AUSTRALIAN ENERGY MARKET OPERATOR

ELECTRICITY STATEMENT OF OPPORTUNITIES

for the National Electricity Market

2011

Revised

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ELECTRICITY STATEMENT OF OPPORTUNITIES

For The National Electricity Market

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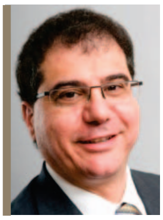
Number	Date	Notes
1	31 August 2011	First issue
2	9 September 2011	Revisions of Chapter 3: • NEM-wide summer MDs (Table 3-5, Fig 3-4) • NEM-wide winter MDs (Table 3-6, Fig 3-5) • VIC summer MDs (Table 3-14, Fig 3-13) • VIC winter MDs (Table 3-15, Fig 3-14)

FOREWORD



I am pleased to introduce AEMO's 2011 Electricity Statement of Opportunities (ESOO), which presents a consolidated picture of supply adequacy and future investment opportunities in the National Electricity Market between 2011 and 2021. By providing this data and analysis, the ESOO forms an important resource for informing generation and demand-side investment decisions.

Now in its twelfth year, the ESOO is one of a suite of AEMO planning documents that present comprehensive information about energy supply, demand and network planning. These documents include the Power System Adequacy – Two Year Outlook, the South Australian Supply and Demand Outlook, the Victorian Annual Planning Report and Update, the National Transmission Network Development Plan, and the Gas Statement of Opportunities.

Australia's stationary energy sector is facing a period of great change. Developments in climate change policy and the present global economic environment have significant potential to influence the way Australia produces and consumes electricity.

These changes can happen quickly, as was exemplified on 10 July 2011 when the Multi-Party Climate Change Committee announced its Clean Energy Agreement, introducing a carbon price from 2012–13. Over time, this will result in a shift in generation sources from coal to less carbon-intensive fuels and renewable resources.

Low carbon dioxide-emitting technologies may lead to clusters of generation in locations previously unconnected to the grid. There is also a growing trend towards small-scale embedded generation that may change the way transmission systems are managed.

Demand-side initiatives also have the potential to greatly affect the power system, and increased consumer participation at all levels will play a significant role in improving overall energy efficiency and reducing peak demands. The ESOO explores these topics in more detail in its discussion of emerging investment trends, government policy developments, and the economic outlook.

Projections included in the ESOO are based on the forecasts originally published in the South Australian Supply Demand Outlook, and the regional annual planning reports from Powerlink Queensland, TransGrid, Transend Networks, and AEMO.

I thank all our stakeholders for their invaluable input and trust that the 2011 ESOO provides a valuable information resource within a rapidly evolving energy market and challenging investment environment.

M. Zema

Matt Zema

Managing Director and Chief Executive Officer

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DISCLAIMER

This publication has been prepared by the Australian Energy Market Operator Limited (AEMO) using information available at 1 July 2011, unless otherwise specified. AEMO must publish the Electricity Statement of Opportunities in order to comply with Clause 3.13.3(q) of the Rules.

The purpose of publication is to provide technical and market data and information regarding opportunities in the National Electricity Market (NEM).

Some information available after 1 July 2011 might have been included in this publication where it has been practicable to do so. This includes a discussion about the impacts of the Australian Government's Clean Energy Future Plan, which was announced 10 July 2011.

Information in this publication does not amount to a recommendation in respect of any possible investment and does not purport to contain all of the information that a prospective investor or participant or potential participant in the NEM might require. The information contained in this publication might not be appropriate for all persons and it is not possible for AEMO to have regard to the investment objectives, financial situation, and particular needs of each person who reads or uses this publication. The information contained in this publication may contain errors or omissions, or might not prove to be correct.

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Acknowledgement

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LIST OF MEASURES AND ABBREVIATIONS

The following sections list the units of measure and abbreviations used throughout the ESOO

Units of Measure

Abbreviation	Unit of Measure
DD	Degree days
EDD	Effective degree days
GJ	Gigajoules
GWh	Gigawatt hours
HDD	Heating degree days
km	Kilometres
kPa	Kilopascals
kV	Kilovolts
MMt/a	Million, million tonnes per annum
Mtpa	Million tonnes per annum
MVA	Megavolt amperes
MVAr	Megavolt amperes reactive
MW	Megawatts
MWh	Megawatt hours
PJ	Petajoules
t/d	Tonnes per day
t/h	Tonnes per hour
t/m	Tonnes per month
TJ	Terajoules
TJ/d	Terajoules per day
$	Australian dollars
$/MWh	Australian dollars per megawatt hour
$/t	Australian dollars per tonne

Abbreviations

Abbreviation	Expanded Name
1P	Proved reserves
2P	Proved reserves + probable reserves
3P	Proved + probable + possible reserves
ABARE	Australian Bureau of Agricultural and Resource Economics
ACRE	Australian Centre for Renewable Energy
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time (see also EDST)
ANTS	Annual National Transmission Statement
APR	Annual planning report
ASI	Australian Solar Institute
AWEFS	Australian Wind Energy Forecasting System
BOM	Bureau of Meteorology
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CEI	Clean Energy Initiative
CO2-e	Carbon dioxide equivalent
COAG	Council of Australian Governments
CPI	Consumer price index
CPRS	Carbon Pollution Reduction Scheme
CPT	Cumulative price threshold
DB	Distribution business
DNSP	Distribution network service provider
DRA	Demand Response Aggregator
DRET	Department of Resources, Energy and Tourism
DSN	Declared Shared Network
DSP	Demand-side participation
DW-H	Decentralised World, high carbon price scenario
DW-M	Decentralised World, medium carbon price scenario
EAAP	Energy Adequacy Assessment Projection
EDR	Economic demonstrated resources
EDST	Eastern Daylight Savings Time (see also AEST)

Abbreviation	Expanded Name
EGS	Enhanced Geothermal Systems
EOD LP	End-of-day linepack
ESIPC	Electricity Supply Industry Planning Council (now part of the Australian Energy Market Operator - AEMO)
ESOO	Electricity Statement of Opportunities
ETS	Emissions Trading Scheme
EUR	Estimated ultimate recovery
FC-H	Fast Rate of Change, high carbon price scenario
FC-M	Fast Rate of Change, medium carbon price scenario
FCAS	Frequency control ancillary service
FCSPS	Frequency control Special protection scheme
FEED	Front-end engineering and design
GDP	Gross domestic product
GPG	Gas powered generation
GSOO	Gas Statement of Opportunities
GSP	Gross state product
HSA	Hot sedimentary aquifers
IDGCC	Integrated drying and gasification combined cycle
IGCC	Integrated gasification combined cycle
IMF	International Monetary Fund
JPB	Jurisdictional planning body
LFRG	Load Forecasting Reference Group
LGC	Large-scale Generation Certificate
LNG	Liquefied Natural Gas
LOR (1, 2, or 3)	Lack of Reserve
LPG	Liquefied Petroleum Gas
LRC	Low reserve condition
LRET	Large-scale Renewable Energy Target
LRMC	Long-run marginal cost
MCE	Ministerial Council on Energy
MD	Maximum demand
MEPS	Minimum Energy Performance Standards
MLF	Marginal loss factor
MMA	McLennan Magasanik Associates
MNSP	Market network service provider

Abbreviation	Expanded Name
MMS	Market Management Systems
MPC	Market price cap
MRET	Mandatory Renewable Energy Target
MRL	Minimum Reserve Level
MPCCC	Multi-Party Climate Change Committee
MT PASA	Medium-term Projected Assessment of System Adequacy
NCAS	Network control ancillary services
NSCAS	Network support and control ancillary services
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEO	National Electricity Objective
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NERR	National Energy Retail Law
NERL	National Energy Retail Rules
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NIEIR	National Institute of Economic and Industry Research
NMNS	Non-market non-schedule
NSA	Network support agreement
NSP	Network service provider
NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
NTS	National Transmission Statement
OCGT	Open cycle gas turbine
ORER	Office of the Renewable Energy Regulator
OS-L	Oil Shock and Adaptation, low carbon price scenario
OS-M	Oil Shock and Adaptation, medium carbon price scenario
PASA	Projected Assessment of System Adequacy
POE	Probability of exceedence
PPI	Producer price index
PR	Proved reserves
PSA	Power System Adequacy – Two Year Outlook

Abbreviation	Expanded Name
PV	Present value
RBA	Reserve Bank of Australia
REC	Renewable Energy Certificate
REDP	Renewable Energy Demonstration Program
RET	Renewable Energy Target - national Renewable Energy Target scheme
RERT	Reliability and Emergency Reserve Trader
RIT-T	Regulatory Investment Test for Transmission
RPAS	Reactive power ancillary service
SASDO	South Australian Supply-Demand Outlook
SCADA	Supervisory Control and Data Acquisition system
SCER	Standing Committee on Energy and Resources
SCO	Standing Committee of Officials
SC-L	Slow Rate of Change, low carbon price scenario
SC-0	Slow Rate of Change, zero carbon price scenario
SENE	Scale efficient network extensions
SRA	Settlements residue auction
SRAS	System restart ancillary service
SRES	Small-scale Renewable Energy Scheme
SRMC	Short-run marginal cost
STC	Small-scale Technology Certificates
ST PASA	Short-term Projected Assessment of System Adequacy
STTM	Short Term Trading Market for Gas
SVC	Static VAr compensator
TNSP	Transmission network service provider
UIGF	Unconstrained Intermittent Generation Forecast
USE	Unserved energy
UW-L	Uncertain World, low carbon price scenario
UW-0	Uncertain World, zero carbon price scenario
VAPR	Victorian Annual Planning Report
VCR	Value of Customer Reliability
VENCorp	Victorian Energy Network Corporation (now part of AEMO)

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KEY FINDINGS

The 2011 Electricity Statement of Opportunities (ESOO) is a broad analysis of opportunities for generation and demand-side investment in the Australian National Electricity Market (NEM).

This publication has been prepared by AEMO using information available at 1 July 2011, and the impacts of changes after this date have been assessed where practicable. This includes discussion about the impact of the Australian Government's Clean Energy Future Plan, announced on 10 July 2011.[1]

> **The Australian Government's Clean Energy Future Plan was announced on 10 July 2011, and targets a reduction in carbon and other greenhouse gas emissions to 5% below year 2000 levels by 2020.**
>
> **The data used in the 2011 ESOO was largely finalised by 1 July 2011, and included a number of scenarios and different carbon price assumptions that are similar to the Government's modelling. AEMO has assessed the implications of the latest proposed initiatives and discusses these in highlighted text boxes throughout relevant parts of the ESOO.**

The Australian Energy Market Operator (AEMO) produces a suite of planning publications that present comprehensive information about energy supply, demand, and transmission network planning. Two of these publications, the ESOO and the Power System Adequacy – Two Year Outlook (PSA), explore issues of electricity supply adequacy. The PSA focuses on operational supply issues over the next two years, and the ESOO explores the investment environment over the next ten years.

Innovations in the 2011 ESOO include a chapter about different types of generation investment opportunities, which outlines key trends and findings from a number of AEMO's planning publications, and under different climate change policies, to provide an overview of investment potential in the NEM. A new historical information attachment provides context for the identified trends, and the fuel supply chapter has been extended to include information about Australia's renewable resources.

Supply-demand outlook

The supply-demand outlook for each region identifies potential generation and demand-side investment opportunities. The need for investment is indicated by projected reserve requirement shortfalls. Specifically, the regional outlooks identify the timing of low reserve condition (LRC) points, indicating when reserve margins will potentially fall below the minimum reserve level (MRL).[2] LRC points do not signify that load shedding will occur, but rather indicate when the power system adequacy is falling below long-term system reliability standards.

AEMO's assessment considers maximum demand projections, demand-side participation (DSP), and existing and committed transmission network capabilities, and assumes that no further capacity enters the market beyond the committed projects that AEMO is aware of.

Table 1 provides an overview of the supply-demand outlook, showing the first year that each region experiences a reserve deficit during summer maximum demand conditions. Tasmania's maximum demand typically occurs in winter, and this region's winter outlook has also been provided.

> **AEMO expects the Clean Energy Future Plan to have little impact on the timing of the regional LRC points identified in the 2011 ESOO.**
>
> **The maximum demand projections already include comparable carbon price assumptions and will be largely unaffected. Any changes to the installed generation mix is likely to occur after 2015, which (with medium economic growth) falls after the LRC points in every region except New South Wales and Tasmania.**

[1] Australian Government. "Clean Energy Future". Available http://www.cleanenergyfuture.gov.au. 27 July 2011.

[2] MRLs represent a safety margin of installed capacity, and are calculated by AEMO using detailed market simulations that model the factors influencing supply adequacy in the NEM.

Table 1— Regional LRC points overview

Region	Low Economic Growth	Medium Economic Growth	High economic Growth
Queensland	2014–15	2013–14	2013–14
New South Wales	2018–19	2018–19	2018–19
Victoria	2016–17	2014–15	2013–14
South Australia	2016–17	2014–15	2013–14
Tasmania (summer)	>2020–21	>2020–21	>2020–21
Tasmania (winter)	>2021	>2021	>2021

Given medium economic growth:

- Queensland requires additional investment by 2013–14, which is consistent with the 2010 ESOO
- New South Wales requires additional generation investment by 2018–19, representing a two-year delay compared with the 2010 ESOO, which is primarily due to a decrease in the maximum demand projections for the region
- Victoria and South Australia require additional generation investment by 2014–15, one year earlier than the 2010 ESOO, which is primarily due to moderate increases in the maximum demand projections for both regions (the LRC points in these regions remain closely aligned due to their substantial ability to share surplus reserves), and
- Tasmania does not experience a reserve deficit within the 10-year outlook period at the time of either the summer or winter maximum demand. Tasmania's summer maximum demand typically occurs during cold weather, resulting in relatively high demand diversity between Tasmania and the mainland regions (where the maximum demand occurs during hot weather). This enables Tasmania and the mainland regions to take advantage of reserve sharing opportunities when meeting maximum demands.

The supply-demand outlook only considers capacity adequacy and cannot indicate a reserve shortfall due to energy limitations. This is significant because Tasmania principally depends on hydroelectric generation and tends to be energy limited rather than capacity limited.

AEMO publishes a quarterly Energy Adequacy Assessment Projection (EAAP) report[3] that provides more information about projected energy limitations and reliability in the Tasmanian region over the next two years. Chapter 8 also provides an assessment of future Tasmanian energy adequacy, and concludes that no energy shortfalls are projected for Tasmania before 2020–21.

From a national perspective, Queensland is the first region to need additional investment to maintain reliability across all three economic growth scenarios.

In addition to those provided by the Queensland jurisdictional planning body, the 2011 ESOO also includes alternative energy and maximum demand projections for Queensland, developed by AEMO.[4] AEMO assessed performance for all regions, and alternative projections were developed for Queensland to address the fact that actual maximum demands over the last five years have been significantly lower than the projections provided by the Queensland Jurisdictional Planning Body. Historical differences of the same magnitude were not observed in the energy and maximum demand projections produced for the other regions.

The alternative projections for Queensland delay the Queensland LRC point by one year until 2014-15.

3 AEMO. "Energy Adequacy Assessment Projection (EAAP)". Available http://www.aemo.com.au/electricityops/eaap.html. 27 April 2011.

4 The alternative Queensland energy and maximum demand projections are discussed in Chapter 3 of the 2011 ESOO.

AEMO continues to work with industry to investigate the drivers for demand in Queensland, and intends to provide a more comprehensive view about NEM demand projections by late 2011.

Chapter 7 provides more information about the supply-demand outlooks for each region.

Investment opportunities

Generation investment opportunities can be classified as capacity-driven, energy-driven, or policy-driven, which recognises the different market signals that can govern investment decisions.

Capacity-driven investment opportunities coincide with periods of supply scarcity, and include future supply and demand-side investments to meet short periods of high regional demand or high electricity spot market prices. Investments of this type are needed to maintain system reliability in each region, deferring possible LRC points.

Energy-driven investment is generally motivated by the quantity of energy required over longer periods, and the average electricity spot market price. Given medium economic growth, Queensland will experience the largest energy deficit of approximately 300 gigawatt hours (GWh) by 2020-21. This is still a relatively small shortfall, and by comparison a typical combined-cycle gas turbine (CCGT) of 380 megawatts (MW) generates 500 GWh per year if running at a capacity factor as low as 15%.[5,6]

Other regions show even smaller energy shortfalls than Queensland, indicating limited opportunities for additional base load generation across the NEM. The introduction of a carbon price, however, may result in the retirement of existing coal-fired capacity, and changes to the relative operating costs of existing and new technology, leading to opportunities for replacement generation.

AEMO expects the Clean Energy Future Plan to have little impact on the installed generation mix prior to 2015.

Financial support for the high CO2-e emitting generation described by the initiatives is conditional upon maintaining system reliability. If a mechanism similar to the original Carbon Pollution Reduction Scheme legislation is adopted, AEMO will be required to certify that the Reliability Standard will be met for two years after a proposed deregistration.

The Government has indicated that up to 2,000 MW of generation will be invited to tender for closure by 2020. The arrangement is to be negotiated during 2011–12 and will take into account AEMO's views on energy security. AEMO expects any payments for closures to occur in the second half of the decade.

Investments in low CO2-e emitting technologies (including renewable generation technologies) will be promoted through the Clean Energy Finance Corporation. This will help to ensure that the national Renewable Energy Target is met, and that support is provided to technologies not yet fully commercialised (such as geothermal and large-scale solar thermal generation).

Policy-driven investments are motivated by government incentives and directives, such as the national Renewable Energy Target (RET) scheme. While this is a market-based mechanism intended to deliver substantial renewable generation within the next decade, other policy initiatives, such as the Solar Flagships Program, are much more prescriptive in terms of the generation technologies and capacities that are to be installed.

In terms of policy-driven investment, a key finding from AEMO's 2010 National Transmission Network Development Plan (NTNDP) was that a combination of the national RET scheme and a carbon-pricing scheme is likely to lead to generation development dominated by low CO2-e emission technologies and fuels. The 2010 NTNDP also showed wind generation being the main technology for new developments in the short term, with up to 6,300 MW of new wind generation installed by 2020–21. Other technologies, such as geothermal and large-scale solar generation do not begin entering the NEM until after 2015 due to assumed technology development lead times.

5 Capacity factors are calculated by comparing the average historical contribution from a generating system with its capacity.

6 Economic crossover points for other technologies and carbon prices are discussed in Chapter 8.

Geothermal and biomass-based generation developments are expected to be fully available to meet maximum demands, however wind and solar thermal generation technologies have intermittent outputs, and may not contribute significantly during periods of high demand.

Renewable generation

Wind generation typically has a capacity factor of between 25% and 40%. The intermittent nature of the wind, however, substantially reduces wind generation's likely contribution to meeting regional maximum demand. This means that while wind generation may be used effectively to meet regional energy requirements (reducing the need for energy-driven investments), it cannot be used to the same extent when meeting capacity requirements. As a result, its ability to defer the regional LRC point projections in Table 1 is limited, based on the seasonal contribution factors listed in Table 2 .[7]

Table 2— Wind contribution factors[a]

Region	Average Capacity Factor (2010–11)	Contribution Factor Summer MD	Contribution Factor Winter MD
New South Wales	25.6%	9.2%	0.4%
Victoria	29.2%	7.7%	3.9%
South Australia	32.6%	5.0%	3.5%
Tasmania	39.2%	1.0%	1.0%

a. Values have not been presented for Queensland due to the limited available data set.

Solar generation (without energy storage capabilities), also only partially contributes to meeting maximum demand. While a maximum demand will typically occur on a hot, sunny day, it will also tend to occur in the mid to late afternoon, and solar photovoltaic systems tend to be at full output in the middle of the day.

AEMO intends to assess the contribution factors to be applied to solar technologies as they begin to affect the supply-demand balance.

Investment trends

The mix of generating technologies in the NEM has started to change, with wind and solar generation increasing in response to government policies that encourage the use of renewable fuels. Gas powered generation (GPG) capacity has also increased, helping to compensate for the intermittent nature of wind and solar generation. Given current government initiatives and carbon pricing announcements, this trend is expected to continue.

As a result, the location of new generation is increasingly being driven by the availability of wind resources or gas pipelines rather than by the proximity of coal mines and rail infrastructure. This shift is causing new generation to connect in areas remote from current transmission assets or where transmission infrastructure may be heavily congested. The implications for the JPBs are significant, with a growing need for transmission network augmentation projects in potentially remote locations. This is particularly true in Victoria and South Australia where the majority of wind generation capacity has been built to date.

The nature of demand is also changing. In the medium and long term, new technologies such as smart meters, smart grids, and electric vehicles are likely to result in and altered energy consumption patterns. AEMO continues to assess the impact of these technologies on the growth rates of both energy and maximum demand.

Chapter 2 provides more information about the impact of climate change policies and emerging technologies on the nature of supply and demand.

[7] Seasonal contribution factors represent the minimum level of output available at least 85 percent of the time during the top 10 percent of the seasonal demands in a region.

Generation investment interest

AEMO surveys registered participants and other parties believed to be developing future generation projects as part of the ESOO data collection process. This data, which is used to update information about current generation capacities and provide an overview of generation investment in the NEM, is classified as either:

- existing (installed) generation, representing generation that is commissioned and operating as at 1 July 2011, and requiring that the operator be a registered market participant
- committed projects, representing generation that is considered to be proceeding, or
- proposed projects, which are further identified as either:
  - advanced proposals, representing generation at an intermediate stage of development, or
  - publicly announced proposals, representing generation at an early stage of development.

Figure 1 compares the fuel source mix of existing (installed) generation with known committed projects and advanced proposals, indicating that interest in new generation may be focused on a different mix of technologies than those that currently dominate the NEM's capacity.

Figure 2 summarises the commitment status of public generation developments in the NEM, and shows high investor interest in gas powered generation and wind investments. This is consistent with the capacity-driven (gas) and policy-driven (wind) investment opportunities discussed in the previous sections.

Figure 1 — Comparison of existing (installed) generation, and committed projects and advanced proposals in the NEM by fuel source (MW)

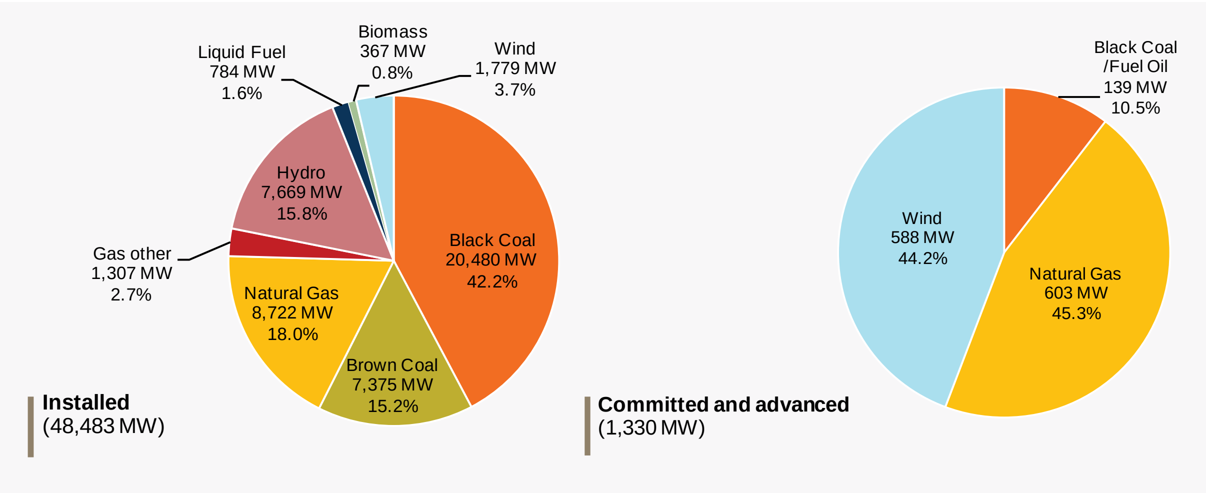
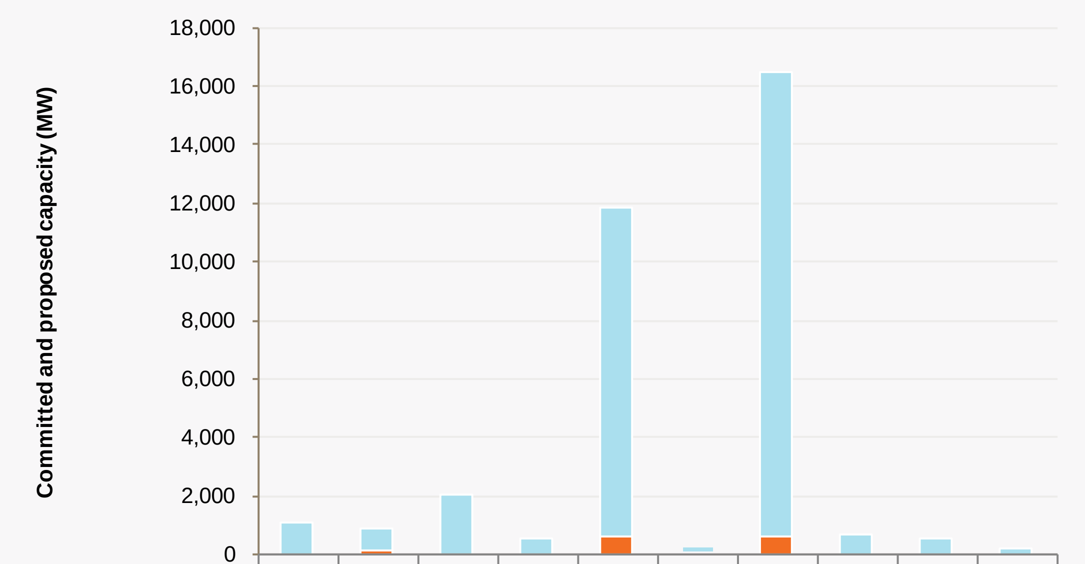


Figure 2 — Capacity of committed and proposed projects in the NEM by fuel source (MW)



	Black coal	Black coal other	Black coal or gas	Brown coal	Gas	Hydro	Wind	Solar	Geo	Bio
Publicly announced	1074	700	2000	550	11217	43	15851	694	525	213
Advanced	0	0	0	0	36	0	0	0	0	0
Committed	0	139	0	0	567	0	588	0	0	0

There are currently over 1,000 MW of committed projects across the NEM, including Woodlawn Wind Farm (48 MW) and the Eraring Power Station upgrade (120 MW) in New South Wales, Mortlake Stage 1 project (566 MW), the Macarthur Wind Farm (420 MW) and the Oaklands Hill Wind Farm (67 MW) in Victoria, and the Bluff Wind Farm (53 MW) in South Australia.

Wind generation projects represent the highest technology interest (by capacity), with advanced and publicly announced proposals totalling over 15,000 MW across the NEM. While wind generation represents a significant part of the committed and proposed generation under development, the contribution from wind towards deferring LRC points approximates only 10 percent of the installed capacity (at most), based on the calculated seasonal contribution factors (see Table 2).

Gas powered generation developments represent the second highest investment interest, with publicly announced proposals totalling over 11,000 MW spread across all regions except Tasmania.

Several publicly announced solar generation proposals are located across the NEM, and include the 250 MW Solar Dawn project in Queensland, and the 150 MW Moree project in New South Wales. Both of these projects were recently announced as successful candidates under the Australian Government's Solar Flagships program.[8]

The publicly announced proposal using geothermal generation is a 500 MW station located at Innamincka in South Australia.

[8] Department of Resources, Energy and Tourism. "Solar Flagships Program". Available http://www.ret.gov.au/energy/clean/cei/sfp/Pages/sfp.aspx. 17 May 2011.

Energy and maximum demand projections

The 2011 ESOO presents energy and maximum demand projections for the next 10 years as a key input into the supply-demand outlook. These projections are based on a number of economic, demographic, and carbon price assumptions, (see Appendix C) which include the assumption that the Australian Government will introduce a carbon price of 10 $/t CO2-e in 2013–14, followed by a full emissions trading scheme in 2014–15.

The current energy and maximum demand projections assume the introduction of a 10 $/t CO2-e carbon price in 2013–14, followed by a full emissions trading scheme in 2014–15. The climate change initiatives recently announced, however, indicate a carbon price of 23 $/t CO2-e introduced in 2012–13, followed by a full emissions trading scheme in 2015–16. The level of short-term price elasticity in the NEM suggests that the impact of these differing assumptions on energy and maximum demand are expected to be minimal.

The energy efficiency and small-scale renewable initiatives recently announced are also consistent with previous assumptions.

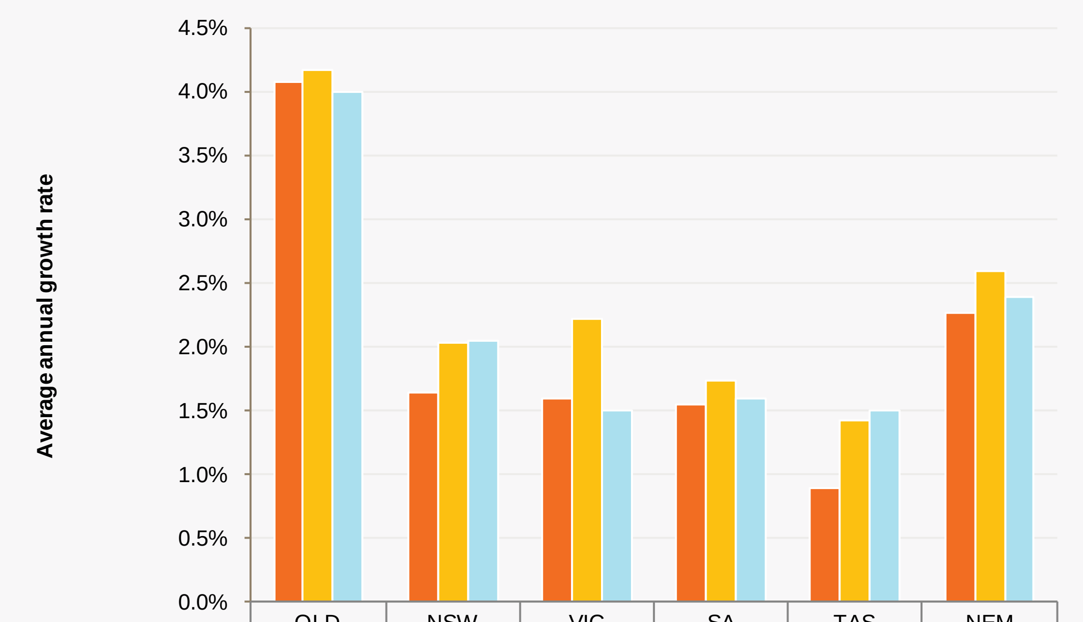
Energy growth projections are characterised by sustained gross domestic product growth of between 2% and 3% in the medium term. Queensland growth projections exceed the other regions due to an anticipated step change increase in demand from Liquefied Natural Gas and mining loads driven by high worldwide commodity prices.

Figure 3 shows the projected average annual growth rates of regional energy consumption and maximum demand[9] (with medium economic growth) until 2020–21. Growth rates vary from region to region due to underlying differences in the composition of regional demand. Queensland consumption is driven primarily by activity in the resources sector, which is growing strongly.

Figure 4 summarises the energy and maximum demand projection changes since the 2010 ESOO. Figure 5 presents the change in projected annual growth rates. While the 2011 ESOO also includes an alternative set of Queensland energy and maximum demand projections, the projections in the following figures represent those developed by Powerlink Queensland.

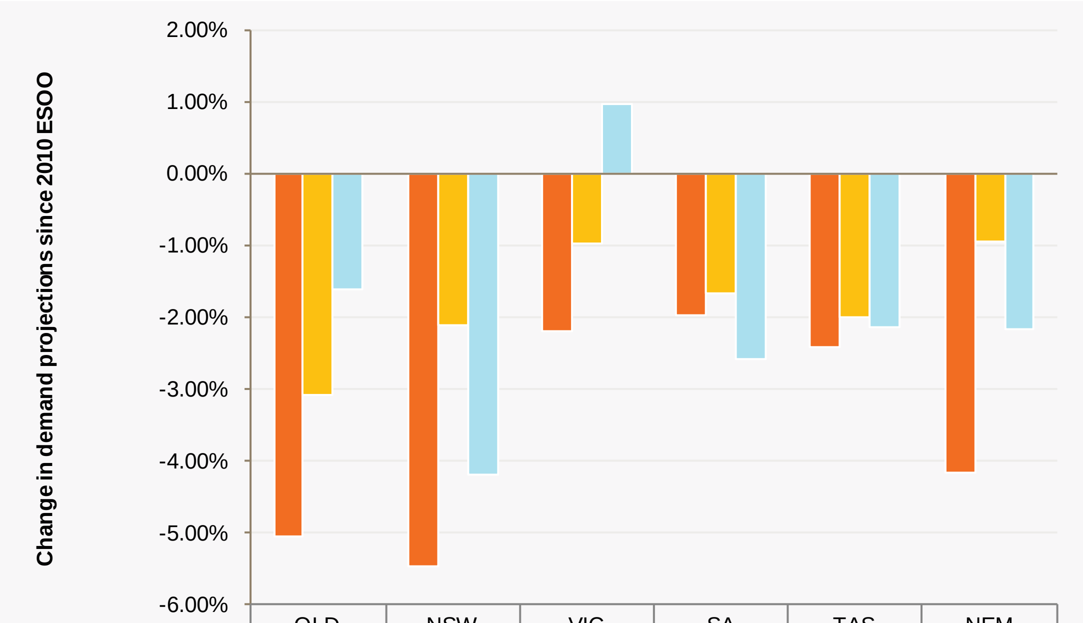
9 In this case, the level of demand that is statistically likely to be exceeded only once in every ten years (a 10% probability of exceedence).

Figure 3 — Average NEM annual energy and maximum demand growth rates



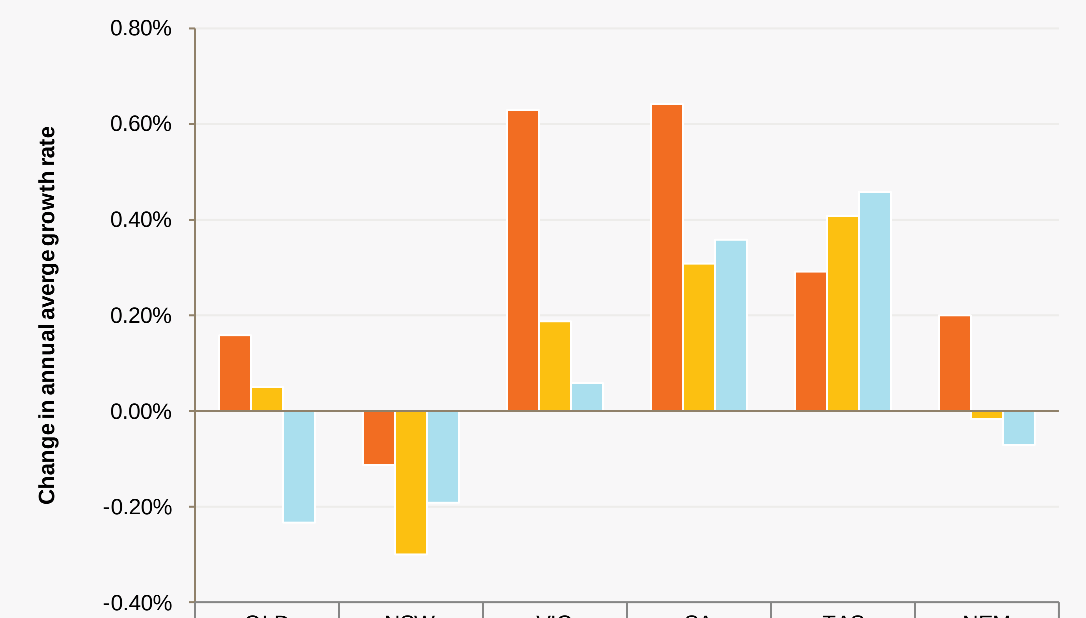
	QLD	NSW	VIC	SA	TAS	NEM
Energy (GWh)	4.1%	1.6%	1.6%	1.5%	0.9%	2.3%
Summer MD (MW)	4.2%	2.0%	2.2%	1.7%	1.4%	2.6%
Winter MD (MW)	4.0%	2.0%	1.5%	1.6%	1.5%	2.4%

Figure 4 — Energy and maximum demand projection changes since the 2010 ESOO



	QLD	NSW	VIC	SA	TAS	NEM
Energy (GWh)	-5.0%	-5.4%	-2.2%	-2.0%	-2.4%	-4.2%
Summer MD (MW)	-3.1%	-2.1%	-1.0%	-1.7%	-2.0%	-0.9%
Winter MD (MW)	-1.6%	-4.2%	1.0%	-2.6%	-2.1%	-2.2%

Figure 5 — Average annual growth rate changes since the 2010 ESOO



	QLD	NSW	VIC	SA	TAS	NEM
Energy	0.2%	-0.1%	0.6%	0.6%	0.3%	0.2%
Summer MD	0.1%	-0.3%	0.2%	0.3%	0.4%	0.0%
Winter MD	-0.2%	-0.2%	0.1%	0.4%	0.5%	-0.1%

Variations between the 2010 and 2011 projections can be attributed to a range of factors specific to each region that include the following:

- In Queensland, Powerlink Queensland suggests that extreme weather in early 2011 reduced mining loads, curtailed electrified rail, and reduced commercial and residential loads. Demand growth projections are driven by mining activity in Central Queensland and flood-related reconstruction. Liquefied Natural Gas development is also expected to add significantly to Queensland demand by late 2013.
- In New South Wales, Transgrid's projections have decreased due to a lower than expected economic growth and the incorporation of new and ongoing energy efficiency policies.
- In Victoria, AEMO attributes greater energy consumption growth to improved economic growth. Industrial loads are also assumed to return to previous levels, mainly associated with the aluminium sector.
- In South Australia, Electranet's industrial load projections from 2013–14 have increased the average annual growth rate in response to mining expansion plans and an improved economic outlook for the region.
- In Tasmania, Transend Networks' projections from 2014–15 onwards are similar to the projections it made in 2010, but there is a reduction in consumption between 2011 and 2014 due to lower economic growth. Energy consumption growth rates are associated with an expected increase in agriculture and mining activity and increased population growth.

Fuel supply

Electricity generation in the NEM continues to be dominated by coal-fired technologies. Queensland and New South Wales have substantial black coal reserves, and Victoria has significant reserves of brown coal. However, the level of GPG is growing quickly as developers look for generation fuels with lower carbon emissions. The NEM has access to conventional natural gas resources located predominantly in Victoria and South Australia, and coal seam gas resources located in South Western Queensland and Northern New South Wales.

In addition to these conventional generation sources, Australia has an abundance of renewable resources. Hydroelectric capacity is mostly developed, while wind generation continues to develop strongly.

Other renewable resources remain largely undeveloped, partly due to the higher per megawatt capital costs currently associated with these technologies. To promote development, the revenue of new renewable generators is supplemented through the Australian Government's national RET scheme. [10]

Many of the identified renewable resources are remote from the existing transmission network, potentially requiring significant investment in transmission infrastructure to enable connection.

Chapter 5 provides more information about the location, availability, and usage of fuel supplies in the NEM, including fuels associated with emerging or undeveloped sources of renewable energy generation.

Minimum reserve levels

AEMO uses Minimum Reserve Levels (MRL) to determine when reserves within a region fall below the point at which the Reliability Standard[11] can be confidently met (the LRC point). MRLs are calculated using detailed market simulations that model system reliability under a range potential demand conditions and generation outage patterns. Chapter 6 provides more information about the calculation and application of MRLs.

In the NEM, adjacent regions generally do not reach their maximum demands at the same time. The MRLs account for this diversity of demand (subject to network limitations), allowing the same capacity to contribute to reliability in more than one region, and reducing overall reserve requirements across the NEM.

The 2011 supply-demand outlook also applies a new MRL formulation, developed during AEMO's 2010 MRL recalculation project. This was published in June 2010 and became operational in December 2010, following a change to the National Electricity Rules.

The new approach allows neighbouring regions to optimally share surplus reserves as system conditions change, so that regions with excess capacity can support regions that are unable to meet their reserve requirements locally. The ability to share is often limited, indicating either that peak demands between regions often occur at the same time, or that the existing interconnector capacity is already fully utilised.

The 2011 ESOO reports that reserve sharing is feasible between Victoria and South Australia, and to a lesser extent between Queensland and New South Wales. No sharing opportunities exist between other regions, beyond that already captured in the MRL values.

The reserve sharing curve for each region pair is presented as a graph of the MRL in one region compared to the MRL in an adjoining region. Each point on the curve represents a pair of MRL values that meet (or exceed) the Reliability Standard in both regions.

Figure 6 and Figure 7 show the reserve sharing curves for Queensland and New South Wales, and Victoria and South Australia, respectively. The slope of each curve indicates the effectiveness of different combinations of reserve sharing. One-to-one slopes indicate the greatest opportunity for optimising reserves between regions, while reserve sharing is less effective for steeper and flatter slopes.

Each curve has a minimum total requirement point, which represents the reserve requirement expected to exactly meet the Reliability Standard using the minimum installed capacity in the two regions (combined). Other points on the curve require more installed capacity.

10 Department of Climate Change and energy Efficiency. "Renewable Energy Target." Available http://www.climatechange.gov.au/en/government/initiatives/renewable-target.aspx. 15 August 2011

11 Australian Energy Market Commission. "Guidelines & Standards". Available http://www.aemc.gov.au/Panels-and-Committees/Reliability-Panel/Guidelines-and-standards.html. 28 April 2011.

Figure 6 — Reserve sharing curve for Queensland and New South Wales

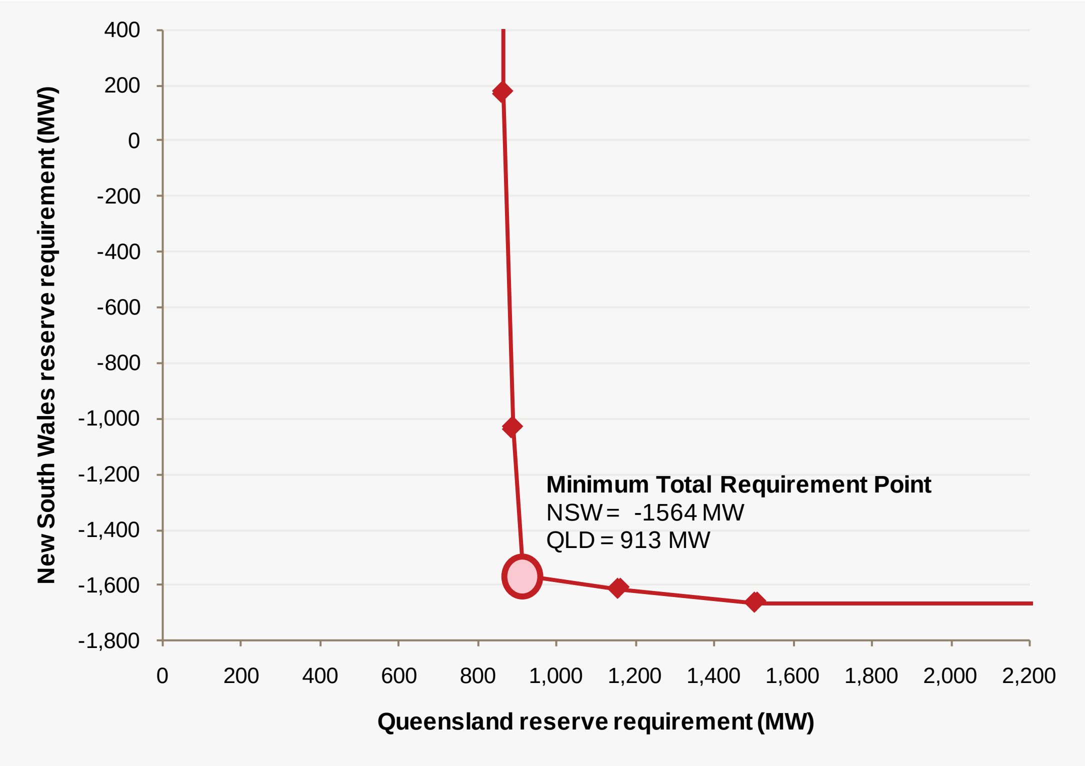
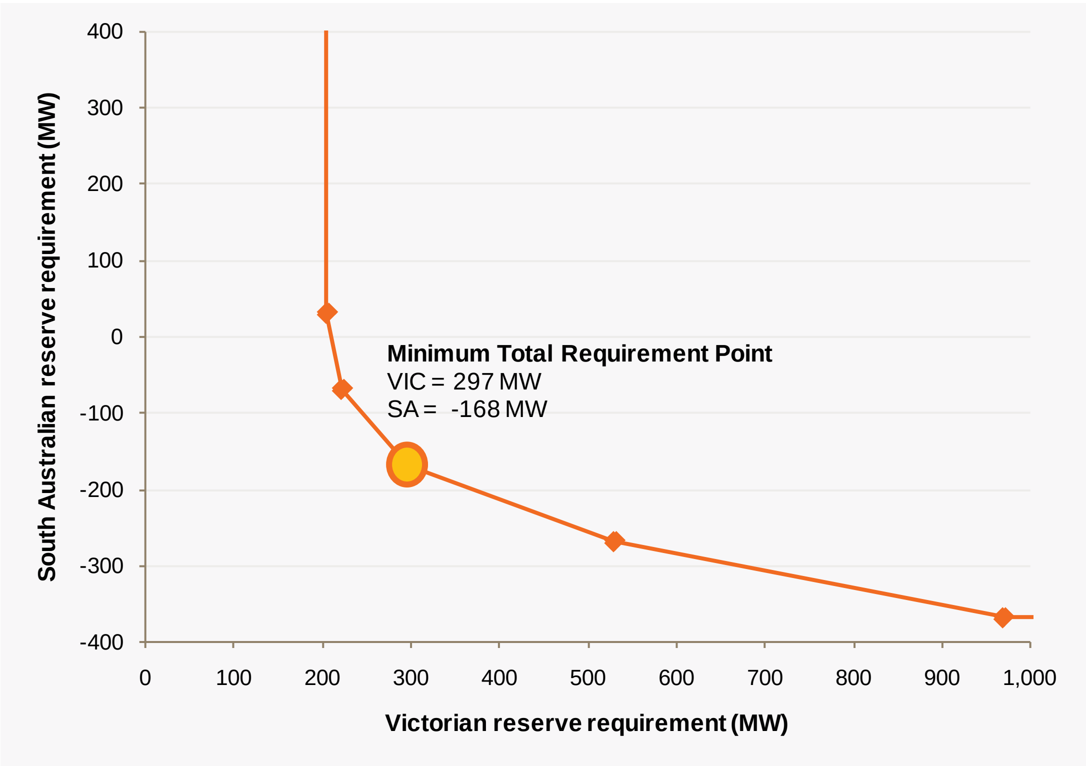


Figure 7 — Reserve sharing curve for Victoria and South Australia



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CHAPTER 1 - INTRODUCTION

The Australian Energy Market Operator (AEMO) publishes an Electricity Statement of Opportunities (ESOO) each year to provide the energy industry and potential investors with information about demand projections, generation capacities, and National Electricity Market (NEM) supply adequacy for the next 10 years. By providing this information, the ESOO aims to present a comprehensive body of information to guide investment decisions and inform market participants and relevant authorities. The ESOO's contents and publication timeframes are stipulated by clause 13.3.3(q) of the National Electricity Rules.

1.1 The ESOO and AEMO's other planning publications

The ESOO is one of a collection of related annual planning publications that together present comprehensive information about energy supply, demand, investment, and network planning. These publications include the:

- South Australian Supply and Demand Outlook (SASDO)[1]
- Victorian Annual Planning Report (VAPR)[1]
- Power System Adequacy – Two Year Outlook (PSA)[2]
- Gas Statement of Opportunities (GSOO)[3], and
- National Transmission Network Development Plan (NTNDP).[1]

Table 1-1 compares these various planning documents, their different focuses, and the types of information they deliver.

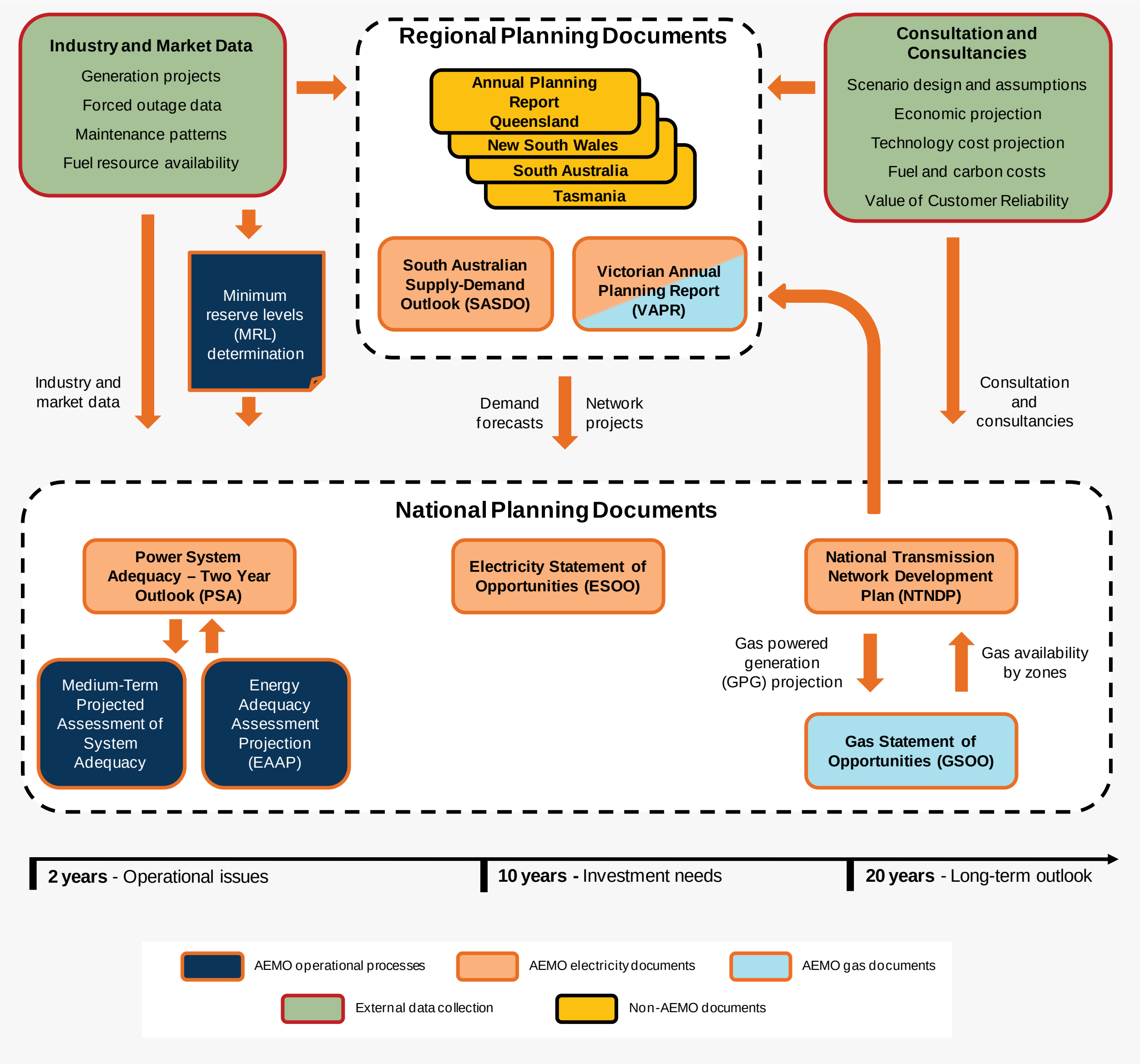
Table 1-1 — AEMO's planning documents

	South Australian Supply and Demand Outlook (SASDO)	Victorian Annual Planning Report (VAPR)	Electricity Statement of Opportunities (ESOO)	Power System Adequacy - Two Year Outlook (PSA)	Gas Statement of Opportunities (GSOO)	National Transmission Network Development Plan (NTNDP)
Published	30 June	30 June	31 August	31 August	30 November	31 December
Focus	Generation and demand-side investment needs and opportunities	Transmission investment needs	Generation and demand-side investment needs and opportunities	Generation and transmission system adequacy	Transmission and supply-side investment opportunities	Generation and transmission outlook
Scope	South Australian electricity	Victorian gas and electricity	NEM electricity	NEM electricity	Eastern Australian gas	NEM electricity
Outlook	10 years	10 years (5-year focus)	10 years	2 years	20 years (5-year detailed Victorian gas forecasts)	20 years
Electricity forecasts	✓	✓	✓	✓	n/a	✓
Gas forecasts	n/a	✓	n/a	n/a	✓	n/a

1 AEMO. "Planning". Available http://www.aemo.com.au/planning/planning.html. 21 April 2011.
2 AEMO. "Market & Power Systems". Available http://www.aemo.com.au/electricityops/market.html. 30 May 2011.
3 AEMO. "2010 Gas Statement of Opportunities". Available http://www.aemo.com.au/planning/gsoo2010.html. 21 April 2011.

Figure 1-1 illustrates the information interactions between these planning documents, and the annual planning reviews provided by the jurisdictional planning bodies (JPBs) (including AEMO in Victoria).

Figure 1-1 — Information interactions between NEM planning documents



While providing extensive electricity market investment environment analysis, the ESOO also plays an important secondary role providing a consistent set of inputs for AEMO's other planning publications.

A major part of the ESOO's preparation involves collecting market data from both internal and external sources, which include the following:

- Economic outlooks, annual energy and maximum demand projections consistent with those presented in the jurisdictional planning bodies (JPBs) annual planning reports (APR).
- Historical and expected demand reductions through the operation of demand-side participation (DSP), collected annually from network service providers (NSPs) and market customers.

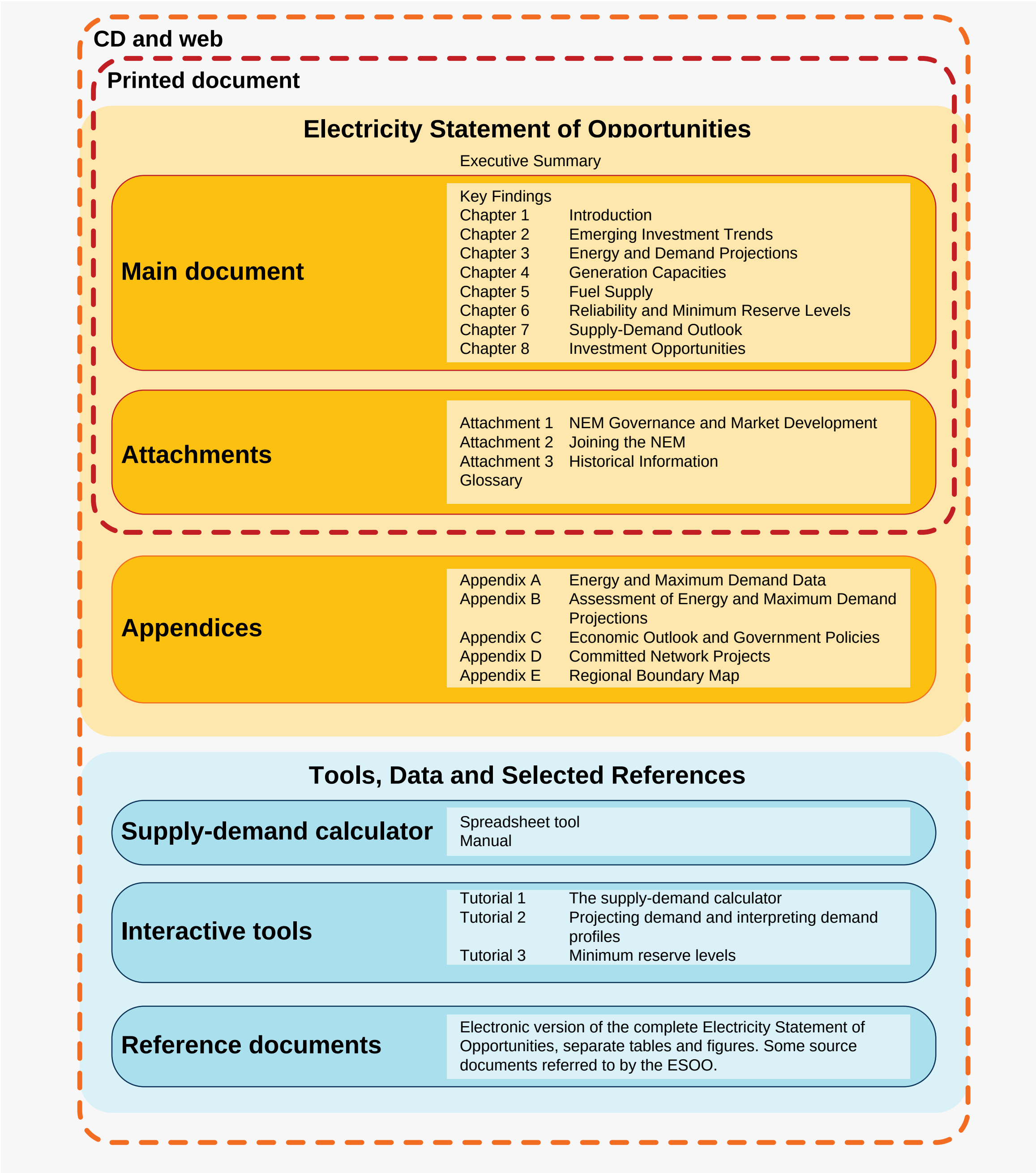
- Information about the expected operation of existing and future generation from generation owners and proponents.
- Existing network capabilities sourced from AEMO's Market Management System (MMS).
- Future network capabilities provided by the transmission network service providers (TNSPs) to account for committed projects.
- The minimum reserve levels (MRL) calculated regularly by AEMO to represent the Reliability Standard specified by the Australian Energy Market Commission's (AEMC) Reliability Panel.

1.2 Content and structure of the ESOO

Each ESOO chapter explores an important aspect of the electrical energy sector. The final two chapters draw on this content to form a consolidated picture of the NEM's supply adequacy and future investment opportunities. Supplementary information referenced by the main document is included as attachments, appendices, and tutorials.

Figure 1-2 summarises the ESOO's structure, which comprises both printed and electronic information.

Figure 1-2 — ESOO document overview



The ESOO printed document

Key Findings, provides an overview of the 2011 ESOO's findings in relation to the supply-demand outlook, energy and maximum demand projection, generation investment trends, and general investment opportunities for each region within the NEM.

Chapter 1, 'Introduction', describes the structure and content of the 2011 ESOO, and its relationship with AEMO's other annual planning publications.

Chapter 2, 'Emerging Investment Trends', presents an overview of the NEM's investment environment, focusing on the potential impact of climate change policies and emerging technologies on the nature of supply and demand.

Chapter 3, 'Energy and Demand Projections', presents energy and maximum demand projections for the next 10 years. To address the risks associated with planning in an uncertain environment, AEMO has adopted a scenario-based approach. The scenarios provide a detailed analysis of the impact of the variations to economic, demographic, and Australian carbon policy assumptions. Chapter 3 is supplemented by Appendix A, Appendix B, and Appendix C.

Chapter 4, 'Generation Capacities', presents information about generation for each region, including current summer and winter generation capacities, planned capacity changes, and generation for which a commitment or proposal to build has been made (according to AEMO's committed project criteria).

The AEMO website's generation information page provides frequent updates about NEM generation capacities.[4]

Chapter 5, 'Fuel Supply', provides an overview of the location, availability, and usage of fuel supplies in the NEM.

Chapter 6, 'Reliability and Minimum Reserve Levels', describes concepts relating to medium and long-term power system reliability, with a specific focus on the calculation and application of minimum reserve levels (MRLs), which form the basis of AEMO's system reliability assessments.

The supply-demand outlook applies MRLs when comparing available generation supplies and maximum demand projections.

Chapter 7, 'Supply-Demand Outlook', presents regional supply-demand balance projections that identify potential opportunities for demand-side response and additional generation and network capacity investment over a 10-year outlook period. Opportunities are identified from the expected timing and magnitude of reserve shortfalls, where existing and committed supply falls below the required capacity for reliability.

These projections are based on the maximum demand projections presented in Chapter 3, the committed generation projects presented in Chapter 4, the MRLs presented in Chapter 6, and the committed network projects listed in Appendix D.

Chapter 8, 'Investment Opportunities', describes trends and key developments identified in the preceding chapters that may present opportunities for new investment within the NEM. This chapter also draws on information from the latest assessments of new technology costs, existing market conditions, and the results of previous published works, such as the latest NTNDP.

Attachment 1, 'NEM Governance and Market Development', presents an overview of the institutional structure governing the energy market. It also presents key market and policy reviews that may affect generation investment and DSP in the NEM.

Attachment 2, 'Joining the NEM', presents an overview of the generation connection process and how to register as a generator in the NEM.

Attachment 3, 'Historical Information', supplements the various projections provided in the ESOO by providing contextual information for investment decisions. In particular, this attachment presents historical levels of operational demand, generation mix, regional spot prices, market directions, and settlements residues.

The ESOO electronic information

In addition to an electronic copy of the printed material, ESOO supplementary information is available from the AEMO website. This information includes the following.

Appendix A, 'Energy and Maximum Demand Data', supplements Chapter 3 by presenting additional information about the scheduled and semi-scheduled energy and maximum demand projections.

Appendix B, 'Assessment of Energy and Maximum Demand Projections', supplements Chapter 3 by reviewing the energy and maximum demand projections provided for each region.

4 AEMO. "Generation Information Page". Available http://www.aemo.com.au/data/gendata.shtml. 21 April 2011.

Appendix C, 'Economic Outlook and Government Policies', supplements Chapter 3 by summarising the assumptions made about future macroeconomic developments, government policy, consumer choice, and technological developments that inform the energy and maximum demand projections.

Appendix D, 'Committed Network Projects', supplements Chapter 7 by providing the committed network projects used to develop the regional supply-demand outlooks.

Appendix E, 'Regional Boundary Map', supplements the chapters by presenting reference information regarding the physical and electrical region boundaries, the routes and locations of major transmission lines, and locations of the major power stations and substations.

The supply-demand calculator is a spreadsheet tool used to calculate the supply-demand outlooks presented in Chapter 7. Inclusion of the supply-demand calculator allows interested parties to conduct independent supply-demand outlook sensitivity studies.

Tutorial 1, 'Supply-Demand Calculator', provides a reference guide for using the supply-demand calculator.

Tutorial 2, 'Projecting Demand and Interpreting Demand Profiles', provides an explanation of the basics of analysing and interpreting regional demand (sometimes referred to as 'load') profiles and demand duration curves. Demand profile analyses can provide an important preliminary assessment in terms of whether (and where) opportunities for investment in the NEM lie.

Tutorial 3, 'Minimum Reserve Levels', provides two videos (one introductory and one advanced) that explore the underlying concepts and outcomes of the MRL calculations.

The Reference Documents provide a collection of tables and figures recorded as spreadsheets and high resolution graphics objects to facilitate the use of the information throughout the publication.

CHAPTER 2 - EMERGING INVESTMENT TRENDS

Summary

This chapter presents an overview of the investment environment in the National Electricity Market (NEM), focusing on the potential impact of climate change policies and emerging technologies on the nature of supply and demand.

The mix of generating technologies in the NEM has begun to change in response to government policies that encourage the use of renewable fuels, specifically wind and solar. Gas powered generation (GPG) capacity has also increased, helping to compensate for the variable nature of wind and solar generation. This trend is expected to continue given the current government initiatives, and the announced introduction of a carbon pricing scheme.[1,2]

As a result of these changes, the location of new generation is increasingly being driven by the availability of wind resources or gas pipelines, rather than by the proximity of coal mines or rail infrastructure. This shift is leading to new generation connections in areas remote from current transmission assets, or in areas where transmission infrastructure may be heavily congested, which has significant implications for jurisdictional planning bodies (JPBs) in terms of transmission network augmentation projects in remote locations.

This is particularly true in Victoria and South Australia where the majority of wind generation capacity has been built to date. A number of national initiatives have commenced in the area of transmission planning to address such issues, including a Transmission Frameworks Review, the Scale-Efficient Network Extensions (SENEs) program, and independent studies investigating the benefits of specific network augmentation options.

The nature of demand is also changing. In the medium and long term, new technologies such as smart meters, smart grids, and electric vehicles are likely to result in increased demand-side participation (DSP) and altered energy consumption patterns. This may reduce the growth rates of both energy and maximum demand.

Key initiatives and institutions impacting generation investment include the proposed carbon pricing policy, the national Renewable Energy Target (RET) scheme, the GreenPower Accreditation Program, the Carbon Capture and Storage (CCS) Flagships Program, the Solar Flagships Program, the Australian Solar Institute (ASI), and the Australian Centre for Renewable Energy (ACRE).

Results of the first round of applications for the Solar Flagships Program have been announced, with Solar Dawn and Moree Solar Farm being the successful applicants. These projects, located at Chinchilla in Queensland and Moree in New South Wales, are expected to total 400 MW and be commissioned by 2015.[3] The government is expected to deliver its decision on the next stage of the CCS Flagships Program towards the end of 2011.

The number of Renewable Energy Certificates (RECs)—now referred to as Large-scale Generation Certificates (LGC) and Small-scale Technology Certificates (STC) after recent changes to the national RET scheme—has increased since 2009, and there is considerable interest in renewable generation investments, particularly wind. However, investment in base load (thermal) generation is slowing in response to carbon price uncertainty and associated difficulties with raising investment capital and borrowings.

[1] Department of Climate Change and Energy Efficiency. “Multi-Party Climate Change Committee”. Available http://www.climatechange.gov.au/government/initiatives/multi-party-committee.aspx. 15 March 2011.

[2] Australian Government, “Clean Energy Future”. Available http://www.cleanenergyfuture.gov.au/. 24 July 2011.

[3] Department of Resources, Energy and Tourism. “Green Light to Build Australia’s Largest Solar Projects”. Available http://minister.ret.gov.au/MediaCentre/MediaReleases/Pages/GreenLighttoBuildAustralia'sLargestSolarProjects.aspx. 29 June 2011.

2.1 The National Electricity Market

The NEM is an alternating current electricity network, geographically spanning over 5,000 kilometres and covering the eastern and southern states of Australia.[4] The annual energy demand in the NEM exceeds 200 TWh, representing approximately 87% of Australia's total electricity demand.[5] The NEM experiences a summer maximum demand of more than 35,000 MW, which is met by an installed capacity of up to 45,000 MW, including wind generation.[6]

The NEM comprises five regions that are approximately aligned with state boundaries. Each region has a JPB with transmission system planning responsibility within its respective jurisdiction. Since the formation of AEMO in 2009, the JPBs for each region are Powerlink Queensland (Queensland), TransGrid (New South Wales), AEMO (Victoria), ElectraNet (South Australia), and Transend Networks (Tasmania).

Figure 2-1 shows the high level structure of the NEM, and the network of high-voltage transmission lines (called interconnectors) that connect the regions. There are two categories of interconnector:

- Regulated interconnectors earn a regulated income based on the value of the asset.
- Unregulated interconnectors, or market network service providers (MNSPs), earn revenue by transferring energy between differently priced regions, or by selling the rights to revenues generated through trading across the interconnector.

AEMO produces the publication 'An Introduction to Australia's National Electricity Market', providing a basic overview of the structure and operation of the NEM.[7] The AEMO Information Centre also provides information about the NEM and AEMO's role within it.[8]

4 AEMO. "About AEMO – Overview". Available http://wwww.aemo.com.au/corporate/aboutaemo.html. 20 June 2011.

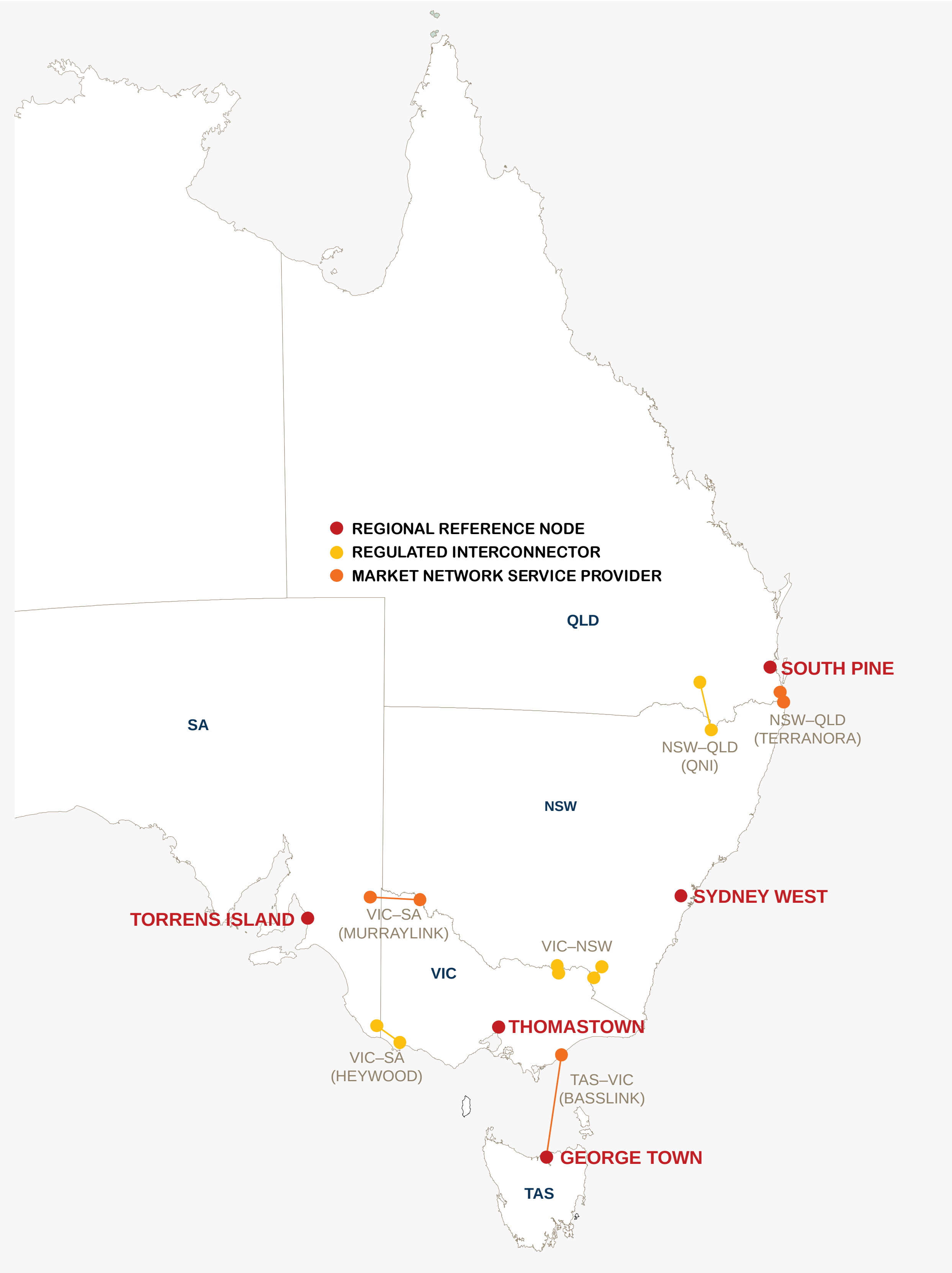
5 ABARE. "Table i - Australian Consumption Of Electricity By State – gigawatts". Available http://www.abareconomics.com/interactive/energyUPDATE08/htm/data.htm. 15 June 2011.

6 While wind generation typically has a capacity factor of between 25% and 40%, its variable nature substantially reduces its minimum reliable contribution to meeting maximum demand. This means that while wind generation may effectively be used to meet regional energy requirements, it does not contribute to capacity requirements in the same way. For more information, see Chapter 8, Section 8.3.3.

7 AEMO. "An Introduction to Australia's National Electricity Market". Available http://wwww.aemo.com.au/corporate/publications.html. 30 May 2011.

8 Contact the Information Centre on 1300 361 011, or email infocentre@aemo.com.au.

Figure 2-1 — Regions and interconnectors in the NEM



2.2 Generation investment trends in the NEM

By changing the economic drivers underlying investment, and encouraging investment in renewable generation and GPG, climate change policies and new generation technologies are reducing the NEM's reliance on coal-fired generation.

The 2010 National Transmission Network Development Plan (NTNDP) identified that, depending on the type of socio-economic scenario and carbon price assumptions, investment of between $35 billion and $130 billion will be required to augment the transmission network and develop sufficient new generation assets to meet demand over the next 20 years.[9]

The NTNDP studied five scenarios, which included the:

- Fast Rate of Change, high carbon price (FC-H) scenario and a medium carbon price (FC-M) sensitivity
- Uncertain World, low carbon price (UW-L) scenario and a zero carbon price (UW-0) sensitivity
- Decentralised World, medium carbon price (DW-M) scenario and a high carbon price (DW-H) sensitivity
- Oil Shock and Adaptation, medium carbon price (OS-M) scenario and a low carbon price (OS-L) sensitivity, and
- Slow Rate of Change, low carbon price (SC-L) scenario and a zero carbon price (SC-0) sensitivity.

Table 2-1 identifies the key differentiating assumptions underpinning the NTNDP scenarios. The final column (emissions targets below 2000 levels) identifies the two carbon price sensitivities each scenario explored.

Table 2-1 — Key assumptions underpinning the 2010 NTNDP scenarios

Scenario	Economic Growth	Population Growth	Global Carbon Policy	Centralised Supply-side Response	Decentralised Supply-side Response	Demand-side Response	Emissions Targets Below 2000 Levels
Fast Rate of Change	High	High	Strong	Strong	Strong	Strong	-25%[d] (sensitivity -15%)
Uncertain World	High	High	Weak	Strong	Weak	Weak	-5%[b] (sensitivity zero carbon price)
Decentralised World	Medium	Medium	Strong	Weak	Strong	Strong	-15%[c] (sensitivity -25%)
Oil Shock and Adaptation	Low	Medium	Moderate	Moderate (renewable)	Weak	Weak	-15%[c] (sensitivity -5%)
Slow Rate of Change	Low (mixed)	Low	Weak	Moderate	Weak	Weak	-5%[b] (sensitivity zero carbon price)

a. CO2-e stands for carbon dioxide equivalent.

b. The -5% carbon emissions target (low carbon price) is associated with a carbon price trajectory from (zero) $0 to $44 per tonne CO2-e.

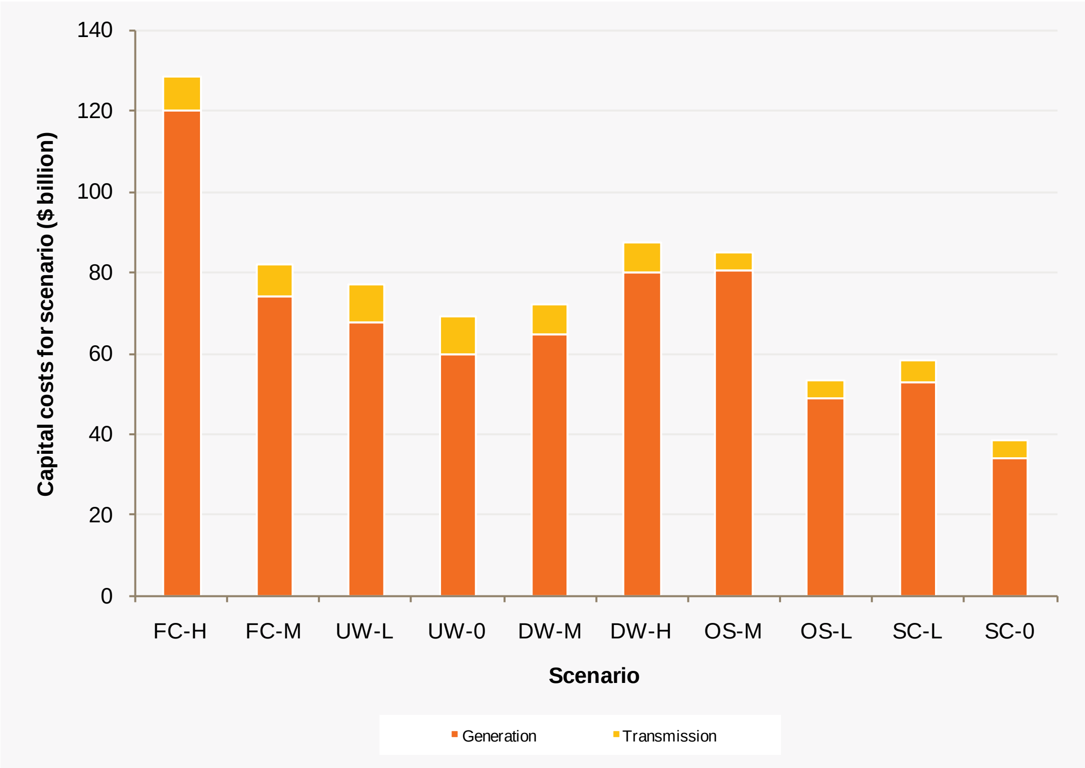
c. The -15% carbon emissions target (med carbon price) is associated with a carbon price trajectory from (zero) $0 to $62 per tonne CO2-e.

d. The -25% carbon emissions target (high carbon price) is associated with a carbon price trajectory from (zero) $0 to $93 per tonne CO2-e.

[9] AEMO. "2010 National Transmission Network Development Plan". Available http://www.aemo.com.au/planning/ntndp.html. 30 May 2011.

Figure 2-2 shows the projected capital costs to 2030 under the 10 NTNDP pairings of socio-economic assumptions and carbon prices.

Figure 2-2 — Projected capital costs in the NEM by 2030[10]



For more information about carbon price policy and regulatory developments, see Attachment 1, Section A1.2. For more information about the generation investment projections and unit retirements in the NTNDP scenario analysis, see Chapter 8, Section 8.4.4.

[10] AEMO. “2010 NTNDP”. Figure 3-1. Available http://aemo.com.au/planning/2010ntndp_cd/downloads/Main%20Report/Chapter03.pdf. 30 May 2011.

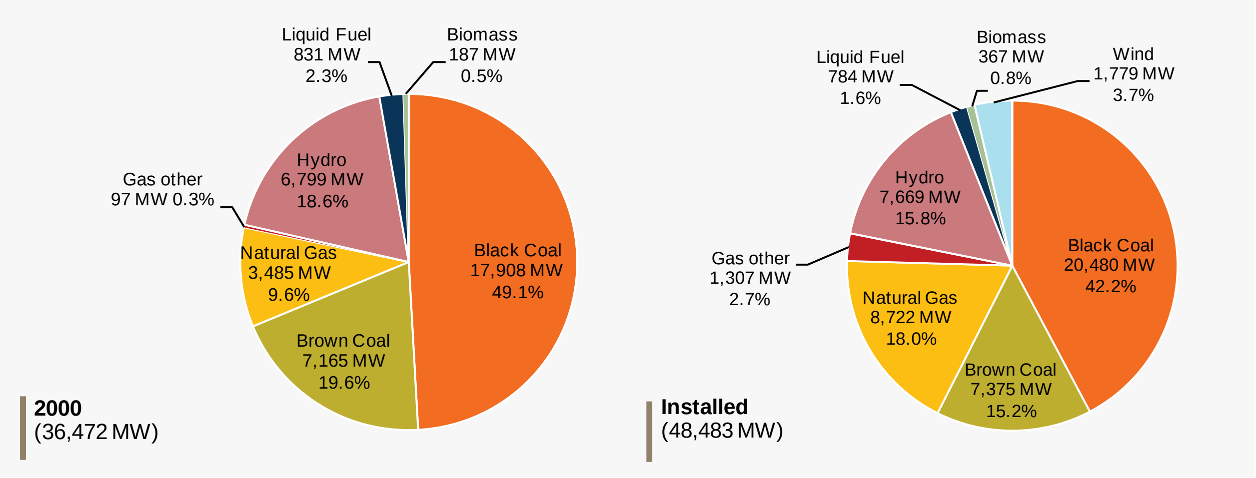
2.2.1 Generation investment over the last 10 years

NEM electricity generation capacity is dominated by coal-fired technologies. However, recent generation investments have largely utilised gas and wind resources, as developers look for less carbon dioxide equivalent (CO2-e) emission intensive technologies.

Australia's hydroelectric resources are largely developed[11], and while Australia has other renewable energy resources, such as solar and geothermal, these technologies are still under development for large-scale deployment. For more information about Australia's fuel resource availability and usage trends, see Chapter 5.

Figure 2-3 shows the change in generation investment over the last 10 years. The increase in renewable technologies, such as wind and solar generation, is largely due to government-sponsored clean energy initiatives, which have resulted in a decrease in the percentage of coal-fired generation.

Figure 2-3 — Installed capacities by fuel source



2.2.2 Key policies impacting generation investment

Key policies driving the shift in generation investment and increasing the demand for renewable energy technologies include the Australian Government's carbon emission reduction policies, the national RET scheme, and the GreenPower Accreditation Program.[12]

[11] ABARE. "Australian Energy Resource Assessment". Available http://adl.brs.gov.au/data/warehouse/pe_aera_d9aae_002/aera.pdf. 28 June 2011.

[12] Department of Climate Change and Energy Efficiency. "Reducing Australia's emissions". Available http://www.climatechange.gov.au/government/reduce.aspx. 20 May 2011.

Carbon emission reduction policies

In late 2008, the Australian Government committed to introduce an Emissions Trading Scheme (ETS).[13] The Carbon Pollution Reduction Scheme (CPRS) Bill 2009 proposed a cap-and-trade mechanism to meet a progressive CO2-e emissions reduction limit. In April 2010, the government announced a delay in implementing the CPRS until the end of the Kyoto Protocol commitment period, and greater clarity about the position of major economies on climate-change issues.

In February 2011, the government announced its intention to introduce a two-stage process to pricing CO2-e emissions, initially involving a government-set carbon price that will eventually convert to a cap-and-trade ETS.[14] The introduction of a carbon price will significantly impact the energy market, and in particular the operating costs of CO2-e-intensive generation, such as brown and black coal-fired power stations.

> **AEMO expects the Clean Energy Future Plan to have little impact on the installed generation mix prior to 2015.**
>
> **Financial support for the high CO2-e emitting generation that the initiatives describe is conditional upon maintaining system reliability. If a mechanism similar to the original Carbon Pollution Reduction Scheme legislation is adopted, AEMO will be required to certify that the Reliability Standard will be met for two years after a proposed deregistration.**
>
> **The Government has indicated that up to 2,000 MW of generation will be invited to tender for closure by 2020. The arrangement is to be negotiated during 2011–12 and will take into account AEMO's views on energy security. The Government expects the closures to occur in the second half of the decade.**
>
> **Investments in low CO2-e emitting technologies (including renewable generation technologies) will be promoted through the Clean Energy Finance Corporation. This will help to ensure that the national Renewable Energy target (RET) is met, and that technologies not yet fully commercialised (such as geothermal and solar thermal generation) are supported.**

The 2010 NTNDP delivered a broad assessment of the investment impact of a range of carbon price trajectories and socio-economic scenarios for the next 20 years.[15] This modelling indicated that:

- a moderate to high carbon price may result in significant levels of generation retirement in Victoria's Latrobe Valley, with subsequent replacement by GPG
- a moderate to high carbon price may also result in retirement of some older and less efficient black coal generation in Queensland and New South Wales, and
- a high carbon price allows a large reduction in CO2-e emissions and a substantial level of new renewable generation (particularly wind), but at the expense of higher NEM spot prices, especially with higher demand.

13 Department of Climate Change and Energy Efficiency. "Carbon Pollution Reduction Scheme" Available http://www.climatechange.gov.au/en/government/initiatives/cprs.aspx. 9 March 2011.

14 See note 1 in this chater.

15 See note 9 in this chapter.

The national Renewable Energy Target scheme

The national RET scheme, which commenced in January 2010, aims to meet a renewable energy target of 20% by 2020.[16] Like its predecessor, the Mandatory Renewable Energy Target (MRET), the national RET scheme requires electricity retailers to source a proportion of their electricity from renewable sources developed after 1997.

The national RET scheme has been implemented through Renewable Energy Certificates (RECs). Eligible renewable sources create RECs in proportion to their energy output, which can be traded, banked, or sold to retailers that must surrender an amount of RECs towards meeting the national target, in proportion to their share of national energy demand. In 2011, the RECs obligation will total 14,825 GWh, increasing annually until it reaches 45,000 GWh in 2020.

In January 2011, the scheme was restructured into two parts[17] comprising the:

- Small-scale Renewable Energy Scheme (SRES), which is a fixed price, unlimited-quantity scheme available only to small-scale technologies (such as solar water heating), and is being implemented via Small-scale Technology Certificates (STC), and
- Large-scale Renewable Energy Target (LRET), which is being implemented via Large Generation Certificates (LGC).

In the 2011 ESOO, certificates prior to 1 January 2011 are referred to as RECs, while discussion of certificates after this date refer to STCs and LGCs.

16 Department of Climate Change and Energy Efficiency. “Renewable Energy Target”. Available http://www.climatechange.gov.au/government/initiatives/renewable-target.aspx. 15 August 2011.

17 Department of Climate Change and Energy Efficiency. “Fact Sheet: Enhanced Renewable Energy Target”. Available http://www.climatechange.gov.au/government/initiatives/renewable-target/fs-enhanced-ret.aspx. 5 May 2011.

The Large-scale Renewable Energy Target

The LRET retains the REC's existing floating price, fixed-quantity structure, and is available only to large-scale power generation, such as hydroelectric, wind, solar, biomass, and geothermal. The objective of the LRET is 41,000 GWh of renewable energy by 2020 (4,000 GWh less than the total national RET scheme).

The 2010 NTNDP modelling included an LRET, with results showing it to be a significant driver of renewable generation investment over the next 10 years. The modelling also predicts the following:

- Achievement of the LRET depends on a carbon price, and was not met in every year of the outlook period under studies with low or zero carbon prices.
- Wind power is the main renewable generation technology investment in the short term, with other technologies, like geothermal and solar generation investment appearing towards the end of the decade to 2020.
- Beyond 2020, renewable investment will slow for a number of years, because initially these technologies are not economic in their own right. As technology costs fall and carbon prices rise, additional renewable generation investment occurs.

In some NTNDP scenarios, high levels of installed wind generation were coupled with significant investment in open-cycle gas turbine (OCGT) generation. This coupling is largely due to the variable nature of wind generation and its uncertain availability during peak demands. While wind generation is able to provide support for regional energy growth, it cannot provide the same level of reliable support at times of maximum demand. This leads to a growing opportunity for peaking capacity to capture high-priced demand peaks as maximum demand grows.

The GreenPower Accreditation Program

The GreenPower Accreditation program is designed to encourage the installation of new renewable energy generation across Australia.[18] Unlike the national RET scheme, which is a mandatory requirement, GreenPower is voluntary.

Approximately 2.2 TWh of GreenPower was sold to customers in 2009, equivalent to the surrender of approximately 2.1 million RECs (including those redeemed by AGL in 2009 that had been banked in 2007 and 2008).

The GreenPower Accreditation program is providing consumers with another way to source renewable energy. More than 182 new GreenPower accredited generating systems have been installed in Australia since 1997, and over 500,000 residential and business customers across Australia have chosen GreenPower products.[19]

18 GreenPower. Available http://www.greenpower.gov.au/home.aspx. 18 May 2011.

19 GreenPower. "About the environmental challenge". Available http://www.greenpower.gov.au/about-the-environmental-challenge.aspx. 20 May 2011.

Technologies currently meeting the national Renewable Energy Target scheme

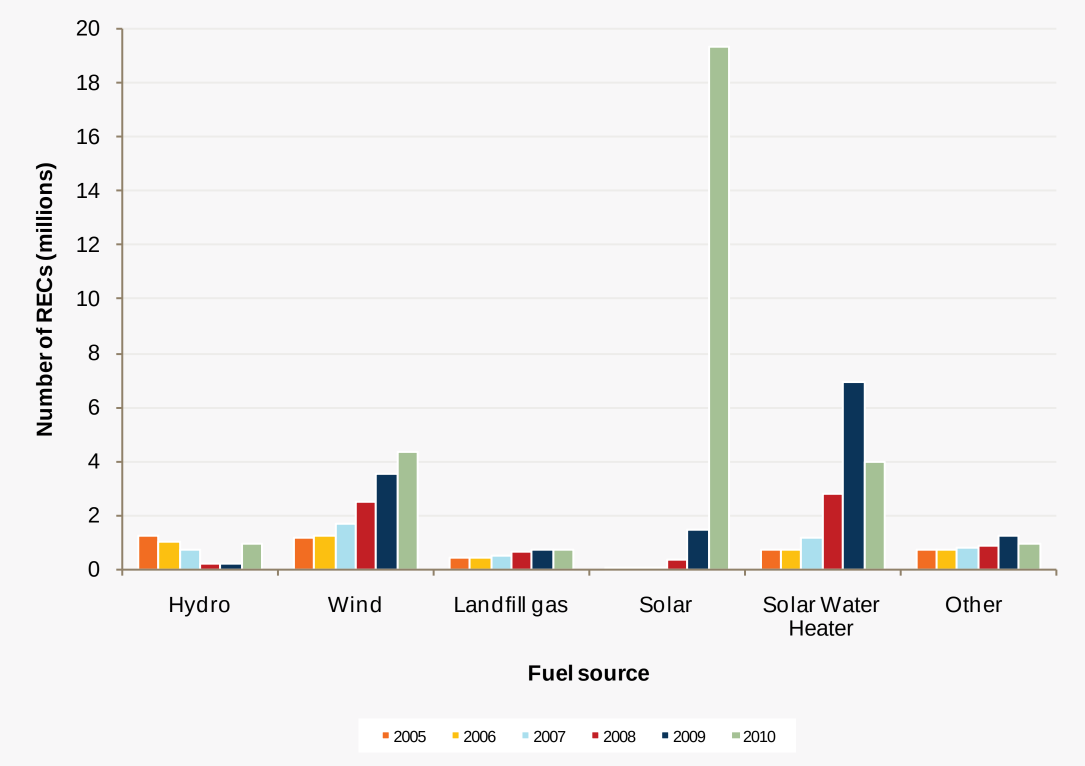
The Australian Government's Office of the Renewable Energy Regulator (ORER) maintains the register of RECs, which provides information about the generation technologies used to produce the RECs sold to retailers.[20]

Figure 2-4 shows the trend of generation technologies used to produce and sell RECs from calendar year 2005 to 2010. This figure demonstrates a large increase in the number of RECs purchased from solar generation in 2010, due largely to the REC solar credits multiplier that applied from 1 July 2010, and grants the technology five certificates per unit of output.[21]

The figure also shows a steady increase in RECs from wind generation and an unsustained spike in solar hot water technologies in 2009. The spike corresponds to the introduction of the Solar Hot Water Rebate Program in early 2009, which was subsequently reduced by the New South Wales Government in early 2010.[22]

Hydroelectric generation accounts for fewer RECs, because the scheme only applies to energy produced in excess of 1997 production-level baselines, at a time when many existing hydroelectric generating units were already generating.

Figure 2-4 — Renewable Energy Certificates by fuel source[23]



[20] Office of the Renewable Energy Regulator. "REC Registry". Available https://www.rec-registry.gov.au/home.shtml. 18 May 2011.

[21] Department of Climate Change and Energy Efficiency. "Fact Sheet: Solar Credits for small generation units". Available http://www.climatechange.gov.au/government/initiatives/renewable-target/fs-solar-credits-small-scale.aspx. 21 May 2011.

[22] Quantum Energy Technologies. "NSW Govt. Reduces Hot Water Rebate on Heat Pumps". Available http://www.quantumenergy.com.au/corporate/news/nsw-govt-reduces-hot-water-rebate-on-solar-heat-pumps-244.aspx. 21 May 2011.

[23] The sharp increase in solar RECs reflects this technology's receipt of five certificates per unit output. The extreme solar growth and relativity with other technologies in the chart is not representative of the installed capacity or energy produced.

2.2.3 Key programs supporting renewable generation investment

The Australian Government's $5.1 billion Clean Energy Initiative (CEI) comprises a series of key programs promoting the development, commercialisation, and deployment of renewable energy and enabling technologies, including the Carbon Capture and Storage (CCS) Flagships Program, the Solar Flagships Program, the Australian Solar Institute (ASI), and the Australian Centre for Renewable Energy (ACRE).[24]

The Carbon Capture and Storage Flagships Program

The CCS Flagships Program supports the construction and demonstration of large-scale, integrated carbon capture and storage projects in Australia.[25] In December 2009, four projects were shortlisted and provided with $120 million for pre-feasibility studies. The independent assessment of further projects for funding is ongoing.

In January 2011, the Australian Government announced a reduction and deferral of funding from the CCS Flagships Program as a result of extreme weather events across Australia that required urgent government funds to support rebuilding efforts. The National Low Emissions Coal Council and the Carbon Storage Taskforce have advised the government to defer the CCS Flagships Program until CO2-e emissions storage sites have been proven to a greater level of certainty.[26]

An independent panel is assessing shortlisted projects for further development and funding, and a commercial demonstration of CCS technology is still anticipated by 2020.[27]

The Solar Flagships Program

The Solar Flagships Program supports the construction and demonstration of large-scale, grid-connected solar power stations in Australia. The Australian Government has committed $1.5 billion to support the construction of up to four power stations, using solar thermal and photovoltaic technologies, with $1.15 billion available to be spent up to 30 June 2015, and a further $370 million available to be spent after 30 June 2015.[28]

The Solar Flagships Council has completed its assessment of the final Round 1 applications. Solar Dawn and Moree Solar Farm have been selected as the two successful consortiums to build solar projects at Chinchilla in Queensland and Moree in New South Wales. These projects are expected to total 400 MW and be commissioned by the end of 2015.[29] The Australian Government has also agreed to continue to engage with solar industry stakeholders as the design of the program's second round is developed.

Australian Solar Institute

The Australian Solar Institute (ASI) has been established to drive collaborative, focused research for the purpose of increasing the cost-effectiveness of solar technologies and accelerating growth in the Australian solar industry. The Australian Government has committed $150 million to support solar thermal and solar photovoltaic technology research and development.[30]

[24] Department of Resources, Energy and Tourism. "Clean Energy Initiative". Available http://www.ret.gov.au/Department/archive/cei/Pages/default.aspx. 15 May 2011.

[25] This program supports the G8 call for 20 demonstration CCS projects worldwide by 2010, to be operational from 2015, and for commercial deployment by 2020.

[26] Department of Resources, Energy and Tourism. "Carbon Capture and Storage Flagships Program". Available http://www.ret.gov.au/Department/archive/cei/ccsfp/Pages/default.aspx. 16 May 2011.

[27] See note 26 in this chapter.

[28] Department of Resources, Energy and Tourism. "Solar Flagships Program". Available http://www.ret.gov.au/energy/clean/cei/sfp/Pages/sfp.aspx. 17 May 2011.

[29] Department of Resources, Energy and Tourism. "Green Light to Build Australia's Largest Solar Projects". Available http://minister.ret.gov.au/MediaCentre/MediaReleases/Pages/GreenLighttoBuildAustralia'sLargestSolarProjects.aspx. 29 June 2011.

[30] Australian Solar Institute. "ASI Strategic Plan". Available http://www.australiansolarinstitute.com.au/publications.htm. 15 May 2011.

Australian Centre for Renewable Energy

The Australian Centre for Renewable Energy's (ACRE) objective is to promote the development, commercialisation, and deployment of renewable energy technologies, and to improve their competitiveness in Australia.[31] ACRE manages in excess of $690 million in funding to develop Australia's substantial potential renewable energy resources through programs including the:

- Renewable Energy Demonstration Program (REDP)
- ACRE solar projects
- Second Generation Biofuels Research and Development Program
- Geothermal Drilling Program
- Wind Energy Forecasting Capability Program
- Advanced Electricity Storage Technologies Program
- Renewable Energy Venture Capital Fund, and
- ACRE Emerging Renewables Program.

2.2.4 New grid-connected generation investments

The recent trend of GPG and wind generation comprising the majority of new generation investments (by capacity) is expected to continue for a number of years. Wind generation is mainly driven by LRET incentives, while a mix of combined-cycle gas turbine (CCGT) and open-cycle gas turbine (OCGT) generation is meeting increasing demand peaks that new wind generation cannot reliably supply.

Geothermal energy has the potential to provide a continuous source of heat for base load electricity generation. Australia has significant potential geothermal resources associated with high-temperature granites, and lower temperature geothermal resources associated with naturally-circulating waters in aquifers (especially in South Australia), and a number of companies are developing projects to exploit geothermal resources for their low marginal cost and zero emissions. Some of these projects, classed as publicly announced proposals in Chapter 4, are due to begin construction work within the next five years.

ACRE is one of the key organisations supporting geothermal energy development, through the Geothermal Drilling Program and the REDP. In November 2009, Geodynamics Ltd. was awarded a $90 million REDP grant to build a 25 MW commercial demonstration plant in the Cooper Basin, now expected to be commissioned by early 2015.[32] Petratherm Ltd. was awarded $63 million for its Paralana geothermal project in South Australia's Flinders Ranges.[33]

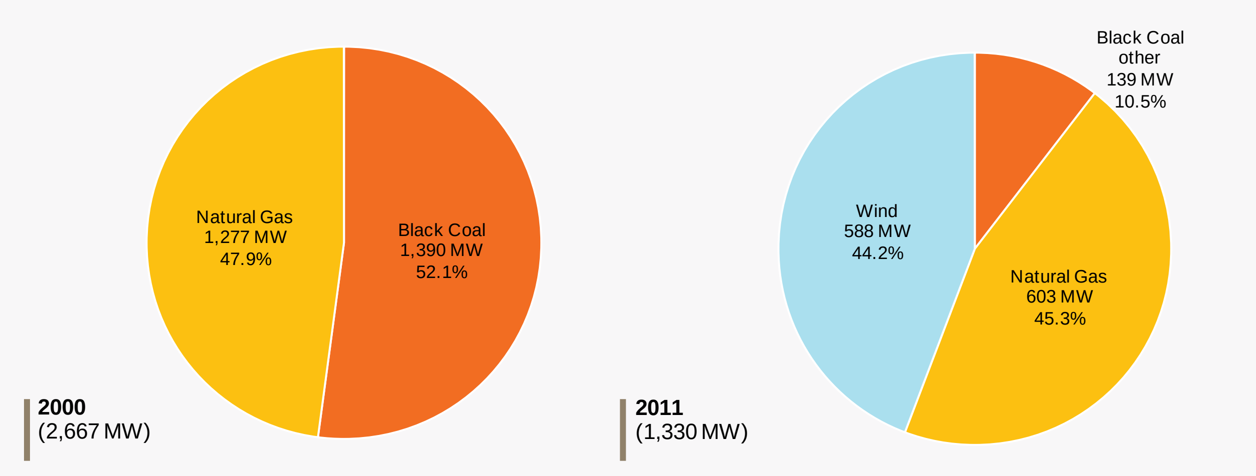
It is anticipated that solar energy projects will occur in the shorter term, driven by the Solar Flagships Program, which supports large-scale (200 MW) developments of both solar photovoltaic and solar thermal-type projects.[34] On a smaller scale, CS Energy was recently awarded REDP support for its Kogan Creek solar boost project, which will add 44 MW of solar thermal capacity to its coal-fired Kogan Creek Power Station.[35]

[31] Department of Resources, Energy and Tourism. "Australian Centre for Renewable Energy". Available http://www.ret.gov.au/energy/clean/cei/acre/Pages/default.aspx. 19 May 2011.
[32] Geodynamics Ltd, "Quarterly report – period ending 30 June 2010". Available http://www.geodynamics.com.au/IRM/Company/ShowPage.aspx/PDFs/2211-46076296/QuarterlyReportJune2010. 20 June 2011.
[33] Petratherm Ltd. "Australian Projects – Paralana". Available http://www.petratherm.com.au/_webapp_117685/Paralana. 17 June 2011.
[34] See note 28 in this chapter.
[35] CS Energy. "Kogan Creek Solar Boost Project". Available www.kogansolarboost.com.au. 20 June 2011.

Generation projects under development

Figure 2-5 shows the trend to lower CO2-e emission technologies for committed projects and advanced proposals. There has been a significant increase over the last 10 years in renewable technology projects, particularly wind generation.

Figure 2-5 — Committed and advanced proposal generation projects by fuel type between 2000 and 2011



For more information about existing, committed, and proposed generation projects, see Chapter 4.

The long-term outlook

In the long term, policy decisions and technological advancements will change the location of generation, as well as generation technologies and installed capacities, which will impact market pricing outcomes, network congestion, and CO2-e emissions.

The 2010 NTNDP showed that a substantial amount of renewable generation, particularly wind, is required to meet the LRET. Results also showed that the LRET encourages development of other renewable technologies including geothermal and solar thermal generation. The cost of solar photovoltaic and solar thermal generation is also expected to fall relatively quickly due to significant international development[36] and various Australian Government subsidy programs (see Section 2.2.3).

With high levels of intermittent renewable generation likely to be installed, opportunities exist for investment in GPG peaking plant with low capital costs but higher fuel costs than other generation technologies. Energy storage technologies, including flywheels, compressed air, and heat pumps are also emerging as a method for reducing the volatility of wind and solar generation output.[37]

[36] Garnaut Climate Change Review. “Update Paper 8: Transforming the Electricity Sector”. Available http://www.garnautreview.org.au/update-2011/update-papers/up8-key-points.html. 20 May 2011.

[37] See note 36 in this chapter.

2.3 Demand-side trends in the NEM

In the medium and long term, new technologies such as smart meters, smart grids, and electric vehicles are likely to result in increased demand-side participation (DSP) and altered energy consumption patterns. This may reduce the growth rates of both energy and maximum demand.

This section explores the changing nature of demand, and identifies some of the policy drivers that will influence the effectiveness future DSP.

2.3.1 The changing nature of demand

Consumer behaviour is expected to change in response to government climate change policies likely to include an increase in energy conservation, DSP, and price transparency through smart meters and smart grids. As a result, the NEM's demand profile is expected to change in response to these changing energy consumption patterns.

In the longer term, adoption of electric vehicles may cause convergence between the electricity and transport sectors, further changing patterns of demand.

Load-management schemes

The NEM's energy market design enables retailers to provide large and medium-sized customer loads with clear pricing signals, facilitating some level of retailer or customer response during supply shortages. Although these schemes are not widespread, improved communication and technological developments (like smart grids) may potentially produce significant advances in this area.

Smaller customer loads are often metered over a period of time, and charged on the basis of a deemed load profile, providing little incentive to respond to high-price periods. Over the next decade, technologies like interval metering, smart grids, and smart appliances are likely to raise customer awareness about consumption decisions, potentially providing incentives for changed consumption patterns.

Demand-side participation

In the NEM, annual maximum demand growth is typically outpacing energy growth. System reliability is determined by how adequately demand peaks can be met. As a result, the growth in maximum demand increases the need for investment in peaking capacity and upgraded transmission network capabilities, adding considerable costs to electricity users. DSP represents a cost-effective alternative.

AEMO conducts an annual survey of DSP, and recent results indicate an upward trend in every region. For more information about the results of the 2011 DSP survey, see Chapter 4.

2.3.2 Policy influences on demand-side participation

A number of Australian and state government policies may potentially influence the future nature of demand. These policy influences involve a current review of DSP, smart meters and smart grids, electric vehicles, and the role of the Australian Government's Task Group on Energy Efficiency.

Review of DSP

The Australian Energy Market Commission (AEMC) is reviewing the use of DSP to identify barriers or disincentives within the National Electricity Rules (NER). Stage 2 of this review (released in December 2009) found that, in the context of current technology, pricing, and demand conditions, the NEM's framework does not impede the use of DSP. The report also acknowledged the potential of smart meters and smart grids to increase DSP in the NEM.

In March 2011, the Ministerial Council on Energy (MCE) directed the AEMC to undertake a further, Stage 3 review considering all market and regulatory arrangements impacting the electricity supply chain. The purpose of this review is to identify market and regulatory arrangements that will potentially enable the participation of both supply and demand-side options to achieve an economically efficient balance.[38]

Smart meters and smart grids

Smart grids have the potential to create opportunities for consumers to change energy consumption at short notice, in response to a variety of signals including electricity price.

The Australian Government has established the Smart Grid Smart City initiative, which aims to support the development of large-scale smart grid testing. This initiative also aims to gather information about the costs and benefits of smart grids to inform government, electricity providers, technology suppliers, and consumers.

Ausgrid[39] intends to demonstrate Australia's first commercial-scale smart grid in Newcastle, New South Wales.[40]

Electric vehicles

AEMO's long-term energy and maximum demand projections include assumptions about the adoption of electric vehicles, given an increasing use of this technology will affect the profile of future electricity demand.

In addition to changing demand consumption profiles, other potential demand impacts from electric vehicles include the potential to support rapid recharging and their use as temporary energy storage devices. The existing transmission network infrastructure may require augmentation to cater for these characteristics.

The New South Wales and Victorian Governments have established initiatives to explore the potential of electric vehicles. Victoria is currently trialling hybrid electric buses, which work in a similar way to hybrid passenger vehicles.[41] An Electric Vehicle Roadmap for Queensland has been introduced, outlining the Queensland Government's intentions, with the aim of developing an effective policy position for Queensland.[42]

In early 2010, there were less than 20 electric vehicles (including trucks) on Victorian roads[43], and the South Australian Government reported the same number[44], indicating a potentially long lead time before electric vehicles represent a substantial portion of Australia's vehicle fleet.

The Task Group on Energy Efficiency

In March 2010, the Australian Government established a Task Group on Energy Efficiency to provide advice about options to improve energy efficiency by 2020. For more information about this Task Group and its functions, see Attachment 1, Section A.1.2.

[38] AEMC. "MCE Terms of Reference for AEMC Stage 3 Demand Side Participation Review (Stage 3 DSP Review)". Available http://www.aemc.gov.au/News/Announcements/MCE-Terms-of-Reference-for-AEMC-Stage-3-Demand-Side-Participation-Review-Stage-3-DSP-Review.html. 21 May 2011.

[39] As of 1 March 2011, the retail and network businesses of EnergyAustralia have separated into EnergyAustralia (the retail business), and Ausgrid (the network business).

[40] Department of Resources, Energy and Tourism. "Smart Grid, Smart City". Available http://www.ret.gov.au/energy/energy_programs/smartgrid/Pages/default.aspx. 22 May 2011.

[41] Department of Primary Industries Victoria. "Electric Vehicles". Available http://new.dpi.vic.gov.au/energy-future/our-options-for-change/transport-energy/electric-vehicles. 19 May 2011.

[42] Office of Climate Change (Queensland Government). "An Electric Vehicle Roadmap for Queensland ". Available http://www.climatechange.qld.gov.au/whatsbeingdone/queensland/electricvehicleroadmap.html. 19 May 2011.

[43] Department of Primary Industries Victoria. "Electric Vehicles". Available http://new.dpi.vic.gov.au/energy-future/our-options-for-change/transport-energy/electric-vehicles. 19 May 2011.

[44] Government of South Australia. "Accelerating the Uptake of Low Emission Vehicles in SA". Available http://www.autocrc.com/files/File/Accelerating%20the%20Uptake%20of%20Low%20Emission%20Vehicles%20in%20SA.pdf. 19 May 2011.

2.4 Transmission network implications

Changes in generation technology and the location of new generation investments may require transmission network augmentation. In this respect, factors relevant to generation investment decision-making will include the cost of connection (related to a generation project's proximity to existing transmission infrastructure), and the transmission network congestion affecting the connection point. Efficient frameworks for network augmentation and an effective congestion management system will also be required to meet reliability standards and ensure the management of potential congestion.

Considering these various factors, current AEMC transmission system issue reviews include the Transmission Frameworks Review and the Review of Energy Market Frameworks in light of Climate Change Policies. Specific studies are also being conducted by interested parties with respect to transmission congestion resulting from renewable generation, and the impact of climate change policies on the regional interconnectors.

2.4.1 Transmission Frameworks Review

The AEMC commenced the Transmission Frameworks Review in April 2010 to consider transmission network efficiencies, and published a directions paper in April 2011 that identifies five key issues to be progressed.[45]

This review stems from the Review of Energy Market Frameworks in Light of Climate Change Policies[46], and aligns with the 2010 NTNDP findings that climate change policies will fundamentally change transmission network usage over time.

For more information about this review, see Attachment 1, Section A1.2.3.

2.4.2 Review of Energy Market Frameworks in light of Climate Change Policies

In 2008, the MCE directed the AEMC to commence the Review of Energy Market Frameworks in light of Climate Change Policies. The intent of this review was to assess the resilience of the energy market framework to changes that may potentially result from the implementation of the national RET scheme and a CPRS. The AEMC's report made a number of recommendations to strengthen energy market frameworks. One of the key recommendations was the introduction of scale efficient network extensions (SENE) to help promote the efficient connection of clusters of new generation.[47]

In March 2011, the AEMC released a draft determination and draft Rule requiring network service providers to provide specific SENE location studies on request, showing potential market opportunities and efficiency gains from coordinating the connection of new generation in a particular area. In June 2011, the AEMC published a report setting out the reasons why the Rule change request has not been finalised, and its decision to extend the period of consideration and include an additional consultation step.

2.4.3 Transmission congestion resulting from renewable generation

The 2010 NTNDP predicted that substantial renewable generation will be required to meet the LRET by 2020. This will necessitate effective transmission network planning to minimise network congestion.

A study undertaken by ROAM consulting for the Clean Energy Council[48] investigated the development of renewable generation to meet the LRET, and its impact on transmission congestion.

45 AEMC. "Transmission Frameworks Review". Available http://www.aemc.gov.au/Market-reviews/Open/Transmission-Frameworks-Review.html. 20 May 2011.

46 AEMC. "Review of Energy Market Frameworks in light of Climate Change Policies". Available http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-Energy-Market-Frameworks-in-light-of-Climate-Change-Policies.html. 20 May 2011.

47 AEMC. "Scale Efficient Network Extensions". Available http://www.aemc.gov.au/Electricity/Rule-changes/Open/Scale-Efficient-Network-Extensions.html. 20 May 2011.

48 Clean Energy Council. "Transmission Congestion and Renewable Generation". Available http://www.cleanenergycouncil.org.au/dms/cec/reports/Clean-Energy-Council-report-on-network-congestion/Clean%20Energy%20Council%20report%20on%20network%20congestion.pdf. 22 May 2011.

The study concluded that, rather than developing new renewable generation in remote locations requiring significant new transmission augmentation, a distributed arrangement of wind farms will still meet the LRET with minimal transmission congestion. The study also suggested there may be a price signal to encourage wind generation development in distributed locations within the existing market so that the regional pool price is not depressed by a significant amount of wind in one region.

2.4.4 Climate change policy and the regional interconnectors

Climate change policies may lead to changes in inter-regional power flows as sources of low emission generation are exploited. To accommodate changes in future electricity supply, large-scale network upgrades are being considered across the NEM. These projects are discussed in more detail by the following sections.

South Australian interconnector joint feasibility study

In November 2010, AEMO and ElectraNet issued a report on a high-level joint feasibility study into transmission development options with the potential to economically increase interconnector power transfer capability between South Australia and other NEM load centres.[49] This feasibility study aimed to identify potential augmentations to facilitate renewable energy export from South Australia, and support South Australian maximum demand as the level of intermittent South Australian generation increases.

The study concluded that relatively low-cost, incremental interconnector upgrades around Heywood in Victoria may be economic as early as 2017–18, while a larger-scale option connecting South East South Australia with the 500 kV transmission network in Victoria may become economic by between 2020 and 2030.

AEMO and ElectraNet subsequently examined the technical and economic feasibility of a range of incremental interconnector upgrades around Heywood. Results indicate that the upgrade may provide positive net benefits over a wide range of scenarios, with optimal timing between 2013 and 2017.[50]

This later study found greater market benefits and an earlier implementation than the original, high-level joint feasibility study, with the difference being partly attributed to high-level, joint feasibility study assumptions that did not capture certain network limitations for the unaugmented case, reducing the calculated benefits. The high-level joint feasibility study also used average wind farm capacity factors, and did not capture benefits from high wind farm outputs.

AEMO and ElectraNet intend to fully assess this option through a joint Regulatory Investment Test for Transmission (RIT-T) in 2011–12.

New South Wales-Queensland (QNI) interconnector

Powerlink and TransGrid are undertaking further investigations based on the 2008 QNI Upgrade Study[51], in light of a number of recent market developments. These developments include mooted generation investments, legislated changes to the national RET scheme, and recent Regulatory Test revisions.

The revised study will evaluate the economic viability and optimal timing of potential QNI interconnector upgrades, based on the principles and methodology of the new RIT-T.[52] Depending on the results, Powerlink and TransGrid will consider formally progressing an upgrade through the NER process.

[49] AEMO. "South Australian Interconnector Feasibility Study Final Report". Available http://www.aemo.com.au/planning/saifs.html. 18 May 2011.

[50] AEMO. "Victorian Annual Planning Report (APR) 2011". Available http://www.aemo.com.au/planning/apr.html. 2 July 2011.

[51] Powerlink Queensland. "Potential Upgrade of Queensland/New South Wales interconnector (QNI) – Assessment of Optimal Timing and Net Market Benefits". Available http://www.powerlink.com.au/data/portal/00005056/content/84931001223869651639.pdf. 23 May 2011.

[52] TransGrid. "New South Wales Annual Planning Report 2011". Available http://www.transgrid.com.au/network/np/Documents/Annual%20Planning%20Report%202011.pdf. 2 July 2011.

NEMLink

The 2010 NTNDP presented results from a pre-feasibility study of NEMLink, which is a high capacity electricity transmission backbone concept, developed to investigate the potential benefits from significantly increasing power transfer capabilities across the NEM. The analysis considered two of the five NTNDP scenarios, the Fast Rate of Change, high carbon price scenario, and the Uncertain World, low carbon price scenario. Results showed that:

- some quantified benefits under one scenario were close to meeting the construction costs
- some components of the concept were likely to provide more market benefits (on a per cost basis) than others, and
- optimising the staging of NEMLink, or the design capacity of certain components, may improve the net market benefits.

Quantifying the benefits and the optimisation of staging some of the components will be undertaken as part of the 2011 NTNDP, to be released in December 2011.

CHAPTER 3 - ENERGY AND DEMAND PROJECTIONS

Summary

This chapter presents regional energy and maximum demand (MD) projections for the next 10 years. Incorporating economic, demographic, and carbon price assumptions, the projections are based on those published in the regional annual planning reports (APRs)[1,2,3,4] and the South Australian Supply and Demand Outlook (SASDO).[5]

The current energy and maximum demand projections assume the introduction of a 10 $/t CO2-e carbon price in 2013–14, followed by a full emissions trading scheme in 2014–15. The climate change initiatives recently announced, however, indicate a carbon price of 23 $/t CO2-e introduced in 2012–13, followed by a full emissions trading scheme in 2015–16. The level of short-term price elasticity in the NEM suggests that the impact of these differing assumptions on energy and maximum demand are expected to be minimal.

The energy efficiency and small-scale renewable initiatives recently announced are also consistent with previous assumptions.

Energy growth projections are characterised by projections of sustained gross domestic product growth (GDP) of between two and three percent in the medium term. Variations between the 2010 and 2011 projections can be attributed to a range of factors specific to each region that include the following:

- In Queensland, Powerlink Queensland suggests that extreme weather in early 2011 reduced mining loads, curtailed electrified rail, and reduced commercial and residential loads. Demand growth projections are driven by mining activity in Central Queensland and flood-related reconstruction. Liquefied Natural Gas development is also expected to add significantly to Queensland demand by late 2013.

  In addition to those provided by the Queensland jurisdictional planning body, the 2011 ESOO also includes alternative energy and maximum demand projections for Queensland, developed by AEMO.[6] AEMO assessed performance for all regions, and alternative projections were developed for Queensland to address the fact that actual maximum demands over the last five years have been significantly lower than the projections provided by the Queensland Jurisdictional Planning Body. Historical differences of the same magnitude were not observed in the energy and maximum demand projections produced for the other regions.
- In New South Wales, Transgrid's projections have decreased due to a lower than expected economic growth and the incorporation of new and ongoing energy efficiency policies.
- In Victoria, AEMO attributes greater energy consumption growth to improved economic growth. Industrial loads are also assumed to return to previous levels, mainly associated with the aluminium sector.
- In South Australia, Electranet's industrial load projections from 2013–14 have increased the average annual growth rate in response to mining expansion plans and an improved economic outlook for the region.
- In Tasmania, Transend Networks' projections from 2014–15 onwards are similar to the projections it made in 2010, but there is a reduction in consumption between 2011 and 2014 due to lower economic growth. Energy consumption growth rates are associated with an expected increase in agriculture and mining activity and increased population growth.

[1] TransGrid. "New South Wales Annual Planning Report 2011". Available http://www.transgrid.com.au/network/np/Documents/Annual%20Planning%20Report%202011.pdf. 2 July 2011.

[2] AEMO. "Victorian Annual Planning Report 2011". Available http://aemo.com.au/planning/VAPR2011/vapr.html. 2 July 2011.

[3] Powerlink Queensland. "Queensland Annual Planning Report 2011. Available http://www.powerlink.com.au/asp/index.asp?sid=5056&page=Corporate/Documents&cid=5250&gid=661. 2 July 2011.

[4] Transend Networks. "Tasmanian Annual Planning Report 2011". Available http://www.transend.com.au/download/D11-63890. 2 July 2011.

[5] AEMO. "South Australian Supply and Demand Outlook 2011". Available http://www.aemo.com.au/planning/SASDO2011/sasdo.html. 2 July 2011.

[6] The alternative Queensland energy and maximum demand projections are discussed in Chapter 3 of the 2011 ESOO.

3.1 Key definitions of energy and maximum demand

This section provides an overview of key definitions and commonly used terms relating to electricity supply and demand, and the components of energy and maximum demand in National Electricity Market (NEM) forecasting. It also provides a summary of the changes in the projections since 2010.

For more information about the:

- regional historical winter and summer MD coincidence factors, see Attachment 3
- regional energy and MD projections supplied by scheduled and semi-scheduled generating units, see Appendix A
- assessment of historical energy and MD projections, see Appendix B, and
- underlying policy assumptions and economic growth forecasts used to develop the projections, see Appendix C.

Throughout this chapter, unless otherwise indicated, medium, high, or low growth refers to an economic growth scenario.

3.1.1 Energy and maximum demand definitions

This section provides an overview of key definitions and commonly used terms relating to electricity supply and demand, and plays an important part in understanding the energy and MD projections presented throughout the chapter. For more information about the underlying technical assumptions used to develop the projections, see Section 3.10.

Supply and demand

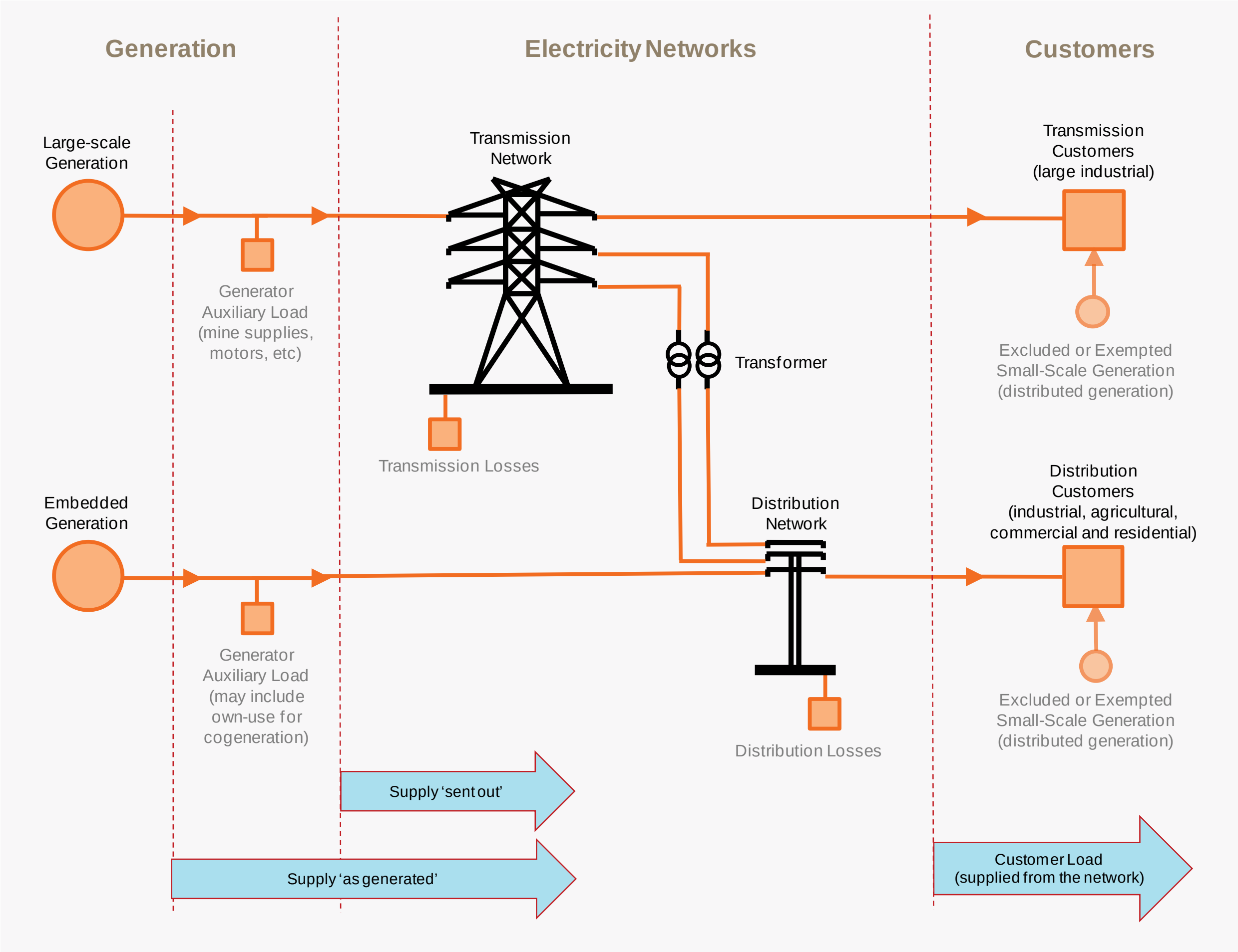
Electricity supply is instantaneous, which means it cannot be stored and supply must equal demand at all times. The NEM provides a central dispatch mechanism that adjusts supply to meet demand through the dispatch of generation every five minutes.

Measuring demand by measuring supply

Electricity demand is measured by metering supply to the network rather than consumption. The benefit of measuring demand in this way is that it includes electricity used by customers, energy lost transporting the electricity (network losses), and the energy used to generate the electricity (auxiliary loads).

Figure 3-1 shows the high-level topology of the electricity transmission network connecting supply (generation) and demand (customers). It also shows the different points at which supply and demand are measured as well as the relative contribution of different types of generation.

Figure 3-1 — Electricity network topology



The basis for measuring demand

The electricity (energy) supplied by a generator can be measured in two ways:

- Supply 'as-generated' is measured at the generator terminals, and represents the entire output from a generator.
- Supply 'sent-out' is measured at the generator connection point, and represents only the electricity supplied to the market, excluding a generator's auxiliary loads.

The basis for projecting energy and MD

The ESOO energy and MD projections are presented in the following way:

- Energy is presented on a sent-out basis. This means that the energy projections include the customer load (supplied from the network) and network losses, but not auxiliary loads.
- MD is presented on an as-generated basis. This means that the MD projections (the highest level of instantaneous demand for electricity during summer and winter each year, averaged over a 30-minute period) include the customer load (supplied from the network), the network losses, and the auxiliary loads.

Categorising generation

Generation types are categorised differently to enable an accurate assessment of generation contribution when it comes to analysing the markets and assessing the supply-demand outlook.

Figure 3-1 shows a high-level representation of the three basic types of generation connected to the electricity network:

- Large-scale generation includes any generating system 30 MW or more that offers its output for control by the NEM dispatch process.
- Embedded generation includes any generating system installed within a distribution network or by industry to meet its own electricity needs. Depending on how it is implemented, embedded generation 30 MW or more can be offered for control by the NEM dispatch process.
- Exempt, small-scale generation, or distributed generation, includes generation installed by customers, including, for example, some relatively large generators that may be located on customer premises, back-up generators that rarely run, roof-top photovoltaics, micro generation from fuel cells, landfill generators, small cogeneration, and very small wind farms.

These three basic generation types can be further categorised in terms of the NEM dispatch process and registration:

- Scheduled generation typically refers to any generating system with an aggregate nameplate capacity of 30 MW or more, unless it is classified as semi-scheduled, or AEMO is permitted to classify it as non-scheduled. The output from scheduled generation is controlled by the NEM dispatch process.
- Semi-scheduled generation refers to any generating system with intermittent output (such as wind or run-of-river hydroelectric) with an aggregate nameplate capacity of 30 MW or more. A semi-scheduled classification gives AEMO the power to limit generation output that may exceed network capabilities, but reduces the participating generator’s requirement to provide information.
- Non-scheduled generation typically refers to generating systems with an aggregate nameplate capacity of less than 30 MW and equal to or greater than 5 MW. Non-scheduled generation is not controlled by the NEM dispatch process. The non-scheduled energy and demand contribution projections provided in this chapter may not include all non-scheduled generators described in Chapter 4. Only those considered to be significant non-scheduled generating units (as nominated by the JPBs) are included in this chapter’s projections.
- Exempt generation is typically smaller generation with a capacity less than 5 MW that is not required to register with AEMO or participate in the NEM dispatch process. Exempt generation is typically operated by customers to offset their load and is not separately metered.

This last category of exempt, small-scale distributed generation is becoming an increasingly important part of electricity supply.

Small-scale distributed generation

Figure 3-1 shows the role that small-scale distributed generation plays in terms of the network. Attaching to both transmission and distribution customers, small-scale distributed generation reduces (or offsets) the amount of electricity that needs to be supplied by large-scale generation.

The projections are developed with the knowledge that some demand is supplied by small-scale distributed generation, as well as off-grid supply to remote customers. This type of supply is effectively unmeasured in its own right and offsets local demand. In terms of the MD projections, this category of generation is identified as excluded generation.

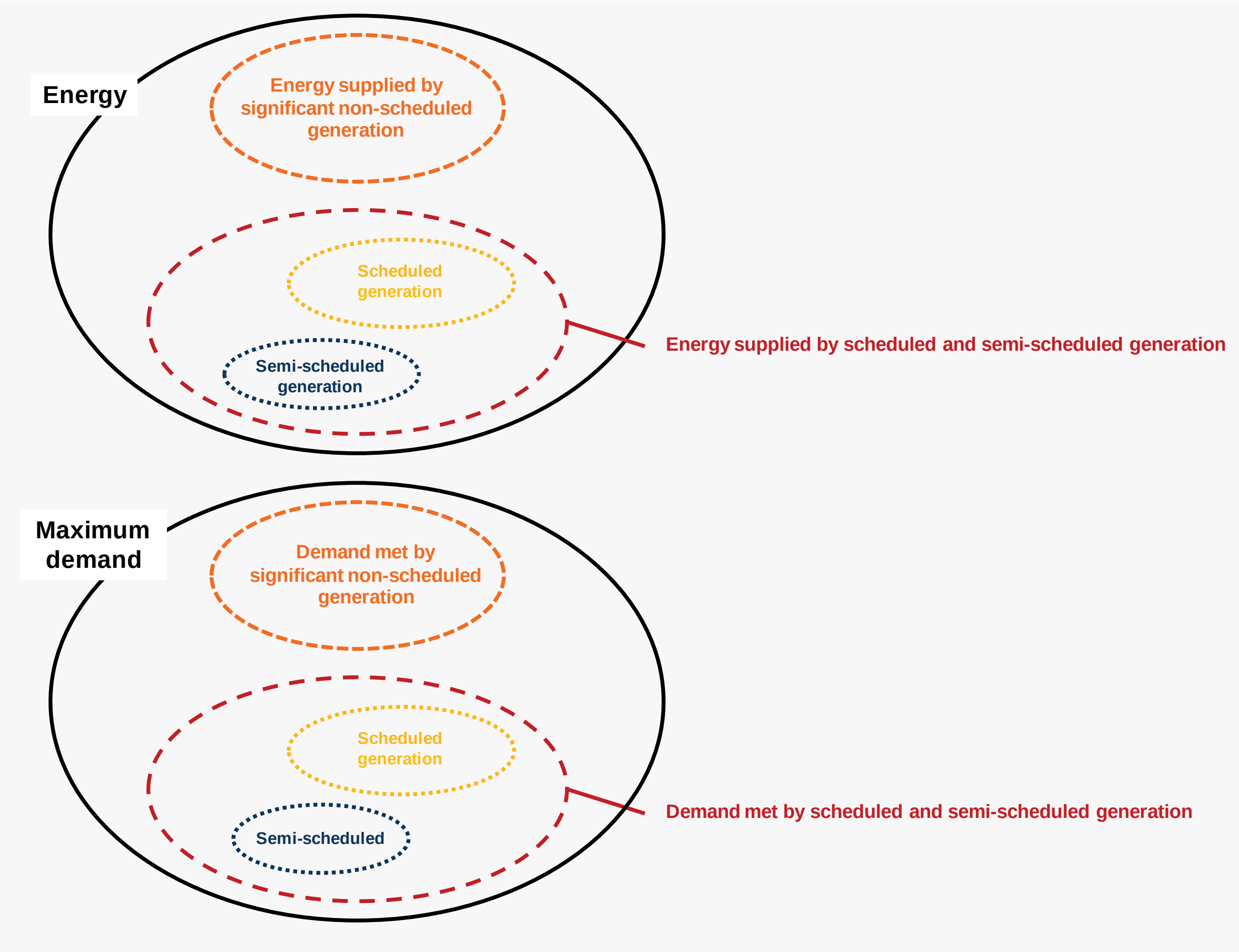
The projections do, however, indirectly account for this type of generation. For example, a large increase in household roof-top photovoltaics is reflected in lower projected growth. Similarly, energy efficiency and load control initiatives act to reduce the demand at customer locations. The projections reflect this as lower demand growth.

From a NEM perspective, it is sometimes difficult to separate the contributions to reduced growth rates from increased local generation, improvements in energy efficiency, and customers controlling their loads at times of high prices. This difficulty increases when these activities are more widespread (down to the level of households). The growing use of 'smart' meters may improve the ability to gauge this level of consumption.

3.1.2 The components of energy and maximum demand in NEM forecasting

Figure 3-2 shows the components of energy and MD, which represent the generation categories being accounted for in the projections.

Figure 3-2 — The components of energy and maximum demand



Calculating energy and maximum demand

The energy projections account for the sent-out energy from scheduled, semi-scheduled, and significant non-scheduled generation. Calculating the amount of energy supplied by generation controlled through the NEM dispatch process (scheduled and semi-scheduled generation) requires subtracting the energy supplied from significant non-scheduled generation.

The MD projections account for the as-generated demand supplied from scheduled, semi-scheduled, and significant non-scheduled and exempt generation. Calculating the MD supplied by generation controlled through the NEM dispatch process requires subtracting the MD met by significant non-scheduled generation.

When establishing the adequacy of NEM generation supplies, both the supply-demand outlook and the Medium-term Projected Assessment of System Adequacy (MT PASA) make assessments based on the demand met by scheduled and semi-scheduled generation only, and do not include non-scheduled or exempt generation unless considered to have a significant impact on network limitations or the behaviour of other plant.

Accounting for demand-side participation

Demand-side participation (DSP), which occurs when customers vary their consumption in response to changed market conditions, is treated as demand that does not need to be met by generation. As a result, DSP is effectively a separate component of the supply and demand equation, with its own set of projections (see Section 3.9).

In the supply-demand outlook, DSP acts to reduce the amount of generation needed to meet projected MD.

Defining the probability of exceedence

A probability of exceedence (POE) refers to the likelihood that an MD projection will be met or exceeded. The various probabilities (generally 90%, 50%, and 10%) provide a range of likelihoods that analysts can use to determine a realistic range of power system and market outcomes.

The MD in any year will be affected by weather conditions, and an increasing proportion of demand is sensitive to, for example, temperature and humidity conditions. For any given season, the:

- 10% POE MD projection is expected to be exceeded, on average, 1 year in 10
- 50% POE MD projection is expected to be exceeded, on average, 5 years in 10, and
- 90% POE MD projection is expected to be exceeded, on average, 9 years in 10.

3.1.3 Changes since the 2010 ESOO

Table 3-1 to Table 3-3 summarise the changes in the medium economic growth scenario energy and MD projections since the 2010 ESOO. The recovery of the Australian economy from the global financial crisis has led to the development of relatively strong GDP growth projections in the short to medium term, which is predicted to lead to continued increases in demand over the next 10 years.

The medium growth projections for the 10-year outlook this year are characterised by sustained GDP growth of between 2% and 3%, driven by strong international demand for commodities, recovering domestic business investment, and increasing consumption expenditure on the back of ongoing household income growth. This is expected to be partially offset by a rise in imports due to the strong Australian dollar.

Growth in demand will continue to be unevenly distributed between NEM regions. Given that there is no single national factor driving changes in the energy and MD projections, there is a mix of positive and negative changes.

Table 3-1 — Energy projection changes since the 2010 ESOO

Region	Change in 2011–12 (GWh)	Change in 2019–20 (GWh)	Change in Average Growth Rate
Queensland	-2,799	-2,087	0.16%
New South Wales	-4,363	-4,940	-0.11%
Victoria	-1,085	2,096	0.63%
South Australia	-281	926	0.64%
Tasmania	-278	66	0.29%
NEM-wide	-8,806	-3,939	0.20%

Table 3-2 — Summer 10% POE maximum demand projection changes since the 2010 ESOO

Region	Change in 2011–12 (MW)	Change in 2019–20 (MW)	Change in Average Growth Rate
Queensland	-336	-176	0.05%
New South Wales	-342	-679	-0.30%
Victoria	-109	183	0.19%
South Australia	-60	80	0.31%
Tasmania	-31	34	0.41%
NEM-wide	-373	16	-0.01%

Table 3-3 — Winter 10% POE maximum demand projection changes since the 2010 ESOO

Region	Change in 2011–12 (MW)	Change in 2019–20 (MW)	Change in Average Growth Rate
Queensland	-145	-267	-0.23%
New South Wales	-630	-996	-0.19%
Victoria	82	213	0.06%
South Australia	-70	70	0.36%
Tasmania	-42	3	0.46%
NEM-wide	-788	-958	-0.07%

3.2 NEM energy and maximum demand projections

This section presents energy and MD projections for the NEM as a whole. The energy projections represent the sum of all the regional values. The MD projections are the scaled-down sum of the regional projections.

The scaling of the projections represents the overall time diversity between MDs in different regions. The diversity factors represent the average diversity between the regions over the last five seasons, and are calculated to be 0.92 for summer and 0.98 for winter (see Attachment 3, Section A3.2.4).

3.2.1 Energy

Table 3-4 presents actual and projected energy (for the medium, high, and low growth scenarios) for the NEM. Energy is projected to increase over the next 10 years at an annual average rate of:

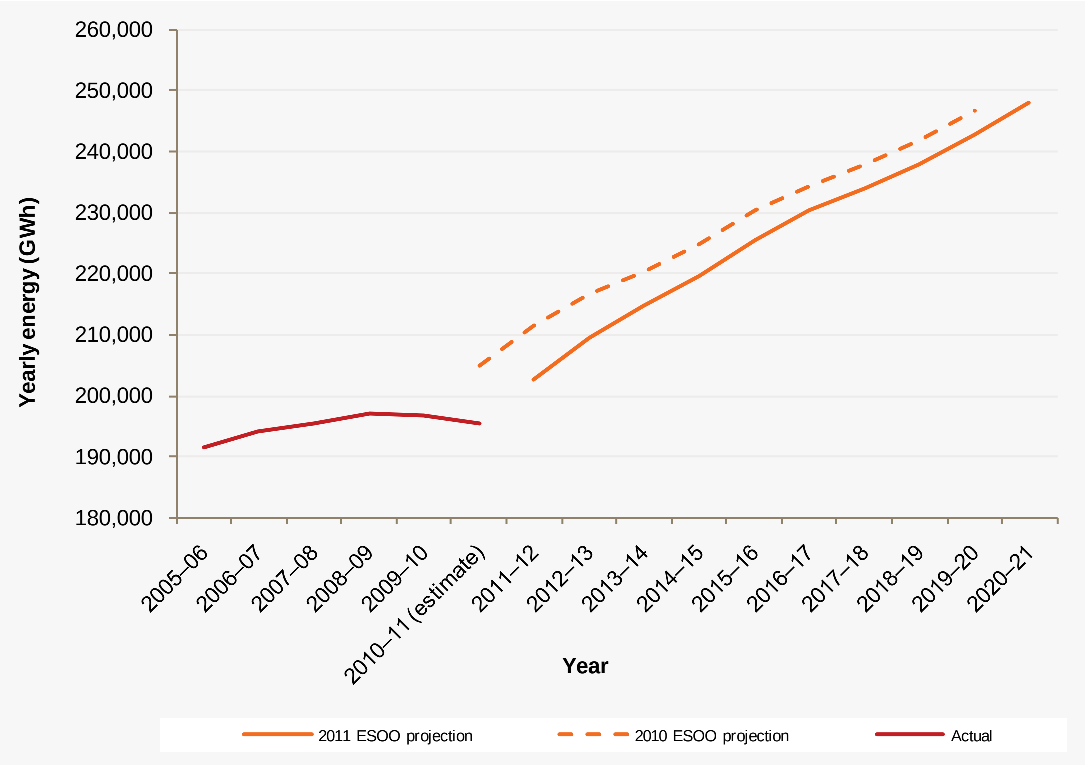
- 2.3% under the medium growth scenario, and
- 3.1% and 1.5% under the high and low growth scenarios, respectively.

Table 3-4 — NEM-wide energy projections (GWh)

	Actual	Medium	High	Low
2005–06	191,710			
2006–07	194,487			
2007–08	196,428			
2008–09	198,295			
2009–10	198,023			
2010–11 (estimate)	196,440			
2011–12		202,598	206,452	201,100
2012–13		209,429	214,671	205,124
2013–14		214,733	221,158	208,679
2014–15		219,595	228,948	212,829
2015–16		225,590	236,575	216,870
2016–17		230,487	244,598	219,931
2017–18		233,817	249,524	222,588
2018–19		237,872	256,555	225,093
2019–20		242,645	264,852	227,880
2020–21		247,973	272,078	229,849
Average annual growth	**0.5%**	**2.3%**	**3.1%**	**1.5%**

Figure 3-3 compares the 2010 and 2011 ESOO medium growth energy projections. The current projection is 5,252 GWh lower (on average). This is due to slower than expected recovery from the global financial crisis, a milder than expected summer, and an increasing end-use customer awareness of electricity prices and potential carbon pricing policies.

Figure 3-3 — Comparison of the NEM-wide medium growth energy projection (GWh)



3.2.2 Maximum demand

Table 3-5 and Table 3-6 present actual and projected summer and winter MDs for the NEM. The 90%, 50%, and 10% POE MD projections are shown for the medium, high, and low growth scenarios.

The summer 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 2.6% under the medium growth scenario, and
- 3.3% and 2.1% under the high and low growth scenarios, respectively.

The winter 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 2.4% under the medium growth scenario, and
- 3.3% and 1.8% under the high and low growth scenarios, respectively.

Table 3-5 — NEM-wide summer maximum demand projections (MW)

	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2005–06	31,468									
2006–07	32,277									
2007–08	32,431									
2008–09	36,027									
2009–10	34,790									
2010–11	36,081									
2011–12		34,750	35,059	34,544	36,741	37,056	36,541	39,121	39,445	38,914
2012–13		35,865	36,373	35,439	37,938	38,477	37,485	40,402	40,949	39,935
2013–14		36,917	37,595	36,268	39,064	39,759	38,384	41,591	42,333	40,924
2014–15		37,978	38,902	37,104	40,221	41,170	39,321	42,856	43,844	41,923
2015–16		38,966	40,153	37,893	41,276	42,496	40,158	43,999	45,259	42,844
2016–17		39,898	41,457	38,618	42,271	43,891	40,967	45,088	46,770	43,699
2017–18		40,713	42,520	39,238	43,159	45,072	41,657	46,040	48,017	44,480
2018–19		41,606	43,811	39,903	44,159	46,434	42,390	47,098	49,507	45,251
2019–20		42,597	45,512	40,577	45,218	48,205	43,148	48,249	51,374	46,100
2020–21		43,477	46,736	41,197	46,147	49,532	43,819	49,290	52,830	46,837
Average annual growth	**1.8%**	**2.5%**	**3.2%**	**2.0%**	**2.6%**	**3.3%**	**2.0%**	**2.6%**	**3.3%**	**2.1%**

Table 3-6 — NEM-wide winter maximum demand projections (MW)

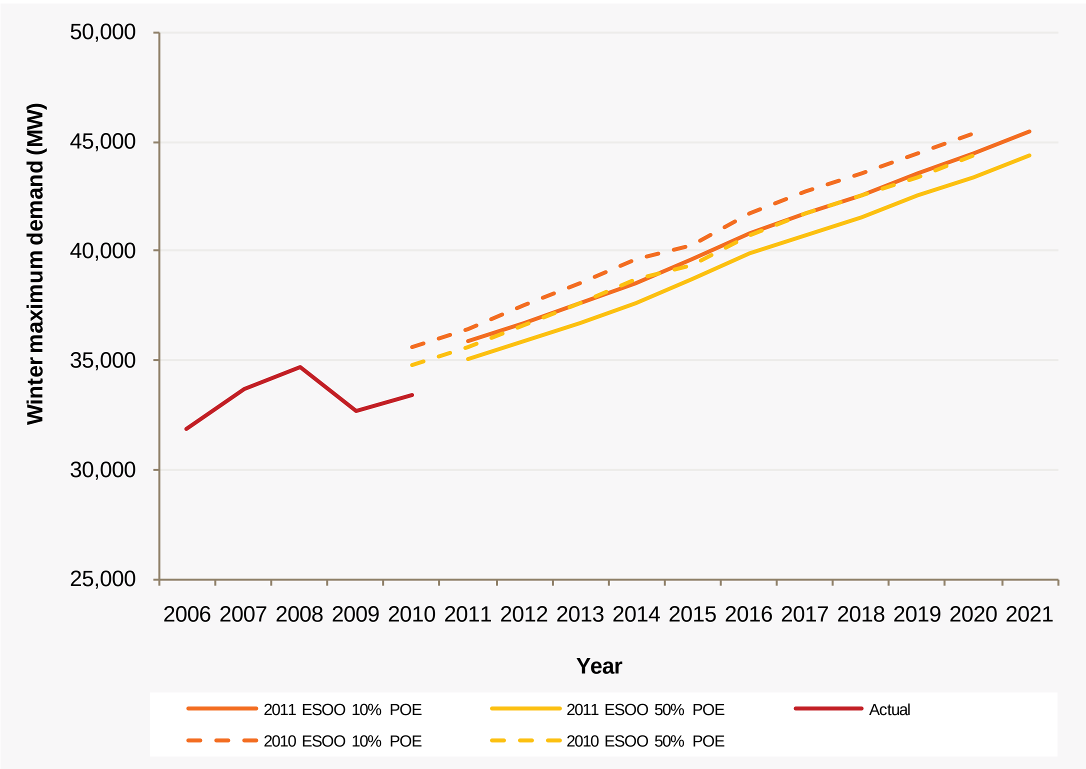
	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2006	31,835									
2007	33,718									
2008	34,733									
2009	32,672									
2010	33,414									
2011		34,275	34,529	33,879	35,050	35,307	34,650	35,910	36,160	35,496
2012		35,070	35,611	34,489	35,854	36,404	35,267	36,711	37,307	36,118
2013		35,915	36,757	35,038	36,710	37,564	35,832	37,623	38,500	36,687
2014		36,800	37,935	35,698	37,633	38,797	36,498	38,540	39,729	37,344
2015		37,837	39,316	36,523	38,696	40,189	37,345	39,618	41,140	38,213
2016		39,012	40,859	37,502	39,883	41,770	38,351	40,822	42,744	39,202
2017		39,842	42,068	38,181	40,725	42,997	39,046	41,700	44,012	39,910
2018		40,614	43,364	38,825	41,517	44,330	39,698	42,516	45,366	40,593
2019		41,571	44,798	39,489	42,516	45,785	40,388	43,518	46,848	41,281
2020		42,442	46,186	40,055	43,395	47,216	40,967	44,429	48,307	41,849
2021		43,411	47,666	40,593	44,394	48,744	41,530	45,443	49,856	42,422
Average annual growth	**0.3%**	**2.4%**	**3.3%**	**1.8%**	**2.4%**	**3.3%**	**1.8%**	**2.4%**	**3.3%**	**1.8%**

Figure 3-4 and Figure 3-5 compare the 2010 and 2011 ESOO summer and winter medium growth 50% and 10% POE MD projections. The 10% POE projections are:

- 373 MW lower for the 2011–12 summer
- 16 MW higher for the 2019–20 summer
- 1,889 MW lower for the 2012 winter, and
- 799 MW higher for the 2020 winter.

Figure 3-4 — Comparison of the NEM-wide medium growth summer maximum demand projections (MW)

Figure 3-5 — Comparison of the NEM-wide medium growth winter maximum demand projections (MW)



3.3 Queensland

Powerlink Queensland provided the energy and MD projections and supporting information for Queensland. The information presented in this section is consistent with the 2011 Queensland Annual Planning Report.[7]

3.3.1 Energy

Table 3-7 presents actual and projected energy (for the medium, high, and low growth scenarios) for Queensland. Energy is projected to increase over the next 10 years at an annual average rate of:

- 4.1% under the medium growth scenario, and
- 5.8% and 2.6% under the high and low growth scenarios, respectively.

Table 3-7 — Queensland energy projections (GWh)

	Actual	Medium	High	Low
2005–06	47,384			
2006–07	48,030			
2007–08	48,831			
2008–09	50,137			
2009–10	50,866			
2010–11 (estimate)	48,786			
2011–12		52,802	54,453	51,685
2012–13		55,854	58,863	54,189
2013–14		59,005	63,191	56,368
2014–15		62,659	68,323	59,517
2015–16		66,042	72,924	61,994
2016–17		68,187	77,418	62,613
2017–18		69,594	80,131	62,776
2018–19		71,370	83,508	63,415
2019–20		73,519	87,437	64,349
2020–21		75,667	90,657	64,856
Average annual growth	**0.6%**	**4.1%**	**5.8%**	**2.6%**

Figure 3-6 compares the 2010 and 2011 ESOO medium growth energy projections. Energy consumption across Queensland has been lower than expected in 2010–11, mainly due to slow economic growth, and a slowdown in the construction and tourism sectors. Additionally, low demand can be attributed to the extreme weather events that occurred in early 2011. This reduced mining loads, curtailed electrified rail services, and reduced commercial and residential loads across the region.

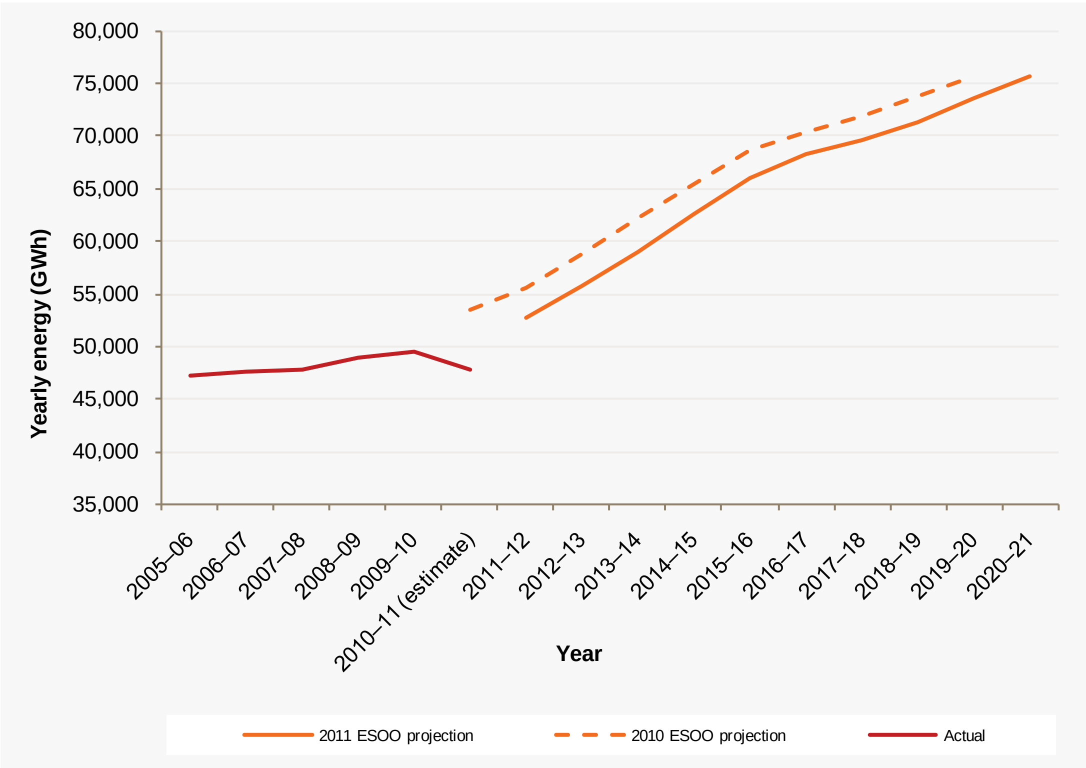
[7] Powerlink Queensland. "Queensland Annual Planning Report 2011". Available http://www.powerlink.com.au/asp/index.asp?sid=5056&page=Corporate/Documents&cid=5250&gid=661. 2 July 2011.

Powerlink Queensland's energy projections for Queensland are driven by expected strong economic and population growth. The assumptions underpinning the projections assume a significant economic recovery starting in 2011–12, driven by increased activity in many sectors related to the rebuilding of damaged infrastructure.

Increased demand is also associated with an expansion of growth in mining activity in Central Queensland (Moranbah) and significant new loads from Liquefied Natural Gas (LNG) developments around the Surat Basin by the second quarter of 2013–14.

For more information about the economic assumptions used to develop the projections, see Appendix C.

Figure 3-6 — Comparison of Queensland medium growth energy projections (GWh)



3.3.2 Maximum demand

Table 3-8 and Table 3-9 present actual and projected summer and winter MDs for Queensland.

The summer 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 4.2% under the medium growth scenario, and
- 5.8% and 3.1% under the high and low growth scenarios, respectively.

The winter 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 4.0% under the medium growth scenario, and
- 6.1% and 2.5% under the high and low growth scenarios, respectively.

Table 3-8 — Queensland summer maximum demand projections (MW)

	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2005–06	8,280									
2006–07	8,673									
2007–08	8,197									
2008–09	8,811									
2009–10	9,070									
2010–11	8,911									
2011–12		9,794	9,920	9,693	10,103	10,233	9,998	10,612	10,748	10,501
2012–13		10,382	10,634	10,163	10,704	10,964	10,477	11,233	11,507	10,995
2013–14		10,956	11,364	10,586	11,290	11,712	10,907	11,840	12,283	11,436
2014–15		11,635	12,219	11,149	11,982	12,586	11,479	12,553	13,188	12,023
2015–16		12,236	12,994	11,626	12,596	13,379	11,966	13,189	14,012	12,526
2016–17		12,688	13,733	11,901	13,063	14,140	12,248	13,679	14,808	12,821
2017–18		13,021	14,302	12,069	13,407	14,727	12,423	14,044	15,425	13,008
2018–19		13,404	14,935	12,312	13,804	15,381	12,673	14,462	16,112	13,271
2019–20		13,851	16,051	12,571	14,267	16,520	12,942	14,953	17,290	13,557
2020–21		14,187	16,636	12,762	14,613	17,123	13,138	15,315	17,920	13,763
Average annual growth	**1.5%**	**4.2%**	**5.9%**	**3.1%**	**4.2%**	**5.9%**	**3.1%**	**4.2%**	**5.8%**	**3.1%**

Table 3-9 — Queensland winter maximum demand projections (MW)

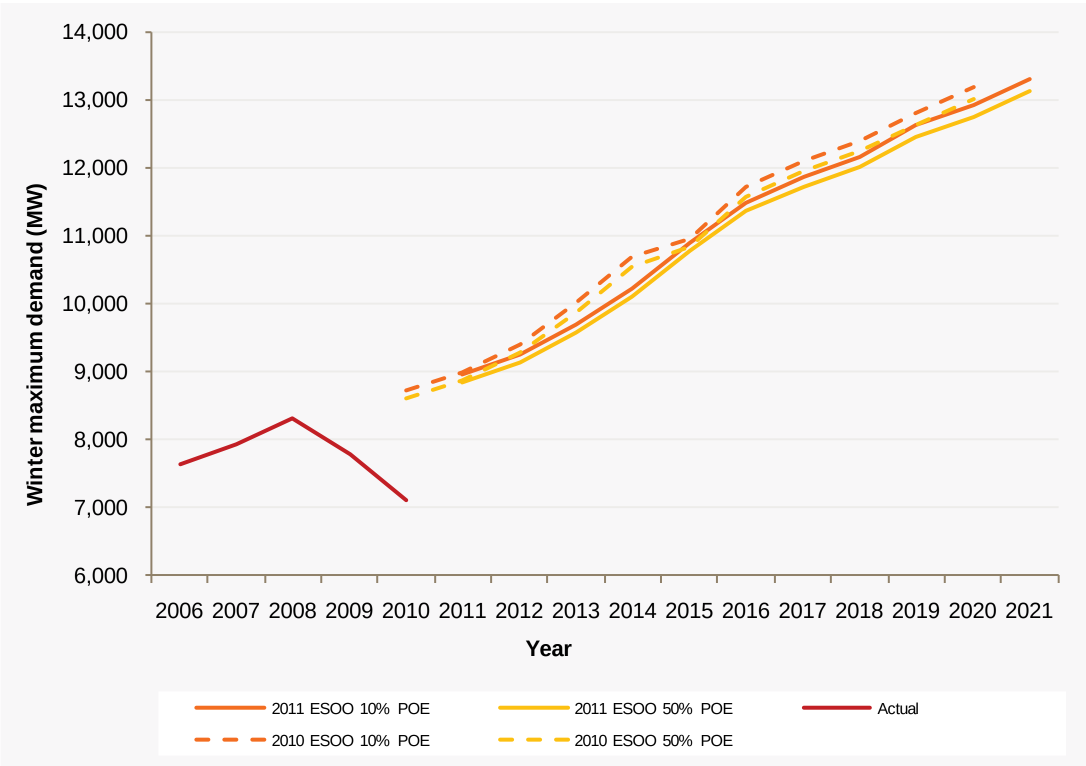
	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2006	7,628									
2007	7,924									
2008	8,312									
2009	7,774									
2010	7,483									
2011		8,677	8,836	8,551	8,847	9,009	8,719	8,966	9,130	8,835
2012		8,960	9,272	8,707	9,134	9,453	8,876	9,256	9,580	8,994
2013		9,399	9,941	8,978	9,578	10,131	9,148	9,705	10,265	9,268
2014		9,920	10,691	9,348	10,105	10,891	9,522	10,236	11,034	9,644
2015		10,572	11,589	9,844	10,764	11,801	10,022	10,900	11,953	10,147
2016		11,155	12,510	10,201	11,354	12,735	10,382	11,495	12,897	10,509
2017		11,511	13,211	10,357	11,716	13,448	10,540	11,862	13,618	10,668
2018		11,790	13,870	10,443	12,001	14,119	10,629	12,151	14,299	10,759
2019		12,246	14,704	10,657	12,466	14,969	10,846	12,622	15,160	10,978
2020		12,525	15,331	10,756	12,750	15,608	10,948	12,910	15,807	11,082
2021		12,909	16,028	10,942	13,141	16,317	11,136	13,306	16,526	11,273
Average annual growth	**-0.5%**	**4.1%**	**6.1%**	**2.5%**	**4.0%**	**6.1%**	**2.5%**	**4.0%**	**6.1%**	**2.5%**

Figure 3-7 and Figure 3-8 compare the 2010 and 2011 ESOO summer and winter medium growth 50% and 10% POE MD projections. The current projections are slightly lower, following lower than expected actual demand.

The actual MD for 2010–11 was 1,101 MW lower than the 2010 50% POE MD projection. Reasons for the lower MD include slower economic growth, the impact from the floods and cyclones over mining and agricultural sector loads across Queensland, and an unusually cool summer leading to lower than expected air-conditioning usage.

Figure 3-7 — Comparison of Queensland medium growth summer maximum demand projections (MW)

Figure 3-8 — Comparison of Queensland medium growth winter maximum demand projections (MW)



3.4 New South Wales, including the Australian Capital Territory

TransGrid provided the energy and MD projections and supporting information for New South Wales. The information presented in this section is consistent with the 2011 New South Wales Annual Planning Report.[8]

3.4.1 Energy

Table 3-10 presents actual and projected energy (for the medium, high, and low growth scenarios) for New South Wales. Energy is projected to increase over the next 10 years at an annual average rate of:

- 1.6% under the medium growth scenario, and
- 1.7% and 1.6% under the high and low growth scenarios, respectively.

Table 3-10 — New South Wales energy projections (GWh)

	Actual	Medium	High	Low
2005–06	74,041			
2006–07	74,790			
2007–08	74,992			
2008–09	75,857			
2009–10	74,955			
2010–11 (estimate)	74,902			
2011–12		75,735	76,431	76,212
2012–13		77,527	78,122	77,319
2013–14		78,301	78,915	78,153
2014–15		79,212	80,251	79,162
2015–16		81,083	81,637	80,796
2016–17		82,271	82,785	82,627
2017–18		83,369	83,587	83,993
2018–19		84,528	84,805	85,517
2019–20		86,022	87,369	87,032
2020–21		87,745	88,844	87,755
Average annual growth	**0.2%**	**1.6%**	**1.7%**	**1.6%**

Figure 3-9 compares the 2010 and 2011 ESOO medium growth energy projections. The projections from 2011–12 onwards are lower than last year by an average of 4,071 GWh. The differences are due to changes in key assumptions, including higher forecast electricity prices resulting from higher distribution and transmission prices, and adjustments to the expected impact of carbon pricing.

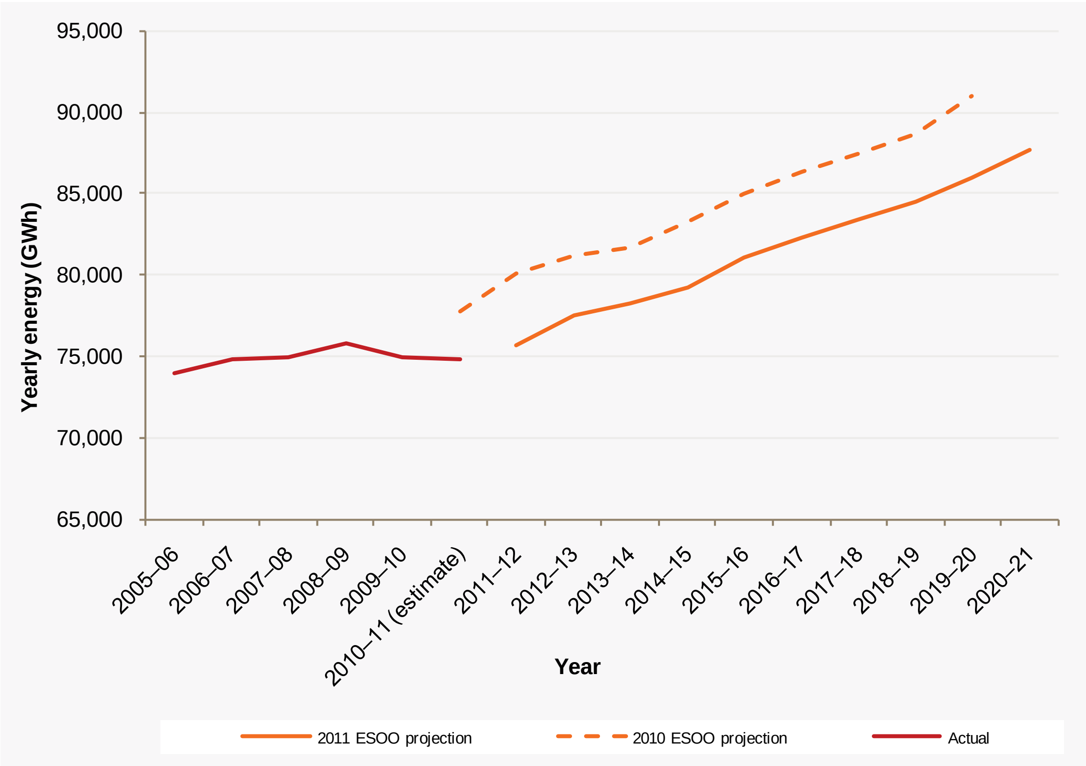
8 TransGrid. “New South Wales Annual Planning Report 2011”. Available http://www.transgrid.com.au/network/np/Documents/Annual%20Planning%20Report%202011.pdf. 2 July 2011.

Differences were also due to a revision to New South Wales semi-scheduled and non-scheduled generation projections, the incorporation of new and ongoing energy efficiency policies (such as the New South Wales Energy Savings Scheme), allowances for the operation of the New South Wales desalination plant, and a slower than expected recovery from the global financial crisis.

Modelling suggests there will be a small increase in demand between 2010–11 and 2011–12 with medium growth, resulting from an increase in gross state product (GSP). Recovery to pre-global financial crisis levels of growth is expected to occur from 2011–12 onwards.

For more information about the economic assumptions used to develop the projections, see Appendix C.

Figure 3-9 — Comparison of New South Wales medium growth energy projections (GWh)



3.4.2 Maximum demand

Table 3-11 and Table 3-12 present actual and projected summer and winter MDs for New South Wales.

The summer 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 2.0% under the medium growth scenario, and
- 2.2% and 1.9% under the high and low growth scenarios, respectively.

The winter 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 2.0% under the medium growth scenario, and
- 2.2% and 2.0% under the high and low growth scenarios, respectively.

Table 3-11 — New South Wales summer maximum demand projections (MW)

	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2005–06	13,461									
2006–07	12,981									
2007–08	13,071									
2008–09	14,287									
2009–10	13,957									
2010–11	14,820									
2011–12		13,827	13,856	13,845	14,807	14,826	14,825	15,827	15,856	15,845
2012–13		14,051	14,088	14,067	15,061	15,108	15,087	16,121	16,168	16,147
2013–14		14,290	14,335	14,316	15,350	15,395	15,376	16,440	16,495	16,466
2014–15		14,551	14,612	14,572	15,651	15,722	15,682	16,781	16,862	16,812
2015–16		14,821	14,894	14,837	15,951	16,044	15,977	17,121	17,214	17,157
2016–17		15,100	15,202	15,119	16,270	16,382	16,289	17,470	17,602	17,499
2017–18		15,387	15,522	15,397	16,597	16,752	16,607	17,837	18,002	17,857
2018–19		15,687	15,872	15,672	16,937	17,132	16,922	18,207	18,422	18,202
2019–20		15,997	16,230	15,932	17,277	17,530	17,222	18,587	18,860	18,532
2020–21		16,300	16,600	16,182	17,610	17,930	17,502	18,960	19,300	18,842
Average annual growth	**1.9%**	**1.8%**	**2.0%**	**1.7%**	**1.9%**	**2.1%**	**1.9%**	**2.0%**	**2.2%**	**1.9%**

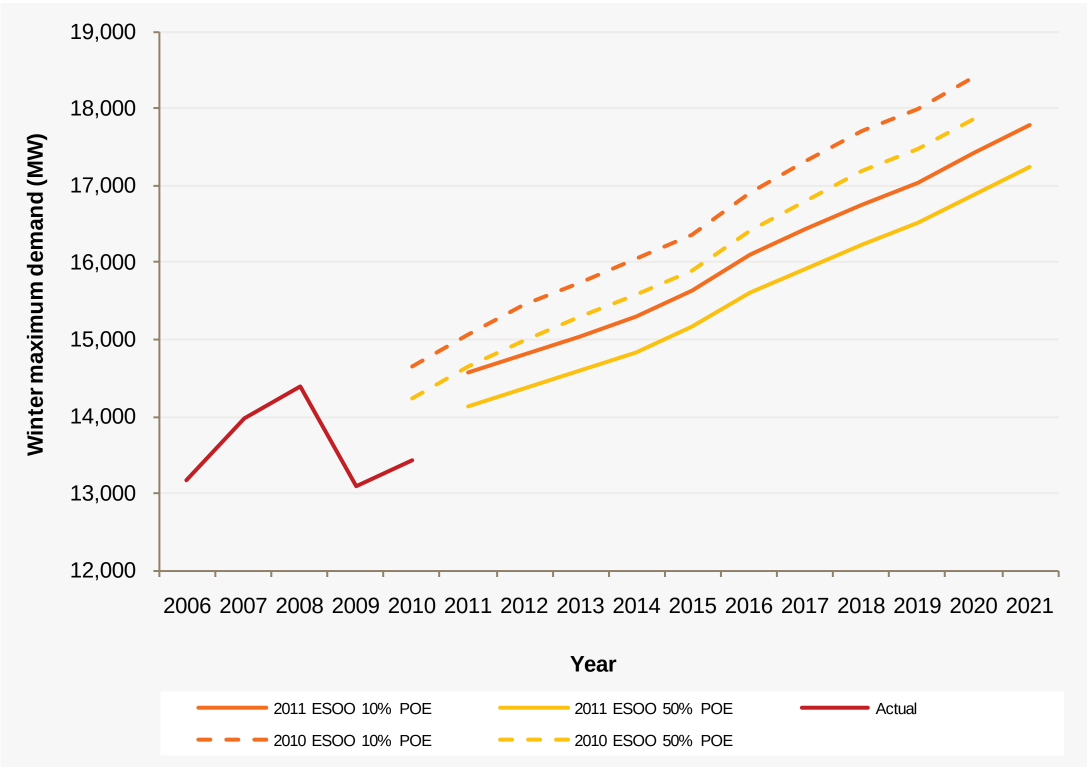
Table 3-12 — New South Wales winter maximum demand projections (MW)

	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2006	13,166									
2007	13,985									
2008	14,398									
2009	13,090									
2010	13,433									
2011		13,760	13,790	13,720	14,129	14,149	14,079	14,568	14,588	14,518
2012		13,999	14,068	13,977	14,369	14,437	14,346	14,818	14,896	14,785
2013		14,213	14,329	14,139	14,592	14,708	14,508	15,051	15,167	14,937
2014		14,451	14,595	14,358	14,840	14,985	14,737	15,309	15,454	15,166
2015		14,771	14,882	14,712	15,161	15,282	15,101	15,640	15,761	15,541
2016		15,200	15,273	15,237	15,610	15,682	15,646	16,109	16,181	16,085
2017		15,509	15,551	15,648	15,929	15,970	16,067	16,428	16,479	16,506
2018		15,805	15,861	16,035	16,234	16,290	16,454	16,753	16,809	16,903
2019		16,055	16,180	16,319	16,504	16,619	16,758	17,023	17,148	17,197
2020		16,425	16,636	16,639	16,874	17,096	17,088	17,413	17,634	17,527
2021		16,777	17,096	16,839	17,236	17,575	17,298	17,785	18,133	17,737
Average annual growth	**0.5%**	**2.0%**	**2.2%**	**2.1%**	**2.0%**	**2.2%**	**2.1%**	**2.0%**	**2.2%**	**2.0%**

Figure 3-10 and Figure 3-11 compare the 2010 and 2011 ESOO summer and winter medium growth 10% and 50% POE MD projections. The differences between the projections are primarily due to a slower than expected recovery from the global financial crisis.

Figure 3-10 — Comparison of New South Wales medium growth summer maximum demand projections (MW)

Figure 3-11 — Comparison of New South Wales medium growth winter maximum demand projections (MW)



3.5 Victoria

AEMO produces the energy and MD projections for Victoria. The information presented in this section is consistent with the 2011 Victorian Annual Planning Report.[9]

3.5.1 Energy

Table 3-13 presents actual and projected energy (for the medium, high, and low growth scenarios) for Victoria. Energy is projected to increase over the next 10 years at an annual average rate of:

- 1.6% under the medium growth scenario, and
- 2.3% and 0.8% under the high and low growth scenarios, respectively.

Table 3-13 — Victorian energy projections (GWh)

	Actual	Medium	High	Low
2005–06	46,426			
2006–07	47,201			
2007–08	47,926			
2008–09	47,436			
2009–10	47,482			
2010–11 (estimate)	47,527			
2011–12		48,314	49,334	48,055
2012–13		49,766	50,787	48,261
2013–14		50,771	51,653	48,730
2014–15		50,964	52,242	48,815
2015–16		51,421	53,115	48,900
2016–17		52,468	54,577	49,536
2017–18		53,058	55,622	50,551
2018–19		53,743	56,832	50,725
2019–20		54,640	58,307	50,876
2020–21		55,732	60,369	51,411
Average annual growth	**0.5%**	**1.6%**	**2.3%**	**0.8%**

Figure 3-12 compares the 2010 and 2011 ESOO medium growth energy projections. The current projection for:

- 2011–12 is lower due to reduced load projections from the aluminium smelters and the Wonthaggi Desalination Plant, and
- 2013–14 onwards is higher due to increased annual growth rates under all economic growth scenarios.

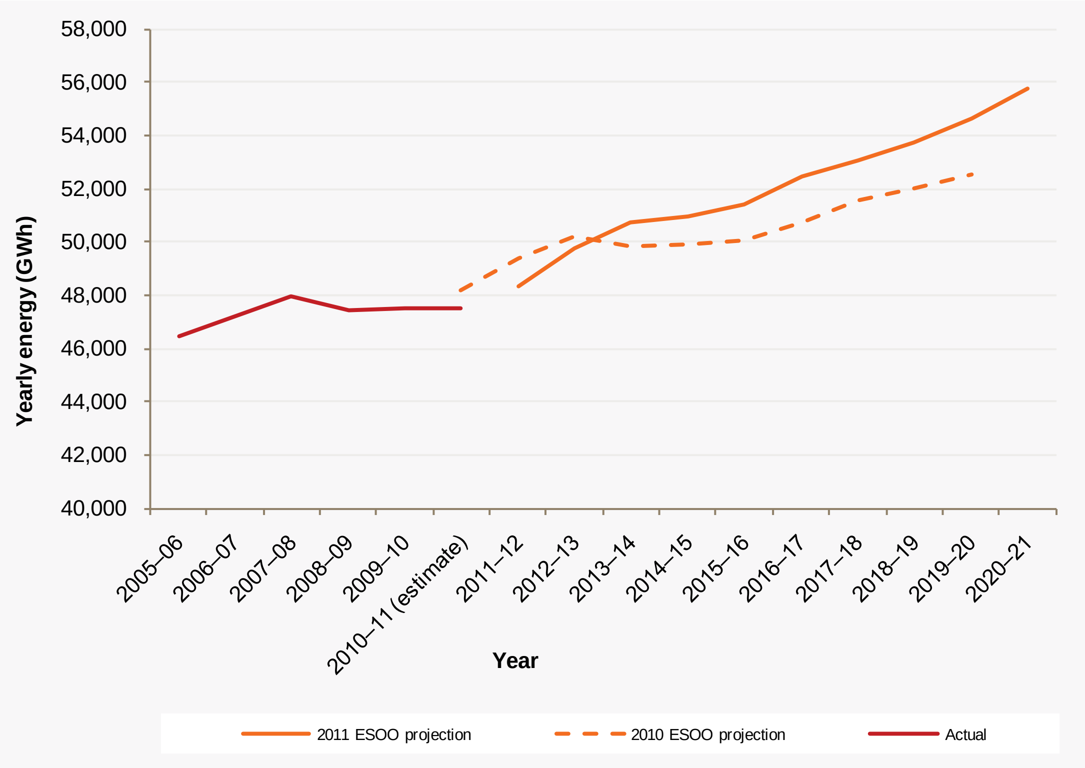
[9] AEMO. "Victorian Annual Planning Report 2011". Available http://www.aemo.com.au/planning/VAPR2011/vapr.html. 2 July 2011.

Factors contributing to these higher and more stable growth rates include the following:

- From 2013–14 onwards, the industrial loads are assumed to return to previous levels, mainly associated with the aluminium sector.
- The overall economic outlook for Victoria has improved, and the GSP growth rate is slightly higher than last year under the medium and high growth scenarios.

For more information about the economic assumptions used to develop the projections, see Appendix C.

Figure 3-12 — Comparison of Victorian medium growth energy projections (GWh)



3.5.2 Maximum demand

Table 3-14 and Table 3-15 present actual and projected summer and winter MDs for Victoria.

The summer 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 2.2% under the medium growth scenario, and
- 2.5% and 1.8% under the high and low growth scenarios, respectively.

The winter 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 1.5% under the medium growth scenario, and
- 2.0% and 1.2% under the high and low growth scenarios, respectively.

Table 3-14 — Victorian summer maximum demand projections (MW)

	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2005–06	8,792									
2006–07	9,164									
2007–08	9,878									
2008–09	10,554									
2009–10	10,282									
2010–11	9,982									
2011–12		9,693	9,818	9,628	10,303	10,430	10,237	10,994	11,123	10,927
2012–13		10,013	10,219	9,860	10,648	10,859	10,493	11,370	11,585	11,213
2013–14		10,231	10,442	10,030	10,895	11,109	10,692	11,646	11,867	11,438
2014–15		10,398	10,608	10,114	11,093	11,308	10,808	11,869	12,093	11,575
2015–16		10,539	10,780	10,213	11,263	11,513	10,930	12,062	12,322	11,723
2016–17		10,720	11,014	10,437	11,468	11,775	11,178	12,296	12,615	11,997
2017–18		10,911	11,217	10,617	11,685	12,007	11,387	12,542	12,879	12,223
2018–19		11,129	11,457	10,779	11,937	12,283	11,574	12,815	13,181	12,439
2019–20		11,367	11,722	10,946	12,203	12,580	11,772	13,113	13,513	12,659
2020–21		11,603	12,022	11,121	12,470	12,914	11,967	13,404	13,877	12,876
Average annual growth	**1.6%**	**2.0%**	**2.3%**	**1.6%**	**2.1%**	**2.4%**	**1.8%**	**2.2%**	**2.5%**	**1.8%**

Table 3-15 — Victorian winter maximum demand projections (MW)

	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2006	7,899									
2007	8,435									
2008	8,097									
2009	8,184									
2010	8,197									
2011		8,240	8,271	8,085	8,359	8,389	8,202	8,517	8,546	8,358
2012		8,457	8,574	8,253	8,572	8,689	8,366	8,732	8,851	8,525
2013		8,599	8,734	8,347	8,719	8,855	8,465	8,903	9,042	8,647
2014		8,673	8,831	8,383	8,807	8,966	8,514	8,970	9,131	8,674
2015		8,746	8,939	8,412	8,878	9,072	8,540	9,041	9,238	8,700
2016		8,842	9,070	8,523	8,970	9,199	8,647	9,134	9,366	8,807
2017		8,943	9,212	8,603	9,075	9,347	8,731	9,252	9,527	8,902
2018		9,082	9,396	8,754	9,219	9,537	8,887	9,396	9,718	9,059
2019		9,273	9,617	8,908	9,403	9,752	9,034	9,585	9,939	9,211
2020		9,432	9,854	8,994	9,575	10,002	9,131	9,745	10,178	9,295
2021		9,587	10,084	9,095	9,743	10,247	9,244	9,924	10,435	9,416
Average annual growth	**0.5%**	**1.5%**	**2.0%**	**1.2%**	**1.5%**	**2.0%**	**1.2%**	**1.5%**	**2.0%**	**1.2%**

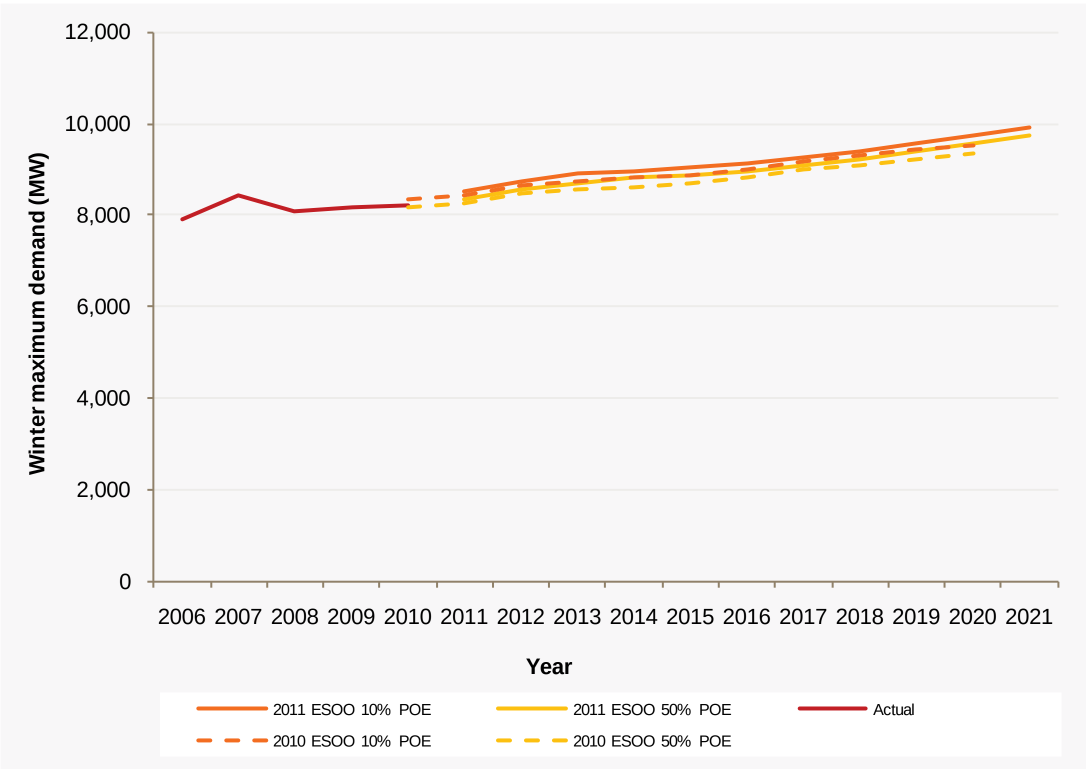
Figure 3-13 and Figure 3-14 compare the 2010 and 2011 ESOO summer and winter medium growth 10% and 50% POE MD projections. The current summer MD projections for 2011–12 are lower, which is mainly due to a reduction in the assumed aluminium smelter load for 2010–11.

After 2013–14, demand growth closely matches last year’s projection, increasing slightly in the final three years due to increases in the GSP growth rate for the current economic outlook.

For more information about the economic assumptions used to develop the projections, see Appendix C.

Figure 3-13 — Comparison of Victorian medium growth summer maximum demand projections (MW)

Figure 3-14 — Comparison of Victorian medium growth winter maximum demand projections (MW)



3.6 South Australia

AEMO provided the energy and MD projections and supporting information for South Australia. The information provided in this section is consistent with the 2011 South Australian Supply and Demand Outlook.[10]

3.6.1 Energy

Table 3-16 presents actual and projected energy (for the medium, high, and low growth scenarios) for South Australia. Energy is projected to increase over the next 10 years at an annual average rate of:

- 1.5% under the medium growth scenario, and
- 2.3% and 1.0% under the high and low growth scenarios, respectively.

Table 3-16 — South Australian energy projections (GWh)

	Actual	Medium	High	Low
2005–06	13,207			
2006–07	13,727			
2007–08	13,671			
2008–09	13,901			
2009–10	13,873			
2010–11 (estimate)	14,030			
2011–12		14,543	14,639	14,389
2012–13		14,839	14,960	14,620
2013–14		15,150	15,332	14,714
2014–15		15,204	15,846	14,625
2015–16		15,444	16,401	14,829
2016–17		15,783	16,924	15,066
2017–18		15,948	17,159	15,173
2018–19		16,309	17,486	15,354
2019–20		16,438	17,697	15,549
2020–21		16,694	18,017	15,749
Average annual growth	**1.2%**	**1.5%**	**2.3%**	**1.0%**

Figure 3-15 compares the 2010 and 2011 ESOO medium growth energy projections. The current projections start lower due to a 3% reduction in actual energy consumption for 2010–11, and a mild 2010–11 summer that limited the number of extended high-demand periods.

Other factors relevant to the lower start include the increasing penetration of rooftop photovoltaic systems, the high Australian dollar (potentially suppressing manufacturing output in some sectors), and increasing end-use customer awareness of electricity prices and the environmental impact of electricity consumption.

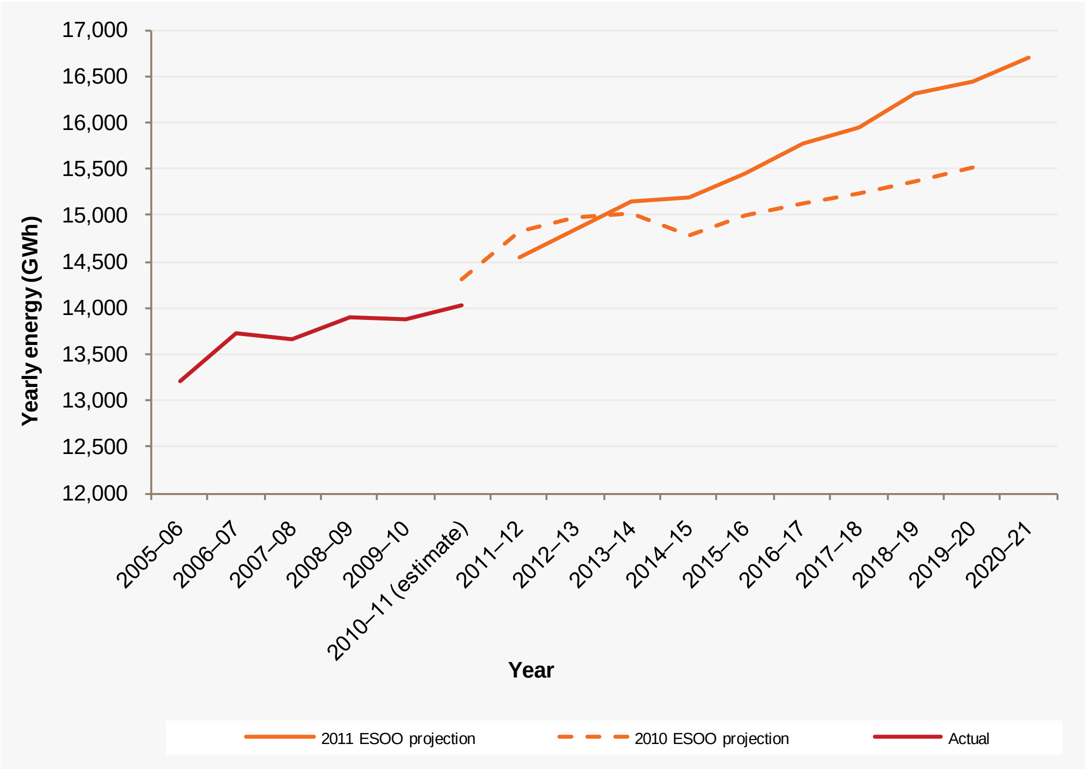
10 See note 5 in this chapter.

Despite these factors, the average annual growth rate of energy over the forecast period has increased due to:

- improvements in the South Australian economic outlook that result in the average gross state product (GSP) growth for the 10-year outlook period increasing by 0.3% (from 2.3% to 2.6%), and
- significant increases to the industrial load forecast from 2013–14 onwards because of recent revisions to mining expansion plans in South Australia.

For more information about the economic assumptions used to develop the projections, see Appendix C.

Figure 3-15 — Comparison of South Australian medium growth energy projections (GWh)



3.6.2 Maximum demand

Table 3-17 and Table 3-18 present actual and projected summer and winter MDs for South Australia.

The summer 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 1.7% under the medium growth scenario, and
- 2.2% and 1.2% under the high and low growth scenarios, respectively.

The winter 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 1.6% under the medium growth scenario, and
- 2.1% and 1.2% under the high and low growth scenarios, respectively.

Table 3-17 — South Australian summer maximum demand projections (MW)

		90% POE			50% POE			10% POE		
	Actual	Medium	High	Low	Medium	High	Low	Medium	High	Low
2005–06	2,971									
2006–07	2,955									
2007–08	3,213									
2008–09	3,490									
2009–10	3,341									
2010–11	3,433									
2011–12		2,980	3,010	2,960	3,230	3,270	3,220	3,570	3,600	3,560
2012–13		3,020	3,040	3,000	3,290	3,320	3,240	3,630	3,650	3,580
2013–14		3,110	3,140	3,050	3,370	3,400	3,290	3,700	3,740	3,660
2014–15		3,140	3,230	3,050	3,420	3,500	3,310	3,780	3,850	3,670
2015–16		3,190	3,330	3,100	3,470	3,590	3,350	3,840	3,950	3,710
2016–17		3,260	3,410	3,130	3,530	3,690	3,410	3,920	4,060	3,750
2017–18		3,320	3,450	3,170	3,590	3,760	3,450	3,960	4,110	3,820
2018–19		3,370	3,520	3,210	3,670	3,820	3,490	4,030	4,210	3,830
2019–20		3,430	3,610	3,250	3,730	3,890	3,540	4,090	4,270	3,910
2020–21		3,490	3,660	3,300	3,770	3,970	3,590	4,170	4,390	3,970
Average annual growth	**2.9%**	**1.8%**	**2.2%**	**1.2%**	**1.7%**	**2.2%**	**1.2%**	**1.7%**	**2.2%**	**1.2%**

Table 3-18 — South Australian winter maximum demand projections (MW)

	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2006	2,399									
2007	2,473									
2008	2,568									
2009	2,460									
2010	2,538									
2011		2,450	2,450	2,430	2,560	2,570	2,550	2,700	2,700	2,680
2012		2,480	2,490	2,460	2,600	2,610	2,580	2,720	2,760	2,710
2013		2,520	2,530	2,480	2,630	2,640	2,610	2,770	2,790	2,730
2014		2,570	2,580	2,520	2,690	2,710	2,630	2,830	2,860	2,760
2015		2,570	2,660	2,520	2,710	2,780	2,640	2,850	2,930	2,780
2016		2,630	2,730	2,550	2,760	2,870	2,680	2,890	3,010	2,800
2017		2,690	2,810	2,590	2,810	2,940	2,720	2,960	3,090	2,840
2018		2,740	2,860	2,620	2,860	3,000	2,750	3,010	3,150	2,890
2019		2,790	2,920	2,640	2,930	3,060	2,780	3,070	3,210	2,920
2020		2,840	2,980	2,700	2,970	3,120	2,830	3,130	3,290	2,970
2021		2,890	3,040	2,740	3,020	3,180	2,870	3,170	3,330	3,010
Average annual growth	**1.4%**	**1.7%**	**2.2%**	**1.2%**	**1.7%**	**2.2%**	**1.2%**	**1.6%**	**2.1%**	**1.2%**

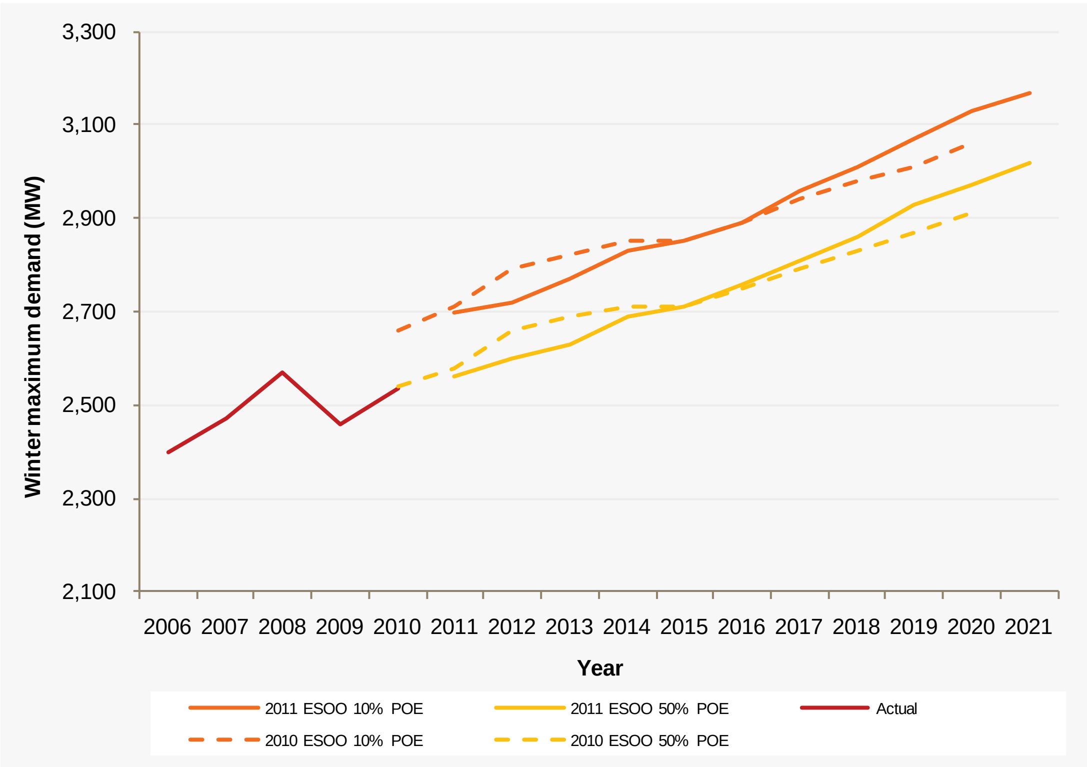
Figure 3-16 and Figure 3-17 compare the 2010 and 2011 ESOO summer and winter medium growth 50% and 10% POE MD projections. The difference between the projections is mainly due to the previous assumption of a considerable electricity price increase in 2014–15 after the introduction of a carbon price. The current projections predict a less significant impact, reducing consumer price responses at times of maximum demand, resulting in steadier growth from 2014–15 onwards.

Reduced energy consumption has also had a slight downwards impact on the summer MD projections in the short term, and the current medium growth scenario projection for the 2011–12 summer 10% POE MD has been reduced by 60 MW.

The higher growth rate for the medium growth scenario is due to both an improved economic outlook and increased industrial load forecasts.

Figure 3-16 — Comparison of South Australian medium growth summer maximum demand projections (MW)

Figure 3-17 — Comparison of South Australian medium growth winter maximum demand projections (MW)



3.7 Tasmania

Transend provided the energy and MD projections and supporting information for Tasmania. The information presented in this section is consistent with the 2011 Tasmanian Annual Planning Report.[11]

3.7.1 Energy

Table 3-19 presents actual and projected energy (for the medium, high, and low growth scenarios) for Tasmania. Energy is projected to increase over the next 10 years at an annual average rate of:

- 0.9% under the medium growth scenario, and
- 2.3% and -0.7% under the high and low growth scenarios, respectively.

Table 3-19 — Tasmanian energy projections (GWh)

	Actual	Medium	High	Low
2005–06	10,652			
2006–07	10,739			
2007–08	11,008			
2008–09	10,964			
2009–10	10,847			
2010–11 (estimate)	11,196			
2011–12		11,204	11,595	10,758
2012–13		11,443	11,939	10,735
2013–14		11,506	12,068	10,715
2014–15		11,556	12,285	10,710
2015–16		11,599	12,499	10,350
2016–17		11,778	12,894	10,090
2017–18		11,849	13,026	10,096
2018–19		11,923	13,924	10,081
2019–20		12,026	14,043	10,074
2020–21		12,135	14,192	10,078
Average annual growth	**1.0%**	**0.9%**	**2.3%**	**-0.7%**

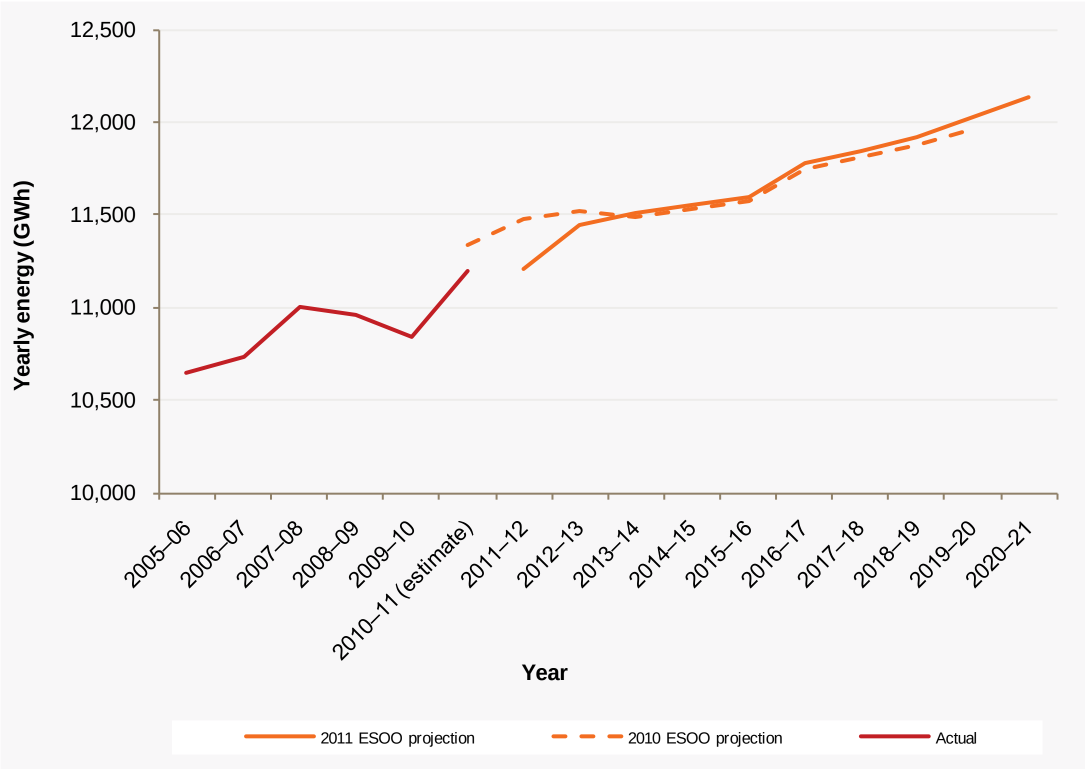
Figure 3-18 compares the 2010 and 2011 ESOO medium growth energy projections. The current projection starts approximately 280 GWh lower, but is almost identical from 2013–14 onwards. This is due to a lower than expected GSP. Part of the reduction can also be attributed to warmer temperatures during winter, which resulted in lower energy consumption overall.

Tasmania's sustained economic growth is associated with an expected increase in agriculture and mining activity and increased population growth.

For more information about the economic assumptions used to develop the projections, see Appendix C.

[11] See note 4 in this chapter.

Figure 3-18 — Comparison of Tasmanian medium growth energy projections (GWh)



3.7.2 Maximum demand

Table 3-20 and Table 3-21 present actual and projected summer and winter MDs for Tasmania.

The summer 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 1.4% under the medium growth scenario, and
- 2.5% and 0.0% under the high and low growth scenarios, respectively.

The winter 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 1.5% under the medium growth scenario, and
- 2.4% and 0.1% under the high and low growth scenarios, respectively.

Table 3-20 — Tasmanian summer maximum demand projections (MW)

	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2005–06	1,315									
2006–07	1,393									
2007–08	1,425									
2008–09	1,475									
2009–10	1,404									
2010–11	1,377									
2011–12		1,477	1,503	1,423	1,493	1,520	1,439	1,519	1,548	1,465
2012–13		1,517	1,555	1,431	1,534	1,572	1,447	1,561	1,600	1,473
2013–14		1,540	1,583	1,440	1,556	1,601	1,456	1,583	1,630	1,482
2014–15		1,556	1,616	1,446	1,572	1,634	1,462	1,599	1,663	1,488
2015–16		1,569	1,648	1,411	1,585	1,666	1,427	1,613	1,696	1,454
2016–17		1,598	1,703	1,388	1,615	1,722	1,405	1,643	1,752	1,431
2017–18		1,615	1,726	1,396	1,633	1,745	1,413	1,661	1,776	1,439
2018–19		1,633	1,835	1,401	1,650	1,855	1,417	1,679	1,887	1,444
2019–20		1,655	1,857	1,407	1,673	1,877	1,424	1,702	1,910	1,450
2020–21		1,678	1,883	1,415	1,696	1,903	1,431	1,726	1,937	1,458
Average annual growth	**0.9%**	**1.4%**	**2.5%**	**-0.1%**	**1.4%**	**2.5%**	**-0.1%**	**1.4%**	**2.5%**	**0.0%**

Table 3-21 — Tasmanian winter maximum demand projections (MW)

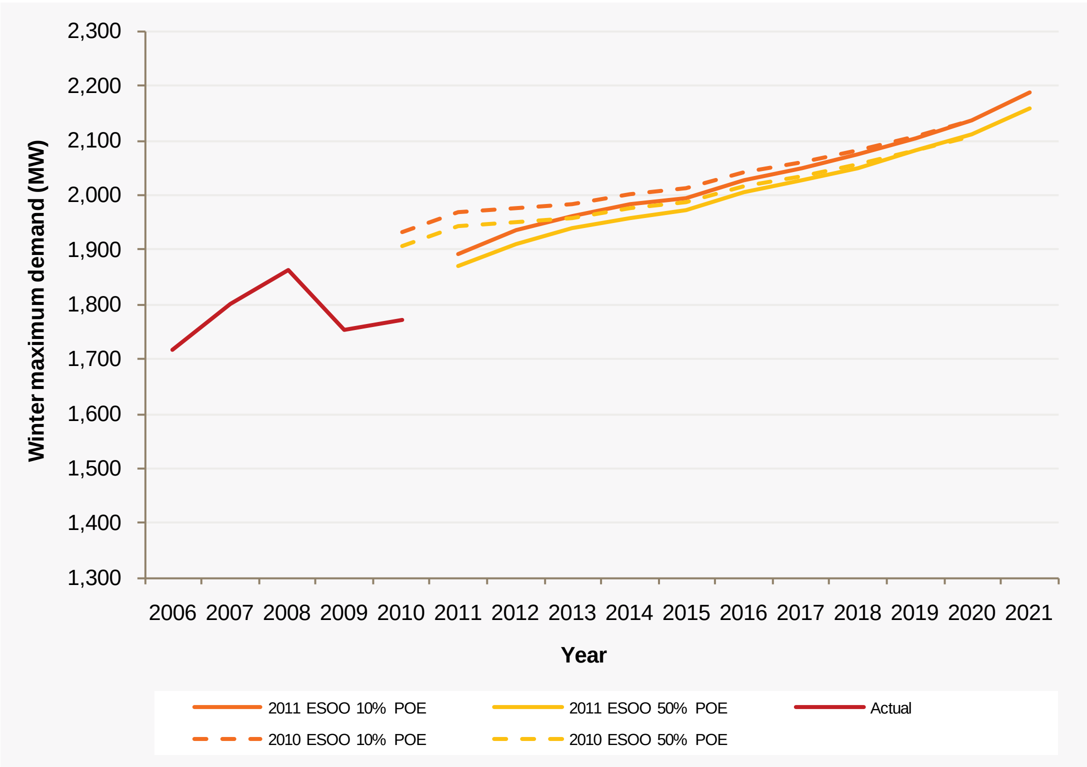
	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2006	1,716									
2007	1,803									
2008	1,861									
2009	1,753									
2010	1,770									
2011		1,847	1,886	1,784	1,869	1,910	1,807	1,892	1,933	1,829
2012		1,889	1,934	1,796	1,912	1,958	1,819	1,935	1,982	1,841
2013		1,917	1,973	1,810	1,940	1,997	1,832	1,962	2,022	1,854
2014		1,936	2,011	1,818	1,959	2,036	1,841	1,982	2,061	1,863
2015		1,949	2,048	1,781	1,973	2,073	1,803	1,996	2,099	1,826
2016		1,981	2,110	1,756	2,004	2,136	1,779	2,028	2,162	1,801
2017		2,002	2,143	1,762	2,026	2,170	1,784	2,050	2,197	1,807
2018		2,026	2,262	1,765	2,050	2,289	1,788	2,074	2,316	1,810
2019		2,055	2,292	1,772	2,080	2,320	1,794	2,105	2,347	1,817
2020		2,087	2,326	1,783	2,112	2,355	1,806	2,138	2,383	1,829
2021		2,134	2,391	1,806	2,160	2,420	1,829	2,186	2,450	1,852
Average annual growth	**0.8%**	**1.5%**	**2.4%**	**0.1%**	**1.5%**	**2.4%**	**0.1%**	**1.5%**	**2.4%**	**0.1%**

Figure 3-19 and Figure 3-20 compare the 2010 and 2011 ESOO summer and winter medium growth 10% and 50% POE MD projections. The differences are caused by the same factors affecting the energy projections, specifically lower than expected economic growth and the closure of a large industrial load.

A reduction in the predicted demand from electric heaters due to warmer winter temperatures also affected the winter maximum demand projection.

Figure 3-19 — Comparison of Tasmanian medium growth summer maximum demand projections (MW)

Figure 3-20 — Comparison of Tasmanian medium growth winter maximum demand projections (MW)



3.8 Non-scheduled generation projections

This section presents regional and NEM-wide projections of contributions from non-scheduled generation to energy and MD. These projections only consider significant non-scheduled generation (as nominated by the jurisdictional planning bodies (JPBs)) and may not include all non-scheduled generators described in Chapter 4.

When establishing the adequacy of NEM generation supplies, both the supply-demand outlook and MT PASA make assessments based on the demand met by scheduled and semi-scheduled generation only, and do not include non-scheduled or exempt generation unless these are considered to have a significant impact on network limitations or the behaviour of other plant.

The non-scheduled generation projections presented in this section are subtracted from the projections of regional energy and MD to create the scheduled and semi-scheduled generation projections used in the supply-demand outlook. For the scheduled and semi-scheduled generation projections, see Appendix A.

3.8.1 NEM-wide energy and maximum demand supplied by non-scheduled generating units

Table 3-22 presents actual, medium, high and low growth NEM-wide projections of non-scheduled generation capacity and energy.

Table 3-23 presents NEM-wide projections of the contribution to summer MD from non-scheduled generation.

Energy supplied by non-scheduled generating units is projected to increase over the next 10 years at an annual average rate of between 4.7% and 11.4%, compared with historical growth of 18.7%. The lower growth rates reflect the fact the majority of all future wind farm projects are expected to register as semi-scheduled, rather than non-scheduled.

Table 3-22 — NEM-wide projections of non-scheduled generation capacity and energy

	Actual Capacity (MW)	Actual Energy (GWh)	Medium Capacity (MW)	Medium Energy (GWh)	High Capacity (MW)	High Energy (GWh)	Low Capacity (MW)	Low Energy (GWh)
2005–06	1,447	2,952						
2006–07	1,700	3,328						
2007–08	1,948	4,190						
2008–09	2,680	5,033						
2009–10	2,836	5,809						
2010–11 (estimate)	2,522	6,956						
2011–12			2,605	6,958	2,639	7,011	2,603	6,951
2012–13			2,645	7,039	2,649	7,046	2,615	6,992
2013–14			2,671	7,107	2,683	7,131	2,666	7,100
2014–15			2,686	7,145	2,695	7,322	2,675	7,125
2015–16			2,820	7,678	2,827	7,722	2,811	7,535
2016–17			2,820	7,678	2,831	7,722	2,813	7,632
2017–18			2,823	7,678	2,831	7,724	2,813	7,633
2018–19			2,824	7,679	3,019	8,505	2,815	7,633
2019–20			2,824	7,679	3,068	8,528	2,816	7,634
2020–21			2,866	7,699	3,068	8,528	2,816	7,634
Average annual growth	**11.8%**	**18.7%**	**4.0%**	**5.0%**	**10.0%**	**11.4%**	**3.4%**	**4.7%**

Table 3-23 — NEM-wide projections of the non-scheduled generation contribution to summer maximum demand (MW)

	Actual	Medium	High	Low
2005–06	415			
2006–07	557			
2007–08	644			
2008–09	566			
2009–10	758			
2010–11	791			
2011–12		730	747	728
2012–13		749	751	734
2013–14		751	761	749
2014–15		758	839	749
2015–16		843	862	777
2016–17		843	862	823
2017–18		843	863	823
2018–19		843	1,029	823
2019–20		843	1,040	824
2020–21		852	1,040	824
Average annual growth	**13.8%**	**6.9%**	**20.7%**	**6.2%**

3.8.2 Queensland

Table 3-24 presents actual, medium, high and low growth projections of non-scheduled generation capacity and energy for Queensland.

Table 3-25 presents projections of the contribution to the summer MD from Queensland non-scheduled generation.

Very little additional non-scheduled generating capacity is expected in Queensland over the next 10 years, and energy from this class of generation is not expected to change. Historical growth of 38.2% can largely be attributed to cogeneration at sugar mills, and the projections do not anticipate any further growth from this source.

Table 3-24 — Queensland projections of non-scheduled generation capacity and energy

	Actual Capacity (MW)	Actual Energy (GWh)	Medium Capacity (MW)	Medium Energy (GWh)	High Capacity (MW)	High Energy (GWh)	Low Capacity (MW)	Low Energy (GWh)
2005–06	0	0						
2006–07	240	381						
2007–08	317	1,053						
2008–09	363	1,164						
2009–10	363	1,388						
2010–11 (estimate)	363	1,390						
2011–12			368	1,390	368	1,390	368	1,390
2012–13			370	1,390	370	1,390	370	1,390
2013–14			370	1,390	370	1,390	370	1,390
2014–15			370	1,390	370	1,390	370	1,390
2015–16			370	1,390	370	1,390	370	1,390
2016–17			370	1,390	370	1,390	370	1,390
2017–18			370	1,390	370	1,390	370	1,390
2018–19			370	1,390	370	1,390	370	1,390
2019–20			370	1,390	370	1,390	370	1,390
2020–21			370	1,390	370	1,390	370	1,390
Average annual growth	**10.9%**	**38.2%**	**0.1%**	**0.0%**	**0.1%**	**0.0%**	**0.1%**	**0.0%**

The non-scheduled generation contribution to summer MD decreased from 2009–10 to 2010–11 due to the Queensland floods, with the following generation showing an output of (zero) 0 MW during the summer MD:

- Pioneer Mill (expected contribution: 30 MW).
- Daandine (expected contribution: 24 MW).
- KR Castlemaine (expected contribution: 3.5 MW).
- Rocky Point (expected contribution: 17 MW).
- Bromelton (expected contribution: 10 MW).

The removal of a 30 MW flood-affected generator has led to a decrease in the projections for the 10-year outlook.

Table 3-25 — Queensland projections of the non-scheduled generation contribution to summer maximum demand (MW)

	Actual	Medium	High	Low
2005–06	0			
2006–07	62			
2007–08	111			
2008–09	104			
2009–10	180			
2010–11	75			
2011–12		150	150	150
2012–13		150	150	150
2013–14		150	150	150
2014–15		150	150	150
2015–16		150	150	150
2016–17		150	150	150
2017–18		150	150	150
2018–19		150	150	150
2019–20		150	150	150
2020–21		150	150	150
Average annual growth	**4.8%**	**0.0%**	**0.0%**	**0.0%**

3.8.3 New South Wales

Table 3-26 presents actual, medium, high and low growth projections of non-scheduled generation capacity and energy for New South Wales.

Table 3-27 presents projections of the contribution to the summer MD from New South Wales non-scheduled generation.

Energy supplied by non-scheduled generating units is projected to increase over the next 10 years at an annual average rate of between 1.1% and 1.5% (depending on economic scenario), compared with historical growth of 12.5%. Much of the historical growth can be attributed to the installation of cogeneration at sugar mills, and the projections do not anticipate any further growth from this source.

The majority of future wind farm projects are expected to register as semi-scheduled rather than non-scheduled. This contributes to relatively low projected growth in non-scheduled energy, capacity, and contribution to the summer MD.

Table 3-26 — New South Wales projections of non-scheduled generation capacity and energy

	Actual Capacity (MW)	Actual Energy (GWh)	Medium Capacity (MW)	Medium Energy (GWh)	High Capacity (MW)	High Energy (GWh)	Low Capacity (MW)	Low Energy (GWh)
2005–06	338	951						
2006–07	347	904						
2007–08	512	913						
2008–09	697	1,192						
2009–10	711	1,681						
2010–11 (estimate)	746	1,711						
2011–12			752	1,486	785	1,539	749	1,479
2012–13			781	1,532	785	1,539	751	1,485
2013–14			781	1,532	793	1,556	777	1,525
2014–15			787	1,545	796	1,722	777	1,525
2015–16			789	1,677	796	1,722	781	1,534
2016–17			789	1,677	800	1,722	782	1,632
2017–18			792	1,677	801	1,724	782	1,632
2018–19			793	1,678	801	1,724	785	1,632
2019–20			793	1,678	849	1,746	785	1,633
2020–21			835	1,698	849	1,746	785	1,633
Average annual growth	**17.2%**	**12.5%**	**1.2%**	**1.5%**	**0.9%**	**1.4%**	**0.5%**	**1.1%**

Table 3-27 — New South Wales projections of the non-scheduled generation contribution to summer maximum demand (MW)

	Actual	Medium	High	Low
2005–06	169			
2006–07	105			
2007–08	131			
2008–09	186			
2009–10	191			
2010–11	225			
2011–12		358	375	356
2012–13		373	375	358
2013–14		373	383	370
2014–15		379	460	370
2015–16		440	460	374
2016–17		440	460	421
2017–18		440	461	421
2018–19		441	461	421
2019–20		441	471	421
2020–21		450	471	421
Average annual growth	**5.9%**	**2.6%**	**2.6%**	**1.9%**

3.8.4 Victoria

Table 3-28 presents actual, medium, high and low growth projections of non-scheduled generation capacity and energy for Victoria.

Table 3-29 presents projections of the contribution to the summer MD from Victorian non-scheduled generation.

Energy supplied by non-scheduled generating units is projected to grow over the next 10 years at an annual average rate of 1.9% (under all economic scenarios), compared with historical growth of 37.4%.

The current projections are based on new proposed project assessments, which assume a small amount of additional non-scheduled wind generation, with the majority of new wind generation expected to register as semi-scheduled or scheduled generation.

The estimates of other new non-scheduled generation types have also been revised down based on more recent information about proposed projects.

Table 3-28 — Victorian projections of non-scheduled generation capacity and energy

	Actual Capacity (MW)	Actual Energy (GWh)	Medium Capacity (MW)	Medium Energy (GWh)	High Capacity (MW)	High Energy (GWh)	Low Capacity (MW)	Low Energy (GWh)
2005–06	349	355						
2006–07	352	417						
2007–08	353	399						
2008–09	809	620						
2009–10	828	735						
2010–11 (estimate)	707	1,737						
2011–12			748	1,828	748	1,828	748	1,828
2012–13			748	1,828	748	1,828	748	1,828
2013–14			774	1,896	774	1,896	774	1,896
2014–15			775	1,898	775	1,898	775	1,898
2015–16			876	2,164	876	2,164	876	2,164
2016–17			876	2,164	876	2,164	876	2,164
2017–18			876	2,164	876	2,164	876	2,164
2018–19			876	2,164	876	2,164	876	2,164
2019–20			876	2,164	876	2,164	876	2,164
2020–21			876	2,164	876	2,164	876	2,164
Average annual growth	**15.2%**	**37.4%**	**1.8%**	**1.9%**	**1.8%**	**1.9%**	**1.8%**	**1.9%**

Table 3-29 — Victorian projections of the non-scheduled generation contribution to summer maximum demand (MW)

	Actual	Medium	High	Low
2005–06	58			
2006–07	72			
2007–08	60			
2008–09	57			
2009–10	225			
2010–11	76			
2011–12		82	82	82
2012–13		82	82	82
2013–14		84	84	84
2014–15		84	84	84
2015–16		92	92	92
2016–17		92	92	92
2017–18		92	92	92
2018–19		92	92	92
2019–20		92	92	92
2020–21		92	92	92
Average annual growth	**44.6%**	**1.3%**	**1.3%**	**1.3%**

3.8.5 South Australia

Table 3-30 presents actual, medium, high and low growth projections of non-scheduled generation capacity and energy for South Australia.

Table 3-31 presents projections of the contribution to the summer MD from South Australian non-scheduled generation.

Energy supplied by non-scheduled generating units is projected to increase over the next 10 years at an annual average rate of 1.7% (under all economic scenarios), compared with historical growth of 3.9%.

The current South Australian projection predicts fewer new non-scheduled generation installations. Based on new proposed project assessments, the projections assume a small amount of additional non-scheduled wind generation, with the majority of new wind generation expected to register as semi-scheduled or scheduled generation.

Table 3-30 — South Australian projections of non-scheduled generation capacity and energy

	Actual Capacity (MW)	Actual Energy (GWh)	Medium Capacity (MW)	Medium Energy (GWh)	High Capacity (MW)	High Energy (GWh)	Low Capacity (MW)	Low Energy (GWh)
2005–06	517	887						
2006–07	517	1,010						
2007–08	517	1,078						
2008–09	554	1,172						
2009–10	449	1,079						
2010–11 (estimate)	449	1,075						
2011–12			481	1,211	481	1,211	481	1,211
2012–13			489	1,246	489	1,246	489	1,246
2013–14			489	1,246	489	1,246	489	1,246
2014–15			497	1,268	497	1,268	497	1,268
2015–16			528	1,403	528	1,403	528	1,403
2016–17			528	1,403	528	1,403	528	1,403
2017–18			528	1,403	528	1,403	528	1,403
2018–19			528	1,403	528	1,403	528	1,403
2019–20			528	1,403	528	1,403	528	1,403
2020–21			528	1,403	528	1,403	528	1,403
Average annual growth	**-2.8%**	**3.9%**	**1.0%**	**1.7%**	**1.0%**	**1.7%**	**1.0%**	**1.7%**

Table 3-31 — South Australian projections of the non-scheduled generation contribution to summer maximum demand (MW)

	Actual	Medium	High	Low
2005–06	92			
2006–07	210			
2007–08	143			
2008–09	136			
2009–10	62			
2010–11	50			
2011–12		66	66	66
2012–13		70	70	70
2013–14		70	70	70
2014–15		70	70	70
2015–16		86	86	86
2016–17		86	86	86
2017–18		86	86	86
2018–19		86	86	86
2019–20		86	86	86
2020–21		86	86	86
Average annual growth	**-11.5%**	**3.0%**	**3.0%**	**3.0%**

3.8.6 Tasmania

Table 3-32 presents actual, medium, high and low growth projections of non-scheduled generation capacity and energy for Tasmania.

Table 3-33 presents projections of the contribution to the summer MD from Tasmanian non-scheduled generation.

Energy supplied by non-scheduled generating units is projected to increase over the next 10 years at an annual average rate of between (zero) 0.0% and 6.4% (depending on economic scenario), compared with historical growth of 6.6%.

Historical growth was mostly driven by increases in small hydroelectric capacity. Future growth is expected to be low, with the majority of new wind generation expected to register as semi-scheduled or scheduled generation.

Table 3-32 — Tasmanian projections of non-scheduled generation capacity and energy

	Actual Capacity (MW)	Actual Energy (GWh)	Medium Capacity (MW)	Medium Energy (GWh)	High Capacity (MW)	High Energy (GWh)	Low Capacity (MW)	Low Energy (GWh)
2005–06	243	759						
2006–07	243	616						
2007–08	248	748						
2008–09	257	885						
2009–10	257	926						
2010–11 (estimate)	257	1,043						
2011–12			257	1,043	257	1,043	257	1,043
2012–13			257	1,043	257	1,043	257	1,043
2013–14			257	1,043	257	1,043	257	1,043
2014–15			257	1,043	257	1,043	257	1,043
2015–16			257	1,043	257	1,043	257	1,043
2016–17			257	1,043	257	1,043	257	1,043
2017–18			257	1,043	257	1,043	257	1,043
2018–19			257	1,043	445	1,824	257	1,043
2019–20			257	1,043	445	1,824	257	1,043
2020–21			257	1,043	445	1,824	257	1,043
Average annual growth	**1.1%**	**6.6%**	**0.0%**	**0.0%**	**6.3%**	**6.4%**	**0.0%**	**0.0%**

Table 3-33 — Tasmanian projections of the non-scheduled generation contribution to winter maximum demand (MW)

	Actual	Medium	High	Low
2006	96			
2007	108			
2008	199			
2009	83			
2010	100			
2011	75			
2012		75	75	75
2013		75	75	75
2014		75	75	75
2015		75	75	75
2016		75	75	75
2017		75	75	75
2018		75	75	75
2019		75	241	75
2020		75	241	75
2021		75	241	75
Average annual growth	**-4.8%**	**0.0%**	**13.9%**	**0.0%**

3.9 Demand-side participation results

Table 3-34 shows the estimated committed and non-committed historical demand-side participation (DSP) results from the 2011 DSP survey. For information about the DSP survey process in 2011, see Section 3.10.10.

Table 3-34 — Estimated historical DSP (MW)

Region	2010 ESOO		2011 ESOO	
	Committed	Non-Committed	Actual Occurrence	Maximum Available
Queensland	31	140	58	58
New South Wales	68	303	69	95
Victoria and South Australia	32	145	80	90
Tasmania	0	0	0	0

Table 3-35 shows the results of the 2011 DSP survey regarding the amount of DSP available for the 2011–12 summer season.

Table 3-35 — DSP available for the 2011–12 summer (MW)

	Very Likely	Even Chance	Very Unlikely
Queensland	25	58	58
New South Wales	29	69	95
Victoria and South Australia	88	100	128
Tasmania	0	0	0

Table 3-36 shows future growth scenarios for DSP. The medium growth scenario is based on the 'very likely' amounts shown in Table 3-35, with percentage increases for small loads expected to grow in line with projected regional load growth. This does not include the DSP from large industrial loads included in Table 3-35, which are expected to remain static. The high growth scenario shows a significant increase in growth rate compared with the medium growth scenario, while in the low growth scenario, DSP generally remains unchanged.

Table 3-36 — Future scenarios for DSP (annual growth)

	Medium	High	Low
Queensland	3.7%	6.6%	0.0%
New South Wales	3.2%	5.8%	0.0%
Victoria and South Australia	5.4%	8.4%	2.1%
Tasmania	0.0%	0.0%	0.0%

3.10 Process and methodology

This section provides a description of the process and methodology used to develop the energy and MD projections. Particular details of the approaches used for individual regions are available in the APR or supply-demand outlook for each region.

Application to the supply-demand balance

This chapter focuses on projections of underlying electricity use, based on patterns of economic behaviour and allowing for specific local investment plans. As a result, energy and demand from all sources of supply are considered.

The supply-demand outlook, however, only focuses on the generation capacity needed for dispatch in the NEM, along with committed levels of DSP. Dispatchable generating units are registered with AEMO as either scheduled or semi-scheduled. Non-dispatchable generating units include those registered as non-scheduled (such as some wind farms commissioned prior to 2011) and generating units that are exempt from registration (such as rooftop solar photovoltaic panels). As a result, the energy and MD projections require some adjustment before being used to generate the supply-demand outlook, which uses:

- the regional 10% POE MD projections supplied by scheduled and semi-scheduled generating units (see Appendix A), and
- committed DSP projections (see Section 3.9).

3.10.1 Sources of the energy and maximum demand projections

Table 3-37 lists the energy and MD projection provider for each region. The projections for Victoria and South Australia were developed by AEMO with the assistance of the National Institute of Economic and Industry Research (NIEIR) and Monash University. The projections for New South Wales (including the Australian Capital Territory), Queensland, and Tasmania were provided by the respective JPBs and were either developed in-house or with the assistance of consultants contracted directly to the JPBs.

Table 3-37 — Provision of the energy and maximum demand projections

Region	Responsibility for Projections
Queensland	Powerlink
New South Wales and the Australian Capital Territory	TransGrid
Victoria and South Australia	AEMO
Tasmania	Transend

3.10.2 Scenario construction

The projections were developed on the basis of medium, high, and low economic growth scenarios. These scenarios reflect different population, economic growth, price and other input assumptions provided by KPMG.[12] KPMG's economic scenarios were designed to be consistent with the energy market scenarios developed jointly by AEMO, the Department of Resources, Energy and Tourism (DRET), and an industry Stakeholder Reference Group (SRG).[13,14] KPMG focussed on the economy-wide aspects of the scenarios (rather than the energy market specifically) to develop growth scenarios based on three broad factors:

- The strength of global economic growth and the resulting demand for Australian commodity exports and the transfer of the benefits of technological innovation.
- The strength of Australian population growth.
- The assumed carbon dioxide equivalent (CO2-e) emissions targets and related carbon-price trajectories associated with an emissions trading scheme.

Treatment of long-term climate change

Rising temperature trends over at least the last 50 years are readily observable (as shown in Figure 3-21) and similar trends may continue in the future[15], and accurately projecting energy and MD with conventional models becomes problematic for two reasons.

Firstly, the historical temperature trend means that any analysis based on the raw data will produce different results, depending on the time period used for analysis.

Secondly, future projections that include a temperature assumption will vary according to the precise nature of that assumption. The projections presented in this chapter have addressed these two problems by:

- making allowances for historical temperature trends, and
- projecting long-run historical temperature trends into the future.

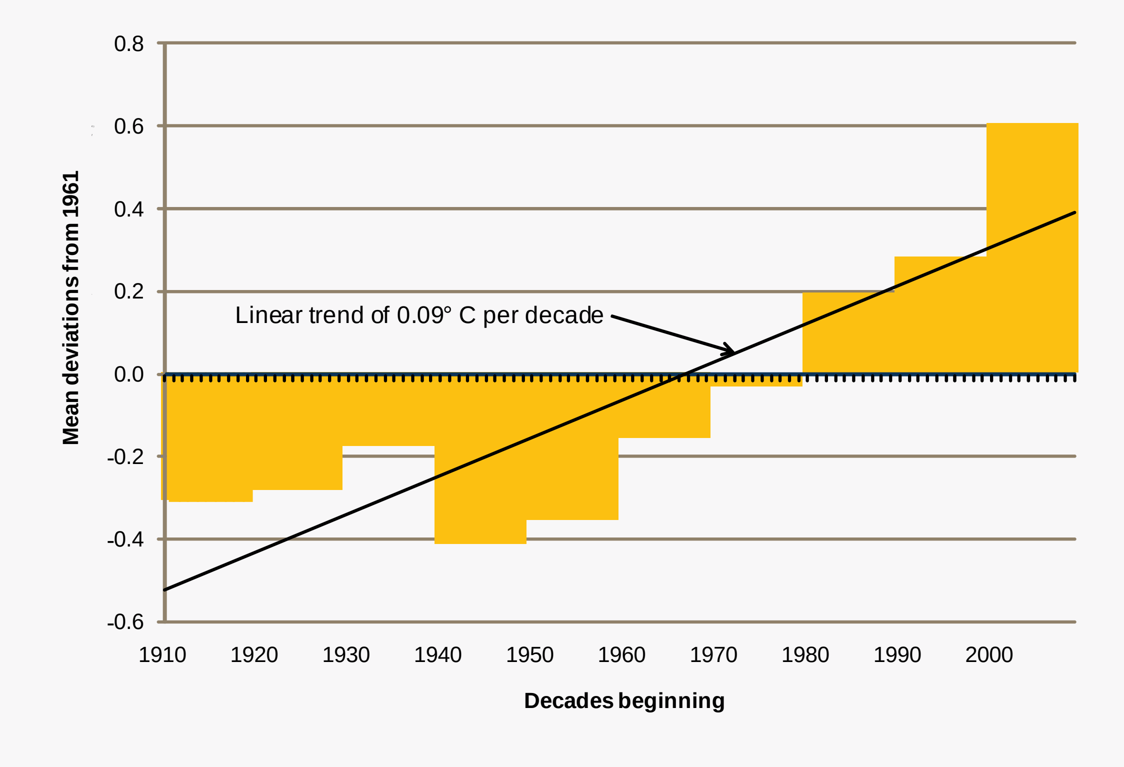
[12] KPMG. "Stage 2 Report – Economic Scenarios and Forecasts 2010-11 to 2034-35. Report to AEMO". April 2011.

[13] The SRG included industry experts with diverse experience and interests. The input of the group after several discussions was synthesised into a report by McLennan Magasanik Associates. This report was approved by the SRG and has been accepted by AEMO and DRET as a common strategic framework for long-term energy modelling.

[14] McLennan Magasanik Associates. "Future Developments in the Stationary Energy Sector: Scenarios for the Stationary Energy Sector 2030. Report to AEMO/DRET". October 2009.

[15] The trend shown in Figure 3-21 is representative of Eastern Australia as a whole. Individual forecasters used temperature measures and trends associated with their respective regions.

Figure 3-21 — Decade-average temperature (Eastern Australia)



3.10.3 Demand-side participation

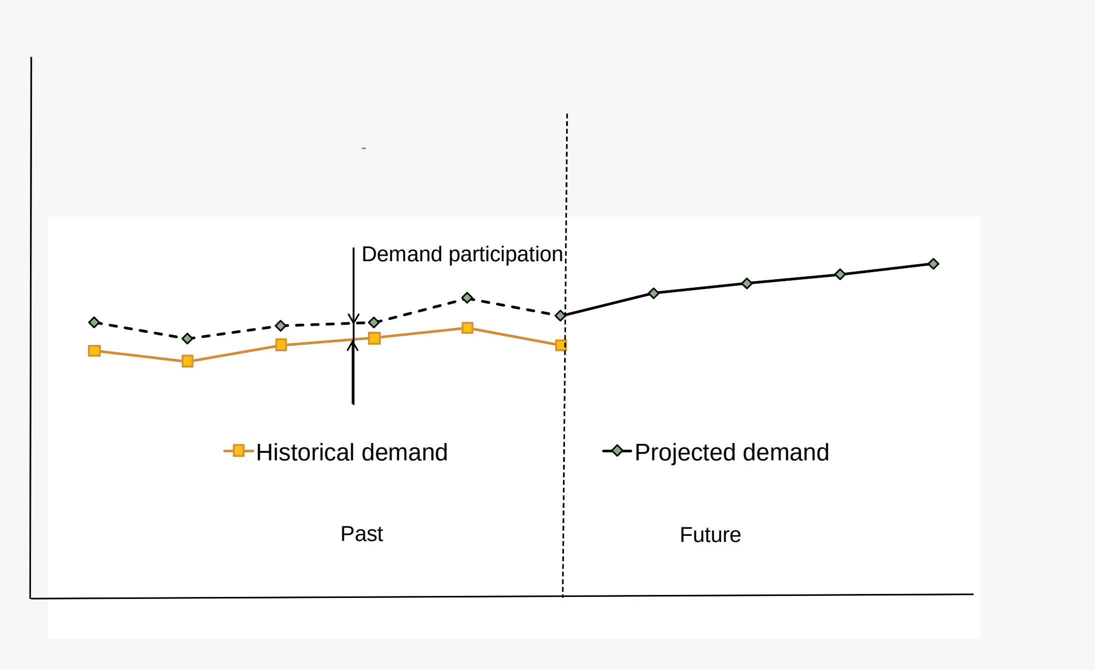
DSP includes all short-term reductions in demand in response to temporary price increases (in the case of retailers and customers) or adverse network loading conditions (in the case of networks). An organised, aggregated response may also be possible. From the perspective of the transmission network, consumers may effectively reduce demand by turning off electricity-using equipment or starting up on-site generators.

AEMO conducted a survey of stakeholders to ascertain potential DSP sites and future DSP opportunities. The results of the survey form the basis of AEMO's regional estimates of historical and projected DSP. For the survey results for each region, see Section 3.9. For a description of the survey itself, see Section 3.10.10.

3.10.4 Treatment of demand-side participation in the maximum demand projections

Figure 3-22 shows how DSP is treated by the demand projections. Historical DSP is added to recorded demand levels as a demand correction, returning it to levels that would have occurred without the economic decision for interruption by the retailer or customer. This corrected figure is used to determine projected ESOO MD trends. Since the projected MDs include DSP, this DSP is then included on the supply side in the supply-demand calculator.

Figure 3-22 — Treatment of demand-side participation in the maximum demand projections



3.10.5 Overall AEMO load forecasting process

The projections for each region were prepared separately, with each contributing organisation applying its own approach, but using consistent definitions and input assumptions.

To support this process, AEMO convened the Load Forecasting Reference Group (LFRG) to coordinate the process, and engaged KPMG as an independent service provider.

The LFRG is made up of the forecasters responsible for the projections in each region and is convened by AEMO. The main objectives of the LFRG are to achieve:

- consistent delivery outputs
- consistent definitions and input assumptions
- delivery of the projections in time for the ESOO, and
- continuous improvement of the load forecasting process.

The LFRG also acts as forum for the resolution of national load forecasting issues.

KPMG provided information to AEMO and each JPB about future energy policy developments, demographic and economic conditions, and growth in non-scheduled generation.

3.10.6 Factors influencing the demand for electricity

This section describes the series of broad factors that are considered significant when developing the long-term regional energy and MD projections.

Demographic and economic influences

Growth in electricity consumption in the longer term is primarily driven by demographic and economic considerations. Key long-term economic drivers include:

- population growth, both as a direct driver of residential demand and as an indirect driver of GDP
- economic activity, affecting both the demand for energy generally as well as electricity usage
- the electricity intensity of the economy, which reflects income level, industry structure, technology, energy prices, and climatic conditions
- electricity prices, particularly in relation to prices of substitute sources of energy, which primarily reflect available fuel sources and technology for generation
- technological change (including more efficient appliances and the potential widespread use of plug-in electric vehicles), and
- domestic non-energy government policies, including government fiscal policy, which can influence the level of economic activity.

Energy sector policy influences

Possible energy sector policy developments that have a significant impact on demand growth include:

- carbon pricing
- incentives for renewable energy under national renewable energy targets, and
- measures to improve the energy efficiency of appliances and buildings, as well as potentially increasing levels of DSP (including the Minimum Energy Performance Standards).

Weather-related, seasonal and large industrial influences

In the short term, considerable variation in demand for electricity occurs around the long-term growth trend. These variations are strongly related to changing weather conditions, but also display predictable seasonal, daily, and hourly patterns.

Certain large industrial and mining projects can also be identified and accounted for directly in the energy and MD projections.

Maintaining energy and maximum demand projection consistency

To ensure that the policy and economic basis for the energy and MD projections is consistent, AEMO engaged KPMG to prepare a series of reports to derive input variable values for the regional projections of energy and MD and to specify projected regional capacity of significant non-scheduled generating units.

For more information about these reports and the policy and economic outlooks considered by AEMO and the JPBs when preparing the projections, see Appendix C.

3.10.7 Summary of projection approaches

The following descriptions of demand projections are based on those provided by the JPBs.

Powerlink Queensland (Queensland)

The following description of demand projections were provided by the JPBs. Powerlink Queensland developed energy and MD projections for Queensland by aggregating the forecasts produced by the distribution network service providers (DNSPs) and major industrial customers in that region. Powerlink also engaged NIEIR to develop modelled projections for Queensland with reference to the common KPMG reports as inputs. Powerlink then reconciled the aggregated DNSP projection with the modelled NIEIR projection.

Queensland DNSPs produce 'most likely' energy and summer and winter MD forecasts for each connection supply point in Powerlink's transmission network. Powerlink aggregated these individual connection supply point forecasts into forecasts for the total Queensland region using network loss and diversity factors, where necessary, observed from historical trends.

NIEIR provided an independent assessment of energy and demand forecasts for Queensland and for broad areas within Queensland. These forecasts were consistent with KPMG forecasts of Queensland GSP, population, dwelling stock and levels of embedded generation. NIEIR also accounted for expected major new industrial and mining developments, and the expected impact of carbon pricing. Unlike the distributor forecasts, the NIEIR MD projections are provided in the form of 90%, 50%, and 10% POE projections, based on temperature sensitivities throughout Queensland.

The reconciliation process matches the distributor 'bottom up' forecast with NIEIR's 'top down' approach. This involves discussing any material differences with the distributors and bringing them into line with the NIEIR projection by appealing to the historical record or recent material changes to the economic outlook or other input assumptions.

Details of Powerlink's load forecasting process are published in the Queensland Annual Planning Report.[16]

TransGrid (New South Wales)

TransGrid developed its own energy and MD projections for New South Wales (including the Australian Capital Territory). The projections depend on the interaction of four separate TransGrid models, with inputs supplied from the KPMG reports, which are common to all regions.

The energy model is an estimated econometric model using monthly demographic, income, price, and weather-dependent variables.

The weather correction model uses an estimated model of half-hourly historical demands with long-run trend, periodic, and weather-related dependent variables. Weather variables are de-trended to account for historical trends. The model is used to simulate a number of different outcomes, using block re-sampling, in order to determine a probability distribution of the summer and winter MDs for all historical years in the sample. The resulting probability distributions reflect a range of possible weather patterns and random model residuals. The 90th, 50th and 10th percentile of each distribution (90%, 50%, and 10% POE) are selected as the historical series of MDs that are projected into the future using the MD models.

The MD models for summer and winter are estimated using historical MDs at the selected percentiles of the distribution. Each model relates MD to underlying energy growth using the projection from the energy model and changes in air-conditioning ownership. Future increasing temperature trends are incorporated in the projected growth trend via weather assumptions incorporated in the energy model. The three models for summer and three models for winter therefore implicitly project future MDs at their respective POE level.

TransGrid's models are generally used to predict energy and MD excluding major industrial loads, for which specific assumptions are made separately. These loads are then added back to the modelled projections.

The modelled New South Wales MD projections were reconciled with the aggregated connection point forecasts provided by the DNSPs and major industrial customers in the region.

Details of TransGrid's load forecasting models are published in TransGrid's Annual Planning Report.[17]

16 See note 3 in this chapter.

17 See note 1 in this chapter.

AEMO (Victoria)

AEMO engaged the NIEIR to prepare energy and MD projections for Victoria using inputs from the KPMG reports, which are common to all regions.

NIEIR's Victorian electrical energy forecasting model determines consumption for a number of individual industry categories. The projections are based on econometric models that link Victorian electricity sales by industry to real output growth by industry, electricity prices, and weather conditions. Residential sales are determined from another model that is based on average consumption per dwelling, with real income, electricity prices, and weather as dependent variables. The Victorian energy projections are based on the sum of each industrial and residential sector, with appropriate allowances for losses.

Victorian summer and winter MD projections were produced using NIEIR's half-hourly PeakSim model. While non-weather dependent demand is also accounted for by NIEIR, the core of the PeakSim model is the strong relationship between demand and prevailing weather. Other contemporaneous influences and underlying drivers of demand are built on and around this relationship, including the regular time-varying component of demand, based on routine consumer behaviour, and the fundamental contribution to weather-varying demand of the stock of cooling equipment such as refrigerators and air conditioners.

The Victorian MD projections are developed by NIEIR using a number of simulated demand projections using different synthetic weather and random model residual inputs, as well as fixed projected energy growth trend and air-conditioning sales assumptions.

NIEIR's models are generally used to predict energy and demand excluding major industrial loads, for which specific assumptions are made separately. These loads are then added back to the modelled projections.

The modelled Victorian MD projections were reconciled with the aggregated connection point forecasts provided by the DSNPs and major industrial customers in the region.

Details of AEMO's load forecasting process for Victoria are published in the Victorian Annual Planning Report.[18]

AEMO (South Australia)

AEMO prepared energy and MD projections for South Australia using models developed by Monash University, and economic assumptions provided by the common KPMG reports.

There are a number of key features of the forecasting approach used by AEMO for South Australia.

A semi-parametric additive model is used to estimate the relationship between half-hourly South Australian electricity demand and its driver variables, which include temperatures measured at two sites in Adelaide, calendar and other time-of-year effects, demographic variables, and economic variables. The model is described in detail in Hyndman (2007).[19]

The model has an annual component, which uses demographic, economic, and climate variables, and a half-hourly component, which uses calendar and time-of-year variables, together with a range of short-term temperature measures. Separate half-hourly models are estimated for each half hour of the day.

The models are used in conjunction with forecasts of the economic driver variables and simulated half-hourly temperatures to forecast the probability distribution of summer and winter MD in future years. Forecasts for 90%, 50%, and 10% POE levels are then identified from these distributions. Forecasts of the annual energy requirement are calculated as the integral of a half-hourly demand trace for a particular year.

18 See note 2 in this chapter.

19 Hyndman, R.J. "Extended Models for Long-Term Peak Half-hourly Electricity Demand for South Australia". Available http://www.esipc.sa.gov.au/site/page.cfm?u=287. 22 May 2007.

The variable selection process used to establish the models was based on out-of-sample forecasting performance. Variables considered for possible use included population, household size, number of households, inflation and interest rates, South Australian GSP, household disposable income, an index of the stock of air conditioning capacity, and average retail electricity prices. The best forecasting model was found to include per capita demand and GSP, average retail price lagged by one year, and summer cooling-degree days.

The temperature simulation process allows for climate change, with adjustments based on CSIRO modelling of future increases in South Australian temperature. The shifts in temperature until 2030 are predicted by CSIRO to be 1.5 °C, 0.9 °C, and 0.3 °C at the ninetieth, fiftieth, and tenth percentiles, respectively.

The modelling process also allows for a random component of half-hourly demand, with model residuals re-sampled as part of the demand simulation process. Prior to re-sampling, model residuals are adjusted for bias found to be present in the unadjusted residuals, with the aim being to accurately capture the upper tail of the maximum demand distribution.

Major industrial loads are treated separately within this modelling framework, with forecasts of the maximum and average level of demand based on project-specific advice provided by South Australian DNSPs. This information is used to create probability distributions of major industrial demands in future years, with random samples drawn from these distributions and incorporated into the simulated demand traces for the region as a whole.

Details of AEMO's load forecasting process for South Australia are published in the SASDO.[20]

Transend Networks (Tasmania)

Transend Networks engaged NIEIR to develop energy and MD projections for Tasmania, consistent with the inputs described in the common KPMG reports.

NIEIR's Tasmanian electrical energy forecasting model determines consumption for a number of individual industry categories. The projections are based on econometric models that link Tasmanian electricity sales by industry to real output growth by industry, electricity prices, and weather conditions. Residential sales are determined from another model that is based on average consumption per dwelling, with real income, electricity prices, and weather as dependent variables. The Tasmanian energy projections are based on the sum of each industrial and residential sector, with appropriate allowances for losses.

Forecasts of summer and winter MDs for Tasmania were developed using econometric relationships. These relationships relate the ratio of MD to energy and average temperature at the time of MD. The Tasmanian summer and winter MD, energy, and weather condition relationship estimates excluded the impact of the top four major industrial customers, which are assumed to be weather insensitive.

A detailed analysis of temperature data for Tasmania for the last 50 years was used to determine the probabilities of alternative winter and summer temperatures. In the NIEIR models, daily electricity MD in summer and winter depends on an average temperature calculated using the ambient minimum temperature:

- during the current day, and
- on the previous day.

The average temperature is defined as the weighted average of the overnight minimum and the previous daily maximum, using weightings of 0.8 and 0.2, respectively. Tasmanian MDs typically occur around 9:00 AM.

All percentile calculations are based only on average temperature, since this is found to be the most important influence on demand variability. Other weather variables, such as humidity, rainfall, and wind were not considered in the POE calculations for Tasmania. The probabilities were calculated excluding weekends and summer holidays but including a warming trend.

NIEIR's models are generally used to predict energy and demand excluding major industrial loads, for which specific assumptions are made separately. These loads are then added back to the modelled projections.

[20] See note 5 in this chapter.

The modelled Tasmanian MD projections were reconciled with the aggregated connection point forecasts provided by DNSPs and major industrial customers in the region.

Details of Transend's load forecasting process are published in the Tasmanian Annual Planning Report.[21]

3.10.8 Own price and income elasticities of demand for electricity

The own price elasticity of electricity demand is defined as the proportional change in electricity consumed in response to a unit change in the price. As with most goods and services, the own price elasticity of electricity is negative, because an increase in price results in a decrease in consumption.

The income elasticity of electricity demand is defined as the proportional change in electricity consumed in response to a unit change in the income of consumers. For example, higher income in aggregate is associated with higher electricity consumption in a region, so the income elasticity is positive.

Elasticity is a proportional measure and may therefore be compared across different products or in different regions. Estimates of elasticities are imprecise, however, and may vary according to the source and methodology adopted, because the:

- consumer response may change over time
- estimated linear response may be a simplified representation of the true, non-linear response, and
- impact of the independent variable (e.g. electricity price) may be imperfectly isolated from the impact of other included or omitted variables.

Different classes of consumers will have different responses to price and income changes. Therefore each region's average elasticity is expected to be different in line with differences in the structure of each regional economy.

Table 3-38 lists the estimates of own price and income elasticity for each region. These latest estimates:

- derive from the forecasting models used to develop the energy and MD projections, and
- in most cases are supported by literature reviews of previous estimates.

See the regional annual planning reports and the SASDO for more information.

Table 3-38 — Long-run price elasticity estimates

Region	Own Price Elasticity	Income Elasticity
Queensland	-0.29	N/A.
New South Wales	-0.16	0.67
Victoria	-0.38	1.15
South Australia	-0.25	1.01
Tasmania	-0.23	N/A.

3.10.9 Variation of demand and calculation of reference temperatures

TransGrid and AEMO (for Victoria and South Australia) use simulation procedures to determine MDs at the given 90%, 50%, and 10% POE levels. This means that New South Wales, Victorian, and South Australian MDs are not linked by the projection methodology to unique temperature events.

However, Powerlink and Transend use techniques that require the prior analysis of historical data to determine those temperatures that are uniquely associated with 90%, 50%, and 10% POE MDs. Table 3-39 and Table 3-40 list the temperatures used to prepare the MD projections for Queensland and Tasmania.

[21] See note 4 in this chapter.

Table 3-39 — Queensland daily average temperatures at associated POE levels (°C)

POE	NQ Non-Industrial (Townsville)	CQ Non-Industrial (Rockhampton)	SWQ (Toowoomba)	SEQ Brisbane (Archerfield)
10% summer	32	32.6	29	30.5
50% summer	30.4	30.7	27	28.4
90% summer	29.8	29.3	25.3	27.3
10% winter	25.7	10.2	4.7	9.6
50% winter	24.2	11.6	6	10.9
90% winter	23.2	12.9	7	12.3

Table 3-40 — Tasmanian daily average temperatures at associated POE levels (°C Hobart)

POE	Summer	Winter
10%	7.7	1.2
50%	9.3	2.4
90%	10.3	3.4

3.10.10 Demand-side participation survey and analysis of results

DSP refers to measures of short-term, market-driven demand reductions that AEMO includes in the supply-demand outlook. DSP has been established for a number of years by surveying demand response aggregators, network service providers (NSP), retailers and other market customers. The survey respondents were asked for confidential DSP MW values that could be regarded as 'committed' or 'non-committed'. These amounts were then aggregated to create regional totals.

The annual procedure involved the following steps:

1. Specific National Metering Identifiers (NMIs) were collected by surveying demand response aggregators, NSPs, retailers, and other market customers. The NMIs collected were those of direct market customers, price-responsive retail customers, and those with specific demand-response arrangements, including network support agreements.
2. The energy data associated with the NMIs was aggregated for each region for the period January 2008 to March 2011. Each regional energy series was then tested for its empirical relationship with extreme prices, using a price function equal to the NEM market price above $100 or else zero. Non-price related movements in the energy series, including regular time-varying movements, were simultaneously accounted for.
3. The estimated energy-price relationships were used to predict the energy series for each region on the basis of the NEM prices that actually occurred over the historical reference period. An alternative prediction was also prepared using a constant zero-price scenario.
4. For each region, the difference between the above two predictions at critical times was defined as historical 'committed' DSP. 'Maximum potential' DSP was defined as the total identified price-responsive load. 'Non-committed' DSP was the difference between maximum potential and committed DSP.
5. Future DSP was identified by aggregating the amounts nominated by the same survey respondents who supplied the NMIs. These amounts were placed by the respondents into one of three categories: 'very likely', 'even chance', or 'extremely unlikely'. Medium, high, and low DSP scenario projections were generated based on the 'very likely' DSP starting-year amounts. These DSP projections should be regarded as being aligned with previously advised 'committed' DSP amounts.

For information about estimated historical DSP and projected future values for each region, see Section 3.9.

3.11 Assessment of forecasting performance

3.11.1 Introduction

In recent years, scrutiny of the energy and MD projections produced by AEMO and the JPBs has increased. While economic uncertainty and natural disasters account for some variance between the projections and the actual outcomes, AEMO is taking steps to provide participants with more information and greater transparency of the methodologies and assumptions made in the creation of demand forecasts.

Part of this process is a review of the accuracy of recent projections, which has highlighted the need for further work in understanding the changing nature of customer demand. AEMO was and will continue to work with industry to improve demand forecasting in the NEM. A starting point for this process was the creation of an alternative energy demand forecast for the Queensland region, aimed at providing a better understanding of demand in the region with the highest forecast growth rate.

3.11.2 Energy and MD projection review

In 2010–11, NEM-wide energy was 4.2% lower than projected in the 2010 ESOO. This was mainly driven by the variances experienced in New South Wales and Queensland, with a major factor attributed to natural disasters and slower-than-projected economic growth.

Each year the Load Forecasting Reference Group (LFRG) undertakes an assessment of the accuracy of the previous year's annual energy projections (published each year in Appendix B). Table 3-41 summarises the results from the most recent review involving projections for the past three years.

Table 3-41 — Annual energy projection variance

Region	Year	Source	Energy Projection (GWh)	Actual Energy (GWh)	Projected/ Actual Variance
NEM-wide	2008–09	2008 ESOO	198,465	198,295	-0.1%
	2009–10	2009 ESOO	198,716	198,023	-0.3%
	2010–11	2010 ESOO	205,034	196,440	-4.2%
	2011–12	2011 ESOO	202,598		
Queensland	2008–09	2008 ESOO	52,194	50,137	-3.9%
	2009–10	2009 ESOO	51,503	50,866	-1.2%
	2010–11	2010 ESOO	53,487	48,786	-8.8%
	2011–12	2011 ESOO	52,802		
New South Wales and the Australian Capital Territory	2008–09	2008 ESOO	75,480	75,857	0.5%
	2009–10	2009 ESOO	75,470	74,955	-0.7%
	2010–11	2010 ESOO	77,720	74,902	-3.6%
	2011–12	2011 ESOO	75,735		
Victoria	2008–09	2008 ESOO	47,449	47,436	0.0%
	2009–10	2009 ESOO	46,895	47,482	1.3%
	2010–11	2010 ESOO	48,186	47,527	-1.4%
	2011–12	2011 ESOO	48,314		

Region	Year	Source	Energy Projection (GWh)	Actual Energy (GWh)	Projected/ Actual Variance
South Australia	2008–09	2008 ESOO	13,140	13,901	5.8%
	2009–10	2009 ESOO	14,145	13,873	-1.9%
	2010–11	2010 ESOO	14,307	14,030	-1.9%
	2011–12	2011 ESOO	14,543		
Tasmania	2008–09	2008 ESOO	10,202	10,964	7.5%
	2009–10	2009 ESOO	10,704	10,847	1.3%
	2010–11	2010 ESOO	11,334	11,196	-1.2%
	2011–12	2011 ESOO	11,204		

Following consecutive years where actual energy has been lower than projected, and considering NEM-wide energy is projected to increase to 202,598 GWh in 2011–12, AEMO has undertaken additional due-diligence with regard to each JPB's projections.

In Queensland, actual energy has been lower than projected for a number of consecutive years. This year, Powerlink Queensland reduced its 2011–12 energy projection by 5.0% (2,799 GWh less than 2010–11). Powerlink advises that this is mainly due to severe weather conditions and low economic growth, as well as the curtailment of mining activities due to the natural disasters experienced early in the period. Powerlink is forecasting a significant increase in demand, specifically related to LNG projects in the Surat Basin and other coal mining developments.

While Powerlink has reduced this year's 2011–12 summer 10% POE MD projection by 336 MW (or 3.1%), there is still significant uncertainty about the potential for the MD to reach the projected 10,612 MW, when the current record MD is 9,070 MW.

In New South Wales, TransGrid's 2011–12 energy projection is 5.4% lower than last year's (a difference of 4,363 GWh), due to slower-than-expected economic growth, increased penetration of rooftop solar photovoltaics, and the incorporation of other new and ongoing energy efficiency policies. TransGrid has also reduced its 2011–12 summer 10% POE MD projection by 342 MW (or 2.1%).

3.11.3 Alternative Queensland energy and maximum demand forecast

Powerlink provided the 2011 ESOO's energy and MD projections and supporting information for Queensland. As in previous years, Powerlink is projecting electricity demand growth in Queensland to be approximately double the other regions (growth of 4.1% for energy, and 4.2% for MD).

A number of industry stakeholders have approached AEMO with concerns about the Queensland projections having exceeded actual outcomes for the past five years. Given this, AEMO undertook a high-level review of historical electricity consumption trends and compared with the JPB projections, with the aim of presenting an alternative projection where considered necessary.

Energy projections, irrespective of region, rely on the assumption that future energy consumption can be predicted by estimating potential trends among related historical factors. These related historical factors tend to focus on the regional economy, and any unexpected or out-of-scope events will impact the projection's accuracy.

Queensland has suffered several unexpected natural disasters and economic events over the last five years, including the floods in Central and Southern Queensland, cyclone Yasi, the ongoing global financial crisis, and a high Australian dollar impacting tourism and manufacturing. All of these factors contribute to uncertainty surrounding both the timing and magnitude of an economic recovery, and present a considerable challenge to forecasting energy in Queensland.

To develop the alternative projection for Queensland, AEMO used energy consumption data from Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES), econometric and demographic data from the Australian Bureau of Statistics and KPMG, and information on new developments in the Queensland region provided by Powerlink. This preliminary forecast, provided below, is at this stage only a draft forecast, which AEMO aims to finalise with the help of Powerlink and other participants by the end of 2011.

Energy

Figure 3-23 shows a comparison of the two medium economic growth energy projections. Financial year 2011–12 is projected as a period of turnaround driven by a positive economic outlook, with expenditure being directed towards rebuilding the region.

Additionally, new and significant levels of energy consumption are expected from the development of new coal mining and LNG ventures by the second quarter of 2013–14.

Table 3-42 presents actual and projected energy (for the medium, high, and low growth scenarios) for Queensland. Energy is projected to increase over the next 10 years at an annual average rate of:

- 3.7% under the medium growth scenario, and
- 4.0% and 3.3% under the high and low growth scenarios, respectively.

Figure 3-23 — Queensland energy projection comparison (AEMO and Powerlink) (GWh)

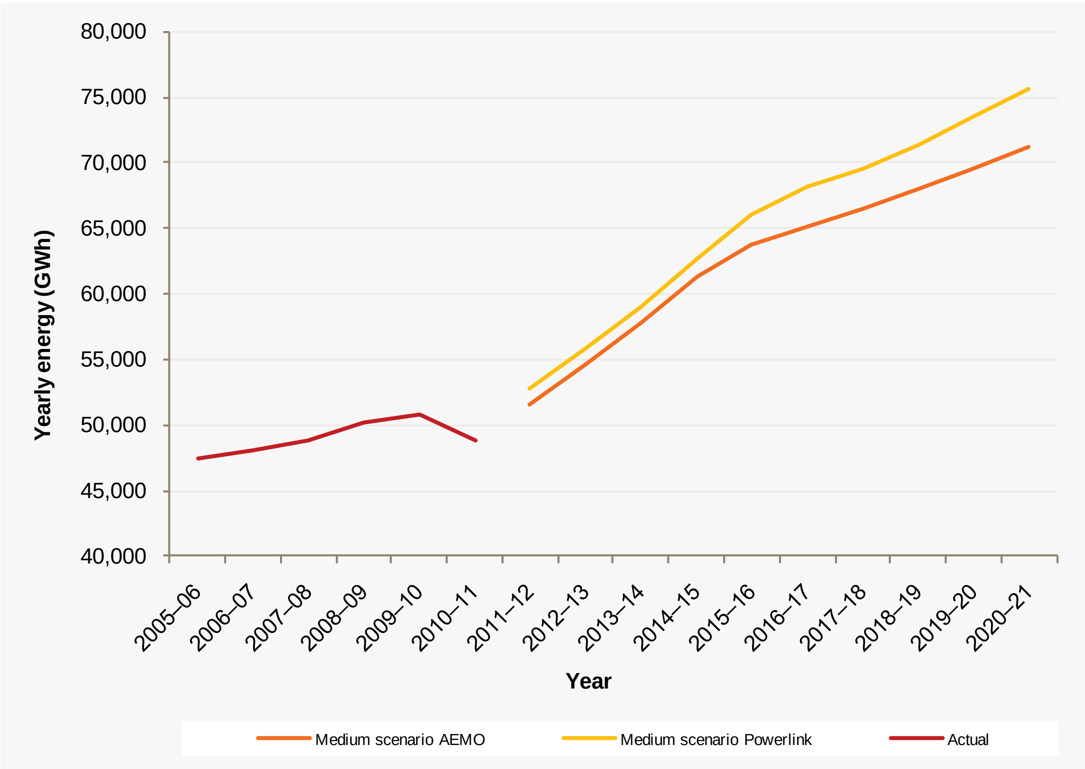


Table 3-42 — AEMO Queensland energy projections (GWh)

	Actual	Medium	High	Low
2005–06	47,384			
2006–07	48,030			
2007–08	48,831			
2008–09	50,137			
2009–10	50,866			
2010–11 (estimate)	48,786			
2011–12		51,520	51,700	51,410
2012–13		54,650	55,000	54,400
2013–14		57,760	58,280	57,400
2014–15		61,270	61,980	60,770
2015–16		63,680	64,530	63,060
2016–17		65,090	66,110	64,340
2017–18		66,550	67,780	65,580
2018–19		68,030	69,530	66,730
2019–20		69,570	71,400	67,820
2020–21		71,180	73,370	68,870
Average annual growth	**0.6%**	**3.7%**	**4.0%**	**3.3%**

Maximum demand

Figure 3-24 and Figure 3-25 show a comparison of the two medium economic growth summer 10% and 50% POE MD projections. AEMO is predicting lower MDs for both summer and winter, which are a direct result of a lower energy projection.

Table 3-43 and Table 3-44 present actual and projected summer and winter MDs for Queensland.

The summer 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 3.7% under the medium growth scenario, and
- 5.4% and 2.6% under the high and low growth scenarios, respectively.

The winter 10% POE MD is projected to increase over the next 10 years at an annual average rate of:

- 3.6% under the medium growth scenario, and
- 5.7% and 2.0% under the high and low growth scenarios, respectively.

Figure 3-24 — Queensland summer maximum demand projection (AEMO and Powerlink) (MW)

Figure 3-25 — Queensland winter maximum demand projection (AEMO and Powerlink) (MW)

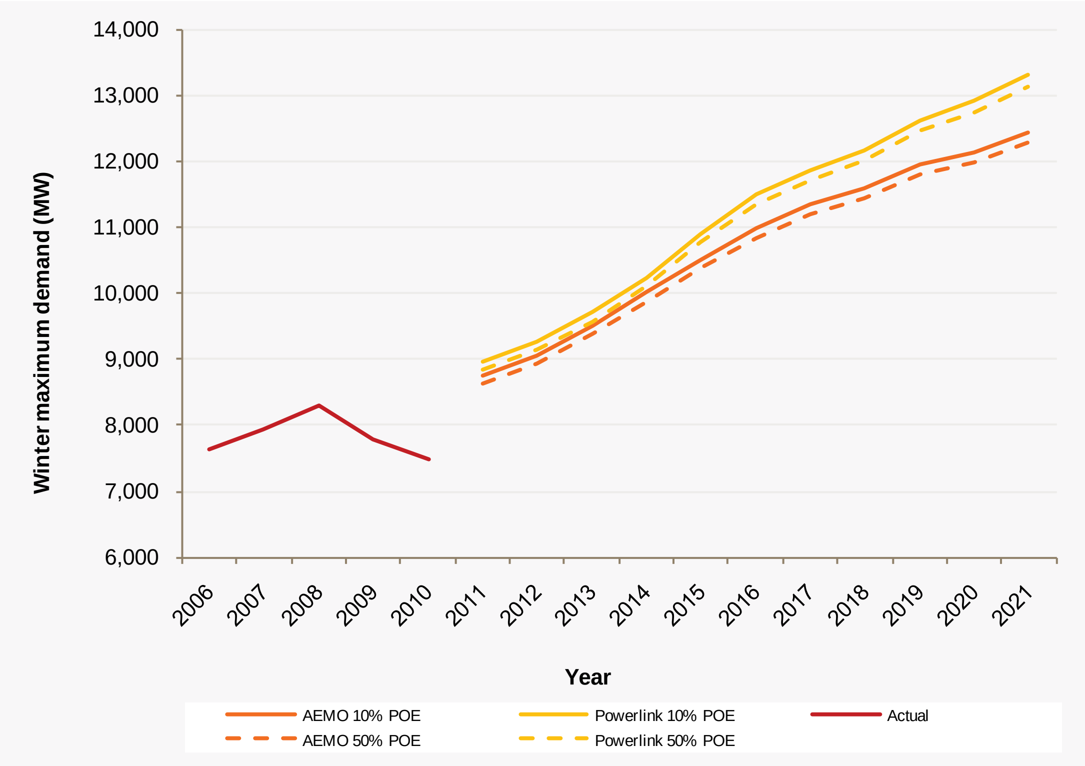


Table 3-43 — Queensland summer maximum demand projections (MW)

	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2005–06	8,280									
2006–07	8,673									
2007–08	8,197									
2008–09	8,811									
2009–10	9,070									
2010–11	8,911									
2011–12		9,557	9,679	9,457	9,858	9,984	9,755	10,354	10,487	10,246
2012–13		10,158	10,405	9,944	10,473	10,728	10,251	10,991	11,259	10,758
2013–14		10,725	11,124	10,363	11,052	11,464	10,677	11,590	12,023	11,195
2014–15		11,377	11,949	10,901	11,717	12,307	11,224	12,275	12,895	11,757
2015–16		11,798	12,529	11,211	12,146	12,901	11,538	12,718	13,511	12,078
2016–17		12,112	13,109	11,360	12,469	13,498	11,691	13,058	14,135	12,239
2017–18		12,451	13,676	11,541	12,821	14,083	11,880	13,430	14,750	12,439
2018–19		12,777	14,236	11,735	13,158	14,661	12,080	13,785	15,357	12,650
2019–20		13,107	15,189	11,895	13,501	15,633	12,247	14,149	16,361	12,829
2020–21		13,345	15,649	12,005	13,746	16,107	12,359	14,407	16,858	12,947
Average annual growth	**1.5%**	**3.8%**	**5.5%**	**2.7%**	**3.8%**	**5.5%**	**2.7%**	**3.7%**	**5.4%**	**2.6%**

Table 3-44 — Queensland winter maximum demand projections (MW)

	Actual	90% POE			50% POE			10% POE		
		Medium	High	Low	Medium	High	Low	Medium	High	Low
2006	7,628									
2007	7,924									
2008	8,312									
2009	7,774									
2010	7,483									
2011		8,467	8,622	8,343	8,633	8,791	8,507	8,748	8,909	8,621
2012		8,767	9,072	8,519	8,937	9,249	8,684	9,057	9,373	8,800
2013		9,201	9,732	8,788	9,376	9,917	8,955	9,500	10,048	9,072
2014		9,700	10,454	9,141	9,881	10,650	9,311	10,009	10,789	9,430
2015		10,194	11,175	9,492	10,379	11,379	9,664	10,510	11,525	9,784
2016		10,648	11,942	9,738	10,838	12,157	9,911	10,973	12,311	10,032
2017		11,008	12,634	9,904	11,204	12,860	10,079	11,343	13,022	10,202
2018		11,238	13,221	9,955	11,440	13,459	10,131	11,582	13,630	10,255
2019		11,588	13,914	10,084	11,796	14,165	10,263	11,944	14,346	10,389
2020		11,782	14,422	10,119	11,994	14,682	10,298	12,144	14,870	10,424
2021		12,060	14,974	10,222	12,277	15,245	10,404	12,431	15,439	10,531
Average annual growth	**-0.5%**	**3.6%**	**5.7%**	**2.1%**	**3.6%**	**5.7%**	**2.0%**	**3.6%**	**5.7%**	**2.0%**

3.11.4 AEMO's National Energy Forecasting Project

With assistance from key industry stakeholders, AEMO is planning to produce independent energy and MD forecasts for all NEM regions over the next 12 months, as part of a National Energy Forecasting Project. The draft alternative energy demand forecast for the Queensland region included in this report represents the first project deliverable.

The National Energy Forecasting Project aims to:

- improve energy forecasting through the delivery of clear, transparent, disaggregated forecasts produced via open-source models, and
- undertake coordinated research in energy consumption areas including rooftop photovoltaics, electric vehicles, price elasticity, and energy efficiency schemes.

Accurate energy and MD forecasts in the NEM are critical inputs to:

- NEM fee-setting processes
- national transmission planning
- calculation of Marginal Loss Factors (MLFs), and
- assessing power system adequacy.

More information about this project will become available as AEMO seeks expressions of interest with respect to forming an energy forecasting reference group with oversight of the project.

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CHAPTER 4 - GENERATION CAPACITIES

Summary

This chapter presents information about generation capacities in the National Electricity Market (NEM), based on the 2011 AEMO survey of NEM generators.

There are currently over 1,000 MW of committed projects across the NEM, including the Woodlawn Wind Farm (48 MW) and the Eraring Power Station upgrade (120 MW) in New South Wales, Mortlake Stage 1 project (566 MW), the Macarthur Wind Farm (420 MW) and the Oaklands Hill Wind Farm (67 MW) in Victoria, and the Hallett (The Bluff) Wind Farm (53 MW) in South Australia.

Wind projects represent the highest technology interest (by capacity), with over 15,000 MW proposed across the NEM that AEMO is aware of. Gas powered generation developments represent the second highest investment interest, with publicly announced proposals totalling over 11,000 MW spread across all regions except Tasmania.

Several solar generation publicly announced proposals are located across the NEM, and include the 250 MW Solar Dawn project in Queensland, and the 150 MW Moree project in New South Wales. Both of these projects were recently announced as successful candidates under the Australian Government's Solar Flagships program.

In this chapter, references to winter indicate the period 1 June–31 August, and references to summer indicate the period 1 November–31 March (for all regions except Tasmania), and 1 December–28 February (for Tasmania).

AEMO expects the Clean Energy Future Plan announced by the Australian Government to have little impact on the installed generation mix prior to 2015.

Financial support for the high CO2-e emitting generation that the initiatives describe is conditional upon maintaining system reliability. If a mechanism similar to the original Carbon Pollution Reduction Scheme legislation is adopted, AEMO will be required to certify that the Reliability Standard will be met for two years after a proposed deregistration.

The Government has indicated that up to 2,000 MW of generation will be invited to tender for closure by 2020. The arrangement is to be negotiated during 2011–12 and will take into account AEMO's views on energy security. AEMO expects any payments for closure to occur in the second half of the decade.

Available scheduled and semi-scheduled generation capacities for 2011–12

Table 4-1 summarises the projected available scheduled and semi-scheduled generation capacity in each region to meet the projected maximum demand (MD) in summer 2011–12 and winter 2012.

Table 4-1 — Available capacities for 2011–12

Region	Summer (MW) 2011–12	Winter (MW) 2012
Queensland	12,299.7	12,533.3
New South Wales	16,875.8	16,971.8
Victoria	10,916.2	11,631.5
South Australia	3,899.0	4,414.1
Tasmania	2,304.1	2,534.2
NEM Total	46,294.8	48,084.9

4.1 Generation projects – completed and committed since 2010

Table 4-2 and Table 4-3 list the scheduled and semi-scheduled generation projects that have been completed since the 2010 ESOO.

Table 4-2 — Completed projects since 2010 – new developments

Registered Participant	Power Station	Project Capacity (MW)	Fuel/Technology
Queensland			
QGC Sales Qld	Condamine	144	Gas - CCGT
New South Wales			
Gunning Wind Energy Developments (ACCIONA Energy)	Gunning Wind Farm	47	Wind Turbine
South Australia			
AGL Hydro Partnership	Hallett 4 – North Brown Hill Wind Farm	132.3	Wind Turbine
Lake Bonney Wind Power	Lake Bonney Stage 3 Wind Farm	39	Wind Turbine
Waterloo Wind Farm	Waterloo Wind Farm	111	Wind Turbine

Table 4-3 — Completed projects since 2010 - upgrades

Registered Participant	Power Station	Project Size (MW)	Fuel/Technology
New South Wales			
Snowy Hydro	Tumut 3 – Upgrade	300[a]	Hydro
Origin Energy	Eraring – Upgrade (Unit 2 and Unit 3)	120	Steam Turbine - Black Coal
Victoria			
Loy Yang Marketing Management Company Pty. Ltd.	Loy Yang A Unit 2 - Upgrade	30	Steam Turbine - Brown Coal
South Australia			
Synergen Power	Port Lincoln – Expansion	23.5	Distillate – OCGT
TRUenergy	Hallett GT – Expansion	27.5	Gas – OCGT

a. A maximum capacity increase, the registered capacity remains unchanged.

Table 4-4 and Table 4-5 list scheduled and semi-scheduled generation projects that are currently committed.

Table 4-4 — Committed projects – new developments

Intending Participant	Power Station	Project Capacity (MW)	Fuel/Technology	Commissioning Date
New South Wales				
Woodlawn Wind Power	Woodlawn Wind Farm	48	Wind Turbine	May 2011
Victoria				
Origin Energy	Mortlake – Stage 1	566	Gas – OCGT	July 2011
Oaklands Hill Wind Farm	Oaklands Hill Wind Farm	67	Wind Turbine	September 2011
Macarthur Wind Farm Unincorporated Joint Venture	Macarthur Wind Farm	420	Wind Turbine	May 2012
South Australia				
AGL Power Generation	Hallett 5 – The Bluff Wind Farm	52.5	Wind Turbine	December 2011

Table 4-5 — Committed projects - upgrades

Registered Participant	Power Station	Project Size (MW)	Fuel/Technology	Commissioning Date
New South Wales				
Origin Energy	Eraring – Upgrade (Units 1 and 4)	120	Steam Turbine – Black Coal	2012/13

4.2 Generation capacity in the NEM

Any person who owns, controls, or operates a generating system connected to a transmission or distribution network must register as a generator. A generating system's registered capacity is the nominal megawatt (MW) capacity registered with AEMO.

The registered capacity is often the same as a generating system's nameplate capacity. The nameplate capacity represents the maximum continuous output or consumption in MW, as specified by the manufacturer, or as subsequently modified. The nameplate capacity can change for a number of reasons, such as upgrade projects, age or a review of performance.

Under the National Electricity Rules (NER), generating systems are classified as scheduled, semi-scheduled, or non-scheduled.

Scheduled (S) generation refers to any generating system with an aggregate nameplate capacity of 30 MW or more, unless classified as semi-scheduled, or AEMO is permitted to classify it as non-scheduled.

Semi-scheduled (SS) generation refers to any generating system with intermittent output (such as wind or run-of-river hydro) with an aggregate nameplate capacity of 30 MW or more. A semi-scheduled classification gives AEMO the power to limit generation output that may exceed network capabilities, but reduces the participating generator's requirement to provide information.

Non-scheduled (NS) generation refers to generating systems with an aggregate nameplate capacity of less than 30 MW and equal to or greater than 5 MW.

Generating systems greater than 30 MW may be classified as non-scheduled if:

- the primary purpose of the generating unit is for local use and the aggregate sent-out generation rarely exceeds 30 MW, or
- it is not practicable for the generating unit to participate in central dispatch.

A generating unit that has a nameplate rating less than 30 MW may also be exempted by AEMO if it exports less than 20 GWh into the grid in a year or extenuating circumstances apply.

4.2.1 Measuring generation capacity

Generation capacity can be measured as either:

- **as-generated** capacity, representing the output measured at a generating unit's terminals, or
- **sent-out** capacity, representing the output after allowing for the consumption of some energy by auxiliary equipment (used to help produce and transmit the electricity).

For more information about the basis for measuring generation, see Chapter 3, Section 3.2.1.

For the purposes of the ESOO and consistent with market systems, AEMO measures scheduled and semi-scheduled generation capacity on an as-generated basis. Non-scheduled generation is measured as sent-out because it can include co-generation plants, where the bulk of the capacity is consumed by the local process.

4.2.2 Temperature effects on generation

The actual level of generation available at any particular time will depend on the condition of the generating plant, which includes factors such as age, outages, and wear (see Section 4.2.3). Another important factor with respect to output is the reduction in thermal efficiency with increasing temperature.

Temperature can affect plant generation capacities in different ways. Basing generation capacities on a region-specific reference temperature facilitates a more effective assessment of the capability of the available generation under weather conditions frequently associated with high demand.

To produce the supply-demand outlook, AEMO in consultation with the Jurisdictional Planning Bodies (JPBs):

- uses historical data to estimate the typical weather conditions, and to determine reference temperatures that are frequently associated with times of 10% probability of exceedence (POE) maximum demand in the major load centres for each region, and
- asks generators to provide generating unit capacities for summer and winter using these common reference temperatures. Table 4-6 lists the common reference temperatures AEMO applies for each region. In general, annual maximum demands occur during summer, with the exception of Tasmania, where the maximum demand periods occur during winter. The summer maximum demands in Tasmania occur during colder temperatures, resulting in a relatively low summer reference temperature.

Table 4-6 — Generation capacity reference temperatures

Region	Summer (°C)	Winter (°C)
Queensland	37	15
New South Wales	42	9
Victoria	41	8
South Australia	43	11
Tasmania	7.7	1.2

4.2.3 Maximum capacity

Some thermal (generation that burns fuel) and non-thermal (renewable generation) generating systems can provide additional, short-term capacity that exceeds the registered capacity. This is known as maximum capacity.

4.3 Proposed generation in the NEM

In addition to capacity forecasts, generation plant owners advise AEMO about the status of generation projects currently under development in each region.

Project proposals involve a range of projects at different stages of development.

Generation is categorised as:

- existing generation, representing generation that is commissioned and operating and requires that the operator be a registered market participant
- committed projects, representing generation that is considered to be proceeding, or
- proposed projects, which are further identified as either:
  - advanced proposals, representing generation at an intermediate stage of development, or
  - publicly announced proposals, representing generation at an early stage of development.

Projects are categorised based on AEMO's commitment criteria, which cover site acquisition, contracts for major components, planning approval, financing, and the date set for construction (see Table 4-7). Committed projects meet all five of the commitment criteria, advanced proposals meet at least three, and publicly announced proposals meet less than three.

Table 4-7 — Generation project commitment criteria

Category	Criteria
Site	The project proponent has purchased/settled/acquired (or commenced legal proceedings to purchase/settle/acquire) land for the construction of the project.
Major components	Contracts for the supply and construction of the major components of plant or equipment (such as generating units, turbines, boilers, transmission towers, conductors, and terminal station equipment) have been finalised and executed, including any provisions for cancellation payments.
Planning consents/ construction approvals/EIS	The proponent has obtained all required planning consents, construction approvals, and licences, including completion and acceptance of any necessary environmental impact statements.
Finance	The financing arrangements for the proposal, including any debt plans, must have been concluded and contracts executed.
Final construction date set	Construction of the proposal must either have commenced or a firm commencement date must have been set.

Table 4-8 lists the abbreviations used throughout this chapter to identify project status.

Table 4-8 — Project status

Description	Abbreviation
Committed project	Com
Advanced proposal	Adv
Publicly announced proposal	Pub An

4.4 Queensland

4.4.1 Existing and committed scheduled and semi-scheduled generation

Table 4-9 lists the existing and committed generation in Queensland. Table 4-10 and Table 4-11 provide forecasts of scheduled and semi-scheduled available capacity for summer and winter, respectively.

These tables represent the generation data used in the supply-demand outlook (See Chapter 7). In some cases, non-scheduled generation capacities have been included, where they were treated as scheduled in the load forecasting process. For Queensland, both Callide A and Yarwun are modelled as scheduled in the supply-demand outlook.

Table 4-9 — Existing and committed scheduled and semi-scheduled generation – Queensland[1]

Power Station	Registered Participant	Units	Registered Capacity (MW)	Plant Type	Fuel Type	Dispatch Type
Barcaldine	Ergon Energy Queensland	1 x 57	55	OCGT	Natural Gas	S
Barron Gorge	Stanwell Corporation	2 x 30	60	Run of River	Water	S
Braemar 2	NewGen Braemar 2 Partnership	3 x 173	519	OCGT	Coal Seam Methane	S
Braemar	Braemar Power Project	3 x 168	504	OCGT	Coal Seam Methane	S
Callide B	CS Energy	2 x 350	700	Steam Subcritical	Black Coal	S
Callide	Callide Power Trading	2 x 420	840	Steam Supercritical	Black Coal	S
Collinsville	Stanwell Corporation	3 x 32 1 x 33 1 x 66	195	Steam Subcritical	Black Coal	S
Condamine A	QGC Sales Qld	2 x 43 1 x 57	144	CCGT	Coal Seam Methane	S
Darling Downs	Origin Energy Electricity	1 x 280 3 x 121	644	CCGT	Coal Seam Methane	S
Gladstone	CS Energy	6 x 280	1,680	Steam Subcritical	Black Coal	S
Kareeya	Stanwell Corporation	2 x 21 1 x 18 1 x 21	88	Run of River	Water	S
Kogan Creek	CS Energy	1 x 744	744	Steam Supercritical	Black Coal	S
Mackay	Stanwell Corporation	1 x 30	30	OCGT	Diesel	S
Millmerran	Millmerran Energy Trader	2 x 426	852	Steam Supercritical	Black Coal	S
Mt Stuart	Origin Energy Electricity	2 x 146 1 x 131	423	OCGT	Kerosene	S
Oakey	AGL Hydro Partnership	2 x 141	282	OCGT	Natural Gas	S

1 Queensland has no committed projects.

Power Station	Registered Participant	Units	Registered Capacity (MW)	Plant Type	Fuel Type	Dispatch Type
Roma	Origin Energy Electricity	2 x 40	80	OCGT	Natural Gas	S
Stanwell	Stanwell Corporation	4 x 350	1,400	Steam Subcritical	Black Coal	S
Swanbank B	Stanwell Corporation	2 x 125	250	Steam Subcritical	Black Coal	S
Swanbank E	Stanwell Corporation	1 x 385	385	CCGT	Natural Gas	S
Tarong	Stanwell Corporation	4 x 350	1,400	Steam Subcritical	Black Coal	S
Tarong North	Stanwell Corporation	1 x 450	443	Steam Supercritical	Black Coal	S
Wivenhoe	CS Energy	2 x 250	500	Pumped-Storage Hydroelectric	Water	S
Yabulu[a]	AGL Hydro Partnership	1 x 160 1 x 82	242	CCGT	Coal Seam Methane	S

a. Formerly known as Townsville GT.

Table 4-10 — Summer aggregate scheduled and semi-scheduled generation – Queensland (MW)

Power Station	2011 –12	2012 –13	2013 –14	2014 –15	2015 –16	2016 –17	2017 –18	2018 –19	2019 –20	2020 –21	Dispatch Type
Barcaldine	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	S
Barron Gorge	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	S
Braemar	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	S
Braemar 2	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	S
Callide A[a]	30.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	NS
Callide B	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	S
Callide C	900.0	900.0	900.0	900.0	900.0	900.0	900.0	900.0	900.0	900.0	S
Collinsville	195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0	S
Condamine A	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	S
Darling Downs	605.0	605.0	605.0	605.0	605.0	605.0	605.0	605.0	605.0	605.0	S
Gladstone	1,680.0	1,680.0	1,680.0	1,680.0	1,680.0	1,680.0	1,680.0	1,680.0	1,680.0	1,680.0	S
Kareeya	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	S
Kogan Creek	724.0	724.0	724.0	724.0	724.0	724.0	724.0	724.0	724.0	724.0	S
Mackay	27.4	27.4	27.3	27.3	27.3	27.3	0.0	0.0	0.0	0.0	S
Millmerran	856.0	856.0	856.0	856.0	856.0	856.0	856.0	856.0	856.0	856.0	S
Mt Stuart	379.2	379.2	379.2	379.2	379.2	379.2	379.2	379.2	379.2	379.2	S
Oakey	281.8	281.8	281.8	281.8	281.8	281.8	281.8	281.8	281.8	281.8	S
Roma	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	S
Stanwell	1,404.3	1,404.2	1,404.4	1,404.6	1,406.5	1,406.5	1,406.2	1,405.8	1,404.6	1,404.6	S
Swanbank B	120.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	S
Swanbank E	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	S
Tarong	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	S
Tarong North	443.0	443.0	443.0	443.0	443.0	443.0	443.0	443.0	443.0	443.0	S
Wivenhoe	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	S
Yabulu[b]	235.0	235.0	234.5	234.5	233.5	233.5	233.0	233.0	233.0	232.5	S
Yarwun[c]	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	155.0	NS
Total	**12,299.7**	**12,179.6**	**12,149.2**	**12,149.4**	**12,150.3**	**12,150.3**	**12,122.2**	**12,121.8**	**12,120.6**	**12,120.1**	

a. Callide A is now registered as non-scheduled, but is included as a scheduled generator in the supply-demand outlook.

b. Formerly known as Townsville GT.

c. Yarwun is a non-scheduled generator, but is included as a scheduled generator in the supply-demand outlook.

Table 4-11 — Winter aggregate scheduled and semi-scheduled generation – Queensland (MW)

Power Station	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Dispatch Type
Barcaldine	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	S
Barron Gorge	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	S
Braemar	504.0	504.0	504.0	504.0	504.0	504.0	504.0	504.0	504.0	504.0	S
Braemar 2	519.0	519.0	519.0	519.0	519.0	519.0	519.0	519.0	519.0	519.0	S
Callide A[a]	30.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	NS
Callide B	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	S
Callide C	900.0	900.0	900.0	900.0	900.0	900.0	900.0	900.0	900.0	900.0	S
Collinsville	195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0	195.0	S
Condamine A	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	S
Darling Downs	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	S
Gladstone	1,680.0	1,680.0	1,680.0	1,680.0	1,680.0	1,680.0	1,680.0	1,680.0	1,680.0	1,680.0	S
Kareeya	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	86.0	S
Kogan Creek	744.0	744.0	744.0	744.0	744.0	744.0	744.0	744.0	744.0	744.0	S
Mackay	31.9	31.9	31.8	31.8	31.8	0.0	0.0	0.0	0.0	0.0	S
Millmerran	856.0	856.0	856.0	856.0	856.0	856.0	856.0	856.0	856.0	856.0	S
Mt Stuart	419.0	419.0	419.0	419.0	419.0	419.0	419.0	419.0	419.0	419.0	S
Oakey	340.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0	S
Roma	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	S
Stanwell	1,466.4	1,466.3	1,466.2	1,466.1	1,468.0	1,468.5	1,469.0	1,469.6	1,468.1	1,466.5	S
Swanbank B	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	S
Swanbank E	370.0	370.0	370.0	370.0	370.0	370.0	370.0	370.0	370.0	370.0	S
Tarong	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	1,400.0	S
Tarong North	443.0	443.0	443.0	443.0	443.0	443.0	443.0	443.0	443.0	443.0	S
Wivenhoe	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	S
Yabulu[b]	244.0	243.5	243.5	243.5	243.0	243.0	243.0	243.0	243.0	242.0	S
Yarwun[c]	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	NS
Total	**12,533.3**	**12,532.7**	**12,502.5**	**12,502.4**	**12,503.8**	**12,472.5**	**12,473.0**	**12,473.6**	**12,472.1**	**12,469.5**	

a. Callide A is now a non-scheduled generator but included as a scheduled generator in the supply-demand outlook.

b. Formerly known as Townsville GT.

c. Yarwun is a non-scheduled generator but is included as a scheduled generator for the supply-demand outlook.

4.4.2 Changes since the 2010 ESOO (existing generation)

Barcaldine Power Station: Ergon Energy advises that Barcaldine has revised its available capacity from 49 MW to 34 MW (-15 MW) in summer and from 49 MW to 37 MW (-12 MW) in winter, as the steam turbine component of the closed-cycle gas turbine (CCGT) plant is no longer available for immediate use.

Callide A Power Station: CS Energy (on behalf of the Callide Oxyfuel Project Group) advises that a project is being undertaken at Callide A to trial oxy-firing technology. The available capacity at Callide A has been revised from 30 MW to (zero) 0 MW (-30 MW) from summer 2013/14 to winter 2015. Callide A's dispatch status has changed from scheduled to non-scheduled.

Mackay GT Power Station: Stanwell Corporation previously advised that Mackay GT would have a tentative retirement date scheduled for early 2016. This has been rescheduled to the end of 2016, resulting in a capacity revision from (zero) 0 MW to 32 MW in winter 2016 and (zero) 0 MW to 27 MW in summer 2016–17.

4.4.3 Committed project developments

AEMO has not been advised of any scheduled or semi-scheduled generation projects in Queensland that are currently classified as committed according to AEMO's commitment criteria.

4.4.4 Plant limitations

Tarong Power Station: Stanwell Corporation advises that Tarong will undergo the following outages:

- Unit 1 will be unavailable during:
  - winter 2012 (from 14 July 2012), and
  - summer 2016–17 (until 12 November 2016).
- Unit 2 will be unavailable during:
  - winter 2013 (from 4 August 2013), and
  - winter 2015 (from 1 August 2015 to 11 August 2015).
- Unit 4 will be unavailable during:
  - summer 2012–13 (until 24 November 2012)
  - winter 2014 (from 2 August 2014), and
  - winter 2016 (from 6 August 2016 to 16 August 2016).

Tarong North Power Station: Stanwell Corporation advises that Tarong North Power Station will undergo the following outages:

- Unit 1 will be unavailable during:
  - summer 2011–12 (until 19 November 2011)
  - summer 2013–14 (until 15 November 2011), and
  - summer 2015–16 (until 14 November 2015).

Wivenhoe Power Station: CS Energy advises that Wivenhoe Power Station will undergo the following outages:

- Unit 1 will be unavailable during:
  - winter 2012 (until 8 June 2012), and
  - winter 2014 (until 15 June 2014).
- Unit 2 will be unavailable during:
  - summer 2012–13 (until 30 November 2012)
  - winter 2013 (until 7 June 2013), and
  - winter 2016 (until 16 June 2016).

Yabulu Power Station: AGL advises that the maximum output at Yabulu (formerly called Townsville GT) varies with ambient temperature.

4.4.5 Plant retirements

Mackay GT Power Station: Stanwell Corporation advises that Mackay GT will be retired at the end of 2016.

Swanbank B Power Station: CS Energy advises that the last remaining unit at Swanbank B (Unit 3) will be retired from April 2012.

4.4.6 Projects under development

AEMO sought information from generators and project proponents about the status of generation projects under development. Some companies provide AEMO with information that is commercial in-confidence, either due to being at an early stage of development, project mergers, changes to project details, or due to a company or project sale process that is currently underway. As a result, some projects have not been listed.

Table 4-12 lists information about projects under development in Queensland.

Table 4-12 — Projects under development – Queensland

Project	Owner	Unit ID	Fuel Type	Generation Type	Land	Equip	Plan	Finance	Date	Unit Status	Nameplate Capacity (MW)	Dispatch Type	Commissioning Start Date
Bowen	Transfield Services	All units	Wind	Wind						Pub An	120-240	SS	TBA
Braemar 3	ERM Power Limited	1-2	Natural Gas	OCGT	✓		✓			Pub An	500	S	December 2013
Burdekin Falls Dam	Stanwell Corporation Limited	1	Water	Gravity Hydroelectric						Pub An	37	SS	January 2015
Coopers Gap	AGL Hydro	1-252	Wind	Wind						Pub An	350	SS	TBA
Crediton	Transfield Services	All units	Wind	Wind						Pub An	40-90	SS	TBA
Crows Nest	AGL Energy	1-67	Wind	Wind						Pub An	200	SS	TBA
Darling Downs Stage 2	Origin Energy	1-3	Natural Gas	OCGT	✓					Pub An	500	S	May 2014
Forsayth	Infigen Energy	1-28	Wind	Wind	✓					Pub An	70	SS	November 2013
High Road	Transfield Services	All units	Wind	Wind	✓					Pub An	35	SS	December 2012
Kogan Creek (Solar Boost)	CS Energy	1	Solar	Solar Thermal	✓					Pub An	44	S	July 2012
Solar Dawn	AREVA Solar, CS Energy and Wind Prospect CWP	1-2	Solar	Solar Thermal with Storage and Boost	✓					Pub An	250	SS	September 2014
Spring Gully	Origin Energy	1-4	Natural Gas	CCGT	✓					Pub An	1,000	S	January 2019
Wandoan Power Project	Stanwell Corporation	1		IGCC						Pub An	504	S	2017/18

Project	Owner	Unit ID	Fuel Type	Generation Type	Land	Equip	Plan	Finance	Date	Unit Status	Nameplate Capacity (MW)	Dispatch Type	Commissioning Start Date
Westlink Power Project	Westlink Pty. Ltd. as trustee for Westlink Industrial Trust	1-2	Natural Gas	OCGT	✓					Pub An	~334 (up to 1,000 for full project)	S	June 2014
		3-4	Natural Gas	OCGT	✓					Pub An	~334 (up to 1,000 for full project)	S	June 2016
		5-6	Natural Gas	OCGT	✓					Pub An	~334 (up to 1,000 for full project)	S	June 2018
Windy Hill II	Transfield Services	All units	Wind	Wind						Pub An	10-30	SS	TBA
Blackwater	Blackwater Power Pty. Ltd.	1-10	Coal Seam Methane	Compression Reciprocating Engine	✓	✓		✓	✓	Adv	29.4	NS	August 2011
Victoria Mill	Sucrogen (Herbert) Pty. Ltd.	4	Bagasse/ Black Coal	Steam Subcritical	✓	✓	✓	✓	✓	Com	19	NS	May 2011

Some projects previously reported as advanced or committed may now be listed as publicly announced. This shift in classification since the 2010 ESOO is due to a more stringent data gathering process that provided additional information about the planning process for each development.

Table 4-13 lists information about non-scheduled generators in Queensland.

Table 4-13 — Existing non-scheduled generation – Queensland

Power Station	Owner	Fuel Type	Technology Type	Nameplate Capacity (MW)	Expected Capacity for Summer MD (MW)	Expected Capacity for Winter MD (MW)
Browns Plains	EDL LFG (Qld) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	2	2	2
Callide A	Oxyfuel Technologies Pty. Ltd.	Black Coal	Steam Subcritical	30	30	30
Daandine	Energy infrastructure Investments Pty. Ltd.	Coal Seam Methane	Compression Reciprocating Engine	30	29	29
German Creek	EDL CSM (Qld) Pty. Ltd.	Waste Coal Mine Gas	Spark Ignition Reciprocating Engine	32	1	1
Inkerman Mill	Pioneer Sugar Mills Pty. Ltd.	Bagasse	Steam Subcritical	21	0	2
Invicta Mill	The Haughton Sugar Company Pty. Ltd.	Bagasse	Steam Subcritical	151	0	34
Kalamia Mill	Sucrogen (Kalamia) Pty. Ltd.	Bagasse	Steam Subcritical	9	0	2
Kareeya 5	Stanwell Corporation Limited	Water	Gravity Hydroelectric	7	7	7
Macknade Mill	Sucrogen (Herbert) Pty. Ltd.	Bagasse/Black Coal	Steam Subcritical	16	0	1
Moranbah North	EDL Projects (Australia) Pty. Ltd.	Waste Coal Mine Gas	Spark Ignition Reciprocating Engine	46	1	1
Oaky Creek	EnviroGen (Oaky) Pty. Ltd.	Waste Coal Mine Gas	Spark Ignition Reciprocating Engine	20	17	19
Pioneer Sugar Mill	Pioneer Sugar Mills Pty. Ltd.	Bagasse	Steam Subcritical	68	32	44
Plane Creek Mill	Sucrogen Plane Creek Mill Pty. Ltd.	Bagasse/Black Coal	Steam Subcritical	28	0	1
Rochedale Renewable Energy Facility	LMS Generation	Landfill Methane	Spark Ignition Reciprocating Engine	4	2	2
Rocky Point Cogeneration	NP Power Pty. Ltd.	Green and Air-dried Wood	Steam Subcritical	30	27	27
Roghan Road	EDL LFG (Qld) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	1	1	1

Power Station	Owner	Fuel Type	Technology Type	Nameplate Capacity (MW)	Expected Capacity for Summer MD (MW)	Expected Capacity for Winter MD (MW)
Tarong GT	Stanwell Corporation	Fuel Oil	OCGT	15	15	15
Veolia Ti Tree Bio Reactor	Veolia Environmental Services	Landfill Methane	Compression Reciprocating Engine	3.3	3.3	4.4
Victoria Mill	Sucrogen (Herbert) Pty. Ltd.	Bagasse/Black Coal	Steam Subcritical	12	0	5
Whitwood Road	LMS Generation	Landfill Methane	Spark Ignition Reciprocating Engine	1	1	1
Windy Hill	Transfield Services Infrastructure Fund	Wind	Wind	12	12	12
Wivenhoe small hydro	Stanwell Corporation Limited	Water	Gravity Hydroelectric	5	5	5
Yarwun	RTA Yarwun Pty. Ltd.	Natural Gas	OCGT	154	155	160
KRC Cogen	AGL Energy	Natural gas	Steam Subcritical	5	3	1
ISIS Central Sugar Mill Cogen	AGL Energy	Bagasse	Steam Subcritical	25	0	0
Suncoast Gold Macadamias	AGL Energy	Biomass	Steam Subcritical	1.5	0.2	0.2

4.5 New South Wales

4.5.1 Existing and committed scheduled and semi-scheduled generation

Table 4-14 lists the existing and committed generation in New South Wales. Table 4-15 and Table 4-16 provide forecasts of scheduled and semi-scheduled available capacity for summer and winter, respectively.

Table 4-14 — Existing and committed scheduled and semi-scheduled generation – New South Wales

Power Station	Registered Participant	Units	Registered Capacity (MW)	Plant Type	Fuel Type	Dispatch Type
Bayswater	Macquarie Generation	4 x 660	2,640	Steam Subcritical	Black Coal	S
Shoalhaven	Origin Energy Electricity	2 x 40 2 x 80	240	Pumped-Storage Hydroelectric	Water	S
Blowering	Snowy Hydro	1 x 70	70	Gravity Hydroelectric	Water	S
Colongra	Delta Electricity	4 x 181	724	OCGT	Natural Gas	S
Eraring	Origin Energy Electricity Limited	4 x 660	2,682	Steam Subcritical	Black Coal	S
Gunning	Gunning Wind Energy Developments	31 x 2.1	47	Wind	Wind	SS
Guthega	Snowy Hydro	2 x 30	60	Gravity Hydroelectric	Water	S
Hume	Eraring Energy	2 x 29	58	Gravity Hydroelectric	Water	S
Hunter Valley	Macquarie Generation	2 x 25	50	OCGT	Diesel	S
Liddell	Macquarie Generation	4 x 500	2,000	Steam Subcritical	Black Coal	S
Mt Piper	TRUenergy	2 x 700	1,400	Steam Subcritical	Black Coal	S
Munmorah	Delta Electricity	2 x 300	600	Steam Subcritical	Black Coal	S
Redbank	Redbank Project	1 x 150	150	Steam Subcritical	Coal Tailings	S
Smithfield Energy Facility	Marubeni Australia Power Services	3 x 38 1 x 62	160	CCGT	Natural Gas	S
Tallawarra	TRUenergy	1 x 460	460	CCGT	Natural Gas	S
Tumut 1[a]	Snowy Hydro	4 x 82	616	Gravity Hydroelectric	Water	S
Tumut 2 [a]	Snowy Hydro	4 x 72	-	Gravity Hydroelectric	Water	S
Tumut 3	Snowy Hydro	6 x 250	1,500	Gravity Hydroelectric	Water	S
Uranquinty	Origin Energy Uranquinty Power	4 x 166	664	OCGT	Natural Gas	S
Vales Point B	Delta Electricity	2 x 660	1,320	Steam Subcritical	Black Coal	S
Wallerawang C	TRUenergy	2 x 500	1,000	Steam Subcritical	Black Coal	S
Committed Projects						
Woodlawn	Woodlawn Wind	23 x 2.1	48	Wind Turbine	Wind	SS

a. Tumut 1 and Tumut 2 have a combined registered capacity of 616 MW.

Table 4-15 — Summer aggregate scheduled and semi-scheduled generation – New South Wales (MW)

Power Station	2011 –12	2012 –13	2013 –14	2014 –15	2015 –16	2016 –17	2017 –18	2018 –19	2019 –20	2020 –21	Class
Bayswater	2,720.0	2,720.0	2,720.0	2,720.0	2,720.0	2,720.0	2,720.0	2,720.0	2,720.0	2,720.0	S
Blowering	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	S
Colongra	668.0	668.0	668.0	668.0	668.0	668.0	668.0	668.0	668.0	668.0	S
Eraring	2,840.0	2,880.0	2,880.0	2,880.0	2,880.0	2,880.0	2,880.0	2,880.0	2,880.0	2,880.0	S
Gunning	46.5	46.5	46.5	46.5	46.5	46.5	46.5	46.5	46.5	46.5	SS
Guthega	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	S
Hume[a]	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	S
Hunter Valley	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	44.0	S
Liddell	2,060.0	2,060.0	2,060.0	2,060.0	2,060.0	2,060.0	2,060.0	2,060.0	2,060.0	2,060.0	S
Mt Piper	1,340.0	1,340.0	1,340.0	1,340.0	1,340.0	1,340.0	1,340.0	1,340.0	1,340.0	1,340.0	S
Munmorah	600.0	600.0	600.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	S
Redbank	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	S
Shoalhaven	240.0	240.0	240.0	240.0	240.0	240.0	240.0	240.0	240.0	240.0	S
Smithfield	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	S
Tallawarra	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	S
Tumut 3	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	S
Upper Tumut	616.0	544.0	544.0	544.0	616.0	544.0	616.0	616.0	616.0	616.0	S
Uranquinty	640.0	640.0	640.0	640.0	640.0	640.0	640.0	640.0	640.0	640.0	S
Vales Point B	1,320.0	1,320.0	1,320.0	1,320.0	1,320.0	1,320.0	1,320.0	1,320.0	1,320.0	1,320.0	S
Wallerawang C	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	S
Committed Projects											
Woodlawn	48.3	48.3	48.3	48.3	48.3	48.3	48.3	48.3	48.3	48.3	**SS**
Total	**16,875.8**	**16,843.8**	**16,843.8**	**16,243.8**	**16,315.8**	**16,243.8**	**16,315.8**	**16,315.8**	**16,315.8**	**16,315.8**	

a. Hume units can be dispatched to either Victoria or New South Wales.

Table 4-16 — Winter aggregate scheduled and semi-scheduled generation – New South Wales (MW)

Power Station	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Class
Bayswater	2,760.0	2,760.0	2,760.0	2,760.0	2,760.0	2,760.0	2,760.0	2,760.0	2,760.0	2,760.0	S
Blowering	80.0	0.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	S
Colongra	724.0	724.0	724.0	724.0	724.0	724.0	724.0	724.0	724.0	724.0	S
Eraring	2,880.0	2,880.0	2,880.0	2,880.0	2,880.0	2,880.0	2,880.0	2,880.0	2,880.0	2,880.0	S
Gunning	46.5	46.5	46.5	46.5	46.5	46.5	46.5	46.5	46.5	46.5	SS
Guthega	35.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	S
Hume[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	S
Hunter Valley	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	S
Liddell	2,060.0	2,060.0	2,060.0	2,060.0	2,060.0	2,060.0	2,060.0	2,060.0	2,060.0	2,060.0	S
Mt Piper	1,340.0	1,340.0	1,340.0	1,340.0	1,340.0	1,340.0	1,340.0	1,340.0	1,340.0	1,340.0	S
Munmorah	600.0	600.0	600.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	S
Redbank	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	S
Shoalhaven	240.0	240.0	240.0	240.0	240.0	240.0	240.0	240.0	240.0	240.0	S
Smithfield Energy	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	S
Tallawarra	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	S
Tumut 3	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	S
Upper Tumut	616.0	534.0	534.0	534.0	534.0	616.0	616.0	616.0	616.0	616.0	S
Uranquinty	664.0	664.0	664.0	664.0	664.0	664.0	664.0	664.0	664.0	664.0	S
Vales Point B	1,320.0	1,320.0	1,320.0	1,320.0	1,320.0	1,320.0	1,320.0	1,320.0	1,320.0	1,320.0	S
Wallerawang C	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	960.0	S
Committed Projects											
Woodlawn	48.3	48.3	48.3	48.3	48.3	48.3	48.3	48.3	48.3	48.3	SS
Total	**16,971.8**	**16,842.8**	**16,922.8**	**16,322.8**	**16,322.8**	**16,404.8**	**16,404.8**	**16,404.8**	**16,404.8**	**16,404.8**	

a. Hume units can be dispatched to either Victoria or New South Wales.

4.5.2 Changes since the 2010 ESOO (existing generation)

Blowering Power Station: Snowy Hydro advises that former plant limitations (due to maintenance and water issues) at Blowering have been removed, and the available capacity has been revised from 40 MW to 80 MW (+40 MW) in both summer and winter.

Eraring Power Station: Origin Energy advises that upgrades of the four Eraring units are progressing as follows:

- Unit 2 and Unit 3 are now complete.
- Unit 1 work commenced in July 2011, with commissioning expected to commence from January 2012.
- Unit 4 work is partially completed, with work to recommence in April 2012 and commissioning expected to commence from October 2012.

Gunning Wind Farm: ACCIONA Energy advises that commissioning of the 46.5 MW wind farm is now complete.

Hume Power Station: Hume has two units located near the Victoria and New South Wales border, which can be dispatched to either region. Eraring Energy has requested that Hume be treated as a single generator for the purposes of the ESOO. Hume's available capacity was formerly listed with one unit in Victoria and one unit in New South Wales.

Liddell Power Station: Macquarie Generation advises that Liddell's available capacity has been revised from 2,075 MW to 2,060 MW (-15 MW) in summer and from 2,090 MW to 2,060 MW (-30 MW) in winter due to a re-assessment of plant capacity.

Mt Piper Power Station: TRUenergy advises that Mt Piper's available capacity has been revised from 1,400 MW to 1,340 MW (-60 MW) in both summer and winter due to revised operating parameters.

Smithfield Energy Facility: Marubeni Power Development Australia advises that Smithfield's available capacity has been revised from 160 MW to 178 MW (+18 MW) in winter due to a change in operational contractual arrangements.

Tallawarra Power Station: TRUenergy advises that Tallawarra's available capacity has been revised from 460 MW to 420 MW (-40 MW) in winter as a result of operational experience.

Wallerrawang C Power Station: TRUenergy advises that Wallerrawang's available capacity has been revised from 1,000 MW to 960 MW (-40 MW) in both summer and winter due to revised operating parameters.

4.5.3 Committed project developments

Eraring Power Station (upgrade): Origin Energy advises that work on Units 2 and 3 is complete (see Section 4.5.2). Work on Unit1 is underway and will be followed by completion of the Unit 4 upgrade.

Woodlawn Wind Farm: Infigen Energy on behalf of Woodlawn Wind Farm Power advises that Woodlawn Wind Farm (48MW) is now a committed project. Commissioning has commenced and completion is expected around September 2011.

Woodlawn Bioreactor: Veolia Environmental Services advises that Woodlawn Unit 4 is now a committed project. Construction of the 1 MW unit is expected to commence in August 2011.

4.5.4 Plant limitations

The output of some hydroelectric generation is limited by water availability, inflows, and dam levels. Similarly, wind generation is limited by wind availability. More specific limitations include the following.

Blowering Power Station: Snowy Hydro advises that Blowering's output is limited by releases controlled by State Water. The power station will also be limited to (zero) 0 MW in winter 2013 due to a planned outage.

Guthega Power Station: Snowy Hydro advises that Guthega's output will be limited to 35 MW in winter 2012 due to a planned outage of Unit 2.

Upper Tumut Power Station: Snowy Hydro advises that Upper Tumut's output will be limited to:

- 544 MW during summer 2012–13 to 2014–15 and 2016–17 due to consecutive outages of Unit 5, Unit 6, Unit 7, and Unit 8, and
- 534 MW during winters 2013 to 2016 due to consecutive outages of Unit 1, Unit 2, Unit 3, and Unit 4.

4.5.5 Plant retirements

Munmorah Power Station: Delta Electricity advises that Munmorah will retire after winter 2014.

4.5.6 Projects under development

AEMO sought information from generators and project proponents about the status of generation projects under development. Some companies provide AEMO with information that is commercial in-confidence, either due to being at an early stage of development, project mergers, changes to project details, or due to a company or project sale process that is currently underway. As a result, some projects have not been listed.

Some projects previously reported as advanced or committed may now be listed as publicly announced. This shift in classification since the 2010 ESOO is due to a more stringent data-gathering process that provided additional information about the planning process for each development.

Table 4-17 lists information about projects under development in New South Wales.

Table 4-17 — Projects under development – New South Wales

Project	Owner	Unit ID	Fuel Type	Generation Type	Land	Equip	Plan	Finance	Date	Unit Status	Nameplate Capacity (MW)	Dispatch Type	Commissioning Start Date
Bango	Wind Prospect CWP Pty. Ltd.	All Units	Wind	Wind						Pub An	150-300	SS	TBA
Bamarang[a]	TRUenergy	All Units	Natural Gas	CCGT or OCGT						Pub An	300 or 400	S	TBA
Bayswater B	Macquarie Generation	All Units	Coal or gas	TBA	✓					Pub An	2000	S	TBA
Ben Lomond	AGL Energy	1–67	Wind	Wind						Pub An	200	SS	TBA
Birrema	Epuron Pty. Ltd.	1–80	Wind	Wind						Pub An	140	SS	TBA
Boco Rock	Wind Prospect CWP Pty. Ltd.	All Units	Wind	Wind						Pub An	270	SS	July 2013
Bodangora	Infigen Energy	1-33	Wind	Wind						Pub An	100	SS	TBA
Buronga	International Power Pty. Ltd.	All Units	TBA	OCGT						Pub An	150	S	TBA
Capital Solar Farm	Infigen Suntech Australia Pty. Ltd.	1-156,000	Solar	PV panels	✓				✓	Pub An	37	SS	October 2012
Capital WF 2	Infigen Energy	Units 1–33	Wind	Wind	✓					Pub An	100	SS	April 2013
Carols Ridge Wind Farm	Epuron Pty. Ltd.	1-15	Wind	Wind						Pub An	30	SS	TBA
Collector	Transfield Services	All units	Wind	Wind						Pub An	120-235	SS	June 2014
Conroys Gap	Origin Energy	1-15	Wind	Wind						Pub An	30	SS	August 2016

Project	Owner	Unit ID	Fuel Type	Generation Type	Land	Equip	Plan	Finance	Date	Unit Status	Nameplate Capacity (MW)	Dispatch Type	Commissioning Start Date
Crookwell 2	Crookwell Development Pty. Ltd.	46	Wind	Wind	✓					Pub An	92	SS	January 2014
Crookwell 3	Crookwell Development Pty. Ltd.	25	Wind	Wind	✓					Pub An	75	SS	July 2014
Crudine Ridge	Wind Prospect CWP Pty. Ltd.	All Units	Wind	Wind						Pub An	165	SS	TBA
Dalton	AGL	1–2	Natural Gas	OCGT	✓					Pub An	500	S	October 2012
Eraring (Upgrade)	Eraring Energy	1	Black Coal/ Fuel Oil	Steam Subcritical	✓	✓	✓	✓	✓	Com	+60	S	January 2012
		4	Black Coal/ Fuel Oil	Steam Subcritical	✓	✓	✓	✓	✓	Com	+60	S	October 2012
Flyers Creek Wind Farm	Infigen Energy	1–36	Wind	Wind						Pub An	108	SS	November 2014
Glen Innes	Glen Innes WindPower Pty. Ltd.	1–25	Wind	Wind						Pub An	62.5-75	SS	TBA
Golspie	Wind Prospect CWP Pty. Ltd.	All Units	Wind	Wind						Pub An	150-300	SS	TBA
Gullen Range Wind Farm	Gullen Range Wind Farm Pty. Ltd.	73	Wind	Wind						TBA	182.5	SS	TBA
Kerrawawy GT	Origin Energy	All units	Natural Gas	OCGT	✓					Pub An	1,000	S	January 2017
Leafs Gully	AGL Energy	2	Natural Gas	OCGT						Pub An	360	S	TBA
Liverpool	Epuron Pty. Ltd.	1–550	Wind	Wind						Pub An	1,100	SS	TBA
Manildra Solar Farm	Infigen Suntech Australia	1-135,000	Solar	PV panels	✓					Pub An	33	SS	July 2013

Project	Owner	Unit ID	Fuel Type	Generation Type	Land	Equip	Plan	Finance	Date	Unit Status	Nameplate Capacity (MW)	Dispatch Type	Commissioning Start Date
Marulan[a]	TRUenergy	All Units	Natural Gas	OCGT or CCGT						Pub An	350 or 450	S	TBA
Moree Photovoltaic Solar Farm	Infigen Energy	Units 1-200,000	Solar	PV panels	✓					Pub An	50	SS	April 2016
Moree Solar Farm	BP Solar/Fotowatio Renewable Ventures/ Pacific Hydro	All Units	Solar	PV panels						Pub An	150	SS	2013
Munmorah Rehabilitation	Delta Electricity	1–2	Black Coal/ Fuel Oil	Steam Subcritical	✓					Pub An	700	S	TBA
Nyngan Photovoltaic Solar Farm	Infigen Energy	Units 1-200,000	Solar	PV panels	✓					Pub An	80	SS	February 2014
Paling Yards	Union Fenosa Wind Australia	50	Wind	Wind						Pub An	150	SS	January 2016
Parkes Peaking	International Power Pty. Ltd.	1–3	Natural Gas	OCGT						Pub An	150	S	TBA
Rye Park	Epuron Pty. Ltd.	1–110	Wind	Wind						Pub An	200	SS	TBA
Sapphire Wind Farm	Wind Prospect CWP Pty. Ltd.	All Units	Wind	Wind						Pub An	425	SS	TBA
Silverton	Silverton Wind Farm Developments Pty. Ltd.	1–598	Wind	Wind						Pub An	1,000	SS	TBA
Tallawarra B	TRUenergy	All Units	Natural Gas	OCGT	✓					Pub An	450	S	TBA
Taralga	RES Southern Cross Pty. Ltd.	1–61	Wind	Wind			✓			Pub An	122	SS	September 2012
Tomago GT	Macquarie Generation	All Units								Pub An	TBA	S	TBA
Uungula	Wind Prospect CWP Pty. Ltd.	All Units	Wind	Wind						Pub An	500-800	SS	TBA

Project	Owner	Unit ID	Fuel Type	Generation Type	Land	Equip	Plan	Finance	Date	Unit Status	Nameplate Capacity (MW)	Dispatch Type	Commissioning Start Date
Wellington	ERM Power Limited	1–2	Natural Gas	OCGT	✓					Pub An	510	S	September 2014
White Rock (Glen Innes)	Epuron Pty. Ltd.	1–119	Wind	Wind						Pub An	238	SS	TBA
Woodlawn	Woodlawn Wind Power Pty. Ltd.	1–23	Wind	Wind	✓	✓	✓	✓	✓	Com	48	SS	May 2011
Yass Valley Wind Farm	Origin Energy	1–111	Wind	Wind						Pub An	222	SS	August 2016
Charlestown Square Cogeneration	GPT RE Limited	1–2	Natural Gas	Spark Ignition Reciprocating Engine	✓	✓		✓	✓	Adv	2.808	NS	February 2011
Woodlawn Bioreactor Energy Generation	Veolia Environmental Services (Aust) Pty. Ltd.	4	Landfill Methane/ Landfill Gas	Spark Ignition Reciprocating Engine	✓	✓	✓	✓	✓	Com	1	NS	September 2011
		5	Landfill Methane/ Landfill Gas	Spark Ignition Reciprocating Engine	✓		✓	✓		Adv	1	NS	December 2012
		6	Landfill Methane/ Landfill Gas	Spark Ignition Reciprocating Engine	✓		✓	✓		Adv	1	NS	March 2014
		7	Landfill Methane/ Landfill Gas	Spark Ignition Reciprocating Engine	✓			✓		Pub An	TBA	NS	May 2015
		8	Landfill Methane/ Landfill Gas	Spark Ignition Reciprocating Engine	✓			✓		Pub An	TBA	NS	August 2016
Woodlawn Bioreactor Energy Generation	Veolia Environmental Services (Aust) Pty.	9	Landfill Methane/ Landfill Gas	Spark Ignition Reciprocating Engine	✓			✓		Pub An	TBA	NS	November 2017

Project	Owner	Unit ID	Fuel Type	Generation Type	Land	Equip	Plan	Finance	Date	Unit Status	Nameplate Capacity (MW)	Dispatch Type	Commissioning Start Date
	Ltd.	10	Landfill Methane/ Landfill Gas	Spark Ignition Reciprocating Engine	✓			✓		Pub An	TBA	NS	February 2019
		11	Landfill Methane/ Landfill Gas	Spark Ignition Reciprocating Engine	✓			✓		Pub An	TBA	NS	May 2020
		12	Landfill Methane/ Landfill Gas	Spark Ignition Reciprocating Engine	✓			✓		Pub An	TBA	NS	August 2021

a. TRUenergy recently acquired this project from Delta Electricity and is not yet able to provide information about the status of the project.

4.5.7 Non-scheduled generation

Table 4-18 lists information about non-scheduled generators in New South Wales.

Table 4-18 — Existing non-scheduled generation – New South Wales

Power Station	Owner	Fuel Type	Technology Type	Nameplate Capacity (MW)	Expected Capacity for Summer MD (MW)	Expected Capacity for Winter MD (MW)
Appin	EDL CSM (NSW) Pty Ltd	Waste Coal Mine Gas/Natural Gas	Spark Ignition Reciprocating Engine	60	1	1
Awaba	LMS Generation	Landfill Methane	Spark Ignition Reciprocating Engine	1	1	1
Bankstown Sports Club	Bankstown Sports Club	Diesel	Compression Reciprocating Engine	2	1	1
Belconnen	EDL LFG (ACT) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	1	1	1
Blayney	Eraring Energy	Wind	Wind	10	10	10
Broadwater	Ferrier Hodgeson, Sunshine Electricity joint venture in receivership	Bagasse/Wood Waste	Steam Subcritical	30	30	38
Broken Hill GT	Essential Energy	Diesel	OCGT	50	20	25
Brown Mountain	Eraring Energy	Water	Gravity Hydroelectric/Run of River	5	5	5
Burrendong	AGL Energy	Water	Gravity Hydroelectric	18	18	18
Burrinjuck	Eraring Energy	Water	Gravity Hydroelectric	27	27	27
Capital	Renewable Power Ventures Pty. Ltd.	Wind/Wind	Wind	141	141	141
Condong	Ferrier Hodgeson, Sunshine Electricity joint venture in receivership	Bagasse/Wood Waste	Steam Subcritical	30	30	30
Copeton	AGL Energy	Water	Gravity Hydroelectric	20	20	20
Crookwell	Eraring Energy	Wind	Wind	5	5	5
Cullerin Range	Cullerin Range Wind Farm Pty. Ltd.	Wind	Wind	30	30	30
EarthPower Biomass Plant	EarthPower Technologies Sydney Pty. Ltd.	Municipal and Industrial Materials	Spark Ignition Reciprocating Engine	4	1	1

Power Station	Owner	Fuel Type	Technology Type	Nameplate Capacity (MW)	Expected Capacity for Summer MD (MW)	Expected Capacity for Winter MD (MW)
Eastern Creek	EDL LFG (NSW) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	5	1	1
Eastern Creek 2 Gas Utilisation Facility	LMS Generation Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	8	8	8
Eraring GT	Eraring Energy	Diesel	OCGT	42	42	35
Glenbawn	AGL Energy	Water	Gravity Hydroelectric	5	5	5
Grange Ave	EDL LFG (NSW) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	1	2	2
Hunter Economic Zone	Infratil Energy Australia Pty. Ltd.	Diesel	Compression Reciprocating Engine	29	29	29
Jacks Gully	EDL LFG (NSW) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	2	1	1
Jindabyne	Snowy Hydro Ltd.	Water	Gravity Hydroelectric	1	1	1
Jounama	Snowy Hydro Ltd.	Water	Gravity Hydroelectric	14	14	14
Keepit	Eraring Energy	Water	Gravity Hydroelectric	7	7	7
Kooragang	Ausgrid	Wind	Wind	1	1	1
Lucas Heights I	EDL LFG (NSW) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	5	2	2
Lucas Heights II	EDL LFG (NSW) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	11	2	2
Mugga Lane	EDL LFG (ACT) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	3	1	1
Nine Network Willoughby	Nine Network	Diesel	Compression Reciprocating Engine	3	1	1
Nymboida	Essential Energy	Water	Gravity Hydroelectric	34	1	1
Oaky	Essential Energy	Water	Gravity Hydroelectric	5	5	5
Pindari	AGL Energy	Water	Gravity Hydroelectric	6	6	6

Power Station	Owner	Fuel Type	Technology Type	Nameplate Capacity (MW)	Expected Capacity for Summer MD (MW)	Expected Capacity for Winter MD (MW)
Revesby Workers Club	Revesby Workers Club	Diesel	Compression Reciprocating Engine	3	2	1
St George Leagues Club	St George Leagues Club	Diesel	Compression Reciprocating Engine	1	1	1
Summer Hill	LMS Generation Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	2	2	2
Teralba	EnviroGen Pty. Ltd.	Waste Coal Mine Gas	Spark Ignition Reciprocating Engine	4	2	2
The Drop	Pacific Hydro Investments Pty. Ltd.	Water	Gravity Hydroelectric	3	0	0
Tower	EDL NSW (CSM) Pty. Ltd.	Waste Coal Mine Gas/ Natural Gas	Spark Ignition Reciprocating Engine	41	1	1
Warragamba	Eraring Energy	Water	Gravity Hydroelectric	50	0	0
West Illawarra Leagues Club	Wests Illawarra Leagues Club	Diesel	Compression Reciprocating Engine	1	1	1
Western Suburbs League Club (Campbelltown)	Western Suburbs League Club (Campbelltown)	Diesel	Compression Reciprocating Engine	1	1	1
Woodlawn Bioreactor Energy Generation	Veolia Environmental Services (Aust) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	6	3	3
West Nowra	AGL Energy	Landfill Methane	Compression Reciprocating Engine	1	1	1

4.6 Victoria

4.6.1 Existing and committed scheduled and semi-scheduled generation

Table 4-19 lists the existing and committed generation in Victoria. Table 4-20 and Table 4-21 provide forecasts of scheduled and semi-scheduled available capacity for summer and winter, respectively.

Table 4-19 — Existing and committed scheduled and semi-scheduled generation – Victoria

Power Station	Registered Participant	Units	Registered Capacity	Plant Type	Fuel Type	Dispatch Type
Bairnsdale	Aurora Energy (Tamar Valley)	2 x 47	94	OCGT	Natural Gas	S
Bogong/Mckay	AGL Hydro Partnership	2 x 80 6 x 25	300	Gravity Hydroelectric	Water	S
Dartmouth	AGL Hydro Partnership	1 x 150	150	Gravity Hydroelectric	Water	S
Eildon	AGL Hydro Partnership	1 x 60 1 x 7.5 1 x 60 1 x 7.5	120	Gravity Hydroelectric	Water	S
Energy Brix Complex	Energy Brix Australia Corporation	1 x 24 2 x 33 1 x 30 1 x 75	195	Steam Subcritical	Brown Coal	S
Hazelwood	Hazelwood Power	8 x 200	1,600	Steam Subcritical	Brown Coal	S
Jeeralang A	Ecogen Energy	4 x 51	204	OCGT	Natural Gas	S
Jeeralang B	Ecogen Energy	3 x 76	228	OCGT	Natural Gas	S
Laverton North	Snowy Hydro	2 x 156	312	OCGT	Natural Gas	S
Loy Yang A	Loy Yang Marketing Management Company	3 x 560 1 x 500	2,180	Steam Subcritical	Brown Coal	S
Loy Yang B	IPM Australia	2 x 500	1,000	Steam Subcritical	Brown Coal	S
Murray 1[a]	Snowy Hydro	10 x 95	1,500	Gravity Hydroelectric	Water	S
Murray 2[a]	Snowy Hydro	4 x 138		Gravity Hydroelectric	Water	S
Newport	Ecogen Energy	1 x 500	500	Steam Subcritical	Natural Gas	S
Somerton	AGL Hydro Partnership	4 x 40	160	OCGT	Natural Gas	S
Valley Power Peaking Facility	Valley Power	6 x 50	300	OCGT	Natural Gas	S

Power Station	Registered Participant	Units	Registered Capacity	Plant Type	Fuel Type	Dispatch Type
West Kiewa	AGL Hydro Partnership	2 x 31	62	Gravity Hydroelectric	Water	S
Yallourn W	TRUenergy Yallourn	2 x 360 2 x 380	1,480	Steam Subcritical	Brown Coal	S
Committed Projects						
Oaklands Hill[b]	Oaklands Hill Wind Farm Pty. Ltd.	32 x 2.1	67.2	Wind	Wind	SS
Macarthur[b]	Macarthur Wind Farm Unincorporated Joint Venture	140 x 3	420	Wind	Wind	SS
Mortlake Stage 1[b]	Origin Energy Power Limited	2 x 283	566	OCGT	Natural Gas	S

a. Murray 1 and Murray 2 have a combined registered capacity of 1,500 MW.

b. Not yet registered.

Table 4-20 — Summer aggregate scheduled and semi-scheduled generation – Victoria (MW)

Power Station	2011 –12	2012 –13	2013 –14	2014 –15	2015 –16	2016 –17	2017 –18	2018 –19	2019 –20	2020 –21	Dispatch Type
Anglesea[a]	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	NS
Bairnsdale	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	S
Bogong/ Mackay	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	S
Dartmouth	130.0	160.0	180.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	S
Eildon	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	S
Hazelwood	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	S
Jeeralang A	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	S
Jeeralang B	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	S
Laverton North	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	S
Loy Yang A	2,190.0	2,190.0	2,190.0	2,190.0	2,190.0	2,190.0	2,190.0	2,190.0	2,190.0	2,190.0	S
Loy Yang B	965.0	965.0	965.0	965.0	965.0	965.0	965.0	965.0	965.0	965.0	S
Morwell/ Energy Brix	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	S
Murray 1	950.0	950.0	950.0	950.0	950.0	950.0	950.0	950.0	950.0	950.0	S
Murray 2	562.5	425.0	562.5	562.5	562.5	562.5	562.5	562.5	425.0	562.5	S
Newport	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0	475.0	S
Somerton	131.7	134.0	132.5	132.5	132.5	132.5	132.5	132.5	132.5	132.5	S
Valley Power	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	S
West Kiewa	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	S
Yallourn W	1,480.0	1,480.0	1,480.0	1,480.0	1,480.0	1,480.0	1,480.0	1,480.0	1,480.0	1,480.0	S
Committed Projects											
Oaklands Hill	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	SS
Macarthur	0.0	394.8	394.8	394.8	394.8	394.8	394.8	394.8	394.8	394.8	SS
Mortlake Stage 1	518.0	518.0	518.0	518.0	518.0	518.0	518.0	518.0	518.0	518.0	S
Total	**10,916.2**	**11,205.8**	**11,361.8**	**11,366.8**	**11,366.8**	**11,366.8**	**11,366.8**	**11,366.8**	**11,229.3**	**11,366.8**	

a. Anglesea is a non-scheduled generator, but has been included in the supply-demand outlook.

Table 4-21 — Winter aggregate scheduled and semi-scheduled generation – Victoria (MW)

Power Station	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Dispatch Type
Anglesea[a]	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0	NS
Bairnsdale	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	S
Bogong/ Mackay	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	S
Dartmouth	130.0	160.0	180.0	185.0	185.0	185.0	185.0	185.0	185.0	185.0	S
Eildon	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	114.0	S
Hazelwood	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	S
Jeeralang A	232.0	232.0	232.0	232.0	232.0	232.0	232.0	232.0	232.0	232.0	S
Jeeralang B	255.0	255.0	255.0	255.0	255.0	255.0	255.0	255.0	255.0	255.0	S
Laverton North	340.0	340.0	170.0	340.0	340.0	340.0	340.0	340.0	340.0	340.0	S
Loy Yang A	2,270.0	2,270.0	2,270.0	2,270.0	2,270.0	2,270.0	2,270.0	2,270.0	2,270.0	2,270.0	S
Loy Yang B	1,050.0	1,050.0	1,050.0	1,050.0	1,050.0	1,050.0	1,050.0	1,050.0	1,050.0	1,050.0	S
Morwell/ Energy Brix	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	S
Murray 1	855.0	950.0	950.0	855.0	950.0	855.0	950.0	950.0	950.0	950.0	S
Murray 2	562.5	562.5	562.5	562.5	562.5	562.5	425.0	425.0	562.5	562.5	S
Newport	501.0	501.0	501.0	501.0	501.0	501.0	501.0	501.0	501.0	501.0	S
Somerton	160.0	162.5	161.0	161.0	161.0	161.0	161.0	161.0	161.0	161.0	S
Valley Power	280.0	336.0	336.0	336.0	336.0	336.0	336.0	336.0	336.0	336.0	S
West Kiewa	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	S
Yallourn W	1,480.0	1,480.0	1,480.0	1,480.0	1,480.0	1,480.0	1,480.0	1,480.0	1,480.0	1,480.0	S
Committed Projects											
Oaklands Hill	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	SS
Macarthur	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	SS
Mortlake Stage 1	553.0	553.0	553.0	553.0	553.0	553.0	553.0	553.0	553.0	553.0	S
Total	**11,631.5**	**11,815.0**	**11,663.5**	**11,743.5**	**11,838.5**	**11,743.5**	**11,701.0**	**11,701.0**	**11,838.5**	**11,838.5**	

a. Anglesea is a non-scheduled generator, but has been included in the supply-demand outlook.

4.6.2 Changes since the 2010 ESOO (existing generation)

Dartmouth Power Station: AGL Energy advises that Dartmouth's available capacity has been revised from 100 MW to 130 MW (+30 MW) for summer 2011–12 and winter 2012 due to changes in water availability and head levels. The forecast availability for the following years has also been revised up by between 45 MW and 60 MW.

Eildon Power Station: AGL Energy advises that Eildon's available capacity has been revised from 92 MW to 114 MW (+22 MW) for summer and 60 MW to 114 MW (+54 MW) in winter due to changes in water availability and head levels.

Hume Power Station: Hume has two units located near the Victoria and New South Wales border, which can be dispatched to either region. Eraring Energy has requested that Hume be treated as a single generator for the purposes of the ESOO, and its forecast capacities are listed under New South Wales. Hume's available capacity was formerly listed with one unit in Victoria and one unit in New South Wales.

Loy Yang A: Loy Yang Power Management advises that Loy Yang Unit 2's upgrade is now complete. The upgrade will result in an increase in the Unit 2 nameplate capacity from 500 MW to 530 MW. Anticipated in 2010, there is no change in forecast availability.

Murray 2 Power Station: Snowy Hydro advises that Murray 2's available capacity has been revised from 578 MW to 563 MW (-16 MW) in summer and winter due to a review of capacities, and changes in head levels and water availability.

Valley Power Station: Snowy Hydro advises that Valley's available capacity has been revised from 336 MW to 275 MW (-61 MW) in winter 2012 due to a planned outage of Unit 1, and from 336 MW to 330 MW each winter after that due to changes in ambient temperature.

West Kiewa Power Station: AGL advises that West Kiewa's available capacity has been revised from 72 MW to 60 MW (-12 MW) in winter due to planned upgrades that did not eventuate.

Yallourn Power Station: TRUenergy advises that Yallourn's available capacity has been revised from 1,420 MW to 1,480 MW (+60 MW) in summer due to a turbine refurbishment.

4.6.3 Committed project developments

Oaklands Hill Wind Farm: AGL Energy advises that Oaklands Hill is a committed project. The 67 MW wind farm is currently under construction with completion expected in September 2011.

Macarthur Wind Farm: AGL Energy advises that Macarthur is a committed project. The 420 MW wind farm is currently under construction with completion expected in January 2013.

Mortlake Power Station Stage 1: Origin Energy advises that Mortlake Stage 1 is a committed project. The 566 MW open-cycle gas turbine (OCGT) power station is currently under construction with completion expected in 2011.

4.6.4 Plant limitations

The output of some hydroelectric generation is limited by water availability, inflows, and dam levels. Similarly, wind generation is limited by wind availability. More specific limitations include the following.

Laverton North Power Station: Snowy Hydro advises that Laverton North's maximum capacity varies with ambient temperature. The plant will also be limited to 170 MW in winter 2014 due to an outage of Unit 2.

Murray 1 Power Station: Snowy Hydro advises that Murray 1's capacity will be limited to:

- 855 MW during winter 2012 due to an outage of Unit 3
- 855 MW during winter 2015 due to an outage of Unit 9, and
- 855 MW during winter 2017 due to an outage of Unit 8.

Murray 2 Power Station: Snowy Hydro advises that Murray 2's available capacity will be limited to:

- 425 MW during summer 2012–13 due to an outage of Unit 3
- 425 MW during winter 2018 due to an outage of Unit 3
- 425 MW during winter 2019 due to an outage of Unit 2, and
- 425 MW during summer 2019–20 due to an outage of Unit 1.

Valley Power Station: Snowy Hydro advises that Valley's maximum capacity varies with ambient temperature.

4.6.5 Plant retirements

AEMO has not been advised of any planned plant retirements in Victoria within the 10-year planning outlook.

4.6.6 Projects under development

AEMO sought information from generators and project proponents about the status of generation projects under development. Some companies provide AEMO with information that is commercial in-confidence, either due to being at an early stage of development, project mergers, changes to project details, or due to a company or project sale process that is currently underway. As a result, some projects have not been listed.

Some projects previously reported as advanced or committed may now be listed as publicly announced. This shift in classification since the 2010 ESOO is due to a more stringent data-gathering process that provided additional information about the planning process for each development.

Table 4-22 lists information about projects under development in Victoria.

Table 4-22 — Projects under development – Victoria

Project	Owner	Unit ID	Fuel Type	Generation Type	Land	Equip	Plan	Finance	Date	Unit Status	Nameplate Capacity (MW)	Dispatch Type	Commissioning Start Date
Ararat	RES Australia Pty. Ltd.	1-75	Wind	Wind						Pub An	247.5	SS	June 2013
Bald Hills	Mitsui & Co. (Australia) Ltd.	52	Wind	Wind	✓					Pub An	~104	SS	TBA
Baynton	Transfield Services	All units	Wind	Wind						Pub An	120-240	SS	TBA
Ben More	Transfield Services	All units	Wind	Wind						Pub An	50-70	SS	TBA
Berrimal	ACCIONA Energy	1-16	Wind	Wind	✓					Pub An	24	SS	September 2013
Berrybank	Berrybank	100	Wind	Wind	✓					Pub An	250	SS	July 2016
Carrajung	Synergy Wind Pty. Ltd.	1-15	Wind	Wind						Pub An	30	SS	TBA
Cherry Tree	Infigen Energy	1-25	Wind	Wind	✓					Pub An	50	SS	October 2013
Crowlands	Pacific Hydro Pty. Ltd.	126	Wind	Wind						Pub An	126	SS	TBA
Darlington	Union Fenosa Wind Australia	150-180	Wind	Wind	✓					Pub An	594	SS	July 2016
Discovery Bay	Synergy Wind Pty. Ltd.	1-15	Wind	Wind						Pub An	30	SS	TBA
East Creek	ACCIONA Energy	1-21	Wind	Wind	✓					Pub An	31.5	SS	January 2016
Hawkesdale	Hawkesdale Development Pty. Ltd.	1-31	Wind	Wind	✓					Pub An	77	SS	July 2014

Project	Owner	Unit ID	Fuel Type	Generation Type	Land	Equip	Plan	Finance	Date	Unit Status	Nameplate Capacity (MW)	Dispatch Type	Commissioning Start Date
HRL Dual Gas Demonstration Project[a]	HRL developments	All units	Brown Coal	IDGCC	✓					Pub An	550	S	2013
Lal Lal (Elaine end)	Elaine Wind Farm Pty. Ltd.	41-64	Wind	Wind	✓					Pub An	48-78	SS	TBA
Lal Lal (Yendon end)	Yendon Wind Farm Pty. Ltd.	1-40	Wind	Wind	✓					Pub An	80-136	SS	December 2012
Lexton – Victoria	Origin Energy	1-19	Wind	Wind						Pub An	38	SS	July 2013
Macarthur	Macarthur Wind Farm Unincorporated Joint Venture	1-140	Wind	Wind	✓	✓	✓	✓	✓	Com	420	SS	May 2012
Moorabool	Moorabool Wind Farm Pty. Ltd.	1-107	Wind	Wind						Pub An	214-342	SS	April 2014
Mortlake East	ACCIONA Energy	1-25	Wind	Wind	✓					Pub An	45-75	SS	June 2016
Mortlake South	ACCIONA Energy	1-51	Wind	Wind	✓					Pub An	77	SS	April 2015
Mortlake Stage 1	Origin Energy Power Limited	1-2	Natural Gas	OCGT	✓	✓	✓	✓	✓	Com	566	S	July 2011
Mortlake Stage 2	Origin Energy Electricity Limited	All units	Natural Gas	OCGT	✓	✓				Pub An	550	S	July 2015
Mt Gellibrand	ACCIONA Energy	1-64	Wind	Wind	✓				✓	Pub An	192	SS	December 2013
Mt Mercer	Mt Mercer Wind Farm Pty. Ltd.	1-64	Wind	Wind						Pub An	TBA	SS	TBA
Naroghid	Drysdale Wind Farm Pty. Ltd.	1-21	Wind	Wind	✓					Pub An	42	SS	TBA
Newfield	ACCIONA Energy	1-15	Wind	Wind	✓					Pub An	23	SS	January 2013

Project	Owner	Unit ID	Fuel Type	Generation Type	Land	Equip	Plan	Finance	Date	Unit Status	Nameplate Capacity (MW)	Dispatch Type	Commissioning Start Date
Oaklands Hill	Oaklands Hill Wind Farm Pty. Ltd.	32	Wind	Wind	✓	✓	✓	✓	✓	Com	67	SS	June 2011
Penshurst	RES Australia Pty. Ltd.	1-200	Wind	Wind						Pub An	600	SS	December 2013
Ryan Corner	Ryan Corner Development Pty. Ltd.	68	Wind	Wind	✓					Pub An	170	SS	July 2014
Shaw River	Santos (TGR) Pty. Ltd.	1	Natural Gas	CCGT	✓					Pub An	500	S	TBA
Sidonia Hills[b]	Hydro-Electric Corporation	1-30	Wind	Wind						Pub An	80	SS	TBA
St Clair	Synergy Wind Pty. Ltd.	1-15	Wind	Wind						Pub An	30	SS	TBA
Stockyard	Origin Energy	1-157	Wind	Wind						Pub An	392	SS	September 2017
Tarrone GT	AGL Energy Limited	2-3	Natural Gas	OCGT	✓					Pub An	500-600	S	TBA
Tarrone WF	Union Fenosa Wind Australia	17-20	Wind	Wind	✓					Pub An	66	SS	July 2016
Waubra North	ACCIONA Energy	1-30	Wind	Wind	✓					Pub An	30-45	SS	July 2015
Willatook	Wind Prospect WA Pty. Ltd.	1-145	Wind	Wind						Pub An	261	SS	TBA
Winchelsea	International Power	1-14	wind	Wind						Pub An	28	SS	TBA
Woolsthorpe	Woolsthorpe Wind Farm Pty. Ltd.	1-20	Wind	Wind	✓				✓	Pub An	46 approx.	SS	June 2012
Yallourn CCGT	TRUenergy	All units	Natural Gas	CCGT	✓					Pub An	1,000	S	TBA

Project	Owner	Unit ID	Fuel Type	Generation Type	Land	Equip	Plan	Finance	Date	Unit Status	Nameplate Capacity (MW)	Dispatch Type	Commissioning Start Date
321 Exhibition Street Trigen	Cogent Energy	1	Natural Gas	Spark Ignition Reciprocating Engine		✓		✓	✓	Adv	1.2	NS	August 2011
Blackwarry	Synergy Wind Pty. Ltd.	1-10	Wind	Wind						Pub An	20	NS	TBA
Bridgewater Lakes	Synergy Wind Pty. Ltd.	1-7/15	Wind	Wind						Pub An	14-30	NS	TBA
Devon North[c]	Synergy Wind Pty. Ltd.	1-7	Wind	Wind	✓					Pub An	14	NS	TBA
Drysdale	Drysdale Wind Farm Pty. Ltd.	1-13	Wind	Wind	✓					Pub An	29.9	NS	TBA
Hallam Road	LMS Generation Pty. Ltd.	1-8	Landfill Methane/ Landfill Gas	Spark Ignition Reciprocating Engine	✓	✓		✓	✓	Adv	1	NS	August 2011
Mortons Lane	Mortons Lane Wind Farm Pty. Ltd.	1-13	Wind	Wind						TBA	20.3	NS	TBA
Portland Stage 4 (Cape Nelson North and Cape Sir William Grant)	Pacific Hydro Portland Wind Farm Pty. Ltd.	1-23	Wind	Wind	✓		✓			Pub An	47	NS	TBA
The Sisters	The Sisters Wind Farm Pty. Ltd.	1-12	Wind	Wind	✓					Pub An	30	NS	TBA
Yaloak South	Pacific Hydro Pty. Ltd.	1-14	Wind	Wind						Pub An	28.7	NS	TBA

a. The proponent did not respond to AEMO's information request. This information is based on the 2010 ESOO.

b. Hydro-Electric Corporation recently acquired this project from Roaring40s and is currently unable to provide further information about the status of the project.

c. Also known as Yarram.

4.6.7 Non-scheduled generation

Table 4-23 lists information about non-scheduled generators in Victoria.

Table 4-23 — Existing non-scheduled generation – Victoria

Power Station	Owner	Fuel Type	Technology Type	Nameplate Capacity (MW)	Expected Capacity for Summer MD (MW)	Expected Capacity for Winter MD (MW)
Anglesea	Alcoa of Australia Limited	Brown Coal/ Diesel	Steam Subcritical	150	157	158
Ballarat Base Hospital	Ballarat Base Hospital	Natural Gas	Compression Reciprocating Engine	2	1	2
Banimboola	AGL Hydro Partnership	Water	Gravity Hydroelectric	13	12	12
Berwick	EDL LFG (Vic) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	5	2	2
Broadmeadows	EDL LFG (Vic) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	6	1	1
Brooklyn	EDL LFG (Vic) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	3	3	3
Challicum Hills	Pacific Hydro Challicum Hills Pty. Ltd.	Wind	Wind	53	53	53
Clayton	EDL LFG (Vic) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	11	1	1
Clover	AGL	Water	Gravity Hydroelectric	29	29	29
Codrington	Energy Pacific (Vic) Pty. Ltd.	Wind	Wind	18	18	18
Corio	EDL LFG (Vic) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	1	1	1
Eildon Small Hydro	Pacific Hydro Investments Pty. Ltd.	Water	Gravity Hydroelectric	5	0	0
Glenmaggie	Pacific Hydro Investments Pty. Ltd.	Water	Gravity Hydroelectric	4	0	0
Hallam Road	LMS Generation Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	4	6	6
Longford	Longford Gas Plant	Natural Gas	OCGT	32	32	32
Mornington Waste Disposal Facility	Energex Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	1	1	1
Portland Stage 1 (Yambuk)	Energy Pacific (Vic) Pty. Ltd.	Wind	Wind	30	30	30

Power Station	Owner	Fuel Type	Technology Type	Nameplate Capacity (MW)	Expected Capacity for Summer MD (MW)	Expected Capacity for Winter MD (MW)
Portland Stage 2 (Cape Bridgewater)	Pacific Hydro Portland Wind Farm Pty. Ltd.	Wind	Wind	58	58	58
Portland Stage 3 (Cape Nelson South)	Pacific Hydro Portland Wind Farm Pty. Ltd.	Wind	Wind	44	44	44
Rubicon Mountain Streams	AGL	Water	Gravity Hydroelectric	14	5	13
Shepparton Wastewater Treatment Facility	Diamond Energy Pty. Ltd.	Sewerage/ Waste Water	Spark Ignition Reciprocating Engine	1	1	1
Springvale	EDL LFG (Vic) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	3	1	1
Symex	Symex Holding Ltd	Natural Gas	OCGT	6	5	5
Tatura Biomass Generator	Diamond Energy Pty. Ltd.	Sewerage/ Waste Water	Spark Ignition Reciprocating Engine	1	1	1
Toora	Transfield Services Infrastructure Fund	Wind	Wind	21	21	21
Waubra	Pyrenees Wind Energy Developments	Wind	Wind	192	3	3
William Hovel	Pacific Hydro Investments Pty. Ltd.	Water	Gravity Hydroelectric	2	0	0
Wollert	LMS Generation Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	4	4	4
Wonthaggi	Regional Wind Farms	Wind	Wind	12	12	12
Wyndham Waste Disposal Facility	Energex Ltd	Landfill Methane	Spark Ignition Reciprocating Engine	1	1	1
Yarrawonga	AGL	Water	Gravity Hydroelectric	10	10	10

4.7 South Australia

4.7.1 Existing and committed scheduled and semi-scheduled generation

Table 4-24 lists the existing and committed generation in South Australia. Table 4-25 and Table 4-26 provide forecasts of scheduled and semi-scheduled available capacity for summer and winter, respectively.

Table 4-24 — Existing and committed scheduled and semi-scheduled generation – South Australia

Power Station	Registered Participant	Units	Registered Capacity	Plant Type	Fuel Type	Dispatch Type
Angaston	Infratil Energy Australia	30 x 1.7	50	Compression Reciprocating Engine	Diesel	S
Clements Gap	Pacific Hydro Clements Gap	27 x 2	57	Wind	Wind	SS
Dry Creek	Synergen Power	3 x 52	156	OCGT	Natural Gas	S
Hallett 1 (Brown Hill)	AGL Hydro Partnership	45 x 2.1	94.5	Wind	Wind	SS
Hallett 2 (Hallett Hill)	AGL Hydro Partnership	34 x 2.1	71.4	Wind	Wind	SS
Hallett 4 (Nth Brown Hill)	AGL Hydro Partnership	63 x 2.1	132.3	Wind	Wind	SS
Hallett	TRUenergy	4 x 16.8 2 x 25.2 4 x 16.8 2 x 17.9	180	OCGT	Natural Gas/ Diesel	S
Ladbroke Grove	Origin Energy Electricity	2 x 40	80	OCGT	Natural Gas	S
Lake Bonney Stage 2	Lake Bonney Wind Power	53 x 3	159	Wind	Wind	SS
Lake Bonney Stage 3	Lake Bonney Wind Power	13 x 39	39	Wind	Wind	SS
Mintaro	Synergen Power	1 x 90	90	OCGT	Natural Gas	S
Northern	Flinders Operating Services	2 x 265	530	Steam Subcritical	Brown Coal	S
Osborne	Origin Energy Electricity	1 x 118 1 x 62	180	CCGT	Natural Gas	S
Pelican Point	Pelican Point Power	2 x 160 1 x 158	478	CCGT	Natural Gas	S
Playford B	Flinders Operating Services	4 x 60	240	Steam Subcritical	Brown Coal	S
Port Lincoln	Synergen Power	2 x 25 1 x 23.5	73.5	OCGT	Diesel	S
Quarantine	Origin Energy Electricity	4 x 24 1 x 128	224	OCGT	Natural Gas	S
Snowtown	Snowtown Wind Farm	47 x 2.1	99	Wind	Wind	SS
Snuggery	Synergen Power	3 x 21	63	OCGT	Diesel	S

Power Station	Registered Participant	Units	Registered Capacity	Plant Type	Fuel Type	Dispatch Type
Torrens Island A	AGL SA Generation	4 x 120	480	Steam Subcritical	Natural Gas/ Fuel Oil	S
Torrens Island B	AGL SA Generation	4 x 200	800	Steam Subcritical	Natural Gas/ Fuel Oil	S
Waterloo	Waterloo Wind Farm	37 x 3	111	Wind	Wind	SS
Committed Project						
Hallett 5 (The Bluff)[a]	AGL Power Generation Pty Limited	25 x 2.1	52.5	Wind	Wind	SS

a. Not yet registered.

Table 4-25 — Summer aggregate scheduled and semi-scheduled generation – South Australia (MW)

Power Station	2011 –12	2012 –13	2013 –14	2014 –15	2015 –16	2016 –17	2017 –18	2018 –19	2019 –20	2020 –21	Dispatch Type
Angaston	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	S
Clements Gap	56.7	56.7	56.7	56.7	56.7	56.7	56.7	56.7	56.7	56.7	SS
Dry Creek	115.0	116.0	117.0	118.0	118.0	118.0	118.0	118.0	118.0	118.0	S
Hallett 1 (Brown Hill)	58.5	58.5	58.5	58.5	58.5	58.5	58.5	58.5	58.5	58.5	SS
Hallett 2 (Hallett Hill)	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	SS
Hallett 4 (Nth Brown Hill)	81.9	81.9	81.9	81.9	81.9	81.9	81.9	81.9	81.9	81.9	SS
Hallett	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	S
Ladbroke Grove	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	S
Lake Bonney 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	SS
Lake Bonney 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	SS
Mintaro	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	S
Northern	544.0	544.0	544.0	544.0	544.0	544.0	544.0	544.0	544.0	544.0	S
Osborne	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	175.0	S
Pelican Point	448.0	448.0	448.0	448.0	448.0	448.0	448.0	448.0	448.0	448.0	S
Playford B	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	S
Port Lincoln	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	S
Quarantine	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	186.0	S
Snowtown	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	SS
Snuggery	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	S
Torrens Island A	472.0	472.0	472.0	472.0	472.0	472.0	472.0	472.0	472.0	472.0	S
Torrens Island B	780.0	780.0	780.0	780.0	780.0	780.0	780.0	780.0	780.0	780.0	S
Waterloo	111.0	111.0	111.0	111.0	111.0	111.0	111.0	111.0	111.0	111.0	SS

Power Station	2011 –12	2012 –13	2013 –14	2014 –15	2015 –16	2016 –17	2017 –18	2018 –19	2019 –20	2020 –21	Dispatch Type
Committed Projects											
Hallett 5 (The Bluff)	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	SS
Total	**3,899.0**	**3,900.0**	**3,901.0**	**3,902.0**	**3,902.0**	**3,902.0**	**3,902.0**	**3,902.0**	**3,902.0**	**3,902.0**	

Table 4-26 — Winter aggregate scheduled and semi-scheduled generation – South Australia (MW)

Power Station	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Dispatch Type
Angaston	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	S
Clements Gap	56.7	56.7	56.7	56.7	56.7	56.7	56.7	56.7	56.7	56.7	SS
Dry Creek	146.0	147.0	148.0	148.0	148.0	148.0	148.0	148.0	148.0	148.0	S
Hallett 1 (Brown Hill)	94.5	94.5	94.5	94.5	94.5	94.5	94.5	94.5	94.5	94.5	SS
Hallett 2 (Hallett Hill)	71.4	71.4	71.4	71.4	71.4	71.4	71.4	71.4	71.4	71.4	SS
Hallett 4 (Nth Brown Hill)	132.3	132.3	132.3	132.3	132.3	132.3	132.3	132.3	132.3	132.3	SS
Hallett	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0	S
Ladbroke Grove	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0	S
Lake Bonney 2	159.0	159.0	159.0	159.0	159.0	159.0	159.0	159.0	159.0	159.0	SS
Lake Bonney 3	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	SS
Mintaro	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	S
Northern	544.0	544.0	544.0	544.0	544.0	544.0	544.0	544.0	544.0	544.0	S
Osborne	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	190.0	S
Pelican Point	474.0	474.0	474.0	474.0	474.0	474.0	474.0	474.0	474.0	474.0	S
Playford B	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	S
Port Lincoln	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	73.0	S
Quarantine	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	S
Snowtown	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	98.7	SS
Snuggery	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	S
Torrens Island A	504.0	504.0	504.0	504.0	504.0	504.0	504.0	504.0	504.0	504.0	S
Torrens Island B	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0	S
Waterloo	111.0	111.0	111.0	111.0	111.0	111.0	111.0	111.0	111.0	111.0	SS
Committed Projects											
Hallett 5 (The Bluff)	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	SS
Total	**4,414.1**	**4,415.1**	**4,416.1**	**4,416.1**	**4,416.1**	**4,416.1**	**4,416.1**	**4,416.1**	**4,416.1**	**4,416.1**	

4.7.2 Changes since the 2010 ESOO (existing generation)

Lake Bonney 2 and Lake Bonney 3 Wind Farm: Infigen Energy advises that at the regional reference temperature of 43 °C, the output from the wind farms will be (zero) 0 MW due to operational temperature limitations.

Playford Power Station: Alinta Energy advises that Playford's available capacity has been revised from 240 MW to 200 MW (-40 MW) in summer and 240 MW to 160 MW (-80 MW) in winter due to a change in operational parameters.

Torrens B Power Station: AGL advises that Torrens B has been revised from 800 MW to 780 MW (-20 MW) in summer and from 820 MW to 800 MW (-20 MW) in winter due to a change in the control systems and operating parameters.

4.7.3 Committed project developments

Hallett 5 (The Bluff) Wind Farm: AGL Energy advises that Hallet 5 is a committed project. The 52.5 MW wind farm is currently under construction with completion expected in December 2011.

4.7.4 Plant limitations

Wind generation will be limited by wind availability.

4.7.5 Plant retirements

AEMO has not been advised of any plant retirements in South Australia within the 10-year planning outlook.

4.7.6 Projects under development

AEMO sought information from generators and project proponents about the status of generation projects under development. Some companies provide AEMO with information that is commercial in-confidence, either due to being at an early stage of development, project mergers, changes to project details, or due to a company or project sale process that is currently underway. As a result, some projects have not been listed.

Some projects previously reported as advanced or committed may now be listed as publicly announced. This shift in classification since the 2010 ESOO is due to a more stringent data-gathering process that provided additional information about the planning process for each development.

Table 4-27 lists information about projects under development in South Australia.

Table 4-27 — Projects under development – South Australia

Project	Owner	Unit ID	Fuel Type	Generation Type	Land	Equip	Plan	Finance	Date	Unit Status	Nameplate Capacity (MW)	Dispatch Type	Commissioning Start Date
Allendale	ACCIONA Energy	1-46	Wind	Wind	✓					Pub An	69	SS	September 2014
Arckaringa[a]	Arckaringa Joint Venture	1-2	Black Coal/Diesel	IGCC						Pub An	570	S	TBA
Barn Hill	Barn HIll Wind Farm Pty. Ltd.	1-62	Wind	Wind	✓					Pub An	124-186	SS	TBA
Carmodys Hill	Pacific Hydro Pty. Ltd.	1-70	Wind	Wind						Pub An	140	SS	TBA
Cherokee Power Station	Tunkillo Powerco Pty. Ltd.	1	Natural Gas	OCGT						Pub An	250	S	December 2013
Collaby Hill	Origin Energy	1-40	Wind	Wind						Pub An	80	SS	July 2015
Green Point	Wind Prospect Pty. Ltd.	1-18	Wind	Wind						Pub An	54	SS	TBA
Hallett (Mt Bryan) Wind Farm	AGL Energy Limited	1-33	Wind	Wind	✓					Pub An	99	SS	TBA
Hallett (The Bluff) Wind Farm	AGL Power Generation Pty. Ltd.	1-25	Wind	Wind	✓	✓	✓	✓	✓	Com	53	SS	December 2011
Innamincka	Geodynamics Limited /Origin Energy Geothermal Pty. Ltd. (Joint Venture)	1	Geological heat	Geoth. HDR-Binary Cycle	✓					Pub An	25	S	March 2015
		2-7	Geological heat	Geoth. HDR-Binary Cycle	✓					Pub An	100	S	March 2018
		4-7	Geological heat	Geoth. HDR-Binary Cycle	✓					Pub An	200	S	March 2018
		8-11	Geological heat	Geoth. HDR-Binary Cycle	✓					Pub An	200	S	March 2019
Keyneton	Pacific Hydro Pty. Ltd.	1-57	Wind	Wind						Pub An	131	SS	TBA
Kongorong	Transfield Services	All units	Wind	Wind						Pub An	100-240	SS	TBA
Kulpara	Transfield Services	All units	Wind	Wind						Pub An	60-150	SS	TBA

Project	Owner	Unit ID	Fuel Type	Generation Type	Land	Equip	Plan	Finance	Date	Unit Status	Nameplate Capacity (MW)	Dispatch Type	Commissioning Start Date
Lincoln Gap	NP Power	1-59	Wind	Wind						Pub An	147.5-177	SS	TBA
Mount Hill	Transfield Services	All units	Wind	Wind						Pub An	80-180	SS	TBA
Pelican Point Stage 2	Pelican Point Power Limited	1-2	Natural Gas	OCGT	✓					Pub An	320	S	TBA
Point Paterson	Acquasol Infrastructure Pty. Ltd.	CCGT Units	Natural Gas/Solar	CCGT						Pub An	150	S	December 2014
		Solar Units	Natural Gas/Solar	Solar Thermal						Pub An	50	S	December 2014
Quarantine 6	Origin Energy	6	Natural Gas	OCGT	✓					Pub An	125	S	October 2015
Robertstown[b]	TRUenergy	1-25	Wind	Wind						Pub An	75	SS	TBA
Snowtown 2	Trustpower	All units	Wind	Wind	✓		✓	✓	✓	Pub An	210-250	SS	December 2012
Stony Gap[b]	TRUenergy	1-41	Wind	Wind						Pub An	123	SS	TBA
Torrens Island C	AGL Energy Ltd.	All units	Natural Gas	OCGT	✓					Pub An	500-750	S	TBA
Waterloo 2[b]	TRUenergy	38-42	Wind	Wind	✓					Pub An	18	SS	TBA
Willogoleche	Willogoleche Power Pty. Ltd.	1-25	Wind	Wind						Pub An	74	SS	TBA
Woakwine Stage 1	Infigen Energy	1-170	Wind	Wind	✓					Pub An	508	SS	July 2015

a. Altona Energy, on behalf of the Arckaringa Joint Venture, advised that 1,140 MW would be installed with 570 MW exported to the NEM if an extension is built.

b. TRUenergy recently acquired this project from Roaring40s and is currently unable to provide further information about the status of the project.

4.7.7 Non-scheduled generation

Table 4-28 lists information about non-scheduled generators in South Australia.

Table 4-28 — Existing non-scheduled generation – South Australia

Power Station	Owner	Fuel Type	Technology Type	Nameplate Capacity (MW)	Expected Capacity for Summer MD (MW)	Expected Capacity for Winter MD (MW)
Canunda	Canunda Power Pty. Ltd.	Wind	Wind	46	46	46
Cathedral Rocks	TRUenergy and ACCIONA Energy	Wind	Wind	66	66	66
Highbury	EDL LFG (SA) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	1	1	1
Lake Bonney Stage 1	Lake Bonney Wind Power Pty. Ltd	Wind	Wind	81	0	81
Lonsdale	Infratil Energy Australia Pty. Ltd.	Diesel	Compression Reciprocating Engine	20	20	20
Mt Millar	Mount Millar Windfarm Pty. Ltd.	Wind	Wind	70	70	70
Pedler Creek	EDL LFG (SA) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	3	1	1
Pt Stanvac A	Infratil Energy Australia Pty. Ltd.	Diesel	Compression Reciprocating Engine	29	29	29
Pt Stanvac B	Infratil Energy Australia Pty. Ltd.	Diesel	Compression Reciprocating Engine	29	29	29
Starfish Hill	Transfield Services Infrastructure Fund	Wind	Wind	35	35	35
Tatiara Meats	Vibe Energy Pty. Ltd.	Diesel	Compression Reciprocating Engine	1	0	0
Tea Tree Gully	EDL LFG (SA) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	1	1	1
Terminal Storage Mini Hydro	Lofty Ranges Power Pty. Ltd.	Water	Gravity Hydroelectric	3	3	3
Wattle Point	Infrastructure Capital Group	Wind	Wind	91	83	91
Wingfield I & II	EDL LFG (SA) Pty. Ltd.	Landfill Methane	Spark Ignition Reciprocating Engine	8	1	1

4.8 Tasmania

4.8.1 Existing and committed scheduled and semi-scheduled generation

Table 4-29 lists the existing and committed generation in Tasmania. Table 4-30 and Table 4-31 provide forecasts of scheduled and semi-scheduled available capacity for summer and winter, respectively.

Table 4-29 — Existing and committed scheduled and semi-scheduled generation – Tasmania

Power Station	Registered Participant	Units	Registered Capacity	Plant Type	Fuel Type	Dispatch Type
Bastyan	Hydro-Electric Corporation	1 x 79.9	79.9	Gravity Hydroelectric	Water	S
Bell Bay Three	Aurora Energy (Tamar Valley)	3 x 35	105	OCGT	Natural Gas	S
Catagunya/Liapootah/ Wayatinah	Hydro-Electric Corporation	2 x 24 3 x 27.9 3 x 12.8	170.1	Gravity Hydroelectric	Water	S
Cethana	Hydro-Electric Corporation	1 x 85	85	Gravity Hydroelectric	Water	S
Devils Gate	Hydro-Electric Corporation	1 x 60	60	Gravity Hydroelectric	Water	S
Fisher	Hydro-Electric Corporation	1 x 43.2	43.2	Gravity Hydroelectric	Water	S
Gordon	Hydro-Electric Corporation	3 x 144	432	Gravity Hydroelectric	Water	S
John Butters	Hydro-Electric Corporation	1 x 144	144	Gravity Hydroelectric	Water	S
Lake Echo	Hydro-Electric Corporation	1 x 32.4	32.4	Gravity Hydroelectric	Water	S
Lemonthyme/Wilmot	Hydro-Electric Corporation	1 x 51 1 x 30.6	81.6	Gravity Hydroelectric	Water	S
Mackintosh	Hydro-Electric Corporation	1 x 79.9	79.9	Gravity Hydroelectric	Water	S
Meadowbank	Hydro-Electric Corporation	1 x 40	40	Gravity Hydroelectric Gravity	Water	S
Poatina	Hydro-Electric Corporation	6 x 50	300	Gravity Hydroelectric	Water	S
Reece	Hydro-Electric Corporation	2 x 115.6	231.2	Gravity Hydroelectric	Water	S
Tamar Valley Combined Cycle	Aurora Energy (Tamar Valley)	1 x 141 1 x 68	208	CCGT	Natural Gas	S
Tamar Valley Peaking	Aurora Energy (Tamar Valley)	1 x 58	58	OCGT	Natural Gas	S
Tarraleah	Hydro-Electric Corporation	6 x 15	90	Gravity Hydroelectric	Water	S
Trevallyn	Hydro-Electric Corporation	4 x 20	80	Gravity Hydroelectric	Water	S

Power Station	Registered Participant	Units	Registered Capacity	Plant Type	Fuel Type	Dispatch Type
Tribute	Hydro-Electric Corporation	1 x 82.8	82.8	Gravity Hydroelectric	Water	S
Tungatinah	Hydro-Electric Corporation	5 x 25	125	Gravity Hydroelectric	Water	S

Table 4-30 — Summer aggregate scheduled and semi-scheduled generation – Tasmania (MW)

Power Station	2011–12	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	Dispatch Type
Bastyan	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	S
Bell Bay Three	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	S
Catagunya/ Liapootah/ Wayatinah	73.6	129.4	170.1	170.1	170.1	170.1	170.1	170.1	170.1	170.1	S
Cethana	85.0	85.0	0.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	S
Devils Gate	60.0	60.0	60.0	0.0	60.0	60.0	60.0	60.0	60.0	60.0	S
Fisher	43.2	0.0	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	S
Gordon	432.0	432.0	432.0	432.0	432.0	432.0	432.0	432.0	432.0	432.0	S
John Butters	144.0	144.0	144.0	0.0	144.0	144.0	144.0	144.0	144.0	144.0	S
Lake Echo	32.4	32.4	32.4	32.4	32.4	32.4	32.4	32.4	32.4	32.4	S
Lemonthyme/ Wilmot	81.6	81.6	30.6	81.6	51.0	81.6	81.6	81.6	81.6	81.6	S
Mackintosh	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	S
Meadowbank	40.0	40.0	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	S
Poatina	300.0	300.0	300.0	300.0	250.0	300.0	300.0	300.0	300.0	300.0	S
Reece	115.6	231.2	231.2	231.2	231.2	231.2	231.2	231.2	231.2	231.2	S
Tamar Valley CCGT	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0	S
Tamar Valley Peaking	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	S
Tarraleah	75.0	45.0	90.0	30.0	90.0	30.0	90.0	90.0	90.0	90.0	S
Trevallyn	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	S
Tribute	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9	S
Tungatinah	100.0	103.0	131.0	131.0	131.0	106.0	106.0	131.0	131.0	131.0	S
Total	**2,304.1**	**2,405.3**	**2,386.2**	**2,298.2**	**2,481.6**	**2,477.2**	**2,537.2**	**2,562.2**	**2,562.2**	**2,562.2**	

Table 4-31 — Winter aggregate scheduled and semi-scheduled generation – Tasmania (MW)

Power Station	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Dispatch Type
Bastyan	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	S
Bell Bay Three	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	S
Catagunya/ Liapootah/ Wayatinah	170.1	170.1	170.1	170.1	170.1	170.1	170.1	170.1	170.1	170.1	S
Cethana	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	S
Devils Gate	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	S
Fisher	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	S
Gordon	432.0	432.0	432.0	432.0	432.0	432.0	432.0	432.0	432.0	432.0	S
John Butters	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	S
Lake Echo	32.4	32.4	32.4	32.4	32.4	32.4	32.4	32.4	32.4	32.4	S
Lemonthyme/ Wilmot	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6	81.6	S
Mackintosh	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	79.9	S
Meadowbank	40.0	40.0	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	S
Poatina	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	S
Reece	231.2	231.2	231.2	231.2	231.2	231.2	231.2	231.2	231.2	231.2	S
Tamar Valley CCGT	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0	208.0	S
Tamar Valley Peaking	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	S
Tarraleah	90.0	75.0	90.0	90.0	75.0	90.0	90.0	90.0	90.0	90.0	S
Trevallyn	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	S
Tribute	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9	S
Tungatinah	103.0	103.0	131.0	131.0	131.0	106.0	106.0	131.0	131.0	131.0	S
Total	**2,534.2**	**2,519.2**	**2,522.2**	**2,562.2**	**2,547.2**	**2,537.2**	**2,537.2**	**2,562.2**	**2,562.2**	**2,562.2**	

4.8.2 Changes since the 2010 ESOO (existing generation)

Gordon Power Station: Hydro Tasmania previously advised that Gordon's available capacity would increase annually due to increasing water storage. This has been revised to 432 MW from 2012 to 2021, representing increases in capacity of between 54 MW in 2012 and 3 MW in 2021.

Hydro Tasmania advises of a number of changes to power station outage schedules. For more information see Section 4.8.4.

4.8.3 Committed project developments

AEMO has not been advised of any scheduled or semi-scheduled generation projects in Tasmania that are currently classified as committed, according to AEMO's commitment criteria.

4.8.4 Plant limitations

The output of some hydroelectric generation will be limited by water availability, inflows, and dam levels. More specific limitations include the following.

Catagunyah/Liapootah/Wayatinah Power Station: Hydro Tasmania advises that Liapootah's available capacity will be (zero) 0 MW during summer 2011–12.

Cethana Power Station: Hydro Tasmania advises that Cethana's available capacity will be (zero) 0 MW during summer 2013–14.

Devils Gate Power Station: Hydro Tasmania advises that Devils Gate's available capacity will be (zero) 0 MW during summer 2014–15.

Fisher Power Station: Hydro Tasmania advises that Fisher's available capacity will be (zero) 0 MW during summer 2012–13.

John Butters Power Station: Hydro Tasmania advises that John Butters' available capacity will be (zero) 0 MW during summer 2014–15.

Lemonthyme/Wilmot Power Station: Hydro Tasmania advises that Lemonthyme's available capacity will be (zero) 0 MW during summer 2013–14.

Lemonthyme/Wilmot Power Station: Hydro Tasmania advises that Wilmot's available capacity will be (zero) 0 MW during summer 2015–16.

Meadowbank Power Station: Hydro Tasmania advises that Meadowbank's available capacity will be (zero) 0 MW during summer 2013–14 and winter 2014.

Poatina Power Station: Hydro Tasmania advises that Poatina's available capacity will be limited to 250 MW during summer 2015–16 due to an outage of Unit 6.

Reece Power Station: Hydro Tasmania advises that Reece's available capacity will be 115.6 MW during summer 2011–12.

Tarraleah Power Station: Hydro Tasmania advises that Tarraleah's available capacity will be:

- 75 MW during summer 2011–12 due to an outage of Unit 4
- 45 MW during summer 2012–13 due to outages of Units 1–3
- 30 MW during summer 2014–15 due to outages of Units 1–4
- 30 MW during summer 2016–17 due to outages of Units 1–4
- 75 MW during winter 2013 due to an outage of Unit 2, and
- 75 MW during winter 2016 due to an outage of Unit 4.

Tungatinah Power Station: Hydro Tasmania advises that Tungatinah's available capacity will be:

- 100 MW during summer 2011–12 due to an outage of Unit 1
- 103 MW during summer 2012–13 due to an outage of Unit 2
- 106 MW during summer 2016–17 due to an outage of Unit 4, and
- 106 MW during summer 2017–18 due to an outage of Unit 5.

4.8.5 Plant retirements

AEMO has not been advised of any planned plant retirements in Tasmania within the 10-year planning outlook.

4.8.6 Advanced and publicly announced proposals

AEMO sought information from generators and project proponents about the status of generation projects under development. Some companies provide AEMO with information that is commercial in-confidence, either due to being at an early stage of development, project mergers, changes to project details, or due to a company or project sale process that is currently underway. As a result, some projects have not been listed.

Some projects previously reported as advanced or committed may now be listed as publicly announced. This shift in classification since the 2010 ESOO is due to a more stringent data-gathering process that provided additional information about the planning process for each development.

Table 4-32 lists information about projects under development in Tasmania.

Table 4-32 — Projects under development – Tasmania

Project	Owner	Unit ID	Fuel Type	Generation Type	Land	Equip	Plan	Finance	Date	Unit Status	Nameplate Capacity (MW)	Dispatch Type	Commissioning Start Date
Bell Bay Pulp Mill Project	Southern Star Corporation	1	Wood Waste	Steam Subcritical	✓	✓				Pub An	213	S	November 2013
Cattle Hill	NP Power Pty. Ltd.	1-80/96	Wind	Wind						Pub An	240	SS	TBA
Musselroe[a]	Hydro-Electric Corporation	1-56	Wind	Wind	✓					Pub An	168	SS	July 2012
Tungatinah (Upgrade)	Hydro-Electric Corporation	2-3	Water	Gravity Hydroelectric	✓	✓				Pub An	6	S	June 2012
White Rock	Eureka Funds Management	All Units	Wind	Wind	✓					Pub An	~400	SS	2016

a. Hydro-Electric Corporation recently acquired this project from Roaring40s and is currently unable to provide further information about the status of the project.

4.8.7 Non-scheduled generation

Table 4-33 lists information about non-scheduled generators in Tasmania.

Table 4-33 — Existing non-scheduled generation – Tasmania

Power Station	Owner	Fuel Type	Technology Type	Nameplate Capacity (MW)	Expected Capacity for Summer MD (MW)	Expected Capacity for Winter MD (MW)
Cluny	Hydro-Electric Corporation	Water	Gravity Hydroelectric	17	17	17
Lake Margaret	Hydro-Electric Corporation	Water	Gravity Hydroelectric	8	8	8
Lower Lake Margaret	Hydro-Electric Corporation	Water	Gravity Hydroelectric	3	3	3
Paloona	Hydro-Electric Corporation	Water	Gravity Hydroelectric	28	28	28
Remount	LMS Generation	Municipal and Industrial Materials	Spark Ignition Reciprocating Engine	2	2	2
Repulse	Hydro-Electric Corporation	Water	Gravity Hydroelectric	28	28	28
Rowallan	Hydro-Electric Corporation	Water	Gravity Hydroelectric	11	11	11
Tods Corner	Hydro-Electric Corporation	Water	Run of River	1	1	1
Woolnorth Studland Bay/ Bluff Point	Hydro-Electric Corporation	Wind	Wind	140	140	140

CHAPTER 5 - FUEL SUPPLY

Summary

This chapter presents an overview of the location, availability, and use of fuel supplies in the National Electricity Market (NEM), as well as established and emerging sources of electricity generation including coal, gas, liquid fuels, wind, solar, geothermal, biomass, and ocean (wave, tidal, and thermal) resources.

Coal-fired technologies dominate electricity generation in the NEM, with substantial high-quality black-coal reserves in Queensland and New South Wales, and large brown-coal reserves available in Victoria.

Gas powered generation (GPG), both combined cycle and open cycle, is increasing as developers look for lower carbon dioxide equivalent (CO2-e) emission-intensive fuels, with substantial conventional natural gas resources located predominately in Victoria and South Australia, and coal seam gas resources located in South West Queensland and Northern New South Wales.

Liquid fuels are often more expensive than coal and natural gas. Predominantly used as back-up and start-up fuels, generation designed to run solely on liquid fuels is limited to peak or emergency generation, or remote locations where fuel transport issues are a concern.

In addition to conventional thermal generation sources, Australia's feasible hydroelectric capacity sites are mostly developed[1], and wind and solar technologies continue to develop strongly. Other renewable resources remain largely undeveloped, partly due to the technology's higher per-megawatt capital costs. The majority of renewable fuel resources are also remote from existing transmission networks, potentially requiring significant transmission infrastructure investment to enable connection.

Australia's renewable resources currently incorporate the following key features:

- Prevailing average wind speeds make large areas along the south western and southern coastlines suitable for high-yield electricity generation. Wind resources also extend inland to include highland areas in South Eastern Australia, and some of the more isolated areas around the eastern coastal regions.
- Significant potential geothermal resources associated with high-temperature granites, and lower temperature geothermal resources linked to naturally-circulating waters in deep sedimentary aquifers, are located in the Northern Territory, North Eastern South Australia, and South Western Queensland.
- Solar energy resources falling on areas (excluding National Parks) within 25 kilometres of Australia's electricity transmission network are nearly 500 times greater than the annual energy consumption of Australia. Australia also experiences the highest average solar radiation per square metre of any continent in the world.[2]
- High quality wave energy resources exist along the southern half of the Australian continental shelf, particularly along the southern coast of Tasmania. These resources are relatively remote from existing NEM transmission assets and internationally only a few demonstration plants are in operation.

To promote the development of these resources, renewable generation revenues are currently being supplemented by the Australian Government's national Renewable Energy Target (RET) scheme.[3] In the long term, carbon pricing and emissions trading scheme (ETS) initiatives have the potential to establish their economic viability.

[1] ABARE. "Australian Energy Resource Assessment". Available http://adl.brs.gov.au/data/warehouse/pe_aera_d9aae_002/aera.pdf. 28 April 2011.

[2] Geoscience Australia. "Solar Energy". Available http://www.ga.gov.au/energy/other-renewable-energy-resources/solar-energy.html. 12 May 2011.

[3] Department of Climate Change and Energy Efficiency. "Renewable Energy Target". Available http://www.climatechange.gov.au/en/government/initiatives/renewable-target.aspx. 8 June 2011.

5.1 Fuel supply to the NEM

Figure 5-1 and Figure 5-2 show the relative proportions of the NEM's total installed scheduled and semi-scheduled capacity (at July 2010) and total annual energy production (during 2010–11), by fuel source.

Figure 5-1 — Total installed scheduled and semi-scheduled capacity by fuel source, July 2011

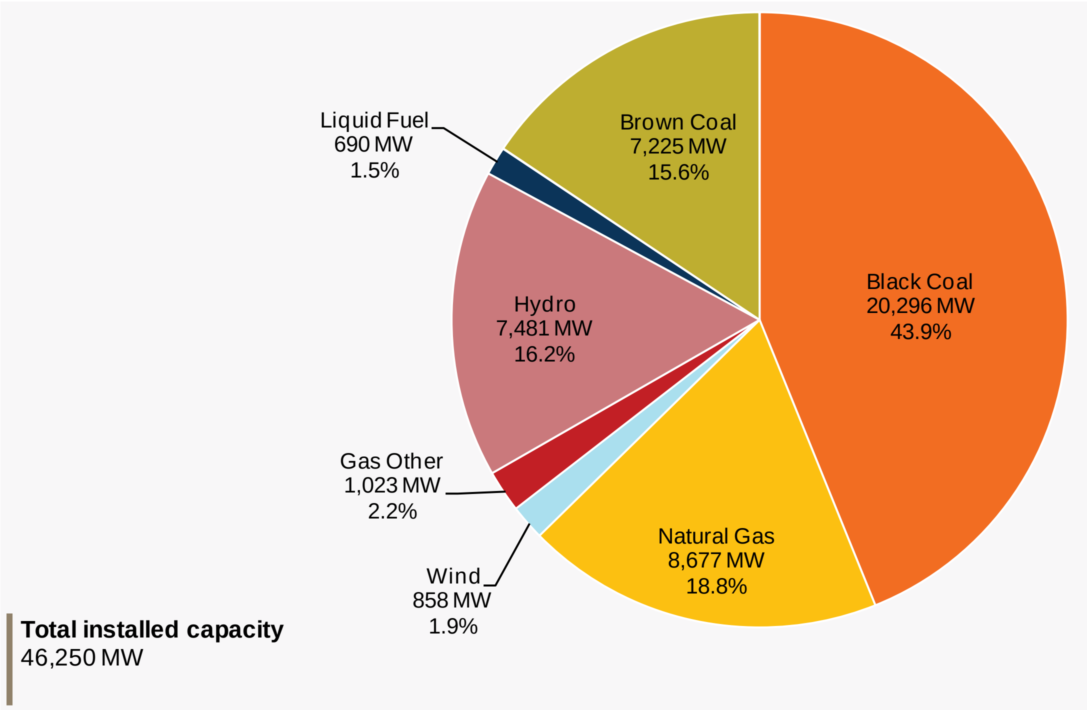
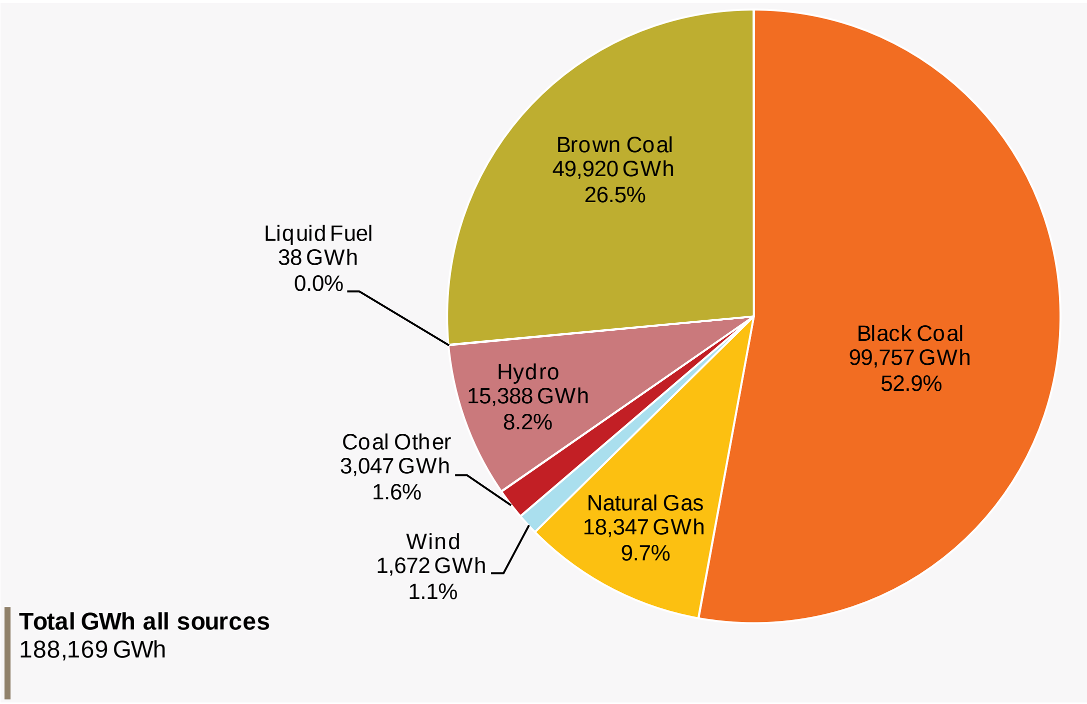


Figure 5-2 — Total annual energy produced by fuel source, 2010–11



Coal remains the dominant base load fuel, representing over half the installed generation capacity, and over three quarters of the annual electrical energy produced. Gas, liquid fuels, and hydroelectric generation together contribute approximately 20% to total energy production, despite making up nearly 40% of the available generation capacity. This peaking behaviour reflects the underlying operating costs and fuel limitations.

While coal is the leading generation technology overall, the prevailing fuel for electricity generation varies from region to region. Queensland and New South Wales primarily rely on black coal, Victoria on brown coal, and Tasmania on hydroelectricity. South Australian demand is not dominated by a single technology but is largely met by a mixture of gas, coal, and wind.

Figure 5-3 and Figure 5-4 show the change in annual energy by fuel source over the last six years. A steady fall in total energy production from black coal resources continued during 2010–11, while the contributions from gas and renewable technologies increased.

The drought that affected hydroelectric generation between 2001 and 2009 has now broken, increasing the level of output from these generating systems as inflows and reservoir levels return to long-term expectations.

The contribution of wind generation to energy production continues to grow, with renewable technology development being accelerated by the national RET scheme, and by a government requirement for some desalination projects to be supplied by renewable energy sources.

Figure 5-3 — Annual scheduled and semi-scheduled energy production by fuel source (coal)

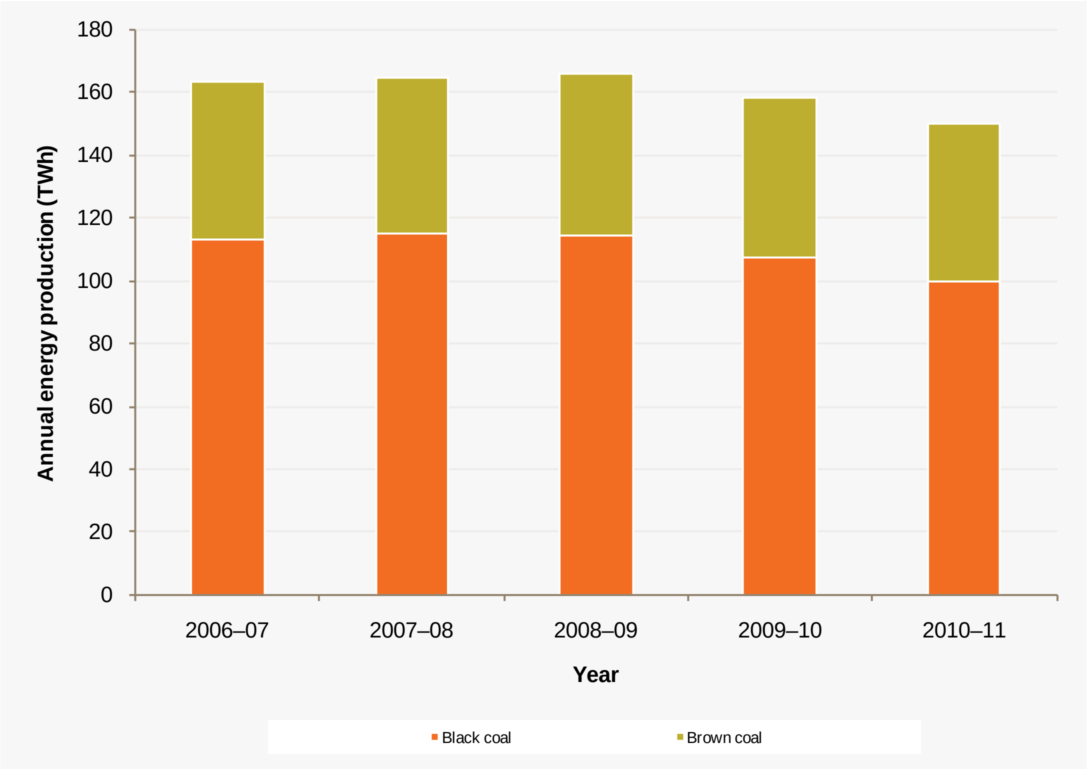
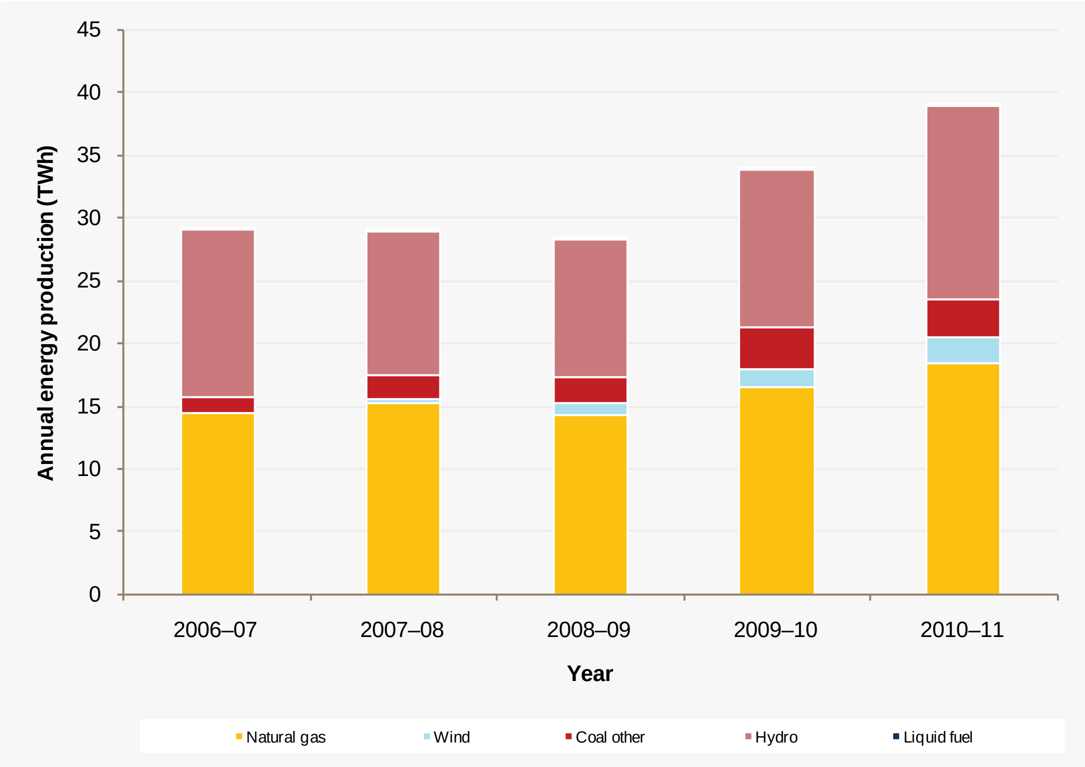


Figure 5-4 — Annual scheduled and semi-scheduled energy production by fuel source (non-coal)



5.2 Coal

The Australian Energy Resource Assessment[4] produced by the Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES) lists coal as Australia's largest energy resource, in terms of both energy production and the size of economic demonstrated resources (EDR). Coal is a low cost fuel and is often located close to areas of demand.

Much of Australia's coal is extracted using open cut mining techniques, and in February 2011 there were 128 operating coal mines and more than 40 proposed new mines or expansions at various stages of development.[5] Based on current production, these mines have approximately 100 years of economic black coal reserves.[4]

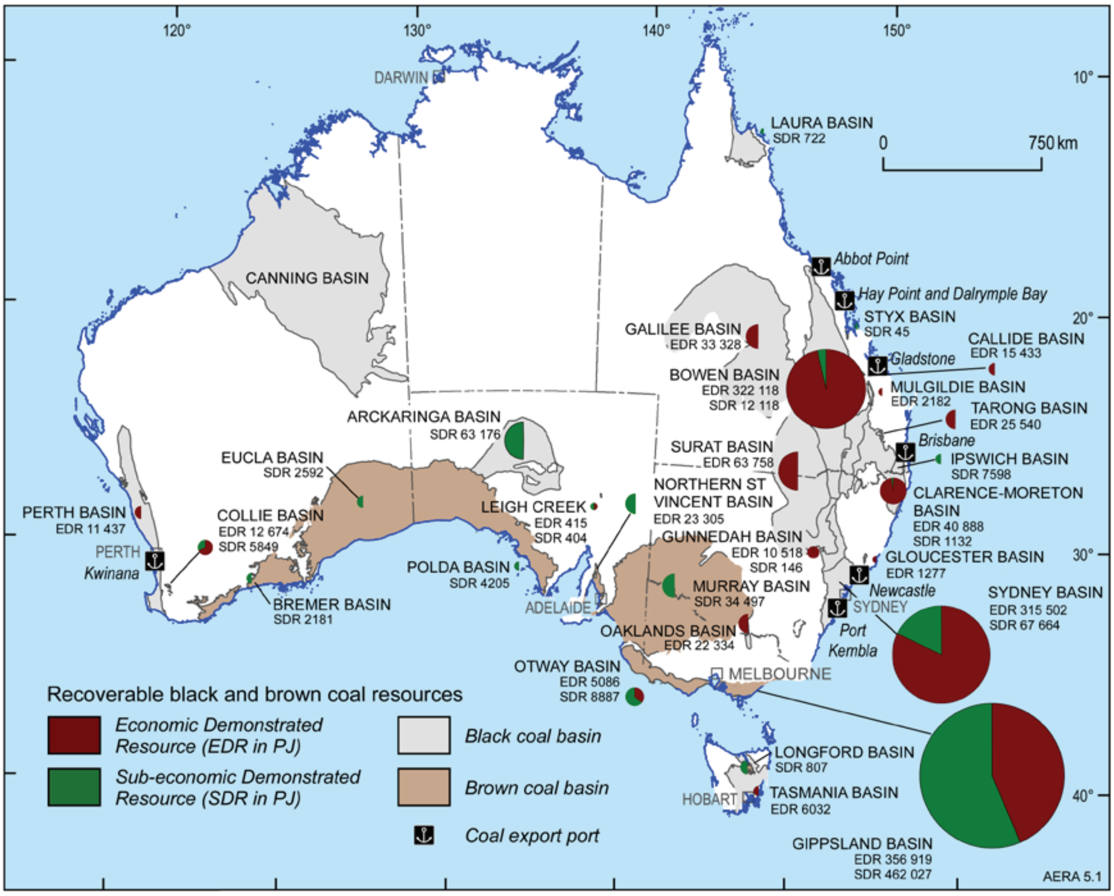
Australia is the world's largest exporter of black coal, providing both thermal coal for power stations and metallurgical coal for steel production in China and other Asian countries. At present, approximately 15% of Australia's coal production is used domestically for electricity generation.

Major black coal deposits are located in New South Wales and Queensland, and substantial brown coal reserves are located in Victoria. Figure 5-5 shows the total recoverable black and brown coal resources available in Australia as at December 2008.

[4] See note 1 in this chapter.

[5] Geoscience Australia. "Operating Mines". Available http://www.australianminesatlas.gov.au/mapping/downloads.jsp#ozmin. 8 June 2011.

Figure 5-5 — Total recoverable resources of black and brown coal as at December 2008[6]



Source: Geoscience Australia

5.2.1 Regional coal resources

The major Eastern Australian recoverable black coal deposits are in the Sydney basin (31% of Australia's black coal EDR), the Bowen Basin (35%), and the Surat Basin (9%)[7], with the remaining 25% located at a number of smaller deposits. Table 5-1 lists coal resources available to NEM generation.

6 See note 1 in this chapter.

7 Geoscience Australia. "Australia's Identified Mineral Resources 2010". Available https://www.ga.gov.au/products/servlet/controller?event=GEOCAT_DETAILS&catno=71584. 12 May 2011.

Table 5-1 — Coal resources (PJ)[8]

Basin	Economic Demonstrated Resources	Sub-Economic Demonstrated Resources	Inferred Resources
Queensland			
Bowen	322,118	12,118	253,400
Gallilee	33,328		89,700
Surat	63,758		
Styx		45	
Callide	15,433		
Mulgildie	2,182		
Tarong	25,540		
Ipswich		7,598	
Laura		722	
New South Wales			
Gunnedah	10,518	146	461,300
Sydney	315,502	67,664	286,600
Clarence Morton	40,888	1,132	
Oaklands	22,334		
Gloucester	1,277		
Victoria			
Murray		34,497	148,358
Gippsland	356,919	462,027	740,880
Otway	5,086	8,887	76,698
Moe Swamp			6,748
South Australia			
Arckaringa		63,176	233,400
Leighcreek	415	404	
Polda		4,205	
Nth St Vincent		23,305	9,006
Tasmania			
Tasmania	6,032		
Longford		807	

8 See note 1 in this chapter.

Queensland

Queensland has approximately 58% of Australia's EDR of black coal.[9] Ten coal-fired power stations operate in Queensland and most are supplied from captive long life coal mines under a variety of mine arrangements. [10]

New South Wales

New South Wales has approximately 38% of Australia's EDR of black coal[11], and eight coal-fired power stations in operation in the Newcastle, Hunter, and Western coalfields. The Hunter power stations have long-term coal supply agreements, with 46% of the region's coal-fired generation supplied by Centennial Coal.[12] Prices are due for re-negotiation from 2012, and a November 2010 Centennial Coal media release advised that no agreement had been reached with one of the New South Wales generators.[13]

As part of the New South Wales Energy Reform process, the New South Wales Government finalised the sale of some of its generation output via a 'gen-trader' arrangement. This sold the Government's output trading rights from a number of generating units (Eraring Energy, Mt Piper Power Station, and Wallerawang Power Station), while retaining ownership of the physical generating units. The Government also sold the retailer components of its electricity businesses (Energy Australia, Country Energy, and Integral Energy). The New South Wales Auditor General has released a report detailing a number of the rights, obligations, risks, and uncertainties associated with the sale.[14] The incoming New South Wales Government has also launched a review of these sales.[15]

As part of the sale process, the New South Wales Government announced the Cobbora open-cut coal mine was proceeding, and would produce coal for all the current coal-fired electricity generation businesses at a discount on international prices. The government-managed mine is expected to have an annual output of 30 million tonnes, and is scheduled to start production in 2013.[16]

Coal costs for all New South Wales generators (excluding Redbank) tend to converge after approximately 2020, due to Cobbora becoming the supplier for the majority of coal to all large New South Wales power stations.

Victoria

Victoria has almost all of Australia's EDR of brown coal (lignite), with approximately 490 years of reserves at current production.[17] There are five privately-owned, mine-mouth coal-fired power stations in the LaTrobe Valley. Victorian brown coal has a high moisture content (48%–70%), a low ash content (<4%), and a low heating value (5.8 MJ/kg–11.5 MJ/kg).[18] Unsuitable for export, Victorian brown coal is generally used for electricity production where power stations are located adjacent to the mine sites. Coal drying techniques that may improve combustion and produce an export-suitable product are being researched.[19]

9 See note 7 in this chapter.

10 EnergyQuest. "Fuel Supplies in the National Electricity Market Report for the Australian Energy Market Operator". April 2010.

11 See note 7 in this chapter.

12 Centennial Coal. "Annual Report 2010". Available http://www.centennialcoal.com.au/index.php?option=com_content&view=article&id=30:download&catid=48:annual-reports&Itemid=185. 7 June 2011.

13 Centennial Coal. "Domestic Contract Discussions Cease". Available http://www.centennialcoal.com.au/index.php?option=com_content&view=article&id=798:domestic-contract-discussions-cease&catid=56:oct-dec&Itemid=180. 7 June 2011.

14 The Audit Office of New South Wales. "The Auditor-General's Report to Parliament – 2010 Volume One". Available http://www.audit.nsw.gov.au/publications/reports/financial/2011/Vol01/contents.htm. 8 June 2011.

15 The Department of Attorney General and Justice of New South Wales. "Special Commission Inquiry into Electricity Transactions". Available http://www.lawlink.nsw.gov.au/lawlink/Special_Projects/ll_splprojects.nsf/pages/sciet_index. 28 June 2011.

16 New South Wales Government – Planning & Infrastructure. "Cobbora Coal Project". Available http://majorprojects.planning.nsw.gov.au/index.pl?action=view_job&job_id=3695. 8 June 2011.

17 See note 1 in this chapter.

18 State Government Victoria - Department of Primary Industries. "Fact Sheet: Victoria, Australia, A principal Brown Coal Province". Available http://new.dpi.vic.gov.au/earth-resources/industries/coal/fact-sheet-brown-coal-victoria. 7 June 2011.

19 Department of Primary Industries. "Our Coal Our Future – Future opportunities for brown coal". Available http://new.dpi.vic.gov.au/earth-resources/investment/our-coal. 6 June 2011

South Australia

The coal supplies for the two South Australian coal-fired generators at Port Augusta are sourced from the Leigh Creek coal mine. The Leigh Creek coal mine is the only operating coal mine in South Australia and is an open-cut mine comprising a number of coal seams located approximately 570 kilometres north of Adelaide. Leigh Creek coal is of a lower quality than New South Wales or Queensland black coal, but higher quality than Victorian brown coal. While there are approximately 150 megatonnes of inferred resources at Leigh Creek, much of this is not economically recoverable. Depending on the operation of the Northern and Playford Power Stations, Leigh Creek coal is expected to be economically exhausted over the next 15 years, and continued coal-firing will require the power station owners to procure some or all of their fuel from alternate sources.

Advice provided to AEMO by CQ Partners indicates that a number of options are available for future Northern and Playford Power Station supplies.[20] These include the development of new coal mines in South Australia and importing coal from other regions or overseas. This advice identifies a number of coal reserves in South Australia with development potential.

Tasmania

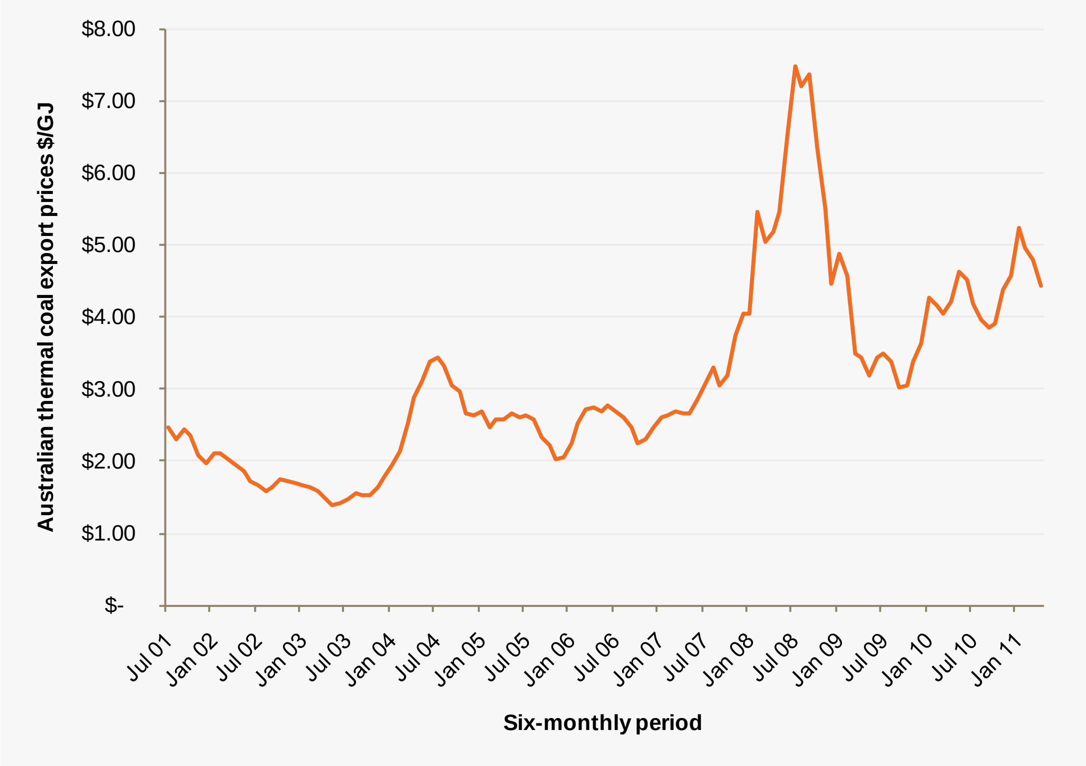
Tasmania has black coal deposits in the Tasmania Basin and brown coal deposits in the Longford Basin. However, there is no coal-fired generation in Tasmania, with almost all the region's power generation supplied by hydroelectricity, gas, and wind. The sole coal mining company, Cornwall Coal, primarily supplies the cement plant at Railton as well as most of Tasmania's general coal requirements.

[20] CQ Partners. "Leigh Creek Life Study". March 2011.

5.2.2 Coal prices

International coal prices have risen slowly over the past few years, and the recent Queensland floods are likely to contribute to a further price rise in the short term. Figure 5-6 shows coal price movements over time. Most coal contracts are written in US dollars, and the rise in the Australian dollar has reduced the impact of international price rises.

Figure 5-6 — Australian thermal coal export prices[21]



As most coal-fired power stations in the NEM are either mine-mouth or have other dedicated mine arrangements, international coal prices may have no direct impact. The major exceptions to this are the New South Wales coal-fired power stations, which currently source fuel from mines that are also able to export, although discounted coal prices from the new Cobbora mine may affect this arrangement (see Section 5.2.1).

[21] International Monetary Fund. "IMF Primary Commodity Prices". Available http://www.imf.org/external/np/res/commod/index.asp. 8 June 2011.

5.3 Gas

The Gas Statement of Opportunities (GSOO), published annually by AEMO and released in December each year, describes gas demand forecasts and resources in Eastern and South Eastern Australian.[22] The NEM regions have large resources of conventional natural gas, located predominantly in Victoria and South Australia, and coal seam gas located in Queensland and New South Wales.

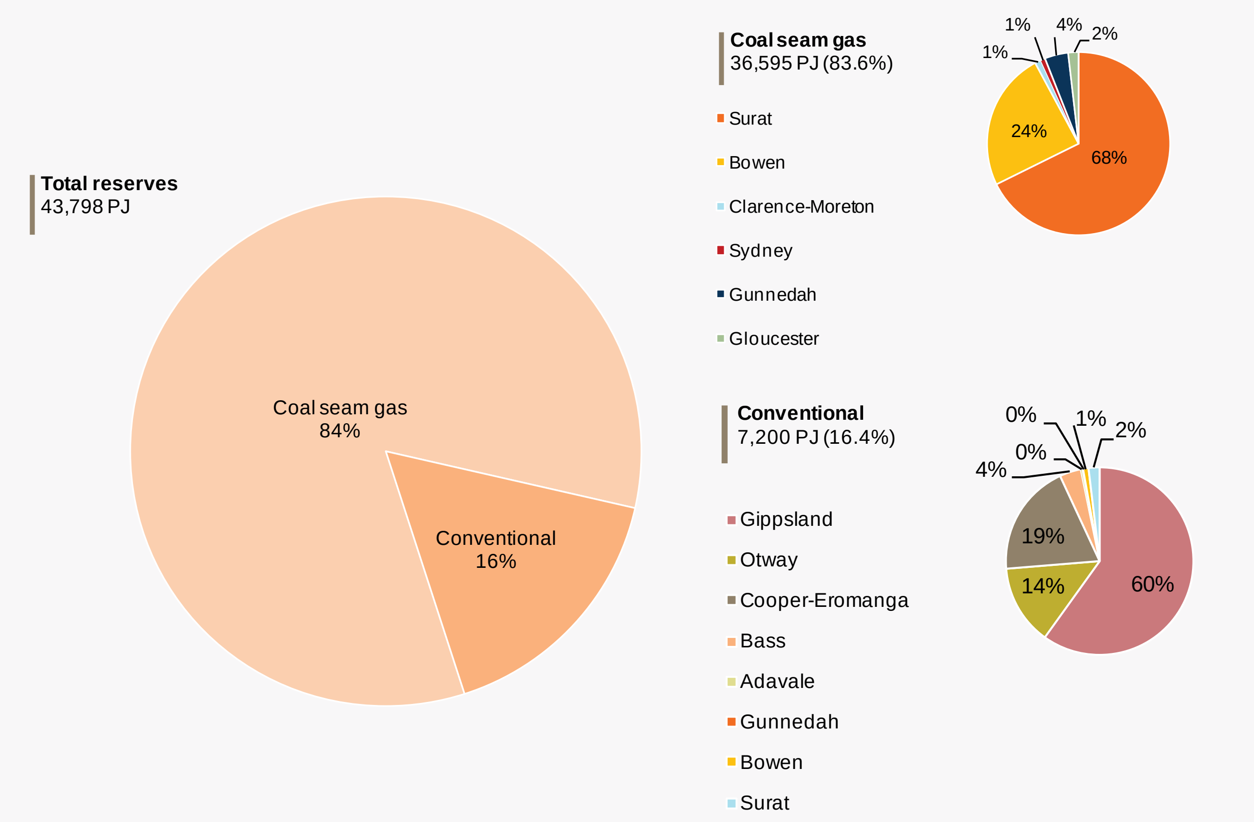
Figure 5-7 shows the major gas basins in Eastern and South Eastern Australian. Figure 5-8 shows the distribution of gas reserve volumes.

[22] AEMO. "2010 Gas Statement of Opportunities". Available http://www.aemo.com.au/planning/gsoo2010.html. 8 June 2011.

Figure 5-7 — Eastern and South Eastern Australian gas basins and processing facilities[23]

23 AEMO. "2010 Gas Statement of Opportunities". Figure 2-2, page 42. Available http://www.aemo.com.au/planning/gsoo2010.html. 8 June 2011.

Figure 5-8 — Eastern Australian 2P gas reserves by basin, December 2010[24]



5.3.1 Development of gas reserves in Eastern and South Eastern Australia

Eastern and South Eastern Australian gas reserves classified as proved and probable totalled 43,798 PJ as at 31 December 2010. These reserves represent over 70 years of gas supply at the current rate of consumption. As reported in the 2010 GSOO[25], when less certain gas reserves are included, gas reserves and resources (as at 31 December 2009) totalled over 274,000 PJ, or nearly 400 years supply at the current consumption rate. In recent years there has been a dramatic increase in coal seam gas reserves identified in Queensland and New South Wales.

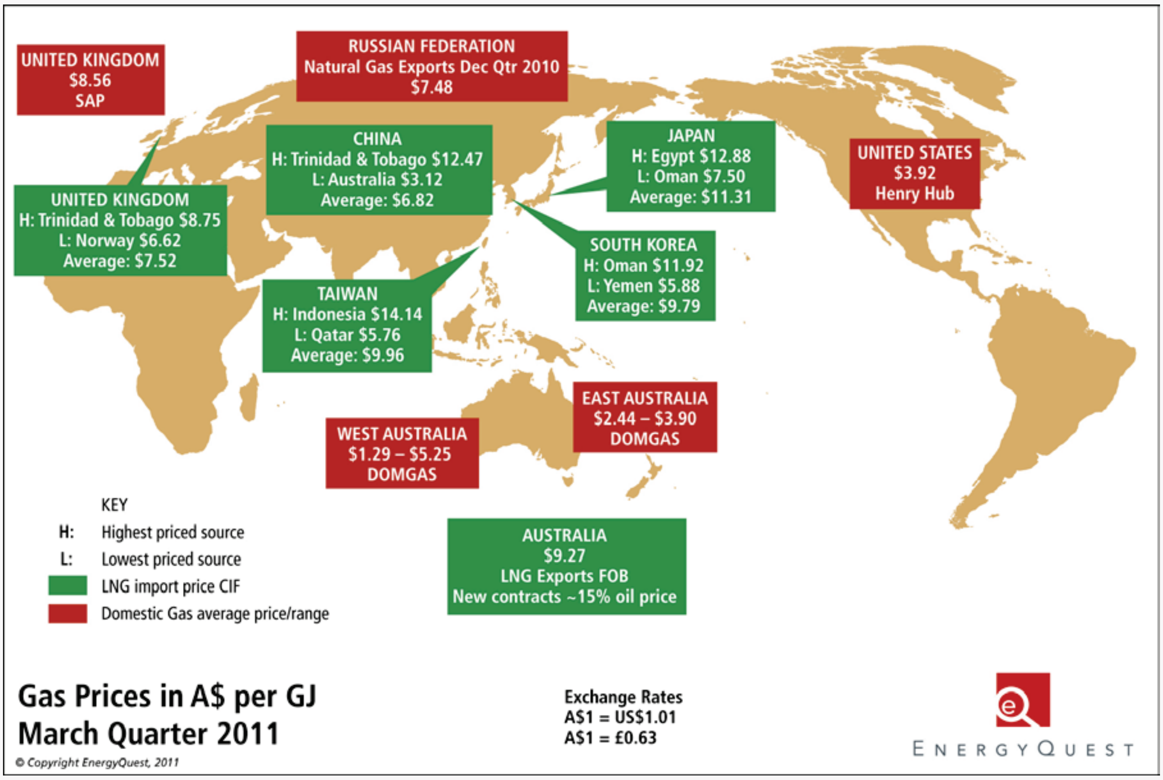
Beyond coal seam gas, other unconventional gas sources (such as shale gas) are being investigated in the Cooper and Eromanga basins in South Australia.[26]

5.3.2 Gas prices

Figure 5-9 shows international and Australian gas prices in dollars per gigajoule ($/GJ) for the 2011 March quarter. International prices are generally higher than prices for Australian domestic gas. Eastern Australian gas prices may rise to export parity as Liquefied Natural Gas (LNG) facilities are built on the East Coast. However, the ongoing proving-up of coal seam gas reserves, and the possibility of future shale gas resource development, may provide downward cost pressure.

[24] Advice to AEMO from Resource Land and Management Services (RLMS). March 2011.
[25] AEMO. “2010 Gas Statement of Opportunities”. Sections 3.4 and 3.5. Available http://www.aemo.com.au/planning/gsoo2010.html. 8 June 2011.
[26] Government of South Australia – Primary Industries and Resources SA. “Shale Gas”. Available http://www.pir.sa.gov.au/petroleum/prospectivity/basin_and_province_information/shale_gas. 7 June 2011.

Figure 5-9 — International and Australian gas prices, 2011 March quarter[27]



5.4 Liquid fuels

Diesel, fuel oil, recycled oils, and kerosene are the primary liquid fuels used for NEM power generation. Approximately 40% of Australia's liquid fuels are sourced internationally and the prices for petroleum products in Australia are strongly linked to international benchmark prices.

Liquid fuels are currently more expensive than coal or natural gas, and generators designed to run solely on liquid fuels are primarily limited to peak or emergency generation, and to remote off-grid power generation, where the cost of fuel transport infrastructure is an issue.

Some open-cycle gas turbines (OCGT) and gas-fired steam turbines may use liquid fuels as back-up when gas supply is restricted. These restrictions can occur for short periods during gas demand peaks, but also during very rare events, such as the 1998 Longford gas plant accident.[28] At present, none of the combined-cycle gas turbines (CCGT) in the NEM can use back-up liquid fuels. a small number of coal-fired plants also use fuel oil or recycled oil as a start-up fuel, or for temporarily maintaining flame stability when changing output.

27 EnergyQuest. "EnergyQuarterly". May 2011.

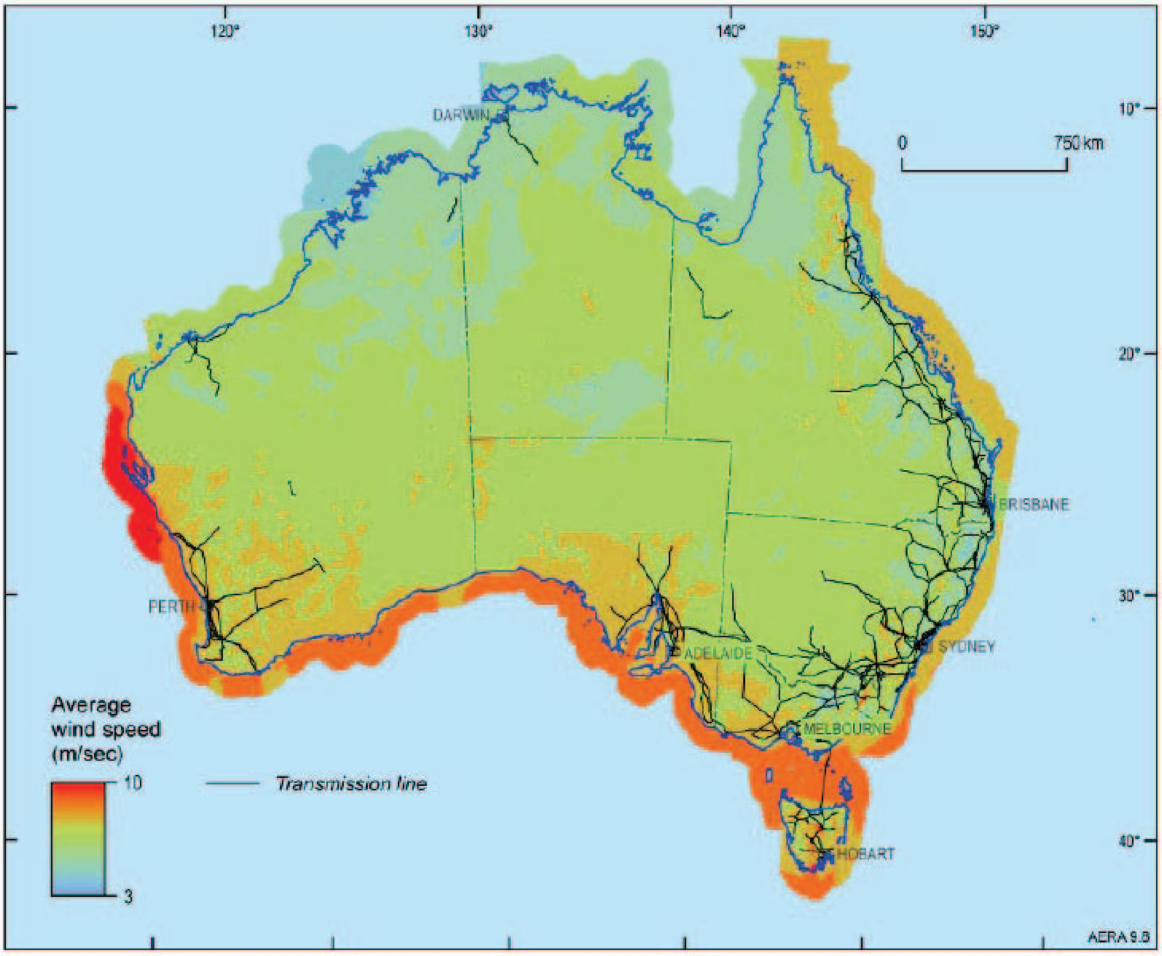
28 Office of the Emergency Services Commissioner. "Longford Gas Plant Explosion". Available http://www.oesc.vic.gov.au/wps/wcm/connect/OESC/Home/Managing+Emergencies/Historic+Emergencies/OESC+-+Longford+Gas+Plant+Explosion+(weblink). 16 August 2011.

5.5 Wind

Australia's south-western and southern coastlines have large areas with average wind speeds suitable for high-yield electricity generation. These resources also extend inland to include highland areas in South Eastern Australia, and some more isolated areas around the coastline that are remote from existing transmission assets.

Figure 5-10 shows the average wind speeds across country and coastal areas. Local topography and local terrain variability are major influences on wind speed and wind variability, requiring developers to carry out detailed local studies of potential wind farm sites.

Figure 5-10 — Predicted average wind speed at a height of 80m[29]

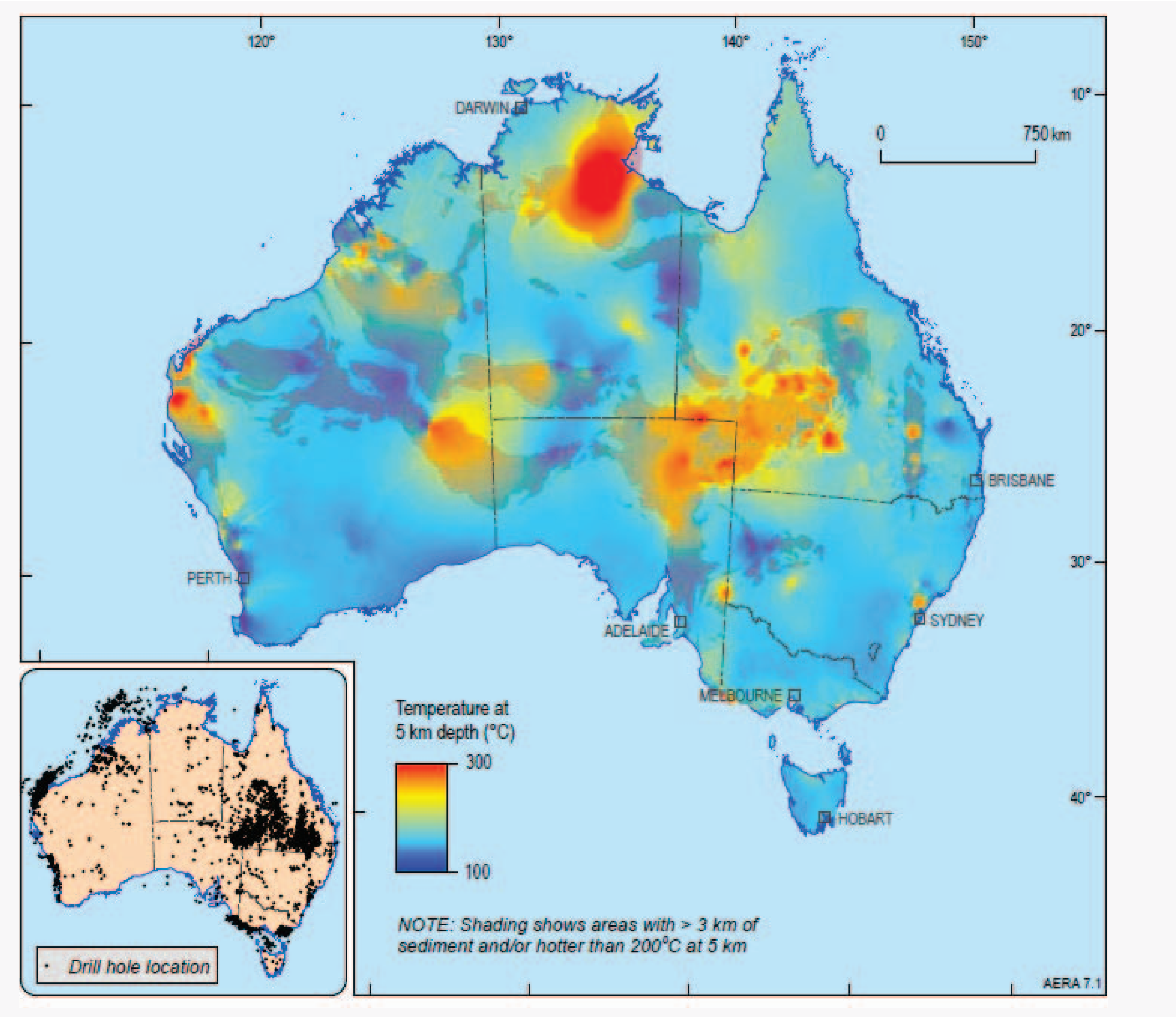


[29] ABARES. "Australian Energy Resource Assessment". Available http://adl.brs.gov.au/data/warehouse/pe_aera_d9aae_002/aera.pdf. based on data from Windlab Systems Pty Ltd. 28 April 2011.

5.6 Geothermal

Australia has significant geothermal resources associated with buried, high-temperature granites and lower-temperature resources linked to naturally-circulating waters in deep sedimentary aquifers. Figure 5-11 shows the predicted temperature profile at a depth of five kilometres, and identifies a significant resource area in South Australia's north east, and Queensland's south west. Many areas with substantial geothermal resource are remote from existing transmission network assets.

Figure 5-11 — Predicted temperatures at five kilometres depth[30]



30 ABARES. "Australian Energy Resource Assessment". Available http://adl.brs.gov.au/data/warehouse/pe_aera_d9aae_002/aera.pdf. Based on data from EarthEnergy Australia Pty Ltd. 28 April 2011.

While geothermal energy has been used in other parts of the world for decades, it is still in an early stage of exploration and development in Australia. Most of the world's current geothermal energy is located in more volcanic regions such as Italy, Mexico, Japan, New Zealand, and Iceland.[31] Lacking a similar geology, investigations are underway in Australia to explore opportunities to extract heat from deeper in the earth's crust.

Approximately 50 companies have applied for geothermal tenements around Australia, with the majority of these licences in South Australia, and three companies are moving towards pilot plants over the next several years.[32]

5.7 Biomass

Agriculture, forestry, and food production in every NEM region produces substantial waste biomass that can be harnessed to create electricity.

Some biomass resources are currently being used to generate electricity, the majority from bagasse-fired cogeneration in the sugar mills of Queensland (23 generators) and Northern New South Wales (5 generators).[33] Other biomass sources include landfill gas (69 generators), sewage gas (24 generators), and various forms of agricultural and other organic wastes (8 generators). The Clean Energy Council's Australian Bioenergy Roadmap identified the potential for over 10 MWh to be generated annually from biomass resources by 2020.[34]

5.8 Hydroelectric

Most of Australia's major available hydroelectric resources have already been developed. Over 100 hydroelectric power stations are installed in Australia, with the majority in New South Wales, Victoria, and Tasmania.

Opportunities still exist in the form of upgrades to existing hydroelectric generating systems, and the installation of new, smaller hydroelectric generating units (typically as part of city water supply systems).

Hydroelectric generation is highly sensitive to changes in climate, and during the recent drought, many dams fell to levels that resulted in severe energy limitations and, in some cases, a full shutdown. With the return of sufficient inflows, hydroelectric generation output rose in 2011.

[31] IEA Geothermal Energy. "Geothermal Information". Available http://www.iea-gia.org/geothermal_information.asp. 8 June 2011.

[32] Australian Geothermal Energy Association Inc. "Australian Projects Overview". Available http://www.agea.org.au/geothermal-energy/australian-projects-overview/. 8 June 2011.

[33] Clean Energy Council Database of Renewable Energy. Available http://www.cleanenergycouncil.org.au/cec/resourcecentre/plantregistermap.html. 29 June 2011.

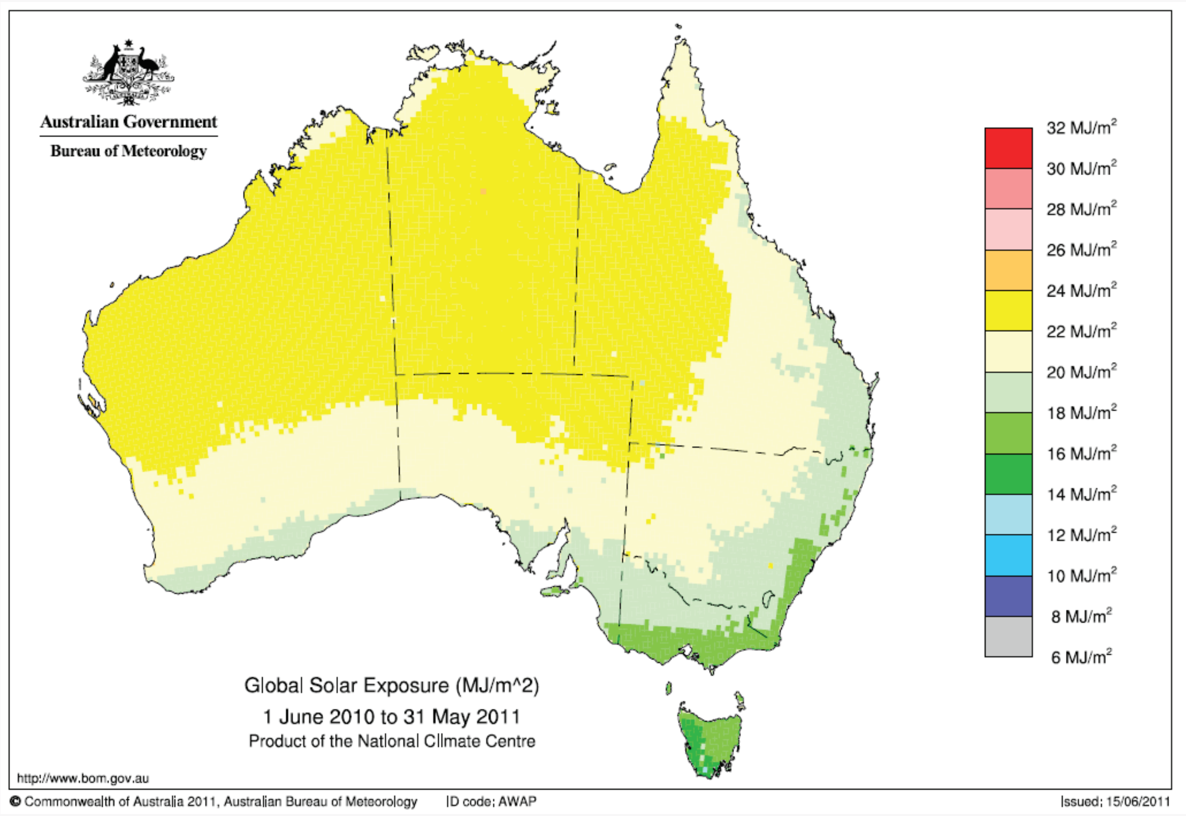
[34] Clean Energy Council. "Australian Bioenergy Roadmap". Available http://www.cleanenergycouncil.org.au/dms/cec/industrydevelopment/bioenergy/01-Australian-Bioenergy-Roadmap/01%20Australian%20Bioenergy%20Roadmap.pdf. 8 June 2011.

5.9 Solar

Australia has the highest average solar radiation per square metre of any continent in the world.[35] The annual solar radiation falling on Australia is roughly 58 million PJ, which is approximately 10,000 times Australia's annual energy consumption.

Figure 5-12 shows the annual average solar resources available across Australia. While solar energy resources are largest in locations remote from the transmission network, there are still significant solar energy resources available near grid-connected areas. The solar energy resource falling on areas (excluding National Parks) within 25 kilometres of an electricity transmission network is nearly 500 times greater than the annual energy consumption of Australia.[36]

Figure 5-12 — Annual average solar radiation [37]



[35] Geoscience Australia. "Solar Energy". Available http://www.ga.gov.au/energy/other-renewable-energy-resources/solar-energy.html. 12 May 2011

[36] See note 2 in this chapter.

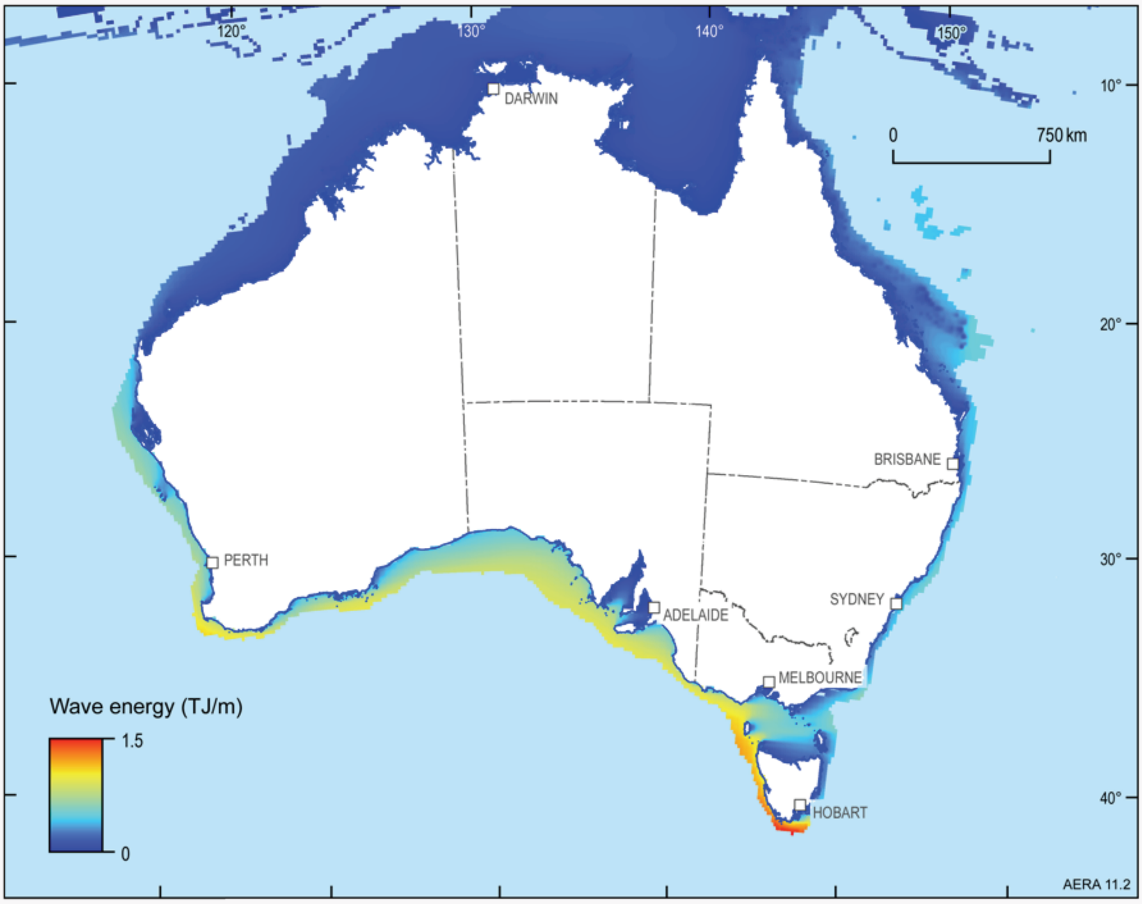
[37] Solar radiation data derived from satellite imagery processed by the Bureau of Meteorology from the Geostationary Meteorological Satellite and MTSAT series operated by Japan Meteorological Agency and from GOES-9 operated by the National Oceanographic & Atmospheric Administration (NOAA) for the Japan Meteorological Agency.

5.10 Ocean

Energy from the ocean comprising wave, tide, and ocean thermal energy, is an undeveloped but potentially substantial renewable energy source. Globally, there are only two tidal barrage power plants[38] and a number of demonstration wave and tidal plants in operation. A substantial amount of research and development is taking place to develop these technologies further.

The southern half of the Australian continental shelf, along the western and southern coastlines, has high quality wave energy resources. Figure 5-13 shows the total annual wave energy on the Australian continental shelf, and identifies a particularly high concentration of wave energy off the southern coast of Tasmania, which is relatively remote from existing NEM transmission assets.

Figure 5-13 — Total annual wave energy on the Australian continental shelf (at less than 300 meters depth)[39]

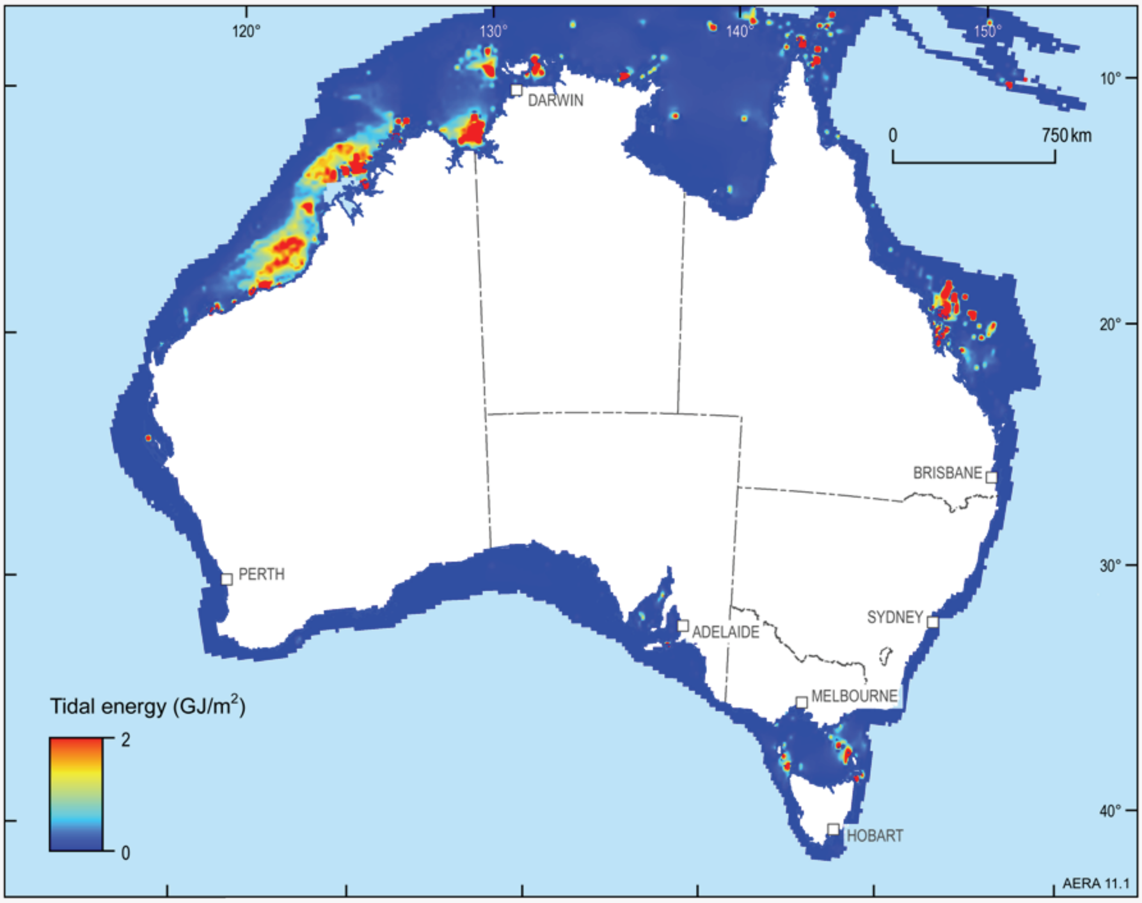


Source: Geoscience Australia

Figure 5-14 shows total annual tidal energy, which is limited along the southern coast, but significant along the northern coast, particularly above Western Australia and Far North Queensland.

38 See note 1 in this chapter.
39 See note 1 in this chapter.

Figure 5-14 — Total annual tidal kinetic energy on the Australian continental shelf (at less than 300 metres depth)[40]



Source: Geoscience Australia

40 See note 1 in this chapter.

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CHAPTER 6 - RELIABILITY AND MINIMUM RESERVE LEVELS

Summary

This chapter describes aspects of power system reliability, with a specific focus on the calculation and application of minimum reserve levels (MRLs). MRLs form the basis of AEMO's operational and long-term planning assessments of system reliability.

Regular review of the MRLs is important to ensure that minimum reserve requirements remain appropriate as the power system evolves. Supply adequacy is particularly sensitive to aspects of the power system that change over time, such as changes in demand diversity, the location and reliability of installed generation capacity, and any significant transmission network topology augmentation. AEMO completed its most recent MRL calculation in July 2010.[1]

As part of the 2010 calculation process, AEMO explored and quantified the ability for neighbouring regions to share surplus reserves. These relationships allow the MRLs to be optimised so that regions with excess available capacity can support neighbouring regions that are unable to meet their MRL locally.

The results of this investigation indicate that substantial reserve sharing opportunities exist between Victoria and South Australia. Reserve sharing between New South Wales and Queensland is also possible, though less efficient. No sharing opportunities exist between New South Wales and Victoria or between Victoria and Tasmania.

For the purposes of the ESOO, the reserve sharing relationships are used to assess supply adequacy over the next 10 years. For more information about the regional results under a range of demand growth assumptions, see Chapter 7.

6.1 Reliability and minimum reserve levels

This section provides a brief overview of the concept of reliability and its relationship to the MRLs.

6.1.1 Reliability and the Reliability Standard

In the context of the National Electricity Market (NEM), reliability refers to the likelihood of having sufficient supply to meet demand, and is measured in terms of the accumulated unserved energy over time, expressed as a percentage of the total energy requirement over the same timeframe.

The Reliability Standard[2], established by the Australian Energy Market Commission's (AEMC) Reliability Panel, defines the minimum acceptable level of reliability to be met in each region. The Reliability Standard currently specifies that, over the long term, the maximum expected regional unserved energy should be no more than 0.002% of a region's annual energy consumption. The Reliability Panel reviews the form and value of the Reliability Standard every two years, and completed its most recent review in April 2010 (for more information, see Section 6.3.1).

1 AEMO. "2010 Regional Minimum Reserve Levels". Available http://www.aemo.com.au/electricityops/mrl.html. 28 April 2011.

2 Australian Energy Market Commission. "Guidelines & Standards". Available http://aemc.gov.au/Panels-and-Committees/Reliability-Panel/Guidelines-and-standards.html. 28 April 2011.

6.1.2 Establishing minimum reserve levels

AEMO translates the Reliability Standard into a required safety margin of surplus installed capacity that can be applied operationally. By convention, this margin is referred to as an MRL and is expressed relative to a region's 10% probability of exceedence (POE) maximum demand, including any demand-side participation (DSP).

MRLs are used in both medium and long-term forecasting to assess whether the level of available capacity is sufficient to satisfy the Reliability Standard. The Medium-Term Projected Assessment of System Adequacy (MT PASA) applies the MRLs to produce a two-year (daily) outlook. This assessment incorporates the scheduled maintenance pattern of generating units and transmission assets. MT PASA is published weekly and is intended to provide information to the market about times when there is a high likelihood of low reserves. Under these conditions, AEMO may need to intervene through the Reliability and Emergency Reserve Trader (RERT) process.[3]

In the longer term, the supply-demand outlook applies the MRLs to produce a 10-year (yearly) outlook.[4] The supply-demand outlook is intended to provide market participants and other interested parties with information about the timing and magnitude of additional investment required to maintain the Reliability Standard.

6.1.3 Calculating minimum reserve levels

MRLs are calculated using detailed market simulations that model the reliability effects of variations in the factors influencing demand and generation outage patterns. This analysis determines the minimum amount of installed capacity required in each region to meet the Reliability Standard.

A reserve sharing analysis then identifies the reserve requirement relationships between neighbouring regions, which are then applied to select optimal MRLs for a given set of system conditions (for more information about the application of reserve sharing, see Section 6.2).

The 2011 ESOO CD includes a two-part video tutorial that provides additional information about the concept of MRLs and their relationship with long-term power system reliability.

6.1.4 MRL sensitivity and triggering MRL recalculations

Minimum reserve levels are sensitive to a variety of system parameters and network topologies. The most significant factors include the following:

- **Generator reliability**. A region's average forced outage rate can change due to aging plant and changes in the mix of generation technologies, which impacts the availability of generation to meet demand, affecting the level of installed capacity required.
- **The magnitude and frequency of high demand periods**. Reserve shortfalls typically occur when demand approaches the regional maximum demand. Changing the length of time the system is exposed to such high demand has a significant impact on the MRLs.
- **Inter-regional demand diversity**. Where the maximum demand in two neighbouring regions occurs at different times[5], the reserve requirement in both regions can be reduced by their ability to support each other. The impact of diversity on the MRLs is tempered by network limitations between the regions.
- **Network limitations**. The ability for regions to exploit spare capacity within (and across) regional boundaries significantly impacts local installed capacity requirements, and regions with significant interconnector power transfer capabilities require less installed capacity to meet the Reliability Standard.

AEMO assesses these factors annually when determining if the MRL recalculation process should be initiated more or less frequently than the default two-year cycle. A new approach enabling MRL adjustments to accommodate changing system conditions (see Section 6.2.1) provides the MRLs with additional robustness and longevity.

[3] AEMO. "Procedure for the Exercise of the Reliability and Emergency Reserve Trader (RERT): Consultation". Available http://www.aemo.com.au/electricityops/rert.html. 28 April 2011.

[4] Incorporating generation scheduled maintenance patterns, when there may be a coincidence with maximum demand.

[5] Described as 'high diversity' when a maximum demand occurs during low demand in a neighbouring region.

6.2 Minimum reserve levels

6.2.1 Changes to the MRL formulation

As part of the 2010 MRL calculation process, AEMO determined regional MRLs for the 2010–11 and 2011–12 financial years, which were then applied in MT PASA and used to produce the 2010 ESOO. Surplus reserve sharing between neighbouring regions was also quantified to explore the ability for regions with excess available capacity to support paired regions that are unable to meet their own MRLs.

The ability to share surplus reserves is described by a reserve sharing curve for each region pair, specifying the possible values the MRLs can take to satisfy the Reliability Standard. This ability (and the shape of the associated curves) is primarily dictated by demand diversity between the regions, network losses within each region, and interconnector power transfer limitations across region boundaries.

Preliminary reserve sharing was implemented in MT PASA from December 2010, and subsequently revised with more detailed reserve sharing relationships in July 2011.[6] The 2011 ESOO supply-demand outlook also applies the new reserve sharing approach (for more information, see Chapter 7).

From a supply-demand outlook perspective, this change means that MRL values are automatically adjusted from year-to-year to minimise reserve deficits by better accommodating changing system conditions across adjoining regions.

6.2.2 Reserve sharing curves

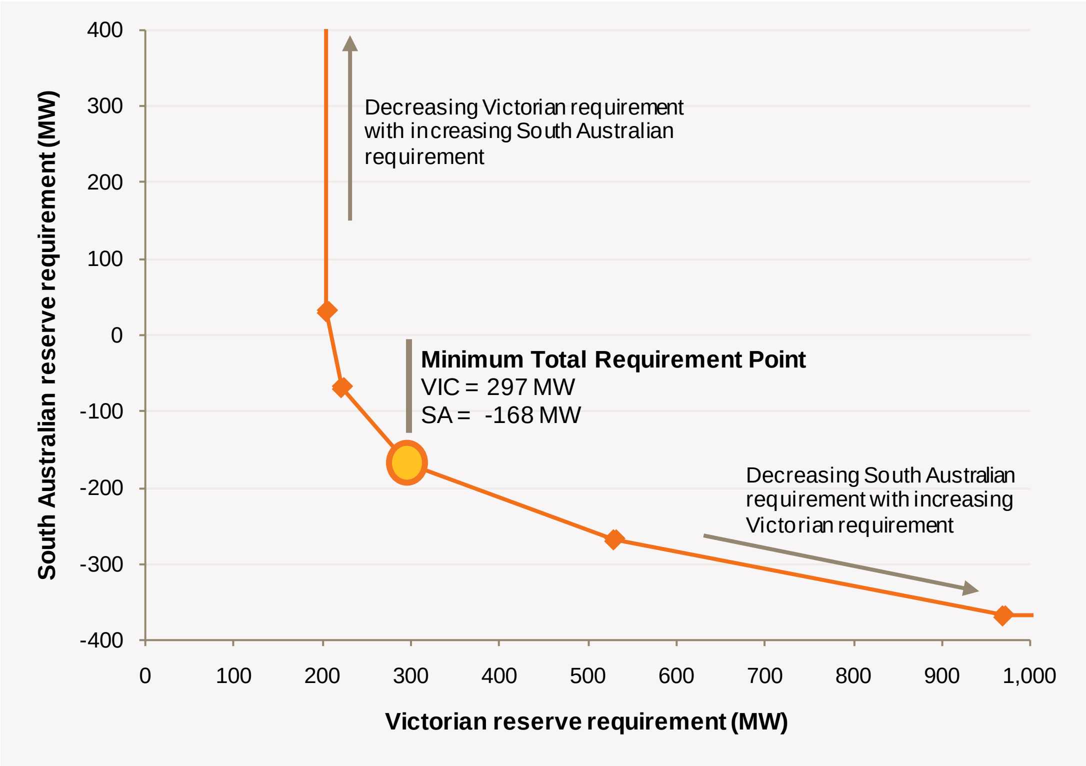
Interpreting reserve sharing curves

The reserve sharing curve for each region pair is presented as a graph of the MRL in one region against the MRL in an adjoining region. Each point on the curve represents a pair of MRL values that meet (or exceed) the Reliability Standard in both regions.

Figure 6-1 provides a guide to interpreting the curves, which are expressed as a series of line segments to enable easy formulation in linear programming tools like MT PASA and the supply-demand calculator.

[6] Reserve sharing in MT PASA is done across the Victorian and South Australian regions only due to limited sharing opportunities across other region boundaries in the near-term. The supply-demand outlook additionally considers sharing between Queensland and New South Wales because, while small, reserve sharing between these regions can impact the assessment of long-term supply adequacy.

Figure 6-1 — Example reserve sharing - Victoria and South Australia



Each curve has a minimum total requirement point, which represents the reserve requirement expected to exactly meet the Reliability Standard using the minimum installed capacity in the two regions (combined). Other points on the curve require more installed capacity.

The slope of each curve indicates the effectiveness of different combinations of reserve sharing. One-to-one slopes are the most effective, while steeper or flatter slopes are less effective.

Unlike a fixed set of regional MRL values, the reserve sharing curves enable an assessment of spare regional reserves for the purpose of sharing benefits with neighbouring regions.

Reserve sharing relationships between region pairs

This section describes the reserve sharing relationships between region pairs and, where appropriate, presents the reserve sharing curves.

Table 6-1 presents the minimum total requirement points defined for each region, representing the MRLs expected to meet the Reliability Standard in all regions using the minimum level of NEM-wide installed capacity.

Table 6-1 — Minimum total requirement points for 2011/12 (MW)[a]

	Queensland	New South Wales	Victoria	South Australia	Tasmania[b]
2011–12	913	-1,564	297	-168	144

a. The 2011–12 MRL values are not the same as reported in the 2010 ESOO, because only a single point was used on the reserve sharing curve to determine reserve sharing for Victoria and South Australia. This process is described in the 2010 ESOO, Chapter 6, Section 6.3.1.

b. The Tasmanian region is largely energy limited, rather than capacity limited. As a result, its supply adequacy is not best represented by an MRL (for more information, see Chapter 7, Section 7.3.7). The MRL recalculation process confirmed that the pre-existing Tasmanian Capacity Reserve Standard (144 MW) remains sufficient to meet (or exceed) the Reliability Standard.

Queensland and New South Wales

Figure 6-2 presents the reserve sharing curve between Queensland and New South Wales. This curve quickly becomes horizontal and vertical at its ends, demonstrating a limited ability to share surplus reserves.

The reserve sharing curve ratio at the minimum total requirement point for the transfer of capacity to Queensland is approximately 1:-20, which means that for each 1 MW reduction in the Queensland capacity requirement, an additional 20 MW of spare capacity is required in New South Wales. In the opposite direction the ratio is approximately 1:-5.

Figure 6-2 — Reserve sharing curve for Queensland and New South Wales

This curve's slope is primarily caused by low demand diversity between the two regions (as their maximum demands tend to be highly correlated). At times when Queensland experiences unserved energy, either New South Wales is also experiencing unserved energy, or the interconnector between the regions is unable to increase power transfers to Queensland. As a result, additional capacity in New South Wales provides little benefit to Queensland, unless interconnector capabilities improve.

This does not imply that additional capacity in New South Wales cannot support Queensland's energy requirements throughout the year, but rather that the additional capacity will not provide significant benefits at times when Queensland is experiencing unserved energy.

Victoria and New South Wales

A reserve sharing curve has not been produced or implemented for Victoria and New South Wales, because there is no ability for further optimisation of reserves. Significant demand diversity exists, but is already being exploited to the best of the transmission network's capability.

In particular, during their respective maximum demands, the region experiencing unserved energy is receiving as much interconnector support as the network will allow, which is already accounted for in the MRL calculations.

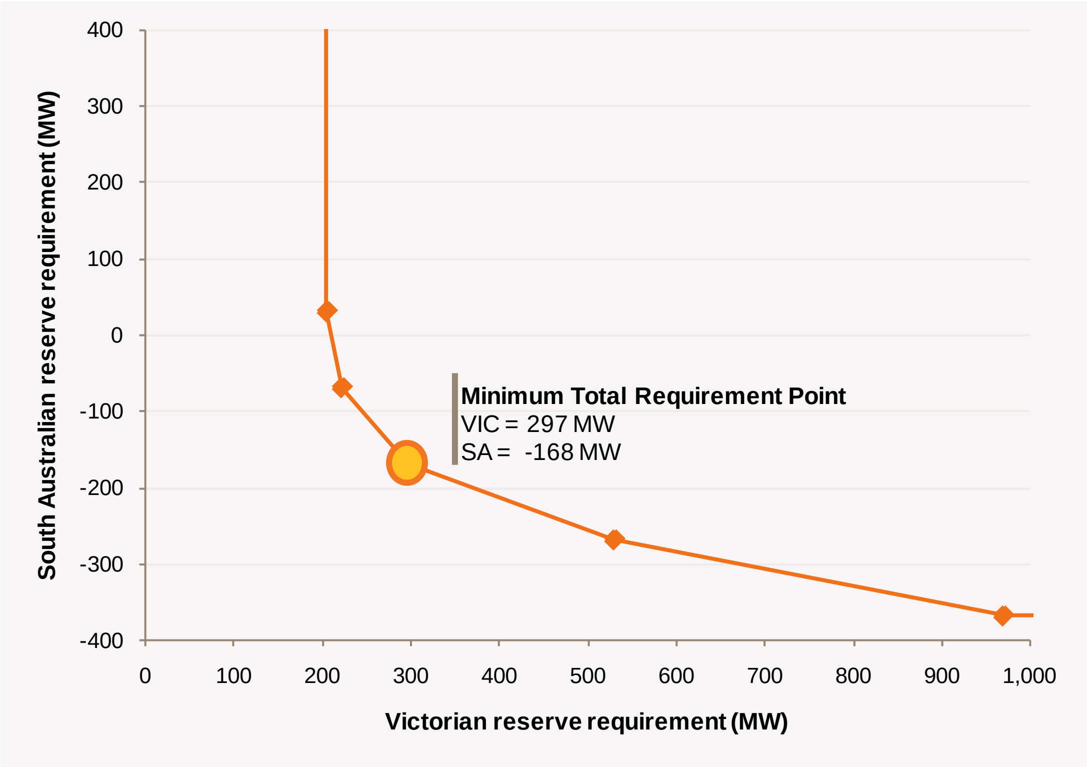
Additional capacity in one region cannot benefit the other during demand peaks without also upgrading the interconnector capability between the two regions.

Victoria and South Australia

Figure 6-3 shows the reserve sharing curve between Victoria and South Australia. This curve's slope is due to low interconnector power transfers that are well within capability during unserved energy events. This means additional reserves in one region can significantly impact the reserve requirement in the other.

The reserve sharing curve ratio at the minimum total requirement point for the transfer of capacity into South Australia is approximately 3:-4, which means that for each 3 MW reduction in the South Australian capacity requirement, an additional 4 MW capacity is required in Victoria. In the opposite direction the ratio is approximately 3:-7. These relatively shallow gradients (compared with Queensland and New South Wales) allow significant optimisation of the reserves between the Victorian and South Australian regions.

Figure 6-3 — Reserve sharing curve for Victoria and South Australia



Victoria and Tasmania

A reserve sharing curve has not been produced or implemented for Victoria and Tasmania, because Tasmania already provides Victoria with as much support at times of unserved energy as the transmission network will allow. Additionally, Tasmania requires little support from Victoria because it does not experience significant unserved energy in the simulations used to produce the MRLs. This is because Tasmanian supply adequacy largely depends on energy limitations, which are sufficient under the long-term average conditions simulated in the MRL studies.

The Tasmanian MRL has been left at 144 MW, as confirmed through the initial 2010 MRL calculation process.

Net import limits

To assess a region's capacity to meet its MRL, the supply-demand calculator and MT PASA implement net import limits that restrict the amount of spare capacity a region can import. To ensure consistency between the assessment of reserve margins and the calculation of MRLs, the reserve sharing relationships already include the same level of assumed import.

The net import limits listed in Table 6-2 are only applied in the supply-demand outlook and PASA outlook calculations. They do not limit actual interconnector power transfers in central dispatch. The MRLs described by Table 6-1, Figure 6-2, and Figure 6-3 already include adjustments to account for these limits.

Table 6-2 — Net import limits (MW)

	Queensland	New South Wales	Victoria	South Australia	Tasmania
Net import limit (MW)	0	-330[a]	940	0	N/A[b]

a. The negative value implies that New South Wales must meet its MRL requirement while also supporting a forced export of 330 MW.

b. Net import limits are not applied to Tasmania's capacity adequacy assessment. Tasmania's MRL is set at the size of the pre-existing Tasmanian Capacity Reserve Standard, and is independent of any assumed interconnector power flow.

6.3 Reliability reviews

This section presents an overview of reviews and National Electricity Rules (NER) change proposals relating to NEM reliability and the MRLs.

6.3.1 Amendments to PASA-related Rules

On 29 April 2010, AEMO submitted an NER change request[7] to the AEMC to amend NER provisions relating to PASA processes. In particular, AEMO sought to remove its obligation to prepare and publish the reserve requirements used in MT PASA for each region.

On 2 December 2010, the AEMC gave notice of its final determination[8], which allows AEMO to use reserve requirements applicable to multiple regions, so MT PASA can more optimally share medium-term capacity reserves. This sharing capability was implemented in MT PASA on 16 December 2010 (using preliminary curves), and the reserve sharing curves (see Section 6.2.2[9]) went into use in July 2011.

[7] AEMO. "RE: Amendments to PASA-related Rules", 29 April 2010. Available http://aemc.gov.au/Media/docs/AEMO%20Rule%20change%20Proposal-8d16259a-a408-47d3-847e-5e72284deed7-0.pdf. 28 April 2011.

[8] AEMC. "Amendments to PASA-related Rules". Available http://aemc.gov.au/Electricity/Rule-changes/Completed/Amendments-to-PASA-related-Rules.html. 28 April 2011.

[9] Reserve sharing in MT PASA is done across the Victorian and South Australian regions only due to limited sharing opportunities across other region boundaries in the near-term. The supply-demand outlook additionally considers sharing between Queensland and New South Wales because, while small, reserve sharing between these regions can impact the assessment of long-term supply adequacy.

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CHAPTER 7 - SUPPLY-DEMAND OUTLOOK

Summary

This chapter presents information about the future adequacy of electricity supplies in the National Electricity Market (NEM), and a 10-year supply-demand outlook for each region, highlighting potential generation and demand-side investment opportunities arising from projected reserve requirement shortfalls.

Specifically, the regional outlooks identify the timing of low reserve condition (LRC) points, which indicate when reserve margins will potentially fall below minimum reserve levels (MRL). LRC points do not signify that load shedding will occur, but rather indicate when the power system is falling below long-term system reliability standards.

AEMO determines the projected shortfalls by considering a number of factors, including maximum demand projections, demand-side participation (DSP), existing and committed generation capacities, and transmission network capabilities.

Given medium economic growth:

- Queensland requires additional investment by 2013–14, which is consistent with the 2010 ESOO
- New South Wales requires additional generation investment by 2018–19, representing a two-year delay compared with the 2010 ESOO, which is primarily due to a decrease in the maximum demand projections for the region
- Victoria and South Australia require additional generation investment by 2014–15, one year earlier than the 2010 ESOO, which is primarily due to moderate increases in the maximum demand projections for both regions (the LRC points in these regions remain closely aligned due to their substantial ability to share surplus reserves), and
- Tasmania does not experience a reserve deficit within the 10-year outlook period at the time of either the summer or winter maximum demand. Tasmania’s summer maximum demand typically occurs during cold weather, resulting in relatively high demand diversity between Tasmania and the mainland regions (where the maximum demand occurs during hot weather). This enables Tasmania and the mainland regions to take advantage of reserve sharing opportunities when meeting maximum demands.

From a national perspective, Queensland is the first region to need additional investment to maintain reliability across all three economic growth scenarios.

The Clean Energy Future Plan announced by the Australian Government is expected to have little impact on the timing of the regional LRC points.

The maximum demand projections already include comparable carbon price assumptions and will be largely unaffected. AEMO expects that any changes to the installed generation mix are likely to occur after 2015, which (with medium economic growth) falls after the LRC points in every region except New South Wales and Tasmania.

7.1 NEM Power system reliability assessments

AEMO assesses power system reliability through outlooks provided by the ESOO, the Power System Adequacy (PSA) – Two-Year Outlook, the Energy Adequacy Assessment Projection (EAAP), and the Medium-term Projected Assessment of System Adequacy (MT PASA). These publications explore system adequacy from differing perspectives and cover overlapping timeframes to provide a continuous indication of future power system reliability.

7.1.1 The Power System Adequacy – Two-Year Outlook

The annual PSA document supplements the ESOO by investigating operational issues over the next two years. In particular, system adequacy is measured against several key indicators including capacity reserve (the size of reserve margin), energy adequacy, frequency control, voltage control, post contingency control, and interconnector capability.

7.1.2 The Energy Adequacy Assessment Projection

The 2011 ESOO supply-demand outlooks apply generation capacity advice provided by NEM generators, but do not specifically account for possible future energy limitations or short-term scheduled maintenance. Accounting for these energy limitations becomes particularly important when determining the likely near-term impacts of drought, or when assessing the reliability of regions with significant hydroelectric generation.

AEMO assesses the impact of energy limitations through quarterly EAAP studies, which use time-sequential market simulations to provide a two-year outlook quantifying the impact of energy constraints under multiple scenarios. The EAAP results are published quarterly on the AEMO website.[1]

7.1.3 MT PASA and the supply-demand outlook

The supply-demand outlook and MT PASA both provide capacity adequacy assessments and consider similar input information. The supply-demand outlook provides an annual assessment over 10 years, while MT PASA provides a daily assessment over two years. This shorter time-frame enables MT PASA to consider more detailed system information available in the short-term, including the scheduled maintenance pattern of generating units.

MT PASA is used operationally to inform the market when there is a high likelihood of experiencing a low reserve condition that may require AEMO to intervene through the Reliability and Emergency Reserve Trader (RERT) process.[2] In contrast, the supply-demand outlook is intended to provide participants and other interested parties with information about the timing and magnitude of the additional investment required in the long term to maintain power system reliability. Table 7-1 compares MT PASA and the supply-demand outlook.

Table 7-1 — MT PASA and the supply-demand outlook

	MT PASA	ESOO Supply-Demand Outlook
Outlook	Two years.	Ten years.
Resolution	Daily.	Yearly.
Updated	Weekly.	Yearly.
Inputs		
Demand	Projected daily 10% probability of exceedence (POE) scheduled and semi-scheduled maximum demand, less committed DSP.	Projected seasonal 10% POE scheduled and semi-scheduled maximum demand, less committed DSP.
Generation	Maintenance outages and short-term variations considered.	Advised summer and winter capacity. Long-term variations considered.

1 AEMO. "Energy Adequacy Assessment Projection (EAAP)". Available http://aemo.com.au/electricityops/eaap.html. 27 April 2011.

2 AEMO. "Procedure for the Exercise of Reliability and Emergency Reserve Trader (RERT): Consultation". Available http://aemo.com.au/electricityops/rert.html. 27 April 2011.

	MT PASA	ESOO Supply-Demand Outlook
Wind generation	Uses 90% POE wind generation forecasts (Australian Wind Energy Forecasting System).	Calculates wind farm available capacity according to peak contribution factors.
Energy capacity	Weekly energy limitations submitted by generators are modelled.	Energy limitations not modelled, except where stated as capacity reductions.
MRLs	MRLs applied to assess adequacy.	MRLs applied to assess adequacy.
Network	System normal operating considerations assumed. Existing transmission capabilities only.	System normal operating considerations assumed. Existing and committed network.
Outputs		
Determine	Reserve levels at daily peak demand, and LRC points.	Reserve levels at summer or winter peak demand, and LRC points.
Indicate	Opportunities for market response (two years)	Opportunities for market response (ten years).
AEMO action	Possible intervention through the RERT process.	No action. Market information purposes only.

7.2 The supply-demand calculator

AEMO uses the supply-demand calculator to generate 10-year reliability outlooks for each region. The supply-demand calculator is a spreadsheet tool that employs a linear programming approach to co-optimise generation dispatch and interconnector flows subject to minimising reserve deficits. The calculator also shares reserve surpluses between regions according to predetermined sharing relationships (see Chapter 6, Section 6.2.2).

The underlying input data and assumptions used by the calculator include:

- regional scheduled and semi-scheduled maximum demand projections for high, medium, and low economic growth scenarios (see Chapter 3)
- levels of committed DSP (see Chapter 3, Section 3.9)
- capacities of existing and committed scheduled and semi-scheduled generation including committed retirements (see Chapter 4)
- MRLs and reserve sharing relationships (see Chapter 6, Section 6.2), and
- existing transmission capabilities and committed transmission projects (see Appendix D).

The 2011 ESOO electronic information includes an interactive version of the supply-demand calculator, enabling interested parties to vary assumptions and assess alternative scenarios. The ESOO's electronic information also includes a tutorial (The Supply-Demand Calculator) explaining how to use the calculator to determine the impact of changing assumptions, and how to view and interpret supply-demand outlook results.

7.2.1 Modelling network capability

The supply-demand calculator models transmission network capability using a set of system normal network constraint equations, which are extracted from AEMO's Market Management System (MMS) or, where appropriate, produced from a detailed analysis of network load-flow snapshots. These constraint equations are adjusted to take account of advice from the jurisdictional planning bodies (JPBs) about how network capabilities may vary with time and operating conditions, including the impact of committed transmission projects. For more information about the committed transmission projects included in the supply-demand calculator, see Appendix D.

Network constraint equations are periodically revised and interested parties should confirm the relevance of the implemented equations prior to using the calculator. The calculator also disables some equations to avoid infeasible or anomalous dispatch outcomes that can occur in some circumstances when operational constraints are implemented in an annual outlook calculation. For more information about these disabled constraint equations, see the supply-demand calculator included with the ESOO electronic information.

7.2.2 MRLs and reserve sharing relationships

As part of the 2010 MRL calculation process[3], AEMO determined regional MRLs for the 2010–11 and 2011–12 financial years, which were then applied in MT PASA and used in the production of the 2010 ESOO.

AEMO also explored and quantified the ability for neighbouring regions to share surplus reserves. These relationships allow the MRLs to be optimised according to changing system conditions, so that regions with excess available capacity can support paired regions unable to meet their own MRLs. Reserve sharing tends to align LRC timings between neighbouring regions.

For more information about regional reserve sharing relationships and their application in the MRLs, see Chapter 6, Section 6.2.2.

7.3 Supply-demand outlook results

This section presents the supply-demand outlook for each region. In particular, it shows projected LRC point timings and the magnitude of the associated reserve deficits. An LRC point does not indicate that load shedding will occur, but rather represents a regional MRL shortfall, indicating when the power system may be falling below long-term system reliability standards.

The outlook assessment for each region commences in summer 2011–12. The supply-demand outlook focuses on summer because scheduled and semi-scheduled maximum demand is generally higher in summer (except in Tasmania). Thermal generation capacities also tend to decrease over summer, increasing the likelihood of low reserve conditions.

For more information about supply adequacy for 2011–12 and 2012–13, see AEMO's weekly MT PASA results[4] and annual PSA.[5]

7.3.1 Summary of low reserve condition points and reserve deficits

The supply-demand outlook assessment considers 10% POE maximum demand projections, demand-side participation, and existing and committed transmission network capabilities. It also assumes no further capacity enters the market other than the committed projects AEMO is aware of. For more information about which generation projects are considered committed, see the regional summaries in Chapter 4.

Table 7-2 provides an overview of the 2011 supply-demand outlook, and the first year each region experiences a reserve deficit (indicating the quantity of additional installed capacity required to meet the reserve requirement). The table also provides sensitivity results for a low and high economic growth scenario (given an increase in economic growth tends to bring the LRC points forward or increase the reserve deficit experienced in a particular year). Tasmania's maximum demand typically occurs in winter, and this region's winter outlook has also been provided.

AEMO expects the Clean Energy Future Plan announced by the Australian Government to have little impact on the timing of the regional LRC points identified in the 2011 ESOO.

The maximum demand projections already include comparable carbon price assumptions and will be largely unaffected. AEMO expects that any changes to the installed generation mix are likely to occur after 2015, which (with medium economic growth) falls after the LRC points in every region except New South Wales and Tasmania.

[3] AEMO. "2010 Regional Minimum Reserve Levels". Available http://www.aemo.com.au/electricityops/mrl.html. 28 April 2011.
[4] AEMO. "Outlook PASA Data". Available http://www.aemo.com.au/data/outlook.html. 27 April 2011.
[5] AEMO. "Market & Power Systems". Available http://www.aemo.com.au/electricityops/market.html. 30 May 2011.

Table 7-2 — Regional LRC points overview

Region	Low Economic Growth		Medium Economic Growth		High Economic Growth	
	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)
Queensland	2014–15	544	2013–14	341	2013–14	779
New South Wales	2018–19	222	2018–19	190	2018–19	367
Victoria	2016–17	218	2014–15	96	2013–14	96
South Australia	2016–17	9	2014–15	46	2013–14	5
Tasmania (summer)	>2020–21	N/A	>2020–21	N/A	>2020–21	N/A
Tasmania (winter)	>2021	N/A	>2021	N/A	>2021	N/A

Given medium economic growth:

- Queensland requires additional investment by 2013–14, which is consistent with the 2010 ESOO
- New South Wales requires additional generation investment by 2018–19, representing a two-year delay compared with the 2010 ESOO, which is primarily due to a decrease in the maximum demand projections for the region
- Victoria and South Australia require additional generation investment by 2014–15, one year earlier than the 2010 ESOO, which is primarily due to moderate increases in the maximum demand projections for both regions (the LRC points in these regions remain closely aligned due to their substantial ability to share surplus reserves), and
- Tasmania does not experience a reserve deficit within the 10-year outlook period at the time of either the summer or winter maximum demand. Tasmania's summer maximum demand typically occurs during cold weather, resulting in relatively high demand diversity between Tasmania and the mainland regions (where the maximum demand occurs during hot weather). This enables Tasmania and the mainland regions to take advantage of reserve sharing opportunities when meeting maximum demands.

From a national perspective, Queensland is the first region to need additional investment to maintain reliability across all three economic growth scenarios.

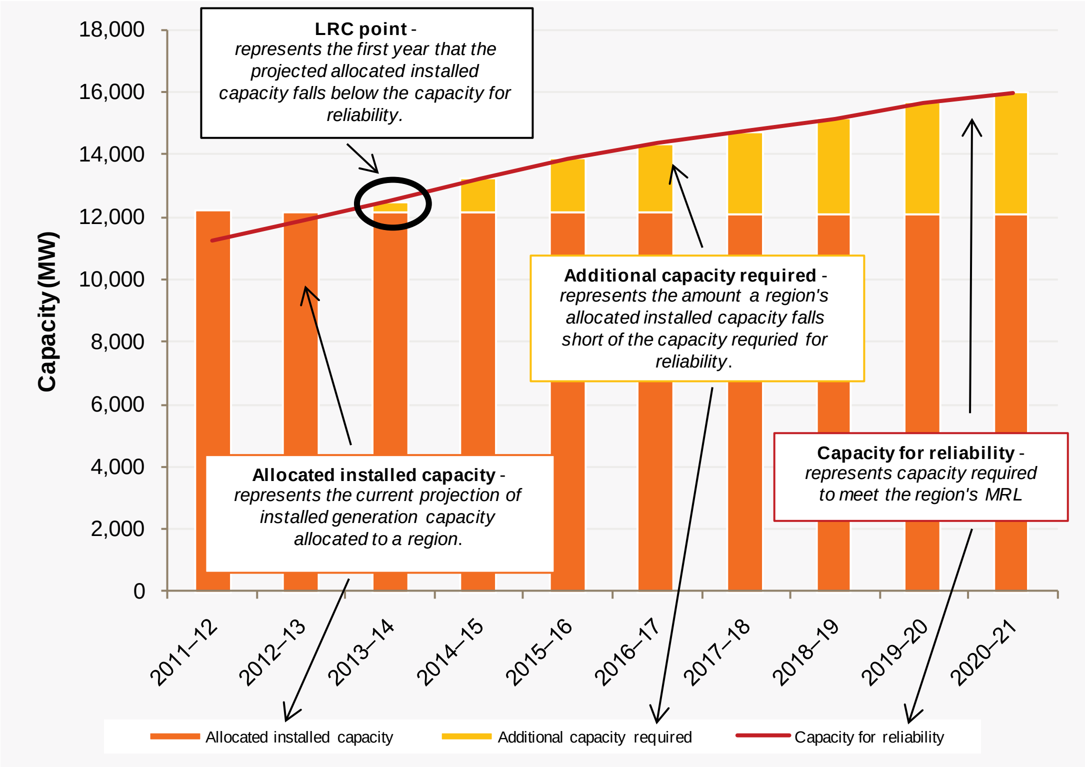
The 2011 ESOO also includes an alternative set of Queensland energy and maximum demand projections. AEMO assessed performance for all regions, and alternative projections were developed for Queensland to address the fact that actual maximum demands over the last five years have been significantly lower than the projections provided by the Queensland Jurisdictional Planning Body. AEMO continues to work with industry to investigate the drivers for demand in Queensland. For more information about the alternative Queensland demand projection, see Chapter 3, Section 3.11.

The regional outlooks examined in the remainder of this section provide graphical results for the medium economic growth scenario only. The supply-demand calculator, available on the ESOO electronic information, can be used to produce graphical results for the high and low economic growth sensitivities.

7.3.2 Interpreting the supply-demand outlook

Each region's summer supply-demand outlook and LRC point are presented as a graph of supply adequacy trends. Figure 7-1 provides a guide to interpreting the outlooks, and the key terms used.

Figure 7-1 — Interpreting the supply-demand outlook



Capacity for reliability

$$\begin{aligned} &\textit{Capacity for Reliability} \\ &\quad = \textit{10\% POE Scheduled and Semi-Scheduled MD} \\ &\quad\quad + \textit{MRL} \\ &\quad\quad - \textit{DSP} \end{aligned}$$

This represents the capacity (comprising local generation plus net import) required to meet the region's MRL. The MRLs are calculated to ensure sufficient supplies are available to meet the Reliability Standard. For more information about the calculation of MRLs, see Chapter 6.

Allocated installed capacity

$$\begin{aligned} &\textit{Allocated Installed Capacity} \\ &\quad = \textit{Regional Scheduled and Semi"-" Scheduled Generation} \\ &\quad\quad + \textit{Net Regional Import} \end{aligned}$$

This represents the current projection of installed generation capacity allocated to a region. The supply-demand calculator allocates regional imports and exports to minimise reserve deficits. Reserve deficits are shared in proportion to the maximum demand for each region up to the interconnector limits.

Net regional imports can be either positive (net import into the region) or negative (net export from the region).

Additional capacity required

$$Allocated\ Capacity\ Required$$
$$= Capacity\ for\ Reliability$$
$$- Allocated\ Installed\ Capacity$$

This represents the amount a region's allocated installed capacity falls short of the capacity required for reliability. It is also referred to as a reserve deficit and is capped at a minimum value of (zero) 0 MW.

LRC point

This represents the first year that the projected allocated installed capacity falls below the capacity for reliability (the year the region's reserve falls below the MRL).

An LRC point does not signify that load shedding will occur. Continued operation with a low reserve, however, indicates the system may not meet the Reliability Standard over the long term.

7.3.3 Queensland outlook

Figure 7-2 shows the projected Queensland summer supply-demand outlook for 2011–12 to 2020–21.

The figure indicates that with medium economic growth, Queensland reaches an LRC point in 2013–14, requiring at least 341 MW of new generation or demand side-investment to delay the shortfall until the following year.

The timing of the Queensland LRC point (2013–14) is consistent with the 2010 ESOO's timing, but the shortfall has decreased from 726 MW. While wind contribution factors have not been calculated for Queensland, experience in other regions (see Chapter 8, Section 8.3.3) suggests that new wind generation in Queensland may contribute up to 10% of its installed capacity towards meeting the 341 MW summer maximum demand reserve deficit.

Table 7-3 shows the LRC point and reserve deficit projections with low, medium, and high economic growth.

The Queensland projection shows that the summer LRC point occurs at the same time with medium or high economic growth (2013–14), and one year later with low economic growth (2014–15).

The 2011 ESOO also includes alternative energy and maximum demand projections for Queensland, developed by AEMO (see Chapter 3, Section 3.11). AEMO assessed performance for all regions, and alternative projections were developed for Queensland to address the fact that actual maximum demands over the last five years have been significantly lower than the projections provided by the Queensland Jurisdictional Planning Body. The alternative projections for Queensland developed by AEMO delay the summer medium economic growth LRC point by one year (to 2014–15), and advance the summer low economic growth LRC point by one year (to 2013-14).

The earlier low economic growth outcome is caused by competing economic influences on demand (for example, while low economic growth may reduce energy consumption, it also discourages consumer investment in energy efficiency technologies and household solar photovoltaics).

The AEMO projection for Queensland did not impact the LRC point timings or magnitudes in other regions.

AEMO continues to work with industry to investigate the drivers for demand in Queensland.

Figure 7-2 — Queensland summer supply-demand outlook

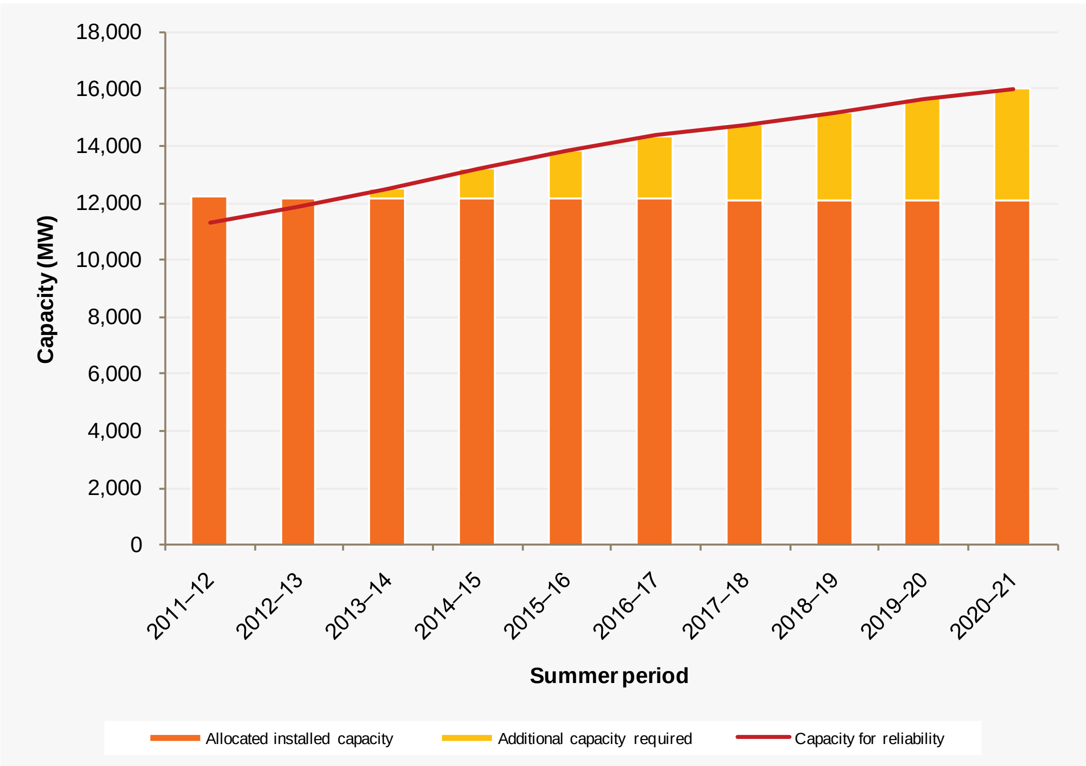


Table 7-3 — Queensland supply-demand outlook summary

Region	Low Economic Growth		Medium Economic Growth		High Economic Growth	
	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)
Queensland (summer)	2014–15	544	2013–14	341	2013–14	779
Queensland (winter)	>2021	N/A	2017	29	2015	86

7.3.4 New South Wales outlook

Figure 7-3 presents the projected New South Wales summer supply-demand outlook for 2011–12 to 2020–21.

The figure indicates that with medium economic growth, New South Wales reaches its LRC point in 2018–19, requiring at least 190 MW of new generation or demand-side investment to delay this shortfall until the following year. Based on analysis of historical New South Wales wind contribution factors at times of maximum demand (see Chapter 8, Section 8.3.3), new wind generation in New South Wales is likely to contribute approximately 9% of its installed capacity towards meeting the 190 MW summer maximum demand reserve deficit.

Adjacent regions often reach maximum demand at different times, allowing the same capacity to contribute to reliability in more than one region via reserve sharing (the extent of which is captured by each region's allocated installed capacity). In Figure 7-3, the allocated installed capacity and the capacity required for reliability are closely matched from 2013–14 onwards, as other regions begin to reach their LRC points and draw on support from New South Wales.

The current LRC point is two years later than the 2010 ESOO's timing, which is primarily due to decreased maximum demand forecasts for New South Wales.

Table 7-4 shows the LRC point and reserve deficit projections with low, medium, and high economic growth.

The New South Wales LRC point occurs in the same year (2018–19) with high, medium, and low economic growth, although the reserve deficit increases with both low and high economic growth due to higher maximum demand projections in these scenarios.

This outcome with low economic growth is caused by competing economic influences on demand (for example, while low economic growth may reduce energy consumption, it also discourages consumer investment in energy efficiency technologies and household solar photovoltaics).

Figure 7-3 — New South Wales summer supply-demand outlook

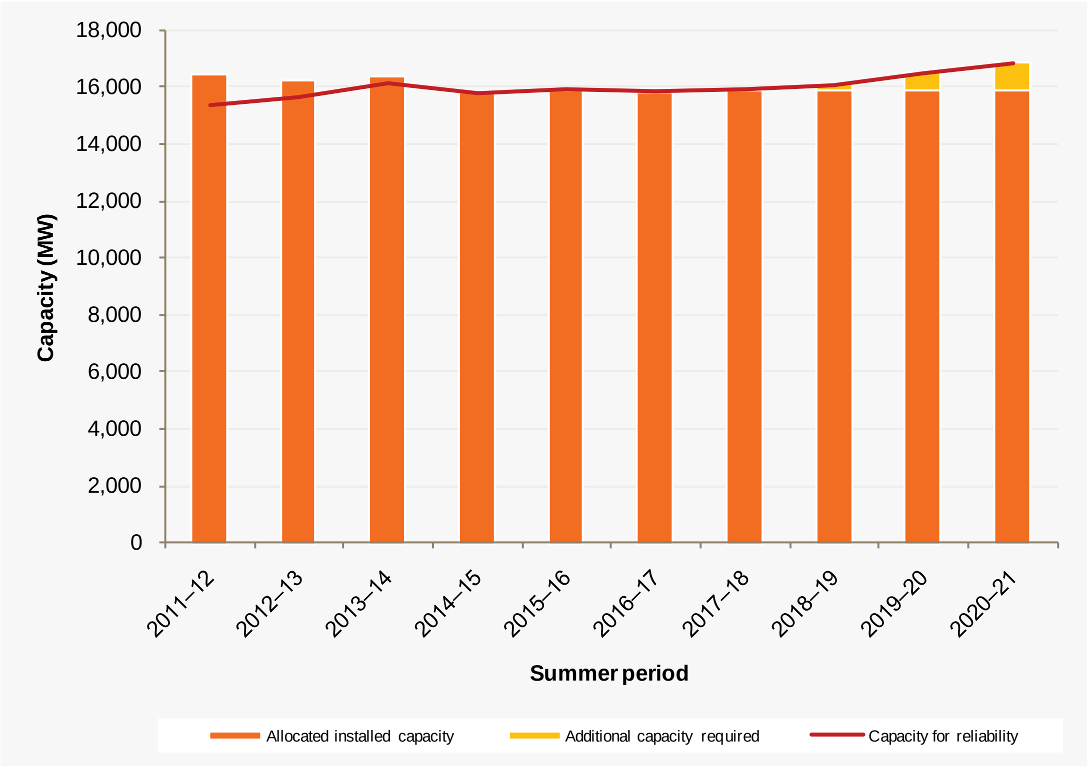


Table 7-4 — New South Wales supply-demand outlook summary

Region	Low Economic Growth		Medium Economic Growth		High Economic Growth	
	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)
New South Wales (summer)	2018-2019	222	2018-19	190	2018-19	367
New South Wales (winter)	>2021	N/A	>2021	N/A	>2021	N/A

7.3.5 Victorian outlook

Figure 7-4 shows the projected Victorian summer supply-demand outlook for 2011–12 to 2020–21.

The figure indicates that with medium economic growth conditions, Victoria reaches its LRC point in 2014–15, requiring at least 96 MW of new generation or demand-side investment to delay this shortfall until the following year. Based on analysis of historical Victorian wind contribution factors at times of maximum demand (see Chapter 8, Section 8.3.3), new wind generation in Victoria is likely to contribute approximately 8% of its installed capacity towards meeting the 96 MW summer maximum demand reserve deficit.

Adjacent regions often reach maximum demand at different times, allowing the same capacity to contribute to reliability in more than one region via reserve sharing (the extent of which is captured by each region's allocated installed capacity). The relatively low local reserve margin in Victoria is due to reserve sharing with neighbouring regions.

The current LRC point is one year earlier than the 2010 ESOO's timing, which is primarily due to increased maximum demand forecasts for Victoria, despite moderate increases in Victoria's projected available capacity.

Table 7-5 shows the LRC point and reserve deficit projections with low, medium, and high economic growth. With high economic growth, the LRC point occurs one year earlier (2013–14), and low economic growth delays the LRC point by two years (2016–17).

Figure 7-4 — Victorian summer supply-demand outlook

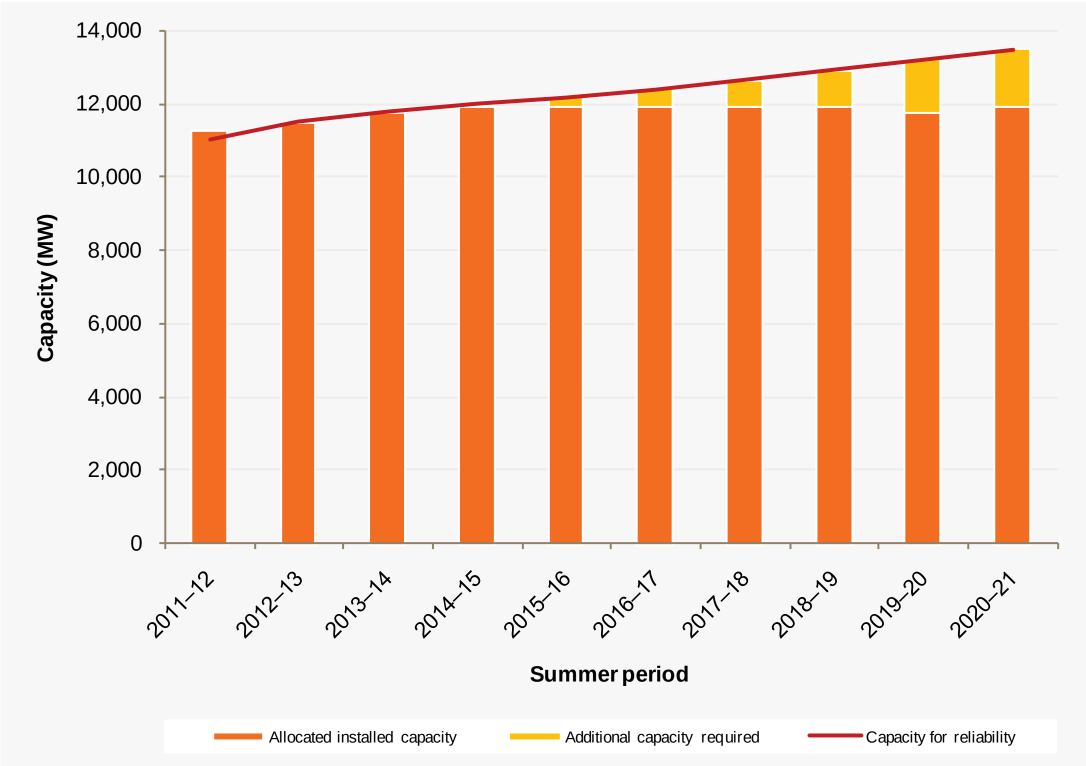


Table 7-5 — Victorian supply-demand outlook summary

Region	Low Economic Growth		Medium Economic Growth		High Economic Growth	
	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)
Victoria (summer)	2016–17	218	2014–15	96	2013–14	96
Victoria (winter)	>2021	N/A	>2021	N/A	>2021	N/A

7.3.6 South Australian outlook

Figure 7-5 shows the projected South Australian summer supply-demand outlook for 2011–12 to 2020–21.

The figure indicates that with medium economic growth, South Australia reaches its LRC point in 2014–15, requiring at least 46 MW of new generation or demand-side investment to delay this shortfall until the following year. Based on analysis of historical South Australian wind contribution factors at times of maximum demand (see Chapter 8, Section 8.3.3), new wind generation in South Australia is likely to contribute approximately 5% of its installed capacity towards meeting the 46 MW summer maximum demand reserve deficit.

Adjacent regions often reach maximum demand at different times, allowing the same capacity to contribute to reliability in more than one region via reserve sharing (the extent of which is captured by each region's allocated installed capacity). The relatively low local reserve margin in South Australia is due to reserve sharing.

The current LRC point is one year earlier than the 2010 ESOO's timing, which is primarily due to moderate increases in the South Australian maximum demand forecasts.

Table 7-6 shows the LRC point and reserve deficit projections with low, medium, and high economic growth. With high economic growth, the South Australian LRC point occurs one year earlier (2013–14), and low economic growth delays the LRC point by two years (2016–17).

Figure 7-5 — South Australian summer supply-demand outlook

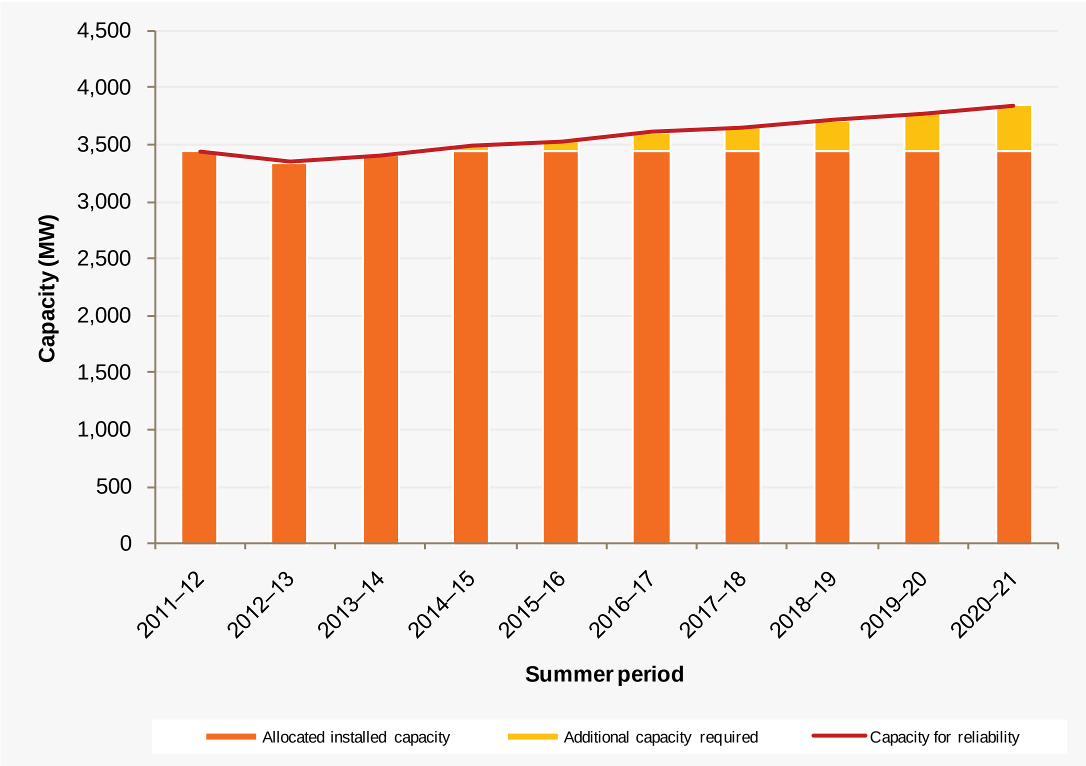


Table 7-6 — South Australian supply-demand outlook summary

Region	Low Economic Growth		Medium Economic Growth		High Economic Growth	
	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)
South Australia (summer)	2016–17	9	2014–15	46	2013–14	5
South Australia (winter)	>2021	N/A	>2021	N/A	>2021	N/A

7.3.7 Tasmanian outlook

Figure 7-6 shows the projected Tasmanian summer supply-demand outlook for 2011–12 to 2020–21. A winter supply-demand outlook is also presented (Figure 7-7) because the Tasmanian maximum demand generally occurs in winter.

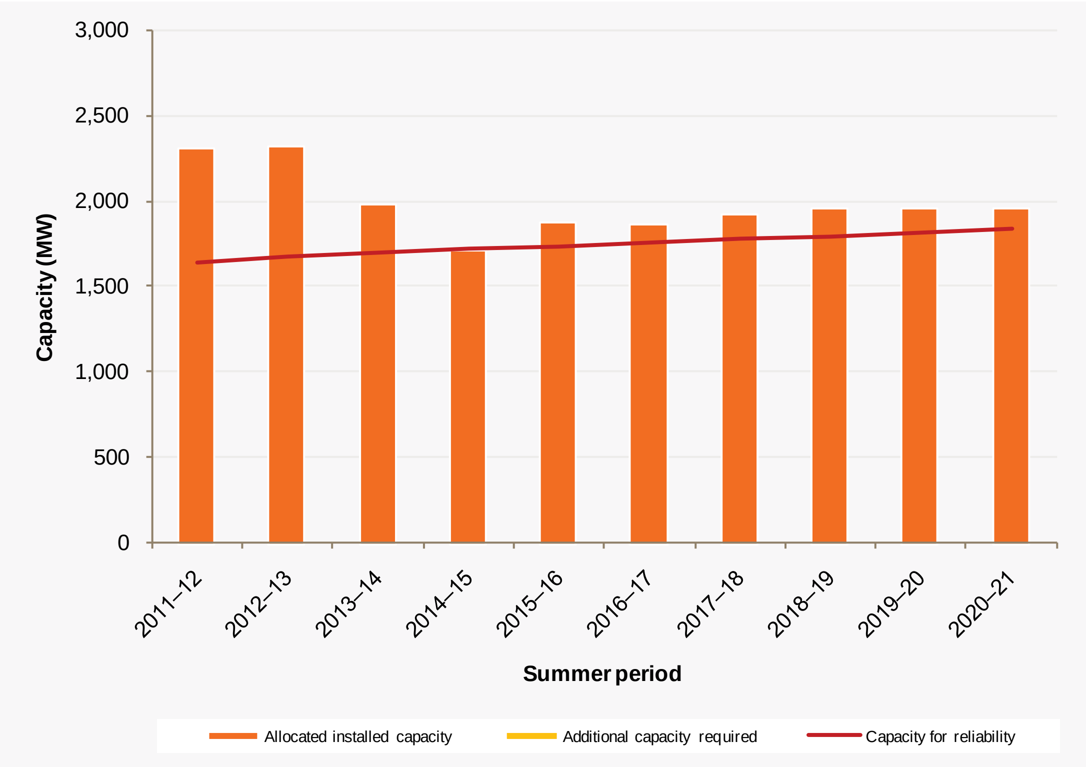
The figures indicate that with medium economic growth, Tasmania does not reach an LRC point during the outlook period. This is consistent with the 2010 ESOO.

Adjacent regions often reach maximum demand at different times, allowing the same capacity to contribute to reliability in more than one region via reserve sharing (the extent of which is captured by each region's allocated installed capacity). The decline in the summer supply-demand outlook's allocated installed capacity until 2014–15 is due to reserve sharing, as Tasmania provides increasing support to Victoria.

Table 7-7 shows that Tasmania does not experience an LRC point prior to 2020–21 in summer and 2021 in winter under any of the assessed economic growth scenarios. The supply-demand outlook, however, only considers capacity adequacy and cannot indicate a reserve shortfall due to energy limitations. This is significant because Tasmania principally depends on hydroelectric generation and tends to be energy limited rather than capacity limited.

AEMO publishes a quarterly EAAP report[6] that provides more relevant information about projected energy limitations and reliability in the Tasmanian region. Chapter 8, Section 8.2.2 also provides a high-level energy adequacy assessment for Tasmania in 2020–21. Consistent with the Transend Networks Annual Planning Report 2011[7], no energy shortfalls are predicted for Tasmania within the outlook period.

Figure 7-6 — Tasmanian summer supply-demand outlook



6 See footnote 1 in this chapter.

7 Transend Networks. "Tasmanian Annual Planning Report 2011". Available http://www.transend.com.au/download/D11-63890. 2 July 2011.

Figure 7-7 — Tasmanian winter supply-demand outlook

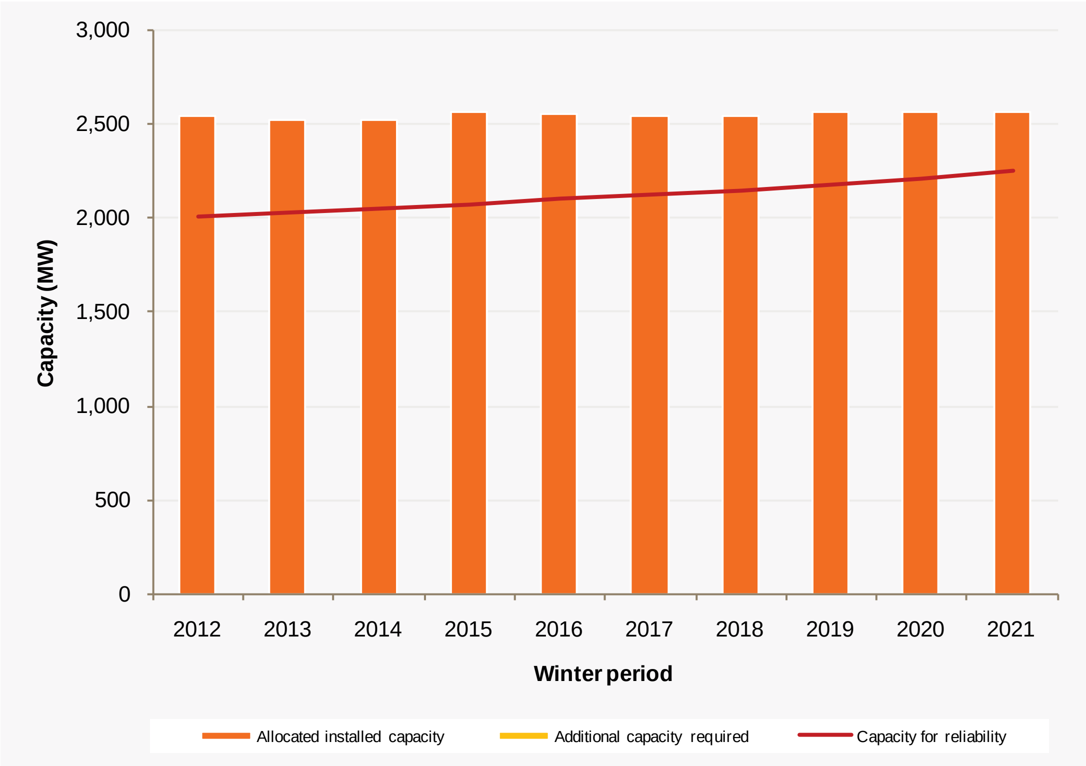


Table 7-7 — Tasmanian supply-demand outlook summary

Region	Low Economic Growth		Medium Economic Growth		High Economic Growth	
	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)
Tasmania (summer)	>2020–21	N/A	>2020–21	N/A	>2020–21	N/A
Tasmania (winter)	>2021	N/A	>2021	N/A	>2021	N/A

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CHAPTER 8 - INVESTMENT OPPORTUNITIES

Summary

This chapter identifies potential opportunities for future investment in the National Electricity Market (NEM) based on existing and emerging energy market trends described in the preceding chapters. This chapter also draws on recent assessments of new technology costs, existing market conditions, and the results of previous published works such as the 2010 National Transmission Network Development Plan (NTNDP). Opportunities in this chapter have been divided into capacity-driven, energy-driven, and policy-driven investment opportunities.

Capacity-driven investment opportunities coincide with periods of supply scarcity and include future supply and demand-side investments to meet short periods of high regional demand or high electricity spot market prices. Investments of this type are needed to maintain system reliability in each region. Based on a medium economic growth scenario, capacity-driven investment is indicated in Queensland, Victoria, and South Australia within the next five years, and New South Wales within the next 10 years.

Energy-driven investment is generally motivated by the quantity of energy required over longer periods, and the average electricity spot market price. Based on medium economic growth, current regional energy projections indicate that no region will experience significant energy deficits by the end of the outlook period, assuming existing generation and committed generation development.

Queensland will experience the largest energy deficit of approximately 300 GWh by 2020-21. This is still a relatively small shortfall, and by comparison a typical combined-cycle gas turbine (CCGT) of 380 megawatts (MW) generates 500 GWh per year if running at a capacity factor as low as 15%. At capacity factors lower than 15%, an open-cycle gas turbine (OCGT) becomes more economic than a CCGT assuming a 25 dollars per tonne ($/t) carbon dioxide equivalent (CO2-e) emission carbon price.

Other regions show even smaller energy shortfalls than Queensland, indicating limited opportunities for additional base load generation across the NEM. However, the introduction of a carbon price may result in the retirement of existing coal-fired capacity, and changes to the relative operating costs of existing and new technology, leading to opportunities for replacement generation.

Tasmania principally depends on hydroelectric generation to meet its local energy requirements, and as a result tends to be an energy-limited region. Subject to constraints governing the operation of Tasmania's hydroelectric power stations, no energy shortfalls are predicted for Tasmania by 2020–21.

Over the last five years, the average spot market price in all regions has dropped by more than 10%. In 2010–11, spot market prices in all regions were below 40 $/MWh for over 90% of the year, and above 100 $/MWh for less than 1% of the year. This reduces the incentive for energy-driven investments in the short term. Electricity futures contract prices show an upward trend, suggesting improved economics for new investments in the years to come.

Policy-driven investments are motivated by government incentives and directives, such as the national Renewable Energy Target (RET) scheme. While this is a market-based mechanism intended to deliver substantial renewable generation within the next decade, other policy initiatives, such as the Solar Flagships Program, are much more prescriptive in terms of the technologies and capacities to be installed.

A key finding from AEMO's 2010 NTNDP was that a combination of the national RET scheme and a carbon-pricing scheme is likely to lead to generation development dominated by low carbon dioxide equivalent (CO2-e) emission technologies and fuels. The NTNDP also showed wind generation being the main technology for new developments in the short term, with up to 6,300 MW of new wind generation installed by 2020–21. Other technologies, such as geothermal and large-scale solar generation do not begin entering the NEM until at least 2015 due to assumed technology development lead times.

8.1 Capacity-driven investment opportunities

8.1.1 Supply-demand outlook

The supply-demand outlook highlights potential generation and demand-side investment opportunities due to projected reserve shortfalls (for more information, see Chapter 7). The supply-demand outlook assessment assumes that only the committed projects AEMO is aware of enter the market, and accounts for the latest energy and maximum demand projections, demand-side participation (DSP), and existing and committed transmission network capabilities.

The Clean Energy Future Plan announced by the Australian Government is expected to have little impact on the timing of the regional Low reserve condition (LRC) points.

The maximum demand projections already include comparable carbon price assumptions and will be largely unaffected. Any changes to installed generation are likely to occur after 2015, which (with medium economic growth) falls after the LRC points in every region except New South Wales and Tasmania.

Results show that every region except Tasmania experiences reserve deficits within the next 10 years.

Table 8-1 shows the first year each region is expected to experience an LRC point. The reserve deficits indicate the quantity of additional installed capacity required to meet the region's minimum reserve level (MRL). The table also provides sensitivity results for the low and high economic growth scenarios. For more information about the assumptions underpinning each economic growth scenario, see Appendix C.

Tasmania's maximum demand typically occurs in winter, and this region's winter outlook has also been provided.

Table 8-1 — Regional LRC points overview

Region	Low Economic Growth		Medium Economic Growth		High Economic Growth	
	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)
Queensland	2014–15	544	**2013–14**	**341**	2013–14	779
New South Wales	2018–19	222	**2018–19**	**190**	2018–19	367
Victoria	2016–17	218	**2014–15**	**96**	2013–14	96
South Australia	2016–17	9	**2014–15**	**46**	2013–14	5
Tasmania (summer)	>2020–21	N/A	**>2020–21**	**N/A**	>2020–21	N/A
Tasmania (winter)	>2021	N/A	**>2021**	**N/A**	>2021	N/A

8.1.2 Investment opportunities for peaking generation and DSP

Reserve deficits represent capacity shortfalls that potentially indicate opportunities for DSP contracts or peaking generation, such as OCGT, which are typically the most economic when additional capacity is required to meet short term supply scarcity. For more information about signals that may influence the location for investments of this type, see Section 8.4.

Chapter 4 provides more information about generation projects in each region that may commence construction before the forecast LRC points.

AEMO is exploring opportunities to expand the supply-demand balance analysis to provide additional information about the nature of expected energy shortfalls while still identifying LRC point timings and magnitudes. These processes may include time-sequential market simulations similar to those conducted for the NTNDP.

8.2 Energy-driven investment opportunities

While capacity-driven investments aim to capture short periods of high electricity spot market prices, energy-driven investments are concerned with energy produced over longer periods and average spot prices. This section focuses on the nature and timing of energy-driven opportunities, and analyses current investment interest, projected demand duration curves, spot prices, and new technology frontier curves.

8.2.1 Current investment interest

As part of the annual ESOO data collection process, AEMO surveys registered participants and other parties believed to be developing future generation projects. The collected data provides existing and committed generator capacity values used by the supply-demand outlook, and provides an overview of the technology, location, and size of future generation proposals.

Figure 8-1 compares the fuel source mix of existing (installed) generation with known committed projects and advanced proposals. The figure indicates that there may be a significant shift occurring in the mix of fuels and technologies utilised in the NEM.

Wind generation and gas powered generation (GPG) compose almost 90% of the committed projects and advanced proposals. While the magnitude of this wind capacity is significant, its contribution towards deferring LRC points will be at most 10% of the installed capacity based on the seasonal contribution factors discussed in Section 8.3.3.

Figure 8-1 — Comparison of existing (installed) generation, and committed projects and advanced proposals by fuel source

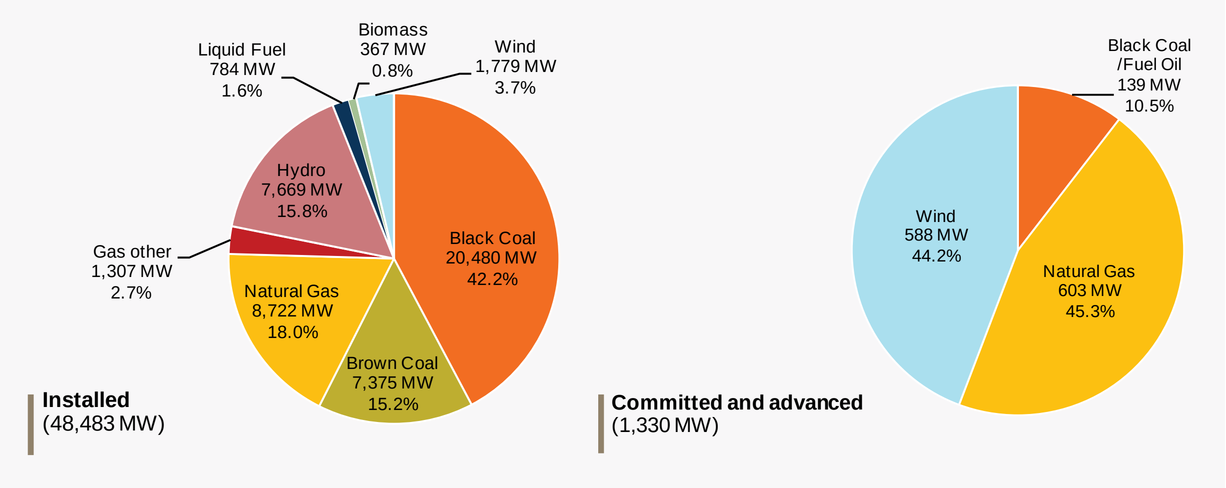
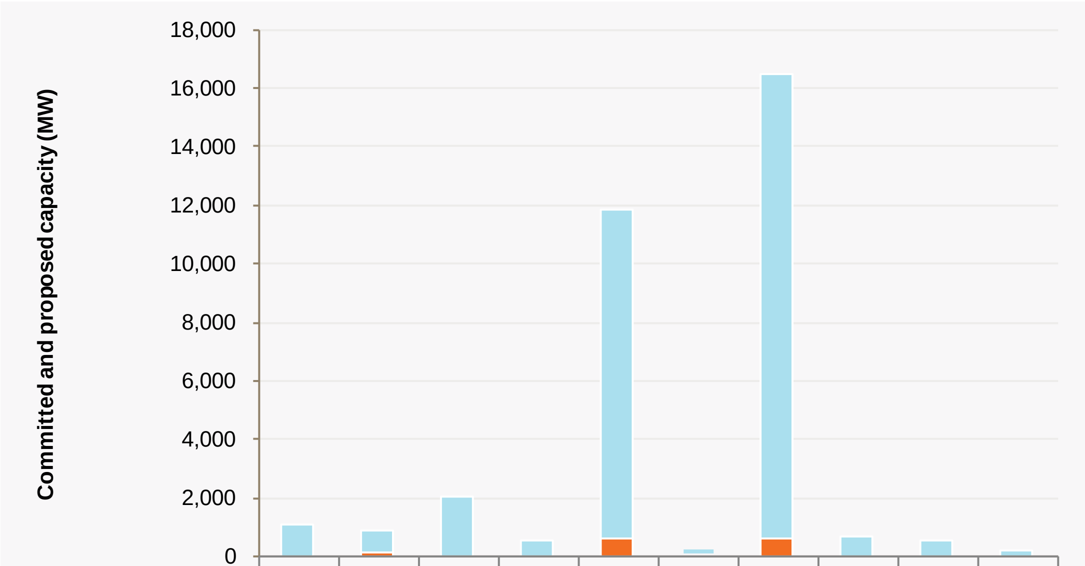


Figure 8-2 summarises the commitment status of generation developments in the NEM.[1]

[1] For more information about the way AEMO classifies generation projects, see Chapter 4, Section 4.4.

Figure 8-2 — Capacity of committed and proposed projects in the NEM by fuel source (MW)



	Black coal	Black coal other	Black coal or gas	Brown coal	Gas	Hydro	Wind	Solar	Geo	Bio
Publicly announced	1074	700	2000	550	11217	43	15851	694	525	213
Advanced	0	0	0	0	36	0	0	0	0	0
Committed	0	139	0	0	567	0	588	0	0	0

There are currently over 1,000 MW of committed projects across the NEM, including Woodlawn Wind Farm (48 MW) and the Eraring Power Station upgrade (120 MW) in New South Wales, Mortlake Stage 1 project (566 MW), the Macarthur Wind Farm (420 MW) and the Oaklands Hill Wind Farm (67 MW) in Victoria, and the Hallett The Bluff Wind Farm (53 MW) in South Australia.

Wind generation projects represent the highest technology interest (by capacity), with advanced and publicly announced proposals totalling over 15,000 MW across the NEM. While wind generation represents a significant part of the committed and proposed generation under development, the contribution from wind towards deferring LRC points approximates only 10% of the installed capacity (at most), based on the calculated seasonal contribution factors (see Section 8.3.3).

GPG developments represent the second highest investment interest, with publicly announced proposals totalling over 11,000 MW spread across all regions except Tasmania.

There are six publicly announced proposals involving solar generation (both solar thermal and photovoltaic totalling 694 MW) located in Queensland, New South Wales, and South Australia. This includes the 250 MW Solar Dawn project in Queensland and the 150 MW Moree project in New South Wales, both recently announced as successful candidates under the Australian Government's Solar Flagships program.

One publicly announced proposals using geothermal generation (totalling over 500 MW) are located at Innamincka in South Australia.

8.2.2 Assessment of energy supply at risk

Demand duration curves indicate the amount of time demand spends above or below a given value during a financial year (either instantaneous in MW, or as a percentage of the maximum demand). These curves can aid the assessment of demand within a region, and the potential timing of generation investments. For more information about demand duration curves, see Tutorial 2 (included with the ESOO's electronic information).

The shape of a region's demand duration curve is driven by patterns in local consumption and the relative growth rates for energy and maximum demand.[2]

The analysis in this section builds on the regional supply-demand outlooks by exploring the energy deficit between future demand duration curves and an assumed level of supply. The assumed level of supply is an approximation used only for this analysis and consists of the existing and committed regional capacities reported in Chapter 4 for 2015–16 (scaled to 90%), wind output based on the summer MD contribution factors listed in Table 8-7, and average regional import limits during the top 20% of regional demands in 2010–11. This does not take account of any committed network augmentations commissioned after July 2011.

Table 8-2 presents both components of assumed supply.

Table 8-2 — Assumed supply (MW)

Region	Existing and Committed Capacity (2015–16)	Interregional Support	Assumed Supply[a]
Queensland	12,150	180	11,115
New South Wales	16,316	1,785	16,383
Victoria	11,367	1,380	11,233
South Australia	3,902	475	3,575
Tasmania	2,562	325	2,631

a. Represented by the assumed supply line in Figure 8-3 to Figure 8-7.

AEMO expects the Clean Energy Future Plan announced by the Australian Government to have little impact on the installed generation mix prior to 2015.

Financial support for the high CO2-e emitting generation initiatives described is conditional upon maintaining power system reliability. If a mechanism similar to the original Carbon Pollution Reduction Scheme legislation is adopted, AEMO will be required to certify that the Reliability Standard will be met for two years after a proposed deregistration.

AEMO expects any Government payment for closures to occur in the second half of the decade

2 A demand duration curve is a cumulative frequency calculation of trading interval demand, with the area under the curve representing the total energy in the period.

The charts and analysis in this section make the following assumptions:

- Ninety percent of installed generation is available to meet demand (this approximates the impact of intra-regional transmission network limitations and unscheduled generation outages).
- Wind generation supplies power as per the peak summer contribution factors listed in Table 8-7.
- Future annual energy and maximum demand values align with the projections described in Chapter 3 for medium economic growth.
- The demand duration curves are based on historical 2010–11 curves, adjusted to represent the energy and weighted contributions of 10% probability of exceedence (POE) and 50% POE maximum demand projections using the NTNDP demand growth process.[3]
- Only the existing and committed generation described in Chapter 4 enters the market.
- Neighbouring regions have sufficient installed capacity to meet their own demand and provide the level of assumed interregional support.

Figure 8-3 to Figure 8-7 show the top-end regional demand duration curves for 2010–11 (historical) and projections for 2013–14, 2015–16, and 2020–21 under these assumptions. These figures provide a high-level indication of the possible timing and type of generation opportunities available in each region over the next 10 years.

These demand duration curves show the amount of time demand in each region falls above or below the region's supply, which is the point where each curve intersects the assumed supply line (the assumed level of available supply). The area above the Supply line indicates the percentage of time that supply will be insufficient to meet demand (the region's unserved energy).

For example, in Queensland by 2020–21, the assumed supply of approximately 11,115 MW will be insufficient to meet demand for approximately 5% of the year on average, and results in almost 300 GWh of unserved energy (the area between the Supply line and the blue 2020–21 demand duration curve).

[3] AEMO. "2010 NTNDP Consultation – Appendix B". Section B.2. Available http://www.aemo.com.au/planning/0418-0004.pdf. 30 June 2011.

Figure 8-3 — Queensland projected demand duration curves

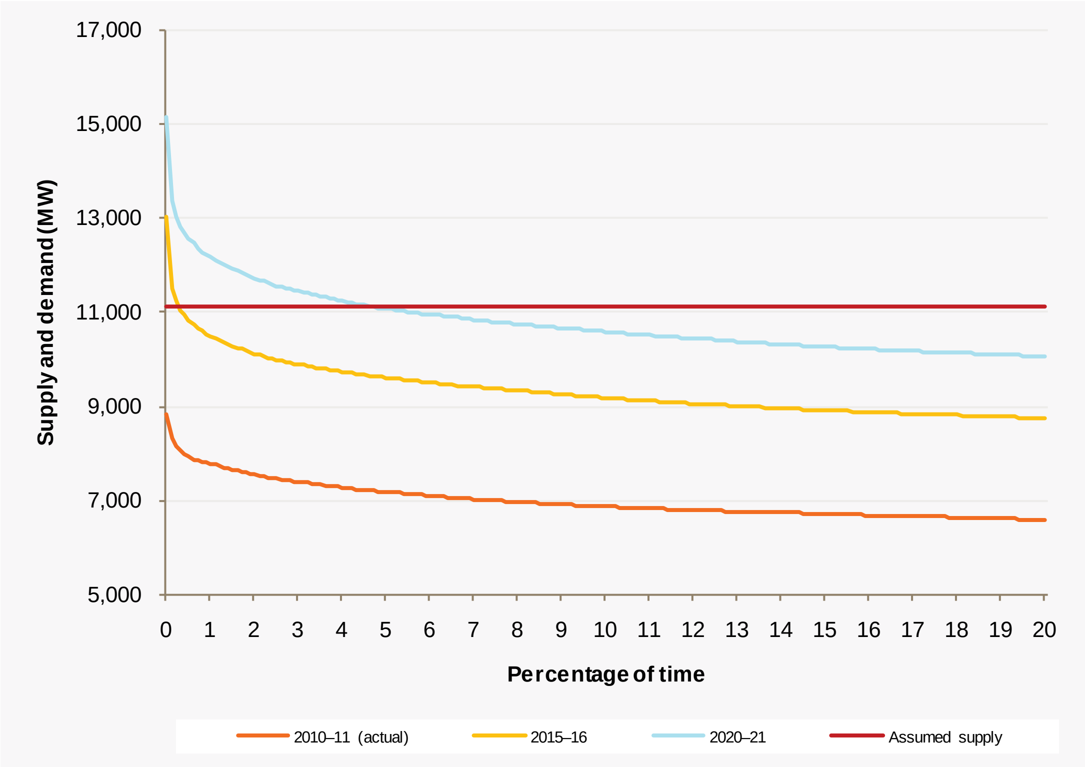


Figure 8-4 — New South Wales projected demand duration curves

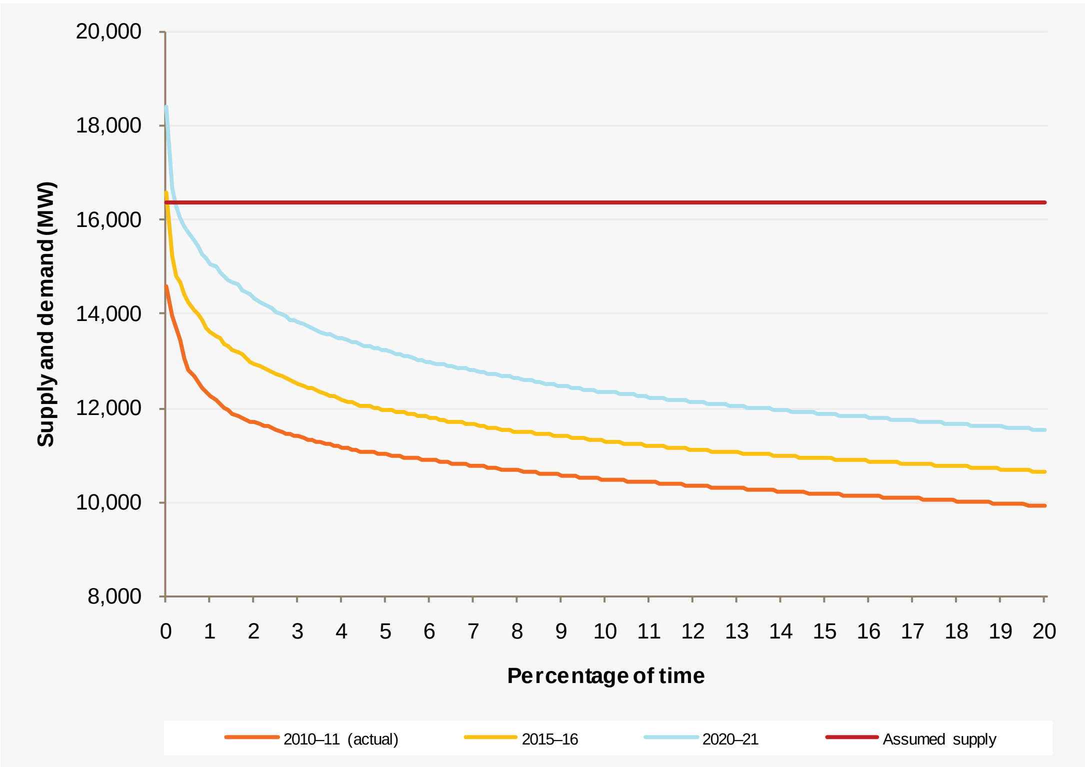


Figure 8-5 — Victorian projected demand duration curves

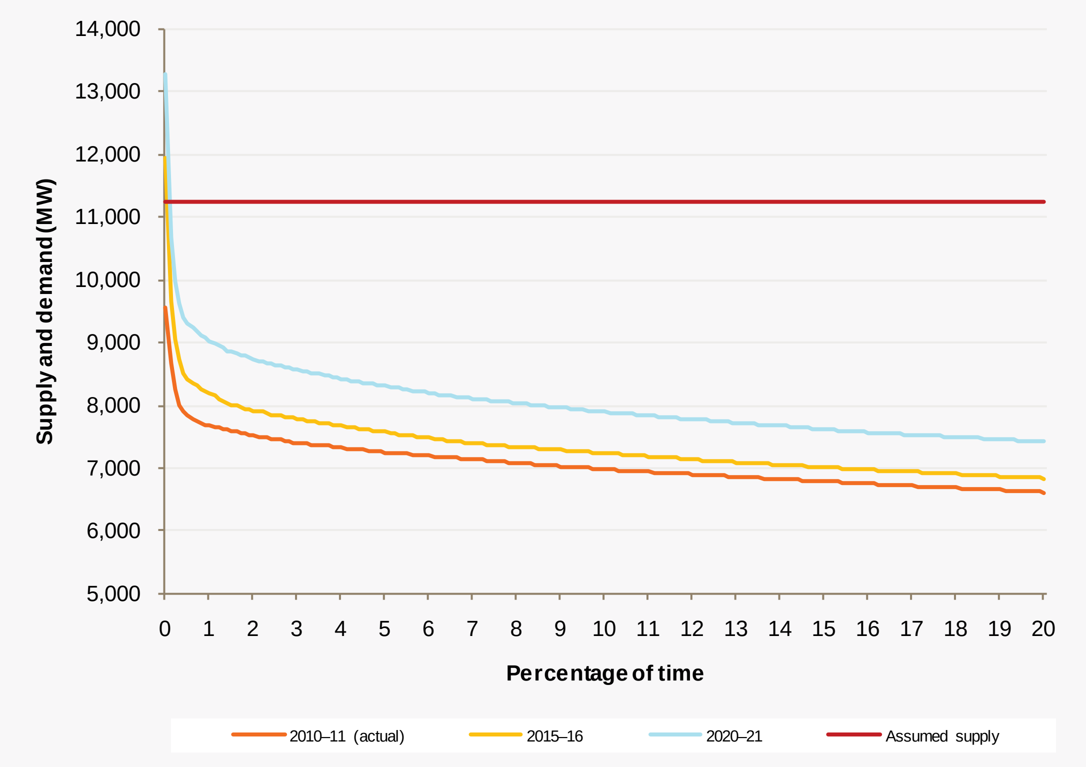


Figure 8-6 — South Australian projected demand duration curves

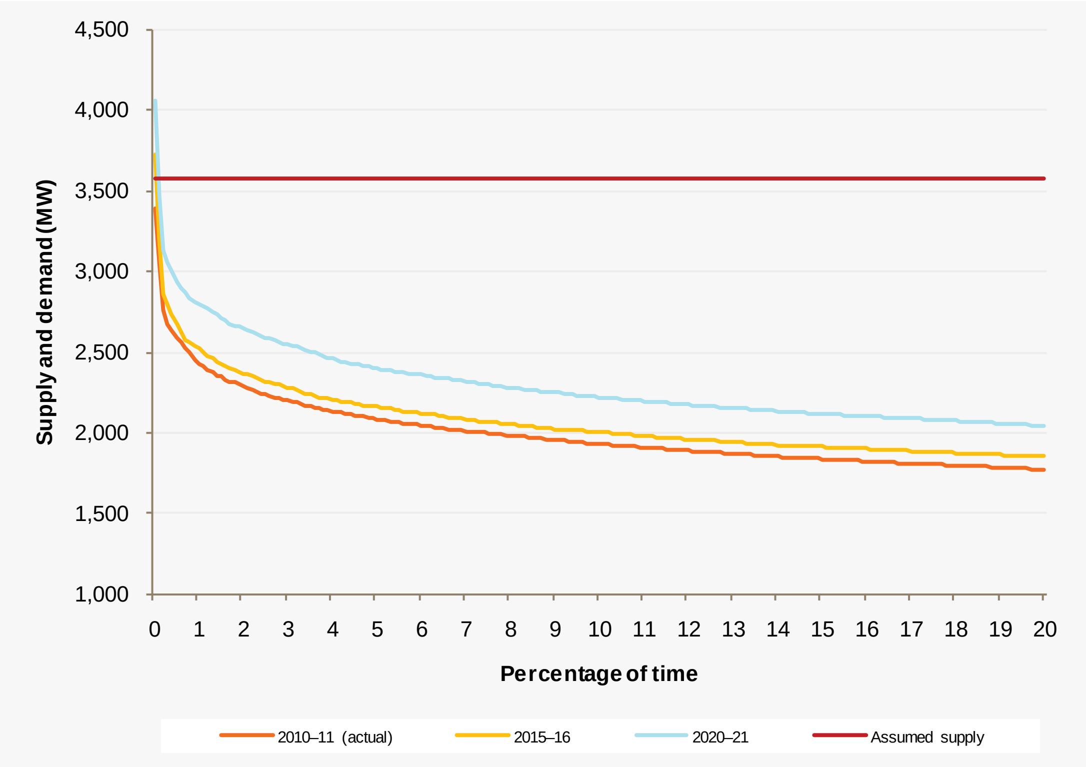


Figure 8-7 — Tasmanian projected demand duration curves

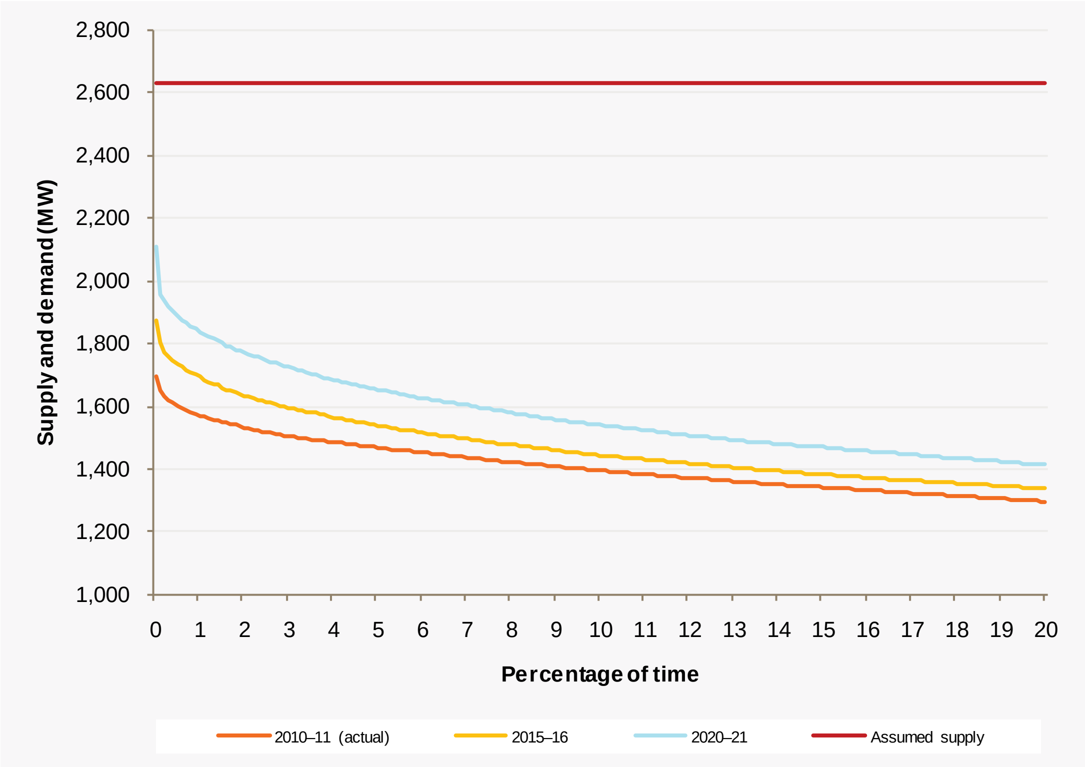


Table 8-3 summarises the area (unserved energy) between each demand curve and the assumed supply line.

Table 8-3 — Approximate area of energy deficit (GWh)

Region	2010–11	2015–16	2020–21
Queensland	0.0	21.6	293.9
New South Wales	0.0	1.6	20.0
Victoria	0.0	6.1	17.8
South Australia	0.0	1.3	4.2
Tasmania	0.0	0.0	0.0

This analysis, with assumed supply, indicates that Queensland will experience the largest energy deficit of approximately 300 GWh by 2020–21. By comparison, a typical CCGT of 380 MW generates 500 GWh per year if running at a capacity factor as low as 15% (the point at which it becomes more economic than an OCGT under a 25 \$/t CO2-e price) (see Section 8.2.5).

Other regions show even smaller energy shortfalls than Queensland, indicating limited opportunities for additional base load generation across the NEM. However, the introduction of a carbon price may result in the retirement of existing coal-fired capacity, and changes to the relative operating costs of existing and new technology, leading to opportunities for replacement generation.

Every region except Tasmania experiences energy deficits by 2015–16. In New South Wales, Victoria, and South Australia, these deficits occur for only a fraction of the year, and may be met with investment in peaking generation or DSP.

Wind farms that can operate at high capacity factors can produce energy that is cost competitive with other forms of generation, resulting in opportunities to supply energy that is currently met by existing generation. This is also true for alternative renewable technologies, such as geothermal and large-scale solar, which have low operating costs and may become commercially viable towards 2020 as technological development continues and revenues continue to be supplemented by the national RET scheme (see Section 8.3.1).

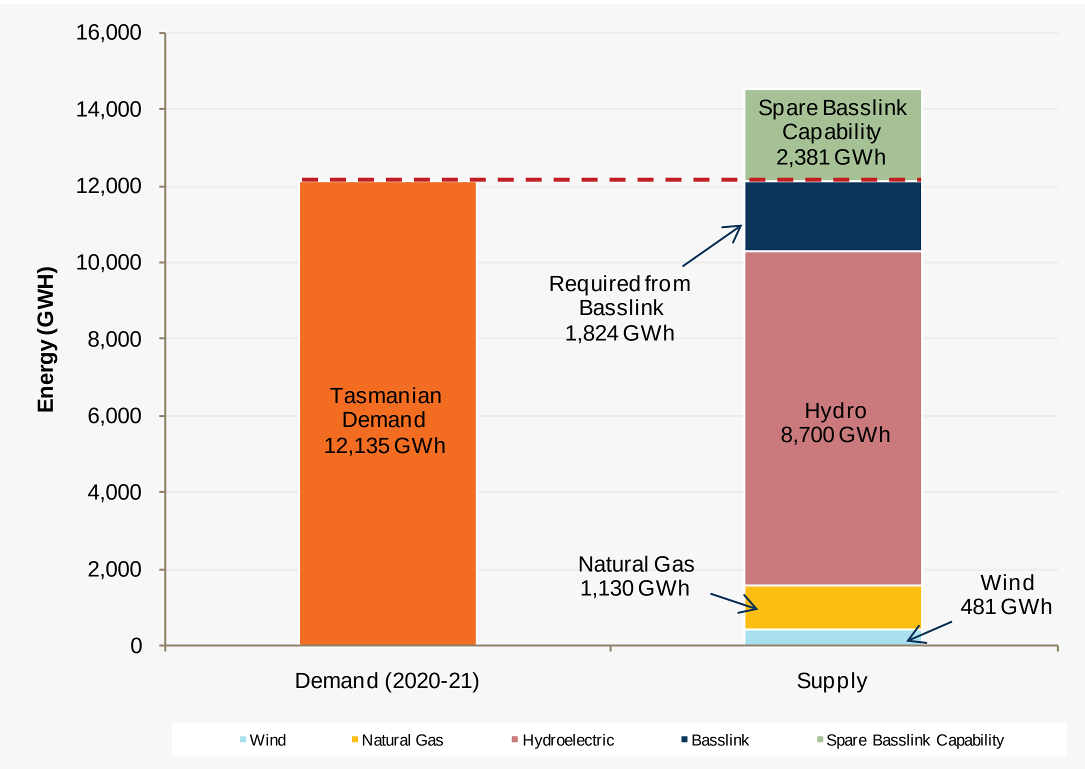
Tasmanian energy balance

Tasmania principally depends on hydroelectric generation to meet its local energy requirements and, as a result, tends to be an energy-limited region. Figure 8-7 assumes 90% of installed capacity is available to run during the top 20% of demand periods, although annual rainfall, reservoir inflows, and other operating restrictions may limit these outputs. Figure 8-8 provides a high-level energy adequacy assessment for Tasmania in 2020–21, assuming:

- medium economic growth projections for energy (see Chapter 3, Section 3.7)
- existing CCGT capacity (209 MW) running at 60% capacity factor
- existing OCGT capacity (178 MW) running at 2% capacity factor
- existing wind capacity (140 MW) running at 39.2% capacity factor (see Section 8.3.3)
- annual hydroelectric energy output (8,700 GWh) consistent with long-term expectations[4], and
- Basslink import capabilities of 480 MW.

Subject to additional constraints or drought conditions governing the operation of Tasmania's hydroelectric power stations, no energy shortfalls are predicted for Tasmania by 2020–21.

Figure 8-8 — Tasmanian energy adequacy assessment (2020–21)



4 Hydro Tasmania. "Electricity in Tasmania A Hydro Tasmania Perspective", p11. Available http://www.hydro.com.au/annual-reports/2009/contents/pdfs/Hydro%20Electricity%20in%20Tasmania.pdf. 25 July 2011.

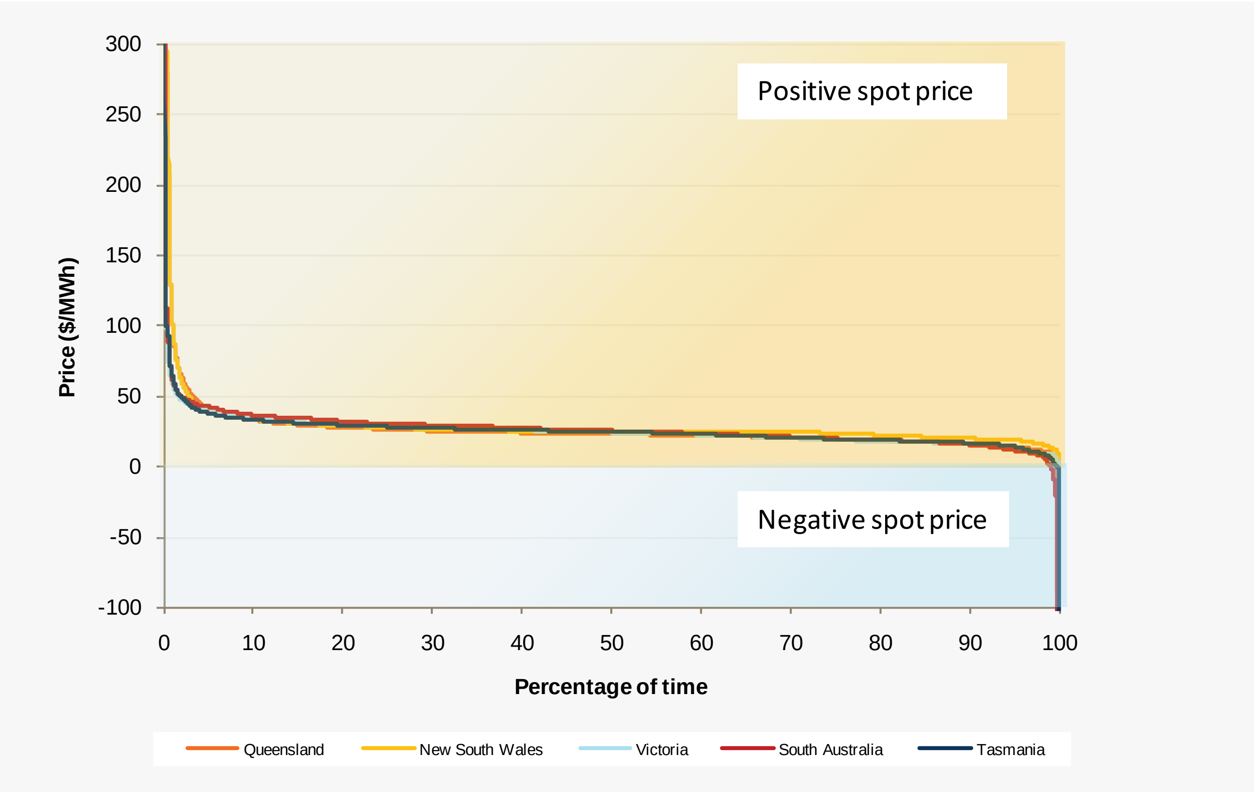
8.2.3 Regional spot market prices

Trends in spot market prices are an important indicator of emerging opportunities for new generation investment. Table 8-4 shows the trend in average regional electricity spot market prices over the last five financial years (rounded to whole numbers). Figure 8-9 shows the regional price duration curves for 2010–11.

Table 8-4 — Approximate average regional spot prices ($/MWh)

Region	2006–07	2007–08	2008–09	2009–10	2010–11	Average Annual Growth
Queensland	52	52	34	33	31	-12%
New South Wales	59	42	39	44	37	-11%
Victoria	55	47	42	36	27	-16%
South Australia	52	74	51	55	33	-11%
Tasmania	50	55	58	29	29	-12%

Figure 8-9 — Regional price duration curves (2010–11)



This curve shows that all regions exhibit low-priced periods (between (zero) 0 $/MWh and 40 $/MWh) for approximately 90% of the year. This reduces the incentive for generation investment with typical spot market bids at the high end of this range (such as CCGTs). Generation with low fuel costs or relatively small capacity (where its entry will not significantly affect the spot market price) may still be economically viable.

The figure also shows a number of periods with negative prices (0.1% of the year in New South Wales and Victoria, 0.2% of the year in Queensland and Tasmania, and 1.0% of the year in South Australia).

Table 8-5 shows how the number of high-priced periods in each region has changed over the last five financial years. In particular, the table identifies a steady decline in moderately priced periods (between 100 $/MWh and 1,000 $/MWh) in every region. This represents a reduction in price-driven investment incentives for new peaking generation investment with typical bid prices in this range.

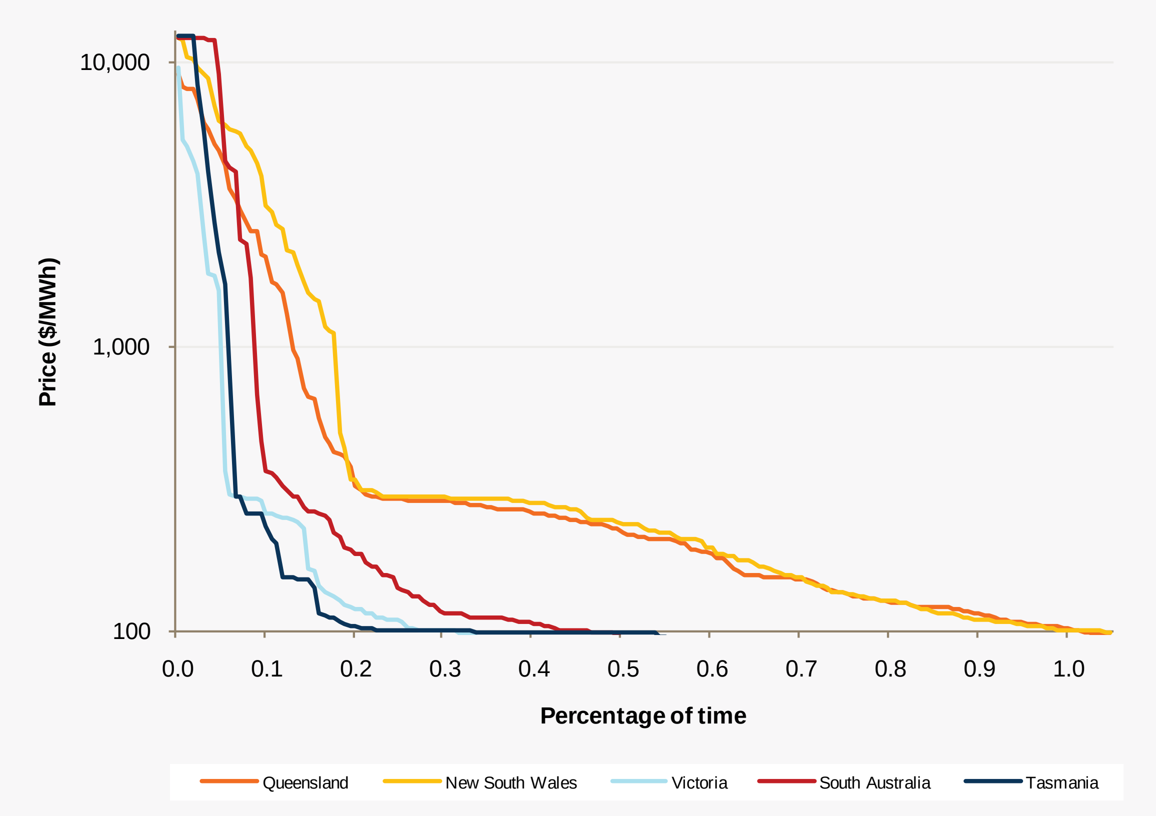
The table also highlights that, while still lower than historical levels, New South Wales and Queensland spot prices were above 100 $/MWh significantly more often than other regions during 2010–11. If this continues, peaking investment in these regions may be more attractive than similar investments in the southern regions.

Figure 8-10 demonstrates this result graphically, showing the price duration curves for prices above 100 $/MWh (2010–11) against a logarithmic price axis.

Table 8-5 — Number of hours of high spot prices by region

Region		2006–07	2007–08	2008–09	2009–10	2010–11
Queensland	> 100 $/MWh	581.5	276.0	111.0	88.5	86.5
	> 1,000 $/MWh	23.0	28.5	11.0	21.0	11.0
New South Wales	> 100 $/MWh	635.0	206.0	117.0	115.5	88.5
	> 1,000 $/MWh	23.0	2.5	12.0	34.5	15.5
Victoria	> 100 $/MWh	509.0	336.0	110.5	67.0	27.0
	> 1,000 $/MWh	22.0	8.0	13.5	19.5	4.5
South Australia	> 100 $/MWh	547.0	364.5	146.5	109.0	39.5
	> 1,000 $/MWh	13.5	31.0	22.5	36.5	7.5
Tasmania	> 100 $/MWh	350.5	423.5	353.0	64.0	28.0
	> 1,000 $/MWh	8.0	3.0	31.5	7.0	5.0

Figure 8-10 — Price duration curves for prices above 100 $/MWh (2010–11)



8.2.4 Forward contract prices

While spot market prices have declined over recent years, forward contract prices indicate an upward trend, which will improve incentives for investment in new generation.

Future delivery of electricity can be traded in bilateral futures contract markets to enable market participants to manage short and medium-term price risks.[5] Table 8-6 provides a regional summary of the prices for base load generation futures contracts as at 3 June 2011. As futures contracts do not contain conditions allowing the pass-through of changes in taxes and charges[6], the quoted prices incorporate a market view of the impact of carbon pricing. Some contracts include pass-through provisions and may be priced at a discount to the futures contracts.

Table 8-6 — Future electricity prices ($/MWh)[7]

	New South Wales	Victoria	Queensland	South Australia
Financial year 2012	40.23	34.50	34.32	39.56
Financial year 2013	50.74	45.59	45.25	57.69
Financial year 2014	58.49	58.75	56.91	69.39

5 D-cypha Trade. "Overview of the Australian Electricity Market". Available http://d-cyphatrade.com.au/products/overview_of_the_australian_el. 21 July 2011.

6 D-cypha Trade. "Electricity Futures and Options Contracts Specifications". Available http://d-cyphatrade.com.au/products/electricity_futures. 10 August 2011.

7 D-cypha Trade. "Market Futures". Available http://d-cyphatrade.com.au/market_futures#A**. 3 June 2011

The Garnaut Climate Change Review found that investors are experiencing difficulty maintaining existing generation asset values and finalising new generation investment decisions due to the lack of certainty surrounding a carbon price.[8] This uncertainty impacts the willingness of financial institutions to fund capital investments in thermal generation. The Department of Resources, Energy and Tourism's draft Electricity Investment Report identified that lending institutions now prefer investments supported by long-term power purchase agreements (PPA).[9] In order to manage risks, businesses may have credit limits that restrict the size or length (or both) of financial contracts that are allowed with any particular counterparty. This has led to a growing trend in vertical integration, with some retail businesses building or buying generation to provide a physical hedge for securing loans.

8.2.5 Long-run marginal costs and technology frontiers

A generator's long-run marginal cost (LRMC) describes the revenue (in $/MWh) required to cover financing costs and the fixed and variable operating and maintenance costs of the investment over the asset's lifetime. The value of this required revenue varies according to a number of factors, including the expected capacity factor.

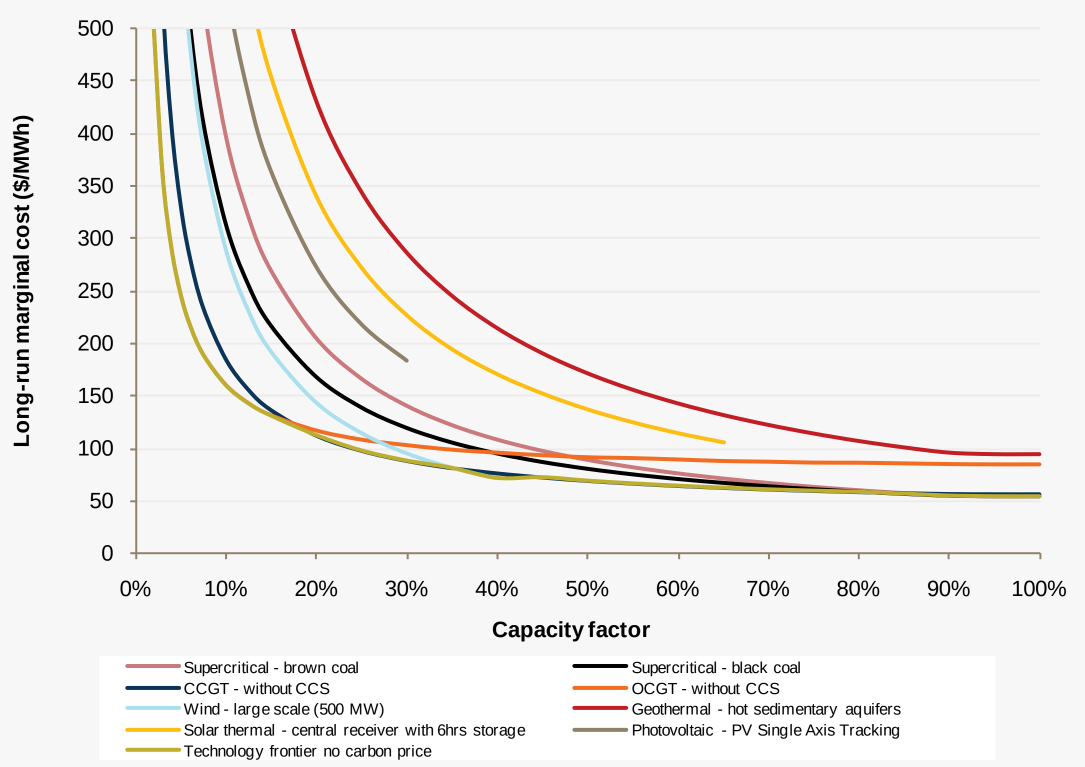
A technology frontier curve comprises segments of the LRMC curves for different technologies, and represents the minimum cost technology for a given capacity factor. Figure 8-11 shows the LRMC for a selection of generation technologies, and the resulting technology frontier curve across a range of capacity factors. This data was calculated based on the 2010 NTNDP input data assumptions.[10] Some pre-screening has been done for technologies that are similar to others, or do not contribute to the technology frontier. A zero carbon price has been assumed.

[8] Garnaut Climate Change Review. "Update Paper 8: Transforming the Electricity Sector". Available http://www.garnautreview.org.au/update-2011/update-papers/up8-key-points.html. 3 June 2011.

[9] Department of Resources, Energy and Tourism. " Independent Review of Investment Activity in The Australian Electricity Generation Sector". Available http://www.ret.gov.au/energy/energy_security/irg/Pages/irg.aspx. 30 May 2011.

[10] AEMO. "2010 National Transmission Network Development Plan Consultation – NTNDP Modelling Assumptions Supply Input Spreadsheets". Available http://www.aemo.com.au/planning/ntndp2010consult.html. 7 July 2011.

Figure 8-11 — Long-run marginal cost and the technology frontier



Each technology has a distinct LRMC for a given level of output due to differing capital and operating costs, even under the same financing arrangements. For example, when run at capacity factors greater than 50%, OCGT technology has higher operating costs than CCGTs and supercritical black coal technologies. The reverse is true for low capacity factor operation.

From Figure 8-11, the most cost-efficient technologies by capacity factor (with no carbon price applied) are:

- OCGTs at capacity factors less than 20%
- CCGTs at capacity factors between 20% and 35%
- wind generation at capacity factors between 35% and 40% (with an assumed maximum capacity factor of 40%)
- CCGTs at capacity factors between 40% and 75%, and
- CCGTs, supercritical black coal, or brown coal at capacity factors above 75%.

The most cost-effective technologies for high capacity factors (CCGTs, supercritical black or brown coal) have LRMCs around the level of futures contracts for South Australia in 2014 (Table 8-6), however, the futures price incorporates an expected carbon-pricing scheme while the LRMCs in Figure 8-11 do not.

Figure 8-12 and Figure 8-13 show the LRMC impact of a 25 $/t CO_2-e and 50 $/t CO_2-e carbon price, respectively.

Figure 8-12 — Long-run marginal cost and the technology frontier (25 $/t CO2-e carbon price)

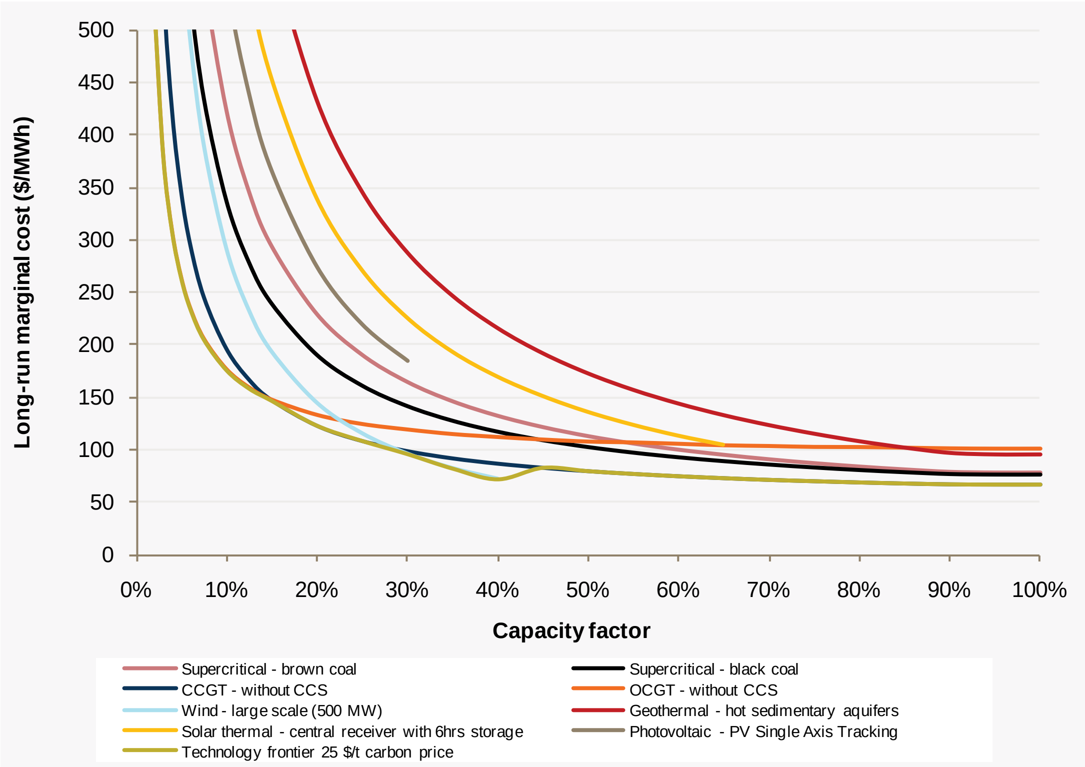
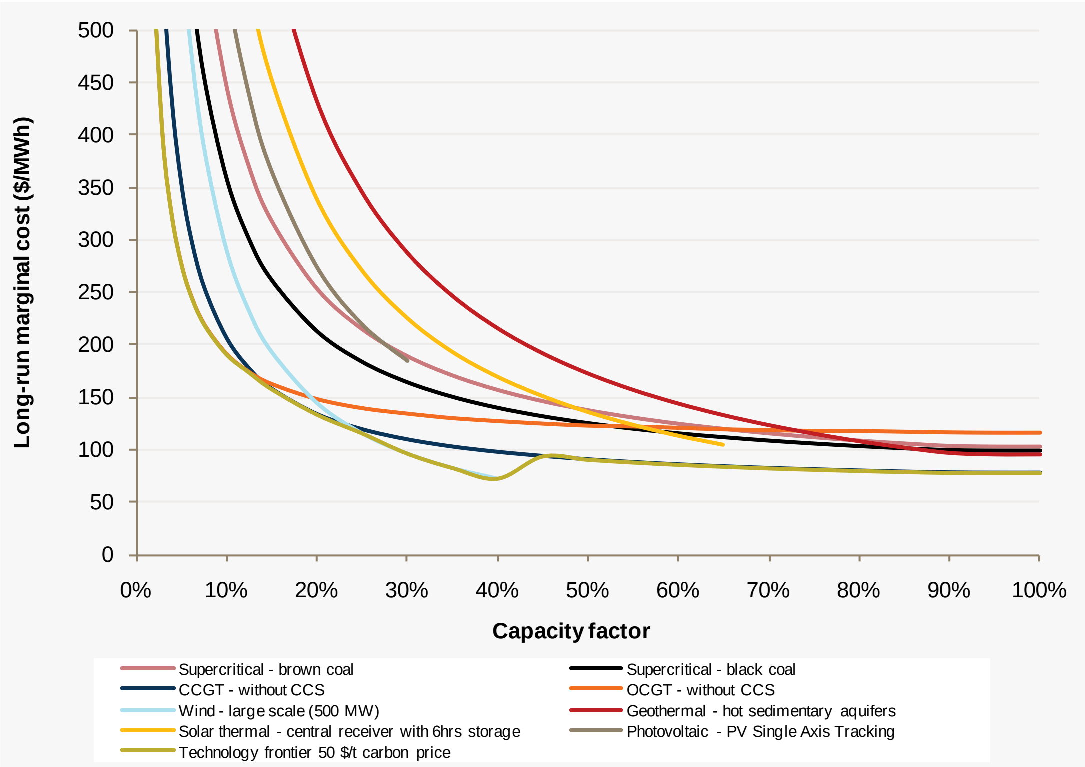


Figure 8-13 — Long-run marginal cost and the technology frontier (50 $/t CO2-e carbon price)



With a carbon price, the LRMC for CCGT and other thermal base load type technologies are significantly higher than the futures prices listed in Table 8-6.

From Figure 8-12, the most cost-efficient technologies with a $25/t CO2-e carbon price by capacity factor are:

- OCGTs at capacity factors less than 15%
- CCGTs at capacity factors between 15% and 30%
- wind generation at capacity factors between 30% and 40% (with an assumed maximum capacity factor of 40%), and
- CCGTs at capacity factors above 40%.

From Figure 8-13, the most cost-efficient technologies for a $50/t CO2-e carbon price by capacity factor are:

- OCGTs at capacity factors less than 12%
- CCGTs at capacity factors between 12% and 25%
- wind generation at capacity factors between 25% and 40% (with an assumed maximum capacity factor of 40%), and
- CCGTs at capacity factors above 40%.

The technologies that perform best across the range of carbon prices are OCGTs, CCGTs, and wind (which is not directly affected by carbon prices). This is consistent with current investor interest (See Figure 8-2 and Chapter 4).

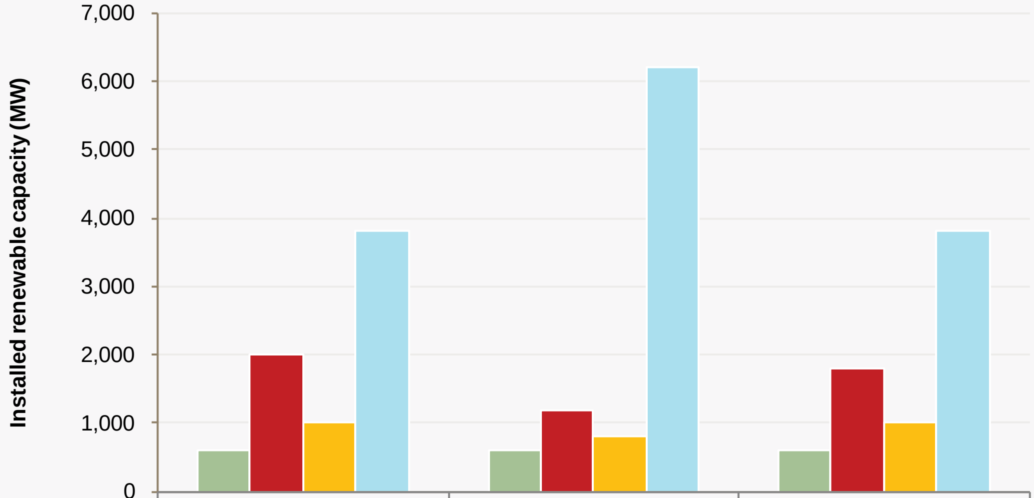
8.3 Policy-driven renewable investment opportunities

The 2010 NTNDP showed that the national RET scheme will be an important driver of renewable generation over the next 10 years.[11] Wind power is likely to be the main renewable generation technology in the short term, with other technologies, like geothermal and large-scale solar generation beginning to appear towards the end of the decade.

Figure 8-14 summarises the installation of new renewable generation capacity by 2020-21 in three of the 2010 NTNDP scenarios: Fast Rate of Change, high carbon price; Decentralised World, medium carbon price; and Slow Rate of Change, low carbon price.

The figure indicates that under this range of scenarios over 7,000 MW of new renewable generation capacity will enter the market by 2020–21. Over half of this capacity is based on wind, with the remainder split amongst geothermal, large-scale solar, and biomass.

Figure 8-14 — New renewable generation capacity by 2020–21 in three NTNDP scenarios



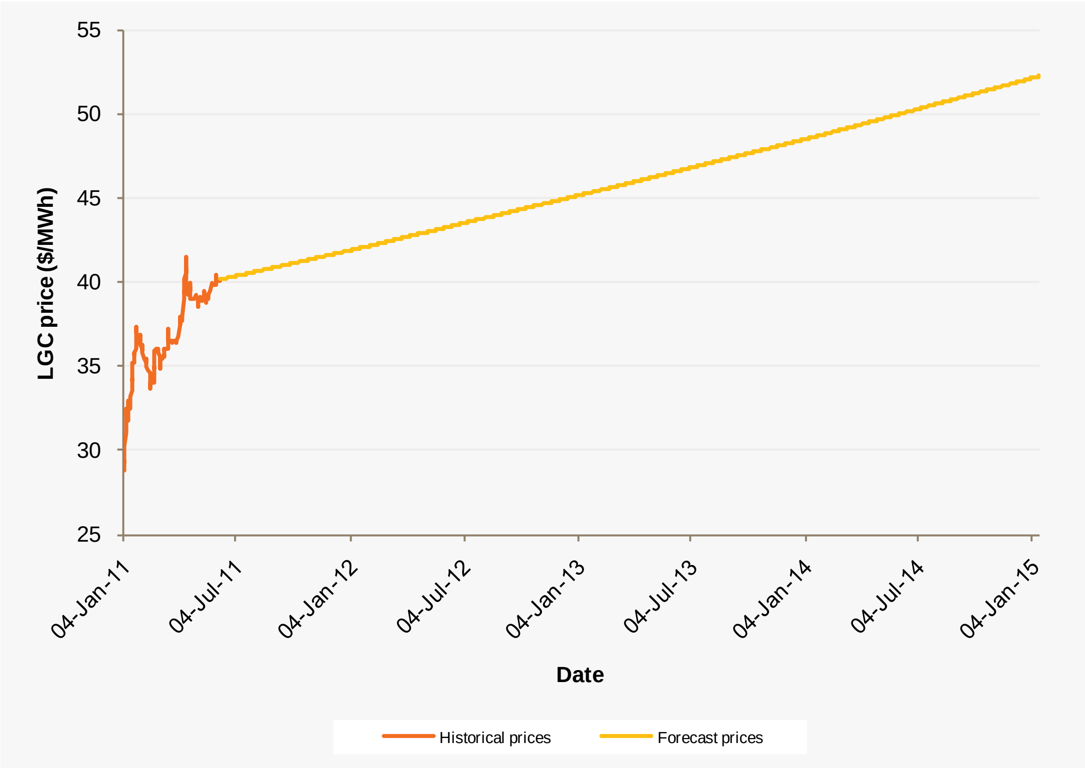
	Fast Rate of Change, high carbon price	Decentralised World, medium carbon price	Slow Rate of Change, low carbon price
Biomass	600	600	600
Geothermal	2,000	1,200	1,800
Solar	1,000	800	1,000
Wind	3,800	6,200	3,800
Total	7,400	8,800	7,200

[11] AEMO. "2010 National Transmission Network Development Plan". Available http://www.aemo.com.au/planning/ntndp.html. 8 June 2011.

8.3.1 Future Large-scale Generation Certificate prices

Renewable investment will largely depend on the price of Large-scale Generation Certificates (LGC)[12], and on the final details of the Australian Government's proposed carbon pricing scheme. Figure 8-15 shows one view of forecast LGC prices provided by TFS Green as at 10 June 2011.

Figure 8-15 — Large-scale Generation Certificate future price estimate[13]



The low price at the start of 2011 was caused by a surplus of certificates generated through rooftop photovoltaic installations. Since the national RET scheme's division (for more information, see Chapter 2, Section 2.2.2), LGC prices have recovered, but there has been some instability over the last 12 months due to continued carbon price policy uncertainty.

The Department of Resources, Energy and Tourism's draft Electricity Investment Report[14] emphasises the fact that swings in LGC prices are making renewable energy projects, particularly projects not backed by PPAs, less attractive for investment.

[12] Previously called Renewable Energy Certificates (RECs).
[13] Data sourced from TFS Green.
[14] See note 8 in this chapter.

8.3.2 Investment opportunities for renewable generation

Investors in renewable generation will receive revenue from both the sale of LGCs and the trade of energy on the spot market or sale under contract.

Adding the future electricity price expectations in Table 8-6 to the LGC price forecast in Figure 8-15, the total exceeds the LRMC for wind generation (from Figure 8-11) within a few years. This indicates that renewable investments may slow in the short term until LRMCs are exceeded.

For a $50/t CO2-e carbon price, both solar thermal and geothermal technologies are near the technology frontier (see Figure 8-13). As they obtain income from LGC sales, they may become competitive with CCGT technology and are, therefore, interesting options for base load applications when this technology matures.

This is a simplistic analysis, and investment decisions will be significantly affected by the impact renewable generation may have on spot market prices (particularly if production from existing units is displaced, lowering spot prices). Investment decisions are also affected by locational signals (for more information, see Section 8.4).

8.3.3 The impact of wind generation

Recent Australian Government policies and initiatives driving an increase in renewable generation have enabled wind generation projects to progress more rapidly than thermal generation. Approximately 15% (by capacity) of the projects classified as advanced in the 2010 ESOO have progressed this year to committed or completed, all of which have been wind farms (except 1 MW of non-scheduled biomass technology). For more information about committed generation projects, see Chapter 4.

The 2010 NTNDP showed a substantial amount of renewable generation, particularly wind, is required to meet the national RET scheme by 2020. While wind generation typically has a capacity factor of between 25% and 40%, its variable nature substantially reduces the minimum likely contribution it has to meeting maximum demand. This means that while wind generation may effectively be used to meet regional energy requirements (reducing the need for base load and intermediate-type generation discussed in Section 8.2.2). It does not contribute to capacity requirements in the same way, thus improving opportunities for complementary peaking generation discussed in Section 8.1.2.

Table 8-7 compares regional wind generation average capacity factors (in 2010–11) against the calculated effective wind contribution factors for summer and winter maximum demand (MD).

Capacity factors are calculated by comparing the average historical wind generation output with its capacity. Seasonal MD contribution factors represent the minimum level of output available at least 85% of the time during the top 10% of the seasonal demands in a region.

Table 8-7 — Wind contribution factors

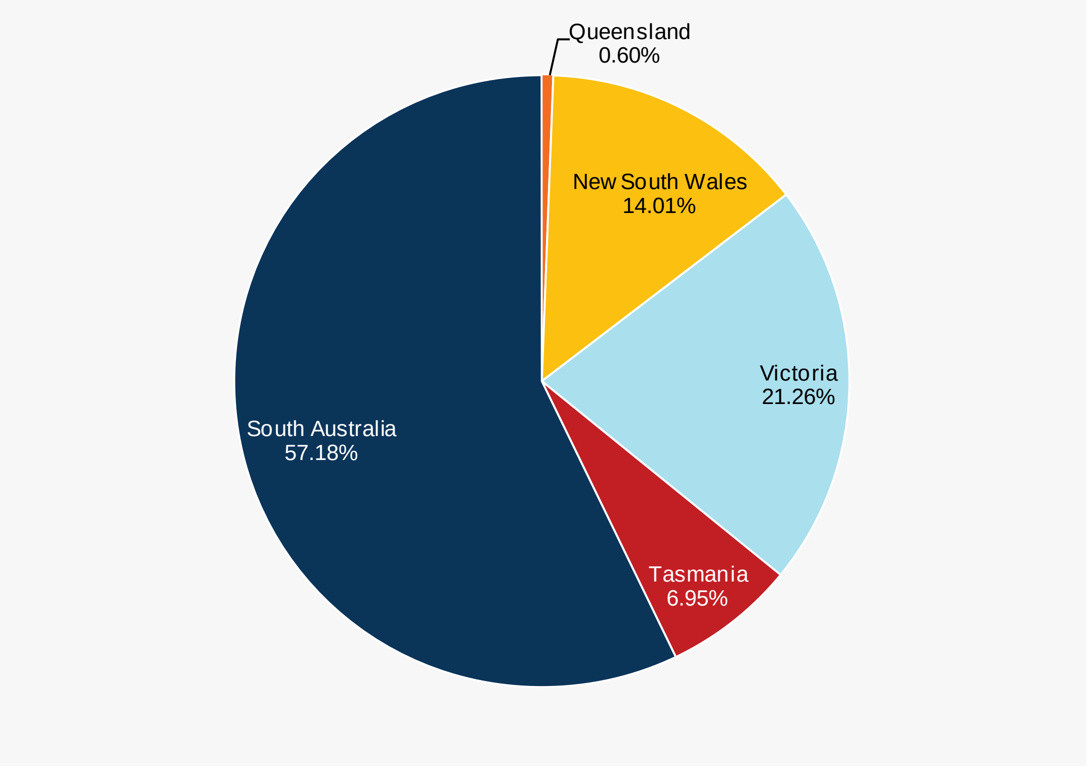
Region	Average Capacity Factor (2010/11)	Contribution Factor Summer MD	Contribution Factor Winter MD
New South Wales	25.6%	9.2%	0.4%
Victoria	29.2%	7.7%	3.9%
South Australia	32.6%	5.0%	3.5%
Tasmania	39.2%	1.0%	1.0%

Wind supply variability is one of the challenges associated with increasing levels of wind generation, in particular where wind farms are located in close proximity to each other or within areas of low wind diversity.[15] Figure 8-16 shows the NEM's current distribution of wind generation by region.

Chapter 4 identifies a number of wind generation proposals in other regions, which may improve the overall diversity of wind output across the NEM, and reduce system issues associated with large and rapid variation in generation output.

The 2011 NTNDP (published by 31 December 2011) will identify and discuss a variety of potential NEM impacts from increasing wind farm generation.

Figure 8-16 — Existing wind capacity in the NEM



15 In this context, areas of low wind diversity refer to geographical locations which experience similar wind speeds, and therefore produce similar wind generation output profiles.

8.4 Signals for investment location

A range of factors should be considered when deciding on the location of investment opportunities in the NEM. Particularly, fuel availability and costs, the impact of network congestion, and the effects of network losses can all impact the economics of investment. This section explores some of these factors, identifying where interested parties can find more information, and concluding with a summary of the 2010 NTNDP generation investment projections by location.

8.4.1 Fuel availability and costs

Fuel availability

The availability of high quality fuel or other resources is important when selecting a technology and location in which to invest. Chapter 5, Fuel Supply, provides geographical information about the availability of thermal and renewable resources across the NEM.

Fuel costs

AEMO consults annually on forecast fuel costs and other technology assumptions for use in the NTNDP. The most recent results can be found on AEMO's website.[16] This information allows interested parties to explore fuel price trajectories at various NEM locations, and under a range of economic and carbon pricing assumptions.

For more information about the projected generation investment from applying the 2010 NTNDP's fuel cost trajectories, see Section 8.4.4.

8.4.2 Network congestion

Network congestion directly impacts a generating system's ability to supply the market and, therefore, its ability to earn revenue. AEMO uses network constraint equations to model power system limitations that cause network congestion. AEMO's Annual Constraints Report[17] describes network constraint equation performance and transmission congestion-related issues, including the drivers of network constraint equation changes, an analysis of constraint equation behaviour, the market impact of constraint equations, and information about other constraint-related issues. AEMO also provides a Congestion Information Resource[18] to consolidate and enhance existing sources of information relevant to the understanding and management of transmission network congestion risk.

The NTNDP[19], the regional annual planning reports (APRs) [20,21,22,23], and the South Australian Supply and Demand Outlook (SASDO) [24] provide information about projected congestion, and the potential generation and network projects that may affect it.

Potential investors should commence enquiries with local transmission network service providers as early as possible to identify any network issues that may impact investment decisions.

16 AEMO. "2011 National Transmission Network Development Plan Consultation". Available http://www.aemo.com.au/planning/ntndp2011consult.html. 3 July 2011.
17 AEMO. "Annual Constraint Report". Available http://www.aemo.com.au/electricityops/0200-0006.html. 3 July 2011.
18 AEMO. "Congestion Information Resource". Available "http://www.aemo.com.au/electricityops/congestion.html. 3 July 2011.
19 See note 10 in this chapter.
20 TransGrid. "New South Wales Annual Planning Report 2011". Available http://www.transgrid.com.au/network/np/Documents/Annual%20Planning%20Report%202011.pdf. 2 July 2011.
21 AEMO. "Victorian Annual Planning Report 2011". Available http://aemo.com.au/planning/VAPR2011/vapr.html. 2 July 2011.
22 Powerlink. "Queensland Annual Planning Report 2011". Available http://www.powerlink.com.au/asp/index.asp?sid=5056&page=Corporate/Documents&cid=5250&gid=661. 2 July 2011.
23 Transend. "Tasmanian Annual Planning Report 2011". Available http://www.transend.com.au/download/D11-63890. 2 July 2011.
24 AEMO. "South Australian Supply and Demand Outlook 2011". Available http://aemo.com.au/planning/SASDO2011/sasdo.html. 2 July 2011.

8.4.3 Marginal loss factors

In the NEM, the impact of network losses on spot market prices is represented by marginal loss factors (MLF) and inter-regional loss factor equations. AEMO calculates these quantities annually to facilitate efficient scheduling and settlement processes, and published the most recent MLFs on 1 April 2011.[25]

Typically, areas with a net injection of energy into a transmission network will have MLFs of less than one, and areas with a net extraction of energy will have an MLF of greater than one. At a connection point, an MLF of:

- less than one indicates network losses will increase as more generation is dispatched and decrease as more load is consumed, creating a market signal for increased load and decreased generation in these areas until local load and generation are in balance and network losses are minimised, and
- greater than one at a connection point indicates that losses will increase as more load is consumed and decrease as more generation is dispatched, creating a market signal for decreased load and increased generation in these areas until local load and generation are in balance and network losses are minimised.

MLF value influences

The MLFs are calculated one year ahead. Although these can provide signals for locating generation investment opportunities, they should not be used in isolation as a reliable indication of future investment revenues.

MLFs are heavily influenced by network topology changes, the relative growth of loads at different connection points, flows between regions, and future generation investments across a region.

In addition, the typical running hours and dispatch patterns experienced at a connection point have a significant impact on the calculated MLF. Any new investment at these locations that substantially changes these factors will result in a significantly different MLF.

MLF analysis outcomes

Analysis of the distribution of forward-looking MLFs generally indicates that the optimal MLFs for generation investment are near existing load centres (for example, Melbourne, Adelaide, and Northern Queensland) and near the net export end of interconnector terminals (for example, George Town at the Tasmanian end of the Basslink interconnector, and Mudgeeraba at the Queensland end of the Terranora interconnector).

In particular, the 2011–12 MLFs indicate that additional generation may be beneficial around:

- Gregory in Central Queensland and the high load Northern Queensland areas of Cairns, Cardwell, Moranbah, and Townsville, although MLFs in these areas are sensitive to local generation patterns
- Forbes-Parkes and Orange in Central New South Wales, and areas around Wagga to Yanco and Wagga to Finley in South Western New South Wales (the MLF values around Broken Hill indicate opportunities for balancing demand in that area), although MLFs in these areas are sensitive to Queensland-New South Wales interconnector flow patterns
- the Horsham and Red Cliffs areas of Country Victoria, and Glenrowan, Shepparton, Angelsea, and Portland in Western Victoria where additional generation will supply local demand
- Tailem Bend and Mt Gambier in South Eastern South Australia, and around the Adelaide area, although MLFs in these areas are sensitive to local wind generation patterns, and
- George Town and Hobart in Tasmania, although MLFs in these areas are sensitive to output from the Gordon hydroelectric power station, especially with high rainfall.

[25] AEMO. “Regional Boundaries and Marginal Loss Factors for the 2011/12 Financial Year”. Available http://wwww.aemo.com.au/electricityops/lossfactors.html. 1 April 2011.

8.4.4 The National Transmission Network Development Plan

The 2010 NTNDP provides information about potential new entry generation developments by zone and fuel/resource type. The studies were done with the objective of minimising total generation and network capital and operating expenses in the market, subject to maintaining system reliability. The NTNDP considers a range of economic growth conditions and carbon policy assumptions.

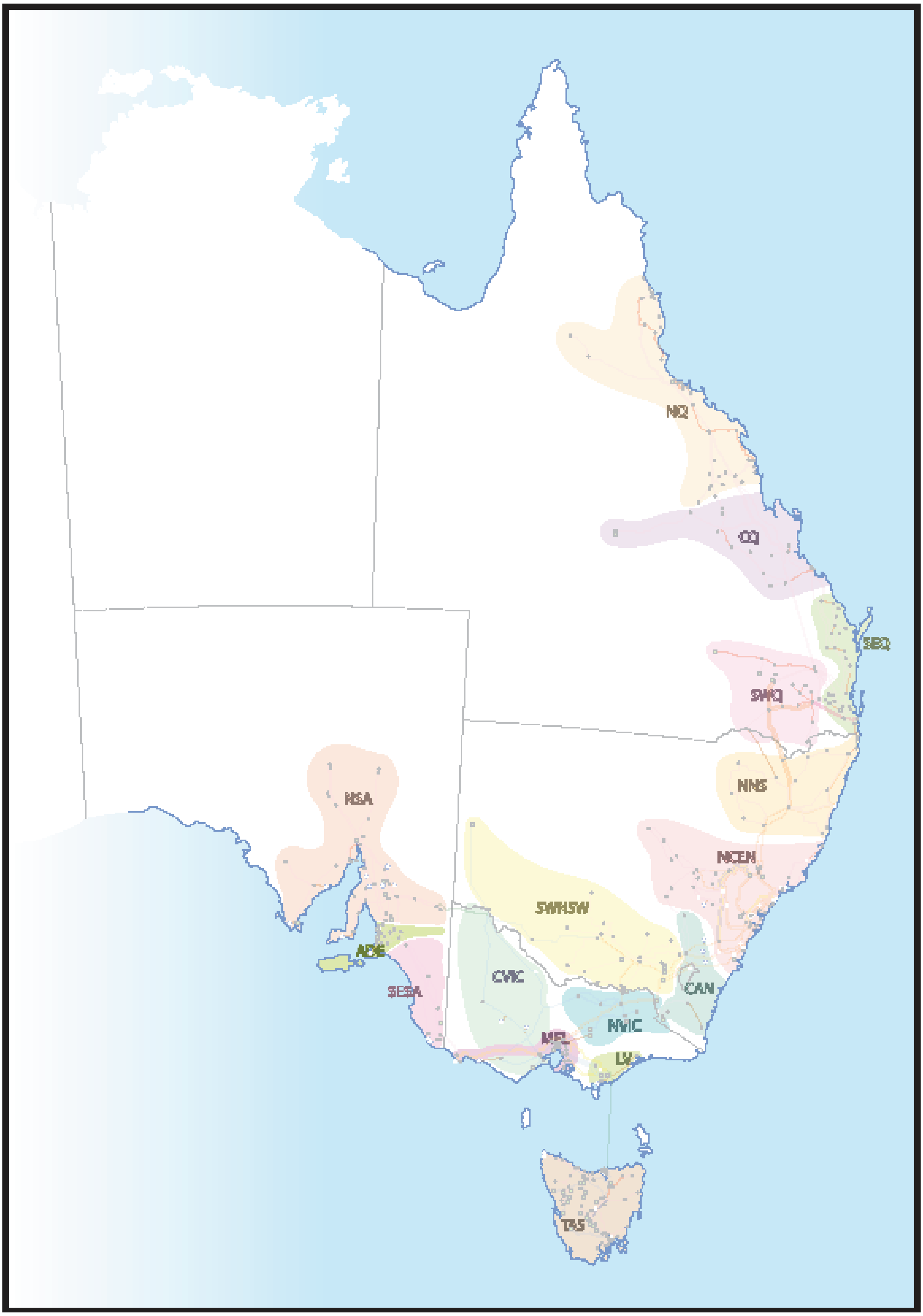
An examination of the generation mix driven by different carbon price sensitivities under the NTNDP scenarios indicates that:

- a moderate to high carbon price will result in significant levels of generation retirement in Victoria's Latrobe Valley, with subsequent replacement by GPG, and retirement of some older and less efficient black coal generation in Queensland and New South Wales
- a high carbon price allows a large reduction in emissions, and a substantial level of new renewable generation, particularly wind, but comes at the expense of higher spot prices, especially with higher demand, and
- the national RET scheme will be an important driver of renewable generation over the next 10 years. Wind generation is likely to be the main renewable new generation technology in the short term, with other technologies like geothermal and solar generation beginning to appear towards the end of the decade.

The following sections present summarised generation investment projections and unit retirements by 2021–22 for three representative scenarios studied in the 2010 NTNDP: Fast Rate of Change, high carbon price; Decentralised World, medium carbon price; and Slow Rate of Change, low carbon price.

Figure 8-17 lists the NTNDP zones that correspond to areas of the NEM assumed to have relatively similar fuel costs, and contain major generation or load centres.

Figure 8-17 — NTNDP Zones



Fast Rate of Change – high carbon price

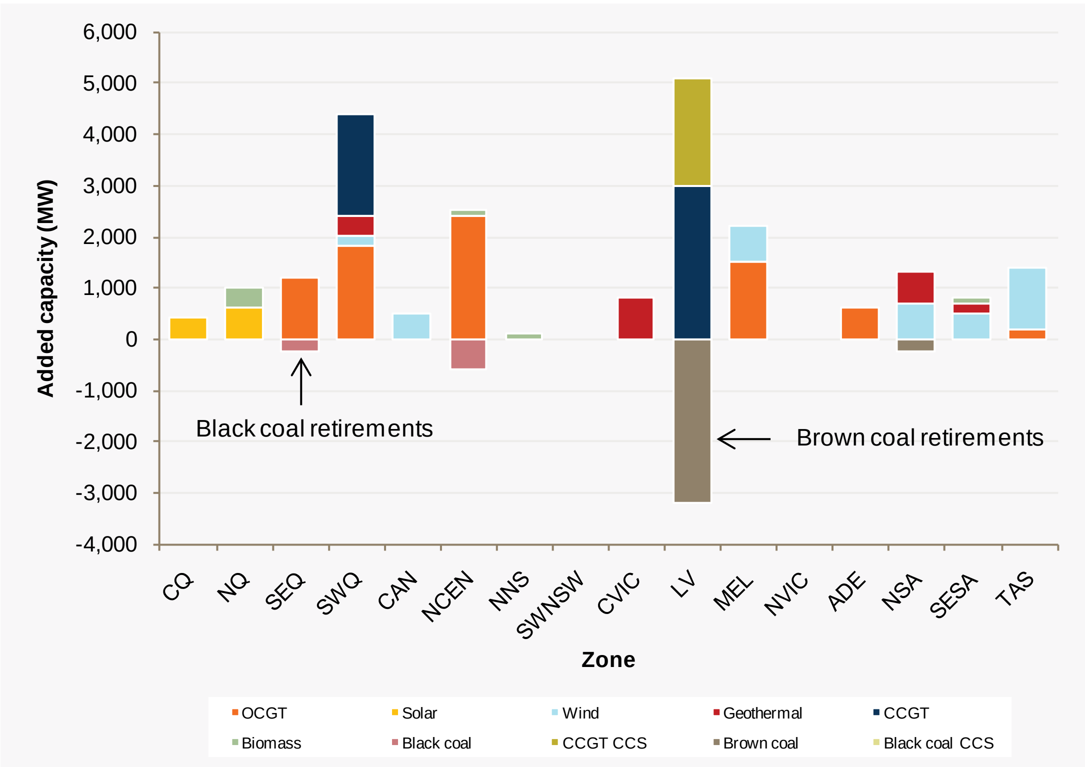
Fast Rate of Change describes a world where relatively strong emission reduction targets have been agreed internationally by both developed and developing countries, and there is high sustained economic growth in Australia. Successful adaptation to a carbon-constrained world is possible due to government and industry investment in the development of new technologies. This is a high carbon price scenario and its sensitivity is a medium carbon price.

Figure 8-18 shows changes in installed capacity by location and technology between 2010–11 and 2021–22 under the Fast Rate of Change, high carbon price. The figure shows significant new GPG developments, particularly in South East Queensland (SEQ), Central New South Wales (NCEN), Victoria's Latrobe Valley (LV), Melbourne (MEL), and Adelaide (ADE) in South Australia.

Substantial renewable investment occurs in all regions driven by the national RET scheme and high carbon prices. Solar technologies dominate Queensland renewable developments, while wind and geothermal plant developments are heavily concentrated in Victoria and South Australia.

A high carbon price also results in substantial retirement of the emission-intensive brown coal generation in Victoria's Latrobe Valley. The medium carbon price sensitivity (not shown) shows markedly less retirement of coal-fired generation.

Figure 8-18 — Capacity changes by technology under the Fast Rate of Change, high carbon price scenario



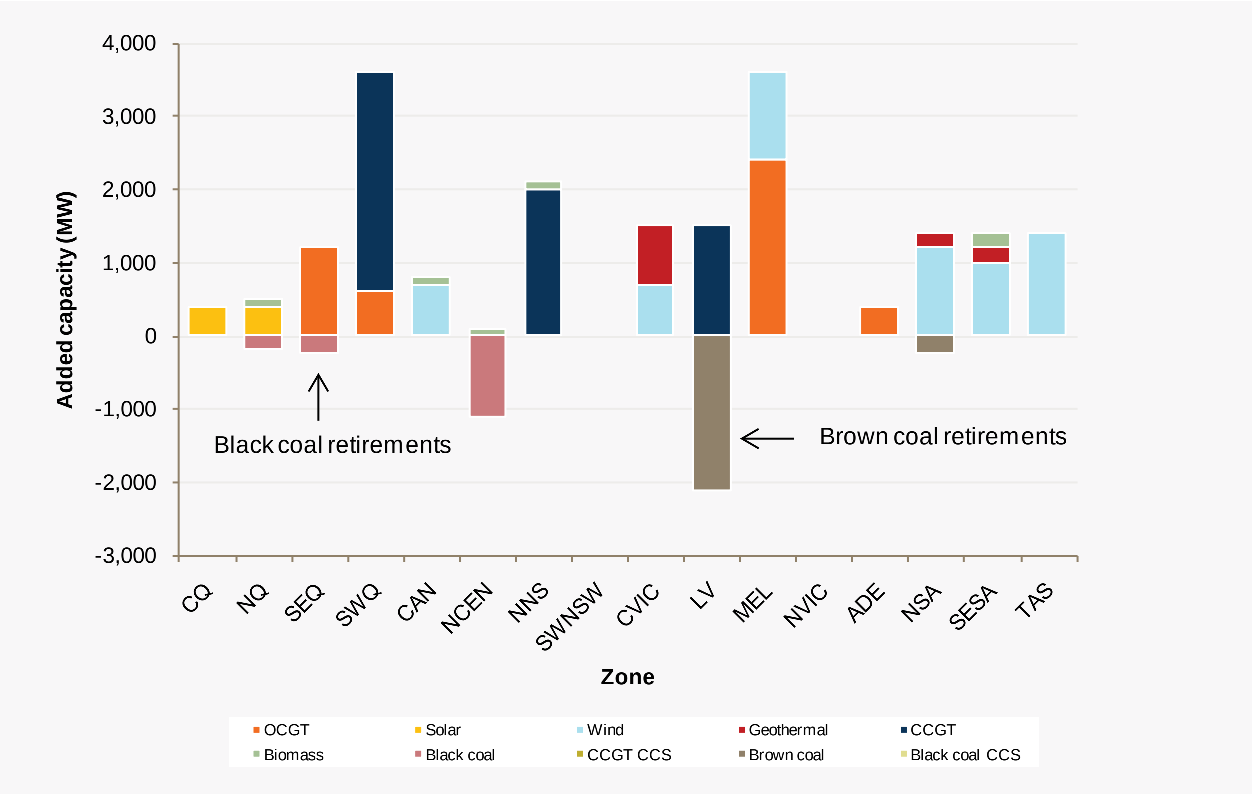
Decentralised World – medium carbon price

Decentralised World describes a world where Australia's energy network becomes highly decentralised by 2030, with significant investment in demand-side technologies. Moderate emission targets are coupled with medium economic and population growth, and all sectors of the Australian economy do well. This is a medium carbon price scenario and its sensitivity is a high carbon price.

Figure 8-19 shows changes in installed capacity by location and technology between 2010–11 and 2021–22 under the Decentralised World, medium carbon price. The figure shows a reasonably high level of base load retirement in response to the medium carbon price and moderate demand.

Moderate demand growth is largely met by GPG developments in South East Queensland (SEQ), South Western Queensland (SWQ), Northern New South Wales (NNS), and Victoria's Latrobe Valley (LV) and Melbourne (MEL). Substantial wind development occurs across the southern NTNDP zones. The high carbon price sensitivity (not shown) shows substantially more retirement of black and brown coal technologies, and more GPG development.

Figure 8-19 — Capacity changes by technology under the Decentralised World, medium carbon price scenario



Slow Rate of Change – low carbon price

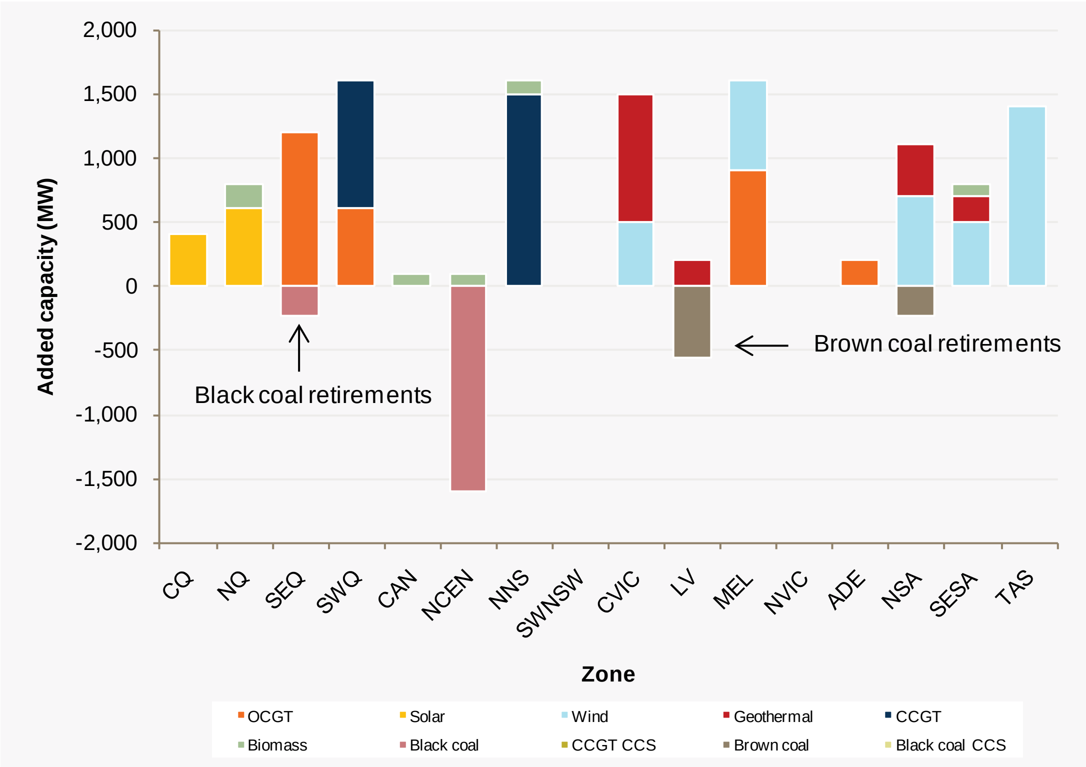
Slow Rate of Change describes a world characterised by low economic growth coupled with internationally agreed low emission targets. Weak economic growth and low levels of population growth are observed. Boosting economic activity becomes a priority. This is a low carbon price scenario and its sensitivity is a zero carbon price.

Figure 8-20 shows changes in installed capacity by location and technology between 2010–11 and 2021–22 under the Slow Rate of Change, low carbon price. The figure shows moderate base load GPG development in South East Queensland (SEQ), Northern New South Wales (NNS), and Melbourne (MEL).

Renewable generation development is spread across the NEM with solar generation in Northern Queensland (NQ), and wind and geothermal generation developments largely occurring in the southern NTNDP zones.

The zero carbon price sensitivity (not shown) shows less renewable generation development, particularly in New South Wales (NNS, NCEN, CAN, SWNSW) and Adelaide (ADE).

Figure 8-20 — Capacity changes by technology under the Slow Rate of Change, low carbon price scenario



ATTACHMENT A1 - NEM GOVERNANCE AND MARKET DEVELOPMENT

Summary

This attachment outlines the governance and legislative framework underpinning the operation of the National Electricity Market (NEM), and the functions and responsibilities of its governing institutions. It also presents the status and outcomes of recent reviews that have the potential to affect the nature of generation or demand in the NEM.

A1.1 NEM governance and regulatory framework

This section outlines the governance and regulatory framework underpinning NEM operation, including information about the National Electricity Law (NEL), the National Electricity Objective (NEO), the National Electricity Rules (NER), and the roles and responsibilities of the Standing Committee on Energy and Resources (SCER)[1], the Australian Energy Market Operator (AEMO), the Australian Energy Market Commission (AEMC), and the Australian Energy Regulator (AER).

A1.1.1 National Electricity Law

The NEM was established in 1998 and is a wholesale market through which generators, market customers, and retailers trade electricity. The NEM covers the five interconnected transmission network regions: Queensland, New South Wales (including the Australian Capital Territory), Victoria, Tasmania, and South Australia (for more information about the regional structure of the NEM, see Chapter 2).

The NEL and the NER compose the current regulatory framework governing the NEM. The NEL is a schedule to the National Electricity (South Australia) Act 1996, which is applied in other participating jurisdictions by application acts. The NEL sets out some of the key high-level elements of the electricity regulatory framework such as the functions and powers of NEM institutions, including AEMO, the AEMC, and the AER. The NER describes the day-to-day operations of the NEM and the framework for network regulation.

National Electricity Objective

The NEL includes the National Electricity Objective (NEO), which provides a single guiding principle for decision making under the NEL, and states its aim is:[2]

> ***"…to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to -***
>
> - ***price, quality, safety, reliability and security of supply of electricity; and***
> - ***the reliability, safety and security of the national electricity system…"***

1 Known as the Ministerial Council on Energy (MCE) until 1 July 2011.

2 Government of South Australia – Attorney-General's Department. "National Electricity (South Australia) Act 1996". Available http://www.legislation.sa.gov.au/LZ/C/A/NATIONAL%20ELECTRICITY%20(SOUTH%20AUSTRALIA)%20ACT%201996.aspx. 16 August 2011.

A1.1.2 National Electricity Rules

The NER describes the day-to-day regulations under which the NEM operates, and the framework for network regulation. The NER has the force of law under Section 9 of the NEL.

The AEMC is responsible for administering, reviewing, and publishing the NER in accordance with the NEL and must have regard to the NEO when performing its rule-making functions. The NER change procedure is outlined in Section 91 of the NEL. The AEMC provides up-to-date information about all NER changes, amendments, and superseded versions on its website.[3,4]

A1.1.3 NEM governing institutions

The NEM is governed by the Standing Committee on Energy and Resources (SCER), Australian Energy Market Commission (AEMC), Australian Energy Regulator (AER), and Australian Energy Market Operator (AEMO).

Standing Committee on Energy and Resource

The Standing Committee on Energy and Resources (SCER) sets the national policy direction for the Australian energy sector and implements the Council of Australian Governments (COAG) national energy policy framework. Established on 1 July 2011, SCER has assumed expanded responsibilities from the Ministerial Council on Energy (MCE), with the objective to provide:

- policy development oversight and coordination to address the future opportunities and challenges facing Australia's energy sector, and
- leadership to enable the effective integration of considerations concerning broader convergence issues and environmental impacts on energy sector decision making.

In providing high-level direction to the AEMC on energy policy issues, the SCER may:

- direct the AEMC to carry out a review and submit a report to the SCER
- initiate SCER change proposals, including in response to an AEMC review
- publish Statements of Policy Principles on any matter relevant to the exercise by the AEMC of its functions under the NEL or the NER, and
- implement energy policy reforms as agreed by COAG.

Australian Energy Market Commission

Established as a statutory commission from 1 July 2005, the AEMC is responsible for rule making and market development. The AEMC's responsibilities include:

- administering, reviewing, and publishing the NER and National Gas Rules (NGR) in accordance with the NEL and National Gas Law (NGL)
- considering and making determinations on proposed NER and NGR changes
- undertaking reviews on its own initiative or as directed by the SCER, and
- providing market development advice to the SCER on the energy market.

AEMC Reliability Panel

The AEMC chairs the Reliability Panel, which includes representatives from AEMO, market customers, generators, transmission network service providers (TNSPs), distribution network service providers (DNSPs), and electricity customers. Clause 8.8.1 of the NER prescribes the Reliability Panel's functions, which include determining the form and value of the Reliability Standard. AEMO applies the reliability standard (in the form of minimum reserve levels) when assessing supply adequacy in the NEM (See Chapter 6).

[3] AEMC. "The National Electricity Rules". Available http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html. 11 March 2011.

[4] AEMC. "Rule changes: Open". Available http://www.aemc.gov.au/Electricity/Rule-changes/Open.html. 18 May 2011.

Australian Energy Regulator

Established as a statutory body from 1 July 2005, the AER enforces and monitors compliance with energy market legislation, and performs economic regulatory functions for the gas and electricity sectors.

The AER's regulatory functions include:

- monitoring and enforcing compliance with the NEL, NGL, NER, NGR, and National Electricity Regulations (South Australia), and
- economic oversight of regulated electricity transmission and distribution in the NEM, and gas transmission and distribution services.

Australian Energy Market Operator

Established by COAG as a company limited by guarantee from 1 July 2009, AEMO is the independent market operator of the NEM and gas markets in the eastern states. Its ownership is currently split between government (60%) and industry (40%), and these arrangements will be reviewed in 2012.

AEMO's electricity functions include:

- operation and administration of the NEM
- planning and directing procurement of augmentations to the Victorian electricity Declared Shared Network (electricity DSN)
- preparing the Electricity Statement of Opportunities (ESOO)
- providing planning advice for the South Australian electricity transmission system, and
- acting as the National Transmission Planner for the NEM.

AEMO's gas functions include:

- operating and administering the declared wholesale market in Victoria
- operating the Short-Term Trading Market (STTM) for gas at the Sydney and Adelaide hubs
- administering the gas retail markets for New South Wales, Queensland, South Australia, and Victoria
- preparing the Gas Statement of Opportunities (GSOO), and
- operating the gas market bulletin board.

In addition to these functions, AEMO assists with developing energy markets by identifying issues, conducting public consultations, and putting forward NER changes to the AEMC.

A1.2 Current policy and regulatory developments

This section focuses on the status or outcome of key reviews or NER changes that in AEMO's view have the potential to affect the NEM's investment environment.

A1.2.1 Carbon pricing

On 10 July 2011, the Australian Government announced details of a carbon pricing package developed through the Multi-Party Committee on Climate Change (MPCCC).[5] The Clean Energy Future Plan proposes a price on carbon dioxide equivalent (CO2-e) emissions from 1 July 2012, with some measures taking effect this financial year.

The policy targets a reduction in CO2-e emissions to 5% below year 2000 levels by 2020, and up to 25% in the presence of equivalent international action. This is between 25%–45% below business-as-usual, although the policy allows for much of the reduction to be achieved via overseas abatement.

[5] Australian Government. "Clean Energy Future". Available http://www.cleanenergyfuture.gov.au. 27 July 2011.

The policy also proposes an 80% reduction from 2000 levels by 2050, and legislation is intended for the 2011 spring session of Parliament.

The carbon price

The policy will introduce a fixed price for the first three years of $23.00, $24.15, and $25.40 $/t CO_2-e, respectively. There will be an unlimited quantity of single-year only permits made available at the fixed price.

After the third year, a floating price will be introduced, commensurate with an emissions target to be set from May 2014. A fixed quantity of permits will progressively be auctioned in advance of the surrender date. Permits may be banked for use in later years and emitters may borrow up to 5% from their following year's obligation. Firms will be able to import up to 50% of their liabilities using permits from similar international schemes with importing arrangements overseen by the scheme regulator. Exports are prohibited.

The emissions target will be recommended by a new body, the Climate Change Authority, taking account of international developments. If the Parliament cannot agree, then the targets will revert to a default trajectory to achieve a 5% reduction from 2000 levels by 2020.

The target will be set such that voluntary action, such as GreenPower, will be accredited as additional to the underlying target.

Until 2018, the floating price will have a:

- ceiling starting at 20 $/t CO_2-e above expected international price levels, increasing annually at 5% in real terms, and
- floor starting at 15 $/t CO_2-e increasing annually at 4% in real terms.

The price ceiling would become the emissions charge (penalty) for non-surrender. Facilities that emit more than 25,000 tonnes of CO_2-e per year are liable to pay the carbon price.

Energy security measures (administrative allocation to coal-fired generators)

Assistance totalling $5.5 billion will be allocated to a pool of generators over the first five years, with $1 billion granted before the scheme starts (in the 2011–12 financial year) followed by $41.7 million in permits per year between years two and five.

Only generators with an as-generated emissions intensity over 1t CO_2-e/MWh will receive assistance, although the compensation is capped for generators with an emissions intensity greater than 1.3t CO_2-e/MWh. The payment will be conditional upon the maintenance of power system reliability.

Payment to close

Generation totalling up to 2,000 MW with an as-generated emissions intensity over 1.2t CO_2-e/MWh will be invited to tender for closure by 2020. The arrangement is to be negotiated during 2011–12, and will take into account AEMO's views on energy security. The Government expects the closures to occur in the second half of the decade.

Energy Security Council

The Energy Security Council will comprise a group of independent experts recommending actions to government to avert systemic energy market disruption (for example, temporary government guarantees to avert insolvency). This will be a permanent feature and appears to apply even if financial problems are unrelated to carbon pricing.

Loans to generators

Short-term loans will be available to generators for working capital to purchase carbon permits at auction in advance of production. These loans will be made on less favourable terms than commercially based finance, and are designed to be loans of last resort.

Loans will also be considered for generators needing to refinance debt when finance is unavailable from the market. These loans would be subject to advice from the Energy Security Council and be made on marginally less favourable pricing than reasonable market rates.

Renewable energy

The national Renewable Energy Target (RET) scheme will remain unchanged. A new Clean Energy Finance Corporation will be formed with access to $10 billion to be used over 10 years from 2013–14 onwards, for low carbon generation and energy efficiency.

Impact on the Electricity Statement of Opportunities

The most immediate effect of this policy is to change the relative marginal costs of generation, which is not reported in the ESOO. In the medium term, it is expected to drive the earlier retirement of some of the most carbon-intensive generation, which is also likely to be eligible for Energy Security Measures allocation or contracts for closure (subject to reliability conditions, which are expected to delay retirements).

Earlier carbon pricing expectations have already accounted for the long-term impact on demand from increasing prices.

A1.2.2 Prime Minister's Task Group on Energy Efficiency

In March 2010, the Prime Minister established the Task Group on Energy Efficiency to advise and make recommendations to the Australian Government by mid-2010 on options to improve Australia's energy efficiency by 2020.[6]

Supported by an advisory group of experts from industry and other non-government organisations, the Task Group has also commissioned analysis to illustrate the costs, benefits, and other impacts of a hypothetical national energy savings initiative.

A1.2.3 Transmission Frameworks Review

The AEMC released its Directions Paper on 14 April 2011[7] and 22 submissions were received in response. The paper identified five key themes that the AEMC considered to be the key areas for discussion (from the issues paper responses):

- the nature of access
- network charging
- congestion
- transmission planning, and
- connections.

The submissions tended to agree that reform is necessary, and stakeholders generally saw a need to make changes to improve the efficiency of the connections process and to explore access arrangements.

A1.2.4 Scale efficient network extensions

The AEMC has made its final determination introducing a planning framework for expanding the electricity transmission network to accommodate remote generation clusters (scale efficient network extensions (SENE).[8] Under the NER, network service providers (NSP) can be asked to provide studies for specific locations on request (from any person), showing potential market opportunities and efficiency gains from coordinating the connection of new generation in a particular area.

[6] Department of Climate Change and Energy Efficiency. "Report of the Prime Minister's Task Group on Energy Efficiency". July 2010. Available http://www.climatechange.gov.au/en/publications/energy-efficiency/report-prime-ministers-taskforce-energy-efficiency.aspx. 11 March 2011.

[7] AEMC. "Transmission Frameworks Review". Available http://www.aemc.gov.au/Market-Reviews/Open/Transmission-Frameworks-Review.html. 1 July 2011.

[8] AEMC. "Scale Efficient Network Extensions". Available http://www.aemc.gov.au/Electricity/Rule-changes/Completed/Scale-Efficient-Network-Extensions.html. 1 July 2011.

According to the AEMC, the study will help potential investors make informed commercial decisions to fund a SENE, taking into account possible scale efficiencies. Decisions to fund, construct, operate, and connect to a SENE will be made by market participants and investors within the NER's existing connections framework.

A1.2.5 The National Energy Customer Framework

The National Energy Customer Framework (NECF) is intended to streamline energy distribution and retail regulatory functions in a national framework, and develop a more efficient national retail energy market with appropriate consumer protection.[9] The framework aims to make both gas and electricity retail market investment more accessible and easier to navigate and will form part of the NER and the NGR.

It will be implemented through new laws and rules called the National Energy Retail Law (NERL) and the National Energy Retail Rules (NERR), which will cover:

- the retailer-customer relationship and associated rights, obligations, and consumer protection measures
- distributor interactions with customers and retailers, and associated rights, obligations, and consumer protection measures
- retailer authorisations, and
- compliance monitoring and reporting, enforcement, and performance reporting.

The AEMC will be the rule-making body for the NERR, with the initial NERR to be made by the South Australian Energy Minister under powers granted by the NERL.

The new rules are to commence operation on 1 July 2012.

A1.2.6 The Energy Market Prudential Readiness Review

In May 2010 (at the request of the MCE), AEMO carried out a review of the adequacy of energy market prudential risk management arrangements used in the NEM and in the administered gas markets.[10] The objective of the review was to ensure the prudential regimes AEMO administers in all energy-related markets are robust and effective, and can support ongoing investment in the NEM and gas markets.

In November 2010, findings were provided to the MCE[11] that included an independent quantitative analysis of past prudential performance in the NEM. Through the review, AEMO has identified a number of areas of potential improvement, predominantly in the NEM, and intends to promote these initiatives via changes to the Rules or procedures in 2011.

A1.2.7 Industry reforms in New South Wales and Queensland

New South Wales

Following a process that commenced in November 2008, the New South Wales Government finalised the sale of some of its generation output via a 'gen-trader' arrangement.[12] This model sold the Government's trading rights to outputs from its generating units (except Macquarie Generation), while retaining ownership of the physical generating units. It also sold the retailer components of its electricity businesses (Energy Australia, Country Energy, and Integral Energy).

TRUenergy acquired Energy Australia's retail business and half of Delta Electricity's trading rights, while Origin Energy acquired Country Energy and Integral Energy's retail businesses and Eraring Energy's trading rights. Trading rights in respect of Delta Coastal and Macquarie Generation were not sold.

9 Department of Resources, Energy and Tourism. "National Energy Customer Framework". Available http://www.ret.gov.au/energy/energy_markets/national_energy_customer_framework/Pages/NationalEnergyCustomerFramework.aspx. 7 July 2011.
10 AEMO. "Energy Market Prudential Readiness Review". Available http://www.aemo.com.au/electricityops/prudential_review.html. 1 July 2011.
11 Known as the SCER from 1 July 2011.
12 New South Wales Government . "New South Wales Energy Reform Strategy Defining an Industry Framework". Available http://www.nsw.gov.au/sites/default/files/NSW-Energy-Reform-Strategy.pdf. 7 July 2011.

Queensland

In late 2010, the Queensland Government announced it was consolidating its generation portfolio from three registered generators to two, moving the generating units operated by Tarong to CS Energy and Stanwell, to encourage private operators to invest in new generation capacity and to mitigate some of the likely challenges resulting from a carbon price. Real annual average pool price reductions in Queensland since the NEM commenced were also cited as a factor for the re-aggregation.

A1.2.8 The Reliability Panel's review of the Reliability Standard and settings

In April 2010, the Reliability Panel provided its biennial report to the AEMC on the Review of the Reliability Standard and Settings[13], which reviewed the market price cap (MPC), price floor, and cumulative price threshold (CPT). These price settings provide important signals to attract investment in the NEM's energy-only market.

On 1 July 2010, an MPC of 12,500 $/MWh, indexed according to the producer price index (PPI), was introduced. The market price floor was maintained at -1,000 $/MWh and the CPT was increased to 187,500 $/MWh annually (using the same index applied to the MPC).

A1.2.9 AEMC review of the effectiveness of NEM security and reliability arrangements in light of extreme weather events

In 2010, the AEMC carried out a review of the effectiveness of NEM security and reliability arrangements in light of extreme weather events and delivered a final report to the MCE on 31 May 2010.[14] In the final report, the AEMC:

- examined the current arrangements for maintaining the security and reliability of supply to electricity consumers, and provided a risk assessment of the capability of those arrangements to maintain adequate, secure, and reliable supplies
- provided advice on the effectiveness of, and options for, cost-effective improvements to current security and reliability arrangements, and
- identified, if appropriate, any cost-effective changes to the market frameworks that may be available to mitigate the frequency and severity of threats to the security and reliability of the power system.

A1.2.10 Minimising barriers to cost-effective small generator participants in the NEM

In August 2010, AEMO published a determination on the Small Generator Framework Design.[15] The intention of the framework is to allow small generators to access and invest in the NEM, facilitating an improved market response to wholesale NEM prices. The determination identified 11 principles for guiding AEMO's priorities for addressing the barriers to small generation participation in the NEM. The key themes of these principles are that:

- the NEM registration process should be streamlined and cost reflective
- metering arrangements and responsibilities for generators connected within embedded networks need to be clarified
- aggregation arrangements and compensation for directions should be reviewed, and
- development of an information resource for small generators is recommended.

Development of these themes may be of particular importance in light of climate change policies, which have encouraged a move towards new renewable generation. Removing the barriers identified by this review would result in an increased ability for small generators to access and invest in the NEM, and in an improved market response to wholesale NEM prices.

13 AEMC. "Review of the Reliability Standard and Settings". Available http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-the-Reliability-Standard-and-Settings.html. 1 July 2011.

14 AEMC. "Review of the Effectiveness of NEM Security and Reliability Arrangements in Light of Extreme Weather Events". Available http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-the-Effectiveness-of-NEM-Security-and-Reliability-Arrangements-in-light-of-Extreme-Weather-Events.html. 21 April 2011.

15 AEMO. "Small Generator Framework Design". Available www.aemo.com.au/registration/0110-0062.pdf. 1 July 2011.

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ATTACHMENT A2 - JOINING THE NEM

Summary

This attachment describes the connection and registration processes for generators in the National Electricity Market (NEM). An intending generator is required to apply to the relevant network service provider (NSP) for connection to the transmission or distribution system, and to AEMO for registration as a generator in the NEM.

A2.1 Connection requirements

Table A2-1 summarises the connection agreement negotiating process set out by the National Electricity Rules (NER).

A connection agreement sets out the rights and obligations of the generator and NSP with respect to the generator, the connection assets, and the shared network assets required for the connection and their performance. When an intending generator applies to an NSP, it must provide details about its generating system's capacity, and the NSP will provide details about the relevant connection asset's capabilities. The generator must also provide details such as generator specifications, proposed output, performance standards, and other details (set out in Chapter 5 of the NER).

Table A2-1 — Connection agreement negotiation process

NER Reference	Negotiation Phase	Action
5.3.2	Connection enquiry.	Intending connection applicant submits a connection enquiry outlining the type, magnitude and timing of its proposed connection to the network.
5.3.3	Response to connection enquiry.	NSP responds to connection enquiry providing information relating to automatic and minimum access standards, plant standards, and capacity of the network and program for assessing connection application.
5.3.4	Application for connection.	Intending connection applicant proceeds with connection and submits a connection application.
5.3.6	Offer to connect.	NSP conducts studies and identifies relevant technical issues and prepares an offer to connect providing all relevant information to the connection applicant, which the applicant funds.
5.3.7	Finalisation of connection agreement.	Connection applicant accepts or declines an offer to connect.

Automatic, minimum, and negotiated access standards

When an NSP receives a connection request, it must notify the applicant of requirements regarding automatic and minimum access standards set out in Schedule 5.2 of Chapter 5 of the NER. These standards represent the technical requirements for a new generating unit.

A proposed generator must either comply with the automatic access standard or negotiate an access standard with the NSP at or above the minimum access standard. The NSP may not require standards above the automatic access standards. Negotiated standards must not adversely affect power system security or the quality of supply of other network users.[1]

Costs and fees

All negotiation, testing, modelling, and other connection-related costs are borne by a connection applicant. An applicant will generally be required to pay a deposit, and must ultimately pay the reasonable costs incurred by the NSP for processing the application. If the deposit does not meet the connection costs, the NSP may request a further instalment. Some NSPs will require the entire estimated cost of the connection to be paid in advance at the commencement of work. If another NSP (such as a neighbouring region’s transmission network service provider (TNSP)) needs to be consulted, the applicant will also need to pay their costs.

If there is a surplus of funds from the deposit or any further payments at the end of the process, the applicant is entitled to a refund of the balance.

Connection agreements

Connection agreements govern a range of matters relating to connecting and operating a generating system and the connection assets, including:

- generating system performance
- authorised power transfer capabilities and other physical connection asset details
- any shared network assets required for the connection
- the entry services payment schedule, and
- any other matter that the connection applicant and NSP agree.

Schedule 5.6 of Chapter 5 of the NER covers matters a connection agreement negotiation should involve.

In respect of the connection assets, a connected generator cannot enforce any system standards unless they are agreed to in the connection agreement as Schedule 5.6 does not impose obligations on an NSP.

Negotiating framework

An NSP is obliged to have a negotiating framework approved by the Australian Energy Regulator (AER) for each revenue cap application (every five years). The purpose of the framework is to ensure that the NSP will negotiate with a connection applicant in good faith. It contains undertakings by the NSP to:

- provide relevant information
- process each application and finalise it in a timely manner
- maintain confidentiality, and
- commit to the dispute resolution process in Part K of Chapter 6A of the NER.

[1] 5.1.3(d) NER.

Connection in Victoria

Victoria's transmission connection process differs from other jurisdictions because AEMO has a planning role within the jurisdiction. AEMO administers all connection applications and negotiated access standards, as well as any shared network augmentations to ensure existing customers' quality of supply.

AEMO will negotiate with the asset-owning NSP to agree to certain interface works (e.g. tower placements, communications requirements, and other technical requirements). If the connection applicant, the relevant asset-owning NSP, and AEMO agree on all necessary aspects of the connection and use of the shared network, the applicant will enter into agreements, including a connection agreement, with the asset-owning NSP, and a use-of-system agreement with AEMO.

In Victoria, there is also an established process in place for contestable augmentations related to connection works.[2] Where a certain threshold is met[3], AEMO may conduct a competitive tender process to build any part of the connection assets and any other necessary shared network augmentations that are deemed contestable. Being competitive, any interested party with suitable qualifications and licences (including the existing asset owner and the connection applicant) may bid for the tendered works.

A2.2 Registering with AEMO

A person proposing to connect a generating unit to the NEM must register with AEMO.[4] When registering, the generating unit must be registered as a class of generator set out in the NER. If the unit meets certain criteria, it may be exempted from having to register in certain classifications or from registering altogether. Application fees are payable for registration applications. Detailed information about the application process, categories, exemptions, technical requirements, fees, rights, and obligations can be found on the AEMO website.[5]

Registration for participation in the ancillary services spot market

A market generator must also register its ancillary service capability in accordance with the requirements of Schedule 5.2 of the NER if it wishes to participate in the ancillary services spot market. For more information, see the AEMO website.[6]

Registering wind farms

The Australian Wind Energy Forecasting System (AWEFS) project was established to assist AEMO to forecast the output of wind farms. This enables AEMO to better integrate intermittent energy sources with other generators. A wind generating system applying for registration and wishing to make its wind farm data available to certain research organisations may enter into a Wind Farm Data Supply Deed at the time of application. For a copy of this Deed see the AEMO website.[7]

Intending participant

A person intending to register as a generator prior to having done everything necessary to connect (such as purchase and prepare the relevant plant or enter into a connection agreement) can apply to register as an intending participant. This entitles them to, among other things, receive and provide information on a confidential basis.

[2] See Part H of Chapter 8 of the NER. Note that this is only available for connections to the transmission network.
[3] 8.11.6 NER.
[4] 2.2.1(e) NER.
[5] AEMO. "Electricity Registration Guides & Forms". Available http://www.aemo.com.au/registration/elec_guidesforms.html. 21 April 2011.
[6] AEMO. "'NEM Generator Registration Guide". Available http://www.aemo.com.au/registration/0110-0100.pdf. 21 April 2011.
[7] See note 5 in this chapter.

Classifications

The classifications available to generating systems are as follows:

- **Scheduled** - A scheduled generating system has an aggregate rating of 30 MW or greater[8] and is able to respond to despatch instructions to increase or decrease output. A scheduled generating system must respond to AEMO's dispatch engine scheduling instructions. The generating unit must have appropriate systems and communications interfaces.
- **Semi-scheduled** - A semi-scheduled generating system has an aggregate rating of 30 MW or greater and an intermittent output. This usually applies to wind farms, solar units, and other generators with an intermittent output profile, but does not usually include hydroelectric units. The generating unit must have appropriate systems and communications interfaces.
- **Non-scheduled** - A non-scheduled system is a generating system with an aggregate rating of less than 30 MW or has been granted an exemption from registering as scheduled or semi-scheduled.

A generator must also be classified as either:

- market, or
- non-market.

A non-market market generator has its sent-out electricity purchased entirely by a local retailer or a customer located at the same connection point.

A market generator is obliged to send all of its output to the market, place offers for that output according to the bidding requirements set out in Chapter 3 of the NER, and is paid for its output in wholesale market receipts (requiring appropriate accounts for funds transfer from AEMO's settlement process).

[8] In each classification, where there are a group of generating units connected to a common connection point, the combined output of all the units will be taken to be the nameplate rating for the purposes of the exemption threshold for that classification.

Exemptions

There are three classes of exemption[9]:

- **Small generator exemption** – This applies to generating systems with a combined rating of less than 5 MW. If a generating system complies with the criteria detailed in AEMO's Guideline on Exemption from Registration as a Small Generator, an automatic exemption from registration applies. No application for exemption from having to register the generator is required.
- **Intermediary exemption** – Where a party agrees to act as an intermediary for the owner of a generating system, the owner may apply for an exemption from having to register as a participant. The intermediary must register fully as a registered participant.
- **Exemptions from central dispatch** – A generating system that exceeds 30 MW and would otherwise register as a scheduled generator, may apply to be exempted from central dispatch. Each application will be assessed by AEMO on its merits.

  When assessing an application for exemption from central dispatch, AEMO will consider whether the primary purpose of the generator is for local use. This applies if more than 50% of its capacity or energy output (gross generation less generation auxiliary load) is used locally. In any case, the sent-out generation must rarely, if ever, exceed 30 MW. Furthermore, AEMO needs to examine whether the physical and technical attributes of the relevant generating unit make it impractical for it to participate in central dispatch. This may occur where the:

  - fuel or energy source for generation depends on some other industrial process not related to electricity production, or
  - generating unit is unable to vary its output in response to a dispatch instruction for some technical reason (other than fuel supply constraints).

  For more information about central dispatch exemption, see Appendix 2 of the NEM Generator Guide, available from the AEMO website.[10]

Technical requirements

A generator seeking registration must confirm that their generating system is either exempted from, or will be able to meet or exceed, the technical requirements of Schedule 5.2 of Chapter 5 of the NER.[10]

A proposed generator must either comply with the automatic access standard or negotiate an access standard with the NSP at or above the minimum access standard. The NSP must seek AEMO's agreement for certain access standards.

Once a generator is registered, the performance standards become registered performance standards and are incorporated in AEMO's register of performance standards.

[9] See note 6 in this chapter.

[10] An over-riding consideration that an NSP and AEMO must apply is that all registered performance standards must at a minimum be consistent with Good Electricity Industry Practice.

Fees

As of 1 July 2011, new fees for registrations were introduced by AEMO. The new fees are set out in the Structure of Participant Fees In the National Electricity Market - Determination and Report, which can be found on AEMO's website.[11]

For the financial year commencing 1 July 2011, fees for new generator registrations are:

- scheduled and semi-scheduled market - $7,100
- scheduled non-market, semi-scheduled non-market, non-scheduled market - $5,100, and
- non-scheduled non-market - $5,000.

Fees will increase annually as shown on page 8 of the Determination and Report.

Transfers

Where the ownership or control of a generating unit is transferred to a party other than the registered party, AEMO must be notified and a transfer application made to reflect the change in ownership or control.

A2.3 Generating plant commissioning, model verification, and testing

After entering into connection/use-of-system agreements with the relevant NSP and registering with AEMO, a registered participant must demonstrate the capability of the generating system to meet its registered performance standards and any registration conditions.[12] In this respect, generators must:

- provide models for the purpose of establishing the characteristics of the generator under simulated NEM conditions, and
- demonstrate consistency with performance standards through a series of tests agreed with the NSP and AEMO (which the NSP may witness for method and results) to ensure the onsite performance meets the expected or designed performance.

The commissioning process is directly managed by the registered participant and NSP, generally in consultation with AEMO (the overall approach to commissioning is outlined in Clause 5.8 of the NER).

AEMO consults with NSPs to ensure generators comply with the agreed performance standards, by checking actual performance against modelled performance. In Victoria, AEMO acts both as system operator and NSP, and is more directly involved in managing the commissioning process. This assists AEMO with managing system security issues during commissioning, and normally represents the commencement of model validation activities.

Where testing fails to demonstrate compliance with a generating system's registered performance standard or model, an NSP may advise AEMO not to proceed with commissioning, or to constrain the generator's output if there is a risk of damage to the transmission network or a risk to system security. Where the generator is connected and acts inconsistently with its registered performance standards, AEMO may also constrain the output of the generator to any output including zero.

[11] AEMO. "Structure of Participant Fees in the National Electricity Market". Available http://www.aemo.com.au/registration/nemfees11.html. 1 July 2011.

[12] This process also applies to upgrades to existing plant, and the addition of units to existing facilities.

ATTACHMENT A3 - HISTORICAL INFORMATION

Summary

This attachment presents a summary of key market outcomes over the last five financial years, and provides a historical context for National Electricity Market (NEM) behaviour. Information is presented for operational demand, interconnector power flows, generation mix, regional spot prices, market directions, and inter-regional settlements residue.

A consolidated historical information attachment was not included in the 2010 ESOO, although much of the historical content was reported throughout relevant ESOO chapters. For ease of reference, the 2011 ESOO compiles this information into a single attachment.

The presented historical information is largely sourced from AEMO's internal Market Management Systems (MMS), and is based on average half hour trading period data unless otherwise specified.

In this chapter, references to winter indicate the period 1 June–31 August (for all regions), and summer indicates the period 1 November–31 March (for all regions except Tasmania), and 1 December–28 February (for Tasmania only).

A3.1 Operational demand

A3.1.1 Demand duration curves

Normalised operational demand duration curves show the amount of time (as a percentage) that a region's operational demand was above or below a given percentage of the operational maximum demand (MD) in the region for the year. The ESOO CD includes a tutorial, Tutorial 2, Projecting Demand and Interpreting Demand Profiles, which explains how to interpret demand duration curves.

Operational demand duration curves can be useful when considering the technologies to employ in new generating units, available opportunities for demand-side participation (DSP), and the potential impacts a particular demand profile may have on reliability. The curves tend to vary from year-to-year in response to prevailing weather conditions and changes in the composition of loads within a region.

Operational demand values presented in this attachment are half-hour averages of regional operational demand, and consider the output of significant non-scheduled generation that includes:

- Cullerin Range Wind Farm (New South Wales)
- Capital Wind Farm (New South Wales)
- Yambuk Wind Farm (Victoria)
- Portland Wind Farm (Victoria)
- Challicum Hills Wind Farm (Victoria)
- Waubra Wind Farm (Victoria)
- Mount Millar Wind Farm (South Australia)
- Cathedral Rocks Wind Farm (South Australia)
- Starfish Hill Wind Farm (South Australia)
- Wattle Point Wind Farm (South Australia)
- Canunda Wind Farm (South Australia)
- Lake Bonney Wind Farm (South Australia), and
- Woolnorth Wind Farm (Tasmania).

Because the MMS does not store historical information for all non-scheduled generation, demand values presented in this section may not align perfectly with demand values presented in other chapters (for example, the MD projections presented in Chapter 3).

Figure A3-1 shows the normalised operational demand duration curve in each region for the financial year ending 30 June 2011. Figure A3-2 shows the top 10% of the operational demand shown in Figure A3-1.

The vertical axis represents percentages of the region's operational MD, and the horizontal axis shows the amount of time (as a percentage of the year) demand was above or below this level. For example, demand in South Australia was greater than approximately 60% of the region's MD for approximately 10% of the time. It was less than 60% of the MD for the rest of the time.

Figure A3-1 — Normalised operational demand duration curves for 2010–11

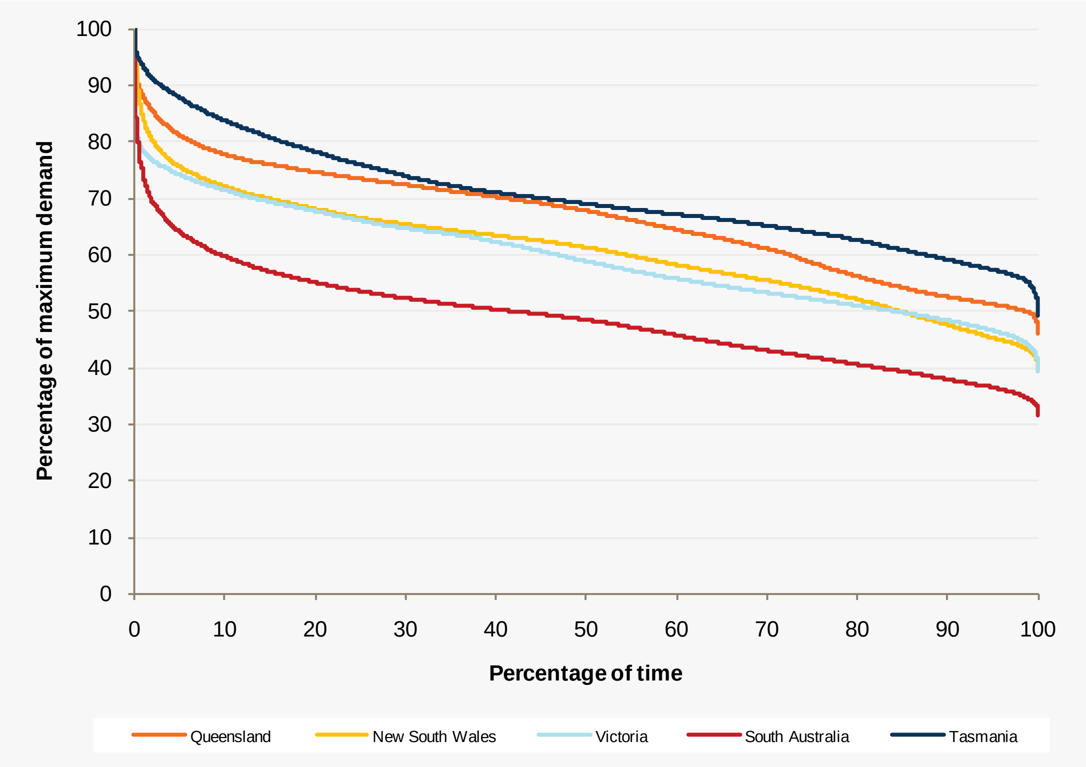
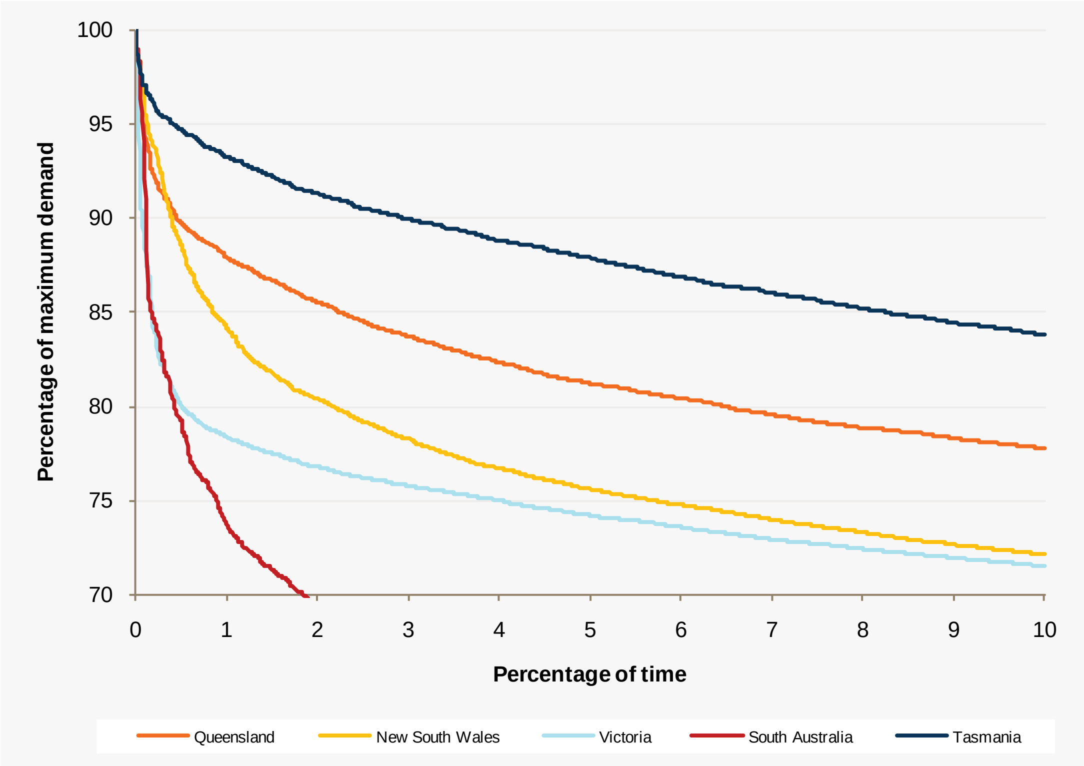


Figure A3-2 — Top-end normalised operational demand duration curves for 2010–11



Numbers of high operational demand days by region

Table A3-1 provides an analysis of the number of summer days that the operational demand in each region (and NEM-wide) was within 10% and 5% of the summer operational MD. For example, in summer 2010–11, Tasmania experienced eight days where operational demand was within approximately 70 MW of the winter operational MD (1,399 MW), and 36 days within approximately 140 MW.

Table A3-2 provides the same analysis for winter days and winter operational MD.

Table A3-1 — Number of summer days within 10% and 5% of the summer operational MD

	Summer	>90% Operational MD (Days)	>95% Operational MD (Days)	MD (MW)
Queensland	2006–07	13	5	8,611
	2007–08	33	9	8,086
	2008–09	27	8	8,707
	2009–10	27	12	8,897
	2010–11	8	3	8,826
New South Wales	2006–07	24	7	12,876
	2007–08	5	3	12,940
	2008–09	13	3	14,101
	2009–10	8	4	13,895
	2010–11	6	3	14,672
Victoria	2006–07	15	8	9,062
	2007–08	6	3	9,818
	2008–09	3	3	10,494
	2009–10	7	1	10,215
	2010–11	2	1	10,000
South Australia	2006–07	11	9	2,915
	2007–08	10	3	3,151
	2008–09	6	4	3,383
	2009–10	5	2	3,308
	2010–11	1	1	3,399
Tasmania	2006–07	32	9	1,377
	2007–08	22	3	1,411
	2008–09	23	4	1,446
	2009–10	65	19	1,398
	2010–11	46	5	1,362
NEM	2006–07	40	15	32,021
	2007–08	23	8	32,132
	2008–09	14	5	35,679
	2009–10	15	7	34,359
	2010–11	5	3	35,779

Table A3-2 — Number of winter days within 10% and 5% of the winter operational MD

	Winter	>90% Operational MD (Days)	>95% Operational MD (Days)	MD (MW)
Queensland	2006	31	2	7,628
	2007	23	7	7,862
	2008	12	1	8,212
	2009	35	5	7,694
	2010	65	17	7,335
New South Wales	2006	49	18	13,076
	2007	26	6	13,871
	2008	12	1	14,289
	2009	31	10	13,013
	2010	25	5	13,345
Victoria	2006	60	32	7,863
	2007	39	7	8,351
	2008	61	27	8,068
	2009	43	10	8,194
	2010	63	38	8,154
South Australia	2006	29	11	2,378
	2007	29	9	2,437
	2008	27	12	2,428
	2009	30	9	2,445
	2010	41	14	2,523
Tasmania	2006	54	22	1,684
	2007	45	17	1,756
	2008	48	9	1,790
	2009	34	7	1,700
	2010	61	22	1,711
NEM	2006	57	32	31,624
	2007	35	13	33,352
	2008	21	3	34,416
	2009	43	15	32,313
	2010	48	10	32,861

A3.1.2 Regional demand profiles for week of maximum demand

Figure A3-3 to Figure A3-8 show the operational demand profiles recorded during the week of the 2010 winter and 2010–11 summer operational MDs. Profiles are presented for each region, and for NEM-wide operational MD.

Figure A3-3 — Weekly demand profiles at times of winter and summer MD - Queensland

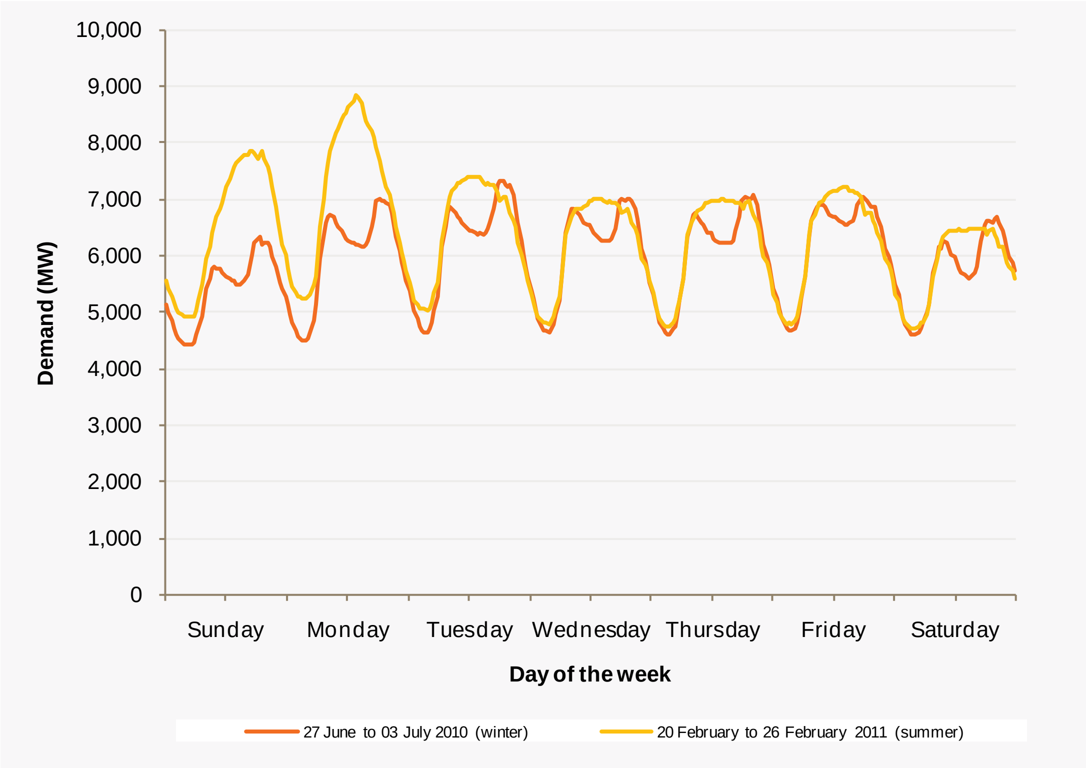


Figure A3-4 — Weekly demand profiles at times of winter and summer MD - New South Wales

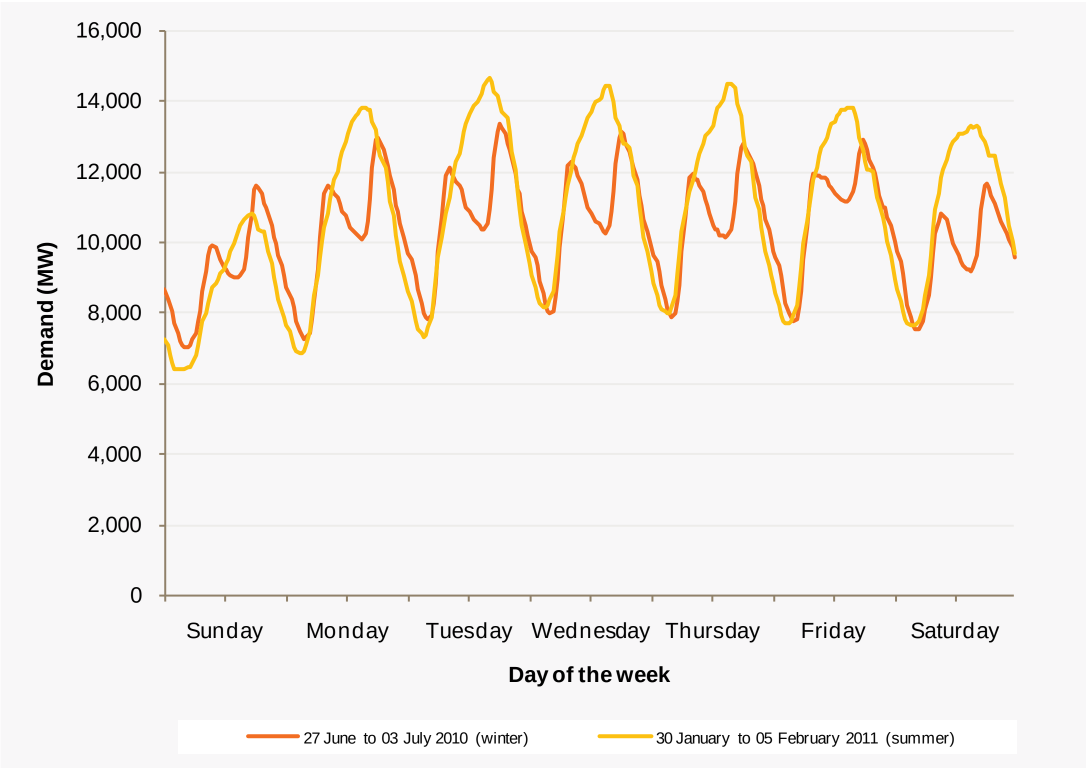


Figure A3-5 — Weekly demand profiles at times of winter and summer MD - Victoria

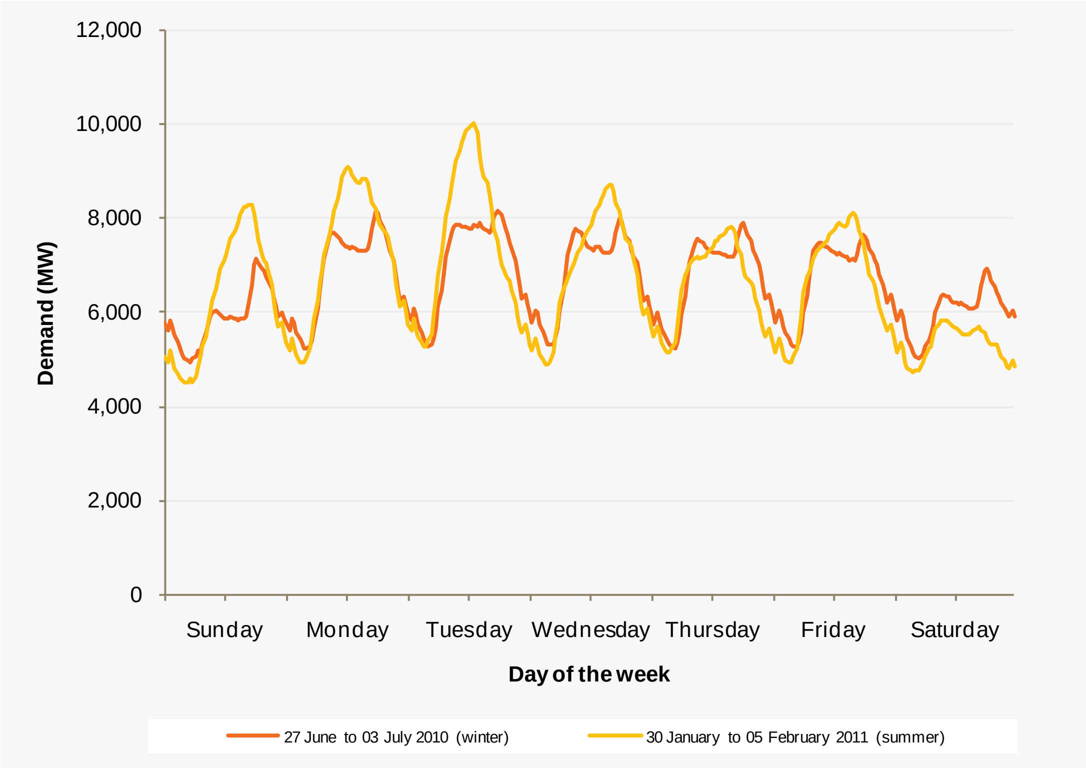


Figure A3-6 — Weekly demand profiles at times of winter and summer MD - South Australia

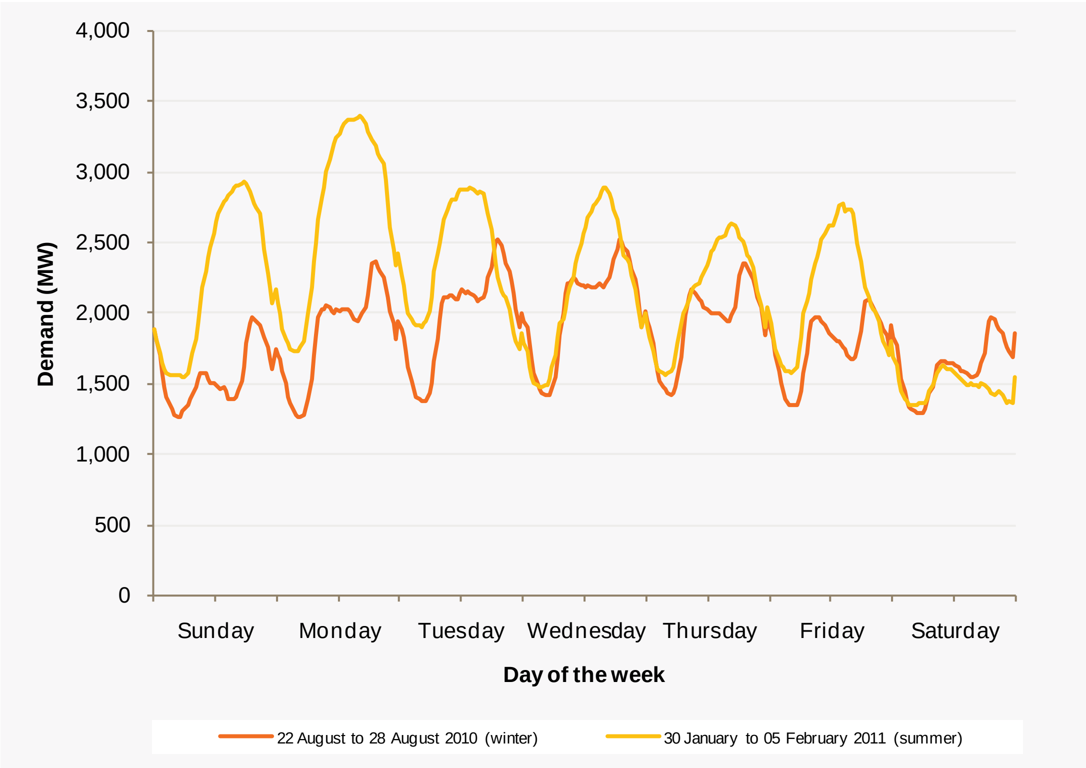


Figure A3-7 — Weekly demand profiles at times of winter and summer MD - Tasmania

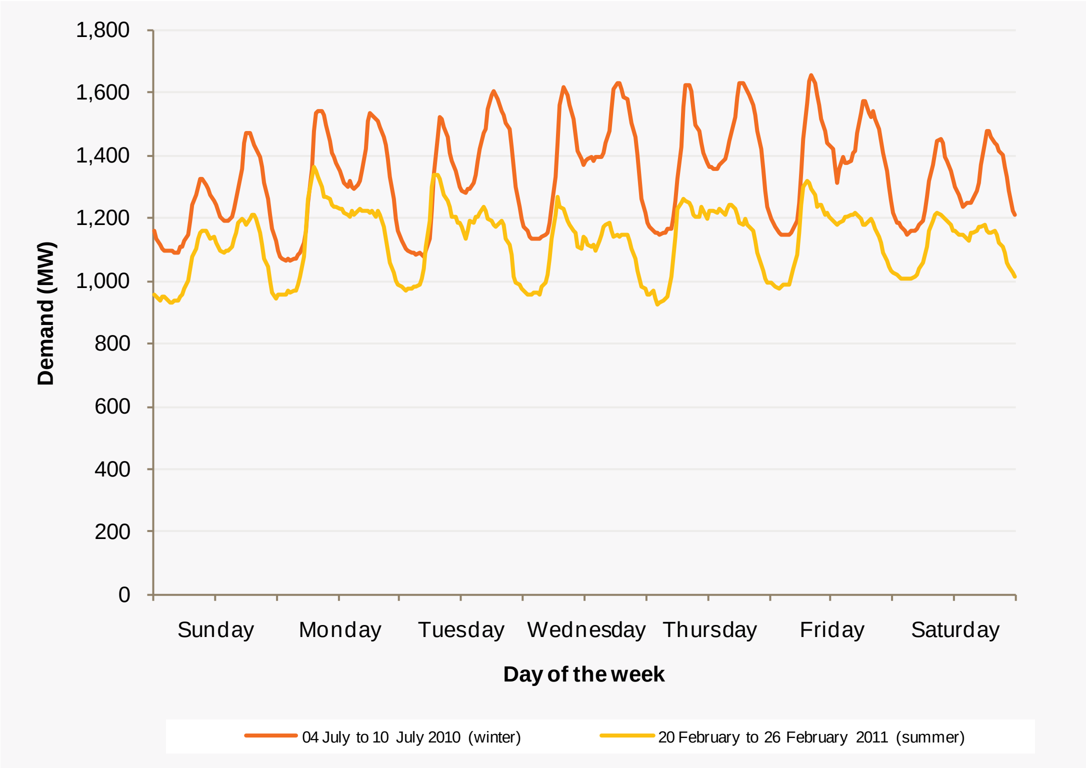
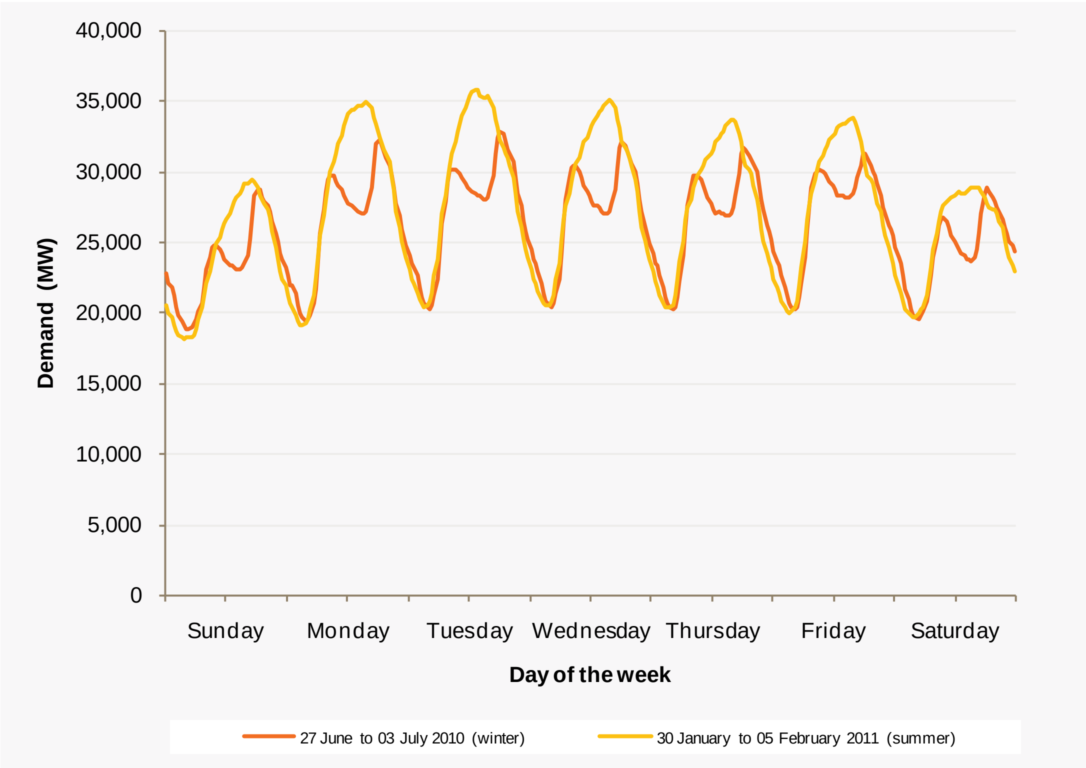


Figure A3-8 — Weekly demand profiles at times of winter and summer MD - NEM-wide



A3.1.3 Coincidence of regional maximum demands

When considering the ability of NEM generation to meet regional demand, it is important to consider the correlation of MDs between regions.

Table A3-3 lists the degree of coincidence between the MDs of each region and the NEM-wide operational MDs for summers from 2006–07 to 2010–11.

At the time of one region's operational MD, the other regions' operational demands are expressed as a percentage of their operational MD (for the same summer or winter).

For example, when Victoria reached its operational MD for the 2010–11 summer (100%), South Australia was at 87.4% of its summer operational MD. For the same year and season, when South Australia reached its operational MD (100%), demand in Victoria was at 84.7% of its operational MD.

Table A3-4 lists the degree of coincidence between the MDs of each region and the NEM-wide operational MDs for the winters of 2006 to 2010.

Table A3-3 — Coincidence of summer regional operational MD

	Summer	Queensland	New South Wales	Victoria	South Australia	Tasmania	NEM-Wide
Queensland operational MD	2006–07	100.0%	78.3%	58.8%	49.9%	82.9%	83.2%
	2007–08	100.0%	86.7%	65.7%	52.5%	82.6%	88.9%
	2008–09	100.0%	74.6%	60.7%	51.2%	83.6%	80.0%
	2009–10	100.0%	89.1%	89.5%	88.2%	76.0%	89.5%
	2010–11	100.0%	88.9%	88.1%	86.2%	79.5%	88.1%
	Average	**100.0%**	**83.5%**	**72.6%**	**65.6%**	**80.9%**	**85.9%**
New South Wales operational MD	2006–07	94.5%	100.0%	75.9%	73.7%	87.8%	97.6%
	2007–08	90.4%	100.0%	78.3%	73.6%	87.2%	98.0%
	2008–09	89.9%	100.0%	80.8%	94.6%	77.7%	97.3%
	2009–10	70.7%	100.0%	84.2%	81.3%	68.1%	84.2%
	2010–11	71.5%	100.0%	94.6%	93.8%	66.1%	94.6%
	Average	**83.4%**	**100.0%**	**82.8%**	**83.4%**	**77.4%**	**94.3%**
Victorian operational MD	2006–07	85.8%	88.6%	100.0%	100.0%	81.8%	99.6%
	2007–08	84.1%	84.9%	100.0%	100.0%	92.1%	99.8%
	2008–09	85.2%	88.3%	100.0%	97.5%	86.5%	97.9%
	2009–10	61.8%	79.7%	100.0%	96.7%	60.1%	100.0%
	2010–11	63.8%	84.8%	100.0%	87.4%	62.7%	100.0%
	Average	**76.1%**	**85.3%**	**100.0%**	**96.3%**	**76.6%**	**99.5%**

	Summer	Queensland	New South Wales	Victoria	South Australia	Tasmania	NEM-Wide
South Australian operational MD	2006–07	85.8%	88.6%	100.0%	100.0%	81.8%	99.6%
	2007–08	84.1%	84.9%	100.0%	100.0%	92.1%	99.8%
	2008–09	85.5%	92.3%	99.6%	100.0%	87.1%	99.6%
	2009–10	49.9%	68.8%	97.6%	100.0%	48.7%	97.6%
	2010–11	53.3%	83.5%	84.7%	100.0%	49.5%	84.7%
	Average	**71.7%**	**83.6%**	**96.4%**	**100.0%**	**71.8%**	**96.3%**
Tasmanian operational MD	2006–07	72.5%	72.4%	68.3%	57.3%	100.0%	77.5%
	2007–08	79.2%	71.6%	66.0%	52.2%	100.0%	78.5%
	2008–09	71.8%	64.6%	61.7%	48.4%	100.0%	69.8%
	2009–10	85.8%	84.3%	89.6%	89.6%	100.0%	89.6%
	2010–11	88.9%	91.3%	91.5%	90.1%	100.0%	91.5%
	Average	**79.6%**	**76.8%**	**75.4%**	**67.5%**	**100.0%**	**81.4%**
NEM-wide operational MD	2006–07	82.9%	93.3%	97.6%	96.5%	87.7%	100.0%
	2007–08	85.6%	88.2%	96.9%	95.7%	89.3%	100.0%
	2008–09	85.7%	93.3%	99.7%	99.0%	87.2%	100.0%
	2009–10	81.1%	97.3%	100.0%	97.7%	73.8%	100.0%
	2010–11	80.3%	98.1%	100.0%	97.1%	68.0%	100.0%
	Average	**83.1%**	**94.0%**	**98.8%**	**97.2%**	**81.2%**	**100.0%**

Table A3-4 — Coincidence of winter regional operational MD

	Winter	Queensland	New South Wales	Victoria	South Australia	Tasmania	NEM-Wide
Queensland operational MD	2006	100.0%	92.8%	96.9%	87.6%	96.7%	98.4%
	2007	100.0%	92.4%	93.6%	91.1%	95.6%	97.1%
	2008	100.0%	98.7%	98.7%	99.8%	87.3%	99.6%
	2009	100.0%	92.2%	92.2%	89.0%	87.8%	97.7%
	2010	100.0%	100.0%	99.0%	94.7%	89.8%	100.0%
	Average	**100.0%**	**95.2%**	**96.1%**	**92.4%**	**91.5%**	**98.6%**
New South Wales operational MD	2006	92.2%	100.0%	96.0%	88.6%	91.7%	99.0%
	2007	93.7%	100.0%	97.3%	95.0%	94.8%	100.0%
	2008	99.3%	100.0%	100.0%	95.7%	88.4%	100.0%
	2009	95.4%	100.0%	99.2%	88.4%	87.3%	99.8%
	2010	100.0%	100.0%	98.3%	86.3%	82.2%	100.0%
	Average	**96.1%**	**100.0%**	**98.2%**	**90.8%**	**88.9%**	**99.8%**

	Winter	Queensland	New South Wales	Victoria	South Australia	Tasmania	NEM-Wide
Victorian operational MD	2006	92.4%	99.5%	100.0%	84.7%	98.9%	99.9%
	2007	90.2%	96.5%	100.0%	87.3%	97.9%	98.0%
	2008	99.3%	100.0%	100.0%	95.7%	88.4%	100.0%
	2009	88.9%	99.8%	100.0%	91.4%	89.8%	97.2%
	2010	99.7%	99.7%	100.0%	97.6%	91.8%	99.7%
	Average	**94.1%**	**99.1%**	**100.0%**	**91.3%**	**93.4%**	**99.0%**
South Australian operational MD	2006	91.1%	97.6%	95.9%	100.0%	84.9%	98.2%
	2007	89.4%	89.0%	92.4%	100.0%	95.8%	93.6%
	2008	99.0%	96.7%	96.9%	100.0%	85.6%	98.0%
	2009	94.8%	93.3%	87.4%	100.0%	78.1%	94.2%
	2010	97.9%	97.9%	93.3%	100.0%	78.6%	97.9%
	Average	**94.4%**	**94.9%**	**93.2%**	**100.0%**	**84.6%**	**96.4%**
Tasmanian operational MD	2006	85.4%	85.2%	92.8%	76.2%	100.0%	90.0%
	2007	89.1%	88.7%	89.4%	79.8%	100.0%	91.4%
	2008	86.1%	86.4%	977.0%	88.2%	100.0%	90.7%
	2009	84.9%	95.0%	95.9%	91.3%	100.0%	90.6%
	2010	92.3%	92.3%	92.6%	95.3%	100.0%	92.3%
	Average	**87.6%**	**89.5%**	**269.5%**	**86.2%**	**100.0%**	**91.0%**
NEM-wide operational MD	2006	94.7%	97.3%	99.1%	96.5%	94.1%	100.0%
	2007	93.7%	100.0%	97.3%	95.0%	94.8%	100.0%
	2008	99.3%	100.0%	100.0%	95.7%	88.4%	100.0%
	2009	96.4%	99.6%	98.9%	92.4%	90.0%	100.0%
	2010	100.0%	100.0%	98.8%	93.0%	87.4%	100.0%
	Average	**96.8%**	**99.4%**	**98.8%**	**94.5%**	**90.9%**	**100.0%**

A3.1.4 NEM-wide coincidence factors

Table A3-5 and Table A3-6 provide actual operational MD values for each region for the summers of 2006–07 to 2010–11, and the winters of 2006 to 2010. They also provide a NEM-wide coincidence factor for each year, calculated by dividing the NEM-wide operational MD by the sum of the regional operational MDs for that year.

The projections of NEM-wide MD used in Chapter 3 are developed using a five-year average of these historical NEM-wide coincidence factors (92% for summer and 98% for winter).

Table A3-5 — NEM-wide coincidence factors as a function of the summer regional operational MD

Condition	2006–07	2007–08	2008–09	2009–10	2010–11	Average
Queensland operational MD (MW)	8,611	8,086	8,707	8,897	8,826	
New South Wales operational MD (MW)	12,876	12,940	14,101	13,895	14,672	
Snowy operational MD (MW)[a]	5	5	N/A	N/A	N/A	
Victorian operational MD (MW)	9,062	9,818	10,494	10,215	10,000	
South Australian operational MD (MW)	2,915	3,151	3,383	3,308	3,399	
Tasmanian operational MD (MW)	1,377	1,411	1,446	1,398	1,362	
Sum of regional operational MD (MW)	34,846	35,411	38,131	37,713	38,259	
NEM-wide operational MD (MW)	32,021	32,132	35,679	34,359	35,779	
NEM-wide coincidence factor	**91.9%**	**90.7%**	**93.6%**	**91.1%**	**93.5%**	**92.1%**

a. The calculation of the sum of the regional operational MDs assumed an operational MD of 5 MW for the Snowy region prior to its abolition on 1 July 2008.

Table A3-6 — NEM-wide coincidence factors as a function of the winter regional operational MD

Condition	2006	2007	2008	2009	2010	Average
Queensland operational MD (MW)	7,628	7,862	8,212	7,694	7,335	
New South Wales operational MD (MW)	13,076	13,871	14,289	13,013	13,345	
Snowy operational MD (MW)[a]	5	5	N/A	N/A	N/A	
Victorian operational MD (MW)	7,863	8,351	8,068	8,194	8,154	
South Australian operational MD (MW)	2,378	2,437	2,428	2,445	2,523	
Tasmanian operational MD (MW)	1,684	1,756	1,790	1,700	1,711	
Sum of regional operational MD (MW)	32,634	34,282	34,787	33,046	33,068	
NEM-wide operational MD (MW)	31,624	33,352	34,416	32,313	32,861	
NEM-wide coincidence factor	**96.9%**	**97.3%**	**98.9%**	**97.8%**	**99.4%**	**98.1%**

a. The calculation of the sum of the regional operational MDs assumed an operational MD of 5 MW for the Snowy region prior to its abolition on 1 July 2008.

A3.2 Generation

A3.2.1 Energy generation by region

Table A3-7 to Table A3-11 show the historical scheduled and semi-scheduled generation output for each region for 2006–07 to 2010–11.

The 2010 ESOO reported generation based on half-hourly power output measurements that are average values for each dispatch interval. This data is sourced from higher-resolution generation energy meters, leading to small discrepancies when compared to previously reported values.

Table A3-7 — Scheduled and semi-scheduled energy - Queensland (GWh)

Power Station	2006–07	2007–08	2008–09	2009–10	2010–11
Barcaldine	99.6	72.5	1.8	3.2	8.2
Barron Gorge	235.0	256.8	264.6	158.0	256.6
Braemar 1	1,290.9	1,935.7	1,846.2	1,753.1	1,823.8
Braemar 2[a]	0.0	0.0	102.0	1,687.3	1,223.4
Callide A	0.0	0.0	14.6	0.0	16.0
Callide B	4,706.4	4,244.0	3,533.5	4,388.8	2,944.3
Callide C	6,541.4	5,394.6	5,637.2	5,489.2	4,803.5
Collinsville	542.8	711.1	501.3	366.6	428.7
Condamine[b]	0.0	0.0	0.0	262.3	654.8
Darling Downs[c]	0.0	0.0	0.0	805.7	2,880.3
Gladstone	8,398.9	8,054.7	7,596.5	6,910.9	5,957.2
Kareeya	650.3	516.8	520.6	373.3	669.6
Kogan Creek[d]	137.9	4,260.6	4,815.0	4,328.6	5,032.9
Mackay GT	0.4	0.3	0.1	0.1	0.1
Millmerran	6,101.8	6,566.8	5,813.7	5,901.8	5,956.0
Mount Stuart	44.9	73.1	28.9	38.0	35.2
Oakey	24.7	27.3	29.9	37.5	26.3
Roma	35.7	70.2	226.8	232.7	42.4
Stanwell	8,853.9	8,725.1	7,856.3	8,075.9	6,338.4
Swanbank B	1,949.2	1,946.5	1,760.5	1,715.2	1,041.4
Swanbank E	2,267.0	2,080.8	2,160.3	2,012.0	2,203.0
Tarong	7,841.1	4,265.1	7,082.3	7,184.0	6,794.4
Tarong North	3,054.7	2,716.2	3,080.0	2,220.1	3,256.7
Townsville GT	1,541.6	1,321.0	1,110.1	1,334.3	886.5
Wivenhoe	129.0	123.8	33.3	40.1	23.8

a. Braemar 2 from 27 March 2009.

b. Condamine from 2 June 2009.

c. Darling Downs from 16 November 2009.

d. Kogan Creek from 3 April 2007.

Table A3-8 — Scheduled and semi-scheduled energy - New South Wales (GWh)

Power Station	2006–07	2007–08	2008–09	2009–10	2010–11
Bayswater	14,295.2	15,438.6	15,871.9	15,183.0	13,614.9
Blowering[a]	120.9	34.9	68.9	61.7	114.9
Colongra[b]	0.0	0.0	3.0	153.8	65.5
Eraring	16,424.5	16,258.7	14,472.7	13,261.8	13,071.7
Gunning Wind Farm[c]	0.0	0.0	0.0	0.0	41.2
Hume NSW	27.4	10.2	22.6	54.2	218.5
Liddell	10,853.1	10,830.4	11,135.2	9,394.3	7,763.5
Mount Piper	9,290.2	9,168.0	8,292.3	9,154.5	10,006.3
Munmorah	1,965.2	2,240.7	2,312.8	694.4	172.2
Redbank	1,137.9	1,178.6	768.6	1,010.5	1,108.5
Shoalhaven	46.4	21.9	33.5	7.4	26.6
Tallawarra[d]	0.0	0.0	786.8	2,379.5	2,724.6
Tumut[a]	909.6	884.8	594.3	912.8	1,162.2
Tumut 3[a]	849.4	1,059.4	614.2	467.6	598.6
Uranquinty[e]	0.0	0.0	192.5	369.5	257.2
Vales Point	6,214.9	7,471.1	8,491.8	8,041.6	5,909.1
Wallerawang C	4,890.9	5,413.0	4,874.7	4,185.4	5,541.3
Woodlawn Wind Farm[f]	0.0	0.0	0.0	0.0	7.7

a. Blowering and Tumut moved from Snowy to New South Wales from 1 July 2008.

b. Colongra from 20 May 2009.

c. Gunning Wind Farm from 25 March 2011.

d. Tallawarra from 14 October 2008.

e. Uranquinty from 28 October 2008.

f. Woodlawn Wind Farm from 3 May 2011.

Table A3-9 — Scheduled and semi-scheduled energy - Victoria (GWh)

Power Station	2006–07	2007–08	2008–09	2009–10	2010–11
Bairnsdale	277.1	236.8	205.5	70.0	56.8
Bogong and McKay Creek[a]	43.6	78.7	63.0	171.7	267.1
Dartmouth	404.9	0.0	0.0	0.0	20.9
Eildon	46.4	57.9	50.3	50.0	33.8
Energy Brix Complex	1,105.4	1,181.5	1,223.4	1,264.7	1,254.7
Guthega[b]	65.7	112.1	105.6	149.3	173.6
Hazelwood	11,063.1	10,609.5	11,390.1	10,775.7	10,576.8
Hume VIC	25.4	32.8	31.8	20.5	32.5
Jeeralang A	13.0	51.8	62.5	13.8	7.8
Jeeralang B	41.2	126.3	227.6	76.9	25.1
Laverton North[c]	440.2	201.3	131.9	208.8	293.8
Loy Yang A	15,484.6	15,692.8	15,204.3	15,786.6	15,375.0
Loy Yang B	7,734.6	8,329.1	8,017.2	7,995.6	7,991.8
Murray[b]	1,878.0	1,298.1	1,628.4	2,049.2	2,731.4
Newport	1,203.2	1,618.9	1,021.2	588.3	224.9
Somerton	141.0	117.9	109.3	96.1	55.4
Valley Power Peaking Facility	380.3	190.5	139.0	54.9	32.4
West Kiewa	61.1	112.6	108.4	169.1	220.9
Yallourn	9,965.1	9,520.4	11,153.5	10,525.2	10,821.9

a. Bogong from 22 September 2009.

b. Guthega and Murray moved from Snowy to Victoria from 1 July 2008.

c. Laverton North from 19 September 2006.

Table A3-10 — Scheduled and semi-scheduled energy - South Australia (GWh)

Power Station	2006–07	2007–08	2008–09	2009–10	2010–11
Angaston	4.0	2.2	1.7	0.4	1.0
Clements Gap Wind Farm[a]	0.0	0.0	2.9	166.5	170.6
Dry Creek	15.4	9.7	5.9	9.3	2.3
Hallett 1 Wind Farm[b]	0.0	91.4	328.8	337.0	320.0
Hallett 2 Wind Farm[c]	0.0	0.0	16.7	249.5	244.5
Hallett GT	149.4	28.3	22.5	26.8	20.8
Ladbroke Grove	245.2	138.6	188.7	187.8	135.5
Lake Bonney Stage 2[d]	3.0	229.8	341.5	277.8	356.4
Lake Bonney Stage 3[e]	0.0	0.0	0.0	0.0	84.4
Mintaro	34.6	7.6	3.5	7.3	2.6
North Brown Hill Wind Farm[f]	0.0	0.0	0.0	0.0	301.0
Northern	4,097.3	3,677.2	3,869.2	3,245.1	3,602.0
Osborne	1,212.0	1,190.8	1,204.5	1,150.0	1,013.1
Pelican Point	2,758.5	3,260.0	3,259.2	2,951.1	2,915.2
Playford B	683.3	781.7	648.1	950.3	297.8
Port Lincoln GT	0.6	1.6	1.7	2.1	1.6
Quarantine[g]	79.4	83.5	95.8	293.3	133.7
Snowtown Wind Farm[h]	0.0	13.4	321.7	361.9	345.1
Snuggery	1.2	2.0	1.7	2.5	0.4
Torrens Island A	353.6	495.8	506.0	421.6	638.4
Torrens Island B	2,211.5	2,622.1	1,849.8	1,595.0	1,572.8
Waterloo Wind Farm[i]	0.0	0.0	0.0	0.0	230.6

a. Clements Gap Wind Farm from 18 April 2009.

b. Hallett 1 Wind Farm from 19 December 2007.

c. Hallett 2 Wind Farm from 11 May 2009.

d. Lake Bonney Stage 2 from 31 May 2007.

e. Lake Bonney Stage 3 from 2 July 2010.

f. North Brown Hill Wind Farm from 8 August 2010.

g. Quarantine capacity increased from 19 December 2008.

h. Snowtown Wind Farm from 10 January 2008.

i. Waterloo Wind Farm from 20 August 2010.

Table A3-11 — Scheduled and semi-scheduled energy - Tasmania (GWh)

Power Station	2006–07	2007–08	2008–09	2009–10	2010–11
Bell Bay[a]	904.1	1,168.7	607.9	0.0	0.0
Bastyan	280.2	284.1	360.9	354.5	354.7
Bell Bay Three	38.8	31.3	31.6	56.2	22.0
Catagunya/Liapootah/Wayatinah	739.2	725.4	744.9	882.1	906.7
Cethana	259.9	306.0	382.6	387.4	463.2
Devils Gate	186.0	220.7	276.0	272.7	337.1
Fisher	162.0	192.8	263.0	263.4	327.9
Gordon	1,933.4	1,072.3	632.1	529.1	845.8
John Butters	415.8	400.9	471.3	554.6	552.4
Lake Echo	54.5	56.4	11.6	60.9	64.3
Lemonthyme/Wilmot	264.5	320.0	395.2	385.2	477.1
Mackintosh	279.0	283.6	357.7	353.0	353.3
MeadowBank	131.6	128.3	147.8	169.1	181.5
Poatina	1,024.3	748.6	531.8	831.7	1,094.1
Reece	751.2	770.8	918.7	958.2	950.1
Tamar Valley CCGT[b]	0.0	0.0	0.1	1,006.9	1,430.0
Tamar Valley OCGT[c]	0.0	0.0	60.6	41.6	15.4
Tarraleah	550.0	505.4	517.5	567.7	560.1
Trevallyn	287.9	262.9	249.5	470.9	587.7
Tribute	176.7	176.6	201.0	220.7	224.2
Tungatinah	353.1	358.4	386.8	510.3	556.8

a. Bell Bay until 14 November 2009.

b. Tamar Valley CCGT from 15 June 2009.

c. Tamar Valley OCGT from 31 March 2009.

A3.3 Interconnector power flows

As an interconnected market, the NEM enables power transfers between adjacent regions across interconnectors, controlled by prevailing market conditions and constraint equations applied to inter-regional flow.

A3.3.1 Energy transfers

Table A3-12 lists the energy transferred across each interconnector for 2006–07 to 2010–11.

Table A3-12 — Energy transfer between regions for 2006–07 to 2010–11 (GWh)

Interconnector	Direction	2006–07	2007–08	2008–09	2009–10	2010–11
QNI	New South Wales to Queensland	43.8	104.8	121.5	54.4	46.7
	Queensland to New South Wales	5,758.6	4,797.6	4,321.1	4,973.6	5,660.4
Terranora	New South Wales to Queensland	1.1	8.8	6.0	0.8	1.4
	Queensland to New South Wales	779.3	623.1	717.3	776.4	833.4
Snowy to New South Wales[a]	Snowy to New South Wales	3,129.3	2,084.0	-	-	-
	New South Wales to Snowy	1,028.8	1,590.4	-	-	-
Victoria to Snowy[a]	Victoria to Snowy	1,857.8	1,366.6	-	-	-
	Snowy to Victoria	2,203.7	2,666.4	-	-	-
Victoria to New South Wales[a]	Victoria to New South Wales	-	-	2,087.8	3,114.4	4,317.3
	New South Wales to Victoria	-	-	1,147.0	1,011.4	557.5
Heywood	Victoria to South Australia	1,245.8	657.0	822.8	1,104.5	1,155.2
	South Australia to Victoria	234.7	525.6	429.3	299.2	364.2
Murraylink	Victoria to South Australia	86.8	40.1	51.5	78.5	79.2
	South Australia to Victoria	155.7	175.9	217.3	265.8	303.9
Basslink	Tasmania to Victoria	586.9	226.4	72.2	665.6	1,314.6
	Victoria to Tasmania	1,961.3	2,519.8	2,642.0	1,797.8	1,102.8

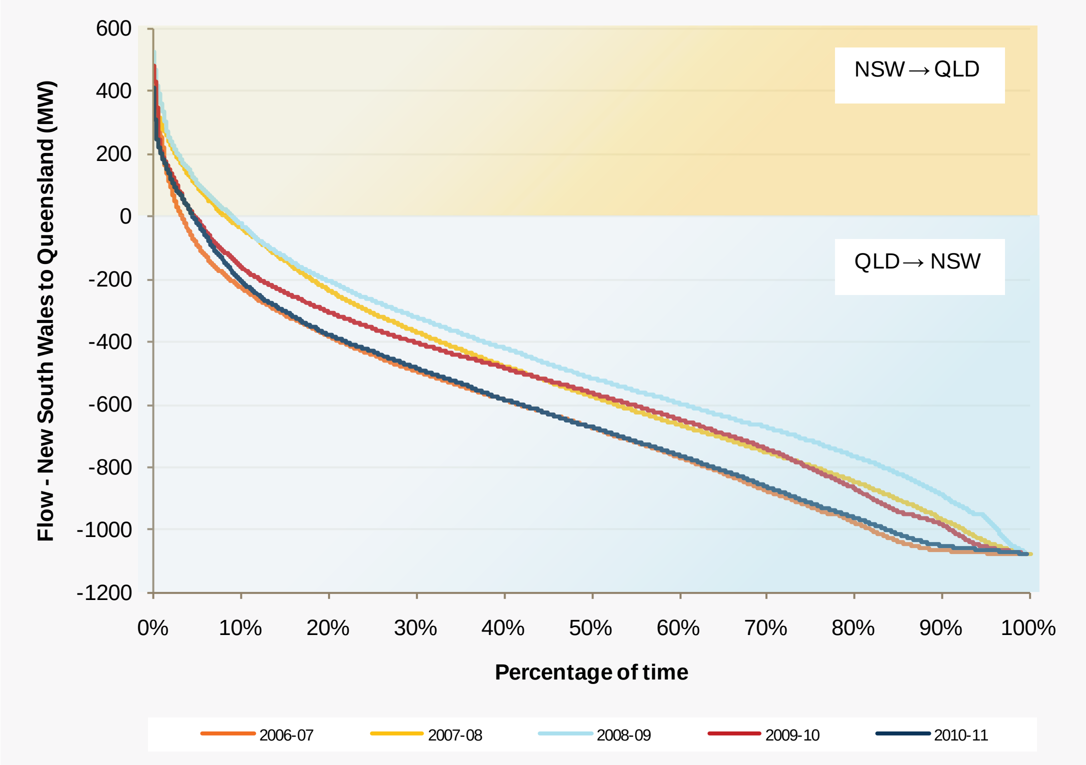
a. On 1 July 2008, the Snowy to New South Wales and Victoria to Snowy interconnectors were replaced by the Victoria to New South Wales interconnector.

A3.3.2 Flow duration curves

Figure A3-9 to Figure A3-14 show the flow duration curves for each interconnector for 2006–07 to 2010–11. In the figures, the vertical axis represents power flow in the conventional positive flow direction[1], with negative values indicating flow in the reverse direction. The horizontal axis represents the percentage of time.

For example, on the New South Wales to Queensland interconnector (QNI) in 2010–11 power flowed from New South Wales to Queensland approximately 4% of the time, and from Queensland to New South Wales approximately 96% of the time. In that year, and in 2006–07, flow on QNI was frequently close to its power transfer limit in the Queensland to New South Wales direction (approximately 1,100 MW).

Figure A3-9 — Flow duration curves for the QNI interconnector for 2006–07 to 2010–11



[1] For interconnectors between Queensland and New South Wales (QNI and Terranora), positive flow is from New South Wales to Queensland. For Basslink, positive flow is from Tasmania to Victoria. For all the other interconnectors (Heywood, Murraylink, and Victoria-New South Wales) positive flow is out of Victoria.

Figure A3-10 — Flow duration curves for the Terranora interconnector for 2006–07 to 2010–11

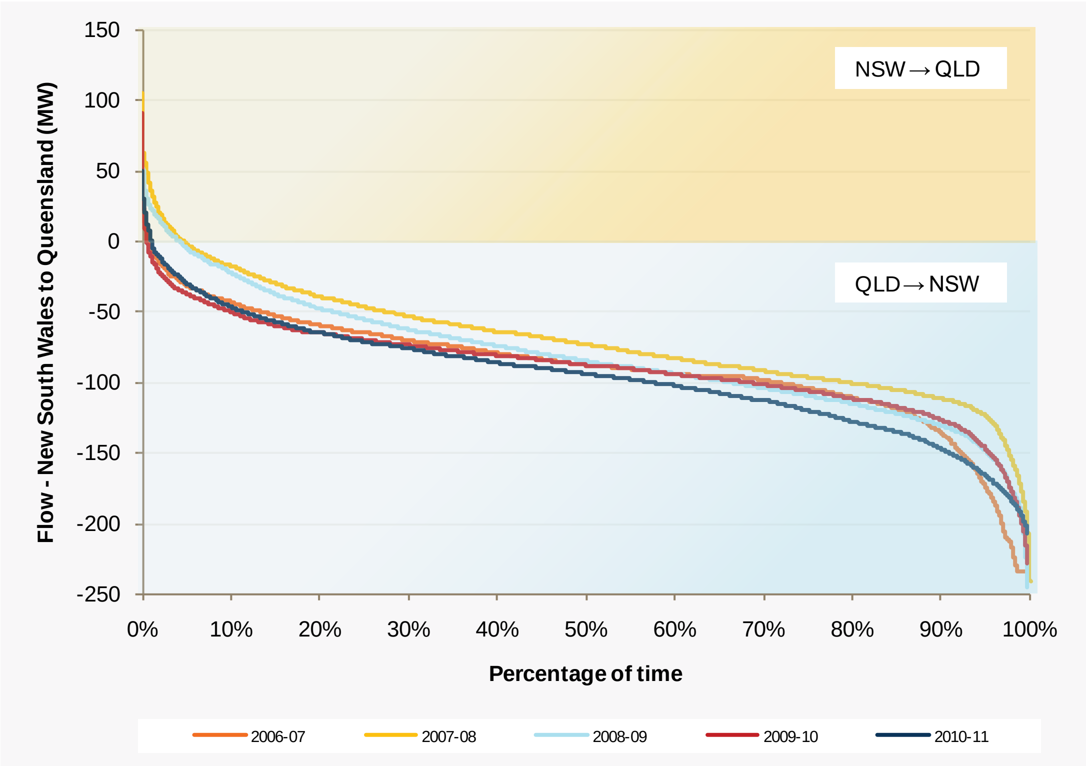


Figure A3-11 — Flow duration curves for the Victoria to New South Wales interconnector for 2008–09 to 2010–11

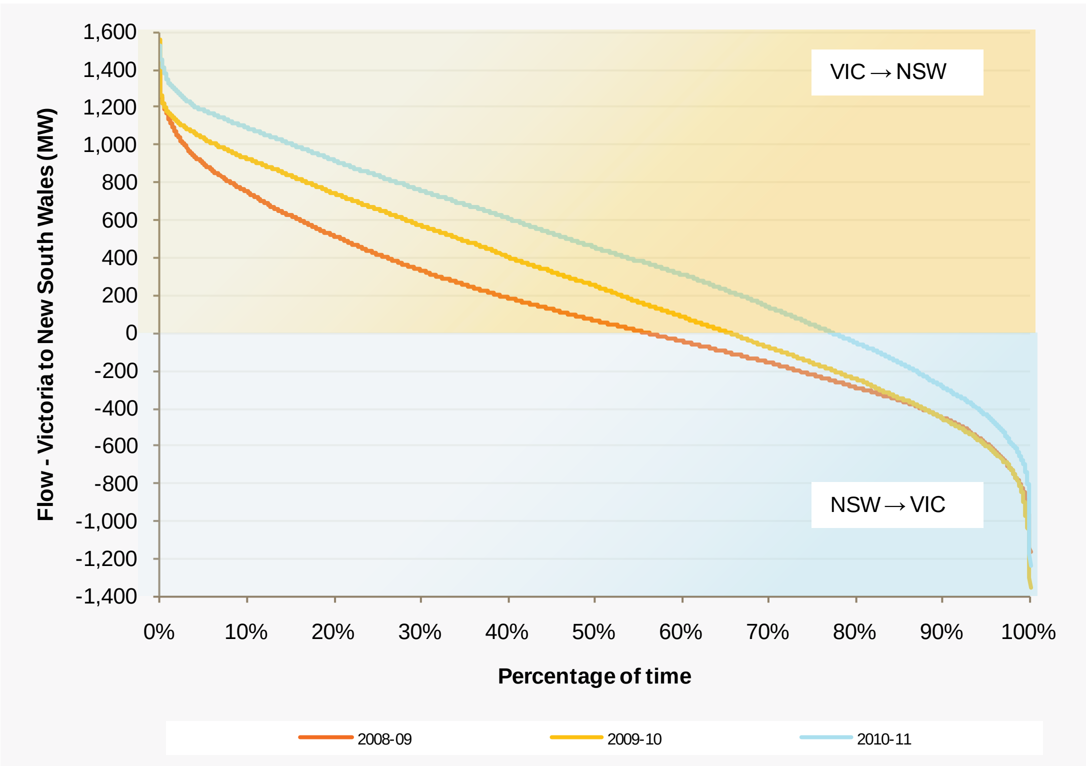


Figure A3-12 — Flow duration curves for the Heywood interconnector for 2006–07 to 2010–11

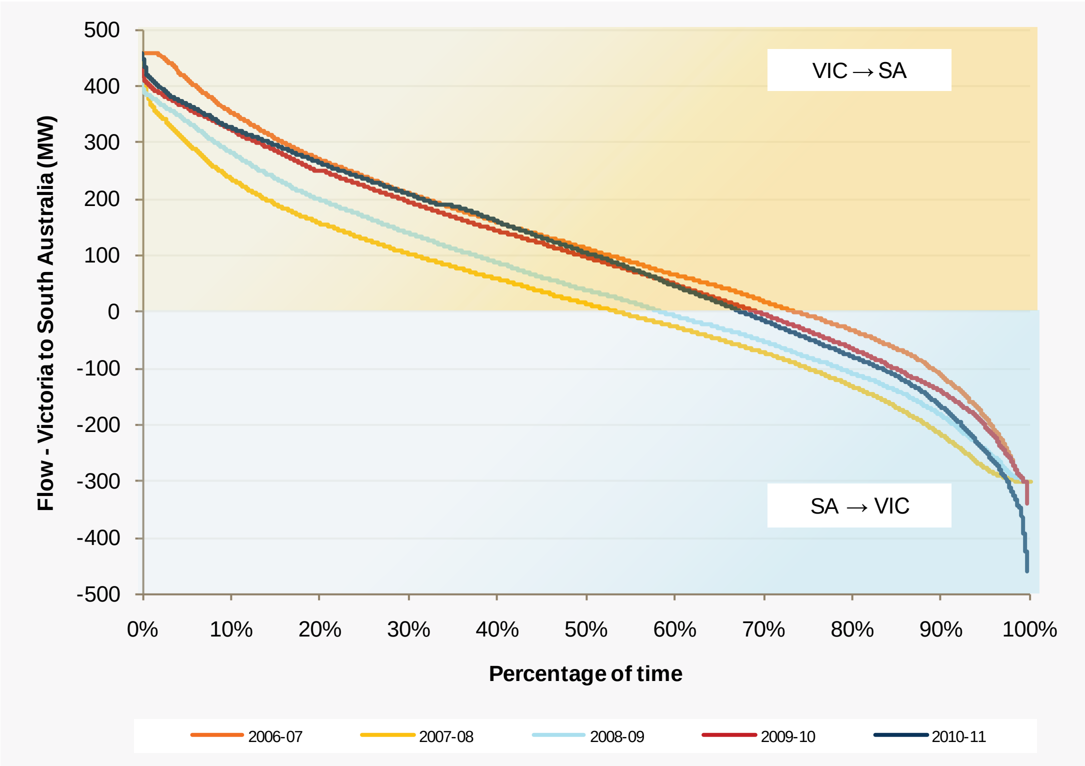


Figure A3-13 — Flow duration curves for the Murraylink interconnector for 2006–07 to 2010–11

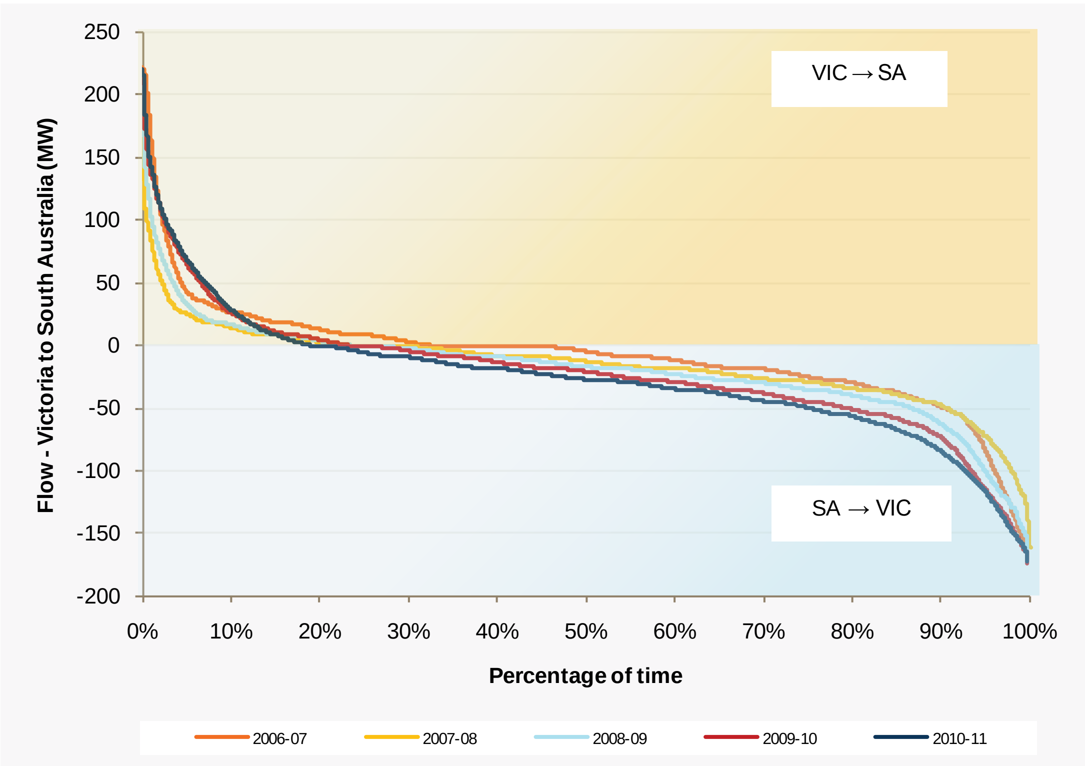
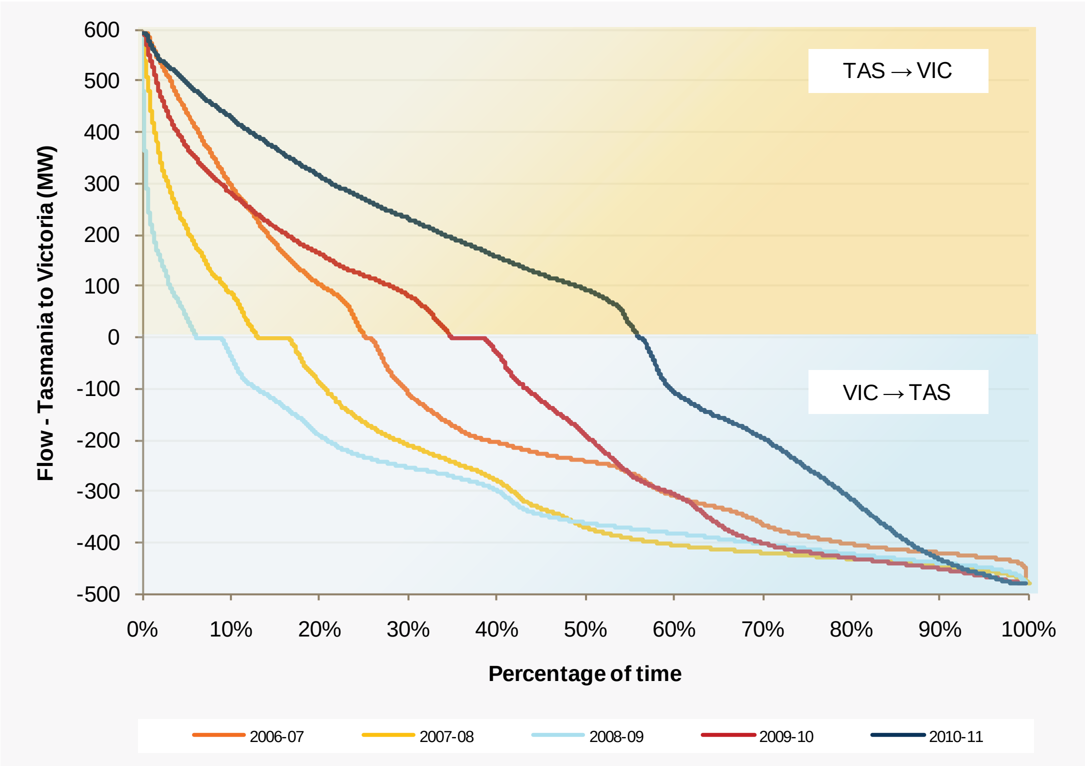


Figure A3-14 — Flow duration curves for the Basslink interconnector for 2006–07 to 2010–11



A3.4 Spot prices

A3.4.1 Regional spot price statistics

Table A3-13 lists the number of hours spot prices in each region exceeded 100 $/MWh, 300 $/MWh, and 1,000 $/MWh, for 2006–07 to 2010–11.

For example, in 2009–10, Queensland experienced prices higher than 100 $/MWh for 88.5 hours. In the same year, prices were higher than 300 $/MWh for 24 hours and 1,000 $/MWh for 21 hours.

The Australian Energy Regulator (AER) reports on market events where spot prices exceed 5,000 $/MWh.[2] Eight reports of this type were produced for 2010–11.

[2] AER. "Prices above $5000/MWh reports". Available: http://www.aer.gov.au/content/index.phtml/itemId/714860. 4 July 2011.

Table A3-13 — Number of hours of high spot prices

		2006–07	2007–08	2008–09	2009–10	2010–11
Queensland	> 100 $/MWh	581.5	276.0	111.0	88.5	86.5
	> 300 $/MWh	66.0	38.5	17.5	24.0	18.5
	> 1,000 $/MWh	23.0	28.5	11.0	21.0	11.0
New South Wales	> 100 $/MWh	635.0	206.0	117.0	115.5	88.5
	> 300 $/MWh	94.5	22.0	18.5	60.0	19.5
	> 1,000 $/MWh	23.0	2.5	12.0	34.5	15.5
Snowy[a]	> 100 $/MWh	556.5	246.5	-	-	-
	> 300 $/MWh	60.0	18.0	-	-	-
	> 1,000 $/MWh	17.5	5.5	-	-	-
Victoria	> 100 $/MWh	509.0	336.0	110.5	67.0	27.0
	> 300 $/MWh	53.0	27.5	17.0	23.5	6.0
	> 1,000 $/MWh	22.0	8.0	13.5	19.5	4.5
South Australia	> 100 $/MWh	547.0	364.5	146.5	109.0	39.5
	> 300 $/MWh	35.5	49.5	33.0	44.0	11.0
	> 1,000 $/MWh	13.5	31.0	22.5	36.5	7.5
Tasmania	> 100 $/MWh	350.5	423.5	353.0	64.0	28.0
	> 300 $/MWh	17.5	8.0	51.0	13.5	5.5
	> 1,000 $/MWh	8.0	3.0	31.5	7.0	5.0

a. The Snowy region was abolished on 1 July 2008.

A3.4.2 Regional spot price duration curves

Figure A3-15 shows the price duration for each region for 2010–11. Figure A3-16 shows a detailed view of top-end prices for the same year where the vertical axis represents price on a logarithmic scale, and the horizontal axis shows the amount of time (as a percentage of total time in the year) the price was above or below this level.

For example, Tasmania's price was higher than $50 approximately 2% of the time, and lower than $50 approximately 98% of the time.

Figure A3-15 — Regional price duration curves for 2010–11

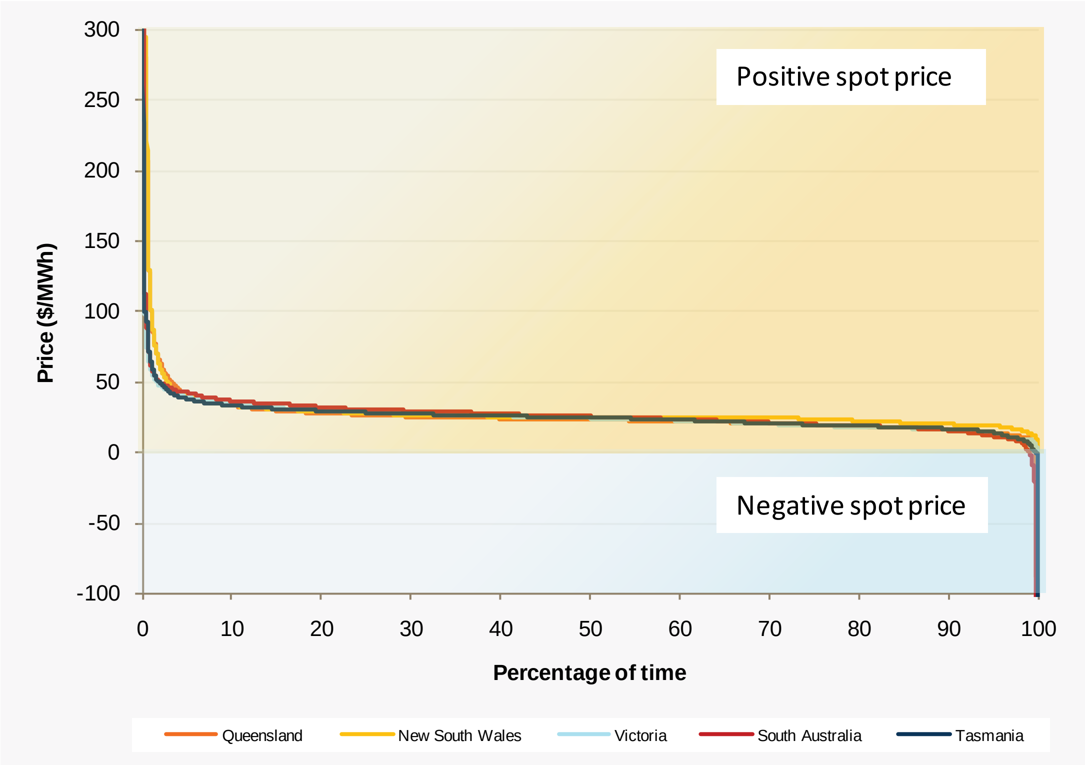
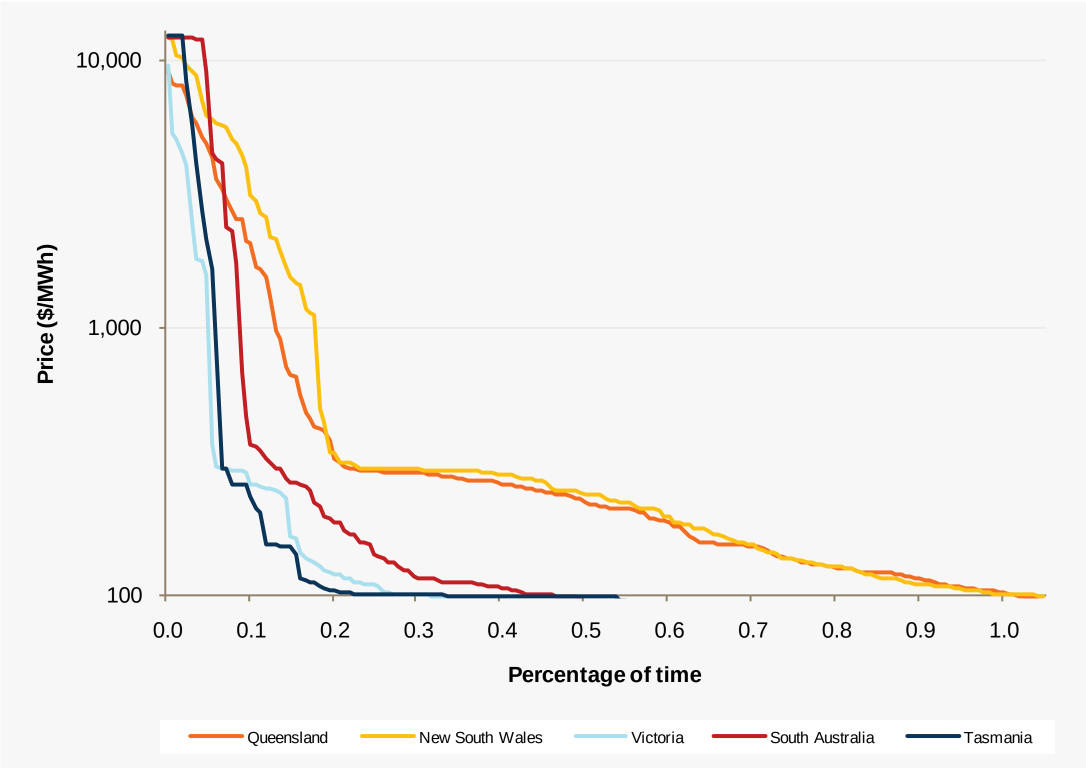


Figure A3-16 — Regional price duration curves for prices above $100 for 2010–11



A3.5 Other market data

A3.5.1 Directions and compensations

Clause 4.8.9 of the National Electricity Rules (NER) enables AEMO to direct market participants for the purposes of maintaining power system security (through security and ancillary service directions) and supply reliability (through reliability directions).

Following the cancellation of a direction, compensation is determined in accordance with the type of direction given. This process can take up to 150 business days to complete, and can result in a determination that no compensation should be paid.

Table A3-14 lists the directions issued for 2006–07 to 2010–11. The table presents the number of directions that occurred in the year, how many of those have been determined, how many determined directions are subject to compensation, and the amount of compensation paid.

The high cost of the two Victorian directions in 2006–07 was associated with manual frequency control requirements immediately after the Victorian region was electrically separated from both the Snowy/New South Wales and South Australian regions on a day of extreme temperatures and demand.

Table A3-14 — Market directions and compensation between 1 July 2006 and 30 June 2011

		2006–07	2007–08	2008–09	2009–10	2010–11
Queensland	Number of directions.	3	5	3	5	0
	Number where compensation is determined.	3	5	3	5	0
	Total number where compensation was paid.	3	1	3	5	0
	Total amount of compensation paid. ($)	**248,124**	**9,449**	**1,146,905**	**1,597,267**	**0**
New South Wales	Number of directions.	0	0	1	1	0
	Number where compensation is determined.	0	0	1	1	0
	Total number where compensation was paid.	0	0	1	0	0
	Total amount of compensation paid. ($)	**0**	**0**	**12,352**	**0**	**0**
Victoria	Number of directions.	6	0	5	0	0
	Number where compensation is determined.	6	0	5	0	0
	Total number where compensation was paid.	2	0	5	0	0
	Total amount of compensation paid. ($)	**1,371,163**	**0**	**801,077**	**0**	**0**
South Australia	Number of directions.	1	1	4	1	0
	Number where compensation is determined.	1	1	4	1	0
	Total number where compensation was paid.	1	1	4	1	0
	Total amount of compensation paid. ($)	**240,387**	**59,961**	**42,986**	**126**	**0**
Tasmania	Number of directions.	0	1	0	1	0
	Number where compensation is determined.	0	1	0	1	0
	Total number where compensation was paid.	0	0	0	1	0
	Total amount of compensation paid. ($)	**0**	**0**	**0**	**135**	**0**

A3.5.2 Settlements residue

Inter-regional settlements residue is associated with transporting electricity between regions.[3] Settlements residue may accrue on each non-market interconnector in each trading period, and is defined as the difference between the value of energy in the importing region and the value of energy in the exporting region. For example, if the price in region A is $10, and the price in region B is $15, and 1,000 MWh is transferred from region A to region B, the residue is 1,000×(15-10) = $5,000.

Residues values are typically positive, as the price of energy in an importing region is typically higher than the price in the exporting region. Occasionally, the application of transmission network constraint equations and marginal loss factors can lead to negative residues, when energy flows from a higher-priced region to a lower-priced region.

AEMO auctions future residue on a quarterly basis. Market participants may choose to purchase units of residue as a hedge against inter-regional trading risks. The proceeds of the auctions, together with any residue surplus not distributed at auction, are paid to the transmission network service providers (TNSP).

Table A3-15 shows the accrued inter-regional settlements residue for 2006–07 to 2010–11.

Table A3-15 — Inter-regional settlements residue ($'000)

Flow Direction	2006–07		2007–08		2008–09		2009–10		2010–11	
	+	-	+	-	+	-	+	-	+	-
Queensland to New South Wales	67,563	2,930	23,737	14,558	51,894	1,787	63,218	857	60,019	5,775
New South Wales to Queensland	1,560	12	13,504	9	3,170	5	3,821	2,418	172	1,190
New South Wales to Snowy[a]	1,231	48	10,314	5,271	-	-	-	-	-	-
Snowy to New South Wales	88,158	48	12,744	42	-	-	-	-	-	-
Snowy to Victoria	32,224	526	15,752	300	-	-	-	-	-	-
Victoria to Snowy	22,092	6	1,846	845	-	-	-	-	-	-
New South Wales to Victoria	-	-	-	-	30,521	1,570	14,371	7,329	875	169
Victoria to New South Wales	-	-	-	-	37,349	109	75,977	20,861	50,154	2,907
Victoria to South Australia	9,886	1,063	87,930	70	37,247	610	74,114	1,802	26,925	290
South Australia to Victoria	7,968	166	3,410	76	3,656	712	1,857	608	6,757	147

a. The Snowy region was abolished on 1 July 2008.

3 AEMO. "Settlement Residue Auction". Available: http://www.aemo.com.au/electricityops/sra.html. 7 June 2011.

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GLOSSARY

Definitions

Many of the terms listed here are already defined in the National Electricity Rules (NER), version 45[1]. For ease of reference, these terms are highlighted in blue. Some terms, although defined in the NER, have been clarified, and these terms are highlighted in green.

Term	Definition
active power	See electrical power.
advanced proposal	A proposed generation project that meets at least three and shows progress on two of the five criteria specified by AEMO for a committed project – generation. See also 'proposed project' and 'publicly announced proposal'.
allocated installed capacity	The generation capacity allocated to a region when assessing the reliability of supply. Allocated installed capacity is equal to the scheduled generation and semi-scheduled generation capacity within a region plus the allocated net import from neighbouring regions. See also 'capacity for reliability'.
ancillary services	Services used by AEMO that are essential for: • managing power system security • facilitating orderly trading, and • ensuring electricity supplies are of an acceptable quality. This includes services used to control frequency, voltage, network loading and system restart processes, which would not otherwise be voluntarily provided by market participants on the basis of energy prices alone. Ancillary services may be obtained by AEMO through either market or non-market arrangements.
annual planning report	An annual report providing forecasts of gas or electricity (or both) supply, capacity, and demand, and other planning information.
as-generated	A measure of demand or energy (in megawatts (MW) and megawatt hours (MWh), respectively) at the terminals of a generating system. This measure includes consumer load, transmission and distribution losses, and generator auxiliary loads.
augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
Australian Wind Energy Forecasting System (AWEFS)	A system used by AEMO to produce wind generation forecasts ranging from five minutes ahead to two years ahead.
automatic access standard	In relation to a technical requirement of access, a standard of performance, identified in a schedule of Chapter 5 (of the NER) as an automatic access standard for that technical requirement, such that a plant that meets that standard would not be denied access because of that technical requirement. (See also minimum access standard and negotiated access standard.)
back assessment	The comparison of old maximum demand (MD) projections with actual (historical) MD values.

[1] An electronic copy of the latest version of the NER can be obtained from http://www.aemc.gov.au/rules.php

Term	Definition
backcasting	Backcasting involves 'forecasting' historical maximum demands (MDs), and applies the current forecasting model to project values of seasonal MD that have already occurred (but were not used to derive the model). Backcasting takes actual economic and climatic conditions and temperatures into account to produce a single point MD projection for each season for comparison with the actual (historical) seasonal MDs.
Base load generating system	A generating system designed to run almost constantly at near maximum capacity levels, usually at lower cost than intermediate or peaking generating systems.
capacitive reactance	The component of a circuit element's impedance that is due to the establishment of an electric field. Current through the capacitive component is proportional to the differential of the voltage across that component. See also 'reactive power'.
capacity factor	The output of generating units or systems, averaged over time, expressed as a percentage of rated or maximum output.
capacity for reliability	The allocated installed capacity required to meet a region's minimum reserve level (MRL). When met, sufficient supplies are available to the region to meet the Reliability Standard. Capacity for reliability = 10% Probability of Exceedence (POE) scheduled and semi-scheduled maximum demand + minimum reserve level – committed demand-side participation.
capacity limited	A generating unit whose power output is limited.
capital deferral benefit	A benefit deriving from the reduced capital costs resulting from being able to reduce (or defer) generation or transmission investment.
causer-pays methodology	A methodology used to allocate frequency control ancillary service (FCAS) costs. See also 'frequency control ancillary services (FCAS)'.
central dispatch	The process managed by AEMO for the dispatch of scheduled generating units, semi-scheduled generating units, scheduled loads, scheduled network services and market ancillary services in accordance with Rule 3.8.
cleared supply	An estimate of the expected demand at the end of a dispatch interval. Calculated at the start of the dispatch interval, it is the sum of the: • generating unit dispatch targets within a region, and • net interconnector dispatch targets into a region.
coincidence factor	An expression of the degree of historical coincidence of the maximum demands (MDs) within different regions in the National Electricity Market (NEM), or between regional MDs and the NEM-wide MD.
committed project	A committed project is any new generation development or non-regulated transmission development that meets all five criteria specified by the AEMO for a committed project – generation (see Chapter 4 of the Electricity Statement of Opportunities (ESOO) for more information).
compound average growth rate	The year-over-year growth rate over a specified period of time.
conceptual augmentation	A proposed transmission network augmentation option that could provide market benefits (possibly including Reliability Benefits). Conceptual augmentations may or may not be built in the future. The timing and value of these projects depends on the development of the electricity market. Conceptual augmentations do not satisfy the criteria for a committed project. See also 'committed project'.
connection asset	The electricity transmission or distribution network components used to provide connection services (for example, 220/66 kV transformers).

Term	Definition
connection point (electricity)	The agreed point of supply established between network service provider(s) and another registered participant, non-reregistered customer or franchise customer.
constrained	A limitation on the capability of a network, load, or a generating unit such that it is unacceptable to either transfer, consume or generate the level of electrical power that would occur if the limitation was removed.
constraint (electricity)	Any limitation on the operation of the transmission system that will give rise to unserved energy (USE) or to generation re-dispatch costs.
connection asset constraint	A constraint applying to an asset connecting the electricity transmission network to the distribution network.
constraint equation	The mathematical expression of a physical system limitation or requirement that must be considered by the central dispatch algorithm when determining the optimum economic dispatch outcome. See also ' 'FCAS constraint equation', 'invoked constraint equation', and 'network constraint equation'.
constraint value estimate	An electricity transmission network constraint's expected cost to the community, weighted by the probability of a contingency event occurring. This cost comprises load shedding and generation rescheduling (for example increased fuel cost).
constraint equation violation	Occurs when the requirements of a constraint equation are not met. Under some power system operating conditions it might not be feasible to meet the requirements of all invoked constraint equations simultaneously in the central dispatch process. Measured in megawatts (MW), the constraint equation violation represents the amount by which a constraint equation's requirements are exceeded.
consumer	See customer.
contingency event	An event affecting the power system, such as the failure or unplanned removal from operational service of a generating unit or transmission network element.
contingency services	Services provided by registered participants that enable the maintenance or restoration of power system security, or both. This includes, for example, actual active and reactive power capacities, which can be made available and used when a contingency event occurs.
credible contingency event	A contingency event AEMO considers reasonably possible, given the circumstances in the power system.
critical contingency	The specific forced or planned outage that has the greatest potential to impact on the electricity transmission network at any given time.
customer (electricity)	A person who engages in the activity of purchasing electricity supplied through a transmission or distribution system to a connection point.
damping torque	A stabilising force applied to the rotor of a generating unit, via the operation of excitation system controls and the electrical network that quickly reduces electrical power oscillations
demand	See electricity demand.
demand diversity	Referring to both intra and inter-regional demand diversity: • 'intra-regional' recognises that the maximum demands (MDs) at each connection point within a region might not occur at the same time, and the sum of the connection point MDs will exceed the regional MD, and • 'inter-regional' recognises that the MDs of different regions may occur at different times, and the sum of the individual regional MDs will exceed the total National Electricity Market (NEM) MD.

Term	Definition
demand response aggregator (DRA)	An organisation contracted to facilitate and administer the provision of demand-side responses.
demand-side management	The act of administering electricity demand-side participants (possibly through a demand-side response aggregator).
demand-side participation (DSP)	The situation where customers vary their electricity consumption in response to a change in market conditions, such as the spot price.
demand-side response aggregator	An organisation or agency for the provision and administration of electricity demand-side responses/participation.
discovered petroleum initially-in-place	The quantity of petroleum estimated, at a given date, contained in known accumulations prior to production.
dispatch algorithm	The algorithm used by AEMO to manage the central dispatch process. This algorithm is run before every dispatch interval. See also 'National Electricity Market Dispatch Engine (NEMDE)'.
dispatch instruction	An instruction issued by AEMO: • to implement central dispatch, or • where AEMO has the power to give a direction.
dispatch interval	A period of five minutes.
dispatch targets	A particular dispatch interval's specified generating unit output and interconnector power flow targets.
dispatched load	The load which has been dispatched as part of central dispatch.
distribution losses	Electrical energy losses incurred in distributing electricity over a distribution network.
distribution network	A network which is not a transmission network.
distribution network service provider (DNSP)	A person who engages in the activity of owning, controlling, or operating a distribution system.
diversity	The lack of coincidence of peak demand across several sources of demand, such as residential, industrial, and gas powered generation.
diversity factor	Refers to the ratio of the NEM maximum demand to the sum of maximum demands in each NEM region. This is sometimes referred to as the demand factor, and is always less than one. See also 'demand diversity'.
economic demonstrated resources (EDR)	A mineral resource for which: • tonnage, grade, and mineral content can be estimated with a high level of confidence, based on verified geological evidence, and • profitable extraction or production has been analytically demonstrated, or assumed with reasonable certainty.
electrical energy	Energy can be calculated as the average electrical power over a time period, multiplied by the length of the time period. Measured on a sent-out basis, it includes energy consumed by the consumer load, and distribution and transmission losses. In large electric power systems, electrical energy is measured in gigawatt hours (GWh) or 1,000 megawatt hours (MWh).
electrical power	Electrical power is a measure of the instantaneous rate at which electrical energy is consumed, generated or transmitted. In large electric power systems it is measured in megawatts (MW) or 1,000,000 watts.

Term	Definition
electricity demand	The electrical power requirement met by generating units. The Electricity Statement of Opportunities (ESOO) reports demand on a generator-terminal basis, which includes: • the electrical power consumed by the consumer load • distribution and transmission losses, and • power station transformer losses and auxiliary loads. The ESOO reports demand as half-hourly averages.
embedded generating unit	A generating unit connected within a distribution network and not having direct access to the transmission network.
embedded generator	A generator who owns, operates or controls an embedded generating unit.
energy	See 'electrical energy'.
Energy Adequacy Assessment Projection (EAAP)	A quarterly report, produced by AEMO, of projected energy availability for each region over a 24-month period for three different rainfall scenarios. The EAAP reports the impact of the projected energy availabilities on regional electrical supply reliability in terms of long-term unserved energy (USE).
energy limited	A generating unit that cannot operate at full capacity over the long term due to fuel or other energy source limitations. A typical example is a hydroelectric generating unit, the long-term output of which is limited by its water storage capacity.
estimated ultimate recovery (EUR)	A term applied to any discovered or undiscovered petroleum accumulations to define potentially recoverable quantities under defined technical and commercial conditions. This includes quantities already produced (total of recoverable resources).
ex-ante	Before the event.
exempted generator	A generator exempted from the requirement to register in accordance with clause 2.2.1 of the NER, and in accordance with the Australian Energy Market Operator's (AEMO) Generator Registration Guide.
FCAS constraint equation	A constraint equation that reflects the need to obtain sufficient frequency control ancillary services (FCAS). See also 'frequency control ancillary services (FCAS)'.
fault clearing control scheme	A protection system designed to isolate an electrical fault of a defined type within a particular area (referred to as a protection zone).
first-tier load	Electricity purchased at a connection point directly and in its entirety from the local retailer and which is classified as a first-tier load in accordance with Chapter 2 (of the NER).
flow path	Those elements of the electricity transmission networks used to transport significant amounts of electricity between generation centres and major load centres.
forced outage	An unplanned outage of an electricity transmission network element (transmission line, transformer, generator, reactive plant, etc).
franchise customer	A person who does not meet its local jurisdiction requirements to make it eligible to be registered by AEMO as a customer for a load.
frequency control ancillary services (FCAS)	Those ancillary services concerned with balancing, over short intervals (shorter than the dispatch interval), the power supplied by generating units and the power consumed by loads. This imbalance is managed by monitoring the power system frequency.
front-end engineering and design (FEED)	An engineering process commonly undertaken to determine the engineering parameters of a construction or development, in terms of engineering design, route selection, regulatory and financial viability assessments, and environmental and native title clearance processes.

Term	Definition
generating plant	In relation to a connection point, includes all equipment involved in generating electrical energy.
generating system	A system comprising one or more generating units that includes auxiliary or reactive plant that is located on the generator's side of the connection point.
generating unit	The actual generator of electricity and all the related equipment essential to its functioning as a single entity.
generation	The production of electrical power by converting another form of energy in a generating unit.
generation capacity	The amount (in megawatts (MW)) of electricity that a generating unit can produce under nominated conditions. The capacity of a generating unit may vary due to a range of factors. For example, the capacity of many thermal generating units is higher in winter than in summer.
generation centre	A geographically concentrated area containing a generating unit or generating units with significant combined generating capability.
generation expansion plan	A plan developed using a special algorithm that models the extent of new entry generation development based on certain economic assumptions.
generator	A person who engages in the activity of owning, controlling or operating a generating system that is connected to, or who otherwise supplies electricity to, a transmission or distribution system and who is registered by AEMO as a generator under Chapter 2 (of the NER) and, for the purposes of Chapter 5 (of the NER), the term includes a person who is required to, or intends to register in that capacity.
generator auxiliary load	Load used to run a power station, including supplies to operate a coal mine (otherwise known as 'used in station load').
generator-terminal basis	A measure of demand at the terminals of a generating unit. This measure covers the entire output of the generating unit, and includes (in megawatts (MW)): • consumer load • transmission and distribution losses • generating unit auxiliary load, and • generator transformer losses.
gen-tailer	A business with both generation and retail portfolios.
greenfield	Land (as a potential industrial site) not previously developed or polluted.
inductive reactance	The component of a circuit element's impedance that is due to the establishment of a magnetic field. Current through the inductive component is proportional to the integral of the voltage across that component. See also 'reactive power'.
inferred resources	A mineral resource for which tonnage, grade, and mineral content can be estimated with a low level of confidence, and that is inferred from geological evidence.
installed capacity	The generating capacity (in megawatts (MW)) of (for example): • a single generating unit, or • a number of generating units of a particular type or in a particular area, or • all of the generating units in a region.
interconnector	A transmission line or group of transmission lines that connects the transmission networks in adjacent regions.
interconnector flow	The quantity of electricity in MW being transmitted by an interconnector.
interconnector power transfer capability	The power transfer capability (in megawatts (MW)) of a transmission network connecting two regions to transfer electricity between those regions.

Term	Definition
intermediate generating system	A generating system that adjusts its output as demand for electricity fluctuates throughout the day. These systems are typically in-between base load and peaking generation in terms of efficiency, speed of start-up and shutdown, construction cost, cost of electricity, and capacity factor.
intermittent	A description of a generating unit whose output is not readily predictable, including, without limitation, solar generators, wave turbine generators, wind turbine generators and hydro-generators without any material storage capability.
initial reserves	Total discovered reserves at a given date, without taking into account the depletion of reserves due to production.
invoked constraint equation	A constraint equation that is active in central dispatch, and can influence the dispatch outcome.
jurisdictional planning body (JPB)	An entity nominated by the relevant Minister of the relevant participating jurisdiction as having transmission system planning responsibility (in that participating jurisdiction). The jurisdictional planning bodies are: • Queensland - Powerlink Queensland • New South Wales – TransGrid • Victoria – AEMO • South Australia – ElectraNet, and • Tasmania – Transend Networks.
Lack of Reserve (LOR) notice/Low Reserve Condition (LRC) notice	A notice to registered participants advising when reserves are projected to be or are below critical levels. See also ‘Lack of Reserve 1 (LOR1)’, ‘Lack of Reserve 2 (LOR2)’, ‘Lack of Reserve 3 (LOR3)’ and ‘low reserve condition (LRC)’.
Lack of Reserve 1 (LOR1)	When, for the nominated period, AEMO considers there are insufficient short-term capacity reserves available. This capacity must be sufficient to provide complete replacement of the contingency capacity reserve when a critical single credible contingency event occurs in the nominated period.
Lack of Reserve 2 (LOR2)	When AEMO considers that the occurrence of a critical single credible contingency event is likely to require involuntary load shedding.
Lack of Reserve 3 (LOR3)	When AEMO considers that customer load (other than ancillary services or contracted interruptible loads) would be, or is actually being, interrupted automatically or manually in order to maintain or restore the security of the power system.
Large-scale Renewable Energy Target (LRET)	See ‘national Renewable Energy Target scheme’.
liquid fuelled generation	Generation that utilises liquid fuel (usually in the form of distillate, kerosene or fuel oil) as its primary fuel source.
Liquefied Natural Gas	Natural gas that has been converted to liquid form for ease of storage or transport. The Melbourne LNG storage facility is located at Dandenong.
load	A connection point or defined set of connection points at which electrical power is delivered to a person or to another network or the amount of electrical power delivered at a defined instant at a connection point, or aggregated over a defined set of connection points.
load shedding	Reducing or disconnecting load from the power system.
local network service provider	Within a local area, a network service provider to which that geographical area has been allocated by the authority responsible for administering the jurisdictional electricity legislation in the relevant participating jurisdiction.

Term	Definition
local retailer	In relation to a local area, the customer who is: • a business unit or related body corporate of the relevant local network service provider, or • responsible under the laws of the relevant participating jurisdiction for the supply of electricity to franchise customers in that local area, or • if neither 1 or 2 is applicable, such other customer as AEMO may determine.
long-run marginal cost (LRMC)	A generator's long-run marginal cost (LRMC) describes the revenue required to exactly cover financing costs, and the fixed and variable operating and maintenance costs of the investment over the generating system's lifetime.
loss factor	A multiplier used to describe the electrical energy loss for electricity used or transmitted.
low reserve condition (LRC)	When the AEMO considers that a region's reserve margin (calculated under 10% probability of exceedence (POE) scheduled and semi-scheduled maximum demand (MD) conditions) for the period being assessed is below the minimum reserve level (MRL).
Mandatory Renewable Energy Target (MRET)	See 'national Renewable Energy Target scheme'.
marginal loss factor (MLF)	A multiplier used to describe the marginal electrical energy loss for electricity used or transmitted.
market	Any of the markets or exchanges described in the NER, for so long as the market or exchange is conducted by AEMO.
market ancillary services	The ancillary services required by AEMO as part of the spot market, which include the services listed in clause 3.11.2(a) of the NER. The prices of market ancillary services are established using the central dispatch process.
market customer (electricity)	A customer who has classified any of its loads as a market load and who is also registered by AEMO as a market customer under Chapter 2 (of the NER).
market generating unit	A generating unit whose sent-out generation is not purchased in its entirety by the local retailer or by a customer located at the same connection point and which has been classified as such in accordance with Chapter 2 (of the NER).
market generator	A generator who has classified at least one generating unit as a market generating unit in accordance with Chapter 2 (of the NER) and who is also registered by AEMO as a market generator under Chapter 2 (of the NER).
market load	A load that is settled through the spot market, and may also be classified as a scheduled load. Customers submit bids in relation to market loads to purchase electricity through the central dispatch process. They must be controllable according to dispatch instructions issued by AEMO.
market network service provider (MNSP)	A network service provider who has classified any of its network services as a market network service in accordance with Chapter 2 (of the NER) and who is also registered by AEMO as a market network service provider under Chapter 2 (of the NER).
market non-scheduled (MNS) generating unit	A generating unit that: • sells energy into the energy spot market, and • is not scheduled by AEMO as part of central dispatch, and • has been classified as an MNS generating unit in accordance with Chapter 2 of the NER.

Term	Definition
market scheduled (MS) generating unit	A generating unit that: • sells energy into the energy spot market • is scheduled by AEMO as part of central dispatch, and • has been classified as an MS generating unit in accordance with Chapter 2 of the NER.
market participant (electricity)	A person who is registered by AEMO as a market generator, market customer or market network service provider under Chapter 2 (of the NER).
market price cap (MPC)	A price cap on regional reference prices as described in clause 3.9.4 (of the NER).
maximum daily quantity	Maximum daily quantity of gas supply or demand.
maximum demand (MD)	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season, or year) either at a connection point, or simultaneously at a defined set of connection points.
Medium-term Projected Assessment of System Adequacy (Medium-term PASA or MT PASA)	The Projected Assessment of System Adequacy in respect of the period from the eighth day after the current trading day to 24 months after the current trading day in accordance with clause 3.7.2 (of the NER).
meter	A device that measures and records volumes and/or quantities of electricity or gas.
metering	The act of recording electricity and gas data (such as volume, peak, quality parameters etc) for the purpose of billing or monitoring quality of supply etc.
metering data	The data obtained from a metering installation, including energy data.
minimum access standard	In relation to a technical requirement of access, a standard of performance, identified in a schedule of Chapter 5 (of the NER) as a minimum access standard for that technical requirement, such that a plant that does not meet that standard will be denied access because of that technical requirement. (See also automatic access standard and negotiated access standard.)
minimum reserve level (MRL)	The reserve margin (calculated under 10% probability of exceedence (POE) scheduled maximum demand (MD) conditions) required in a region to meet the Reliability Standard.
National Electricity Law	The National Electricity Law (NEL) is a schedule to the National Electricity (South Australia) Act 1996, which is applied in other participating jurisdictions by application acts. The NEL sets out some of the key high-level elements of the electricity regulatory framework, such as the functions and powers of NEM institutions, including AEMO, the AEMC, and the AER.
National Electricity Market (NEM)	The wholesale exchange of electricity operated by AEMO under the NER.
National Electricity Objective (NEO)	To promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: • price, quality, safety, reliability and security of supply of electricity, and • the reliability, safety and security of the national electricity system. This is defined in Section 7 of the National Electricity Law (NEL).
National Electricity Market Dispatch Engine (NEMDE)	The software that calculates the optimum economic dispatch of the National Electricity Market (NEM) every five minutes, subject to a number of constraint equations that reflect additional physical power system requirements. The software co-optimises the outcome of the energy spot market and the frequency control ancillary services (FCAS) market.
National Electricity Rules (NER)	The National Electricity Rules (NER) describes the day-to-day operations of the NEM and the framework for network regulations. See also ‘National Electricity Law’.

Term	Definition
National Gas Law	The National Electricity Law and National Electricity Rules and the National Gas Law and National Gas Rules bring electricity and gas distribution under a national framework administered by the Australian Energy Regulator (AER).
National Gas Objective (NGO)	To promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.
National Gas Rules (NGR)	See National Gas Law.
national Renewable Energy Target scheme	The national Renewable Energy Target (RET) scheme, which commenced in January 2010, aims to meet a renewable energy target of 20% by 2020. Like its predecessor, the Mandatory Renewable Energy Target (MRET), the national RET scheme requires electricity retailers to source a proportion of their electricity from renewable sources developed after 1997. The national RET scheme is currently structured in two parts: • Small-scale Renewable Energy Scheme (SRES), which is a fixed price, unlimited-quantity scheme available only to small-scale technologies (such as solar water heating) and is being implemented via Small-scale Technology Certificates (STC), and • Large-scale Renewable Energy Target (LRET), which is being implemented via Large-scale Generation Certificates (LGC), and targets 41,000 GWh of renewable energy by 2020.
National Transmission Network Development Plan (NTNDP)	An annual report to be produced by AEMO that replaces the existing National Transmission Statement (NTS) from December 2010. Having a 20-year outlook, the NTNDP will identify transmission and generation development opportunities for a range of market development scenarios, consistent with addressing reliability needs and maximising net market benefits, while appropriately considering non-network options.
National Transmission Statement (NTS)	An AEMO report replacing the Annual National Transmission Statement (ANTS) for 2009 only. The National Transmission Network Development Plan (NTNDP) replaced the NTS in December 2010.
negotiated access standard	In relation to a technical requirement of access for a particular plant, an agreed standard of performance determined in accordance with clause 5.3.4A (of the NER) and identified as a negotiated access standard for that technical requirement in a connection agreement. See also ‘minimum access standard’ and ‘automatic access standard’.
net import limit	Net import limits are: • equal to the assumed net regional imports arising from the minimum reserve level (MRL) calculations • necessary to ensure consistency between the calculation of MRLs and the assessment of reserve margins (as MRLs need to be met without violating the net import limits), and • only used in the Medium-term Projected Assessment of System Adequacy (Medium-term PASA or MT PASA), Short-term Projected Assessment of System Adequacy (Short-term PASA or ST PASA), and the supply-demand outlook. The net import limits are not included in central dispatch and do not limit actual interconnector power flows.
net regional import	The total interconnector flow into a region minus the interconnector flow out of a region.
network	The apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) excluding any connection assets. In relation to a network service provider, a network owned, operated or controlled by that network service provider.

Term	Definition
network capability	The capability of the network or part of the network to transfer electricity from one location to another.
network congestion	When a transmission network cannot accommodate the dispatch of the least-cost combination of available generation to meet demand.
network control ancillary service	A service identified in clause 3.11.4(a) (of the NER) which provides AEMO with a capability to control the real or reactive power flow into or out of a transmission network in order to: • maintain the transmission network within its current, voltage or stability limits following a credible contingency event, or • enhance the value of spot market trading in conjunction with the central dispatch process.
network constraint equation	A constraint equation deriving from a network limit equation. Network constraint equations mathematically describe transmission network technical capabilities in a form suitable for consideration in the central dispatch process. See also 'constraint equation'.
network limit	Defines the power system's secure operating range. Network limits also take into account equipment/network element ratings. See also 'ratings'.
network limitation	Describes network limits that cause frequently binding network constraint equations, and can represent major sources of network congestion. See also 'network congestion'.
network limit equation	Describes the capability to transmit power through a particular portion of the network as a function of: • generating unit outputs • interconnector flows • transmission equipment ratings • demand at one or more connection points, and • equipment status or operating mode. The set of all network limit equations fully describes a network's capability. AEMO translates network limit equations into network constraint equations for use in the central dispatch process. See also 'constraint equation'.
network service	Transmission service or distribution service associated with the conveyance, and controlling the conveyance, of electricity through the network.
network service provider	A person who engages in the activity of owning, controlling or operating a transmission or distribution system and who is registered by AEMO as a network service provider under Chapter 2 (of the NER).
network support agreement (NSA)	An agreement between a network service provider and a market participant or any other person providing network support services to improve network capability by providing a non-network alternative to a network augmentation.
non-coincident peak day demand	A given customer's (or group of customers') gas demand peak day. This does not necessarily occur at the same time as the system demand peak day.
non-contestable augmentation	Electricity transmission network augmentations that are not considered to be economically or practically classified as contestable augmentations.
non-credible contingency	Any planned or forced outage for which the probability of occurrence is considered very low. For example, the coincident outages of many transmission lines and transformers, for different reasons, in different parts of the electricity transmission network.

Term	Definition
non-market ancillary services	Network control ancillary services (NCAS), reactive power ancillary services (RPAS) and system restart ancillary services (SRAS). These services are delivered under agreements entered into with AEMO following a call for offers made in accordance with clause 3.11 (of the NER).
non-market generating unit	A generating unit whose sent out generation is purchased in its entirety by the local retailer or by a customer located at the same connection point and which has been classified as such in accordance with Chapter 2 (of the NER).
non-market generator	A generator who has classified a generating unit as a non-market generating unit in accordance with Chapter 2 (of the NER).
non-market non-scheduled (NMNS) generating unit	A generating unit that: • sells its entire output directly to a local retailer or customer at the same connection point under a power purchase agreement (not through the spot market), and • is not scheduled by AEMO as part of central dispatch, and • has been classified as an NMNS generating unit in accordance with Chapter 2 (of the NER).
non-market scheduled (NMS) generating unit	A generating unit that: • sells its entire output directly to a local retailer or customer at the same connection point under a power purchase agreement (not through the spot market), and • is scheduled by AEMO as part of central dispatch, and • has been classified as an NMS generating unit in accordance with Chapter 2 (of the NER).
non-network option	An option intended to relieve a limitation without modifying or installing network elements. Typically, non-network options involve demand-side participation (DSP) (including post contingent load relief) and new generation on the load side of the limitation.
non-registered customer	A person who: • purchases electricity through a connection point with the national grid other than from the spot market, and • is eligible to be registered by AEMO as a customer and to classify the load described in (1) as a first-tier load or a second-tier load, but is not so registered.
non-scheduled generating system	A generating system comprising non-scheduled generating units.
non-scheduled generating unit	A generating unit that is not scheduled by AEMO as part of the central dispatch process, and which has been classified as such in accordance with Chapter 2 (of the NER).
non-scheduled generator	A generator in respect of which any generating unit is classified as a non-scheduled generating unit in accordance with Chapter 2 (of the NER).
normalised wind trace	Used in market stimulations to determine the maximum available wind farm generation capacity for each dispatch interval. Normalised wind traces were developed using: • wind speed data from the Australian Bureau of Meteorology to produce wind speed traces, and • wind farm turbine characteristics (power curves) to convert wind speed traces into wind generation output availability traces.
operating cost benefit	A benefit deriving from reduced fuel, operating and maintenance costs, indicating reduced operating costs.

Term	Definition
operational demand	That part of the electricity demand supplied by scheduled, semi-scheduled, and significant non-scheduled generating units. The significant non-scheduled generating units included in the definition of operational demand are: • Cullerin Range Wind Farm (New South Wales) • Capital Wind Farm (New South Wales) • Yambuk Wind Farm (Victoria) • Portland Wind Farm (Victoria) • Challicum Hills Wind Farm (Victoria) • Waubra Wind Farm (Victoria) • Mount Millar Wind Farm (South Australia) • Cathedral Rocks Wind Farm (South Australia) • Starfish Hill Wind Farm (South Australia) • Wattle Point Wind Farm (South Australia) • Canunda Wind Farm (South Australia) • Lake Bonney Wind Farm (South Australia), and • Woolnorth Wind Farm (Tasmania).
outage constraint equation	A constraint equation invoked when an outage has occurred due to maintenance or a contingency event. See also ‘system normal constraint equation’ and ‘invoked constraint equation’.
over voltage	A condition when the operating voltage of network components is above their nominated operation limit.
overload capacity	A measure of a generating unit’s ability to generate more electricity than its registered capacity for a given period of time.
own price elasticity	The proportional change in electrical energy consumption in response to a proportional change in retail electricity price.
participant	A person registered with AEMO in accordance with the NGR (Victorian gas industry).
peaking generating system	A generating system that typically runs only when demand (and spot market price) is high. These systems usually have lower efficiency, higher operating costs, and very fast start up and shutdown times compared with base load and intermediate systems.
petajoule	Petajoule (PJ), SI unit, 1 PJ equals 1×10^{15} Joules. Also PJ/yr or petajoules per year.
pipeline	A pipe or system of pipes for or incidental to the conveyance of gas and includes a part of such a pipe or system.
pipeline injections	The injection of gas into a pipeline.
pipeline throughput	The amount of gas that is transported through a pipeline.
planning criteria	Criteria intended to enable the jurisdictional planning bodies (JPBs) to discharge their obligations under the NER and relevant regional transmission planning standards. The JPBs must consider their planning criteria when assessing the need to increase network capability.
planned outage	A controlled outage of a transmission element for maintenance and/or construction purposes, or due to anticipated failure of primary or secondary equipment for which there is greater than 24 hours notice.
plant capacity	The maximum power output an item of electrical equipment is able to achieve for a given period.
possible reserves (3P reserves)	Estimated quantities which have a chance of being discovered under favourable circumstances.
post-contingent	The timeframe after a power system contingency occurs.
power	See ‘electrical power’.

Term	Definition
power station	In relation to a generator, a facility in which any of that generator's generating units are located.
power system	The National Electricity Market's (NEM) entire electricity infrastructure (including associated generation, transmission, and distribution networks) for the supply of electricity, operated as an integrated arrangement.
power system reliability	The ability of the power system to supply adequate power to satisfy customer demand, allowing for credible generation and transmission network contingencies.
power system security	The safe scheduling, operation, and control of the power system on a continuous basis in accordance with the principles set out in clause 4.2.6 (of the NER).
post-contingent	The timeframe after a power system contingency occurs.
pre-contingent	The timeframe before a power system contingency occurs.
pre-dispatch	Forecast of dispatch performed one day before the trading day on which dispatch is scheduled to occur.
present value (PV)	The value of a future cash flow expressed in today's dollars, and calculated using a particular discount rate. Present value calculations provide a means to meaningfully compare cash flows at different times.
price elasticity of demand	A measure of the proportional change in demand (for a commodity) in response to a proportional change in price.
prior outage conditions	A weakened electricity transmission network state where a transmission element is unavailable for service due to either a forced or planned outage.
probable reserves (2P reserves)	The estimated quantities of petroleum, which with a reasonable probability of being produced under existing economic and operating conditions.
probability of exceedence (POE) maximum demand	The probability, as a percentage, that a maximum demand (MD) level will be met or exceeded (for example, due to weather conditions) in a particular period of time. For example, for a 10% POE MD for any given season, there is a 10% probability that the corresponding 10% POE projected MD level will be met or exceeded. This means that 10% POE projected MD levels for a given season are expected to be met or exceeded, on average, 1 year in 10.
proposed project	All generation project proposals that have come to the Australian Energy Market Operator's (AEMO) attention and are not committed. Proposed projects are further classified as either advanced proposals or publicly announced proposals.
prospective resources	Quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations through future development projects.
proved reserves (1P reserves)	The estimated quantities of petroleum resources, which with a reasonable level of certainty are recoverable in future years from known reservoirs under existing economic and operating conditions.
publicly announced proposal	A proposed generation project that has come to the Australian Energy Market Operator's (AEMO) attention, but cannot be classified as an advanced proposal.
range of uncertainty	A range of estimated quantities potentially recoverable from an accumulation by a project.
ratings	Describes an aspect of a network element's operating parameters, including categories like current-carrying capability, maximum voltage rating, and maximum fault level interrupting and withstand capability. Network elements must always be operated within their ratings. Network elements may have ratings that depend on time duration (such as short-term current-carrying capacity).

Term	Definition
reactive energy	A measure, in varhour-(varh), of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of current flow across a connection point.
reactive power	The rate at which reactive energy is transferred. Reactive power, which is different to active power, is a necessary component of alternating current electricity. In large power systems it is measured in MVAr (1,000,000 volt-amperes reactive). It is predominantly consumed in the creation of magnetic fields in motors and transformers and produced by plant such as: • alternating current generators • capacitors, including the capacitive effect of parallel transmission wires, and • synchronous condensers. Management of reactive power is necessary to ensure network voltage levels remain within required limits, which is in turn essential for maintaining power system security and reliability.
regional reference node	The reference point (or designated reference node) for setting a region's spot price. The current regions and their reference nodes are: • Queensland - South Pine Substation 275 kV bus • New South Wales - Sydney West Substation 330 kV bus • Tasmania – George Town 220 kV bus • Victoria - Thomastown Terminal Station 66 kV bus, and • South Australia - Torrens Island Power Station 66 kV bus.
region	An area determined by the AEMC in accordance with Chapter 2A (of the NER), being an area served by a particular part of the transmission network containing one or more major load centres or generation centres or both.
registered capacity	In relation to a generating unit, the nominal megawatt (MW) capacity of the generating unit registered with AEMO.
registered participant	A person who is registered by AEMO in any one or more of the categories listed in clauses 2.2 to 2.7 (of the NER) (in the case of a person who is registered by AEMO as a trader, such a person is only a registered participant for the purposes referred to in clause 2.5A (of the NER)). However, as set out in clause 8.2.1(a1) (of the NER), for the purposes of some provisions of clause 8.2 (of the NER) only, AEMO and connection applicants who are not otherwise registered participants are also deemed to be registered participants.
regulated interconnector	An interconnector which is referred to in clause 11.8.2 (of the NER) and is subject to transmission service regulation and pricing arrangements in Chapter 6A (of the NER).
regulatory investment test for transmission (RIT-T)	The test developed and published by the AER in accordance with clause 5.6.5B, as in force from time to time, and includes amendments made in accordance with clause 5.6.5B.
Regulatory Test	The test promulgated by the Australian Energy Regulator (AER) to identify the most cost-effective option for supplying electricity to a particular part of the network. The test may also compare a range of alternative projects, including, but not limited to, new generation capacity, new or expanded interconnection capability, and transmission network augmentation within a region, or a combination of these. After 1 August 2010, projects are assessed under the RIT-T (subject to transitional arrangements).
reliability	The probability that plant, equipment, a system, or a device, will perform adequately for the period of time intended, under the operating conditions encountered. Also, the expression of a recognised degree of confidence in the certainty of an event or action occurring when expected.

Term	Definition
Reliability and Emergency Reserve Trader (RERT)	The actions taken by AEMO in accordance with clause 3.20 (of the NER) to ensure reliability of supply by negotiating and entering into contracts to secure the availability of reserves under reserve contracts. These actions may be taken when: • reserve margins are forecast to fall below minimum reserve levels (MRLs), and • a market response appears unlikely.
reliability benefit	A benefit deriving from improved customer reliability as measured by reduced unserved energy (USE). See also 'unserved energy (USE)'.
Reliability Panel	The panel established by the AEMC under section 38 of the National Electricity Law.
reliability of supply	The likelihood of having sufficient capacity (generation or demand-side participation (DSP)) to meet demand. See also 'electricity demand'.
Reliability Standard	The power system reliability benchmark set by the Reliability Panel. The maximum permissible unserved energy (USE), or the maximum allowable level of electricity at risk of not being supplied to consumers, due to insufficient generation, bulk transmission or demand-side participation (DSP) capacity, is 0.002% of the annual energy consumption for the associated region, or regions, per financial year.
remaining reserves	Reserves at a given date, taking into account the depletion of reserves due to production.
Renewable Energy Target (RET)	See 'national Renewable Energy Target scheme'.
reserve	See 'reserve margin'.
reserve deficit	The amount by which a region's reserve margin falls below its (specified) minimum reserve level (MRL).
reserve margin	The supply available to a region in excess of the scheduled and semi-scheduled demand. The supply available to a region includes generation capacity within the region, demand-side participation (DSP), and capacity available from other regions through interconnectors. A region's reserve margin is defined as the difference between the allocated installed capacity (plus any DSP), and the region's scheduled and semi-scheduled demand.
reserves	Quantities of resource anticipated to be commercially recoverable from known accumulations from a given date under defined conditions.
retailer	Those selling the bundled product of energy services to the customer.
routine augmentation	Transmission augmentations that do not meet the criterion for committed projects, but that are likely to proceed, being routine in nature.
runback	A controlled reduction in the flow of electricity in a given network element, usually in association with a specific event. Murraylink has a runback system that rapidly reduces its power flow in response to the operation of an associated protection system.
satisfactory operating state	Operation of the electricity transmission network such that all plant is operating at or below its rating (whether the continuous or, where applicable, short-term rating).
scale efficient network extensions (SENE)	A development model for connecting clusters of generation, proposed by the Australian Energy Market Commission (AEMC) as part of its review of energy market frameworks in light of climate change policies.

Term	Definition
scenario	A consistent set of assumptions used to develop forecasts of demand, transmission, and supply.
scheduled demand	That part of the electricity demand supplied by scheduled generating units. Scheduled demand is measured on a generator-terminal basis. For a region, the measure includes the output of scheduled generating units within the region plus net imports (imports into the region minus exports from the region).
scheduled energy	The electrical energy requirement supplied by scheduled generating units. Scheduled energy is measured on a sent-out basis. For a region, the measure includes the output of scheduled generating units within the region plus net imports (imports into the region minus exports from the region).
scheduled generating unit	A generating unit that: • has its output controlled through the central dispatch process, and • is classified as a scheduled generating unit in accordance with Chapter 2 of the NER.
scheduled generator	A generator in respect of which any generating unit is classified as a scheduled generating unit in accordance with Chapter 2 (of the NER).
scheduled load	A market load which has been classified by AEMO in accordance with Chapter 2 (of the NER) as a scheduled load at the market customer's request. Under Chapter 3 (of the NER), a market customer may submit dispatch bids in relation to scheduled loads. For the purposes of Chapter 3 (of the NER) and rule 4.9, two or more scheduled loads referred to in paragraph (a) that have been aggregated in accordance with clause 3.8.3 (of the NER).
scheduled network service	A network service which is classified as a scheduled network service in accordance with Chapter 2 (of the NER). For the purposes of Chapter 3 (of the NER) and rule 4.9, two or more scheduled network services referred to in paragraph (a) that have been aggregated in accordance with clause 3.8.3 (of the NER).
scheduling	The process of scheduling nominations and increment/decrement offers, which AEMO is required to carry out in accordance with the NGR, for the purpose of balancing gas flows in the transmission system and maintaining the security of the transmission system.
second-tier load	Electricity purchased at a connection point in its entirety other than directly from the local retailer or the spot market and which is classified as a second-tier load in accordance with Chapter 2 (of the NER).
secure operating state	Operation of the electricity transmission network such that should a credible contingency occur, the network will remain in a 'satisfactory' state. See also 'satisfactory operating state'.
semi-scheduled demand	That part of the electricity demand supplied by semi-scheduled generating units. Semi-scheduled demand is measured on a generator-terminal basis. For a region, the measure includes the output of semi-scheduled generating units within the region.
semi-scheduled energy	The electrical energy requirement supplied by semi-scheduled generating units. Semi-scheduled energy is measured on a sent-out basis. For a region, the measure includes the output of semi-scheduled generating units within the region.
semi-scheduled generating system	A generating system comprising semi-scheduled generating units.
semi-scheduled generating unit	A generating unit: • with intermittent output • with a total capacity of 30 megawatts (MW) or greater, and • that may have its output limited to prevent the violation of network constraint equations.

Term	Definition
semi-scheduled generator	A generator in respect of which any generating unit is classified as a semi-scheduled generating unit in accordance with Chapter 2 (of the NER).
sent-out basis	A measure of demand or energy (in megawatts (MW) and megawatt hours (MWh), respectively) at the connection point between the generating system and the network. This measure includes consumer load and transmission and distribution losses.
settlements residue	Any surplus or deficit of funds retained by AEMO upon completion of settlements to all market participants in respect of a trading interval.
settlements residue auction (SRA)	Auctions run by AEMO to sell the rights to the settlements residue associated with inter-regional transfers. Only certain classifications of participants may participate in the auctions. Participants may use the settlements residue for hedging and underwriting inter-regional trading in electricity.
short run marginal cost (SRMC)	The increase in costs for an incremental increase in output. This includes the additional cost of: • fuel required, and • non-fuel variable costs like maintenance, water, chemicals, ash disposal, etc.
Short-term Projected Assessment of System Adequacy (Short-term PASA or ST PASA)	The PASA in respect of the period from 2 days after the current trading day to the end of the 7th day after the current trading day inclusive in respect of each trading interval in that period.
significant non-scheduled generating unit	Refers to all: • market non-scheduled (MNS) generating units, and • non-market non-scheduled (NMNS) generating units and generating units exempted from registration (with an aggregate capacity greater than 1 MW), for which AEMO and the jurisdictional planning bodies (JPBs) have sufficient data to enable the development of energy and maximum demand (MD) projections.
Small-scale Renewable Energy Scheme (SRES)	See ‘national Renewable Energy Target scheme’.
Smart grids	Smart grids potentially create opportunities for consumers to change energy consumption at short notice, in response to a variety of signals including electricity price.
special participant	A system operator or a distribution system operator.
spot market	Wholesale trading in electricity is conducted as a spot market. The spot market: • enables the matching of supply and demand • is a set of rules and procedures to determine price and production levels, and • is managed by AEMO. See also ‘spot price’.
spot price	The price in a trading interval for one megawatt hour (MWh) of electricity at a regional reference node. Prices are calculated for each dispatch interval (five minutes) over the length of a trading interval (a 30-minute period). The six dispatch prices are averaged each half hour to determine the price for the trading interval.
Statement of Opportunities	The (gas or electricity) Statement of Opportunities published annually by AEMO.
sub-economic demonstrated resources	A mineral resource for which: • tonnage, grade and mineral content can be estimated with a high level of confidence, based on verified geological evidence, and • profitable extraction or production has not been analytically demonstrated, or assumed with reasonable certainty.
summer	Unless otherwise specified, refers to the period 1 November–31 March (for all regions except Tasmania), and 1 December–28 February (for Tasmania only).

Term	Definition
supervisory control and data acquisition (SCADA)	Equipment used to collect power system data. SCADA data: • may be transmitted to or from electrical substations, power stations, and control centres, and • is normally collected for a variety of power system quantities at rates of once every two to four seconds (depending on the quantities measured). The equipment can also be used to send or receive control signals for power system equipment and generating units. The data and control signals are used to manage the operation of the power system from control centres.
supply	The delivery of electricity.
system capacity	The maximum demand that can be met on a sustained basis over several days given a defined set of operating conditions. System capacity is a function of many factors and accordingly a set of conditions and assumptions must be understood in any system capacity assessment. These factors include: • load distribution across the system • hourly load profiles throughout the day at each delivery point • heating values and the specific gravity of injected gas at each injection point • initial linepack and final linepack and its distribution throughout the system • ground and ambient air temperatures • minimum and maximum operating pressure limits at critical points throughout the system, and • powers and efficiencies of compressor stations.
system normal constraint	A constraint that arises even when all electricity plant is available for service.
system normal	The condition where: • no network elements are under maintenance or forced outage, and • the network is operating in a normal configuration (according to day to day network operational practices).
supply-demand outlook	The future state of supply's ability to meet projected demand.
synchronous condensor mode	Operation of a synchronous machine to generate or absorb reactive power, enabling control of system voltage.
system normal constraint equation	Constraint equations used in central dispatch when: • all transmission elements are in service, or • the network is operating in its normal network configuration.
system restart ancillary services (SRAS)	The set of contracted restart services procured by AEMO to facilitate the supply of sufficient energy to enable the orderly restart of other (large) generating units.
Tasmanian Capacity Reserve Standard	The standard by which Tasmanian reserve adequacy was assessed prior to Tasmania's entry into the NEM. The standard was set by the Tasmanian Reliability and Network Planning Panel, and was specified as the greater of the level: • required to ensure that there was a reasonable probability that all single credible contingency events could be sustained without involuntary load shedding, and • calculated to achieve a reliability standard such that unserved energy in Tasmania would not exceed targets appropriate for Tasmania's transition into the NEM.
terajoule	Terajoule (TJ). An SI unit, 1 TJ equals $1x10^{12}$ Joules. Also TJ/d or terajoules per day.
thermal generation	Generation that relies on the combustion of a fuel source. Thermal generation in the National Electricity Market (NEM) typically relies on the combustion of either coal or natural gas.
trader	Anyone who wishes to participate in a settlements residue auction (SRA) and is not already registered with AEMO as a market customer or a generator must register as a trader.

Term	Definition
trading interval	A 30 minute period ending on the hour (EST) or on the half hour and, where identified by a time, means the 30 minute period ending at that time.
transmission losses	Electrical energy losses incurred in transporting electrical energy through a transmission system.
transmission network	A network within any participating jurisdiction operating at nominal voltages of 220 kV and above plus: any part of a network operating at nominal voltages between 66 kV and 220 kV that operates in parallel to and provides support to the higher voltage transmission network, any part of a network operating at nominal voltages between 66 kV and 220 kV that is not referred to in paragraph (a) but is deemed by the Australian Energy Regulator (AER) to be part of the transmission network.
transmission pipeline	A pipeline that is not a distribution pipeline.
transmission pipeline owner	A person who owns or holds under a lease a transmission pipeline which is being or is to be operated by AEMO.
transmission system (electricity)	A transmission network, together with the connection assets associated with the transmission network, which is connected to another transmission or distribution system.
transmission system (gas)	The transmission pipelines or system of transmission pipelines forming part of the 'gas transmission system' as defined under the Gas Industry Act.
tri-generation	A generation system that produces at least three different forms of energy from the primary energy source: hot water, chilled water, and power generation (electrical energy).
Unconstrained Intermittent Generation Forecast (UIGF)	A forecast produced by the Australian Energy Market Operator's (AEMO) Australian Wind Energy Forecasting System (AWEFS) for an intermittent generating unit, considering: • generating unit (turbine) availability • the availability of the energy required for the unit's energy conversion process (for example wind, solar, or tidal), and • assuming no network limitations. The UIGF applies as an upper dispatch limit for an intermittent generating unit.
under excitation limit	A control function performed by the excitation systems of synchronous machines in a power plant, usually to prevent unstable operation of a generating unit.
unrecoverable	The portion of discovered or undiscovered petroleum initially-in-place quantities, which is estimated as of a given date, deemed not recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur.
unserved energy (USE)	The amount of energy that cannot be supplied because there is insufficient generation capacity, demand-side participation (DSP), or network capability to meet demand. Under the provisions of the Reliability Standard, each region's annual USE can be no more than 0.002% of its annual energy consumption. Compliance is assessed by comparing the 10-year moving average annual USE for each region with the Reliability Standard. See also 'Reliability Standard'.
Value of Customer Reliability (VCR)	A measure of the cost of unserved energy used in Regulatory Test assessments for planned augmentations for the Victorian electricity transmission system. The VCR is determined through a customer survey approach that estimates direct end-user customer costs incurred from power interruptions at the sector and State levels.

Term	Definition
violated constraint equation	A constraint equation for which the network attributes for a particular dispatch solution do not satisfy the equation's requirement.
voltage instability	An inability to maintain voltage levels within a desired operating range. For example, in a 3-phase system, voltage instability can lead to all three phases dropping to unacceptable levels or even collapsing entirely.
voltage unbalance	A quality of supply problem in a 3-phase system, voltage unbalance occurs when the three phases are not equal in magnitude or equidistant (120 degrees) in phase, and can cause plant failures, typically through overheating.
winter	Unless otherwise specified, refers to the period 1 June–31 August (for all regions).

Company Names

The following table lists the full name and Australian Business Number (ABN) of companies that may be referred to in this document.

Company	Full Company Name	ABN/ACN
Access Economics	The Trustee for Access Economics Trust	82 113 621 361
Acciona Energy	Acciona Energy Oceania Pty Ltd	98 102 345 719
ACIL Tasman	ACIL Tasman Pty Ltd	68 102 652 148
AEMC	Australian Energy Market Commission	49 236 270 144
AEMO	Australian Energy Market Operator	92 072 010 327
AGL Energy	AGL Energy Limited	74 115 061 375
Alinta Energy	Alinta Energy (Australia) Pty Ltd	16 108 664 151
Aurora Energy Tamar Valley Power	Aurora Energy (Tamar Valley) Pty Ltd	29 123 391 613
Australian Academy of Technological Science and Engineering	Australian Academy of Technological Sciences and Engineering Limited	58 008 520 394
Australian National Low Emission Coal Research And Development	Australian National Low Emissions Coal Research And Development Ltd	64 135 762 533
Australian Petroleum Production and Exploration Association (APPEA)	Australian Petroleum Production & Exploration Association Limited	44 000 292 713
Australia Pipeline Industry Association (APIA)	Australia Pipeline Industry Association Limited	29 098 754 324
Babcock & Brown Power	Redbank Energy Limited	67 116 665 608
Babcock & Brown Wind Partners	Infigen Energy Limited	39 105 051 616
Carbon Market Economics (CME)	Carbon Market Economics Pty Ltd	23 128 476 415
Cathedral Rocks Wind Farm	Cathedral Rocks Wind Farm Pty Ltd	87 107 113 708
Clean Energy Council	Clean Energy Council Limited	84 127 102 443
Commonwealth Scientific and Industrial Research Organisation (CSIRO)	Commonwealth Scientific and Industrial Research Organisation	41 687 119 230
Country Energy	Essential Energy	37 428 185 226
CS Energy	C S Energy Limited	54 078 848 745

Company	Full Company Name	ABN/ACN
CSR	CSR Limited	90 000 001 276
CRA International	CRA International Pty Ltd	12 095 147 738
Delta Electricity	Delta Electricity Australia Pty Ltd	26 074 408 923
Diamond Energy	Diamond Energy Pty Ltd	97 107 516 334
Eastern Star	Eastern Star Gas Limited	29 094 269 780
Ecogen	Ecogen Energy Pty Ltd	86 086 589 611
EDL	Energy Developments Limited	84 053 410 263
ElectraNet	Electranet Pty Limited	41 094 482 416
Energy Australia	AusGrid	67 505 337 385
Energy Brix	Energy Brix Australia Corporation Pty Ltd	79 074 736 833
Energy Networks Association (ENA)	Energy Networks Association Limited	75 106 735 406
Energy Response	Energy Response Pty Ltd	49 104 710 278
Energy Retailers Association of Australia (ERAA)	Energy Retailers Association of Australia Limited	24 103 742 605
Energy Supply Association of Australia	Energy Supply Association of Australia Limited	98 052 416 083
Energy Users Association of Australia (EUAA)	Energy Users Association of Australia	83 814 086 707
Envirogen	Envirogen Pty Limited	95 088 169 135
Epuron	EPURON Pty Ltd	70 104 503 380
Eraring Energy	Eraring Energy	31 357 688 069
ERM Power	ERM Power Pty Limited	28 122 259 223
ESCOSA	The Essential Services Commission of South Australia	91 774 807 273
Eureka Funds Management	Eureka Funds Management Administration Pty Limited	62 107 346 903
Flinders Power	Flinders Operating Services Pty Ltd	36 094 130 837
Gunns	Gunns Limited	29 009 478 148
The GPT Group	GPT RE Limited	27 107 426 504
HRL	HRL Limited	89 061 930 756
Hydro Tasmania	Hydro-Electric Corporation	48 072 377 158
IES	Intelligent Energy Systems Pty Ltd	51 002 572 090
IMO	Independent Market Operator	95 221 850 093
Inifigen Energy	Infigen Energy Limited	39 105 051 616
Infratil Energy	Infratil Energy Australia Pty Ltd	87 115 291 042
International Power	International Power (Australia) Pty Ltd	59 092 560 793
Investec	Investec Bank (Australia) Limited	55 071 292 594
KEMA Consulting	KEMA Incorporated	61 074 914 579
KPMG	KPMG Australia (A Busuttil & P Murray)	51 194 660 183

Company	Full Company Name	ABN/ACN
LMS Generation	LMS Generation Pty Ltd	39 059 428 474
Loy Yang Marketing Management Company	Loy Yang Marketing Management Company Pty Limited	19 105 758 316
McLennan Magasanik Associates (MMA)	McLennan Magasanik Pearce Unit Trust	33 579 847 254
Macquarie Generation	Macquarie Generation	18 402 904 344
Marubeni Corporation	Marubeni Australia Power Services Pty Ltd	40 064 462 111
Millmerran	Millmerran Energy Trader Pty Ltd	23 084 923 973
Minerals Council of Australia	Minerals Council of Australia	21 191 309 229
National Generators Forum	National Generators Forum Limited	83 113 331 623
NIEIR	National Institute of Economic and Industry Research Pty Ltd	72 006 234 626
NP Power	N.P.Power Pty Ltd	82 094 423 006
Origin Energy	Origin Energy Electricity Limited	33 071 052 287
Pacific Hydro	Pacific Hydro Pty Ltd	31 057 279 508
Powerlink Queensland	Queensland Electricity Transmission Corporation Limiited	82 078 849 233
Progressive Green	Progressive Green Pty Ltd	27 130 175 343
QGC	QGC Pty Limited	11 089 642 553
Redbank Power	Redbank Project Pty Limited	34 075 222 561
Renewable Power Ventures	Renewable Power Ventures Pty Ltd	25 102 696 159
Rio Tinto	Rio Tinto Aluminium (Holdings) Limited	37 004 502 694
ROAM Consulting	Roam Consulting Pty Ltd	54 091 533 621
Roaring 40s	HT Wind Operations Pty Ltd	63 111 996 313
Rocky Point Green Power	Rocky Point Power Project Pty Ltd	21 117 462 889
Santos	Santos Ltd	80 007 550 923
Solar Systems	Solar Systems Pty Ltd (A.C.N 090 609 868 Pty Ltd)	43 090 609 868
Snowy Hydro	Snowy Hydro Limited	17 090 574 431
Southern Hydro	AGL Southern Hydro Pty Limited	89 088 976 327
SP AusNet	SP Australia Networks (Transmission) Ltd	48 116 124 362
Stanwell Corporation	Stanwell Corporation Limited	37 078 848 674
Strike Oil	Strike Energy Limited	59 078 012 745
Synergen	Synergen Power Pty Limited	66 092 560 819
Tarong Energy	Tarong Energy Corporation Limited	52 078 848 736
TME	TME Australia Pty Ltd	71 094 361 850
Transend Networks	Transend Networks Pty Ltd	57 082 586 892
Transfield Services	RATCH – Australia Corporation Limited	31 106 617 332
TransGrid	TransGrid	19 622 755 774

Company	Full Company Name	ABN/ACN
TRUenergy	Truenergy Pty Ltd	99 086 014 968
TrustPower	TrustPower Australia Holdings Pty Ltd	15 101 038 331
Union Fenosa	Union Fenosa Wind Australia Pty Ltd	74 130 542 031
Veolia Environmental Services	Veolia Environmental Services (Australia) Pty Ltd	20 051 316 584
Vic Power	State Electricity Commission (VIC)	58 155 836 293
West Wind	WestWind Energy Pty Ltd	94 109 132 201
Wind Farm Development	Wind Farm Developments Pty Ltd	87 100 010 348
Windlab Systems	Windlab Systems Pty Ltd	26 104 461 958
Wind Power Pty Ltd	Wind Power Pty Ltd	68 117 035 766
Wind Prospect	Wind Prospect Pty Ltd	22 091 885 924