

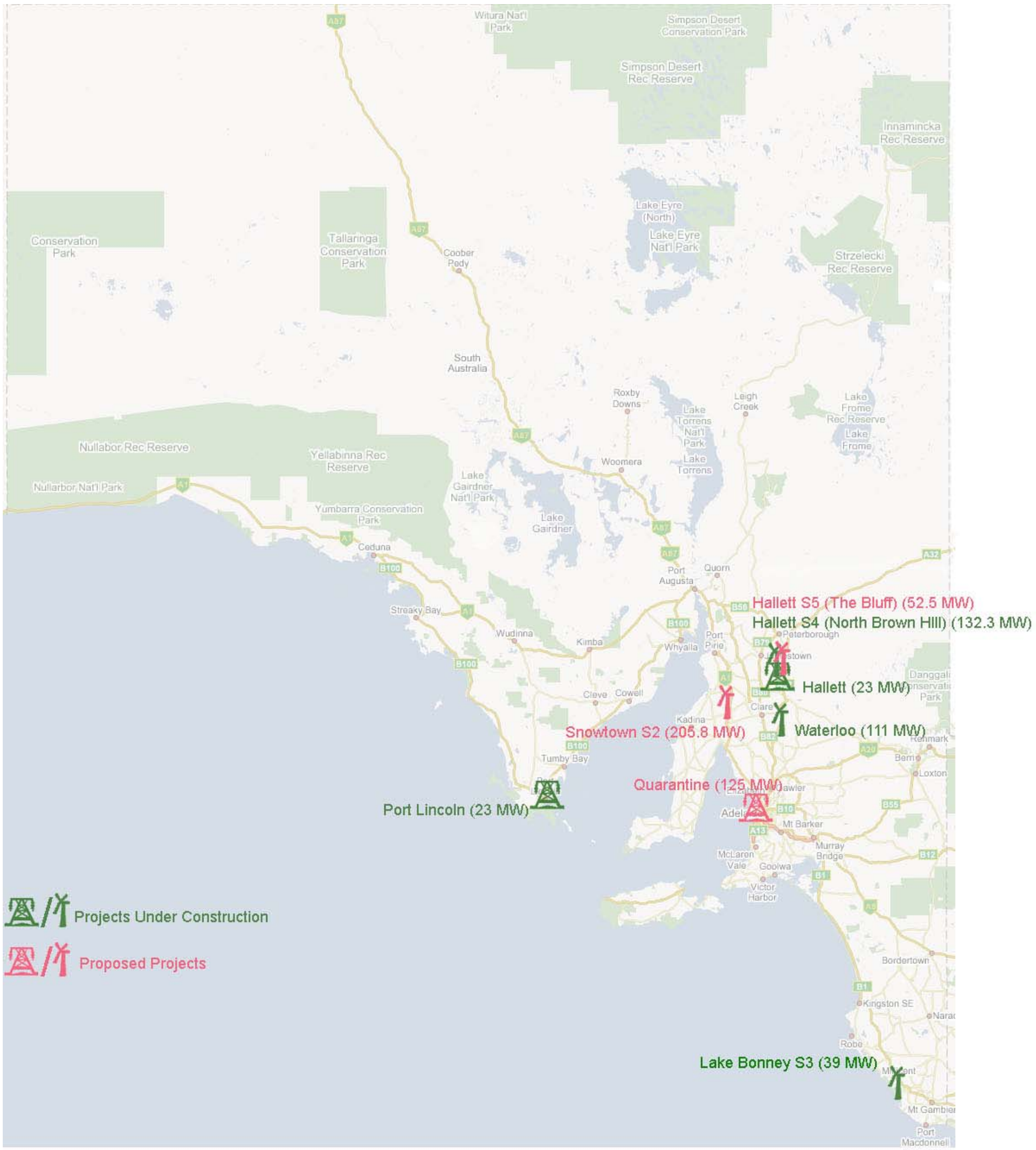
AGL Energy announced it had entered into agreements for the construction of the 52.5 MW Hallett 5 wind farm at the Bluff Range in the mid-north of South Australia. Construction is expected to begin in July with completion anticipated in December 2011.

Origin Energy has Development Approval to expand the quarantine power station further by adding a steam turbine to generate power using the heat produced by the exhaust from the existing generators. However, this project is yet to be approved by the Origin Board.

Trust Power has publicly announced plans to expand its Snowtown Wind Farm by adding around 98, 2.1 MW turbines. No firm date has been announced yet for construction of Snowtown Stage 2.

[4] Capacity here refers to the Name-Plate of the units rather than their potential output during peak demand periods.

Figure 3-2 – Location of generators under construction, committed or advanced



3.5.5 New Projects - "Publicly Announced"

Table 3-8 provides a summary of the new generation proposals for South Australia that have been publicly announced. There are a number of projects which proponents have regarded as being confidential. These have not been included in the list at the request of the proponents.

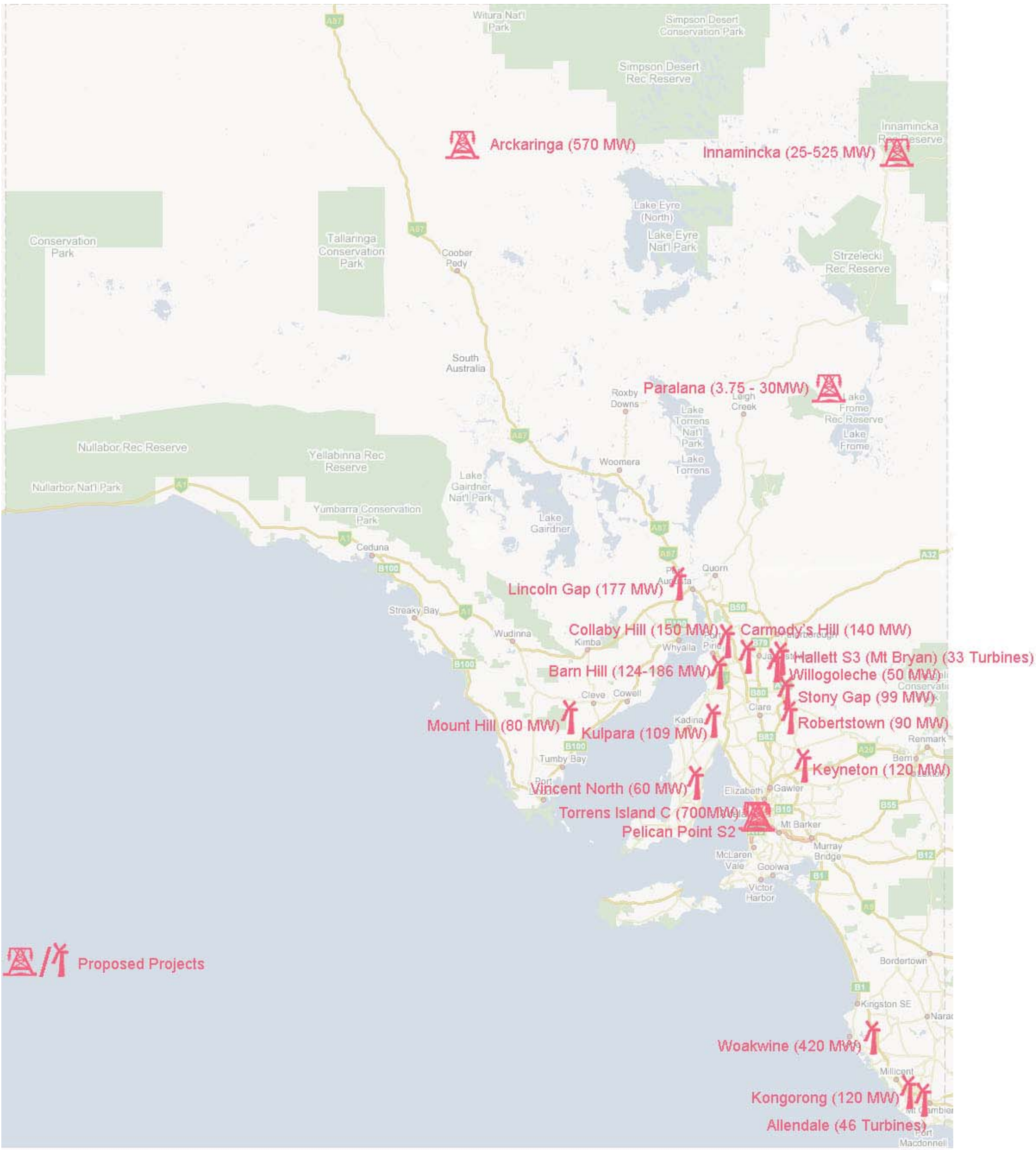
Table 3-8 – Generation Projects "Committed" and "Advanced"

Developer	Project	Fuel/Plant Type	Capacity	Classification/ Approximate date of completion
Acciona Energy	Allendale WF	Wind	46 turbines	Publicly Announced Potential Completion: Q1, 2013
AGL Energy	Hallett (Mt Bryan) WF	Wind	33 Turbines	Publicly Announced Potential Completion: Mid 2014
AGL Energy	Torrens Island C	Gas	~700 MW	Publicly Announced Potential Completion: TBA
AGL Energy/Transfield[5]	Barn Hill WF	Wind	124-186 MW	Publicly Announced: No firm date
Altona Energy	Arckaringa	Scheduled	2 x 285 MW = 570 MW	Publicly Announced Potential Completion: 2015
Geodynamics	Innamincka	Geothermal	1 x 25 MW + 10 x 50 MW = 525 MW	Publicly Announced Expect to supply local load in 2015 and grid connection 2018
Infigen	Woakwine	Wind	~420 MW	Publicly Announced No firm date
International Power	Pelican Point S2	Scheduled	300 MW	Publicly Announced No firm date
International Power	Willogoleche WF	Wind	25 x 2 MW = 50 MW	Publicly Announced No firm date
National Power	Lincoln Gap WF	Wind	59 x 3 MW = 177 MW	Publicly Announced Potential Completion: end 2011
Origin Energy	Collaby WF	Wind	75 x 2 MW = 150 MW	Publicly Announced No firm date
Pacific Hydro	Carmody's Hill	Wind	70 x 2 MW = 140 MW	Publicly Announced No firm date
Pacific Hydro	Keyneton	Wind	60 x 2 MW = 120 MW	Publicly Announced No firm date
Pacific Hydro	Vincent North	Wind	30 x 2 MW = 60 MW	Publicly Announced No firm date
Petratherm	Paralana	Geothermal	3.75 MW Pilot Plant	Publicly Announced Potential Completion: 2012
Roaring 40s	Roberts Town WF	Wind	30 x ~3 MW = ~90 MW	Publicly Announced
Roaring 40s	Stony Gap WF	Wind	33 x ~3 MW = ~99 MW	Publicly Announced
Transfield Services	Kongorong WF	Wind	57 x 2.1 MW = 120 MW	Publicly Announced
Transfield Services	Kulpara WF	Wind	52 x 2.1 MW = 109 MW	Publicly Announced
Transfield Services	Mount Hill WF	Wind	38 x 2.1 MW = 80 MW	Publicly Announced

Figure 3-3 provides the locations of these publicly announced generation projects.

[5] This project is currently being sold by Transfield to AGL Energy.

Figure 3-3 – Map of Publicly Announced Projects in South Australia



Acciona Energy is proposing a new wind farm at Allendale 7 km South of Mt Gambier in the South East of South Australia. Grant District Council's development assessment panel has approved plans to install 46 turbines at the site.

AGL Energy's Hallett Stage 3 - Mt Bryan wind farm proposal covers a ridge spanning approximately 11 km directly west of the township of Mount Bryan. The wind farm is planned to comprise 33 turbines.

On 6 November 2009, AGL Energy announced plans to increase peaking generation at Torrens Island Power Station by more than 50 per cent with the installation of either two larger or four smaller new generation gas turbines and the construction of a major new gas storage facility. Combined the new generators will be capable of producing 700 megawatts of peaking generation.

AGL is acquiring the right to install up to 62 turbines (estimated capacity between 124 MW and 186 MW) at Barn Hill from Transfield Services. The wind farm is to be located 170km north of Adelaide near the settlement of Red Hill and will utilise a high voltage transmission line separate from the line which is used by AGL at its nearby complex of Hallett wind farms.

Altona Energy along with China National Off-shore Oil Corporation’s New Energy Investment Company are joint Venture partners in the Arckaringa Project, located about 120km north of Coober Pedy. The project is large scale and complex, involving the establishment of a conventional open cut coal mine followed by processing and an oil refinery/petro-chemicals plant with efficient integrated combined cycle electricity generation which captures and uses waste heat. The joint venture is concluded pre-feasibility studies in 2008, and found sufficient justification to move on to final feasibility studies. If the project is completed, Altona expect to construct a 570 MW power generation plant at the site.

Geodynamics is developing the utilisation of Hot Fractured Rock geothermal power in the far north east of the State near Moomba.

In March 2009, Geodynamics announced that it had successfully proven its ability to extract heat from hydraulically stimulated hot fractured rock to create power.

To date, the company has drilled five wells - Habanero 1, Habanero 2, Habanero 3, Jolokia 1 and Savina 1. Of these, Habanero 1 and 2 are not of commercial scale, and Habanero 2 is not sufficiently connected to the reservoir because of lost equipment in the hole. Habanero 3, was the first well to be drilled using the 'Lightning Rig' to a depth of 4,200 m making it the largest well of this depth ever drilled onshore in Australia and the first commercial scale Hot Fractured Rock production well to be drilled. Jolokia 1 was drilled to 4,900 m and Savina 1 was drilled to 3,700 m.

On 24 April 2009, Geodynamics experienced a well control incident at Habanero 3. Once under control, a detailed investigation was conducted which found that the casing material had cracked due to hydrogen embrittlement, which was caused by dissolved gases in the reservoir fluid.

A heavier duty drilling rig is due to arrive in Australia in October and will commence drilling Habanero 4 in November, followed immediately by Habanero 5.

The Innamincka 1 MW Pilot Plant will be powered by the Habanero 4 and 5 well doublets. The commissioning of the 1 MW Power Plant is now expected by early 2012.

Geodynamics plans to finalise its preferred design for a 25 MW commercial demonstration plant in 2010. The company expects to be in a position to make a final investment decision on the commercial demonstration plant after 12 months of successful operation of the Habanero closed loop (incorporating the1 MW Power Plant) by early 2013.

Infigen has publicly announced its proposal to construct a 420 MW wind farm at Woakwine.

International Power has proposed:

- an expansion of its Pelican Point power station of up to 300 MW, and
- a wind farm located west of the township of Hallett, 200 km north of Adelaide in the mid-north of South Australia. The Willogoleche Wind Farm has a proposed capacity around 50 MW.

National Power is examining the feasibility of a wind farm at Lincoln Gap about 20 km south west of Port Augusta on the Eyre Peninsula.

Origin Energy is pursuing a number of wind farm developments in South Australia and Victoria having purchased the development projects from Wind Farm Developments and Wind Power Pty Ltd. In South Australia their main interest is in Collaby Hill where it is investigating installing up to 150 MW of wind turbines.

Pacific Hydro is examining the feasibility of three wind farms:

- A proposed 140 MW wind farm at Carmody's Hill located on the ridgeline to the east of Georgetown and runs approximately 18km north from Mt Misery;
- Preliminary investigations have been conducted for a proposed wind farm at Keyneton in South Australia. The site is 6km west of Sedan and 10km south east of Angaston and runs approximately 18km north to south. Current wind energy analysis indicates that the site is suitable for a wind farm of up to 60 generators with a total capacity of up to 120 MW; and
- A 60 MW wind farm at Vincent North located between Port Julia and Port Vincent on the Yorke Peninsula. The project was given planning approval by Yorke Peninsula District Council in December 2003. Further studies are being undertaken to determine the overall feasibility of the project.

Petratherm and its joint venture partners, Beech Energy and TRUenergy, completed the first of two deep wells at its Paralana site last year. Following completion of the second well and proving circulation between the two wells, the company plans to construct a 3.75 MW pilot plant. If operation of a pilot plant is successful, Petratherm will expand to a 30 MW commercial demonstration plant capable of meeting the growing needs of the Beverley Uranium Mine and the proposed mine development at the nearby Four Mile deposit.

Large scale generation will require a network connection between Paralana and the NEM. Petratherm has proposed network solutions that will be capable of delivering up to 520 MW.

Roaring 40's (a joint venture between Hydro Tasmania and CLP Power Asia) has two projects under proposal in close vicinity to its Waterloo Wind Farm Project, currently under construction.

Robertstown Wind Farm is likely to comprise over 30 turbines, with a maximum total generating capacity of up to 96 MW. The wind farm is located on a ridgeline to the west of the town of Robertstown, approximately 120 km north of Adelaide.

Stony Gap Wind Farm is likely to comprise approximately 33 turbines, with a maximum total generating capacity of up to 109 MW. The wind farm is located to the south of the town of Burra, approximately 120 km north of Adelaide.

Transfield Services has three projects publicly proposed projects in South Australia:

- Kongorong Wind Farm is to be located around 20km south west of Mount Gambier;
- Kulpara Wind Farm is to be located around 16km north-west of Port Wakefield at the top of the Yorke Peninsula; and
- Mount Hill Wind Farm is located near Butler, 80km north-east of Port Lincoln on the Eyre Peninsula.

Other Companies: AEMO is also aware of a number of other proposed generators in various stages of development. In particular, AEMO has been in contact with many of the geothermal exploration companies in South Australia. Most are still in the early stages of establishing the scope of resources and potential development paths. Some companies have also provided commercial in-confidence information to AEMO about their proposed projects. Where information about projects has been limited AEMO has included as much publicly available information as possible.

3.6 Historic Generation Levels and Performance

Table 3-9 shows historical generation for South Australian Power Stations from 2002-03 to date. 2009/10 figures are calculated on a pro-rata basis from data up to April 2010.

Table 3-9 – Historical Generation for South Australian Generators

Station Name	2002-03 (GWh)	2003-04 (GWh)	2004-05 (GWh)	2005-06 (GWh)	2006-07 (GWh)	2007-08 (GWh)	2008/09 (GWh)	2009/10 (GWh)
Angaston	0	0	0	2	4	2	2	0
Dry Creek	5	2	1	1	16	10	6	11
Hallett	14	18	23	22	151	28	23	32
Ladbroke Grove	596	493	503	348	249	141	192	185
Mintaro	15	2	3	1	36	8	4	9
Northern	4,124	4,248	4,352	3,997	4,466	4,013	4,213	3,670
Osborne	1,272	1,254	1,068	1,176	1,251	1,230	1,244	1,167
Pelican Point	2,394	1,365	1,103	1,620	2,775	3,281	3,281	2,892
Playford	13	167	483	541	722	870	695	1,000
Port Lincoln	0	1	1	1	1	2	2	2
Quarantine	45	42	65	128	80	84	97	271
Snuggery	3	1	1	0	1	2	2	3
Torrens A	179	168	418	396	376	527	538	312
Torrens B	2,113	2,571	2,450	2,141	2,350	2,782	1,976	1,714
Lake Bonney S2 Wind Farm	0	0	0	0	3	230	342	296
Snowtown S1 Wind Farm	0	0	0	0	0	11	320	376
Hallett S1 WF	0	0	0	0	0	91	327	347
Hallett S2 WF	0	0	0	0	0	0	16	257
Clements Gap	0	0	0	0	0	0	3	172
Non Scheduled Wind	4	102	344	765	901	967	999	1,062
Total	**10,777**	**10,434**	**10,815**	**11,139**	**13,382**	**14,279**	**14,282**	**13,778**

Figure 3-4 and Figure 3-5 show the capacity factors of generators in South Australia based on the name plate capacity for each generator.

Figure 3-4 – Financial Year Capacity Factors for Scheduled and Semi Scheduled South Australian Generators

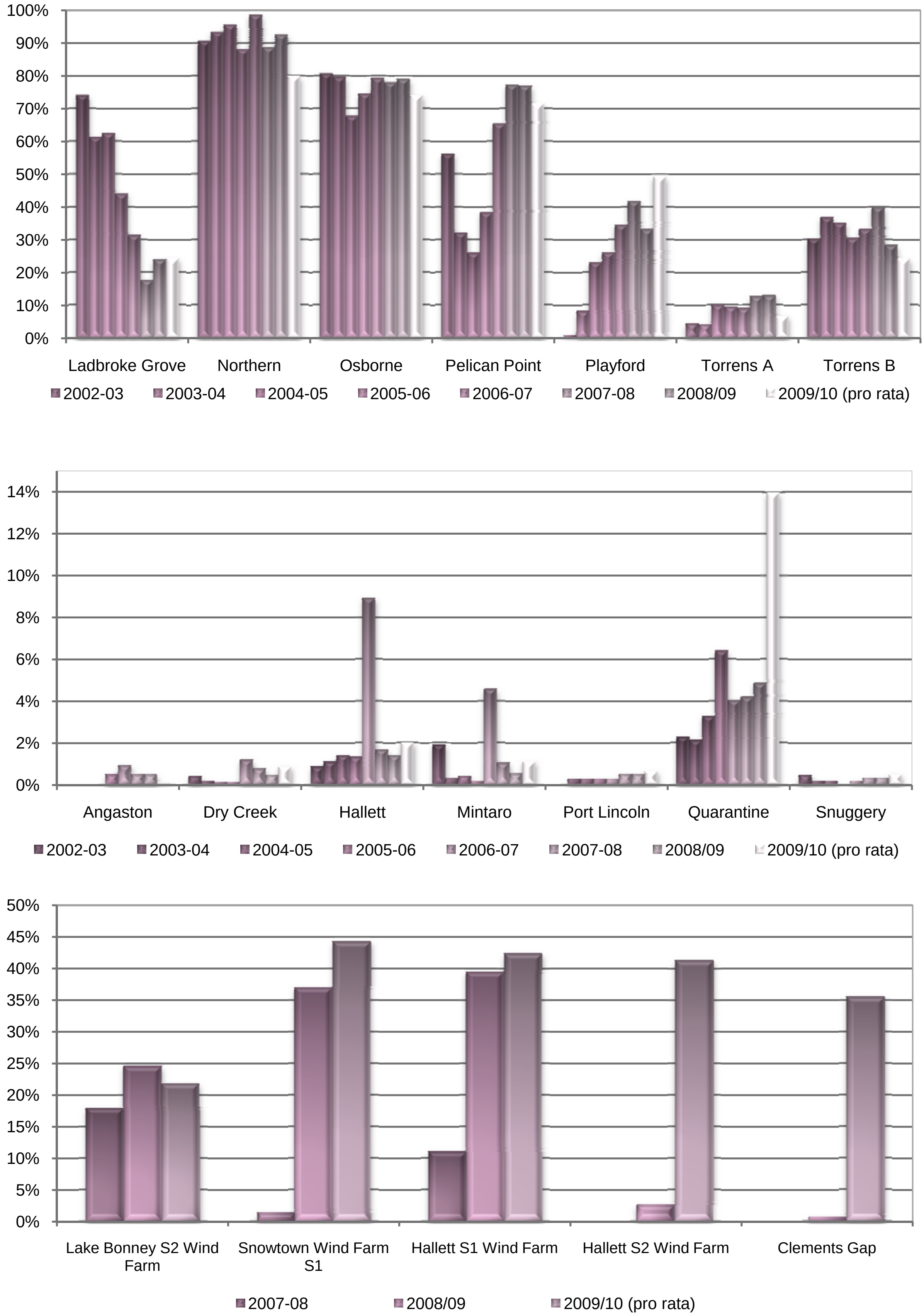
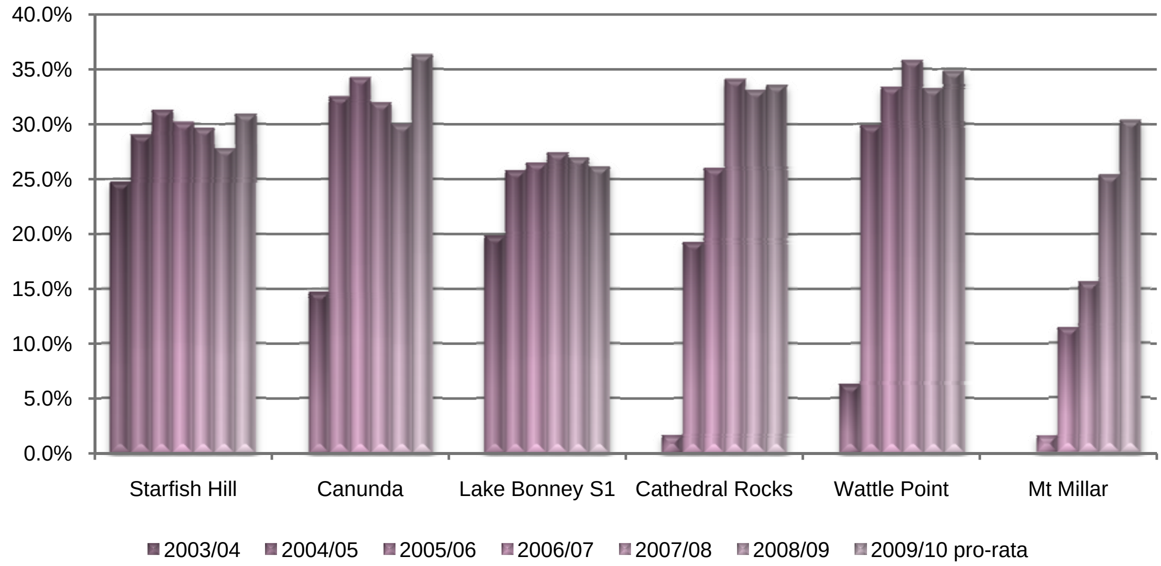


Figure 3-5 – Financial Year Capacity Factors for Non-scheduled Wind Farms



Note: Mt Millar Wind Farm capacities are lower in the early years due to limited access to the market.

3.7 Interstate Supply

3.7.1 Existing South Australian Interconnectors

South Australia is connected to the rest of the National Electricity Market via Victoria by the Heywood and Murraylink interconnectors. Each of these is defined as operating between the two relevant regional reference nodes; i.e. Torrens Island 66 kV bus in South Australia and the Thomastown 66 kV bus in Victoria.

3.7.2 Transfer Capability Calculation

The maximum operating capability of the notional interconnectors between the South Australian and Victorian regional reference nodes is affected by a number of physical and electrical limits. These limits are described by a series of specific equations (constraint equations) that include operational factors, such as demand, the output from certain generators and the status of specific items of transmission plant in both regions. These equations have been developed by the transmission entities in South Australia and Victoria for use by AEMO in determining dispatch patterns. There are many constraints that may reduce the maximum transfer capability of the interconnectors in certain circumstances. Constraint equations should also change over time to address specific changes to the transmission network, including network augmentations, the connection of new loads and the commissioning of new generation.

Transfers between regions are managed within the limits defined by these equations by AEMO in the NEM Dispatch Engine (NEMDE). The generators are dispatched and inter-regional flows are calculated in each five minute dispatch interval. Pricing between regional reference nodes includes the cost of losses based on the marginal loss factor equations that define the relative cost of imported energy at the receiving reference node. More information regarding constraint equations can be found in AEMO's publication entitled "List of Regional Boundaries Marginal Loss Factors for the 2010-2011 Financial Year".

3.7.3 Heywood Interconnector

The physical and security related constraints on the existing Heywood Interconnector have been developed to ensure the secure operation of the power system.

Most constraints can also be influenced by dispatch offers from generators in the South-East and non-scheduled generation from the local wind farms, and can result in local generation displacing power flow from Victoria.

The NEMDE can optimise the output of the scheduled generators in the region but does not optimise the dispatch of unscheduled wind farms. A “Semi-Scheduled” category was created for registration for intermittent generators that have no control over their “fuel” supplies. This category enables the output from wind farms in this category to be optimised during periods when constraints, in which they are included, are binding.

Numerous equations determine the maximum transfer instantaneous capability for the Heywood Interconnector at the region boundary. Historically, the nominal maximum import capacity of the Heywood Interconnector was 460 MW. ElectraNet revised the import constraint equations for the Heywood Interconnector significantly reducing its capacity, particularly during peak periods, leading to a noticeable impact on the flows of electricity from Victoria to South Australia. ElectraNet has indicated that this reduction was a result of the change in the maximum capacity of the Northern Power Station units, the completion of Tungkillo Substation and the completion of the Lake Bonney Stage 2 Wind Farm.

With more wind generation in South Australia, there has been a greater interest in the export limits out of South Australia. ElectraNet has re-examined the network limits relating to exports and has advised that it considers that the export limit can be raised, under certain circumstances, to 460 MW.

3.7.4 Murraylink

Murraylink has been operating as a regulated interconnector since October 2003. Under favourable circumstances, Murraylink nominally provides 220 MW of additional import capacity into the South Australian region. Murraylink transfer capacity is dependent on regional demand in the Riverland, demand in north-western Victoria and the operation of some generators in South Australia.

The capacity of Murraylink is also dependent on the availability of a number of transmission network elements in South Australia, Victoria and New South Wales. Murraylink is now controlled by a very fast “runback” scheme which rapidly reduces transfers across Murraylink in the event of an element failure further back in the network. While this scheme increases the amount of time that Murraylink is available for its nominal capacity, the failure of any one of the transmission elements within the runback scheme will reduce the capacity to zero.

3.7.5 Historic Interconnector Flows

Table 3-10 and Table 3-11 show the total energy imported and exported and the average flow rates for both the Murraylink and Heywood interconnectors, calculated from half-hourly data for each financial year.

Figure 3-6 shows total net imports into South Australia from 1999-2000 to 2009-10. Flows are measured at the regional boundary between South Australia and Victoria. Historically, South Australia is an importer of electricity from Victoria, however, net flows from 2006-07 to 2009-10 have decreased. This corresponds with the recent increases in wind capacity in South Australia well as prevailing drought conditions affecting supply in the eastern states. A recovery in rainfall will increase the available supply in the eastern states. This affects the market in South Australia as low cost supply from wind generators is balanced against cheaper energy imported over the interconnectors.

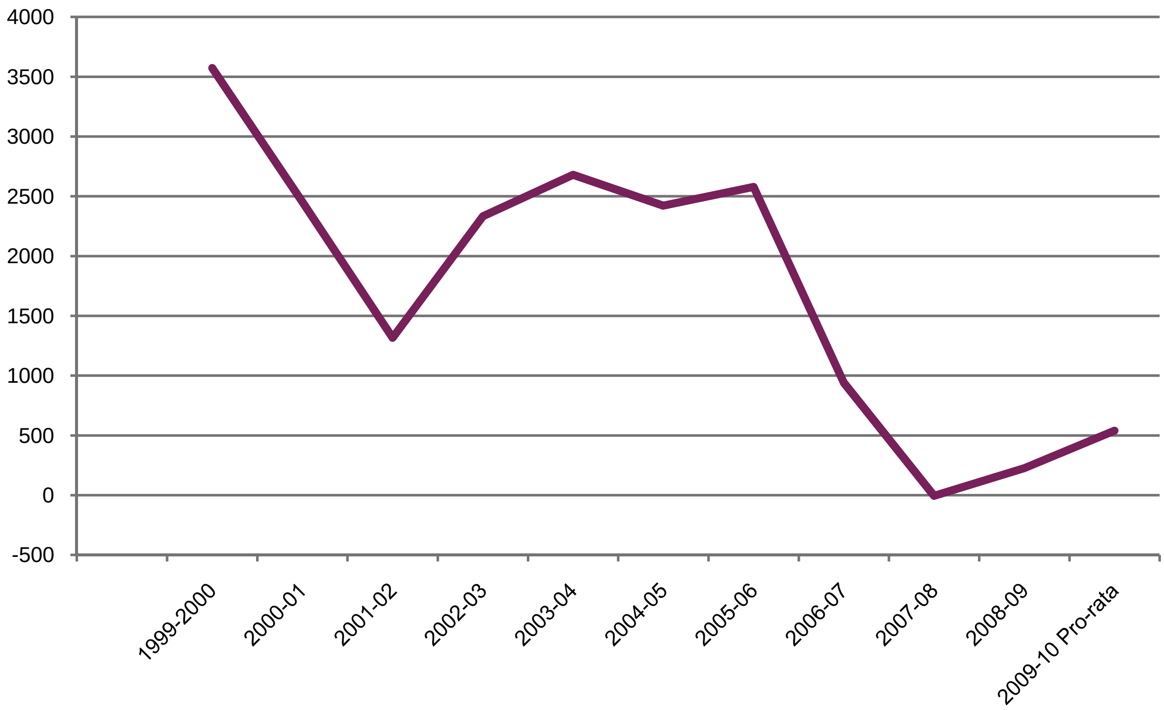
Table 3-10 – Historic Murraylink Interconnector Flow

Financial Year	Total Imports (GWh)	Total exports (GWh)	Import average (MW)	Export Average (MW)
2002-03	206	10	86	35
2003-04	217	60	46	28
2004-05	305	38	46	22
2005-06	270	31	41	20
2006-07	87	156	30	33
2007-08	40	176	20	29
2008-09	52	218	24	35
2009-10 Pro-rata	75	285	30	45

Table 3-11 – Historic Heywood Interconnector Flow

Financial Year	Total Imports (GWh)	Total Exports (GWh)	Import Average (MW)	Export Average (MW)
1999-2000	3,574	1	408	63
2000-01	2,471	18	291	69
2001-02	1,439	123	198	83
2002-03	2,191	54	272	77
2003-04	2,554	31	305	74
2004-05	2,214	59	272	95
2005-06	2,374	35	285	83
2006-07	1,246	235	193	102
2007-08	657	526	140	129
2008-09	829	436	156	119
2009-10 Pro-rata	1068	318	179	114

Figure 3-6 – Net Imports into South Australia



3.8 Wind Study

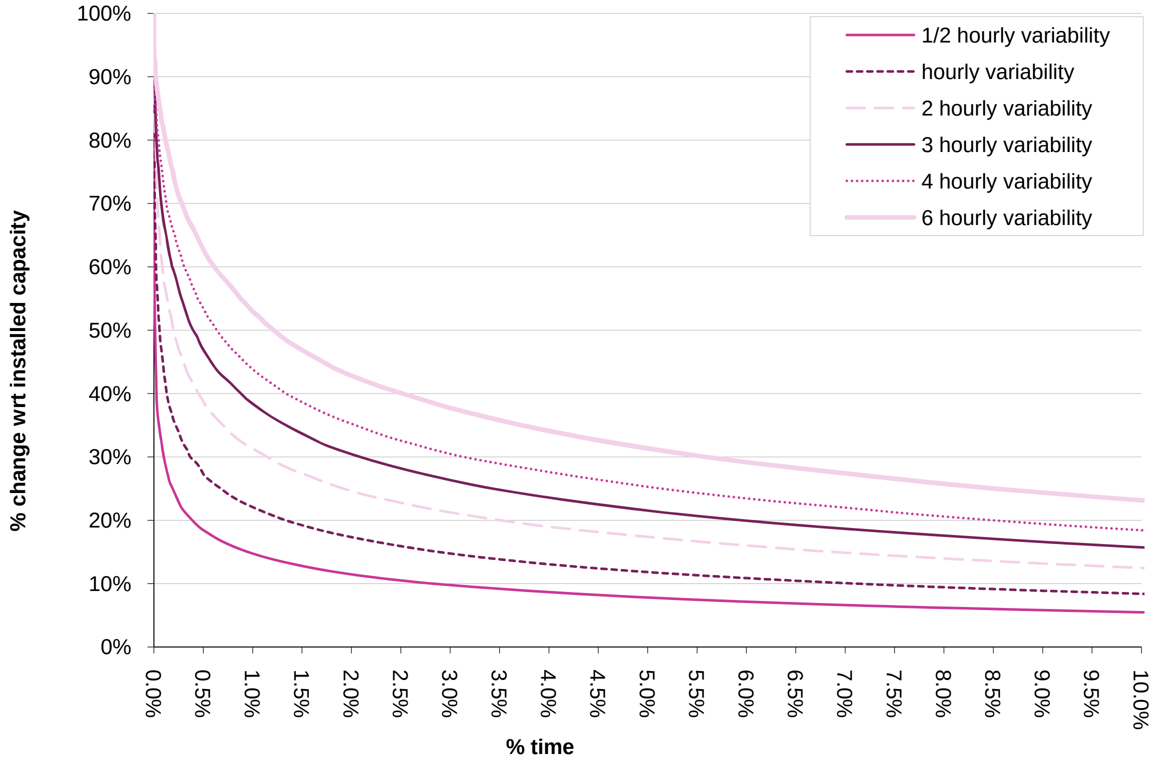
3.8.1 Wind Variability

South Australia has the deepest penetration of wind in the country. Consequently, wind variability is more prominent as the amount of energy being generated by wind can vary significantly over a short period. For example, From 1 July 2009 to 1 May 2010, the largest half hour increase in wind generation was 223 MW and occurred from 5:30pm to 6:00pm on 8 December 2009. The largest half hour decrease of 135 MW occurred on the same day two hours later.

Figure 3-7 shows changes in wind generation as a proportion of total installed capacity from 2003 to April 2010. For the majority of the time the half hourly wind variations are quite small. For almost 90% of the time the changes in half hourly variability were around 5% or less of the installed capacity. However, there were some occurrences when the change was more significant. For example, there were 16 occurrences where the shift was more than half of the installed capacity.

Figure 3-7 also shows that there are greater shifts in variability over longer time periods. When considering variability over a 6 hourly periods, 90% of the time changes of up to 23% of installed capacity were observed.

Figure 3-7 – Wind Variability as a proportion of installed capacity



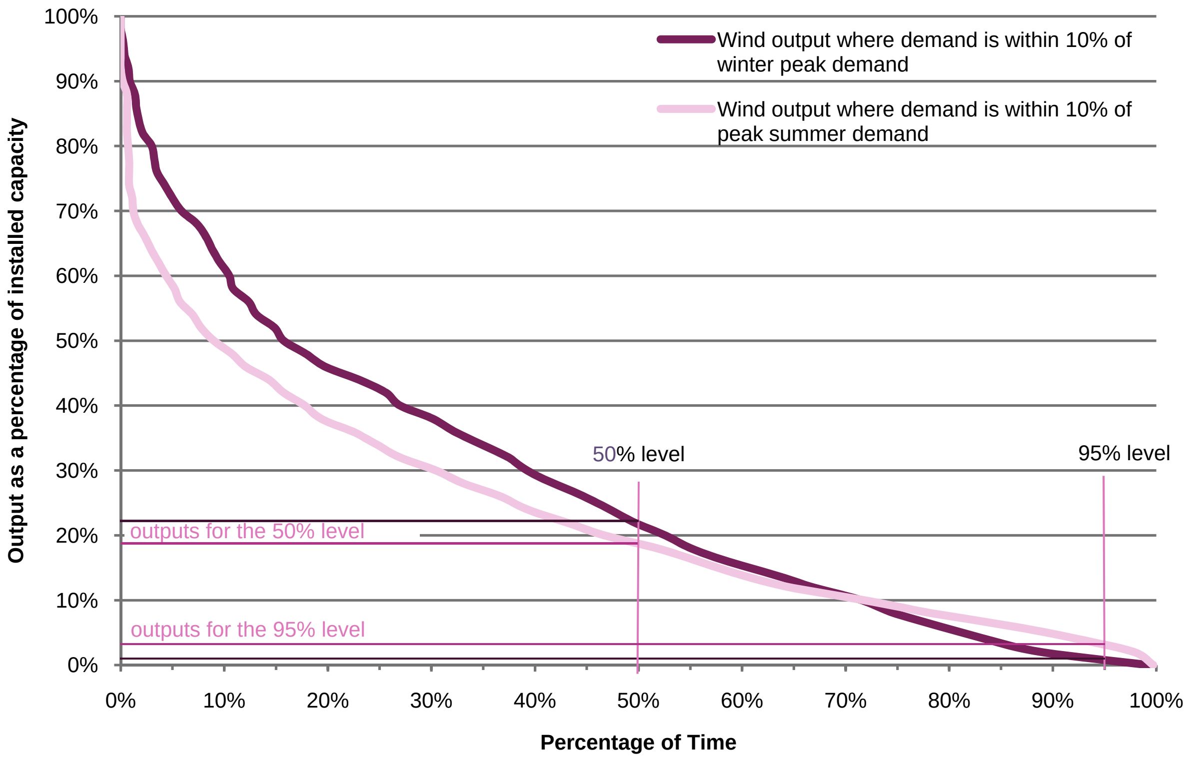
AEMO is undertaking further work on wind variability, in particular, incorporating fluctuations in wind and generation into the Australian Wind Energy Forecasting System (AWEFS).

3.8.2 Wind Contribution During Peak Demand Periods

Figure 3-8 graphically represents the contribution of wind generation as a proportion of peak demand in both winter and summer. AEMO considers that a level of dependability at least as good as that from other forms of generation is appropriate when considering the firm contribution of wind to peak demand. A 5% level of unavailability as a result of forced outages would be considered at the low end of acceptable performance by industry standards, and has been used in this analysis to establish the proportion of installed wind capacity that can be considered to be operating reliably at times of peak demand. Hence the 95% line on the graph represents a reasonable level of availability.

During the top 10% of summer peak demand periods, 95% of the time at least 3% of total installed wind capacity was generating power to contribute to demand. For winter, during 10% of winter peaks, at least 1% of the total wind capacity was available for 95% of the time. These peak demand contribution factors are used to develop the wind farm capacities in Table 3-4 and Table 3-5.

Figure 3-8 – Wind generation during peak demand



3.8.3 Wind performance during the November 2009 heatwave

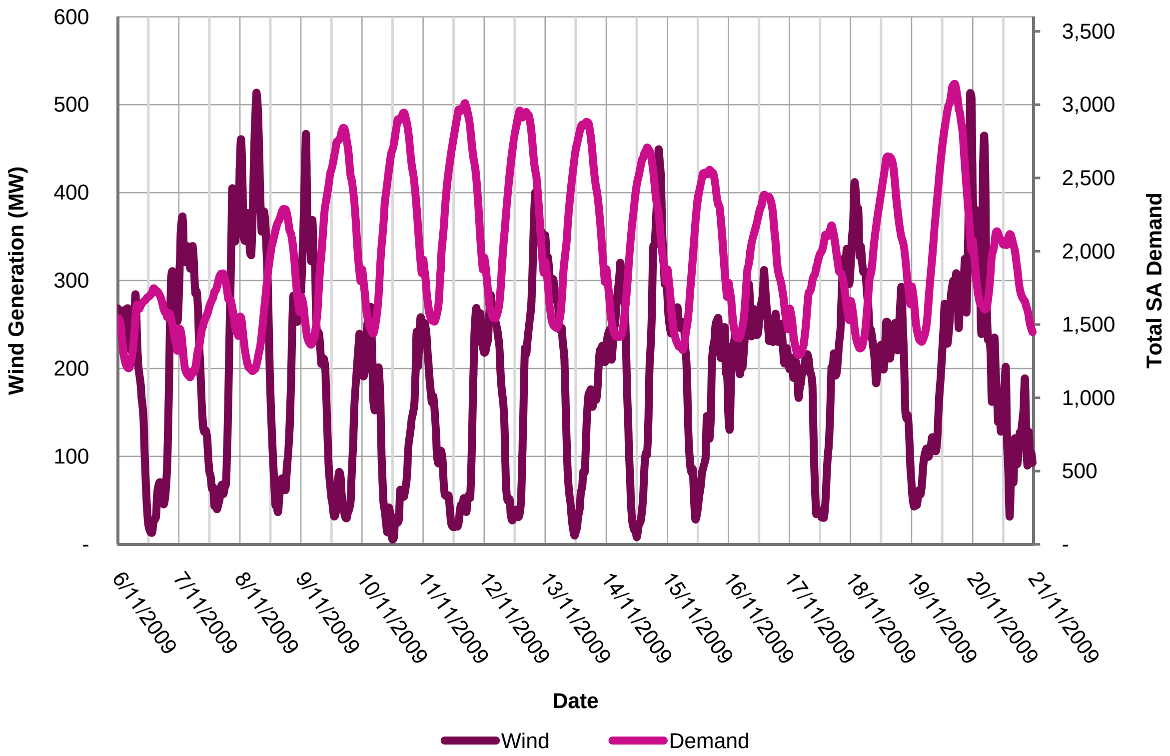
South Australia experienced an unseasonal heatwave during November 2009. Table 3-12 describes maximum daily temperatures over this period.

Table 3-12 - November 2009 heatwave temperatures

Date	7th	8th	9th	10th	11th	12th	13th	14th	15th	16th	17th	18th	19th
Day	Sa	Su	Mo	Tu	We	Th	Fr	Sa	Su	Mo	Tu	We	Th
Max Temp (°C)	34.4	36.7	37.0	38.9	39.2	39.2	38.7	39.5	39.4	31.9	29.0	38.9	43.0

During the heatwave peak wind generation reached 513 MW on 8 November 2009 and demand peaked at 3,141 MW on 19 November 2009. While wind generation contributed to meeting demand during this period, wind generation tended to decrease during the peak demand periods of most days. This can be seen more clearly in Figure 3-9. The reduction in wind generation during peak periods, or at the hottest times of the day, can be partially attributed to limits placed on some turbines at high temperatures to prevent overheating.

Figure 3-9 Wind Generation and Total South Australian Demand from 6 November 2009 to 21 November 2009

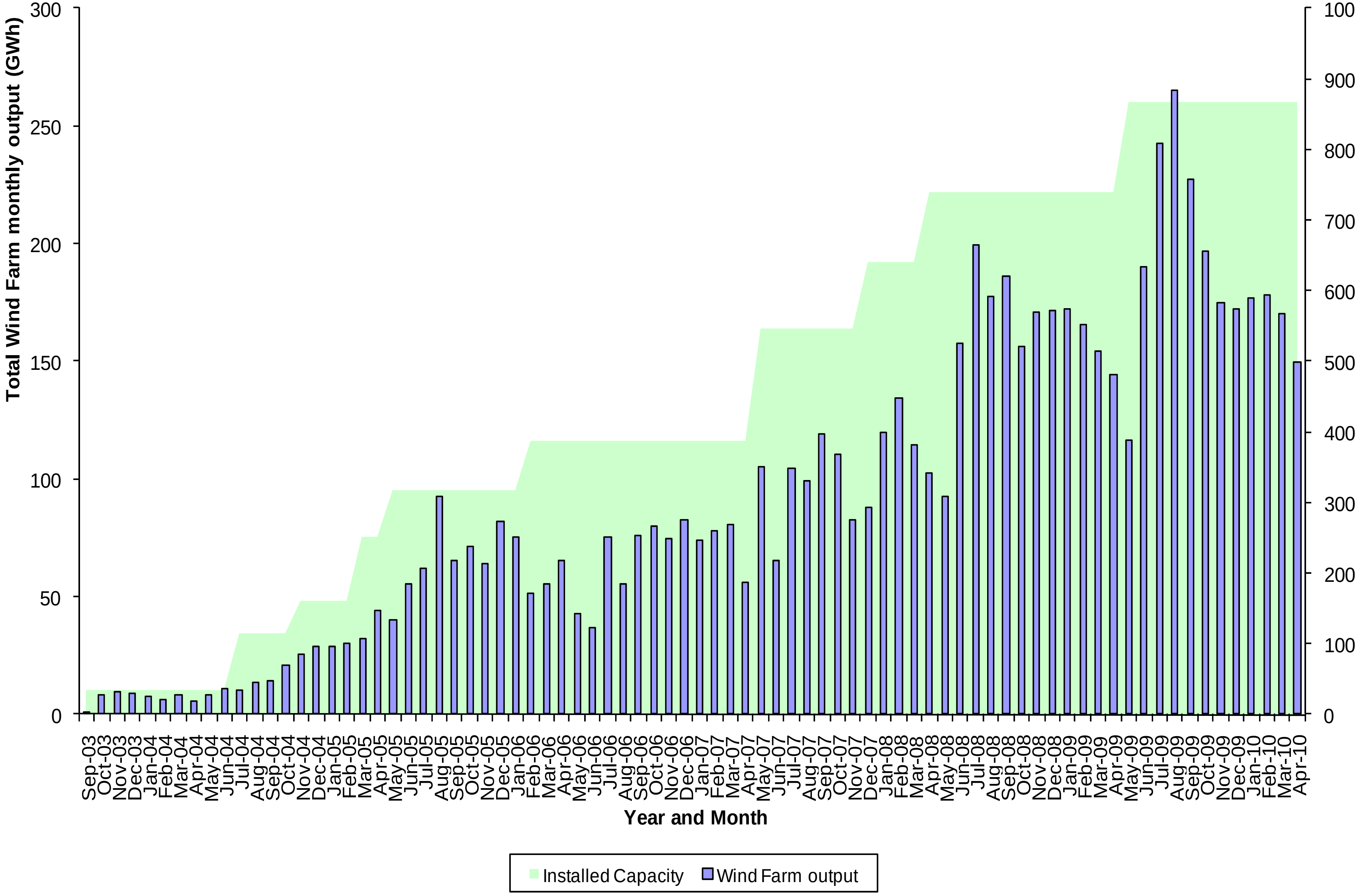


3.8.4 Seasonal Variations in Wind Generation.

Figure 3-10 shows monthly wind generation in South Australia from 2003 when the first major wind farm, Starfish Hill, was constructed to April 2010. A trend is emerging where total wind generation can be seen to taper off towards autumn and followed by a period of peak production in winter. It is worth noting that during commissioning, most wind farm proponents complete registration and licensing procedures so that they may gradually export energy from the wind farm as it is constructed. Hence a higher operational capacity was installed in April 2010 when generation can be seen to decrease, than there was in August 2009 where wind output peaks.

Climatologists have found decadal patterns in solar and wind energy. In the next few years AEMO intends to examine whether there is a correlation between wind energy production and decadal wind patterns.

Figure 3-10 – South Australian Total Wind Generation September 2003 to April 2010



Note: Wind farm capacities are incremented on the date the farm first exports energy into the network.

4 Fuel Supply

4.1 Summary

Fuel supply for electricity generation in South Australia is affected by the demand and supply for gas generally in eastern Australia and by coal supply in South Australia.

Costs for both coal and gas for domestic power generation in the NEM continue to be below export prices. In comparison to export contracts, domestic coal and gas contracts for local generation are generally considered more secure, not exposed to currency or trade risk and require less transport costs. However, as international fuel prices increase and facilities are developed to export larger volumes, there will be increasing pressure on domestic gas and coal prices to rise. This will in turn affect electricity prices.

Use of gas for both base load and peaking power is expected to continue to grow strongly. However, the rate of growth will be affected by energy policies, improvements in technology and changes in supply and demand. The pattern of gas production is also changing, with falling production from the Cooper Basin, growing Queensland coal seam gas (CSG) production and significant production from the Otway and Bass basin, offshore Victoria, substituting for Gippsland production. New South Wales and South Australia both rely on Victoria for around half their gas demand and Queensland is now exporting CSG to the southern states.

Liquid fuels only play a minor role in generation in the NEM and are generally available as needed.

Overall, Australia has significant fuel reserves. Export markets for higher quality coals and LNG are expanding. Over the long term, fuel prices are likely to increase as existing long term contracts expire and new contracts are negotiated, at prices potentially closer to those on the export market. At the same time, companies are exploring many of the untapped resources such as shale, CSG, deep coal deposits and distant coal fields. These may become more accessible as prices increase and technology improves.

In this Chapter:

- Section 4.2 presents Fuel Use history and background;
- Section 4.3 discusses the use of gas as fuel in South Australia;
- Section 4.4 discusses the use of coal as fuel in South Australia;
- Section 4.5 discusses the use of liquid fuels in South Australia;
- Section 4.6 discusses fuel prices; and
- Section 4.7 discusses greenhouse gas emissions in the NEM.

4.2 Fuel Use history and background

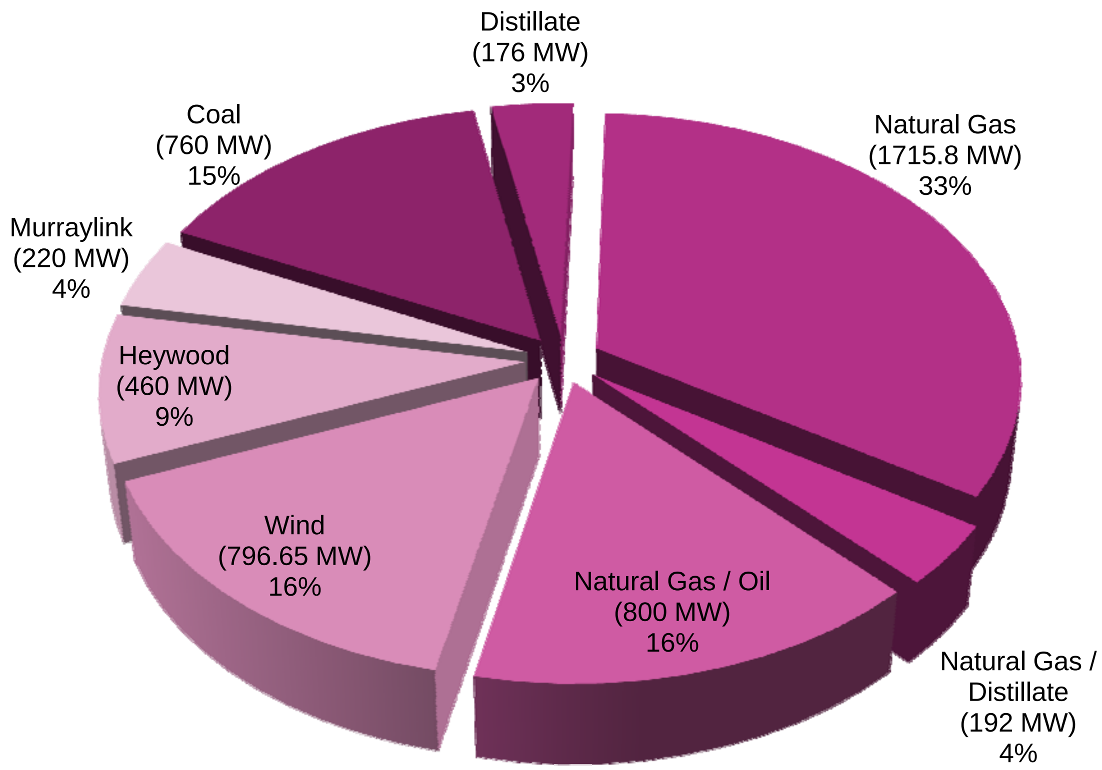
The National Electricity Market (NEM) relies on coal for around 85% of power generation. Another 8% of power generated is supplied by gas, with the remainder from hydro, wind and liquid fuels.

In 2009-10, South Australia relied on coal for around 32% of generation, gas for 46%, and wind for 18%. The remainder was sourced from the interconnector and small amounts of distillate.

Figure 4-1 shows the relative percentage of the total South Australian installed generator capacity of each fuel source. It demonstrates the dependence of the State on natural gas and the diversity benefit that dual fuel capability provides the State. Approximately 53% of the installed capacity in South Australia is dependent on natural gas and the percentage of installed capacity from wind has risen to 16%.

Figure 4-1 assumes that approximately 800 MW of Torrens Island Power Station is capable of generating from either natural gas or oil and all of the Hallett Power Station can be operated on either gas or distillate.

Figure 4-1 - South Australian Installed Capacity by Fuel Source (2009-10[6])



Wind energy has been making a growing contribution to South Australia's generation mix, increasing steadily from 0% in 2002-03 to 18% in 2009-10. At the same time, net imports of energy over the Heywood and Murraylink interconnectors have been generally lower. This is shown graphically in Figure 4-2 which details the electricity contribution in South Australia by fuel source including wind and the net energy transfers over the Heywood and Murraylink interconnectors.

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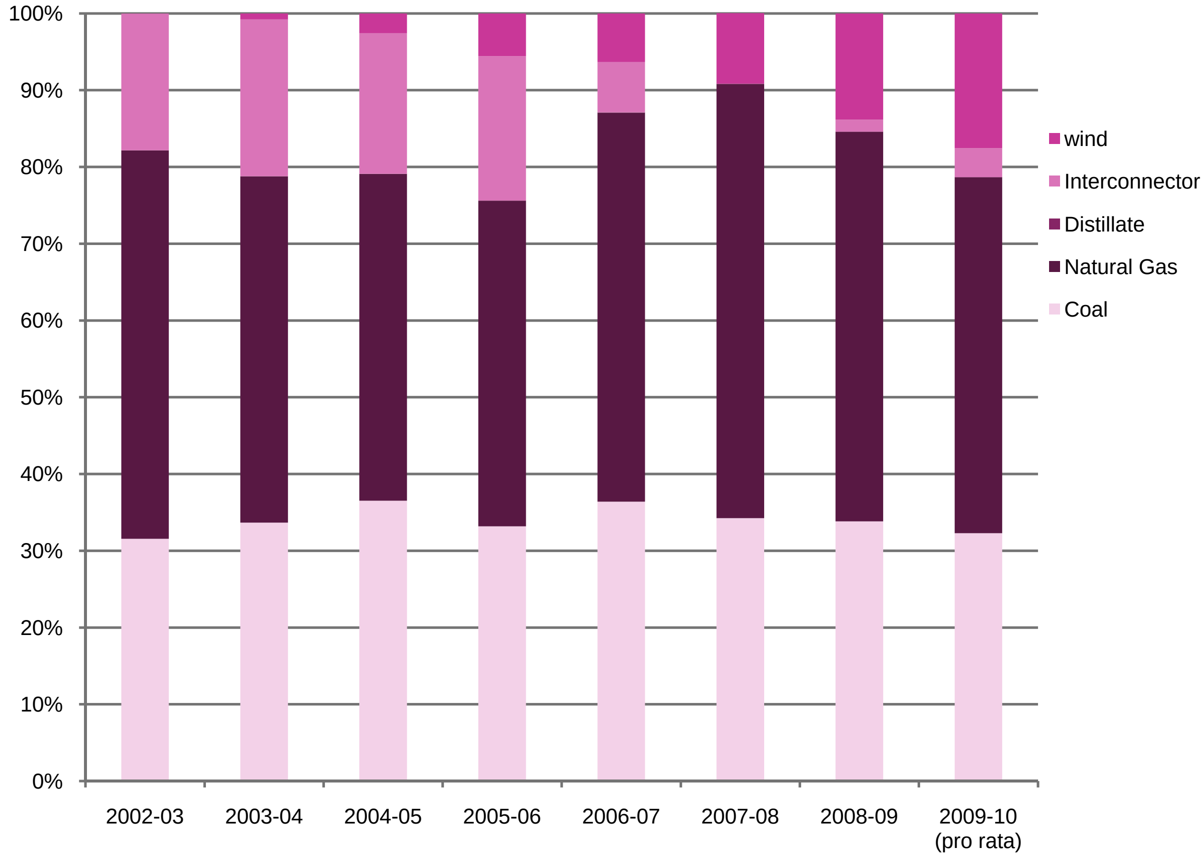
[6] Each station has been categorised in accordance with their fuel dependence as shown in Table 3-1 from Chapter 3.

Figure 4-2 - Percentage of South Australian Energy Contribution by Fuel Source



4.3 Use of gas as fuel in South Australia

South Australia currently relies on gas for around half its electricity generation. The State's traditional source of gas supply has been from the Cooper Basin. Production in the Cooper Basin reached a peak of 278 PJ in 2001 and has since declined to 115 PJ in 2009. While the immediate production outlook is for continued decline, Cooper Basin producers have identified significant contingent resources. There is substantial potential for further commercialisation at higher gas prices and/or lower costs.

Gas is currently supplied from the Cooper Basin, Victoria and Queensland. The pattern of gas production is changing, with falling production from the Cooper Basin, growing Queensland CSG production and significant production from the Otway and Bass basin, offshore Victoria, substituting for Gippsland production. NSW and South Australia both rely on Victoria for around half their gas demand and Queensland is now exporting CSG to the southern states. South Australia is well served with pipeline infrastructure, much of which is operating below capacity.

Eastern Australia has just over 100,000 PJ of gas reserves and resources (3P plus 2C)[7] or 160 times current production. CSG comprises three-quarters of 2P reserves and nearly 80% of total gas reserves and resources. However there are substantial reserves and resources offshore Victoria too, amounting to 10,800 PJ or 30 times current Victorian production.

Altogether eastern Australia appears to have sufficient gas reserves and resources to meet both export and domestic demand beyond 2030, although much of the CSG reserves and resources base requires further appraisal. Higher commodity prices will encourage more exploration and conversion of resources to reserves mitigated by higher costs and potential emission penalties.

In the longer term the cost of gas in South Australia is likely to increase in real terms due to higher development costs in Victoria and higher CSG prices from Queensland. At higher prices additional Cooper Basin resources are likely to become economic.

South Australia can access gas storage at Moomba in South Australia and Iona in Victoria. Other than line pack in pipelines, there is currently no significant gas storage close to the main load centre. This may become an issue if the demand for gas becomes more volatile as a result of the increased penetration of intermittent renewable generation technologies.

It is worth noting that AGL Energy are developing a proposal to expand Torrens Island Power Station which will include a gas storage facility.

4.3.1 Issues affecting the gas market

Key issues likely to affect the gas market in South Australia include:

- Changes in policy, such as the implementation of a Short Term Trading Market (STTM);
- The introduction of a carbon price which will change the relative costs of coal, gas and other energy sources;
- More gas generation required to manage increasing peakiness due to increasing penetration of intermittent generation and increasing domestic energy demand.
- Balancing changes in supply and demand such as
  - Declining production from the Cooper Basin, in South Australia,
  - Growing production in Queensland, especially from coal seam gas sources,
  - Increased sales of LNG to gas export markets,
  - Accessibility of new gas sources, such as shale gas and coal seam gas.

The following sections outline some of these changes in more detail.

4.3.2 The Short Term Trading Market

The STTM is intended to create a market environment that enables and encourages participants to explore the commercial opportunities that an open market makes possible.

The development of a STTM has been driven by the Ministerial Council on Energy's policy agenda for the reform of the energy industry. The STTM is designed to provide a market-based wholesale gas balancing mechanism to facilitate the trading of gas between pipelines, participants and production centres over the short term.

[7] Based on the Society of Petroleum Engineers classification of reserves. The SPE distinguishes between Reserves (commercial) and Contingent Resources (sub-commercial) and classifies reserves as Proved (1P); Proved and Probable (2P) and Proved, Probable and Possible (3P). Resources are classified as Low Estimate (1C), Best Estimate (2C) and High Estimate (3C).

Sydney and Adelaide have been established as gas hubs around which the STTM will operate however it is expected that the STTM will, in the future, be expanded to include hubs in Queensland and the Australian Capital Territory.

The market itself will run once a day, on the day ahead, for each hub. It will use bids, offers and forecasts submitted by participants to determine schedules for deliveries from the pipelines linking producers to transmission users and the hubs.

The market will set a daily market price at each hub and settle each hub based on the schedules and deviations from schedules. Participant's daily transactions will be settled at market prices and potentially billed monthly. Suitable prudential, credit and governance arrangements will be established.

AEMO only operates the STTM, the physical operation of the actual pipelines or network assets will remain under the control of the asset owners.

The existing retail gas markets in South Australia and New South Wales will also continue to operate in conjunction with the STTM wholesale gas market in each state. The Victorian wholesale gas market will continue to run in parallel with the emerging national gas market.

The STTM will commence operation on 1 September 2010.

4.3.3 Increased penetration of intermittent generation

Government policies such as the increased Mandatory Renewable Energy Target are likely to encourage growth in the construction of renewable power stations such as wind generators. Increased penetration of intermittent generation sources may require more peaking capacity which has been traditionally supplied by gas generators.

4.3.4 Clean Coal Policies and Carbon Price

Uncertainty about climate change policies such as the potential introduction of a carbon price has resulted in generation proponents avoiding or deferring plans to construct higher emission generators.

A carbon price would increase the cost of fossil fuelled power generation. As coal fired generation produces higher emissions than gas, the relative cost of gas and coal generation will change and likely result in a greater uptake of gas generation.

In recent years, there have also been calls from environmental groups for governments to implement policies that limit emissions from coal generators. In late 2009, The Queensland Government announced one such policy, as part of its climate change strategy, that no new coal-fired power station will be approved in Queensland unless:

- it uses world's best practice low emission technology in order to achieve the lowest possible levels of emissions; and
- it is carbon capture and storage (CCS) ready and will retrofit that technology within five years of CCS being proven on a commercial scale.

Coal generators currently supply the majority of base load in the NEM. Policies discouraging the construction of new coal plants will likely result in a greater penetration of gas generation in the future and higher electricity prices.

4.3.5 Increasing domestic demand

Increasing demand, and in particular increase in peak demand due to increased penetration of reverse cycle air conditioning may result in an increased need for gas supply for both base load and peaking plants.

4.3.6 Shale gas

Shale gas is natural gas produced from shale, and has become an increasingly more important source of natural gas in the United States. Shales generally have insufficient permeability to allow significant fluid flow to a well bore, making shale gas a difficult resource to access. However, advancements in modern technology in hydraulic fracturing have made it more plausible for these resources to be reached.

Australia has shale gas resources, however, due to the difficulty in accessing them, the quantities have not been well defined. A number of companies have actively been assessing the potential of shale resources in the Cooper Basin. At higher gas prices, or lower development costs, shale resources may become more viable.

4.3.7 LNG exports reducing the reserves available for domestic use

With the development of LNG projects, eastern Australian gas prices are likely to be more strongly influenced by international energy prices,

There are four major LNG projects proposed in eastern Australia, all of which have involvement of major international oil and gas companies. The combined gas requirements of these projects have the potential to dwarf current domestic gas demand. At the same time, the potential of these projects and the expectations of realising international gas prices have spurred CSG exploration, appraisal and reserves assessment, bringing about a substantial increase in estimated CSG reserves and resources.

4.4 Use of coal as a fuel in South Australia

Northern and Playford are the only coal fired power stations in South Australia. Low grade lignite for the stations is railed 260 km from the Leigh Creek mine. The Main and Upper seams at Leigh Creek can be mined until 2017 or 2018. Recently the Mine operator, Alinta, began mining the lower seams which may extend mine life by up to 10 years.

There are other coal deposits in South Australia that could potentially substitute for Leigh Creek coal, although the suitability and cost of these sources is problematic.

Coal suitable for combustion in the Northern and Playford power stations is significantly different to conventional thermal coals and which are unsuitable for South Australian coal-fired generation, although it may be possible to blend these coals with Leigh Creek coal.

Table 4-1 describes coal deposits in South Australia. The South Australian lignite deposits have some potential to support new power generation opportunities, however they would require new purpose built power stations. There have been some proposals to develop coal mines in Arckaringa Basin, Clinton and Kingston to satisfy a number of competitive options such as export, gasification, coal to liquids or combined generation-mining projects.

Uncertainty over Australian carbon policy is likely to continue to affect investment decisions in coal technologies. The long term demand for coal for electricity generation will depend on whether a carbon price is introduced in Australia, and on the development and uptake of technologies that reduce carbon emissions.

Table 4-1 – Summary of Coal Deposits in South Australia

Rank	Basin/Area	Deposit	Resources: Measured-Indicated (million tonnes)	Resources: Inferred (million tonnes)	Mining Owner
Bituminous to Anthracite	Cooper		-	~100,000+	None
	Pedirka		-	NA	None
Sub-bituminous	Arckaringa	Wintinna	837	450	Arckaringa Energy (Altona Resources)
		East Wintinna		690	SAPEX (Linc Energy)
		Murloocoppie	550	2600	Arckaringa Energy (Altona Resources)
		Westfield	300	500	
		Weedina		1000	SAPEX (Linc Energy)
		Lake Phillipson	-	5,000	SA Coal Corp (Felix Resources)
	Leigh Creek	Telford Basin Lobe B	150	350	Flinders Power (Alinta)
		Northfield Lobes C & D	12	-	
		Copley Basin Lobes A & E	11	-	
	Leigh Ck to Pt Augusta area	Springfield	-	-	None
		Boolcunda	-	-	None
	Polda	Lock	260-600	-	Energy Expl Ltd (Centrex Resources)
Lignite	Northern St Vincent	Bowmans	1,250	350	Syngas Energy P/L
		Clinton	138	47	
		Beaufort	114	135	
		Whitwarta	21	103	
		Lochiel	625	-	Alinta
	Otway	Kingston	578	-	Hybrid Energy SA P/L
	Murray	Anna	58	-	Anglo Coal Australia
		Sedan	184	-	
		Moorlands	32	-	Syngas Energy P/L

4.5 Use of Liquid Fuels for Generation in South Australia

Using oil products as the primary fuel source currently remains uneconomic relative to coal or natural gas. For this reason, most diesel and kerosene fuel plants supply power in peak periods when the price of electricity is at its highest.

In South Australia, the Torrens Island Power Station (TIPS) uses natural gas as its primary fuel type. Generating power from fuel oil occurs rarely.

Smaller regional power plants in South Australia that use diesel have better logistical options in the event of unplanned demand. These plants are primarily operated to meet off-grid needs or peak demand in the NEM. In addition to their onsite storage, they tend to have ready access to coastal fuel terminals in the State. Delivery turnaround time is relatively short. However, with the Snuggery plant (near Mt Gambier, SA) diesel would need to be accessed from more distant sources such as Adelaide or interstate refineries in the event of sustained and continual plant operation.

Australian refineries are currently operating at full capacity and unable to meet Australia's demand for diesel, kerosene and fuel oil. As a result, Australia is becoming increasingly reliant on imports of these fuels to meet demand. Furthermore, Australia has an established infrastructure of fuel import terminals located around the coast. These coastal terminals can accept diesel and kerosene and, in limited cases, fuel oil imports from overseas or from Australian refineries. The terminal fuel storage infrastructure underpins fuel supply security for most oil based generators.

Biodiesel remains a more expensive option to fossil fuels for diesel generators. Feedstock prices for biodiesel are high and move independently of oil prices. Biodiesel cannot be stored un-agitated for long periods, making it less practical as a reliable long-term fuel source.

Significant research is ongoing internationally to develop the algae based biodiesels. While the latest research indicates that there is the potential for the proposed process for algae based biodiesel production to be significantly more productive per acre than other means, the commercial process is still being developed and current production costs are high.

4.6 Fuel Prices

Relative fuel costs are an important determinant of fuel use. Figure 4-3 shows international fuel prices for oil (WTI), LNG imported into Japan, US gas (Henry Hub) and thermal coal imported into Japan.

Oil is the most expensive fuel on an energy basis and coal is the cheapest. Gas imported into north Asia as LNG is indexed to oil prices and is relatively expensive. US gas prices, a global benchmark for gas prices, fell heavily in 2009 due to the recession and the increase in US gas production.

Figure 4-3 - International fuel prices 2004-2009 (USD/GJ)

Sources: BP, US Energy Information Administration

The cost of coal and gas for NEM power generation is below international prices. Coal costs vary, depending on the type of coal, quality, its location in relation to the power station and the nature of the contract. In many cases, coal deposits are owned by the generator, making it difficult to estimate costs. In cases where coal is purchased from third parties, prices are generally confidential. However coal is generally the cheapest fuel source, ranging from below A$0.50 per gigajoule (GJ) in Victoria to between A$1.00 and A$2.00/GJ in New South Wales, Queensland and South Australia.

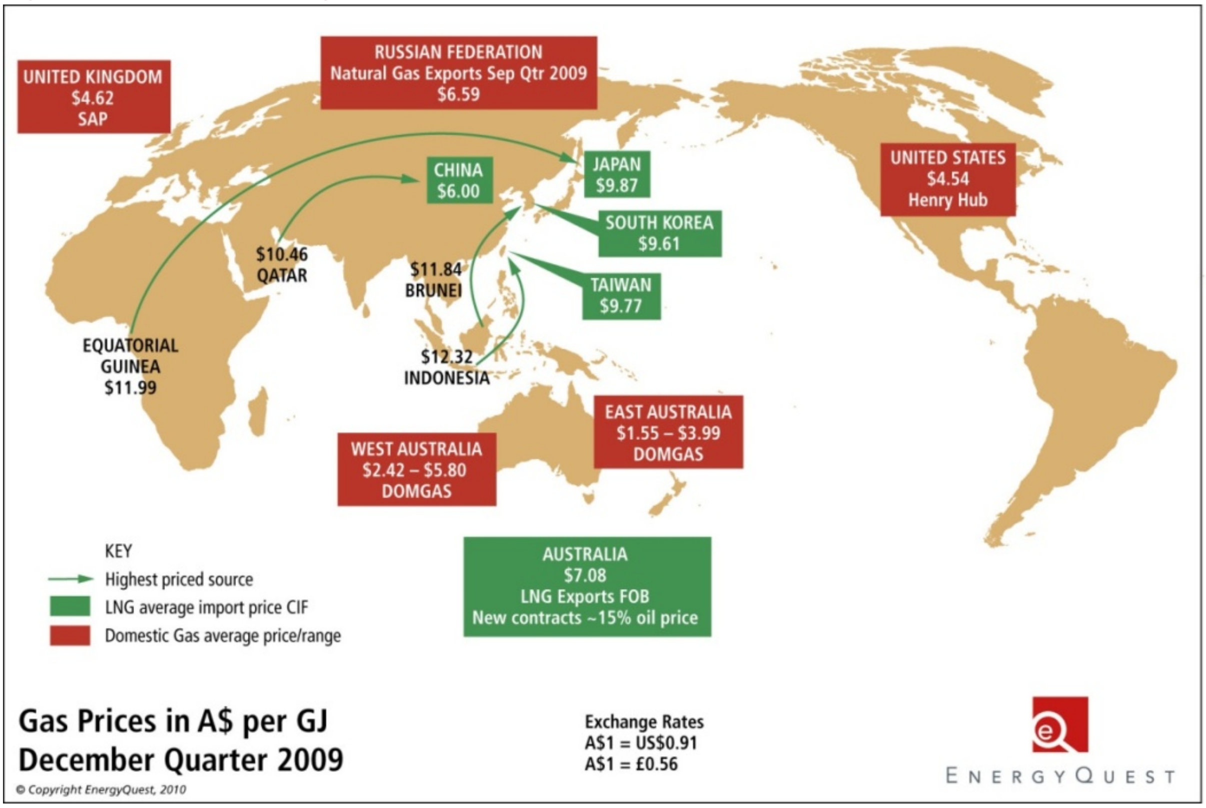
Exports of thermal coal are sold both under long-term contracts (around 70%) and on a spot basis (around 30%). Spot prices for export ex-Newcastle as of February 2010 were US$93.25 per tonne, around A$3.90/GJ. There is now some pressure from the coal export market on coal prices for domestic power generation.

Similarly there continue to be disparities between domestic gas prices and export prices.

Figure 4-3 shows international and Australian gas prices in A$/GJ for the December quarter 2009. The international figures include the UK system average price (SAP), US Henry Hub spot gas price, average export price for gas (predominantly pipeline gas) from Russia and average landed import prices (CIF) (green boxes) for LNG into Japan, Korea, Taiwan and China. The arrows show the highest average price imports into each country in the December quarter. The figure also shows the average price for Australian LNG exports in the December quarter compared with domestic gas prices (ex-field).

International prices continue to be higher than Australian domestic prices, giving rise to concerns that east coast gas prices may ultimately rise. It is worth noting that domestic fuel purchases for power generation are generally considered lower risk, due to the ability to make longer term volume contracts, low currency risk, and potentially lower transport costs.

Figure 4-4 - International gas prices



Source: EnergyQuest

4.7 Greenhouse Gas Emissions

AEMO has calculated the approximate annual carbon dioxide equivalent (CO2e) emissions for the electricity consumed in South Australia and the emission contribution from the energy imported from the rest of the NEM.

The methodology for calculating this has changed from previous publications of the Electricity Supply Industry Planning Council's (ESIPC) Annual Planning Reports (APR).

In previous APRs, emissions for local South Australian generation were calculated using generator information and emissions factors, published in the National Greenhouse Gas Inventory (NGGI). Emission levels for imports into South Australia were calculated from weekly national greenhouse intensity figures published by NEMMCO (now AEMO), and modified to remove the contribution of the South Australian generators.

This year, for consistency, all emissions have been calculated on a financial year basis and emissions from imports/exports were calculated using emissions factors published in the NGGI. Emissions for each generator in the NEM, excluding South Australia, were calculated and averaged to create an emission factor for energy imported to South Australia. Emissions from exports were calculated in a similar manner based on South Australian generators only. Figure 4-5 shows the results of this analysis. Total emissions over the interconnector have been calculated on a net financial year basis.

Figure 4-5 – South Australian Annual Emissions