NATIONAL ELECTRICITY FORECASTING REPORT

For the National Electricity Market (NEM)

2012

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

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FOREWORD

This is the first edition of AEMO's National Electricity Forecasting Report (NEFR), which represents the first time AEMO has developed independent electricity demand forecasts on a consistent basis for the five National Electricity Market (NEM) regions, namely New South Wales (including the Australian Capital Territory), Queensland, South Australia, Tasmania, and Victoria.

National Electricity Forecasting represents a package of information papers and reports that document the input data, assumptions, and methodology used to develop a set of annual energy and maximum demand forecasts for the NEM, ensuring an open and transparent process. This will then allow AEMO to engage and work collaboratively with stakeholders to ensure continued efficiency in terms of NEM operations.

In the past, AEMO has published demand forecasts via a series of AEMO planning publications, namely the Electricity Statement of Opportunities (ESOO), the Victorian Annual Planning Report (VAPR), and the South Australian Supply and Demand Outlook (SASDO).

From 2012, the NEFR will be the only AEMO publication presenting electricity demand forecasts for the NEM.

Robust independent forecasting is needed to assist AEMO with planning efficient future investment in electricity infrastructure to service the long-term needs of energy consumers. These forecasts are used for both operational purposes, including the calculation of marginal loss factors, and as a key input into AEMO's national transmission planning role.

Significant factors currently influencing changes in demand involve the penetration of rooftop photovoltaic systems, changing consumption patterns in the industrial sector (particularly in mining and manufacturing), consumer responses to rising electricity prices and energy efficiency initiatives, and changes in domestic and international economics.

In the second half of 2012, AEMO will be holding regional forums that will promote further dialogue with stakeholders, with an aim to discuss the forecasts and assumptions related to National Electricity Forecasting. This will also provide an opportunity for stakeholders to be involved in discussions about the future direction of NEM forecasting.

I look forward to working more closely with our stakeholders to ensure this forecasting process is a success.

M. Zema

Matt Zema

Managing Director and Chief Executive Officer

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EXECUTIVE SUMMARY

Annual energy and maximum demand forecasts are significantly lower than those contained in the 2011 ESOO, signalling an expected delay for new generation and network investment.

To benefit the long-term needs of energy consumers, robust independent forecasting of electricity supply and consumption is needed to assist with planning future efficient investment.

For the first time AEMO has developed an independent set of electricity forecasts for each region of the National Electricity Market (NEM) to capture and assess the notable changes taking place.

AEMO will be using the National Electricity Forecasting Report as a basis for further collaboration with our stakeholders to maintain the quality and value of this work.

Key observations for the 2012 National Electricity Forecasts detailed in this report are as follows:

- Across the NEM, annual energy for 2011-12 is projected to be 2.4 per cent lower than 2010-11 and 5.7 per cent lower than forecast in the 2011 ESOO under a “medium” economic growth scenario.
- Forecast annual energy for 2012-13 is projected to remain flat (0.0% growth), which represents an 8.8 per cent reduction from the 2011 ESOO forecast.
- Average growth in annual energy for the 10-year period is now forecast to be 1.7 per cent, down from the 2.3 per cent forecast in the 2011 ESOO.
- Growth in annual energy consumption is strongly linked to large industrial projects in Queensland, most notably coal seam gas developments.
- Maximum demand forecasts across the five regions are much lower than in previous years, but are expected to continue to grow into the future.

The main factors influencing these changes are as follows:

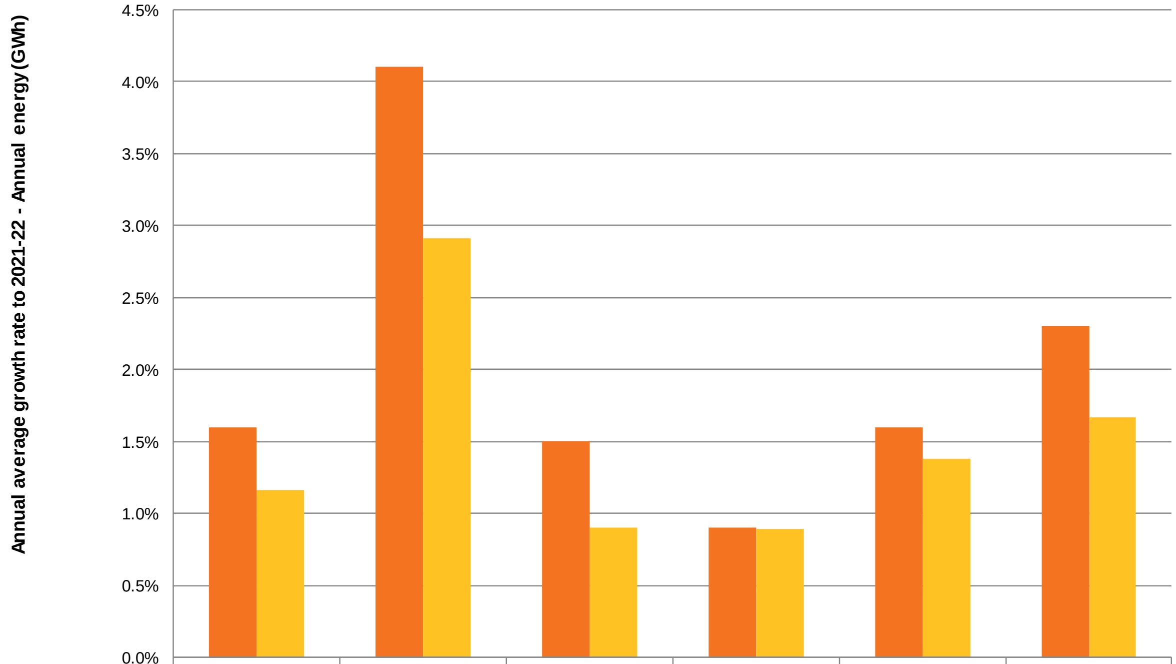
- Changes in the economic outlook. Reduced energy forecasts are consistent with a moderation in gross domestic product (GDP), especially in the short term.
- Reduced manufacturing consumption in response to the high Australian dollar. An expected increase in cheaper imports is anticipated to impact domestic manufacturing growth.
- Significant penetration of rooftop PV systems (South Australia has the highest penetration of rooftop PV of all the NEM states). The impact of rooftop PV installations is expected to partially offset the need for increased electricity generation. By 2021-22, this is forecast to increase to 7,558 GWh or 3.4% of annual energy.
- Consumer response (commercial and residential) to rising electricity costs and energy efficiency measures.

Future implications

Structural change in the Australian economy – acceleration in the mining sector in the northern states together with a decline in manufacturing in Victoria, South Australia and Tasmania – is having disparate impacts across the NEM states, particularly in the wake of the global financial crisis.

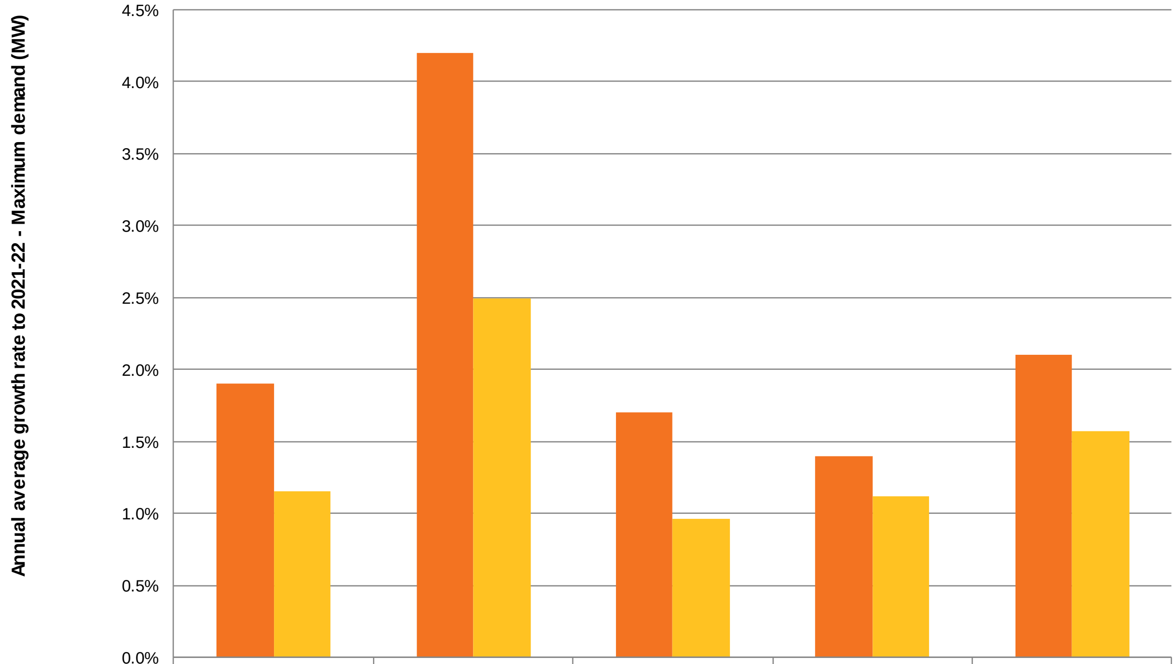
Across the NEM, lower than forecast annual energy for 2011-12 under a “medium” economic growth scenario points to a likely delay in the need for new generation investment including the potential for a reduction in significant large-scale investment.

Figure 1 — Revised annual energy growth rates



	NSW	QLD	SA	TAS	VIC	NEM
2011 ESOO	1.6%	4.1%	1.5%	0.9%	1.6%	2.3%
2012 NEFR	1.2%	2.9%	0.9%	0.9%	1.4%	1.7%

Figure 2 — Revised maximum demand growth rates



	NSW	QLD	SA	TAS	VIC
2011 ESOO	1.9%	4.2%	1.7%	1.4%	2.1%
2012 NEFR	1.2%	2.5%	1.0%	1.1%	1.6%

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CHAPTER 1 - INTRODUCTION

1.1 National Electricity Forecasting

AEMO has changed the way it develops and publishes electricity demand forecasts for the electricity industry, by developing independent forecasts for each region in the National Electricity Market (NEM).

Electricity demand forecasts are used for operational purposes, for the calculation of marginal loss factors, and as a key input into AEMO's national transmission planning role. This requires a close understanding of how the forecasts are developed to ensure forecasting processes and assumptions are consistently applied and fit for purpose. AEMO is ideally positioned to undertake this task and lead collaboration with the industry to ensure representative and reliable forecasts are consistently produced for each region.

Previously, AEMO developed demand forecasts for South Australia and Victoria, while the regional transmission network service providers (TNSPs) developed forecasts for Queensland, New South Wales (including the Australian Capital Territory), and Tasmania. These forecasts were subsequently published via a series of AEMO publications including the Electricity Statement of Opportunities (ESOO), the Victorian Annual Planning Report (VAPR), and the South Australian Supply and Demand Outlook (SASDO).

National electricity forecasting

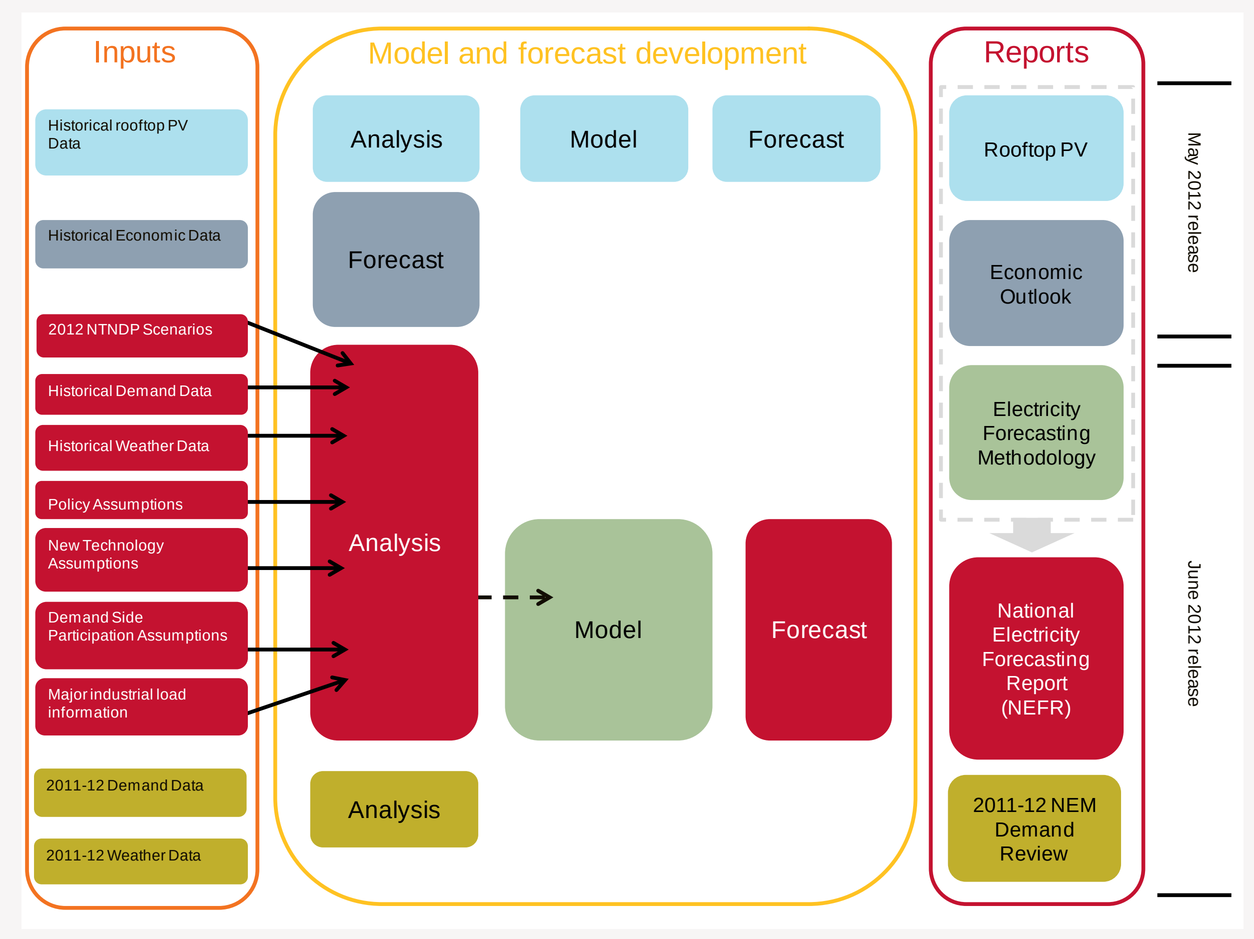
To facilitate greater forecasting transparency and stimulate discussion with the electricity industry, AEMO is now publishing the electricity demand forecasts via a series of separate information papers and reports:

- **Economic Outlook Information Paper** is AEMO's assessment of the work undertaken by the National Institute of Economic and Industry Research (NIEIR), published in May 2012.
- **Rooftop PV Information Paper** quantifies the impact of rooftop photovoltaic (PV) systems on the electricity market, published in May 2012.
- **2011–12 NEM Demand Review Information Paper** reviews 2011–12 NEM demand.
- **Forecasting Methodology Information Paper** describes the modelling process underpinning the demand forecast development.
- **2012 National Electricity Forecasting Report (NEFR)** presents the electricity demand forecasts for the five NEM regions.

Figure 1-1 illustrates the inputs, the modelling and forecast development processes, and the subsequent reports underpinning AEMO's new approach to national electricity forecasting.

This is first time AEMO has developed forecasts for the NEM, so more work still needs to be done, and AEMO will continue to improve the underpinning data, modelling, and interpretation, as well as engaging with industry on an ongoing basis to ensure an open and transparent process.

Figure 1-1 — AEMO's national electricity forecasting



1.2 The NEFR and AEMO's other planning publications

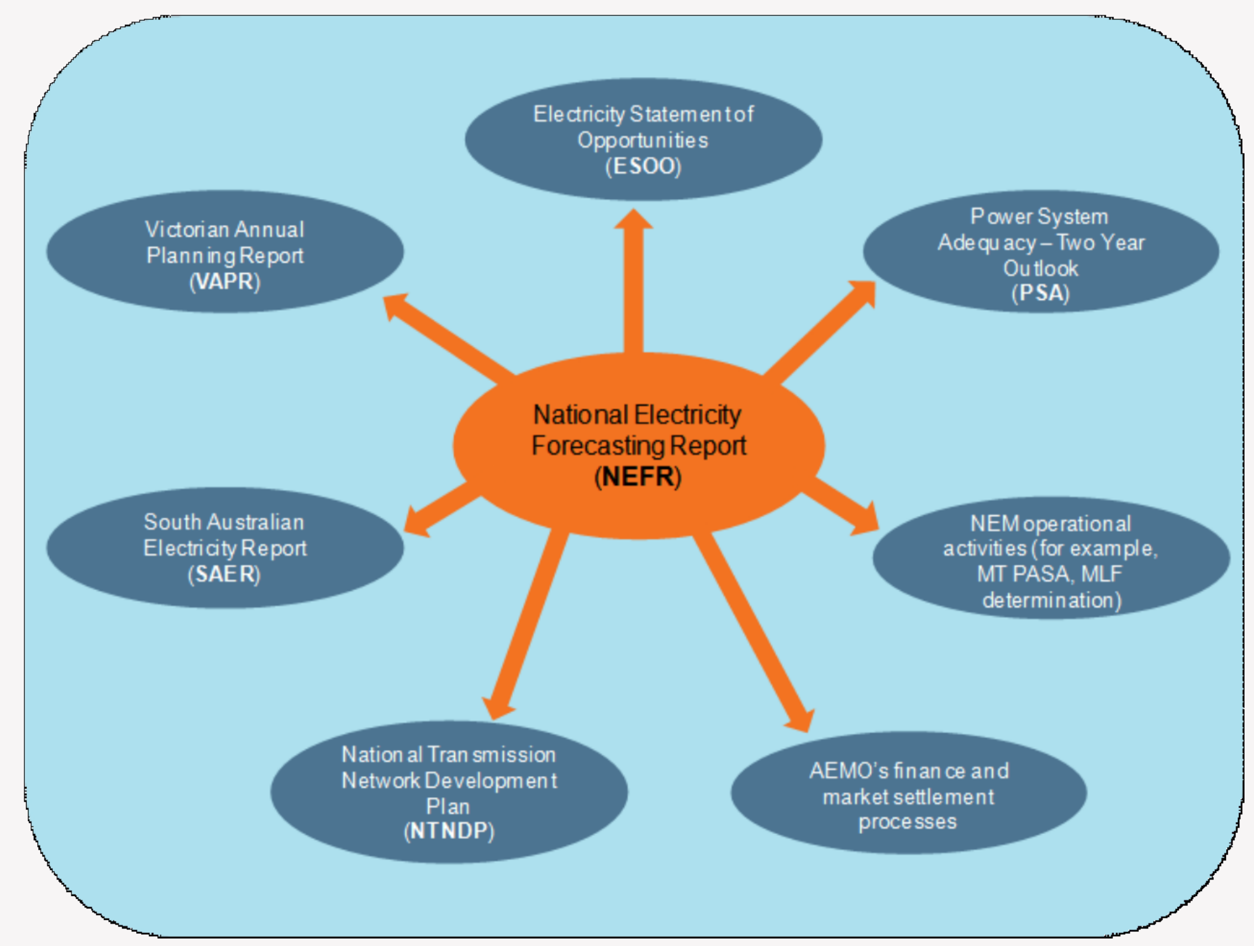
The NEFR is one of a collection of related annual planning publications that together present comprehensive information about energy supply, demand, investment, and network planning:

- South Australian Electricity Report (SAER).[1]
- Victorian Annual Planning Report (VAPR).
- Power System Adequacy – Two Year Outlook (PSA).
- Gas Statement of Opportunities (GSOO).
- National Transmission Network Development Plan (NTNDP).

Figure 1-2 illustrates the information interactions between these documents, and the annual planning reviews provided by the jurisdictional planning bodies (JPBs) (including AEMO in Victoria).

[1] Formerly known as the South Australian Supply and Demand Outlook (SASDO).

Figure 1-2 — Forecasts as inputs into AEMO publications and processes



1.3 Content and structure of the NEFR

The NEFR presents annual energy and maximum demand forecasts for each region, with key results presented for three main scenarios:

- Scenario 2, Fast World Recovery, is equivalent to a high economic growth scenario.
- Scenario 3, Planning, is equivalent to a medium economic growth scenario and is the base case scenario.
- Scenario 6, Slow Growth, is equivalent to a low economic growth scenario.

The NEFR printed document

The executive summary provides an overview of the key findings in relation to the annual energy and maximum demand projections for each NEM region.

Chapter 1, Introduction, provides background information about National Electricity Forecasting and outlines the key bodies responsible for developing forecasts in the 2011 ESOO and the 2012 NEFR.

Chapter 2, Definitions, process and methodology, provides a definition of demand, a high level overview of the forecasting methodology used to develop the forecasts, construction and mapping of scenarios, and changes in annual energy and maximum demand forecasts since the 2011 ESOO.

Chapter 3, NEM-wide forecasts, provides annual energy and small non-scheduled generation forecasts for the NEM.

Chapter 4, New South Wales (including ACT) forecasts, provides annual energy, summer and winter maximum demand, and small non-scheduled generation forecasts for New South Wales.

Chapter 5, Queensland forecasts, provides annual energy, summer and winter maximum demand, and small non-scheduled generation forecasts for Queensland.

Chapter 6, South Australia forecasts, provides annual energy, summer and winter maximum demand, and small non-scheduled generation forecasts for South Australia.

Chapter 7, Tasmania forecasts, provides annual energy, summer and winter maximum demand, and small non-scheduled generation forecasts for Tasmania.

Chapter 8, Victoria forecasts, provides annual energy, summer and winter maximum demand, and small non-scheduled generation forecasts for Victoria.

Appendix A, Regional model equations for non-large industrial consumption, presents the AEMO models for non-large industrial consumption for each NEM region.

Appendix B, Energy efficiency, analyses and forecasts the impact of a range of energy efficiency and greenhouse gas abatement measures on future electricity consumption and maximum demand for the regions and the NEM.

Appendix C, Small non-scheduled generation, lists generating systems by region that have been included in native and operational demand definitions. Specific information about each generating system has been included for installed capacity (MW), plant type, fuel type, and dispatch type.

Appendix D, Demand-side participation, presents the demand-side participation survey and forecasts for 2012.

NEFR electronic information

In addition to an electronic copy of the printed material, NEFR supplementary information is available from the AEMO website[2], and includes the following information:

- Historical actual data and input assumptions.
- Annual energy forecasts for six scenarios over the 20-year outlook period-year outlook period from 2012–13 to 2031–32. Forecasts are provided for the regions and NEM. Components of these forecasts are also provided, including forecasts for the mass market, transmission losses, auxiliary loads, large industrial loads, rooftop PV and energy efficiency.
- Summer and winter maximum demand forecasts for six scenarios and over the 20-year outlook period from 2012–13 to 2031–32. Forecasts are provided for 10%, 50% and 90% probability of exceedence (POE) for the NEM regions. Components of these forecasts are also provided, including forecasts for mass market, transmission losses, auxiliary loads, large industrial loads, rooftop PV and energy efficiency.

[2] AEMO, available http://www.aemo.com.au/en/Electricity/Forecasting. Viewed June 2012.

CHAPTER 2 - DEFINITIONS, PROCESS AND METHODOLOGY

2.1 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 2011.

Other information relevant to this report can be found at the following references:

- For information about the economic growth forecasts used to develop the projections, see the Economic Outlook Information Paper.[1]
- For information about the rooftop photovoltaic (PV) forecasts used to develop the projections, see the Rooftop PV Information Paper. [2]
- For information about the energy efficiency forecasts used to develop the projections, see Appendix B.
- For a list of the small non-scheduled generating units used to develop the regional energy and maximum demand projections, see Appendix C.

2.1.1 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 maximum demand projections.

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

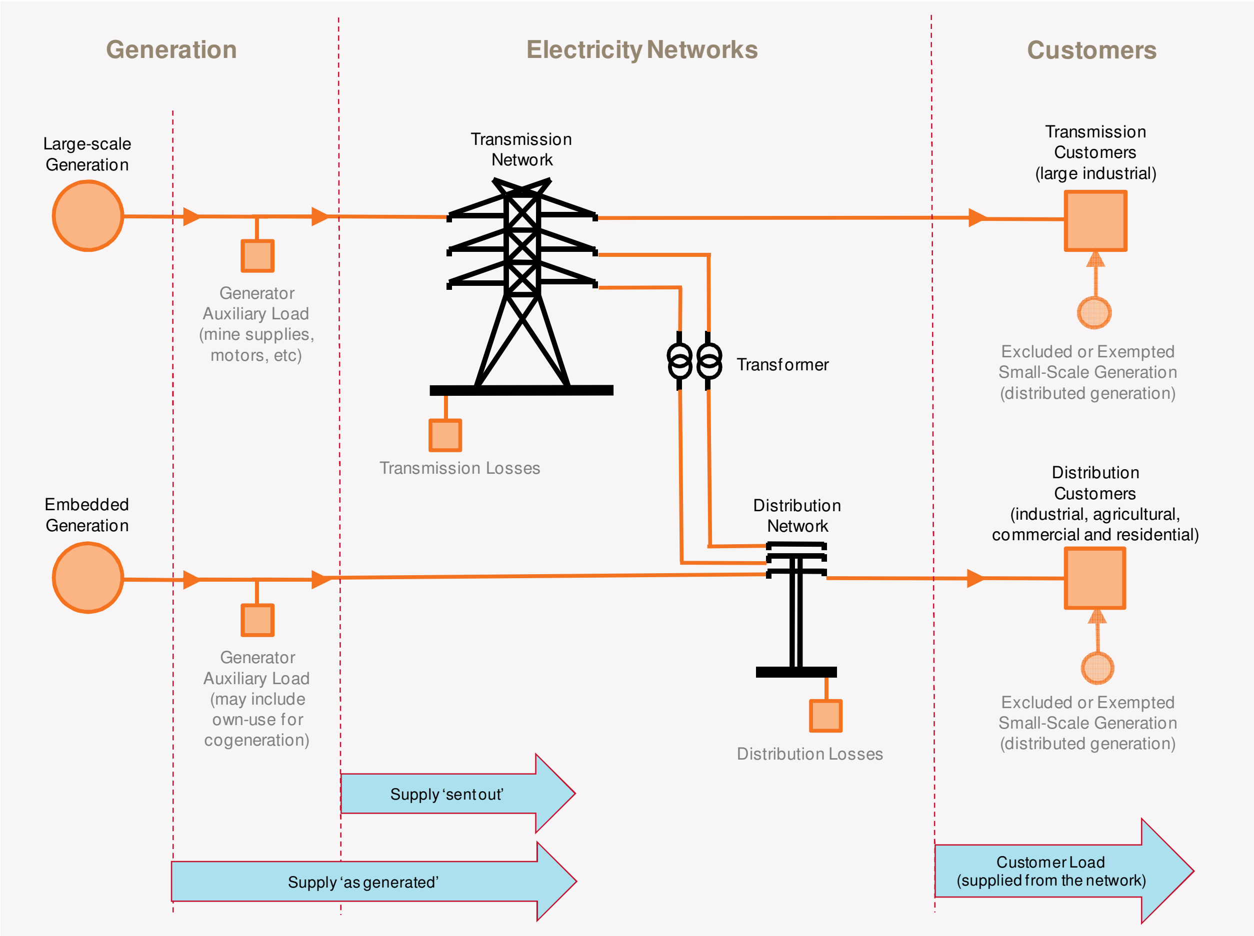
Electricity demand is measured by metering supply to the network rather than consumption. The benefit of measuring demand this way is that it includes electricity used by customers, energy lost transporting the electricity (network losses), and the energy used to generate the electricity (auxiliary loads).

Figure 2-1 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.

[1] AEMO, available http://www.aemo.com.au/en/Electricity/Forecasting. Viewed June 2012.

[2] See note 1.

Figure 2-1 — 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 maximum demand

The ESOO energy and maximum demand 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.
- Maximum demand is presented on an as-generated basis. This means that the maximum demand 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 2-1 — shows a high-level representation of the three basic types of generation connected to the electricity network:

- Large-scale generation includes any generating system of 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 of 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 PV, 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.
- 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 embedded generation

Figure 2-1 — shows the role that small-scale embedded generation plays in the network. Attaching to both transmission and distribution customers, small-scale embedded generation reduces (or offsets) the amount of electricity that needs to be supplied by large-scale generation.

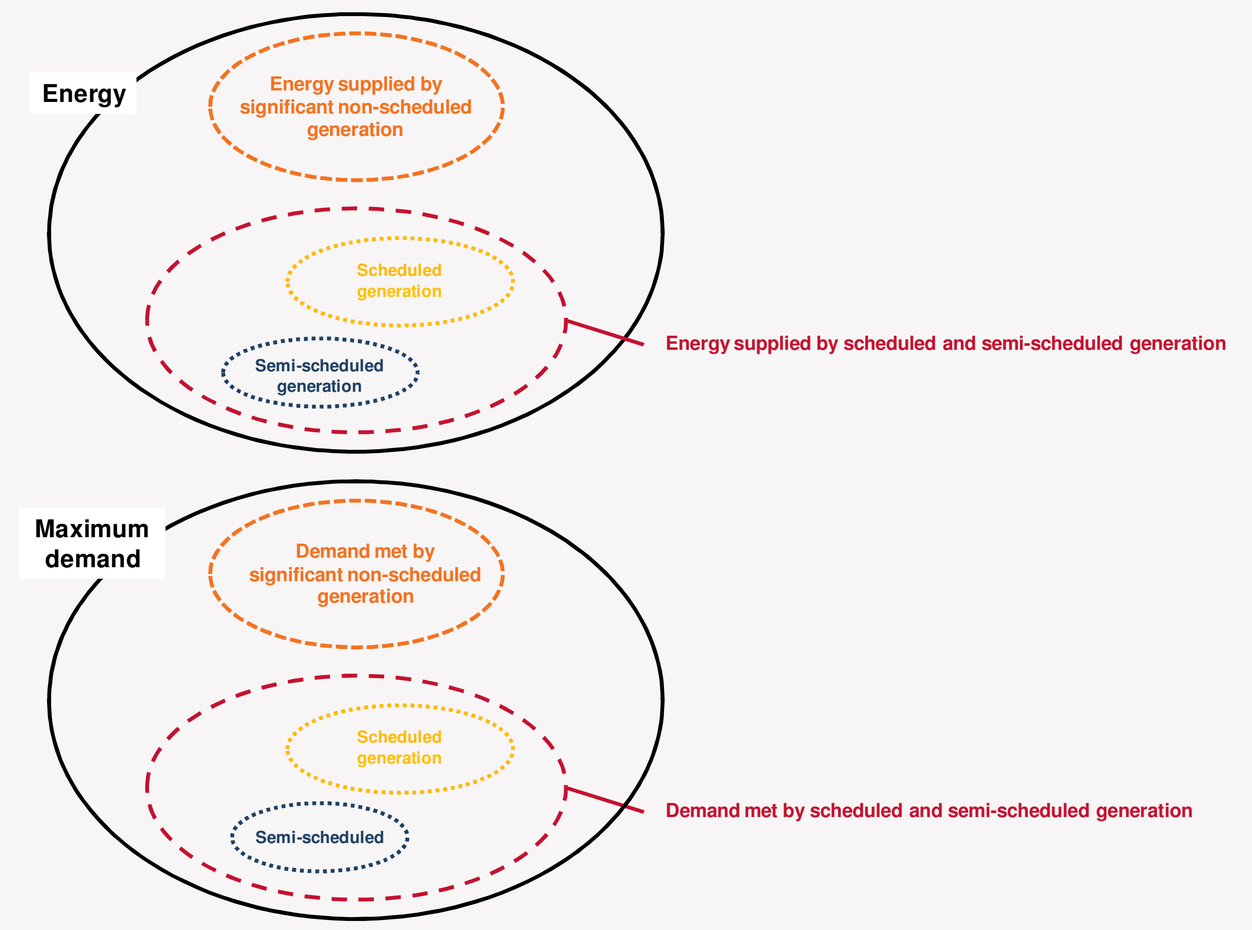
The projections do, however, indirectly account for this type of generation. For example, a large increase in household rooftop PV is reflected in lower projected growth. Similarly, energy efficiency and load control initiatives act to reduce the demand at customer locations. The projections reflect 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), and the growing use of 'smart' meters may improve the ability to gauge this level of consumption.

2.1.2 The components of energy and maximum demand in NEM forecasting

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

Figure 2-2 — 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 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 maximum demand projections account for the as-generated demand supplied from scheduled, semi-scheduled, and significant non-scheduled and exempt generation. Calculating the maximum demand supplied by generation controlled through the NEM dispatch process requires subtracting the maximum demand 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 it has 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 Appendix D).

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

Defining the probability of exceedence

A probability of exceedence (POE) refers to the likelihood that an maximum demand 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 maximum demand (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:

- A 10% POE MD projection is expected to be exceeded, on average, 1 year in 10.
- A 50% POE MD projection is expected to be exceeded, on average, 5 years in 10 (or 1 year in 2).
- A 90% POE MD projection is expected to be exceeded, on average, 9 years in 10.

2.2 Process and methodology

This section provides a description of the process and methodology used to develop the energy and maximum demand forecasts.

The energy and maximum demand forecasts presented do not include an assumed level of demand-side participation (DSP). Forecast levels of DSP, at times of very high NEM wholesale spot price are included in Appendix D.

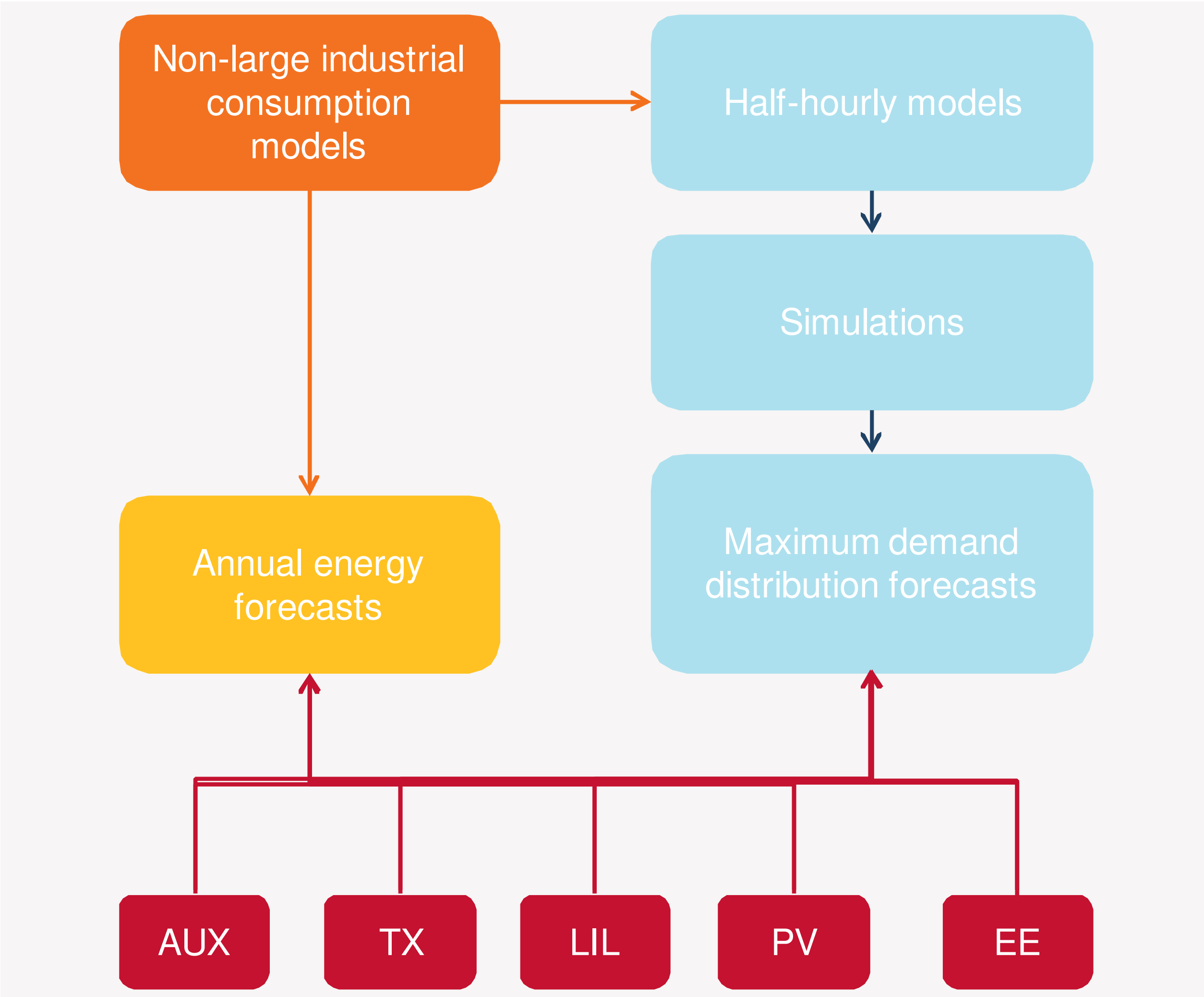
2.2.1 Overview of the AEMO forecasting process

This section provides a brief overview of the consistent approach used by AEMO to develop the annual energy and maximum demand forecasts for the NEM regions. For a more detailed description of the AEMO modelling process, with a detailed example, see the Forecasting Methodology Information Paper.[3]

Energy and maximum demand forecasts are interconnected, as the energy forms an average level of demand around which the half-hourly variations are modelled. Figure 2-3 shows an overview of the forecasting process.

[3] See note 1.

Figure 2-3 — Overview of forecasting process



The forecasting process comprises modelling and forecasting each of the components on the right hand side of the following equation for each NEM region:

$$forecast = AUX + TX + LIL - PV + NLIC - EE$$

Annual energy and maximum demand forecasts have been calculated based on a combination of components:

- **Large industrial loads (LIL)**. Large industrial loads are generally transmission-connected customers with electricity consumption that varies principally because of major investment or decommissioning decisions and is not weather-sensitive. AEMO developed projections of future LIL using a combination of transmission network service provider (TNSP) information and public announcements in the shorter term, and assumptions based on long-term trends in the longer term.
- **Power station auxiliaries (AUX)**. AEMO prepared estimates of future power station auxiliary consumption based on known historical measures and assumptions about future power station operations.
- **Transmission losses (TX)**. AEMO prepared estimates of future power station transmission losses based on known historical measures and assumptions about future power station operations.

- **Rooftop photovoltaic generation (PV)**. Data for installation and self-generation from rooftop PV was collected with the assistance of distribution network service providers (DNSPs) in each region. AEMO developed the forecasts based on assumptions about future installed capacity and generation models that project historical sunlight exposure. For information about the collection of historical rooftop PV data and forecast development, see the Rooftop PV Information Paper.[4]
- **Energy efficiency policies and measures (EE)**. The overall energy efficiency impact of recent initiatives was assessed by AEMO and an average allowance was developed for each region for each future year, in terms of replacement generation. For more information about specific EE allowances, see Appendix B.
- **Non-large industrial consumption (NLIC)**. This was generally modelled by AEMO as a function of regional income, energy prices and weather.

Mass market (energy) forecasts

In the 2012 NEFR, forecasts for the mass market are defined as:

$$mass\ market\ demand\ forecast = NLIC - PV - EE$$

For each NEM region, a separate econometric model was developed for the non-large industrial consumption component. This component represents the underlying demand for electricity as closely as is practically possible, which can be modelled using economic drivers.

Final regional model equations are provided in Appendix A. Forecasts of PV and EE have then been subtracted to obtain forecasts for the mass market.

Maximum demand forecasts

Regional summer and winter maximum demand forecasts are based on modelling undertaken by Monash University (Department of Econometrics and Business Statistics). For more information, see the Forecasting Methodology Information Paper.[5]

2.2.2 NTNDP scenarios

Equivalent to the scenarios for the 2012 National Transmission Network Development Plan (NTNDP) and 2012 Gas Statement of Opportunities (GSOO), the regional forecasts were developed on the basis of six scenarios[6]:

- **Scenario 1: Fast Rate of Change**. With higher economic growth, a carbon dioxide equivalent (CO2-e) emissions reduction target of 25% by 2020 and 80% by 2050, and a strong rate of new technology development, this scenario includes currently legislated carbon policies based on the Australian Treasury's high scenario.[7]
- **Scenario 2: Fast World Recovery**. With higher economic growth, a CO2-e emissions reduction target of 5% by 2020 and 80% by 2050, and a moderate rate of new technology development, this scenario is similar to the planning scenario, but with increased economic growth, and the inclusion of currently legislated carbon policies based on the Australian Treasury's core scenario.[8]
- **Scenario 3: Planning**. Based on AEMO's best estimate of the future direction of major drivers, and designed as a central growth scenario, this scenario includes any policy or other changes that can be predicted with reasonable certainty. With predicted economic growth, a CO2-e emissions reduction target of 5% by 2020 and 80% by 2050, and a moderate rate of new technology development, this also scenario includes currently legislated carbon policies based on the Treasury core scenario.[9]

[4] See note 1.
[5] See note 1.
[6] AEMO, available http://www.aemo.com.au/planning/2418-0005.pdf. Viewed June 2012.
[7] The Australian Government's Treasury and the Department of Climate Change and Energy Efficiency modelled the potential economic impacts of reducing emissions over the medium and long term proposed in the 'Strong Growth, Low Pollution, Modelling a Carbon Price' Report, released on 10 July 2011, available http://archive.treasury.gov.au/carbonpricemodelling/content/default.asp. Viewed May 2012.
[8] See note 7.
[9] See note 7.

- **Scenario 4: Decentralised World**. With predicted economic growth, a CO2-e emissions reduction target of 5% by 2020 and 80% by 2050, and a moderate rate of new technology development, this scenario includes currently legislated carbon policies based on the Treasury core scenario.[10] It is similar to the planning scenario, but with an increased uptake of localised generation and energy efficiency measures.
- **Scenario 5: Slow Rate of Change.** With lower economic growth, a CO2-e emissions reduction target of 0% by 2020 and 80% by 2050, and the development of new technologies slowed, this scenario includes currently legislated carbon policies based on the Treasury core scenario[11] for the first 3 years, and a $0/t CO2-e after that.
- **Scenario 6: Slow growth**. With lower economic growth, a CO2-e emissions reduction target of 5% by 2020 and 80% by 2050, and the development of new technologies slowed, this scenario includes currently legislated carbon policies based on the Treasury core scenario.[12] It is similar to the slow rate of change scenario, but with a continuing carbon price in line with the Australian Treasury's core scenario.

2.2.3 Mapping the NTNDP scenarios

The energy and maximum demand projections were developed on the basis of high, medium, and low economic growth scenarios, which correspond with three of the six scenarios developed for the 2012 NTNDP. For energy forecasting purposes, these scenarios have been designed to reflect different levels of economic growth, non-large industrial consumption, large industrial consumption, rooftop PV penetration, energy efficiency (EE), and small non-scheduled generation.

Table 2-1 lists the correlation between the various national electricity forecasting scenarios and their component forecasts:

- Economic variable forecasts are calculated for a range of economic scenarios defined by AEMO, based on different assumptions about productivity growth, commodity prices, carbon prices, and growth of the working age population. For more information, see the AEMO Economic Outlook Information Paper .[13]
- Non-large industrial consumption forecasts are the same as the forecasts for the economic variables.
- Large industrial consumption forecasts are linked to the high, medium and low economic growth scenarios.
- Rooftop PV uptake forecasts are calculated for three rooftop PV uptake scenarios defined by AEMO (rapid, moderate and slow), based on retail electricity prices, rooftop PV system costs, and government incentives (including the price obtained for excess energy fed into the power system).[14]
- Energy efficiency forecasts are calculated only for the base case scenario, with an estimated percentage impact applied (see Appendix B).
- Small non-scheduled generation forecasts are developed for three uptake scenarios defined by AEMO, based on assumed CO2-e reduction targets and/or incentives being provided for distributed generation.

[10] See note 7.
[11] See note 7.
[12] See note 7.
[13] See note 1.
[14] See note 1.

Table 2-1 — Mapping scenarios for national electricity forecasting

2012 NTNDP scenarios	2012 NEFR scenarios	Component forecasts					
		Economic variables	Non-large industrial consumption	Large industrial	Rooftop PV	Energy efficiency	Small non-scheduled generation
Scenario 1 - Fast Rate of Change	-	HCO25	HCO25	High	Rapid	100%	High (rapid)
Scenario 2 - Fast World Recovery	High	HCO5	HCO5	High	Moderate	50%	Medium (moderate)
Scenario 3 - Planning	Medium	MCO5[a]	MCO5 [a]	Medium	Moderate	50%	Medium (moderate)
Scenario 4 – Decentralised World	-	MCO5 [a]	MCO5 [a]	Medium	Rapid	50%	High (rapid)
Scenario 5 - Slow Rate of Change	-	LCO0	LCO0	Low	Slow	50%	Low (slow)
Scenario 6 - Slow growth	Low	LCO5	LCO5	Low	Moderate	50%	Medium (Moderate)

a. As an example, MCO5 is a medium scenario that assumes medium economic and population growth. A base case scenario contingent on expected or most likely economic and population growth rates, it also assumes carbon emission targets of 5% by 2020. For more information about the economic variable assumptions, see the Economic Outlook Information Paper (available http://www.aemo.com.au/en/Electricity/Forecasting. Viewed June 2012).

The 2012 NEFR only presents results for the three main scenarios, Fast World Recovery (the high scenario), Planning (the medium scenario), and Slow Growth (the low scenario). Abridged references in text to high, medium and low are made for the purposes of simplification.

For forecasts for all six 2012 NTNDP scenarios, see the AEMO website.[15]

2.3 Changes since the 2011 ESOO

Table 2-2 to Table 2-4 summarise the changes in the medium scenario energy and maximum demand projections since the 2011 ESOO.

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

[15] See note 2.

Table 2-2 — Energy projection changes since the 2011 ESOO

Region	Change in 2012–13 (GWh)	Change in 2020–21 (GWh)	Change in average growth rate[a]
Queensland	-5,791	-11,459	-0.7%
New South Wales	-7,520	-10,797	-0.4%
Victoria	-2,256	-2,591	-0.02%
South Australia	-1,808	-2,586	-0.5%
Tasmania	-977	-966	0.1%
NEM-wide	-18,353	-28,400	-0.4%

a. Growth rate calculated from 2012–13 to 2020–21.

Table 2-3 — Summer 10% POE maximum demand projection changes since the 2011 ESOO

Region	Change in 2012–13 (MW)	Change in 2020–21 (MW)	Change in average growth rate[a]
Queensland	-1,908	-3,795	-1.3%
New South Wales	-2,056	-3,463	-0.8%
Victoria	-746	-1,247	-0.4%
South Australia	-359	-597	-0.6%
Tasmania	-149	-190	-0.2%

a. Growth rate calculated from 2012–13 to 2020–21.

Table 2-4 — Winter 10% POE maximum demand projection changes since the 2011 ESOO

Region	Change in 2012 (MW)	Change in 2020 (MW)	Change in average growth rate[a]
Queensland	-696	-2,136	-1.3%
New South Wales	-857	-2,085	-0.9%
Victoria	11	184	0.2%
South Australia	-146	-297	-0.6%
Tasmania	-113	-156	-0.2%

a. Growth rate calculated from 2012 to 2020.

CHAPTER 3 - NEM-WIDE FORECASTS

Summary

This chapter presents information about annual energy, maximum demand (summer and winter), and non-scheduled generation for the National Electricity Market (NEM) as a whole. It also includes information about historical annual energy, mass market forecasts, large industrial forecasts, and an annual electrical energy requirement breakdown.

Annual energy

Key differences between the 2011 Electricity Statement of Opportunities (ESOO) and the 2012 National Electricity Forecasting Report (NEFR) annual energy forecasts include the following:

- Annual energy for 2011–12 is expected to be 2.4% lower than 2010–11 and 5.7% lower than forecast in the 2011 ESOO (medium economic growth scenario).
- Forecast annual energy for 2012–13 is expected to remain flat (0.0% growth), which represents a 8.8% reduction from 2011 ESOO forecasts.
- Average growth in annual energy for the 10-year outlook period is now forecast to be 1.7%, down from the 2.3% forecast in the 2011 ESOO.
- Growth in NEM annual energy is strongly linked to large industrial projects in Queensland (for example, coal seam gas developments).

Main factors contributing to forecast change

Annual energy and maximum demand forecasts have decreased since the 2011 ESOO for several main reasons:

- A slower than expected forecast increase in consumption from large industrial customers. From 2011–12 to 2012–13 energy use in the large industrial sector is expected to decline by 3.0%.
- Significant penetration of rooftop photovoltaics (PV) (South Australia has the highest penetration of rooftop PV of all the regions). The impact of rooftop PV penetration is expected to offset mass market energy. In 2011–12, rooftop PV systems are estimated to have generated 1,702 GWh or 0.9% of estimated annual energy.[1] In 2012–13, rooftop PV energy is forecast to be 2,473 GWh or 1.3% of annual energy under the Planning (medium) scenario. By 2021–22, this is forecast to increase to 7,558 GWh or 3.4% of annual energy. Over the 10-year outlook period, the average annual growth rate of rooftop PV energy is expected to be 13.2%. For more information, see AEMO's Rooftop PV Information Paper .[2]
- Reduced manufacturing consumption in response to the high Australian dollar. An expected increase in cheaper imports is expected to partially offset domestic growth.
- Changes in the economic outlook. Expected lower energy forecasts are consistent with changes in economic forecasts from the 2011 ESOO, in particular a moderation in gross domestic product (GDP), especially in the short term. In 2011–12, when the Australian economy is expected to grow 2.8%, the 2011 ESOO forecasts an equivalent higher growth rate of 3.6%. Over the 10-year outlook period annual average growth rates are forecast to be similar (3.0 % for the 2012 NEFR and 2.9% for the 2011 ESOO).
- Increasing (real) residential electricity prices. In 2011–12 and 2012–13, electricity prices are expected to increase, and then (on average) moderate from 2013–14 until the end of the outlook period for all regions of the NEM.

[1] Estimated annual energy does not include generation by rooftop PV systems.
[2] AEMO, available http://www.aemo.com.au/en/Electricity/Forecasting. Viewed June 2012.

- Consumer response (commercial and residential) to rising electricity costs and energy efficiency measures.

3.1 Annual energy forecasts

This section presents annual energy forecasts for the NEM based on the sum of the forecasts for the five regions (for more information, see Chapter 4 to Chapter 8).

Annual energy is defined on a ‘sent-out’ basis. Actual annual energy in 2011–12 includes two financial quarters of actual data and two quarters of estimated data.

3.1.1 Annual energy forecasts

Annual energy increased on average by 1.5% per year from 2000–01 to 2011–12. The factors supporting this growth are changes in economic activity, and changes in developments in the industrial sector.

Annual energy increased by an average of 3.4% from 2000–01 to 2005–06, followed by moderate average growth of 1.7% until 2008–09, and decreasing by 1.7% (on average) from 2009–10 to 2011–12.

Annual energy for the NEM is projected to increase over the 10-year outlook period from 2012–13 to 2021–22 at an annual average rate of 1.7% under the medium scenario, and 2.3% and 0.9% under the high and the low scenarios, respectively.

It is expected that in 2012–13 forecasts are similar to actual energy in 2011–12. From 2013–14, changes in the mass market and LNG sector in Queensland are mainly driving changes in demand.

Annual energy forecasts are offset by the penetration of rooftop PV systems and energy efficiency savings, which are expected to grow across the 10-year outlook period under all scenarios.

Figure 3-1-shows the forecast and actual energy under the three main scenarios. Table 3-1 lists the data used to plot the forecast charts.

Figure 3-1 — Annual energy forecasts for the NEM

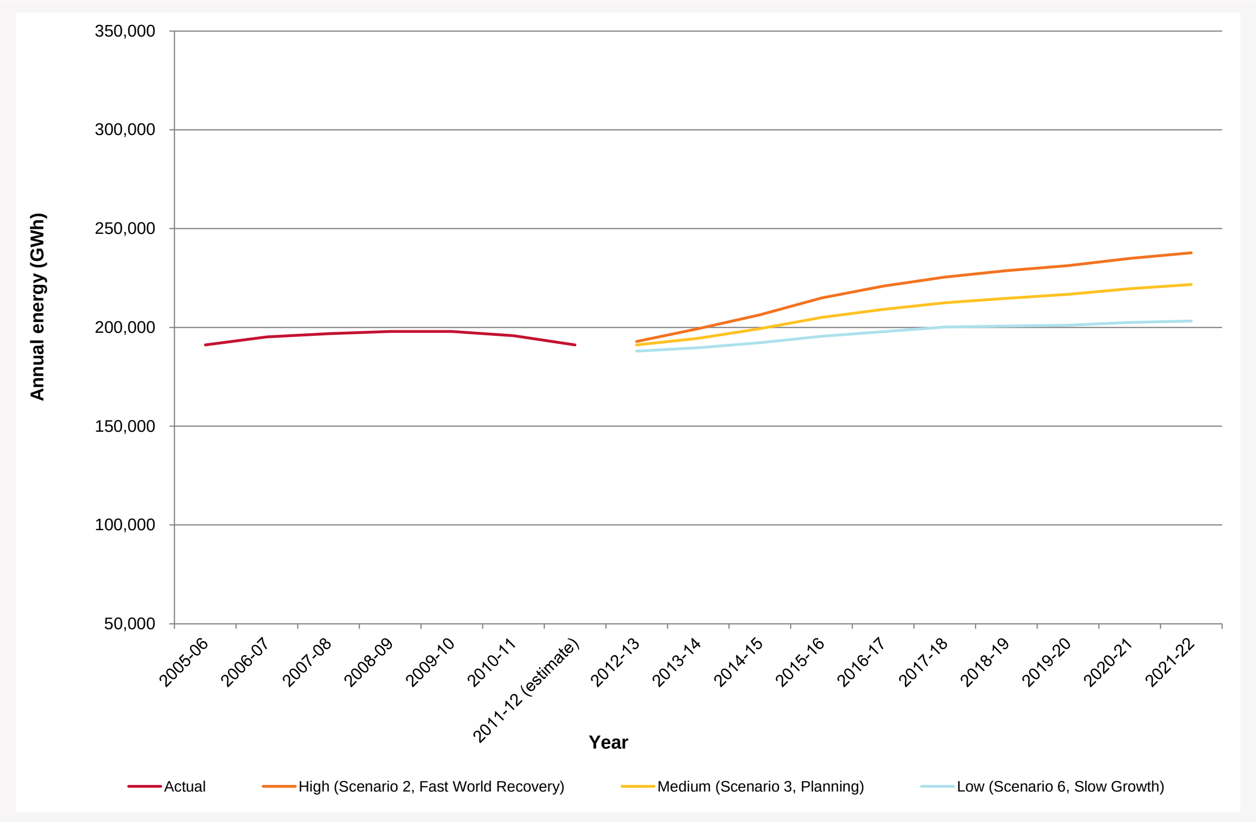


Table 3-1 — NEM annual energy forecasts (GWh)

	Actual	High (Scenario 2, Fast World Recovery)	Medium (Scenario 3, Planning)	Low (Scenario 6, Slow Growth)
2005–06	191,089	-	-	-
2006–07	195,173	-	-	-
2007–08	196,820	-	-	-
2008–09	197,908	-	-	-
2009–10	197,944	-	-	-
2010–11	195,791	-	-	-
2011–12 (estimate)	191,125	-	-	-
2012–13	-	192,826	191,076	188,018
2013–14	-	199,303	194,492	189,725
2014–15	-	206,358	199,388	192,205
2015–16	-	214,888	205,053	195,498
2016–17	-	220,906	209,078	197,872
2017–18	-	225,485	212,487	200,170
2018–19	-	228,717	214,658	200,641
2019–20	-	231,237	216,744	201,099
2020–21	-	234,856	219,573	202,516
2021–22	-	237,723	221,654	203,194
Average annual growth	-	2.35%	1.66%	0.87%

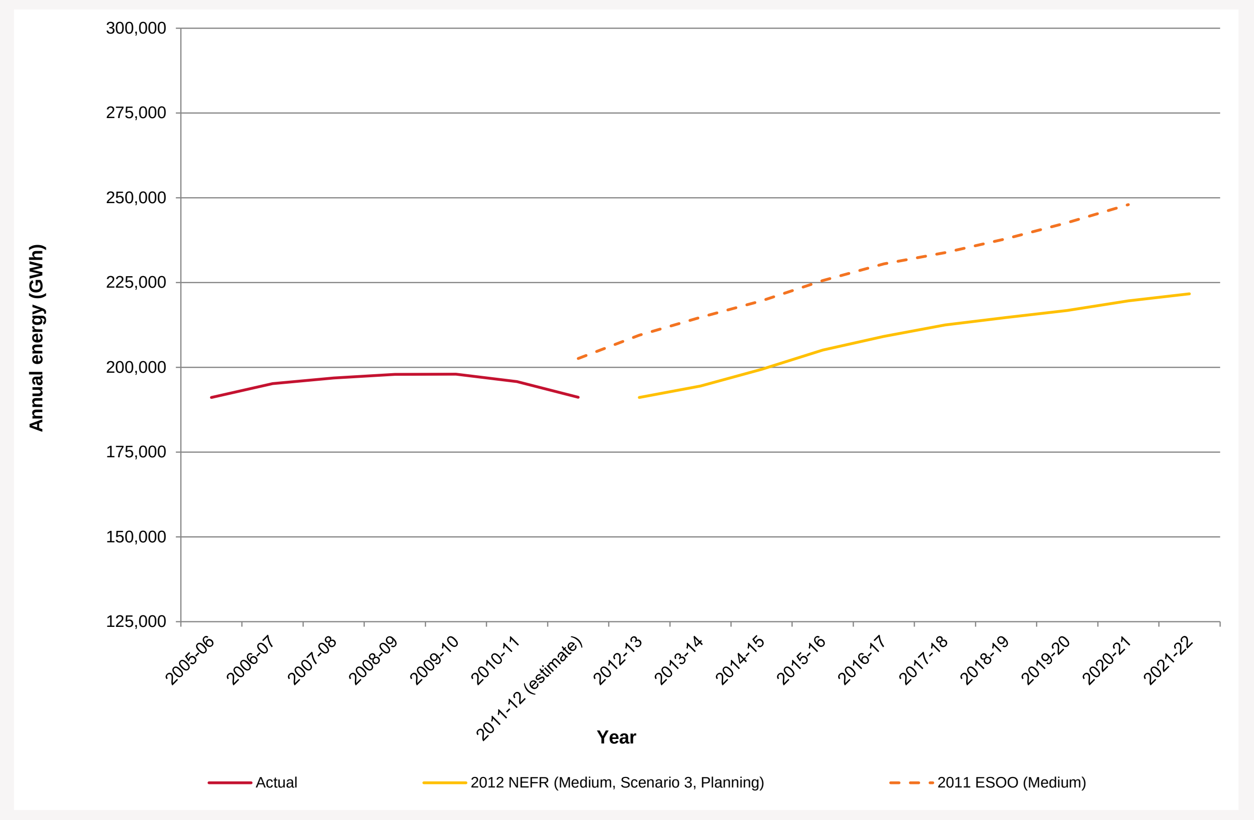
2011 and 2012 forecast comparison

Over the 9-year outlook period from 2012–13 to 2020–21, the 2012 NEFR annual energy forecasts begin from a lower base and have a more modest trajectory than the 2011 ESOO. There is an average decrease in annual energy of approximately 22,177 GWh from the 2011 ESOO's medium economic growth scenario forecasts when compared with the 2012 NEFR medium scenario forecasts. This is equivalent to a decrease in average annual growth from 2.3% in the 2011 ESOO to 1.7% in 2012 NEFR.

Figure 3-2 shows historical actual annual energy and compares the two annual energy forecasts.

In the near term, 2011–12 annual energy is expected to be 5.7% lower than forecast for the 2011 ESOO forecast. From 2011–12 to 2012–13, it is expected to decrease by 0.03%, with the annual energy forecast for 2012–13 representing a 8.8% reduction from 2011 ESOO forecasts.

Figure 3-2 — Comparison of the 2012 NEFR and 2011 ESOO annual energy forecasts for the NEM



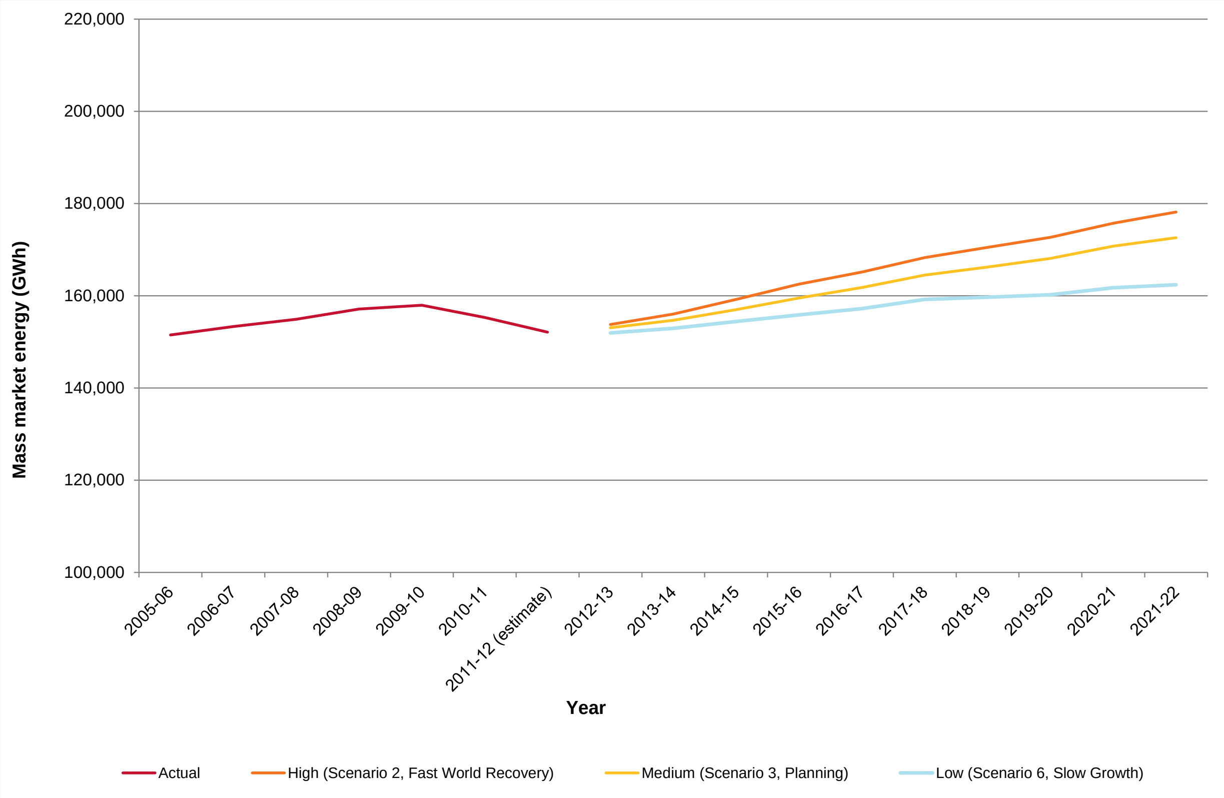
3.1.2 Mass market forecasts

Over the 10-year outlook period, the average annual growth rate for the medium, high and low scenarios is expected to be 1.3%, 1.6% and 0.7%, respectively.

There is only a small divergence between the medium and high scenarios due to stronger economic growth and higher electricity prices being offset under the high scenario.

Figure 3-3 shows forecast and actual consumption in the mass market under these scenarios.

Figure 3-3 — Mass market forecasts for the NEM

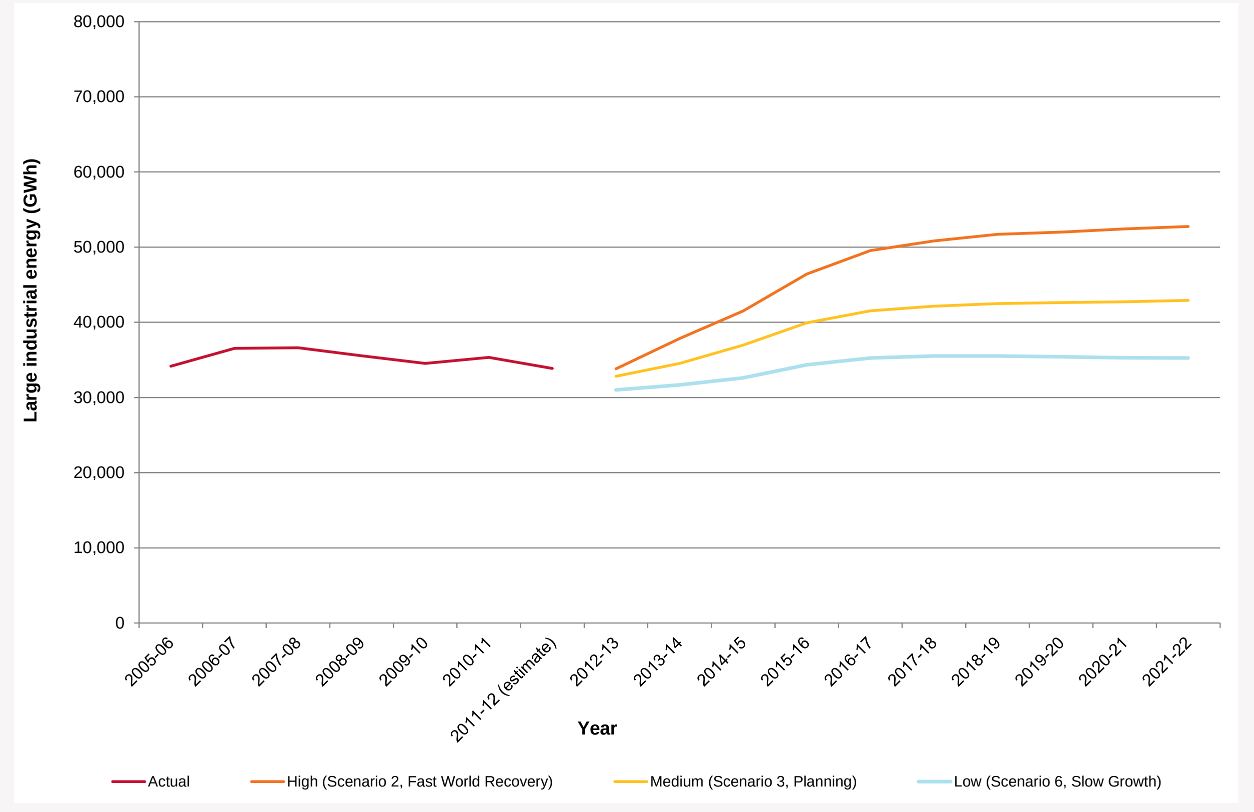


3.1.3 Large industrial forecasts

Forecasts for the large industrial sector include new projects, site closures, and increases and decreases of existing sites. For more information about each region, see Chapter 4 to Chapter 8.

Figure 3-4 shows forecast and actual consumption in the large industrial sector under the three main scenarios. Annual energy consumption is forecast to increase over the next 10 years at an annual average rate of 3.0% under the medium scenario, and 5.1% and 1.4% under the high and low scenarios, respectively.

Figure 3-4 — Large industrial forecasts for the NEM



3.1.4 Annual electrical energy requirement breakdown

Table 3-2 provides a breakdown of the annual energy forecasts by customer sales, network losses, and auxiliary energy use by generators under the medium scenario.

Table 3-2 — NEM-wide annual electrical energy requirement breakdown (GWh)

	Customer sales	Transmission network losses	Annual energy (sent out basis)[a]	Auxiliary energy use	Annual energy (as-generated basis)[b]
Actual					
2005–06	185,659	5,431	191,089	13,179	204,269
2006–07	189,851	5,322	195,173	13,154	208,327
2007–08	191,518	5,301	196,820	13,599	210,418
2008–09	192,646	5,257	197,908	14,243	212,151
2009–10	192,434	5,493	197,944	13,889	211,833
2010–11	190,598	5,152	195,791	13,658	209,450
2011–12 (estimate)	185,938	5,187	191,125	13,135	204,259
Scenario 3 - Planning					
2012–13	185,905	5,171	191,076	13,105	204,181
2013–14	189,213	5,279	194,492	13,273	207,765
2014–15	193,952	5,436	199,388	13,437	212,825
2015–16	199,421	5,632	205,053	13,599	218,652
2016–17	203,304	5,774	209,078	13,705	222,784
2017–18	206,596	5,891	212,487	13,818	226,305
2018–19	208,702	5,956	214,658	13,872	228,530
2019–20	210,725	6,019	216,744	13,932	230,677
2020–21	213,459	6,114	219,573	13,973	233,546
2021–22	215,472	6,182	221,654	14,026	235,680

a. Annual energy (sent out basis) is defined as the total of customer sales and transmission network losses.

b. Annual energy (as-generated basis) is defined as the total of annual energy (sent out basis) and auxiliary energy use.

3.2 Maximum demand forecasts

In the 2011 ESOO, summer and winter maximum demand forecasts were calculated by scaling-down the sum of all the regional forecasts by an assumed diversity factor. The diversity factors used in the 2011 ESOO were calculated as the average diversity between the regions over the past five summers and winters, and were used to indicate the coincidence of the maximum demand between each region. For summer the diversity factor was 0.92, and for winter the diversity factor was 0.98.

Using a single percentage-based diversity factor to approximate the NEM maximum demand does not reflect the true diversity that may result from actual conditions and producing probability of exceedence (POE) forecasts using this approach is inconsistent with how the regional maximum demand forecasts are developed. AEMO does not consider this estimation method to be robust, and as a consequence has not continued to use this approach to calculate maximum demand for the 2012 NEFR. This is an area of future work that will be developed for the 2013 NEFR, using time-sequential modelling to understand the coincidence between each region's maximum demand.

3.3 Small non-scheduled generation forecasts

This section presents forecasts of the contribution from small non-scheduled generation (excluding semi-scheduled, significant non-scheduled, and exempt generation) to annual energy and maximum demand, which are not included in the definition of operational demand.

It is possible that some non-scheduled generators may not be included due to their small size, lack of production, or lack of accurate data. These forecasts consider all non-scheduled generation (as nominated by the jurisdictional planning bodies (JPBs)), which is different from previous reports.

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 only on the demand met by scheduled and semi-scheduled generation, 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 generation.

The small non-scheduled generation forecasts presented in this section are subtracted from both the annual energy and maximum demand forecasts to calculate operational generation forecasts used in the supply-demand outlook.

For a list of the scheduled and semi-scheduled generators (by region) used to calculate these forecasts, see Appendix C.

Forecasts of small non-scheduled generation energy for the NEM

Table 3-3- lists the forecast and actual energy of small non-scheduled generation under the three main scenarios.

The contribution to maximum demand from small non-scheduled generation in the NEM is not provided, as a concurrent NEM maximum demand has not been separately forecast.

Energy supplied by small non-scheduled generating units in the NEM is forecast to increase over the next 10 years at an annual average rate of between 1.7% and 5.6% (depending on economic scenario), compared with historical annual average growth of 7.0%. Much of the forecast growth can be attributed to the installation of wind, hydro and other renewable generation sources.

The majority of large projects are expected to register as semi-scheduled rather than non-scheduled. This contributes to relatively low to medium projected growth in non-scheduled energy, capacity, and the contribution to summer maximum demand.

Table 3-3 — Forecasts of small non-scheduled generation energy for the NEM (GWh)

	Actual	High (Scenario 2, Fast World Recovery)[a]	Medium (Scenario 3, Planning)[a]	Low (Scenario 6, Slow Growth)[a]
2005–06	1,747	-	-	-
2006–07	1,939	-	-	-
2007–08	2,109	-	-	-
2008–09	2,465	-	-	-
2009–10	2,498	-	-	-
2010–11	2,553	-	-	-
2011–12 (estimate)	2,624	-	-	-
2012–13	-	2,595	2,595	2,595
2013–14	-	2,701	2,701	2,701
2014–15	-	2,807	2,807	2,807
2015–16	-	2,913	2,913	2,913
2016–17	-	3,019	3,019	3,019
2017–18	-	3,125	3,125	3,125
2018–19	-	3,230	3,230	3,230
2019–20	-	3,336	3,336	3,336
2020–21	-	3,442	3,442	3,442
2021–22	-	3,548	3,548	3,548
Average annual growth	7.0%	3.2%	3.2%	3.2%

a. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

CHAPTER 4 - NEW SOUTH WALES (INCLUDING ACT) FORECASTS

Summary

This chapter presents information about annual energy, maximum demand (summer and winter), and non-scheduled generation for the New South Wales (including the Australian Capital Territory) region. It also includes information about historical annual energy, mass market forecasts, large industrial forecasts, and an annual electrical energy requirement breakdown.

Annual energy

Key differences between the 2012 National Electricity Forecasting Report (NEFR) and the TransGrid 2011 annual energy forecasts, published in the 2011 ESOO, include the following:

- Annual energy for 2011–12 is expected to be 4.1% lower than 2010–11, and 5.6% lower than forecast in the 2011 ESOO (medium economic growth scenario).
- Forecast annual energy for 2012–13 is expected to further decrease by 2.0%, which represents a 9.7% reduction from the 2011 ESOO forecasts.
- Average growth in annual energy for the 10-year outlook period is now forecast to be 1.2%, down from the 1.6% forecast in the 2011 ESOO.

Maximum demand

Key differences between the 2012 NEFR and the TransGrid 2011 summer maximum demand medium economic growth scenario forecasts include the following:

- The 2011–12 actual summer maximum demand was 1,690 MW below TransGrid's 90% POE forecast.
- The NEFR 2012–13 forecast summer 10% POE maximum demand is 2,060 MW lower than the TransGrid's 2011 forecast.
- Average growth in summer 10% POE maximum demand for the 10-year outlook period is now forecast to be 1.2%, down from the 2.0% forecast in the 2011 ESOO.

Main factors contributing to forecast change

Annual energy and maximum demand forecasts have decreased since the 2011 ESOO for several main reasons:

- Reduced consumption from large industrial customers. In 2011–12, energy use is expected to decline mainly due to the announced closure of Norsk Hydro's aluminium smelter at Kurri Kurri.
- Increasing penetration of rooftop photovoltaics (PV). In 2011–12, rooftop PV systems are estimated to have generated 559 GWh or 0.8% of estimated annual energy.[1] In 2012–13, rooftop PV energy is forecast to be 740 GWh or 1.1% of annual energy under the Planning (medium) scenario. By 2021–22, this is forecast to increase to 2,702 GWh or 3.5% of annual energy. Over the 10-year outlook period, the average annual growth rate of rooftop PV energy is expected to be 15.5%. For more information, see AEMO's Rooftop PV Information Paper.[2]
- Reduced manufacturing consumption in response to the high Australian dollar. An expected increase in cheaper imports is expected to partially offset domestic growth.

[1] Estimated annual energy does not include generation by rooftop PV systems.
[2] AEMO, available http://www.aemo.com.au/en/Electricity/Forecasting. Viewed June 2012.

- Economic growth (measured by gross state product (GSP)) is a significant driver of annual energy. In the short term, GSP forecasts for the 2012 NEFR are lower than the 2011 ESOO, influencing a lower level of annual energy.
- Increasing (real) residential electricity prices. In 2011–12 and 2012–13, electricity prices are expected to increase, and then (on average) moderate from 2013–14 until the end of the outlook period.
- Consumer response (commercial and residential) to rising electricity costs and energy efficiency measures.

4.1 Annual energy forecasts

This section presents annual energy forecasts for New South Wales based on AEMO modelling. For more information about the modelling, see AEMO's Forecasting Methodology Information Paper.[3]

Annual energy is defined on a 'sent-out' basis. Actual annual energy in 2011–12 includes two financial quarters of actual data and two financial quarters of estimated data

4.1.1 Annual energy forecasts

Annual energy increased on average by only 0.7% per year from 2000–01 to 2011–12, underpinned by a slowdown in economic activity, increasing electricity prices, and industrial sector weakness. Historical annual energy peaked in 2007–08, and shows a negative average annual growth of 1.5% over the last 4 years.

Annual energy in New South Wales is projected to grow over the 10-year outlook period from 2012–13 to 2021–22 at an annual average rate of 1.2% under the medium scenario, and 1.6% and 0.3% under the high and the low scenarios, respectively.

It is expected that in 2012–13 forecasts are similar to actual energy in 2011–12. From 2013–14, changes in the mass market and the aluminium sector are driving changes in the forecasts. Forecast annual energy is expected to return to the 2010–11 level by 2016–17.

Annual energy forecasts are offset by the penetration of rooftop PV systems and energy efficiency savings, which are expected to grow across the 10-year outlook period under these three main scenarios.

[3] See note 2.

Figure 4-1 shows the forecast and actual energy under the three main scenarios. Table 4-1 lists the data used to plot the forecast charts.

Figure 4-1 — Annual energy forecasts for New South Wales (including the ACT)

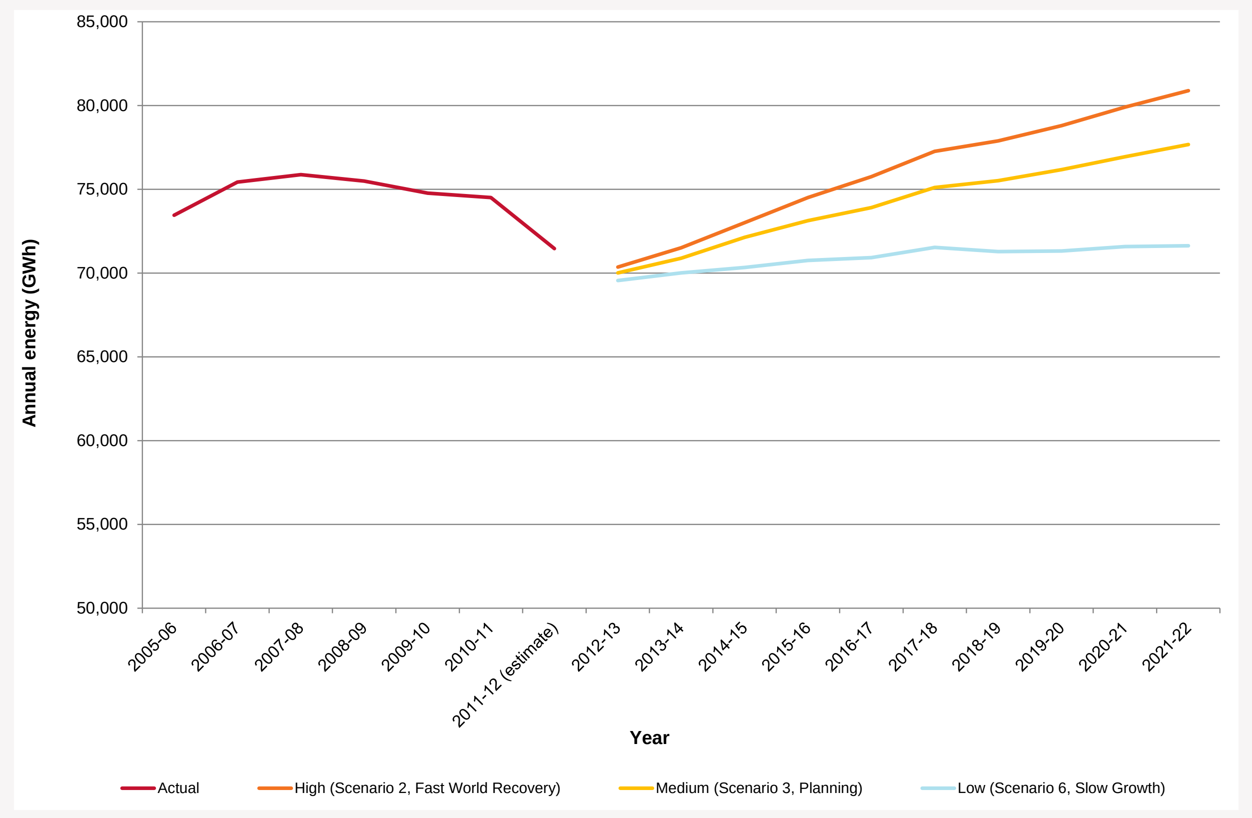


Table 4-1 — Annual energy forecasts for New South Wales (including the ACT) (GWh)

	Actual	High (Scenario 2, Fast World Recovery)	Medium (Scenario 3, Planning)	Low (Scenario 6, Slow Growth)
2006–07	75,436	-	-	-
2007–08	75,878	-	-	-
2008–09	75,488	-	-	-
2009–10	74,772	-	-	-
2010–11	74,512	-	-	-
2011–12 (estimate)	71,468	-	-	-
2012–13	-	70,354	70,007	69,551
2013–14	-	71,507	70,887	70,015
2014–15	-	73,006	72,133	70,341
2015–16	-	74,503	73,128	70,750
2016–17	-	75,757	73,912	70,929
2017–18	-	77,268	75,106	71,540
2018–19	-	77,886	75,518	71,282
2019–20	-	78,805	76,181	71,322
2020–21	-	79,902	76,948	71,578
2021–22	-	80,894	77,669	71,633
Average annual growth	-	1.56%	1.16%	0.33%

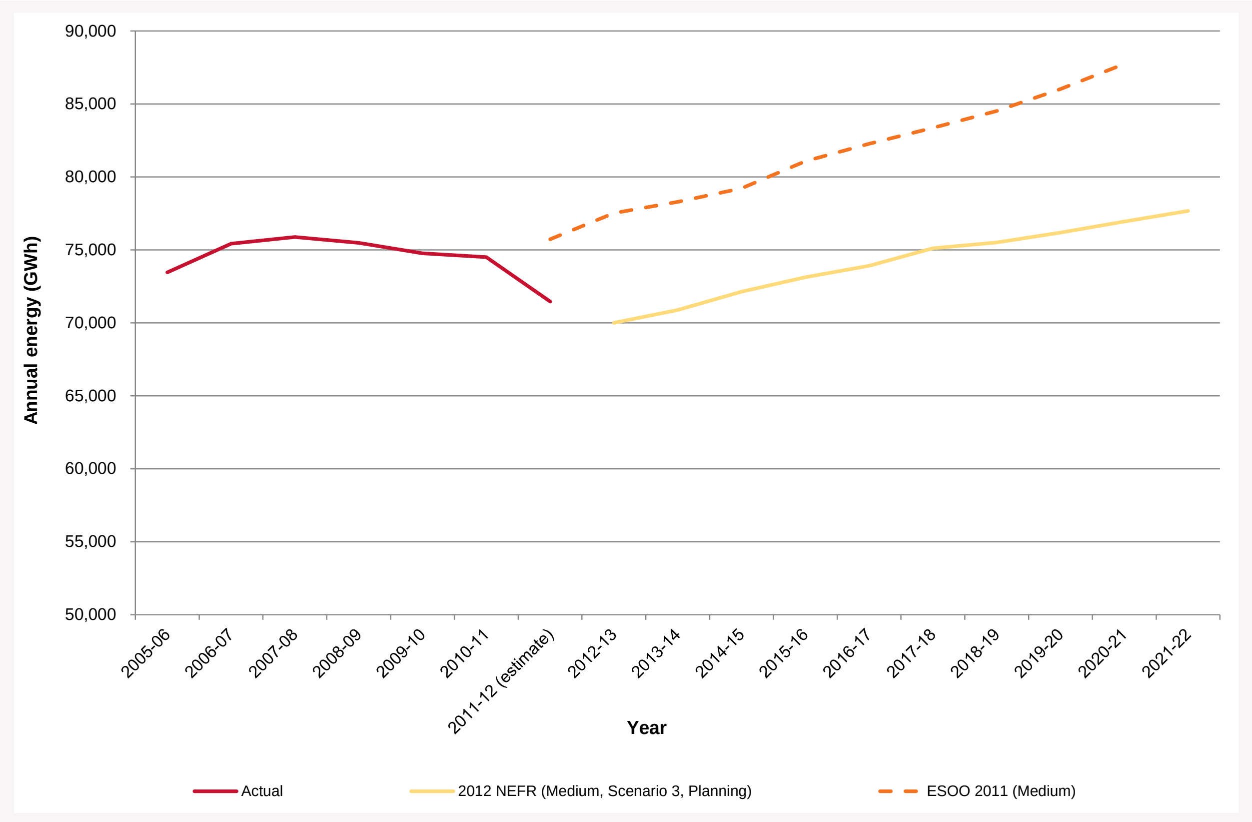
2011 and 2012 forecast comparison

Over the 9-year outlook period from 2012–13 to 2020–21, there is an average decrease in annual energy of approximately 8,470 GWh from the 2011 ESOO medium economic growth scenario forecasts when compared with the 2012 medium scenario forecasts. This is equivalent to a decrease in average annual growth from 1.6 % in the 2011 ESOO to 1.2% in the 2012 NEFR.

Figure 4-2 shows actual energy and compares the forecast energy for the two forecasts.

In the near term, 2011–12 annual energy is expected to be 5.6% lower than the 2011 ESOO forecast. From 2011–12 to 2012–13, it is expected to decrease by 2.0%, with the annual energy forecast for 2012–13 representing a 9.7% reduction from 2011 ESOO forecasts.

Figure 4-2 — Comparison of the 2012 NEFR and 2011 ESOO annual energy forecasts for New South Wales (including the ACT)



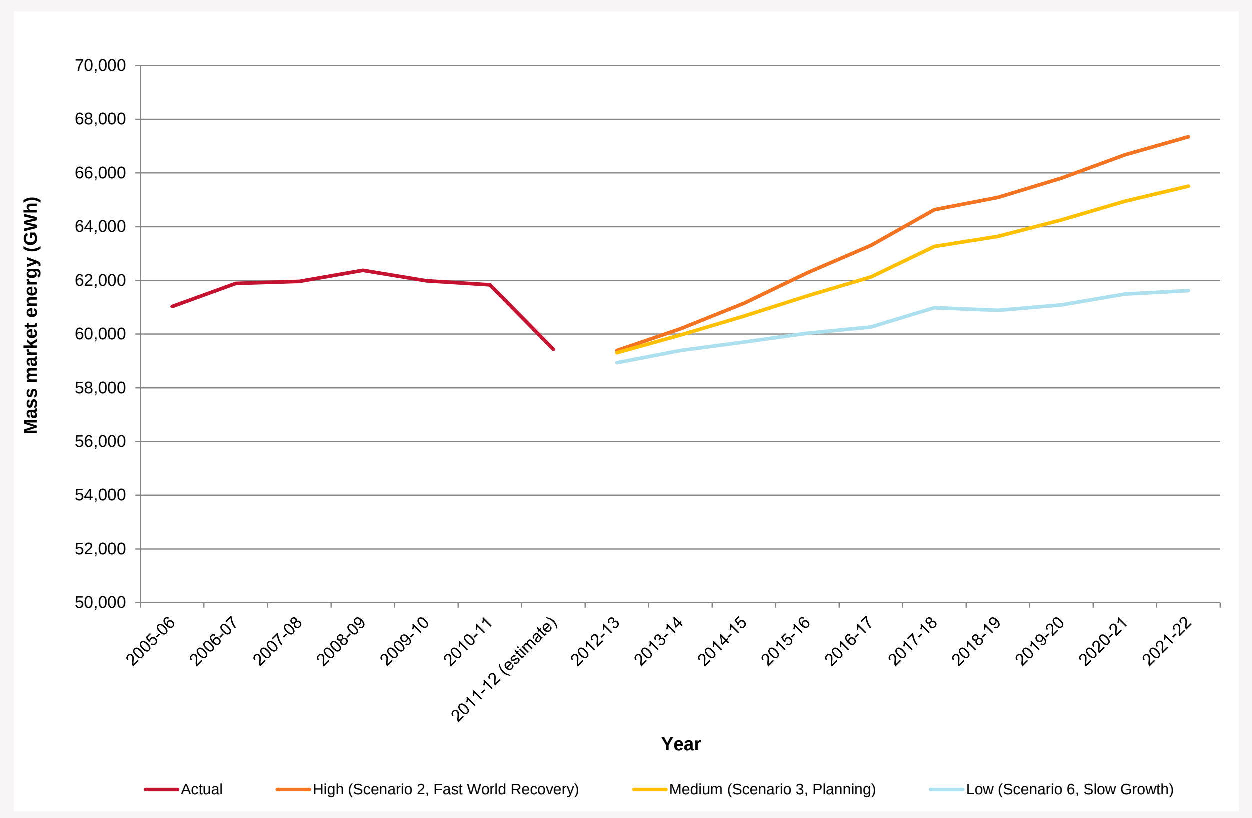
4.1.2 Mass market forecasts

Over the 10-year outlook period, the average annual growth rate for the medium, high and low scenarios is expected to be 1.1%, 1.4% and 0.5%, respectively.

Figure 4-3 shows forecast and actual consumption in the mass market sector under these scenarios.

Forecasts for the mass market have been calculated by developing a model for non-large industrial consumption, and then subtracting forecasts for rooftop PV and energy efficiency savings. For more information about the model for non-large industrial consumption, see Appendix A.

Figure 4-3 — Mass market forecasts for New South Wales (including the ACT)



4.1.3 Large industrial forecasts

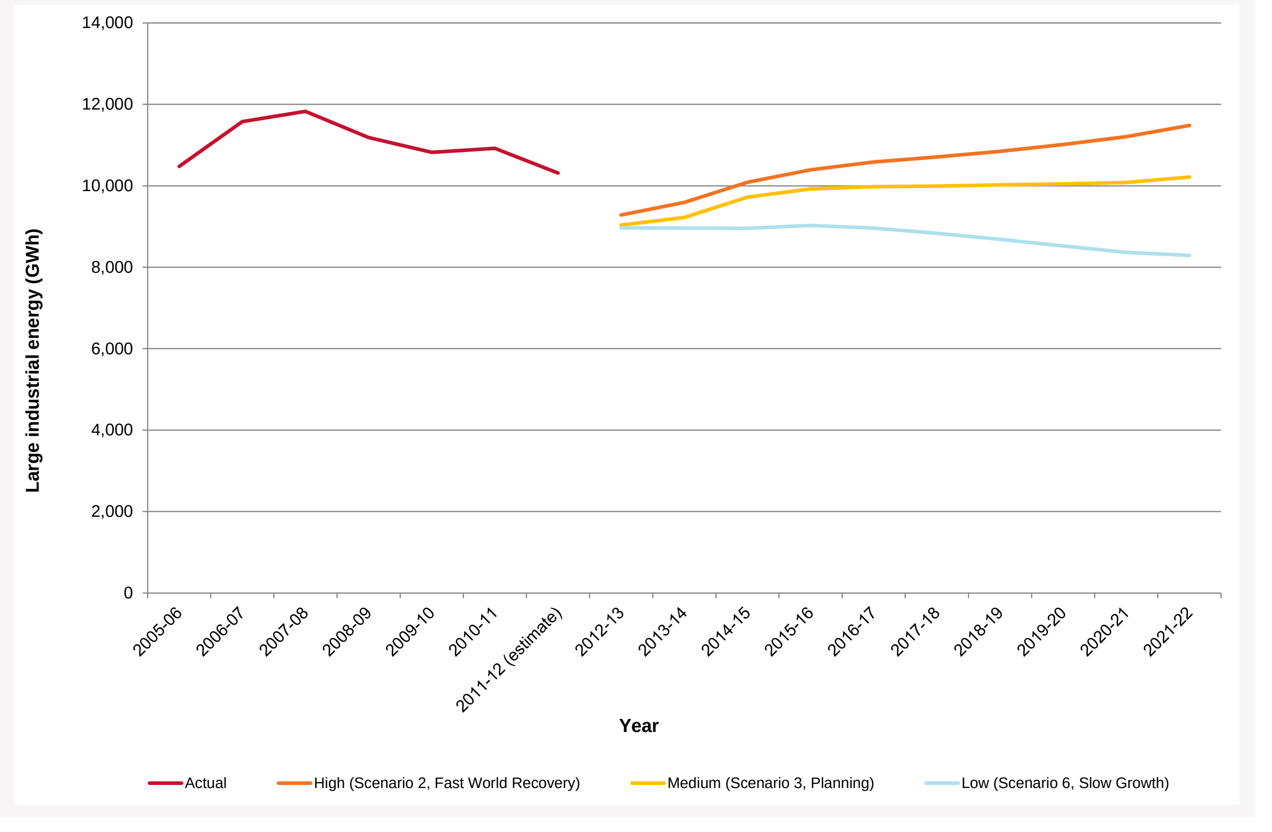
The large industrial forecasts account for a number of new projects:

- The recently announced closure of the Kurri Kurri aluminium smelter[4] and general weakness in the aluminium sector.
- Newcrest Cadia East gold mine.[5]
- Xstrata's Ulan West thermal coal mine.[6]

Under the high scenario, some additional small prospective mining projects have been included in the forecasts.

Figure 4-4 shows forecast and actual consumption in the large industrial sector under the three main scenarios. Energy consumption is forecast to increase over the next 10 years at an annual average rate of 1.4% under the medium scenario, and 1.6% and -0.9% under the high and low scenarios, respectively.

Figure 4-4 — Large industrial forecasts for New South Wales (including the ACT)



[4] As of January 2012, the Kurri Kurri aluminium smelter closed one of its three potlines, reducing electricity consumption by approximately one third. As of May 2012, Norsk Hydro announced a total curtailment of production due to low global aluminium prices, a high Australian dollar and high electricity prices. Hydro, available http://www.hydro.com/en/Press-room/News/Archive/2012/Hydro-is-considering-full-curtailment-of-the-Kurri-Kurri-aluminium-plant-in-Australia/. Viewed May 2012.

[5] Newcrest, available http://www.newcrest.com.au/projects.asp?category=3 Viewed May 2012.

[6] Xsrata, available http://www.xstrata.com/media/news/2010/08/03/0730CET/. Viewed May 2012.

4.1.4 Annual electrical energy requirement breakdown

Table 4-2 provides a breakdown of the annual energy forecasts by customer sales, network losses, and auxiliary energy use by generators under the medium scenario.

Table 4-2 — Annual electrical energy requirement breakdown for New South Wales (including the ACT) (GWh)

	Customer sales	Transmission network losses	Annual energy (sent out basis)[a]	Auxiliary energy use	Annual energy (as-generated basis)[b]
Actual					
2005–06	71,490	1,969	73,459	4,039	77,498
2006–07	73,450	1,985	75,436	4,119	79,554
2007–08	73,772	2,106	75,878	4,320	80,198
2008–09	73,546	1,943	75,488	4,487	79,975
2009–10	72,771	2,001	74,772	4,252	79,024
2010–11	72,731	1,781	74,512	4,166	78,678
2011–12 (estimate)	69,748	1,720	71,468	4,100	75,568
Medium scenario (Scenario 3, Planning)					
2012–13	68,337	1,670	70,007	4,051	74,058
2013–14	69,187	1,700	70,887	4,078	74,964
2014–15	70,390	1,743	72,133	4,113	76,246
2015–16	71,351	1,777	73,128	4,141	77,269
2016–17	72,107	1,805	73,912	4,164	78,076
2017–18	73,258	1,848	75,106	4,192	79,298
2018–19	73,655	1,863	75,518	4,198	79,716
2019–20	74,294	1,887	76,181	4,212	80,393
2020–21	75,033	1,915	76,948	4,232	81,180
2021–22	75,727	1,942	77,669	4,256	81,926

a. Annual energy (sent out basis) is defined as the total of customer sales and transmission network losses.

b. Annual energy (as-generated basis) is defined as the total of annual energy (sent out basis) and auxiliary energy use.

4.2 Maximum demand forecasts

Currently, the maximum demand in New South Wales (including ACT) occurs during summer. From 2015, however, the maximum demand is forecast to start occurring during winter.

Half-hourly temperature data was obtained from the Sydney Observatory Hill and Richmond RAAF stations.

4.2.1 Summer maximum demand forecasts

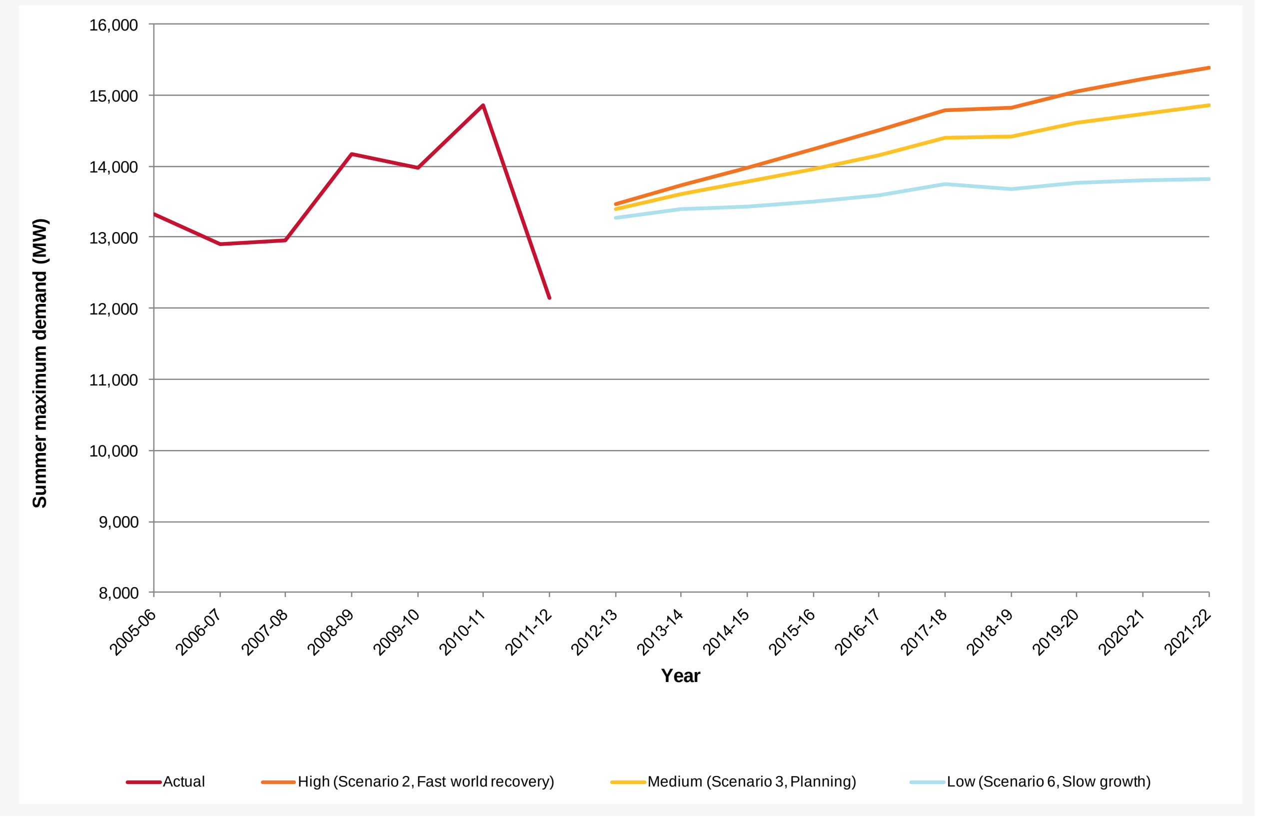
Figure 4-5 shows summer 50% POE maximum demand forecasts under the three main scenarios (and actual data).

The summer 50% POE maximum demand is forecast to increase over the next 10 years at an annual average growth rate of 1.2% under the medium scenario, and 1.5% and 0.4% under the high and low scenarios, respectively. Trends in maximum demand are largely the same as annual energy.

The load factor[7] has remained relatively stable averaging approximately 17.9% during the last 10 years.

Summer maximum demand peaked on 1 February in 2010–11 at 14,744 MW, decreasing by 2,670 MW in summer 2011–12.

Figure 4-5 — Summer 50% POE maximum demand forecasts for New South Wales (including the ACT)



[7] The load factor is defined as the annual maximum demand divided by the annual energy.

Table 4-3 presents actual and forecast summer 10%, 50% and 90% POE maximum demand for New South Wales (including ACT) under the three main scenarios.

Table 4-3 — Summer maximum demand forecasts for New South Wales (including the ACT)

	Actual	High (Scenario 2, Fast World Recovery)			Medium (Scenario 3, Planning)			Low (Scenario 6, Slow Growth)		
		10%	50%	90%	10%	50%	90%	10%	50%	90%
2005–06	13,328	-	-	-	-	-	-	-	-	-
2006–07	12,896	-	-	-	-	-	-	-	-	-
2007–08	12,956	-	-	-	-	-	-	-	-	-
2008–09	14,176	-	-	-	-	-	-	-	-	-
2009–10	13,969	-	-	-	-	-	-	-	-	-
2010–11	14,863	-	-	-	-	-	-	-	-	-
2011–12	12,141	-	-	-	-	-	-	-	-	-
2012–13	-	14,145	13,474	12,764	14,065	13,399	12,697	13,937	13,277	12,586
2013–14	-	14,421	13,737	13,012	14,289	13,609	12,898	14,061	13,393	12,700
2014–15	-	14,665	13,968	13,229	14,467	13,779	13,059	14,099	13,427	12,720
2015–16	-	14,959	14,246	13,489	14,660	13,960	13,226	14,177	13,497	12,783
2016–17	-	15,236	14,504	13,731	14,865	14,151	13,398	14,279	13,590	12,867
2017–18	-	15,532	14,781	13,986	15,130	14,398	13,622	14,454	13,750	13,013
2018–19	-	15,580	14,822	14,021	15,158	14,420	13,638	14,378	13,672	12,933
2019–20	-	15,834	15,057	14,225	15,363	14,607	13,806	14,474	13,757	12,997
2020–21	-	16,019	15,232	14,400	15,497	14,732	13,921	14,531	13,806	13,047
2021–22	-	16,191	15,392	14,548	15,636	14,860	14,039	14,542	13,813	13,047
Average annual growth	-	1.51%	1.49%	1.46%	1.18%	1.16%	1.12%	0.47%	0.44%	0.40%

2011 and 2012 forecast comparison

Figure 4-6 compares the 2012 NEFR medium scenario and 2011 ESOO medium economic growth scenario summer 10%, 50% and 90% POE maximum demand forecasts.

The average annual summer 10% POE maximum demand forecast growth rate is expected to be 1.2% over the 9-year outlook period from 2012–13 to 2020–21, representing a 0.8% reduction from the 2011 ESOO forecasts.

Figure 4-6 — Comparison of the 2012 NEFR and 2011 ESOO summer maximum demand forecasts for New South Wales (including the ACT)

4.2.2 Winter maximum demand forecasts

Figure 4-7 shows winter 50% POE maximum demand forecasts under the three main scenarios (and actual data).

The winter 50% POE maximum demand is forecast to increase over the next 10 years at an annual average rate of 1.2% under the medium scenario, and 1.5% and 0.6% under the high and low scenarios, respectively. Trends in maximum demand are largely the same as annual energy.

Winter maximum demand peaked on 28 July 2008 at 14,289 MW. Winter maximum demand in 2010 was 13,345 MW), decreasing by 403 MW in winter 2011.

Under each of the three main scenarios, maximum demand growth rates are slightly higher in winter than summer, due to the minimal impact of rooftop PV, which is assumed to be zero during winter, and because maximum demand in New South Wales often occurs at or after 6:30 PM.

Figure 4-7 — Winter 50% POE maximum demand forecasts for New South Wales (including the ACT)

Table 4-4 presents actual and forecast winter 10%, 50% and 90% POE maximum demand for New South Wales (including ACT) under the three main scenarios.

Table 4-4 — Winter maximum demand forecasts for New South Wales (including the ACT) (MW)

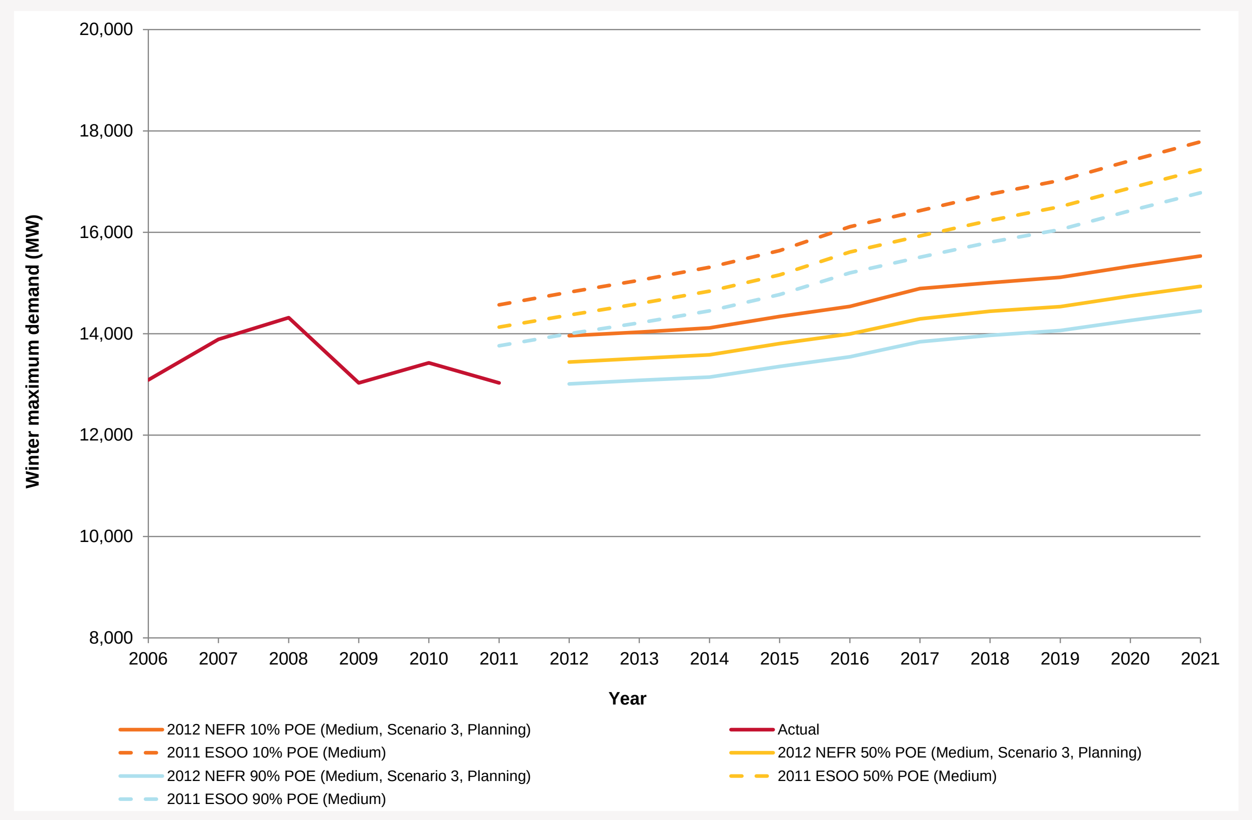
	Actual	High (Scenario 2, Fast World Recovery)			Medium (Scenario 3, Planning)			Low (Scenario 6, Slow Growth)		
		10%	50%	90%	10%	50%	90%	10%	50%	90%
2006	13,088	-	-	-	-	-	-	-	-	-
2007	13,890	-	-	-	-	-	-	-	-	-
2008	14,316	-	-	-	-	-	-	-	-	-
2009	13,028	-	-	-	-	-	-	-	-	-
2010	13,424	-	-	-	-	-	-	-	-	-
2011	13,030	-	-	-	-	-	-	-	-	-
2012	-	13,940	13,422	12,988	13,961	13,441	13,007	13,875	13,360	12,926
2013	-	14,042	13,527	13,089	14,032	13,511	13,080	13,919	13,398	12,975
2014	-	14,192	13,667	13,218	14,115	13,581	13,144	13,896	13,377	12,946
2015	-	14,528	13,989	13,528	14,338	13,807	13,353	13,998	13,477	13,033
2016	-	14,793	14,237	13,776	14,539	13,994	13,543	14,066	13,531	13,100
2017	-	15,179	14,577	14,121	14,892	14,290	13,841	14,321	13,739	13,302
2018	-	15,329	14,760	14,273	15,005	14,442	13,967	14,353	13,813	13,357
2019	-	15,453	14,877	14,389	15,112	14,535	14,063	14,367	13,821	13,368
2020	-	15,719	15,132	14,633	15,328	14,743	14,261	14,505	13,951	13,494
2021	-	15,969	15,368	14,855	15,531	14,935	14,447	14,610	14,045	13,582
Average annual growth	-	1.52%	1.52%	1.50%	1.19%	1.18%	1.17%	0.58%	0.56%	0.55%

2011 and 2012 forecast comparison

Figure 4-8 compares the 2012 NEFR medium scenario and 2011 ESOO medium economic growth scenario winter 10%, 50% and 90% POE maximum demand forecasts.

The average annual winter 10% POE maximum demand forecast growth rate is expected to be 1.3% over the 10-year outlook period from 2012 to 2021, representing a 0.7% reduction from the 2011 ESOO forecasts.

Figure 4-8 — Comparison of the 2012 NEFR and 2011 ESOO winter maximum demand forecasts for New South Wales (including the ACT)



4.3 Small non-scheduled generation forecasts

This section presents forecasts of the contribution from small non-scheduled generation (excluding semi-scheduled, significant non-scheduled, and exempt generation) to annual energy and maximum demand, which are not included in the definition of operational demand.

It is possible that some non-scheduled generators may not be included due to their small size, lack of production, or lack of accurate data. These forecasts consider all non-scheduled generation (as nominated by the jurisdictional planning bodies (JPBs)), which is different from previous reports.

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 only on the demand met by scheduled and semi-scheduled generation, 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 generation.

The small non-scheduled generation forecasts presented in this section are subtracted from both the annual energy and maximum demand forecasts to calculate operational generation forecasts used in the supply-demand outlook.

For a list of the scheduled and semi-scheduled generators (by region) used to calculate these forecasts, see Appendix C.

Forecasts of small non-scheduled generation energy for New South Wales

Table 4-5 lists the forecast and actual energy of small non-scheduled generation under the three main scenarios.

Table 4-6 presents forecasts of the contribution to summer and winter maximum demand from New South Wales (including ACT) small non-scheduled generation.

Energy supplied by small non-scheduled generating units is forecast to increase over the next 10 years at an annual average rate of between 1.4% and 4.7% (depending on economic scenario), compared with historical annual average growth of 10.4%. Much of the forecast growth can be attributed to the installation of wind, hydro and other renewable sources.

The majority of large projects are expected to register as semi-scheduled rather than non-scheduled. This contributes to relatively low to medium projected growth in non-scheduled energy, capacity, and contribution to summer maximum demand.

Table 4-5 — Forecasts of small non-scheduled generation energy for New South Wales (including ACT) (GWh)

	Actual	High (Scenario 2, Fast World Recovery)[a]	Medium (Scenario 3, Planning)[a]	Low (Scenario 6, Slow Growth)[a]
2005–06	469	-	-	-
2006–07	469	-	-	-
2007–08	474	-	-	-
2008–09	806	-	-	-
2009–10	806	-	-	-
2010–11	848	-	-	-
2011–12 (estimate)	848	-	-	-
2012–13	-	873	873	873
2013–14	-	899	899	899
2014–15	-	924	924	924
2015–16	-	950	950	950
2016–17	-	975	975	975
2017–18	-	1,000	1,000	1,000
2018–19	-	1,026	1,026	1,026
2019–20	-	1,051	1,051	1,051
2020–21	-	1,077	1,077	1,077
2021–22	-	1,102	1,102	1,102
Average annual growth	10.4%	2.62%	2.62%	2.62%

a. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

Table 4-6 — Forecasts of the small non-scheduled generation contribution to maximum demand for New South Wales (including ACT) (MW)

	Actual	Summer maximum demand			Actual	Winter maximum demand		
		High (Scenario 2, Fast World Recovery)[a]	Medium (Scenario 3, Planning)[a]	Low (Scenario 6, Slow Growth)[a]		High (Scenario 2, Fast World Recovery)[b]	Medium (Scenario 3, Planning)[b]	Low (Scenario 6, Slow Growth)[b]
2005–06	36	-	-	-		-	-	-
2006–07	20	-	-	-	13	-	-	-
2007–08	16	-	-	-	19	-	-	-
2008–09	75	-	-	-	27	-	-	-
2009–10	75	-	-	-	15	-	-	-
2010–11	119	-	-	-	80	-	-	-
2011–12	115	-	-	-	37	-	-	-
2012–13	-	118	118	118	-	115	115	115
2013–14	-	121	121	121	-	118	118	118
2014–15	-	125	125	125	-	121	121	121
2015–16	-	128	128	128	-	125	125	125
2016–17	-	132	132	132	-	128	128	128
2017–18	-	135	135	135	-	132	132	132
2018–19	-	139	139	139	-	135	135	135
2019–20	-	142	142	142	-	139	139	139
2020–21	-	146	146	146	-	142	142	142
2021–22	-	149	149	149	-	146	146	146
Average annual growth	-	2.62%	2.62%	2.62%	-	2.69%	2.69%	2.69%

a. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

b. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

CHAPTER 5 - QUEENSLAND FORECASTS

Summary

This chapter presents information about annual energy, maximum demand (summer and winter), and non-scheduled generation for the Queensland region. It also includes information about historical annual energy, mass market forecasts, large industrial forecasts, and an annual electrical energy requirement breakdown.

Annual energy

Key differences between the 2012 National Electricity Forecasting Report (NEFR) and Powerlink Queensland's 2011 annual energy forecasts include the following:

- Annual energy for 2011–12 is expected to be 1.0% lower than 2010–11, and 6.5% lower than forecast in the 2011 Electricity Statement of Opportunities (ESOO) (medium economic growth scenario).
- Forecast annual energy for 2012–13 is expected to only grow by 1.4%, which represents a 10.4% reduction from the 2011 ESOO forecasts.
- Average growth in annual energy for the 10-year outlook period is now forecast to be 2.9%, down from the 4.0% forecast in the 2011 ESOO.

Maximum demand

Key differences between the 2012 NEFR and Powerlink Queensland's 2011 summer maximum demand medium economic growth scenario forecasts include the following:

- The 2011–12 actual summer maximum demand was 990 MW below Powerlink's 90% probability of exceedence (POE) forecast.
- AEMO's 2012–13 summer 10% POE maximum demand forecast is 1,910 MW lower than Powerlink's 2011 forecast.
- Average growth in 10% POE summer maximum demand for the 10-year outlook period is now forecast to be 2.5%, down from the 4.2% forecast in the 2011 ESOO.

Main factors contributing to forecast change

Annual energy and maximum demand forecasts have decreased since the 2011 ESOO for several main reasons:

- Lower expectation on new project developments from the large industrial sector, including coal seam gas developments and new mining projects forecast to commence from 2013–14.

- Increasing penetration of rooftop photovoltaics (PV). In 2011–12, rooftop PV systems are estimated to have generated 517 GWh or 1% of estimated annual energy.[1] In 2012–13, rooftop PV energy is forecast to be 766 GWh or 1.5% of annual energy under the Planning (medium) scenario. By 2021–22, this is forecast to increase to 2,421 GWh or 3.7% of annual energy. Over the 10-year outlook period, the average annual growth rate of rooftop PV energy is expected to be 13.6%. For more information, see AEMO's Rooftop PV Information Paper.[2]
- Reduced manufacturing consumption in response to the high Australian dollar. An expected increase in cheaper imports is expected to partially offset domestic growth.
- A moderation in gross state product (GSP) compared to the 2011 ESOO economic outlook, especially in the short term, influences reduced annual energy forecasts.
- Increasing (real) residential electricity prices. In 2011–12 and 2012–13, electricity prices are expected to increase, and then (on average) moderate from 2013–14 until the end of the outlook period.
- Consumer response (commercial and residential) to rising electricity costs and energy efficiency measures.
- Powerlink uses different maximum demand forecasting methodology.

5.1 Annual energy forecasts

This section presents annual energy forecasts for Queensland based on AEMO modelling. For more information about the modelling, see AEMO's Forecasting Methodology Information Paper.[3]

Annual energy is defined on a 'sent-out' basis. Actual annual energy in 2011–12 includes two financial quarters of actual data and two financial quarters of estimated data.

5.1.1 Annual energy forecasts

Annual energy increased on average by 1.8% per year from 2000–01 to 2011–12, underpinned by increasing population and economic growth, higher penetration of air-conditioning units, and increased developments in the industrial sector. Historical annual energy peaked in 2009–10, and has shown negative average annual growth of 1.3% over the last 24 months, with severe weather conditions (floods and cyclones) having an impact.

Annual energy in Queensland is projected to grow over the 10-year outlook period from 2012–13 to 2021–22 at an annual average rate of 2.9% under the medium scenario, and 4.1% and 1.8% under the high and the low scenarios, respectively.

It is expected that in 2012–13 forecasts are similar to actual energy in 2011–12. From 2013–14, changes in the mass market and CSG sector are driving changes in the forecasts.

Annual energy forecasts are offset by the penetration of rooftop PV and energy efficiency savings, which are expected to grow across the 10-year outlook period under all three main scenarios.

[1] Estimated annual energy does not include rooftop PV generation.
[2] AEMO, available http://www.aemo.com.au/en/Electricity/Forecasting. Viewed June 2012.
[3] See note 2.

Figure 5-1 shows the forecast and actual energy under the three main scenarios. Table 5-1 lists the data used to plot the forecast charts.

Figure 5-1 — Annual energy forecasts for Queensland

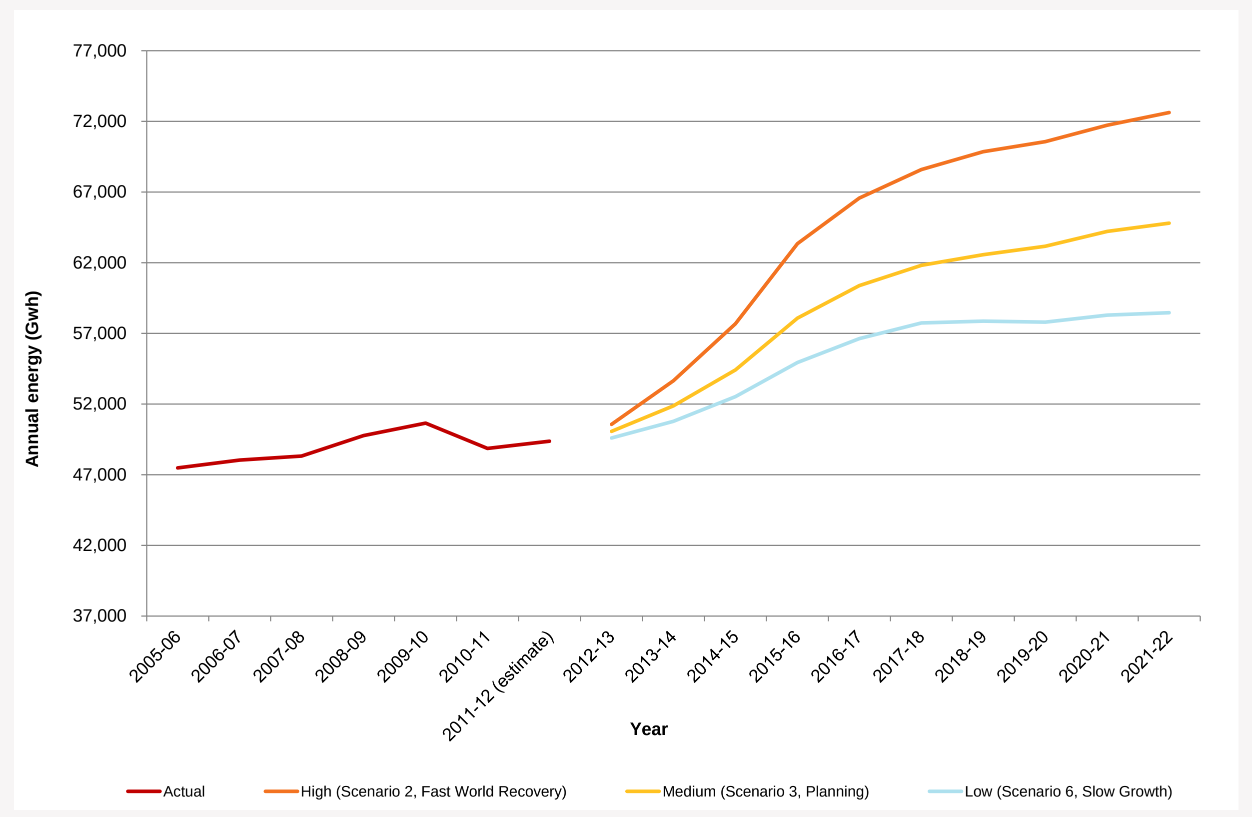


Table 5-1 — Annual energy forecasts for Queensland (GWh)

	Actual	High (Scenario 2, Fast World Recovery)	Medium (Scenario 3, Planning)	Low (Scenario 6, Slow Growth)
2005-06	47,487			
2006–07	48,036	-	-	-
2007–08	48,313	-	-	-
2008–09	49,770	-	-	-
2009–10	50,641	-	-	-
2010–11	48,862	-	-	-
2011–12 (estimate)	49,374	-	-	-
2012–13	-	50,560	50,063	49,590
2013–14	-	53,651	51,873	50,775
2014–15	-	57,682	54,407	52,516
2015–16	-	63,351	58,082	54,943
2016–17	-	66,573	60,383	56,622
2017–18	-	68,583	61,815	57,738
2018–19	-	69,857	62,570	57,860
2019–20	-	70,566	63,157	57,785
2020–21	-	71,728	64,208	58,290
2021–22	-	72,624	64,795	58,465
Average annual growth	-	4.1%	2.9%	1.8%

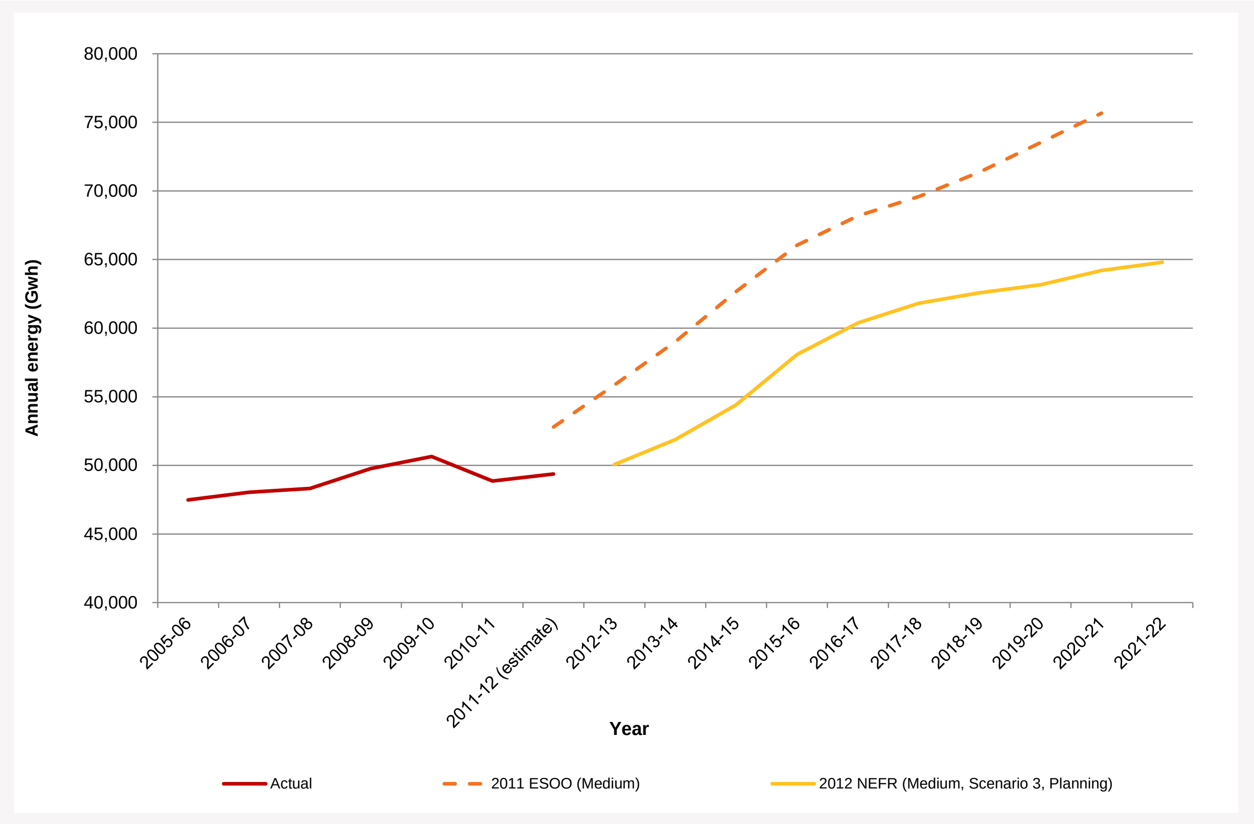
2011 and 2012 forecast comparison

Over the 9-year outlook period from 2012–13 to 2020–21, there is an average decrease in annual energy of approximately 8,021 GWh from the 2011 ESOO's medium economic growth scenario forecasts when compared with the 2012 medium scenario forecasts. This is equivalent to a decrease in average annual growth, from 3.9% in the 2011 ESOO to 3.2% in 2012 NEFR.

Figure 5-2 shows actual energy and compares the forecast energy for the two forecasts.

In the near term, 2011–12 annual energy is expected to be 6.5% lower than the 2011 ESOO forecast. From 2011–12 to 2012–13, it is expected to grow by 1.4%, with the annual energy forecast for 2012–13 representing a 10.4% reduction from the 2011 ESOO forecasts.

Figure 5-2 — Comparison of the 2012 NEFR and 2011 ESOO annual energy forecasts for Queensland



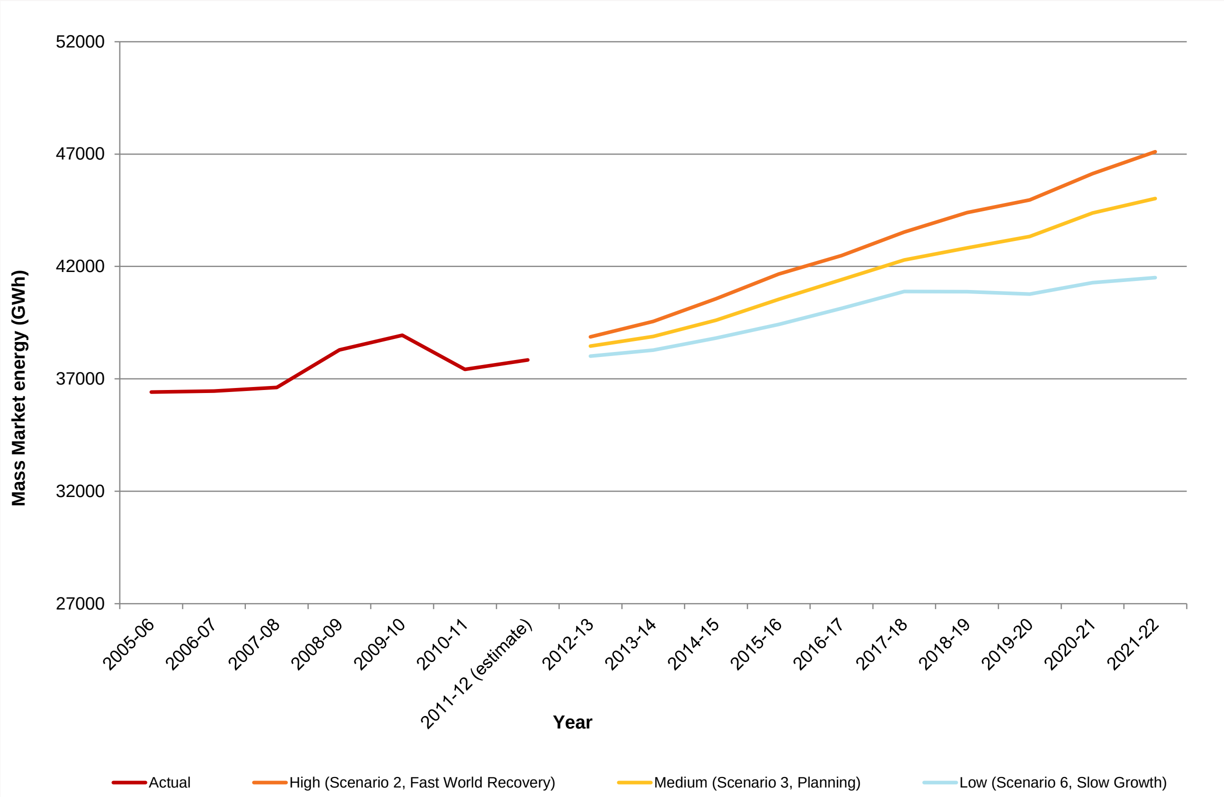
5.1.2 Mass market forecasts

Over the 10-year outlook period, the average annual growth rate for the medium, high and low scenarios is expected to be 1.8%, 2.2% and 1.0%, respectively.

Figure 5-3 shows forecast and actual consumption in the mass market sector under the three main scenarios.

Forecasts for the mass market have been calculated by developing a model for non-large industrial consumption, and then subtracting forecasts for rooftop PV and energy efficiency savings. For more information about the model for non-large industrial consumption, see Appendix A.

Figure 5-3 — Mass market forecasts for Queensland



5.1.3 Large industrial forecasts

Energy consumption in the large industrial sector in Queensland is forecast to increase sharply in the next few years when proposed coal seam gas projects commence operation.

The large industrial forecasts account for a number of new large industrial projects:

- The Xstrata Wandoan coal project.
- Coal seam gas projects in the Bowen and Surat Basins, including:
  - Australia Pacific liquefied natural gas (LNG) coal seam gas (CSG) projects – Columbula connections and Orana and North West Surat connections.
  - QGC – Kumbarilla Park and Woleebee Creek connections.
  - Arrow Energy Surat Gas project.
  - Santos Bowen/Surat Basin CSG project.

Although at different stages of project development, all four LNG projects associated with these CSG projects have been approved. Assumptions regarding the scale of these projects vary according to the different scenarios.

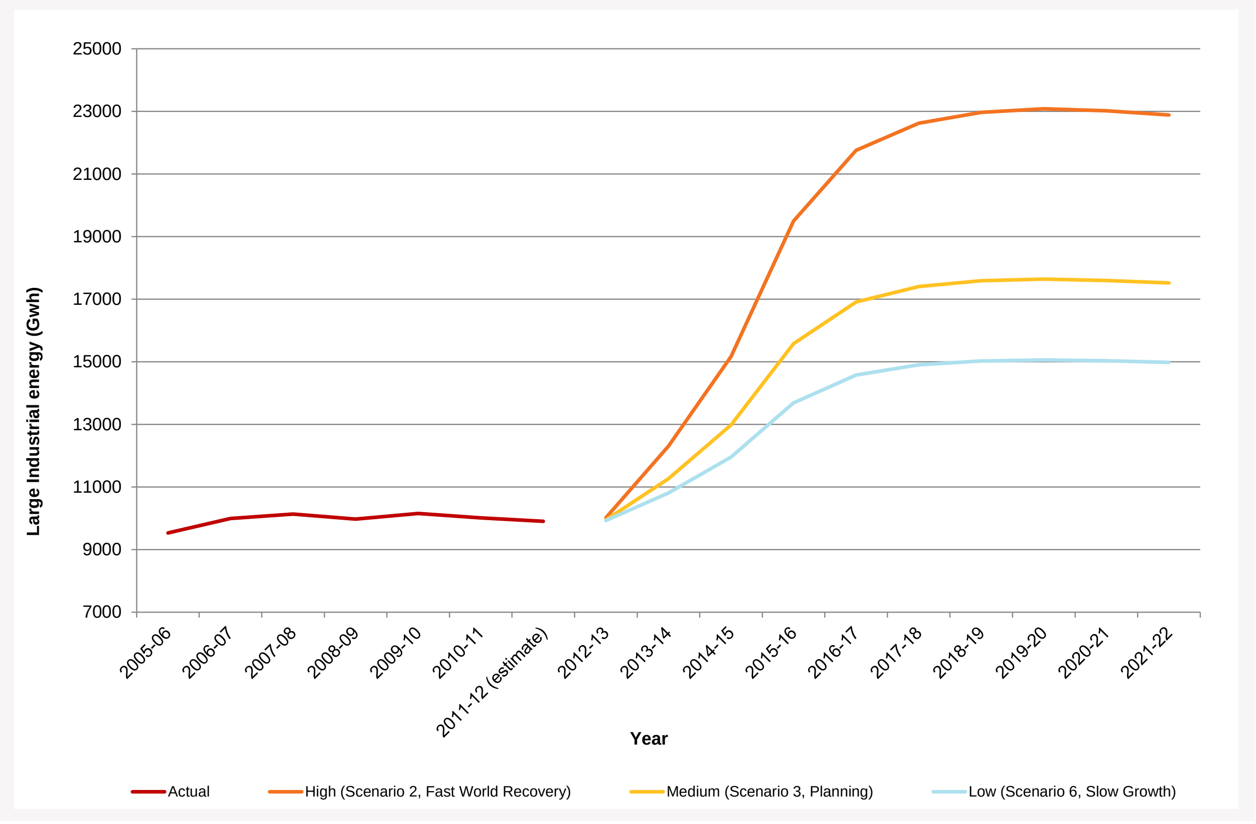
AEMO has not included other potential mining and large industrial projects due to the uncertainty that these projects will go ahead.

Figure 5-4 shows forecast and actual consumption in the large industrial sector for the three main scenarios. Energy consumption is forecast to increase over the next 10 years at an annual average rate of 6.5% under the medium scenario, and 9.6% and 4.7% under the high and low scenarios, respectively.

The difference in these growth rates is primarily due to different assumptions of the scale of LNG projects supported by CSG developments and mining projects in the region. All scenarios assume the 6 committed LNG trains become fully operational by 2017–18.

The low scenario assumes there are no other new large industrial customers commencing operations over the 10 year outlook. Under the medium scenario it is assumed an additional 2,500 GWh, above the low scenario, of large industrial load (equivalent to an additional 3 LNG trains or large mining developments) comes online by 2018–19. Under the high scenario, the majority of the remaining large industrial projects that have commenced feasibility studies are included, which represents an additional 5,500 GWh of large industrial load, by 2018–19, above the medium scenario.

Figure 5-4 — Large industrial forecasts for Queensland



5.1.4 Annual electrical energy requirement breakdown

Table 5-2 provides a breakdown of the annual energy forecasts by customer sales, network losses, and auxiliary energy use by generators under the medium scenario.

Table 5-2 — Annual electrical energy requirement breakdown for Queensland (GWh)

	Customer sales	Transmission network losses	Annual energy (sent out basis)[a]	Auxiliary energy use	Annual energy (as-generated basis)[b]
Actual					
2005–06	45,947	1,539	47,487	3,891	51,377
2006–07	46,455	1,581	48,036	3,792	51,828
2007–08	46,757	1,557	48,313	3,861	52,174
2008–09	48,266	1,505	49,770	3,947	53,717
2009–10	49,099	1,541	50,641	4,008	54,649
2010–11	47,439	1,423	48,862	3,822	52,684
2011–12 (estimate)	47,743	1,632	49,374	3,760	53,135
Medium scenario (Scenario 3, Planning)					
2012–13	48,407	1,656	50,063	3,788	53,851
2013–14	50,152	1,721	51,873	3,896	55,769
2014–15	52,591	1,816	54,407	4,002	58,409
2015–16	56,120	1,962	58,082	4,137	62,220
2016–17	58,325	2,058	60,383	4,232	64,615
2017–18	59,695	2,120	61,815	4,284	66,099
2018–19	60,418	2,153	62,570	4,310	66,880
2019–20	60,979	2,179	63,157	4,337	67,494
2020–21	61,983	2,226	64,208	4,377	68,585
2021–22	62,543	2,252	64,795	4,397	69,192

a. Annual energy (sent out basis) is defined as the total of customer sales and transmission network losses.

b. Annual energy (as-generated basis) is defined as the total of annual energy (sent out basis) and auxiliary energy use.

5.2 Maximum demand forecasts

The maximum demand in Queensland generally occurs in summer.

Half-hourly temperature data was obtained from the Brisbane (Archerfield), Rockhampton and Townsville stations.

5.2.1 Summer maximum demand forecasts

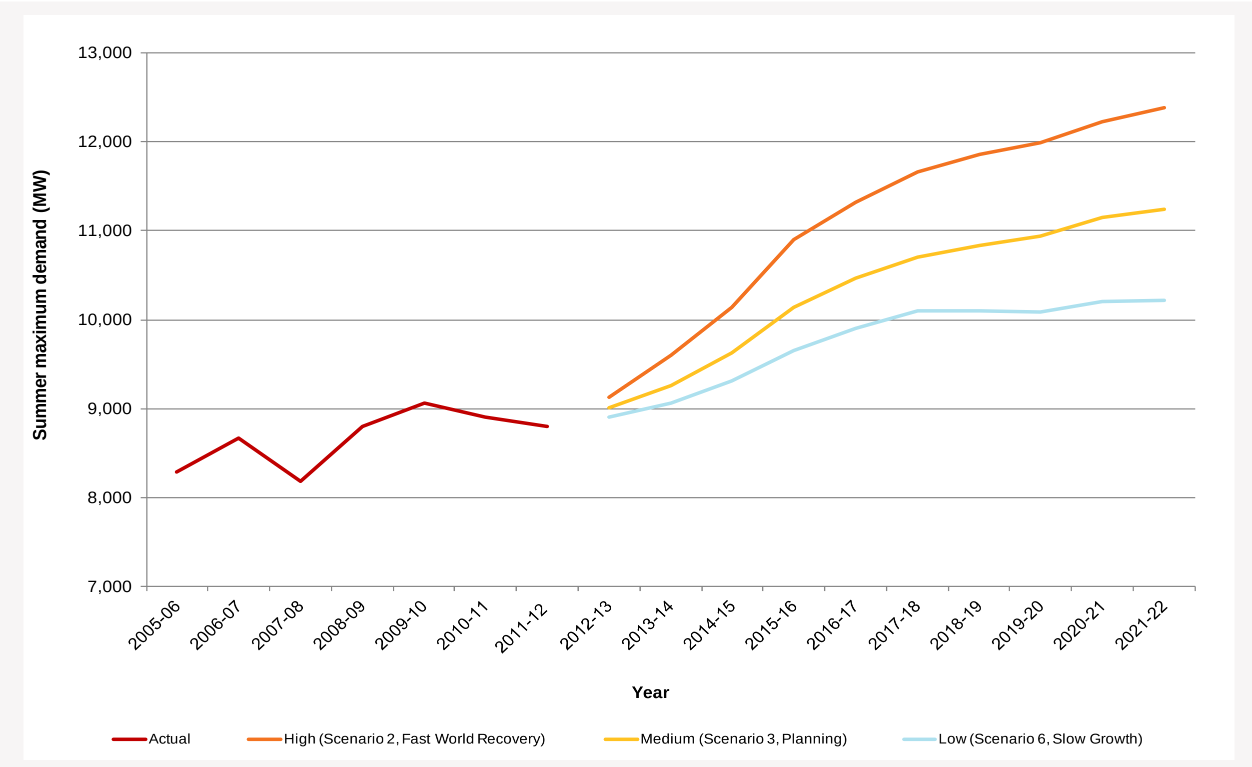
Figure 5-5 shows summer 50% POE maximum demand forecasts under the three main scenarios (and actual data).

The summer 50% POE maximum demand is forecast to increase over the next 10 years at an annual average rate of 2.5% under the medium scenario, and 3.4% and 1.5% under the high and low scenarios, respectively. Trends in maximum demand are largely the same as annual energy.

The load factor[4] has remained relatively stable, averaging approximately 17.4% during the last 10 years except for 2007–08.

Summer maximum demand peaked on 9 January in 2011–12 at 8,806 MW, decreasing by 102 MW from summer 2010–11.

Figure 5-5 — Summer 50% POE maximum demand forecasts for Queensland



4 The load factor is defined as the annual maximum demand divided by the annual energy.

Table 5-3 presents actual and forecast summer 10%, 50%, and 90% POE maximum demand for Queensland under the three main scenarios.

Table 5-3 — Summer maximum demand forecasts for Queensland (MW)

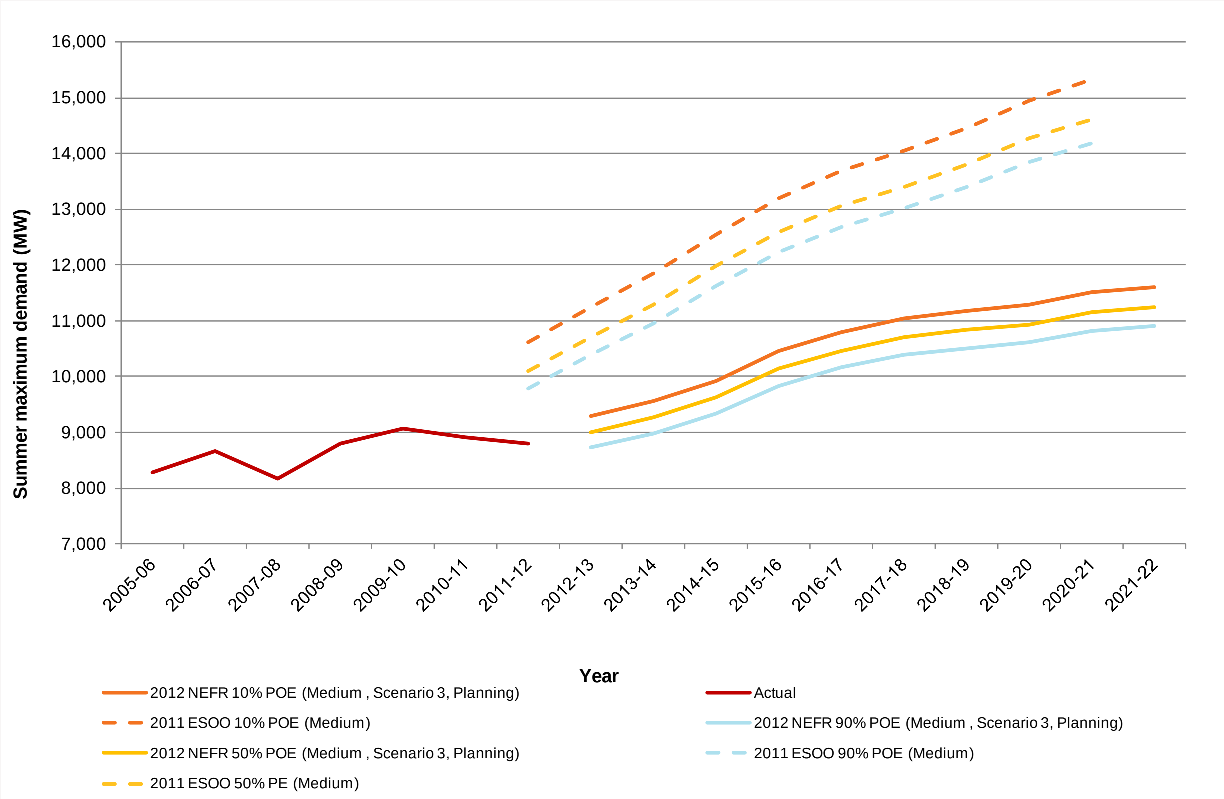
	Actual	High (Scenario 2, Fast World Recovery)			Medium (Scenario 3, Planning)			Low (Scenario 6, Slow Growth)		
		10%	50%	90%	10%	50%	90%	10%	50%	90%
2005–06	8,289	-	-	-	-	-	-	-	-	-
2006–07	8,664	-	-	-	-	-	-	-	-	-
2007–08	8,181	-	-	-	-	-	-	-	-	-
2008–09	8,800	-	-	-	-	-	-	-	-	-
2009–10	9,061	-	-	-	-	-	-	-	-	-
2010–11	8,908	-	-	-	-	-	-	-	-	-
2011–12	8,806	-	-	-	-	-	-	-	-	-
2012–13	-	9,427	9,129	8,834	9,299	9,007	8,726	9,192	8,904	8,628
2013–14	-	9,896	9,599	9,309	9,558	9,262	8,987	9,355	9,063	8,791
2014–15	-	10,455	10,142	9,844	9,926	9,625	9,334	9,612	9,315	9,038
2015–16	-	11,217	10,895	10,584	10,453	10,142	9,841	9,963	9,659	9,374
2016–17	-	11,650	11,321	11,003	10,785	10,464	10,160	10,218	9,906	9,614
2017–18	-	11,996	11,656	11,326	11,040	10,708	10,396	10,423	10,100	9,801
2018–19	-	12,208	11,860	11,521	11,169	10,830	10,512	10,433	10,099	9,794
2019–20	-	12,339	11,983	11,637	11,285	10,941	10,615	10,417	10,086	9,782
2020–21	-	12,600	12,226	11,872	11,509	11,155	10,817	10,530	10,198	9,887
2021–22	-	12,769	12,388	12,020	11,610	11,245	10,906	10,560	10,217	9,899
Average annual growth	-	3.4%	3.4%	3.5%	2.5%	2.5%	2.5%	1.5%	1.5%	1.5%

2011 and 2012 forecast comparisons

Figure 5-6 compares the 2012 NEFR medium scenario and 2011 ESOO medium economic growth scenario summer 10%, 50%, and 90% POE maximum demand forecasts.

The average annual summer 10% POE maximum demand forecast growth rate is expected to be 1.6% over the 9-year outlook period from 2012–13 to 2020–21, representing a 0.4% reduction from the 2011 ESOO forecast.

Figure 5-6 — Comparison of the 2012 NEFR and 2011 ESOO summer maximum demand forecasts for Queensland



5.2.2 Winter maximum demand forecasts

Figure 5-7 shows winter 50% POE maximum demand forecasts under the three main scenarios (and actual data). Winter 50% POE maximum demand is forecast to increase over the next 10 years at an annual average growth rate of 2.9% under the medium scenario, and 3.8% and 2.0% under the high and low scenarios, respectively. Trends in maximum demand are largely the same as annual energy.

Winter maximum demand peaked in 2008 at 8,284 MW, decreasing by 446 MW in winter 2011.

Under each of the three main scenarios, maximum demand growth rates are slightly higher in winter than in summer, due to the minimal impact of rooftop PV, which is assumed to be zero during winter, and because maximum demand in Queensland often occurs after 5:00 PM.

Figure 5-7 — Winter 50% POE maximum demand forecasts for Queensland

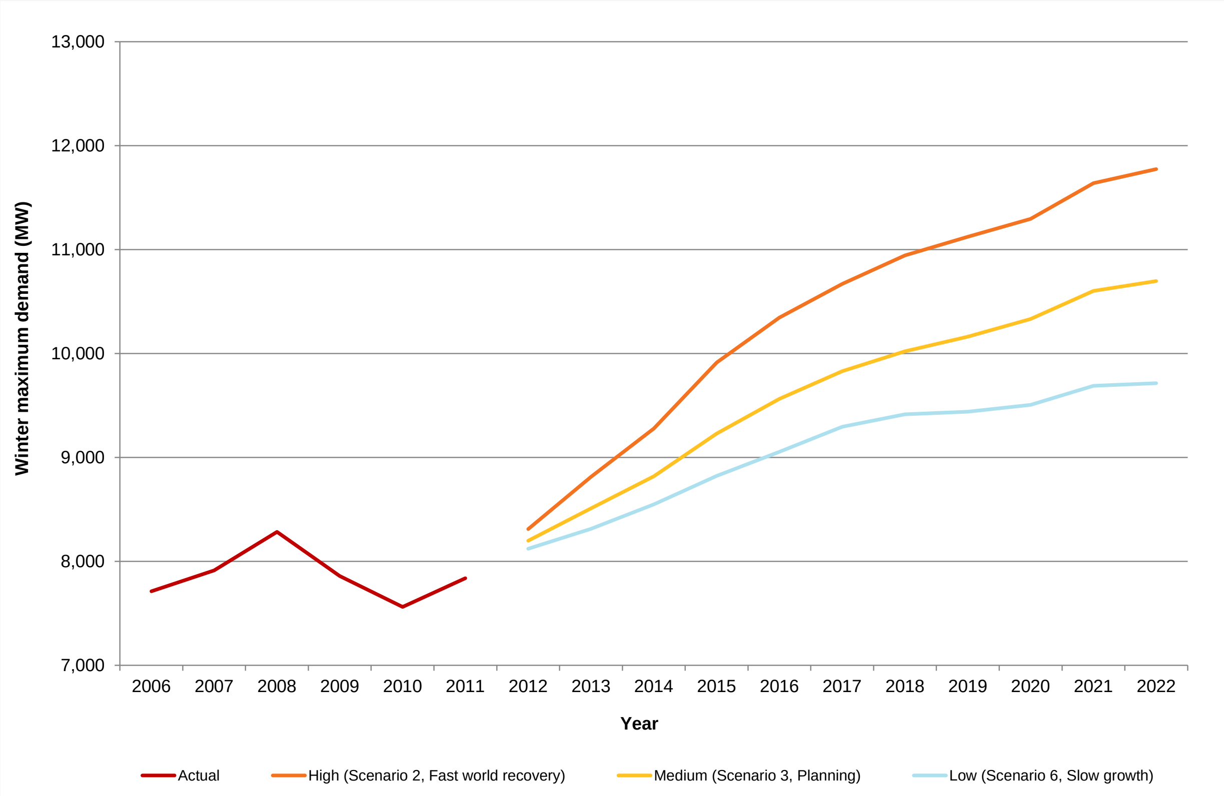


Table 5-4 presents actual and forecast winter 10%, 50% and 90% POE maximum demand for Queensland under the three main scenarios.

Table 5-4 — Winter maximum demand forecasts for Queensland (MW)

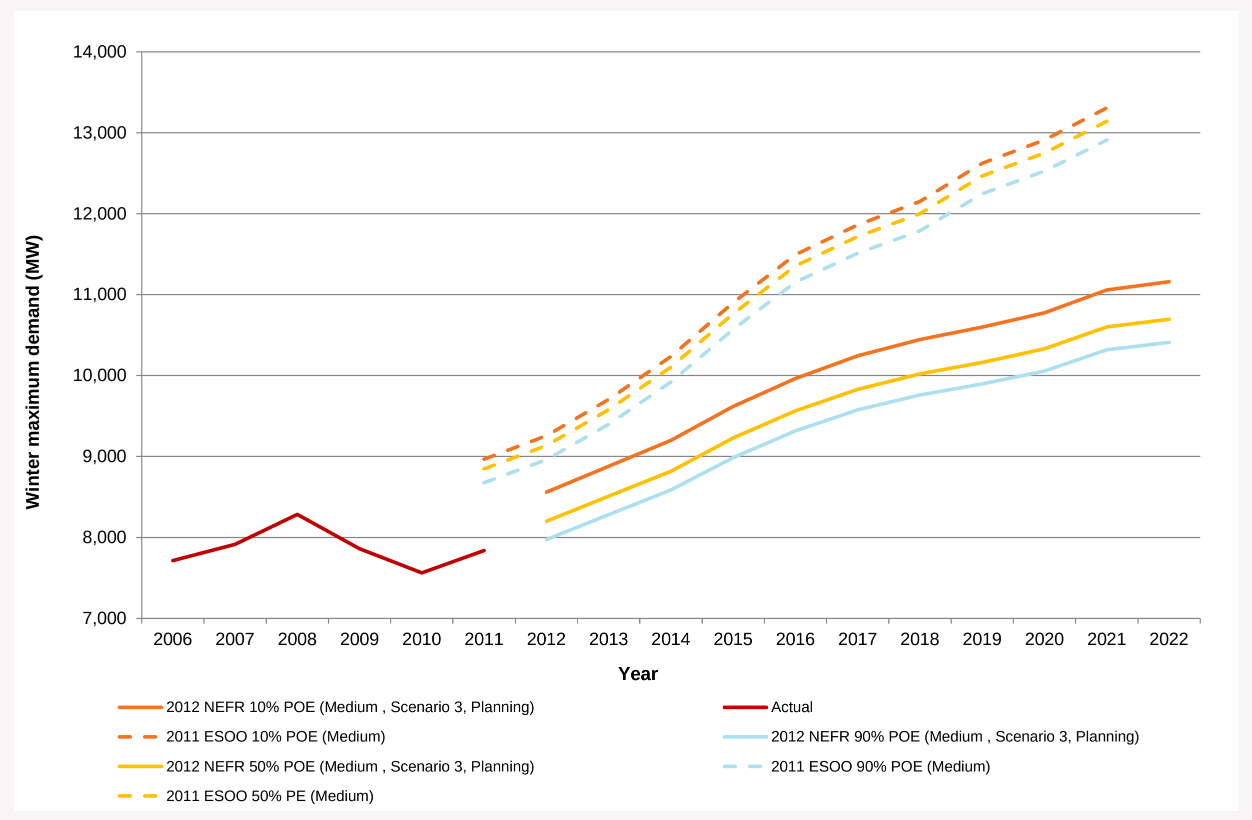
	Actual	High (Scenario 2, Fast World Recovery)			Medium (Scenario 3, Planning)			Low (Scenario 6, Slow Growth)		
		10%	50%	90%	10%	50%	90%	10%	50%	90%
2006	7,713	-	-	-	-	-	-	-	-	-
2007	7,914	-	-	-	-	-	-	-	-	-
2008	8,284	-	-	-	-	-	-	-	-	-
2009	7,860	-	-	-	-	-	-	-	-	-
2010	7,563	-	-	-	-	-	-	-	-	-
2011	7,838	-	-	-	-	-	-	-	-	-
2012	-	8,675	8,311	8,085	8,560	8,199	7,974	8,484	8,122	7,901
2013	-	9,182	8,812	8,582	8,880	8,510	8,281	8,678	8,313	8,089
2014	-	9,668	9,278	9,041	9,200	8,818	8,585	8,919	8,548	8,319
2015	-	10,308	9,913	9,667	9,618	9,229	8,987	9,207	8,824	8,590
2016	-	10,758	10,345	10,092	9,964	9,563	9,316	9,443	9,055	8,813
2017	-	11,093	10,670	10,411	10,244	9,830	9,576	9,696	9,296	9,049
2018	-	11,379	10,944	10,674	10,445	10,021	9,759	9,822	9,416	9,169
2019	-	11,574	11,124	10,847	10,598	10,162	9,897	9,850	9,440	9,193
2020	-	11,750	11,295	11,013	10,774	10,331	10,055	9,922	9,507	9,250
2021	-	12,110	11,638	11,345	11,058	10,601	10,318	10,113	9,689	9,433
2022	-	12,258	11,773	11,476	11,158	10,696	10,410	10,138	9,713	9,453
Average annual growth	-	3.8%	3.8%	3.8%	2.9%	2.9%	2.9%	2.0%	2.0%	2.0%

2011 and 2012 forecast comparison

Figure 5-8 compares the 2012 NEFR medium scenario and 2011 ESOO medium economic growth scenario winter 10%, 50% and 90% POE maximum demand forecasts.

The average annual winter 10% POE maximum demand forecast growth rate is expected to be 2.9% over the 10-year outlook period from 2012 to 2021, representing a 1.2% reduction from the 2011 ESOO forecasts.

Figure 5-8 — Comparison of the 2012 NEFR and 2011 ESOO winter maximum demand forecasts for Queensland



5.3 Small non-scheduled generation forecasts

This section presents forecasts of the contribution from small non-scheduled generation (excluding semi-scheduled, significant non-scheduled, and exempt generation) to annual energy and maximum demand, which are not included in the definition of operational demand.

It is possible that some non-scheduled generators may not be included due to their small size, lack of production, or lack of accurate data. These forecasts consider all non-scheduled generation (as nominated by the jurisdictional planning bodies (JPBs)), which is different from previous reports.

When establishing the adequacy of NEM generation supplies, both the supply-demand outlook and Medium-term Projected Assessment of System Adequacy (MT PASA) make assessments based only on the demand met by scheduled and semi-scheduled generation, 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 plants.

The small non-scheduled generation forecasts presented in this section are subtracted from both the annual When establishing the adequacy of NEM generation supplies, both the supply-demand outlook and the MT PASA make assessments based only on the demand met by scheduled and semi-scheduled generation, 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 generation.

The small non-scheduled generation forecasts presented in this section are subtracted from both the annual energy and maximum demand forecasts to calculate operational generation forecasts used in the supply-demand outlook.

For a list of the scheduled and semi-scheduled generators (by region) used to calculate these forecasts, see Appendix C.

Forecasts of small non-scheduled generation energy for Queensland

Table 5-5 lists the forecast and actual energy of small non-scheduled generation under the three main scenarios.

Table 5-6 presents forecasts of the contribution to summer and winter maximum demand from Queensland small non-scheduled generation.

Energy supplied by small non-scheduled generating units in Queensland is forecast to increase over the next 10 years at an annual average rate of between 1.4% and 4.7% (depending on economic scenario), compared with historical annual average growth of 8.6%.

The majority of large projects are expected to register as semi-scheduled rather than non-scheduled. This contributes to relatively low to medium projected growth in non-scheduled energy, capacity, and contribution to summer maximum demand.

Table 5-5 — Forecasts of small non-scheduled generation energy for Queensland (GWh)

	Actual	High (Scenario 2, Fast World Recovery)[a]	Medium (Scenario 3, Planning)[a]	Low (Scenario 6, Slow Growth)[a]
2005–06	507	-	-	-
2006–07	628	-	-	-
2007–08	786	-	-	-
2008–09	812	-	-	-
2009–10	834	-	-	-
2010–11	834	-	-	-
2011–12 (estimate)	834	-	-	-
2012–13	-	860	860	860
2013–14	-	885	885	885
2014–15	-	910	910	910
2015–16	-	936	936	936
2016–17	-	961	961	961
2017–18	-	987	987	987
2018–19	-	1,012	1,012	1,012
2019–20	-	1,037	1,037	1,037
2020–21	-	1,063	1,063	1,063
2021–22	-	1,088	1,088	1,088
Average annual growth	8.6%	2.7%	2.7%	2.7%

a. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

Table 5-6 — Forecasts of the small non-scheduled generation contribution to maximum demand for Queensland (MW)

	Actual	Summer maximum demand			Actual	Winter maximum demand		
		High (Scenario 2, Fast World Recovery)[a]	Medium (Scenario 3, Planning)[a]	Low (Scenario 6, Slow Growth)[a]		High (Scenario 2, Fast World Recovery)[b]	Medium (Scenario 3, Planning)[b]	Low (Scenario 6, Slow Growth)[b]
2005–06	9	-	-	-		-	-	-
2006–07	53	-	-	-	4	-	-	-
2007–08	95	-	-	-	52	-	-	-
2008–09	93	-	-	-	72	-	-	-
2009–10	164	-	-	-	231	-	-	-
2010–11	82	-	-	-	225	-	-	-
2011–12	157	-	-	-	200	-	-	-
2012–13	-	163	163	163	-	157	157	157
2013–14	-	169	169	169	-	163	163	163
2014–15	-	175	175	175	-	169	169	169
2015–16	-	181	181	181	-	175	175	175
2016–17	-	187	187	187	-	181	181	181
2017–18	-	193	193	193	-	187	187	187
2018–19	-	199	199	199	-	193	193	193
2019–20	-	205	205	205	-	199	199	199
2020–21	-	211	211	211	-	205	205	205
2021–22	-	217	217	217	-	211	211	211

a. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

b. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

CHAPTER 6 - SOUTH AUSTRALIA FORECASTS

Summary

This chapter presents information about annual energy, maximum demand (summer and winter), and non-scheduled generation for the South Australian region. It also includes information about historical annual energy, mass market forecasts, large industrial forecasts, and an annual electrical energy requirement breakdown.

Annual energy

Key differences between the 2011 Electricity Statement of Opportunities (ESOO) and the 2012 National Electricity Forecasting Report (NEFR) include the following:

- Annual energy for 2011–12 is expected to be 5.2% lower than 2010–11, and 10.5% lower than forecast in the 2011 ESOO (medium economic growth scenario).
- Forecast annual energy for 2012–13 is expected to only grow by 0.1%, which represents a 12.2% reduction from the 2011 ESOO forecasts.
- Average growth in annual energy for the 10-year outlook period is now forecast to be 0.9%, down from the 1.5% forecast in the 2011 ESOO.

Maximum demand

Key differences between the 2011 ESOO medium economic growth scenario and the 2012 NEFR Planning (medium) scenario summer maximum demand forecasts include the following:

- The 2011–12 actual summer maximum demand was the same as the 2011 ESOO 90% probability of exceedence (POE) forecast.
- The 2012–13 forecast summer 10% POE maximum demand has been reduced by 360 MW.
- Average growth in summer 10% POE maximum demand for the 10-year outlook period is now forecast to be 1.0%, down from the 1.7% forecast in the 2011 ESOO.

Main factors contributing to forecast change

Annual energy and maximum demand forecasts have decreased since the 2011 ESOO for several main reasons:

- A slower than expected forecast increase in consumption from large industrial customers, including developments in the mining sector and the Port Stanvac water desalination plant.
- The significant penetration of rooftop photovoltaics (PV). Among the regions, South Australia has the highest penetration of rooftop PV. In 2011–12, rooftop PV systems are estimated to have generated 306 GWh, or 2.4% of estimated annual energy.[1] In 2012–13, rooftop PV energy is forecast to be 448 GWh or 3.4% of annual energy under the Planning (medium) scenario. By 2021–22, this is forecast to increase to 900 GWh or 6.4% of annual energy. Over the 10-year outlook period, the average annual growth rate of rooftop PV energy is expected to be 8.1%. For more information, see AEMO's Rooftop PV Information Paper.[2]
- Reduced manufacturing consumption in response to the high Australian dollar. An expected increase in cheaper imports is expected to partially offset domestic growth.
- A moderation in gross state product (GSP) compared to the 2011 ESOO economic outlook, especially in the short term, has influenced reduced annual energy forecasts.

[1] Estimated annual energy does not include rooftop PV generation.

[2] AEMO, available http://www.aemo.com.au/en/Electricity/Forecasting. Viewed June 2012.

- Increasing (real) residential electricity prices. In 2011–12 and 2012–13, electricity prices are expected to increase, and then (on average) moderate from 2013–14 until the end of the outlook period.
- Consumer response (commercial and residential) to rising electricity costs and energy efficiency measures.

6.1 Annual energy forecasts

This section presents annual energy forecasts for South Australia based on AEMO modelling. For more information about the modelling, see AEMO's Forecasting Methodology Information Paper.[3]

Annual energy is defined on a 'sent-out' basis. Actual annual energy in 2011–12 includes two financial quarters of actual data and two financial quarters of estimated data.

6.1.1 Annual energy forecasts

Annual energy increased on average by 0.5% per year from 2000–01 to 2011–12. Historical annual energy decreased by 3.5% on average from 2000–01 to 2001–02, followed by an increase of 1.6% on average until 2010–11, and a decrease of 5.2% from 2010–11 to 2011–12.

Annual energy in South Australia is projected to grow over the 10-year outlook period from 2012–13 to 2021–22 at an annual average rate of 0.9% under the medium scenario, and 1.6% and 0.03% under the high and the low scenarios, respectively.

It is expected that in 2012–13 forecasts are similar to actual energy in 2011–12. From 2013–14, changes in the mass market and the mining sector are driving changes in the forecasts.

Annual energy forecasts are offset by the penetration of rooftop PV and energy efficiency savings, which are expected to grow across the 10-year outlook period under these three main scenarios.

Figure 6-1 shows the forecast and actual energy under the three main scenarios. Table 6-1 lists the data used to plot the forecast charts.

[3] See note 2.

Figure 6-1 — Annual energy forecasts for South Australia

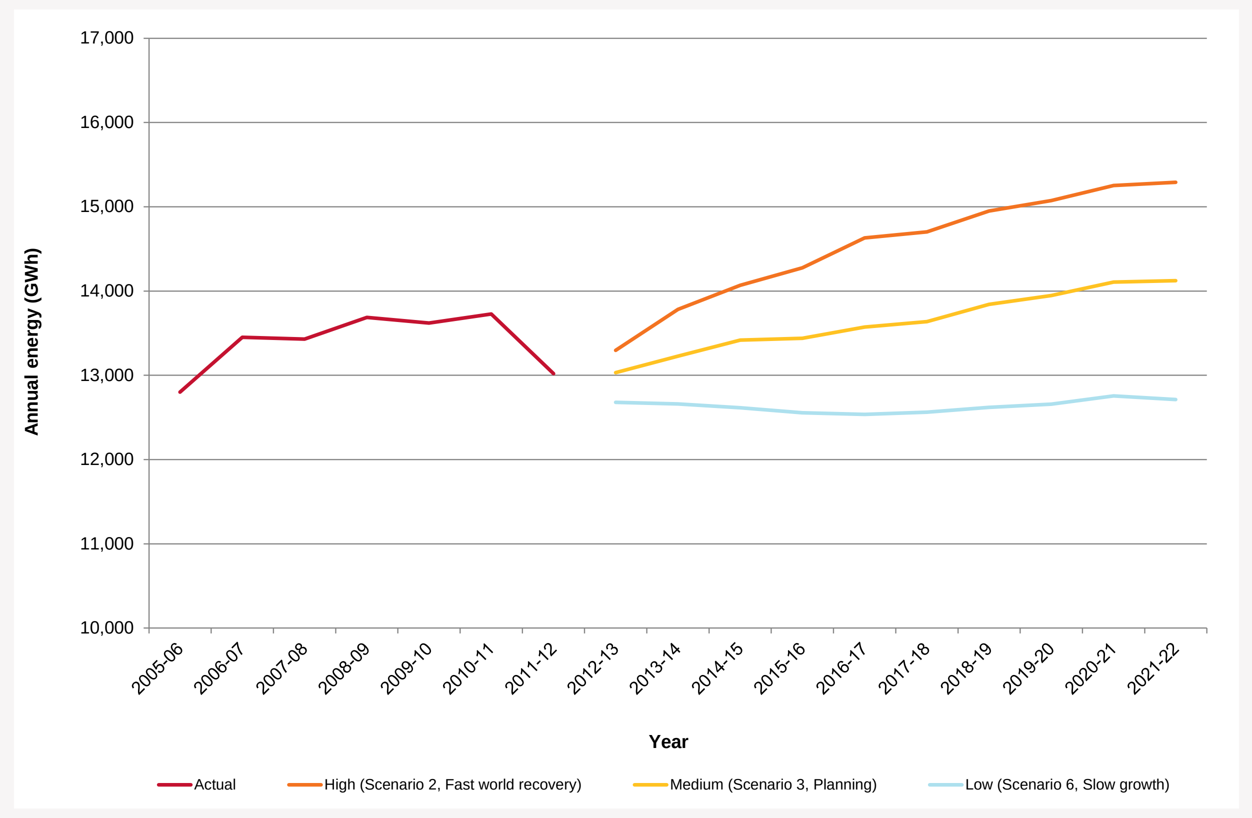


Table 6-1 — Annual energy forecasts for South Australia (GWh)

	Actual	High (Scenario 2, Fast World Recovery)	Medium (Scenario 3, Planning)	Low (Scenario 6, Slow Growth)
2005–06	12,802	-	-	-
2006–07	13,451	-	-	-
2007–08	13,431	-	-	-
2008–09	13,686	-	-	-
2009–10	13,621	-	-	-
2010–11	13,729	-	-	-
2011–12 (estimate)	13,020	-	-	-
2012–13	-	13,296	13,031	12,680
2013–14	-	13,783	13,226	12,659
2014–15	-	14,068	13,418	12,616
2015–16	-	14,275	13,440	12,556
2016–17	-	14,632	13,572	12,535
2017–18	-	14,703	13,637	12,563
2018–19	-	14,950	13,843	12,619
2019–20	-	15,073	13,947	12,659
2020–21	-	15,254	14,108	12,755
2021–22	-	15,290	14,123	12,713
Average annual growth	-	1.56%	0.90%	0.03%

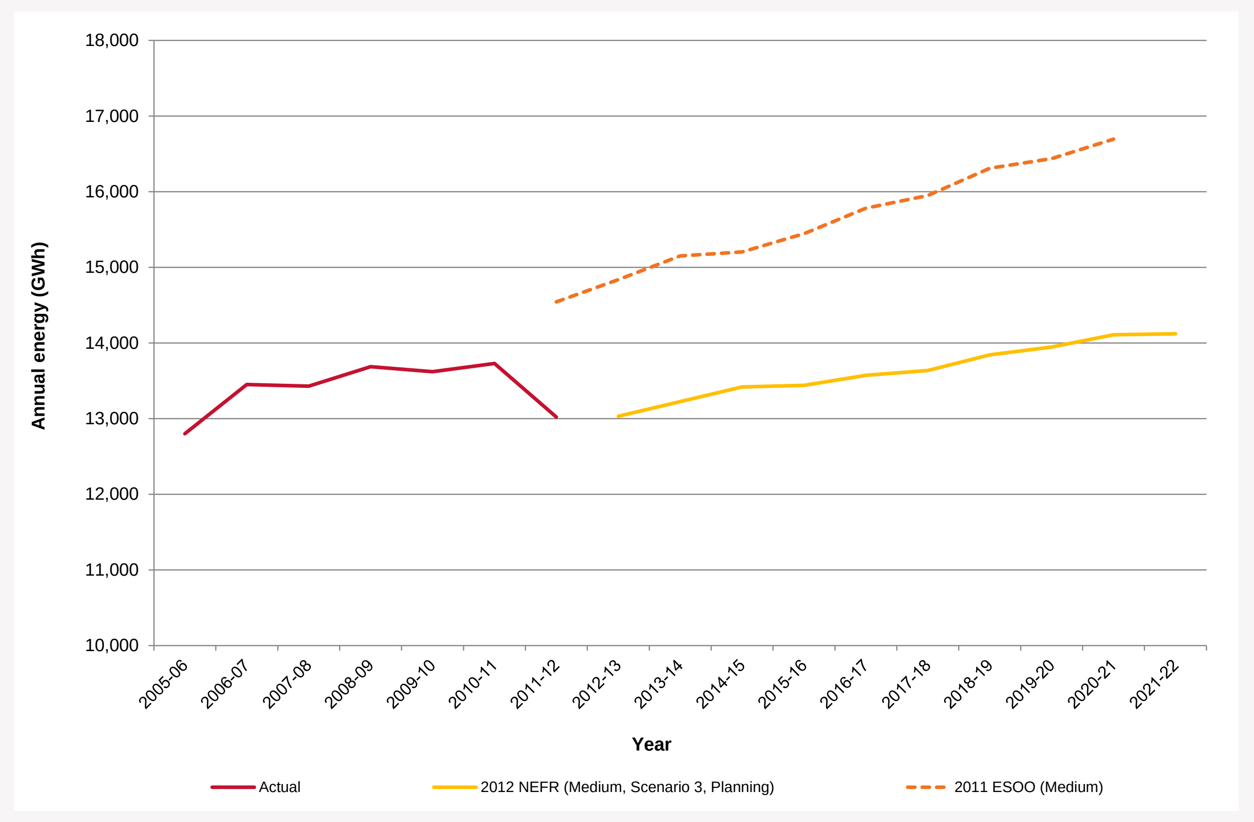
2011 and 2012 forecast comparison

Over the 9-year outlook period from 2012–13 to 2020–21, there is an average decrease in annual energy of approximately 2,180 GWh from the 2011 ESOO's medium economic growth scenario forecasts when compared with the 2012 medium scenario forecasts. This is equivalent to a decrease in average annual growth, from 1.5% in the 2011 ESOO to 0.9% in the 2012 NEFR.

Figure 6-2 shows actual energy and compares the forecast energy for the two forecasts.

In the near term, 2011–12 annual energy is expected to be 10.5% lower than the 2011 ESOO forecast. From 2011–12 to 2012–13, it is expected to remain flat, with the annual energy forecast for 2012–13 representing a 12.2% reduction from the 2011 ESOO forecast.

Figure 6-2 — Comparison of the 2012 NEFR and 2011 ESOO annual energy forecasts for South Australia



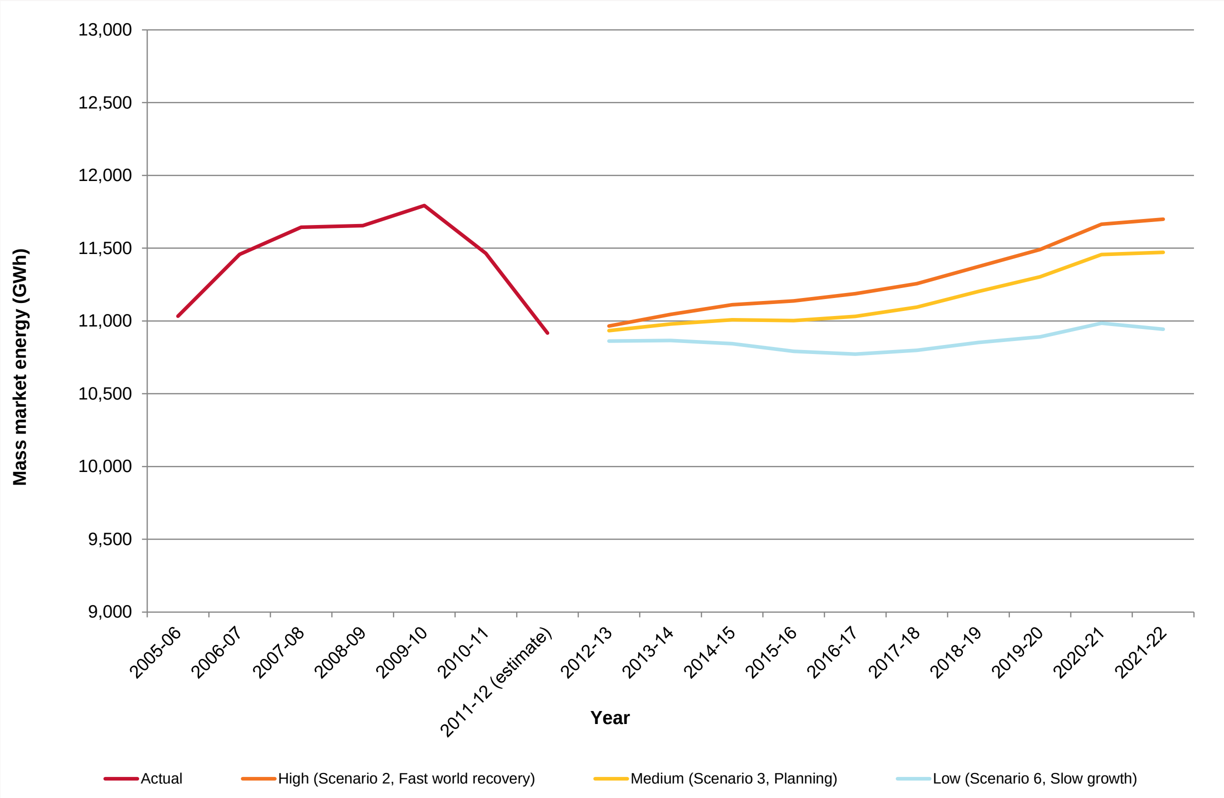
6.1.2 Mass market forecasts

Over the 10-year outlook period, the average annual growth rate for the medium, high and low scenarios is expected to be 0.5%, 0.7% and 0.1%, respectively.

Figure 6-3 shows forecast and actual consumption in the mass market under the three main scenarios.

Forecasts for the mass market have been calculated by developing a model for non-large industrial consumption, and then subtracting forecasts for rooftop PV and energy efficiency savings. For more information about the model for non-large industrial consumption, see Appendix A.

Figure 6-3 — Mass market forecasts for South Australia



6.1.3 Large industrial forecasts

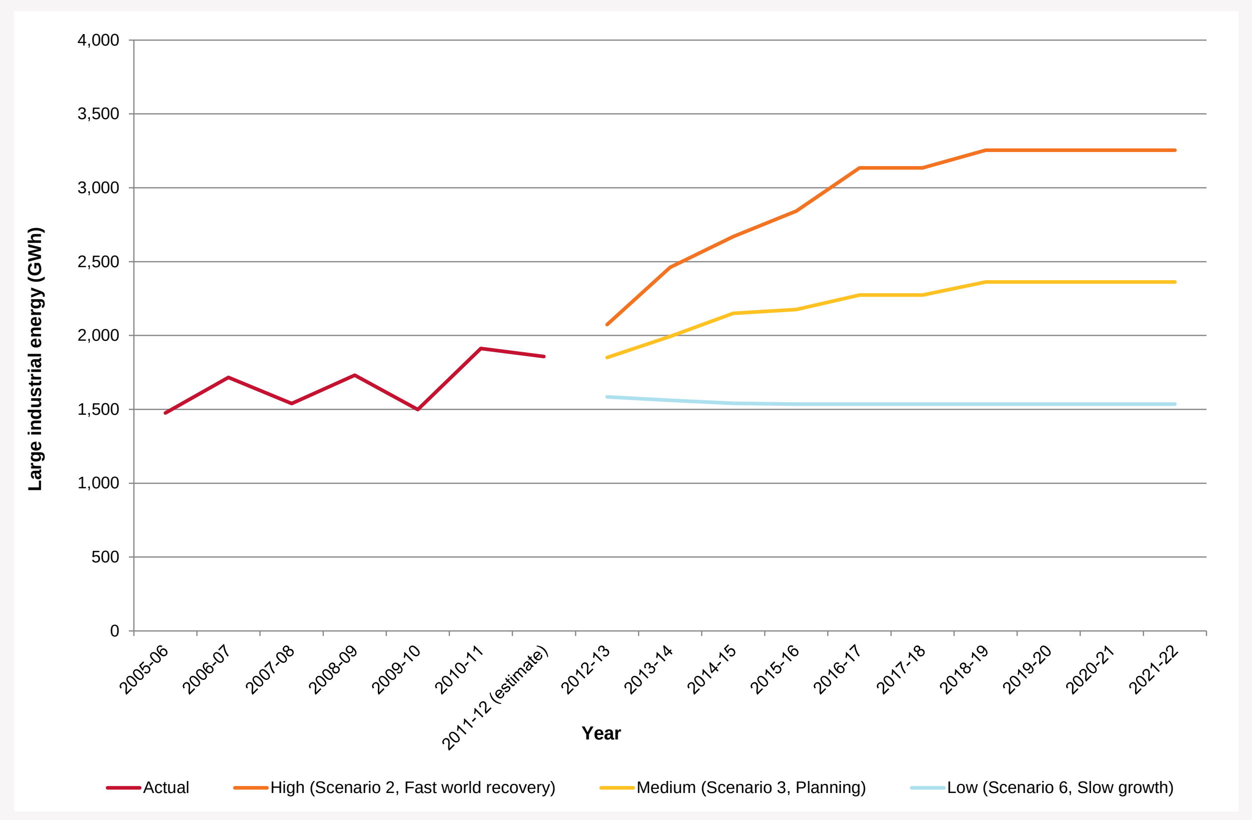
The large industrial forecasts include a number of new and existing customers:

- DSC Woomera.
- SANTOS Stony Point.
- SA Water (including the seawater desalination pumping stations).
- AMCOR Roseworthy.
- BHP Billiton (Olympic Dam).
- One Steel Middleback.
- Alinta Energy Leigh Creek Coal-field.
- Kimberly Clark.

New planning proposals for future large industrial projects (requiring transmission network connection points) and further mining exploration activity may potentially be developed in South Australia, but are not accounted for by the scenarios, due to a lack of sufficient information.

Figure 6-4 shows forecast and actual consumption in the large industrial sector under the three main scenarios. Energy consumption is forecast to increase over the next 10 years at an annual average rate of 2.8% under the medium scenario, and 5.2% and 0.4% under the high and low scenarios, respectively.

Figure 6-4 — Large industrial forecasts for South Australia



6.1.4 Annual electrical energy requirement breakdown

Table 6-2 provides a breakdown of the annual energy forecasts by customer sales, network losses, and auxiliary energy use by generators under the medium scenario.

Table 6-2 — Annual electrical energy requirement breakdown for South Australia (GWh)

	Customer sales	Transmission network losses	Annual energy (sent out basis)[a]	Auxiliary energy use	Annual energy (as-generated basis)[b]
Actual					
2005–06	12,509	293	12,802	876	13,678
2006–07	13,174	277	13,451	773	14,224
2007–08	13,183	247	13,431	840	14,271
2008–09	13,386	296	13,686	807	14,493
2009–10	13,291	313	13,621	780	14,401
2010–11	13,376	311	13,729	769	14,498
2011–12 (estimate)	12,774	246	13,020	725	13,745
Medium scenario (Scenario 3, Planning)					
2012–13	12,785	246	13,031	714	13,745
2013–14	12,973	254	13,226	721	13,947
2014–15	13,158	261	13,418	727	14,145
2015–16	13,178	262	13,440	727	14,166
2016–17	13,305	267	13,572	730	14,302
2017–18	13,368	269	13,637	735	14,373
2018–19	13,565	277	13,843	741	14,584
2019–20	13,666	281	13,947	749	14,696
2020–21	13,820	288	14,108	753	14,861
2021–22	13,834	288	14,123	754	14,877

a. Annual energy (sent out basis) is defined as the total of customer sales and transmission network losses.

b. Annual energy (as-generated basis) is defined as the total of annual energy (sent out basis) and auxiliary energy use.

6.2 Maximum demand forecasts

The maximum demand in South Australia occurs in summer.

Half-hourly temperature data was obtained from the Kent Town station.

6.2.1 Summer maximum demand forecasts

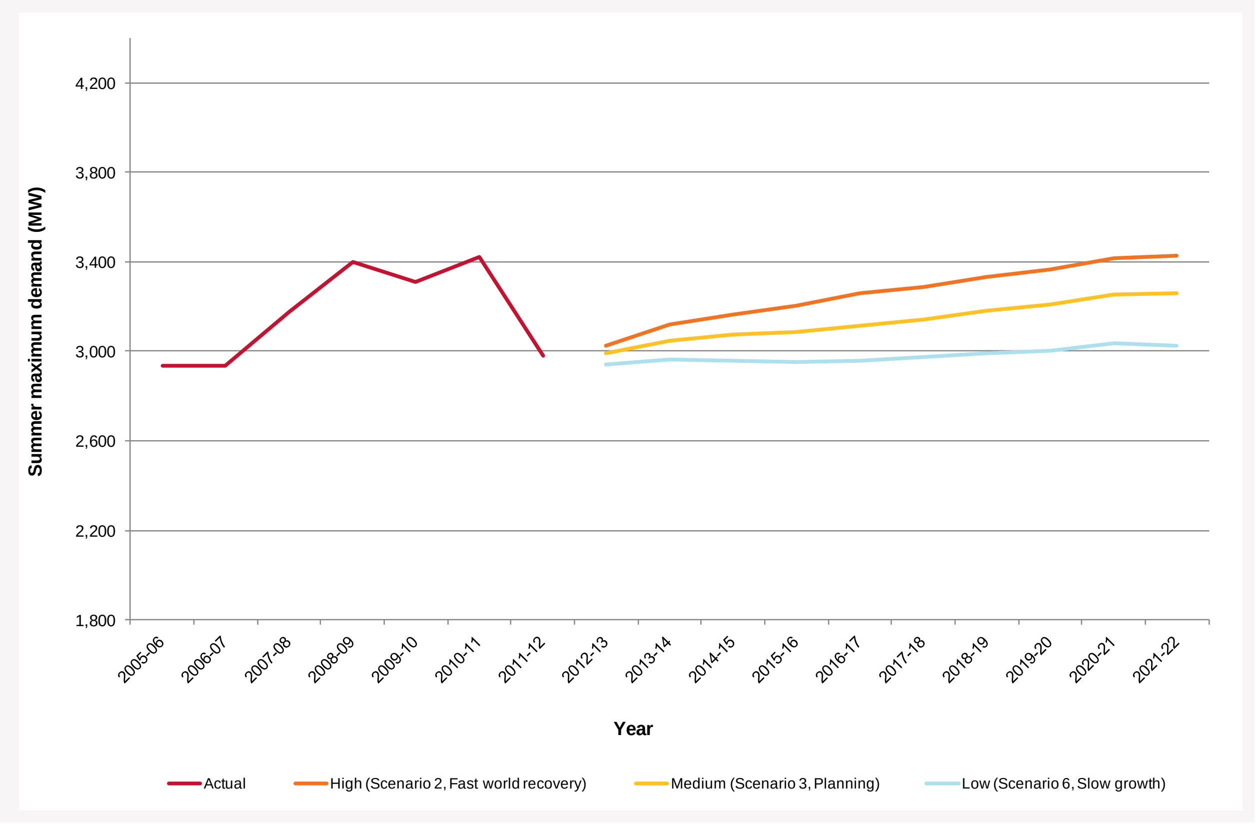
Figure 6-5 shows summer 50% POE maximum demand forecasts under the three main scenarios (and actual data).

The summer 50% POE maximum demand is forecast to increase over the next 10 years at an annual average rate of 1% under the medium scenario, and 1.4% and 0.3% under the high and low scenarios, respectively. Trends in maximum demand are largely the same as annual energy.

The load factor[4] for summer has averaged approximately 23% during the last 10 years.

Summer maximum demand peaked on 31 January in 2010–11 at 3,423 MW, decreasing by 445 MW in summer 2011–12.

Figure 6-5 — Summer 50% POE maximum demand forecasts for South Australia



[4] The load factor is defined as the annual maximum demand divided by the annual energy.

Table 6-3 presents actual and forecast summer 10%, 50%, and 90% POE maximum demand for South Australia under the three main scenarios.

Table 6-3 — Summer maximum demand forecasts for South Australia (MW)

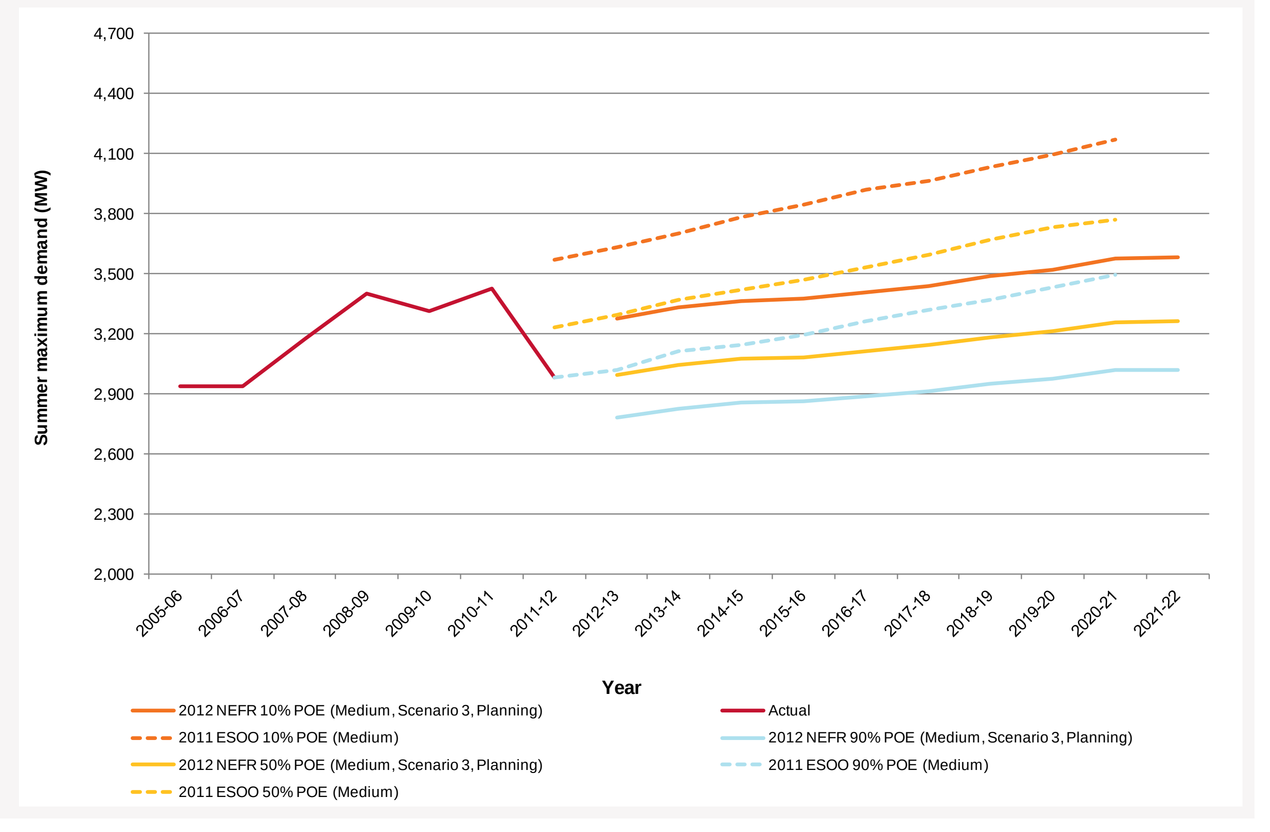
	Actual	High (Scenario 2, Fast World Recovery)			Medium (Scenario 3, Planning)			Low (Scenario 6, Slow Growth)		
		10%	50%	90%	10%	50%	90%	10%	50%	90%
2005–06	2,935	-	-	-	-	-	-	-	-	-
2006–07	2,936	-	-	-	-	-	-	-	-	-
2007–08	3,173	-	-	-	-	-	-	-	-	-
2008–09	3,401	-	-	-	-	-	-	-	-	-
2009–10	3,309	-	-	-	-	-	-	-	-	-
2010–11	3,424	-	-	-	-	-	-	-	-	-
2011–12	2,979	-	-	-	-	-	-	-	-	-
2012–13	-	3,308	3,025	2,811	3,271	2,990	2,778	3,218	2,939	2,728
2013–14	-	3,410	3,118	2,901	3,332	3,045	2,826	3,247	2,963	2,747
2014–15	-	3,455	3,163	2,943	3,362	3,073	2,855	3,242	2,957	2,742
2015–16	-	3,496	3,201	2,976	3,375	3,083	2,861	3,236	2,950	2,734
2016–17	-	3,558	3,259	3,031	3,407	3,112	2,887	3,245	2,956	2,737
2017–18	-	3,591	3,287	3,056	3,439	3,140	2,911	3,268	2,975	2,752
2018–19	-	3,646	3,335	3,100	3,488	3,183	2,951	3,288	2,992	2,766
2019–20	-	3,682	3,367	3,128	3,521	3,211	2,974	3,305	3,005	2,777
2020–21	-	3,740	3,417	3,173	3,573	3,256	3,015	3,340	3,036	2,804
2021–22	-	3,750	3,425	3,177	3,578	3,259	3,015	3,332	3,026	2,792
Average annual growth	-	1.4%	1.4%	1.4%	1.0%	1.0%	0.9%	0.39%	0.33%	0.26%

2011 and 2012 forecast comparison

Figure 6-6 compares the 2012 NEFR medium scenario and 2011 ESOO medium economic growth scenario summer 10%, 50%, and 90% POE maximum demand forecasts.

The average annual summer 10% POE maximum demand forecast growth rate is expected to be 1.1% over the 9-year outlook period from 2012–13 to 2020–21, representing a 0.6% reduction from the 2011 ESOO forecast.

Figure 6-6 — Comparison of the 2012 NEFR and 2011 ESOO summer maximum demand forecasts for South Australia



6.2.2 Winter maximum demand forecasts

Figure 6-7 shows winter 50% POE maximum demand forecasts under the three main scenarios (and actual data).

The winter 50% POE maximum demand is forecast to increase over the next 10 years at an annual average rate of 1.2% under the medium scenario, and 1.8% and 0.4% under the high and low scenarios, respectively. Trends in maximum demand are largely the same as annual energy.

Winter maximum demand peaked on 29 July 2008 at 2,530 MW (and was only slightly lower in 2010 at 2,523 MW), decreasing by 143 MW in winter 2011.

The impact of rooftop PV on winter maximum demand is assumed to be zero due to the maximum demand in South Australia often occurring in the evening around 6:30 PM to 7:30 PM, coinciding with increased use of space heating and electrical appliances.

Figure 6-7 — Winter 50% POE maximum demand forecasts for South Australia

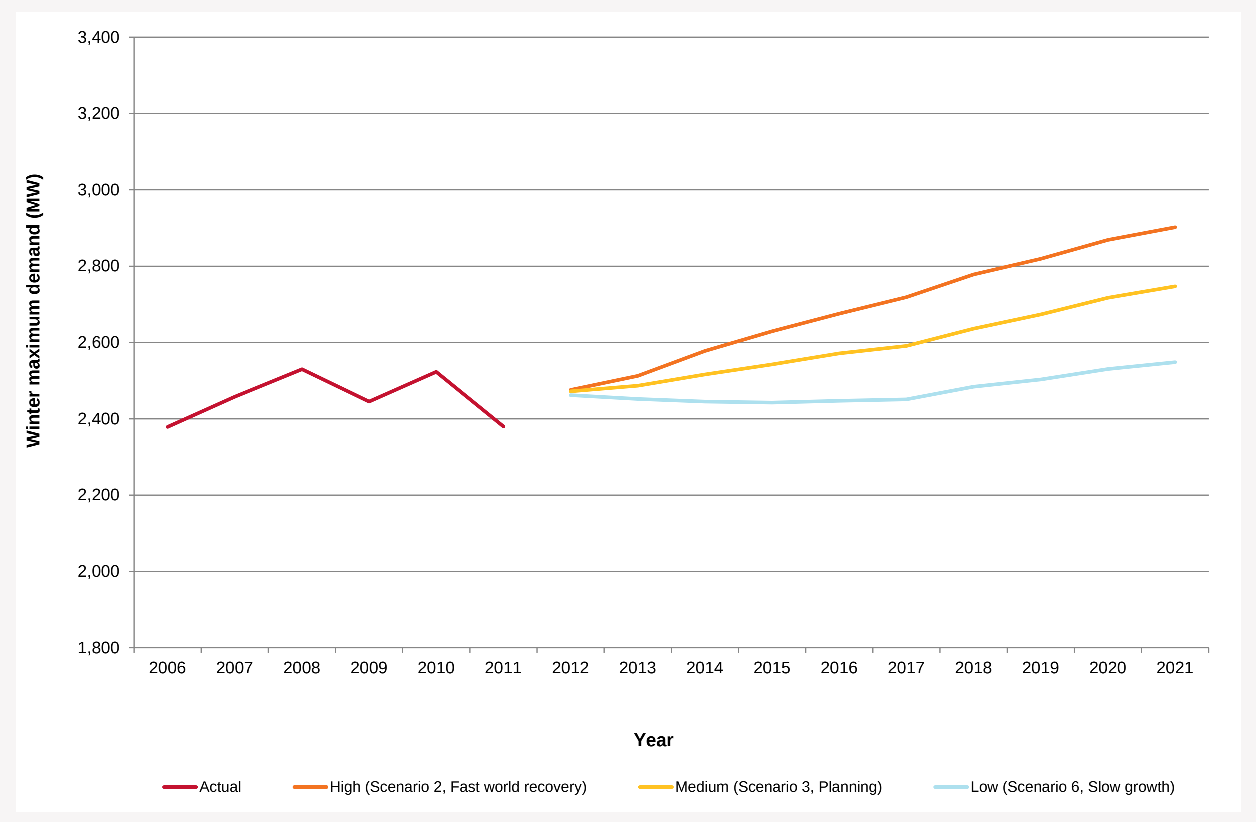


Table 6-4 lists actual and forecast winter 10%, 50%, and 90% POE maximum demand for South Australia under the three main scenarios.

Table 6-4 — Winter maximum demand forecasts for South Australia (MW)

	Actual	High (Scenario 2, Fast World Recovery)			Medium (Scenario 3, Planning)			Low (Scenario 6, Slow Growth)		
		10%	50%	90%	10%	50%	90%	10%	50%	90%
2006	2,379	-	-	-	-	-	-	-	-	-
2007	2,458	-	-	-	-	-	-	-	-	-
2008	2,530	-	-	-	-	-	-	-	-	-
2009	2,445	-	-	-	-	-	-	-	-	-
2010	2,523	-	-	-	-	-	-	-	-	-
2011	2,380	-	-	-	-	-	-	-	-	-
2012	-	2,578	2,476	2,412	2,574	2,472	2,408	2,565	2,462	2,398
2013	-	2,623	2,513	2,447	2,596	2,487	2,421	2,561	2,452	2,387
2014	-	2,690	2,578	2,511	2,627	2,516	2,450	2,556	2,445	2,380
2015	-	2,743	2,629	2,562	2,653	2,542	2,475	2,552	2,442	2,377
2016	-	2,789	2,676	2,607	2,682	2,571	2,505	2,557	2,447	2,381
2017	-	2,836	2,719	2,649	2,705	2,591	2,523	2,563	2,451	2,385
2018	-	2,894	2,778	2,708	2,748	2,636	2,567	2,594	2,484	2,417
2019	-	2,937	2,819	2,748	2,788	2,674	2,603	2,615	2,503	2,436
2020	-	2,987	2,869	2,796	2,833	2,717	2,645	2,642	2,530	2,461
2021	-	3,026	2,902	2,828	2,869	2,747	2,675	2,667	2,548	2,479
Average annual growth	-	0.43%	0.38%	0.37%	1.21%	1.18%	1.17%	1.80%	1.78%	1.79%

2011 and 2012 forecast comparison

Figure 6-8 the 2012 NEFR medium scenario and 2011 ESOO medium economic growth winter 10%, 50%, and 90% POE maximum demand forecasts.

The average annual winter 10% POE maximum demand forecast growth rate is expected to be 1.2% over the 10-year outlook period from 2012 to 2021, representing a 0.4% reduction from the 2011 ESOO forecasts.

Figure 6-8 — Comparison of the 2012 NEFR and 2011 ESOO forecasts for South Australia

6.3 Small non-scheduled generation forecasts

This section presents forecasts of the contribution from small non-scheduled generation (excluding semi-scheduled, significant non-scheduled, and exempt generation) to annual energy and maximum demand, which are not included in the definition of operational demand.

It is possible that some non-scheduled generators may not be included due to their small size, lack of production, or lack of accurate data. These forecasts consider all non-scheduled generation (as nominated by the jurisdictional planning bodies (JPBs)), which is different from previous reports.

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 only on the demand met by scheduled and semi-scheduled generation, 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 generation.

The small non-scheduled generation forecasts presented in this section are subtracted from both the annual energy and maximum demand forecasts to calculate operational generation forecasts used in the supply-demand outlook.

For a list of the scheduled and semi-scheduled generators (by region) used to calculate these forecasts, see Appendix C.

Forecasts of small non-scheduled generation energy for South Australia

Table 6-5 lists the forecast and actual energy of small non-scheduled generation under the three main scenarios.

Table 6-6 presents forecasts of the contribution to summer and winter maximum demand from South Australian small non-scheduled generation.

Energy supplied by small non-scheduled generating units in South Australia is forecast to increase over the next 10 years at an annual average rate of between 9.1% and 17.9% (depending on economic scenario), compared with historical annual average growth of 38%.

The majority of large projects are expected to register as semi-scheduled rather than non-scheduled. This contributes to relatively low to medium projected growth in non-scheduled energy, capacity, and contribution to summer maximum demand.

Table 6-5 — Forecasts of small non-scheduled generation energy for South Australia (GWh)

	Actual energy	High (Scenario 2, Fast World Recovery)[a]	Medium (Scenario 3, Planning)[a]	Low (Scenario 6, Slow Growth)[a]
2005–06	10	-	-	-
2006–07	10	-	-	-
2007–08	10	-	-	-
2008–09	10	-	-	-
2009–10	10	-	-	-
2010–11	10	-	-	-
2011–12 (estimate)	69	-	-	-
2012–13	-	90	90	90
2013–14	-	111	111	111
2014–15	-	133	133	133
2015–16	-	154	154	154
2016–17	-	175	175	175
2017–18	-	196	196	196
2018–19	-	217	217	217
2019–20	-	238	238	238
2020–21	-	260	260	260
2021–22	-	281	281	281
Average annual growth	32.1%	12.5%	12.5%	12.5%

a. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

Table 6-6 — Forecasts of the small non-scheduled generation contribution to maximum demand for South Australia (MW)

	Actual	Maximum demand					
		Scenario 1 Fast Rate of Change	Scenario 2 Fast World Recovery	Scenario 3 Planning	Scenario 4 Decentralised World	Scenario 5 Slow Rate of Change	Scenario 6 Slow Growth
2005-06	19						
2006-07	21						
2007-08	21						
2008-09	17						
2009-10	1						
2010-11	25						
2011-12	21						
2012-13		22	22	22	22	22	22
2013-14		23	23	23	23	23	23
2014-15		24	24	24	24	24	24
2015-16		26	26	26	26	26	26
2016-17		27	27	27	27	27	27
2017-18		28	28	28	28	28	28
2018-19		29	29	29	29	29	29
2019-20		30	30	30	30	30	30
2020-21		31	31	31	31	31	31
2021-22		32	32	32	32	32	32
2022-23		34	34	34	34	34	34
2023-24		35	35	35	35	35	35
2024-25		36	36	36	36	36	36
2025-26		37	37	37	37	37	37
2026-27		38	38	38	38	38	38
2027-28		39	39	39	39	39	39
2028-29		40	40	40	40	40	40
2029-30		42	42	42	42	42	42
2030-31		43	43	43	43	43	43
2031-32		44	44	44	44	44	44

a. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

b. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

CHAPTER 7 - TASMANIA FORECASTS

Summary

This chapter presents information about annual energy, maximum demand (summer and winter), and non-scheduled generation for the Tasmanian region. It also includes information about historical annual energy, mass market forecasts, large industrial forecasts, and an annual electrical energy requirement breakdown.

Annual energy

Key differences between the 2012 National Electricity Forecasting Report (NEFR) and Transend Network's 2011 annual energy forecasts, published in the 2011 ESOO, include the following:

- Annual energy for 2011-12 is expected to be 5.0% lower than 2010-11 and 7.3% lower than what was forecast in the 2011 ESOO (medium economic growth scenario).
- Forecast annual energy for 2012-13 is expected to increase by 0.7%, which represents an 8.5% reduction from the 2011 ESOO forecasts.
- Average growth in annual energy for the 10-year outlook period is forecast to be 0.9%, the same as was forecast in the 2011 ESOO.

Maximum demand

Key differences between the 2012 NEFR and Transend Network's 2011 winter maximum demand medium economic growth scenario forecasts include the following:

- The 2011 actual winter maximum demand was 40 MW below Transend Network's 90% POE forecast.
- The 2012 forecast winter 10% POE maximum demand is 110 MW lower than Transend's 2011 forecast.
- Average growth in winter 10% POE maximum demand for the 10-year outlook period is now forecast to be 1.1%, down from the 1.4% forecast in the 2011 ESOO.
- AEMO and Transend use different maximum demand forecasting methodology.

Main factors contributing to forecast change

Annual energy and maximum demand forecasts have decreased since the 2011 ESOO for several main reasons:

- Reduced consumption from large industrial customers. In 2011–12, energy use is expected to decline mainly due to BHP's Tasmanian Electro Metallurgical Company (TEMCO) manganese smelter suspending production between March and May 2012. In May 2012, BHP announced that TEMCO operations will be restarted and resume operating at full capacity by the end of August 2012.
- Increasing penetration of rooftop photovoltaics (PV). In 2011–12, rooftop PV systems are estimated to have generated 15 GWh or 0.1% of estimated annual energy.[1] In 2012–13, rooftop PV energy is forecast to be 30 GWh or 0.3% of annual energy under the Planning (medium) scenario. By 2021–22, this is forecast to increase to 147 GWh or 1.3% of annual energy. Over the 10-year outlook period, the average annual growth rate of rooftop PV energy is expected to be 19.3%. For more information, see AEMO's Rooftop PV Information Paper.[2]
- Reduced manufacturing consumption in response to the high Australian dollar. An expected increase in cheaper imports is expected to partially offset domestic growth.

[1] Estimated annual energy does not include rooftop PV generation.
[2] AEMO, available http://www.aemo.com.au/en/Electricity/Forecasting. Viewed June 2012.

- A decrease in economic growth (measured by gross state product (GSP)) forecasts since the 2011 ESOO influences lower energy forecasts, particularly in the short term.
- Increasing (real) residential electricity prices. In 2011–12 and 2012–13, electricity prices are expected to increase, and then (on average) moderate from 2013–14 until the end of the outlook period.
- Consumer response (commercial and residential) to rising electricity costs and energy efficiency measures.

7.1 Annual energy forecasts

This section presents annual energy forecasts for Tasmania based on AEMO modelling. For more information about the modelling, see AEMO's Forecasting Methodology Information Paper.[3]

Annual energy is defined on a 'sent-out' basis. Actual annual energy in 2011–12 includes two financial quarters of actual data and two financial quarters of estimated data.

7.1.1 Annual energy forecasts

Annual energy increased on average by 0.7% per year from 2002–03 to 2011–12. Historical annual energy peaked in 2007–08 and 2008–09, followed by largely negative annual average growth until 2011–12. In 2010–11, there was a brief recovery in economic growth, cooler winter conditions, and an increase in energy use in the industrial sector.

Annual energy in Tasmania is projected to grow over the 10-year outlook period from 2012–13 to 2021–22 at an annual average rate of 0.9% under the medium scenario, and 1.7% and -0.02% under the high and the low scenarios, respectively.

It is expected that in 2012–13 forecasts are similar to actual energy in 2011–12. From 2013–14, changes in the large industrial sector (smelting and mining) are driving changes in the forecasts.

Annual energy forecasts are offset by the penetration of rooftop PV and energy efficiency savings, which are expected to grow across the 10-year outlook period under these three main scenarios.

[3] See note 2.

Figure 7-1 shows the forecast and actual energy for the three main scenarios.

Table 7-1 lists the data used to plot the forecast charts.

Figure 7-1 — Annual energy forecasts for Tasmania

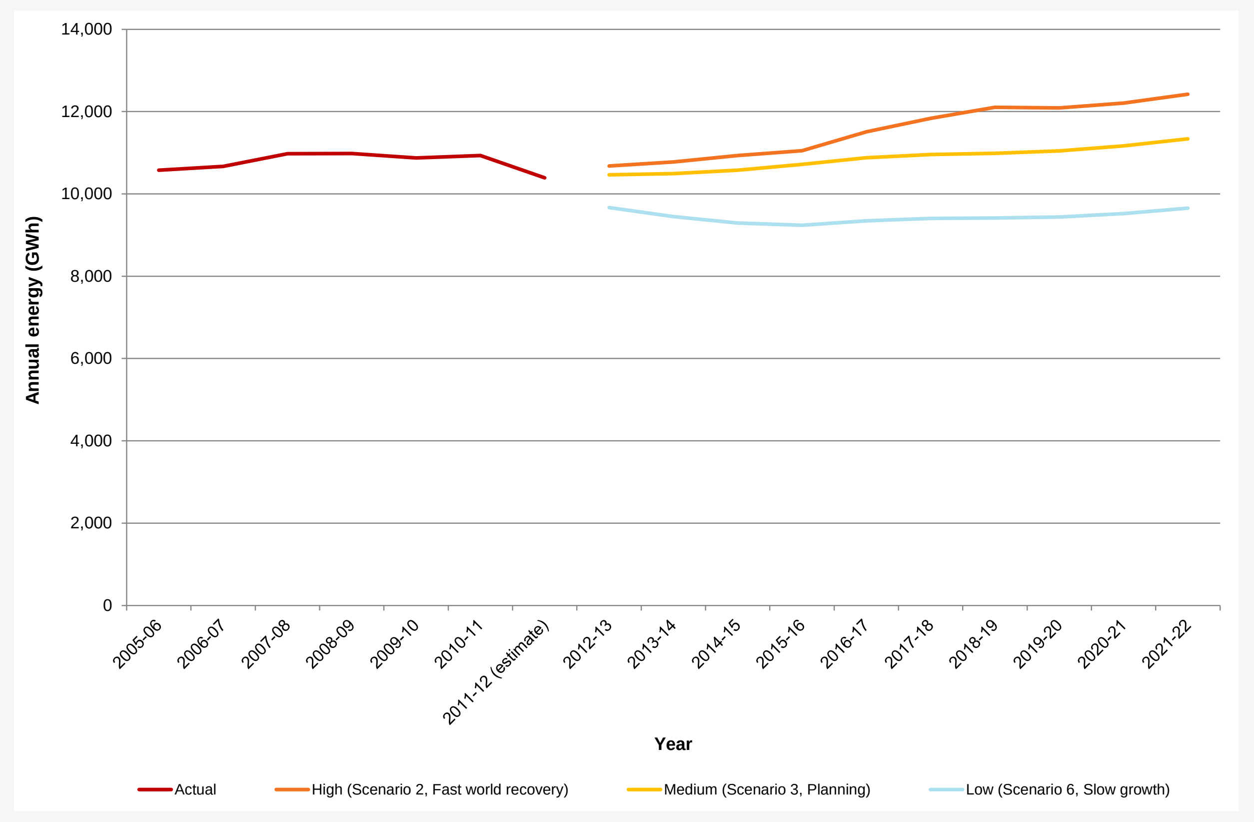


Table 7-1 — Annual energy forecasts for Tasmania (GWh)

	Actual	High (Scenario 2, Fast World Recovery)	Medium (Scenario 3, Planning)	Low (Scenario 6, Slow Growth)
2005–06	10,574	-	-	-
2006–07	10,667	-	-	-
2007–08	10,974	-	-	-
2008–09	10,979	-	-	-
2009–10	10,877	-	-	-
2010–11	10,934	-	-	-
2011–12 (estimate)	10,391	-	-	-
2012–13	-	10,681	10,466	9,666
2013–14	-	10,778	10,494	9,451
2014–15	-	10,930	10,578	9,291
2015–16	-	11,050	10,716	9,239
2016–17	-	11,507	10,877	9,346
2017–18	-	11,835	10,959	9,404
2018–19	-	12,104	10,988	9,414
2019–20	-	12,091	11,044	9,438
2020–21	-	12,205	11,169	9,520
2021–22	-	12,419	11,336	9,652
Average annual growth	-	1.69%	0.89%	-0.02%

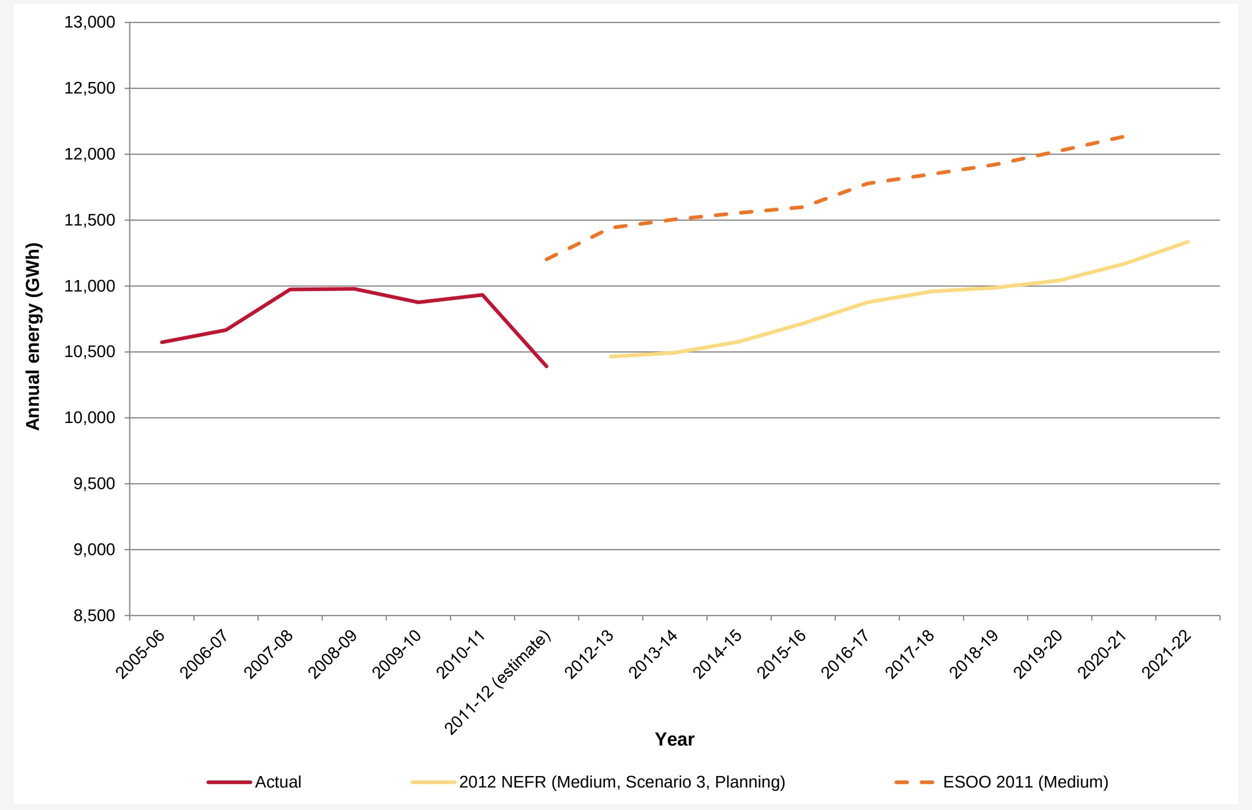
2011 and 2012 forecast comparison

Over the 9-year outlook period from 2012–13 to 2020–21, there is an average reduction of 947 GWh from the 2011 ESOO's medium economic growth scenario forecasts when compared with the 2012 medium scenario forecasts. This is equivalent to average annual growth of 0.9% for both the 2011 ESOO and the 2012 NEFR.

Figure 7-2 shows actual energy and compares the forecast energy for the two forecasts.

In the near term, 2011–12 annual energy was 7.3% lower than the 2011 ESOO forecast. From 2011–12 to 2012–13, it is expected to grow by 0.7%, with the annual energy forecast for 2012–13 representing an 8.5% reduction from the 2011 ESOO forecasts.

Figure 7-2 — Comparison of the 2012 NEFR and 2011 ESOO annual energy forecasts for Tasmania



7.1.2 Mass market forecasts

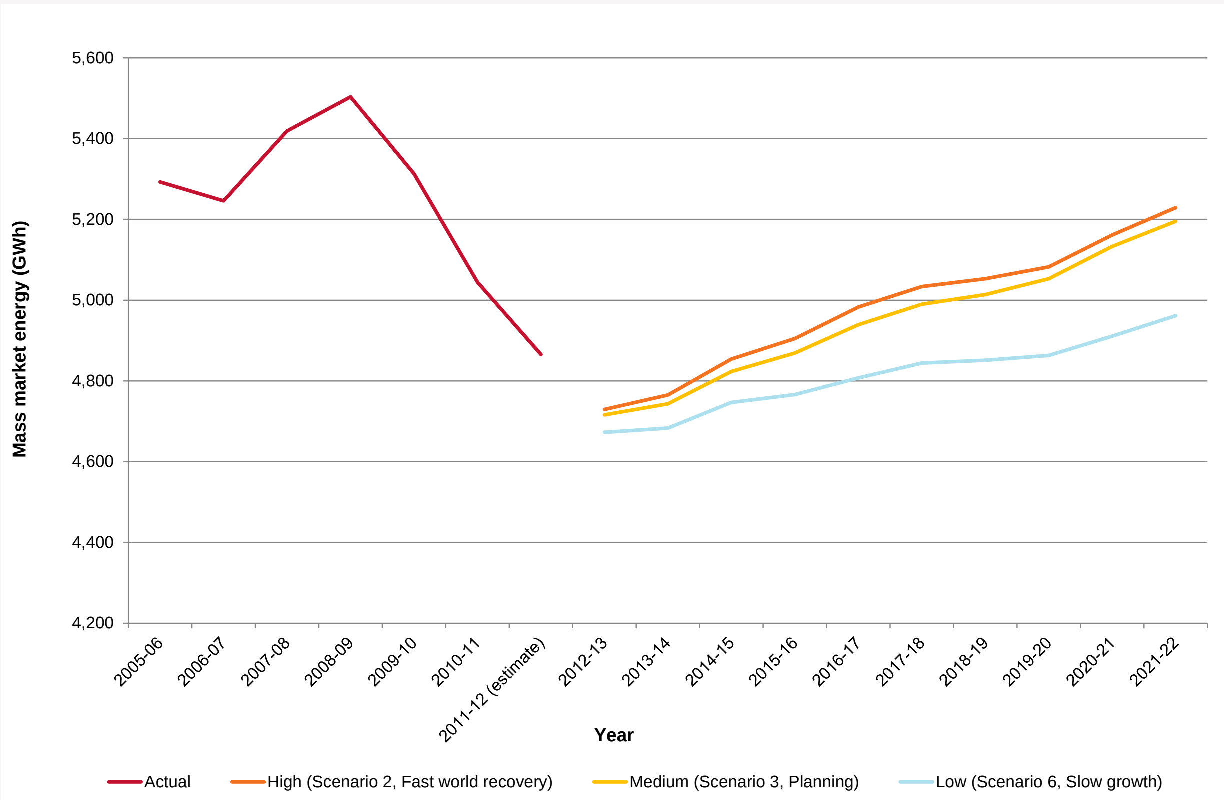
Over the 10-year outlook period, the average annual growth rate for the medium, high and low scenarios is expected to be 1.1%, 1.1% and 0.7%, respectively.

There is only a small difference between the medium and high scenarios, which is due to stronger economic growth and higher electricity prices offsetting each other under the high scenario.

Figure 7-3 shows forecast and actual consumption in the mass market sector under the three main scenarios.

Forecasts for the mass market have been calculated by developing a model for non-large industrial consumption, and then subtracting forecasts for rooftop PV and energy efficiency savings. For more information about the model for non-large industrial consumption, see Appendix A.

Figure 7-3 — Mass market forecasts for Tasmania



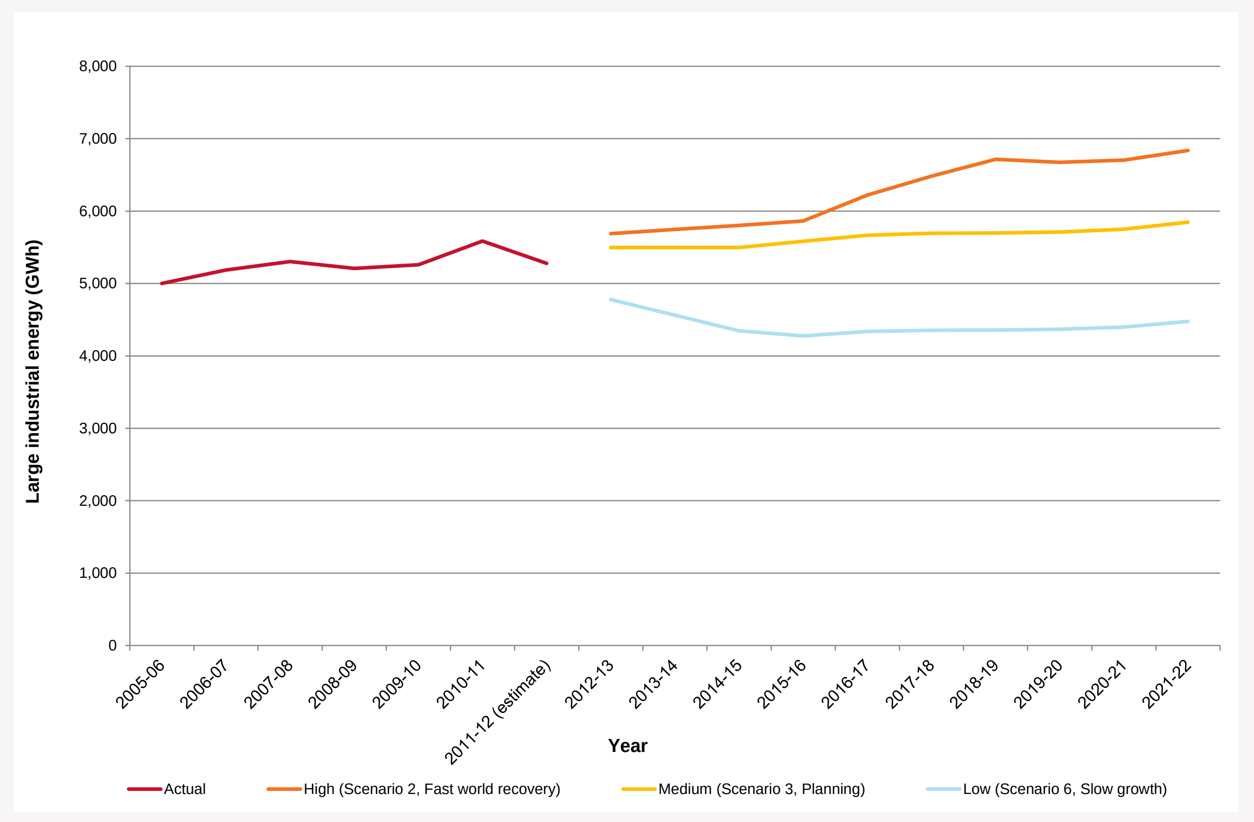
7.1.3 Large industrial forecasts

The large industrial forecasts account for a number of new and existing projects:

- BHP's TEMCO manganese smelter suspended production between March and May 2012, with operations to resume at full capacity by the end of August 2012.[4]
- Gunn's Pulp Mill at Bell Bay, which contributes significantly to growth under the high scenario.
- Weakness in the metals sector, which slows growth under the low scenario.

Figure 7-4 shows forecast and actual consumption in the large industrial sector for the three main scenarios. Energy consumption is forecast to increase over the next 10 years at an annual average rate of 0.7% under the medium scenario, and 2.1% and -0.7% under the high and low scenarios, respectively.

Figure 7-4 — Large industrial forecasts for Tasmania



[4] See note 5.

7.1.4 Annual electrical energy requirement breakdown

Table 7-2 provides a breakdown of the annual energy forecasts by customer sales, network losses, and auxiliary energy use by generators under the medium scenario.

Table 7-2 — Annual electrical energy requirement breakdown for Tasmania (GWh)

	Customer sales	Transmission network losses	Annual energy (sent out basis)[a]	Auxiliary energy use	Annual energy (as-generated basis)[b]
Actual					
2005–06	10,293	281	10,574	65	10,639
2006–07	10,431	236	10,667	121	10,788
2007–08	10,722	252	10,974	117	11,091
2008–09	10,711	268	10,979	58	11,037
2009–10	10,572	304	10,877	73	10,950
2010–11	10,631	304	10,934	126	11,060
2011–12 (estimate)	10,142	249	10,391	78	10,469
Scenario 3 - Planning					
2012–13	10,213	252	10,466	78	10,543
2013–14	10,240	254	10,494	78	10,572
2014–15	10,320	258	10,578	78	10,656
2015–16	10,452	264	10,716	78	10,795
2016–17	10,605	272	10,877	79	10,956
2017–18	10,683	276	10,959	79	11,038
2018–19	10,711	278	10,988	79	11,067
2019–20	10,763	280	11,044	79	11,123
2020–21	10,882	287	11,169	79	11,248
2021–22	11,041	295	11,336	80	11,415

a. Annual energy (sent out basis) is defined as the total of customer sales and transmission network losses.

b. Annual energy (as-generated basis) is defined as the total of annual energy (sent out basis) and auxiliary energy use.

7.2 Maximum demand forecasts

The maximum demand in Tasmania occurs in winter.

Half-hourly temperature data was obtained from Hobart's Ellerslie Road station.

7.2.1 Summer maximum demand forecasts

Figure 7-5 shows summer 50% POE maximum demand forecasts under the three main scenarios (and actual data).

The summer 50% POE maximum demand is forecast to increase over the next 10 years at an annual average rate of 1.1% under the medium scenario, and 1.8% and 0.3% under the high and low scenarios, respectively. Trends in maximum demand are largely the same as annual energy.

Figure 7-5 — Summer 50% POE maximum demand forecasts for Tasmania

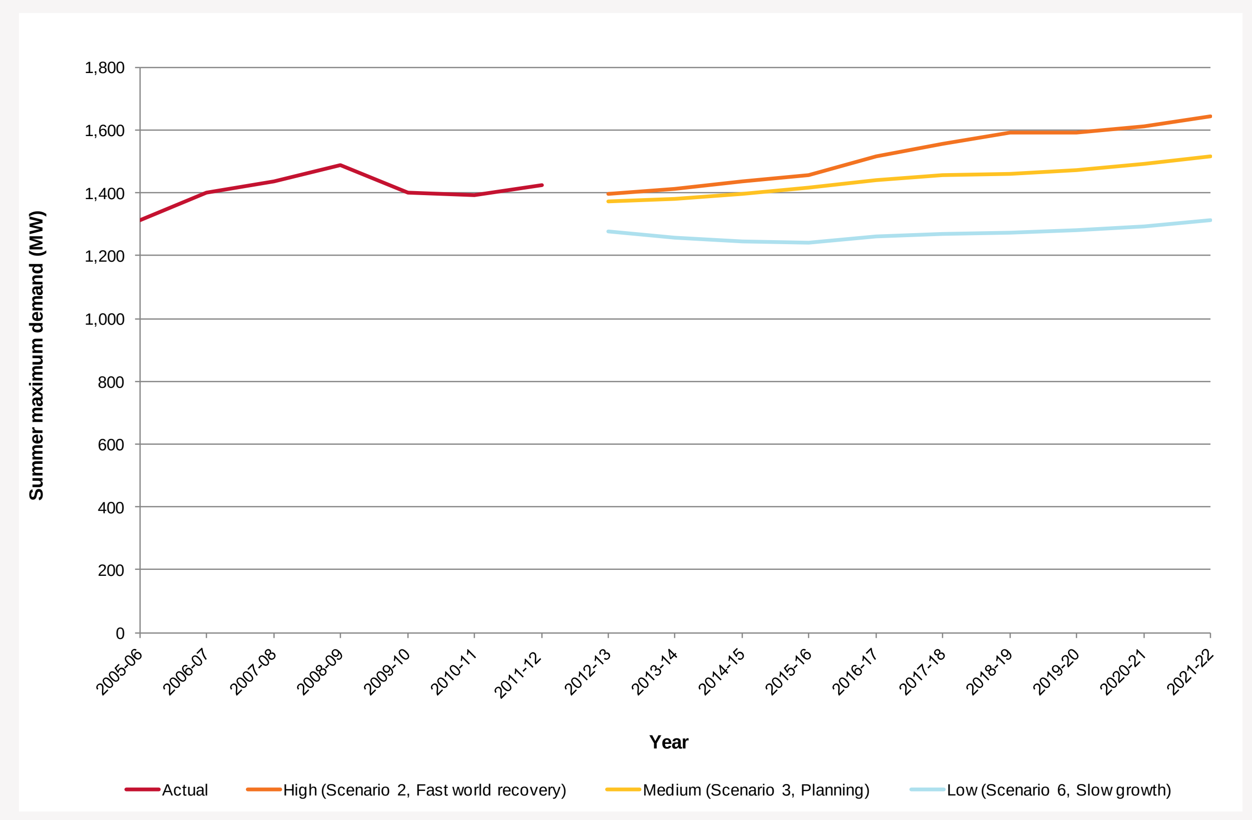


Table 7-3 presents actual and forecast summer 10%, 50% and 90% POE maximum demand for Tasmania under the three main scenarios.

Table 7-3 — Summer maximum demand forecasts for Tasmania (MW)

		High (Scenario 2, Fast World Recovery)			Medium (Scenario 3, Planning)			Low (Scenario 6, Slow Growth)		
	Actual	10%	50%	90%	10%	50%	90%	10%	50%	90%
2005–06	1,311	-	-	-	-	-	-	-	-	-
2006–07	1,401	-	-	-	-	-	-	-	-	-
2007–08	1,438	-	-	-	-	-	-	-	-	-
2008–09	1,487	-	-	-	-	-	-	-	-	-
2009–10	1,400	-	-	-	-	-	-	-	-	-
2010–11	1,392	-	-	-	-	-	-	-	-	-
2011–12	1,423	-	-	-	-	-	-	-	-	-
2012–13	-	1,437	1,397	1,365	1,412	1,371	1,339	1,317	1,277	1,245
2013–14	-	1,454	1,414	1,380	1,420	1,381	1,347	1,298	1,259	1,225
2014–15	-	1,478	1,437	1,402	1,436	1,395	1,360	1,283	1,243	1,210
2015–16	-	1,498	1,456	1,421	1,459	1,417	1,382	1,283	1,242	1,209
2016–17	-	1,557	1,514	1,478	1,483	1,440	1,405	1,301	1,260	1,225
2017–18	-	1,601	1,557	1,520	1,498	1,455	1,418	1,313	1,271	1,236
2018–19	-	1,636	1,591	1,554	1,505	1,461	1,425	1,317	1,275	1,239
2019–20	-	1,637	1,593	1,556	1,516	1,472	1,435	1,322	1,280	1,245
2020–21	-	1,657	1,612	1,573	1,536	1,492	1,453	1,336	1,294	1,257
2021–22	-	1,688	1,643	1,603	1,561	1,516	1,477	1,358	1,315	1,278
Average annual growth	-	1.80%	1.82%	1.81%	1.13%	1.12%	1.10%	0.34%	0.32%	0.29%

2011 and 2012 forecast comparison

Figure 7-6 compares the 2012 NEFR medium scenario and 2011 ESOO medium economic growth scenario summer 10%, 50% and 90% POE maximum demand forecasts.

The average annual summer 10% POE maximum demand forecast growth rate is expected to be 1.1% over the 9-year outlook period from 2012–13 to 2020–21, representing a 0.3% reduction from the 2011 ESOO forecasts.

Figure 7-6 — Comparison of the 2012 NEFR and 2011 ESOO summer maximum demand forecasts for Tasmania

7.2.2 Winter maximum demand forecasts

Figure 7-7 shows winter 50% POE maximum demand forecasts under the three main scenarios (and actual data).

The winter 50% POE maximum demand is forecast to increase over the next 10 years at an annual average rate of 1.1% under the medium scenario, and 1.7% and 0.2% under the high and low scenarios, respectively. Trends in maximum demand are largely the same as annual energy.

The load factor[5] for winter has remained relatively stable, averaging approximately 16.6% during the last 6 years.

Winter maximum demand peaked on 21 July 2008 at 1,879 MW. The 2011 winter maximum demand was 72 MW lower than this, at 1,807 MW.

The impact of rooftop PV on winter maximum demand is assumed to be zero due to the maximum demand in Tasmania often occurring in the early morning between 8:30 AM and 9:00 AM.

Figure 7-7 — Winter 50% POE maximum demand forecasts for Tasmania

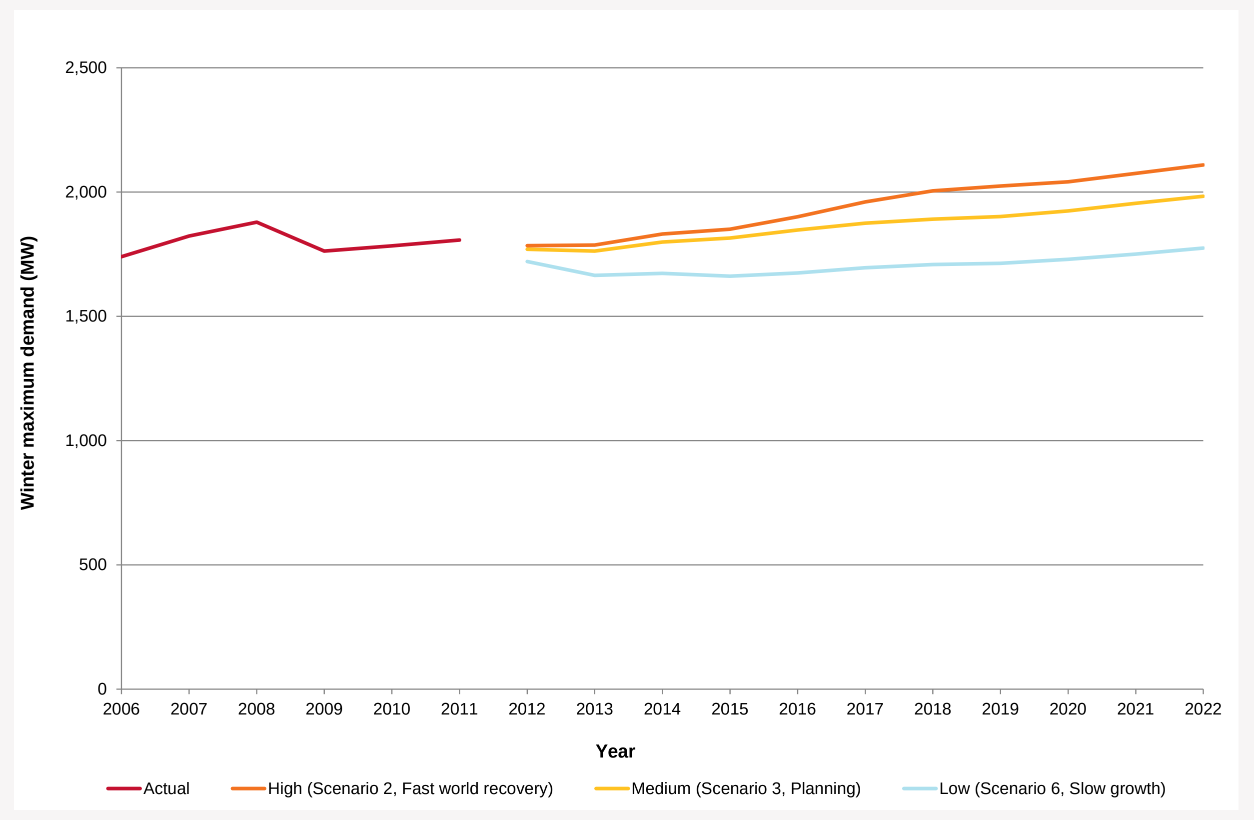


Table 7-4 presents actual and forecast winter 10%, 50% and 90% POE maximum demand for Tasmania under the three scenarios.

[5] The load factor is defined as the annual maximum demand divided by the annual energy.

Table 7-4 — Winter maximum demand forecasts for Tasmania (MW)

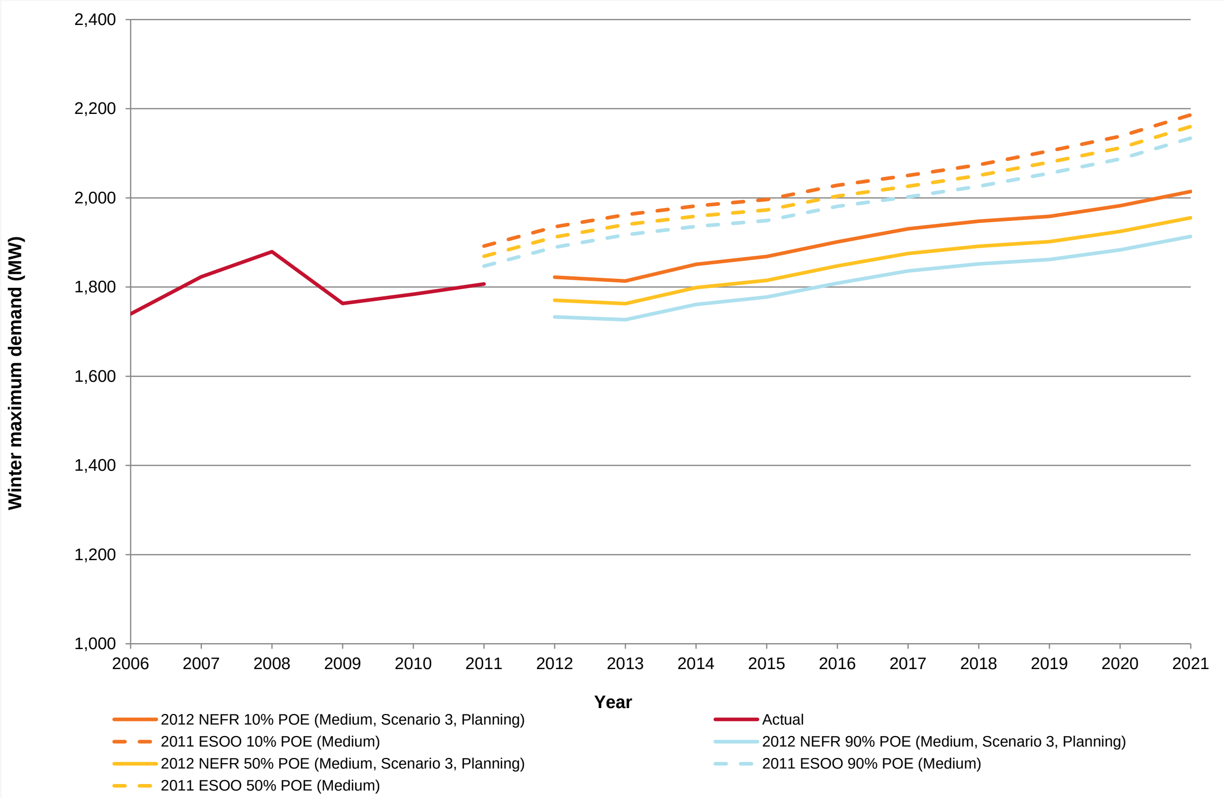
	Actual	High (Scenario 2, Fast World Recovery)			Medium (Scenario 3, Planning)			Low (Scenario 6, Slow Growth)		
		10%	50%	90%	10%	50%	90%	10%	50%	90%
2006	1,740	-	-	-	-	-	-	-	-	-
2007	1,823	-	-	-	-	-	-	-	-	-
2008	1,879	-	-	-	-	-	-	-	-	-
2009	1,763	-	-	-	-	-	-	-	-	-
2010	1,784	-	-	-	-	-	-	-	-	-
2011	1,807	-	-	-	-	-	-	-	-	-
2012	-	1,836	1,784	1,747	1,822	1,770	1,733	1,772	1,721	1,683
2013	-	1,837	1,786	1,750	1,813	1,763	1,727	1,715	1,665	1,630
2014	-	1,883	1,831	1,794	1,851	1,799	1,761	1,724	1,673	1,636
2015	-	1,904	1,851	1,813	1,868	1,815	1,777	1,714	1,662	1,625
2016	-	1,955	1,901	1,862	1,901	1,847	1,809	1,728	1,675	1,638
2017	-	2,016	1,961	1,920	1,931	1,875	1,836	1,750	1,696	1,658
2018	-	2,062	2,005	1,965	1,948	1,891	1,852	1,763	1,709	1,670
2019	-	2,082	2,025	1,984	1,958	1,902	1,862	1,768	1,714	1,675
2020	-	2,100	2,041	2,000	1,982	1,925	1,883	1,785	1,729	1,690
2021	-	2,134	2,075	2,032	2,014	1,955	1,914	1,807	1,751	1,711
Average annual growth	-	1.69%	1.69%	1.70%	1.12%	1.11%	1.11%	0.22%	0.19%	0.18%

2011 and 2012 forecast comparison

Figure 7-8 compares the 2012 NEFR medium scenario and 2011 ESOO medium economic growth scenario winter 10%, 50% and 90% POE maximum demand forecasts.

The average annual winter 10% POE maximum demand forecast growth rate is expected to be 1.1% over the 10-year outlook period from 2012 to 2021, representing a 0.3% reduction from the 2011 ESOO forecasts.

Figure 7-8 — Comparison of the 2012 NEFR and 2011 ESOO winter maximum demand forecasts for Tasmania



7.3 Small non-scheduled generation forecasts

This section presents forecasts of the contribution from small non-scheduled generation (excluding semi-scheduled, significant non-scheduled, and exempt generation) to annual energy and maximum demand, which are not included in the definition of operational demand.

It is possible that some non-scheduled generators may not be included due to their small size, lack of production, or lack of accurate data. These forecasts consider all non-scheduled generation (as nominated by the jurisdictional planning bodies (JPBs)), which is different from previous reports.

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 only on the demand met by scheduled and semi-scheduled generation, 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 generation.

The small non-scheduled generation forecasts presented in this section are subtracted from both the annual energy and maximum demand forecasts to calculate operational generation forecasts used in the supply-demand outlook.

For a list of the scheduled and semi-scheduled generators (by region) used to calculate these forecasts, see Appendix C.

Forecasts of small non-scheduled generation energy for Tasmania

Table 7-5 lists the forecast and actual energy of small non-scheduled generation under the three main scenarios.

Table 7-6 presents forecasts of the contribution to summer and winter maximum demand from Tasmanian small non-scheduled generation.

Energy supplied by small non-scheduled generating units in Tasmania is forecast to increase over the next 10 years at an annual average rate of between 2.0% and 6.2% (depending on economic scenario), compared with historical annual average growth of 0.2%.

The majority of large projects are expected to register as semi-scheduled rather than non-scheduled. This contributes to relatively low to medium projected growth in non-scheduled energy, capacity, and contribution to summer maximum demand.

Table 7-5 — Forecasts of small non-scheduled generation energy for Tasmania (GWh)

	Actual energy	High (Scenario 2, Fast World Recovery)[a]	Medium (Scenario 3, Planning)[a]	Low (Scenario 6, Slow Growth)[a]
2005–06	287	-	-	-
2006–07	287	-	-	-
2007–08	291	-	-	-
2008–09	291	-	-	-
2009–10	291	-	-	-
2010–11	291	-	-	-
2011–12 (estimate)	291	-	-	-
2012–13	-	304	304	304
2013–14	-	317	317	317
2014–15	-	330	330	330
2015–16	-	342	342	342
2016–17	-	355	355	355
2017–18	-	368	368	368
2018–19	-	380	380	380
2019–20	-	393	393	393
2020–21	-	406	406	406
2021–22	-	418	418	418
Average annual growth	0.2%	3.6%	3.6%	3.6%

a. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

Table 7-6 — Forecasts of the small non-scheduled generation contribution to maximum demand for Tasmania (MW)

	Actual	Summer maximum demand			Actual	Winter maximum demand		
		High (Scenario 2, Fast World Recovery)[a]	Medium (Scenario 3, Planning)[a]	Low (Scenario 6, Slow Growth)[a]		High (Scenario 2, Fast World Recovery)[b]	Medium (Scenario 3, Planning)[b]	Low (Scenario 6, Slow Growth)[b]
2005–06	70	-	-	-	-	-	-	-
2006–07	34	-	-	-	74	-	-	-
2007–08	67	-	-	-	40	-	-	-
2008–09	82	-	-	-	89	-	-	-
2009–10	24	-	-	-	63	-	-	-
2010–11	24	-	-	-	73	-	-	-
2011–12	86	-	-	-	58	-	-	-
2012–13	-	90	90	90	-	86	86	86
2013–14	-	93	93	93	-	90	90	90
2014–15	-	97	97	97	-	93	93	93
2015–16	-	101	101	101	-	97	97	97
2016–17	-	105	105	105	-	101	101	101
2017–18	-	108	108	108	-	105	105	105
2018–19	-	112	112	112	-	108	108	108
2019–20	-	116	116	116	-	112	112	112
2020–21	-	120	120	120	-	116	116	116
2021–22	-	123	123	123	-	120	120	120
Average annual growth	-	3.6%	3.6%	3.6%	-	3.7%	3.7%	3.7%

a. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

b. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

CHAPTER 8 - VICTORIA FORECASTS

Summary

This chapter presents information about annual energy, maximum demand (summer and winter), and non-scheduled generation for the Victorian region. It also includes information about historical annual energy, mass market forecasts, large industrial forecasts, and an annual electrical energy requirement breakdown.

Annual energy

Key differences between the 2011 Electricity Statement of Opportunities (ESOO) and the 2012 National Electricity Forecasting Report (NEFR) annual energy forecasts include the following:

- Annual energy for 2011–12 is expected to be 1.8% lower than 2010–11 and 3.0% lower than what was forecast in the 2011 ESOO (medium economic growth scenario).
- Forecast annual energy for 2012–13 is expected to only grow by 1.4%, which represents a 4.5% reduction from the 2011 ESOO forecasts.
- Average growth in annual energy for the 10-year outlook period is now forecast to be 1.4%, down from the 1.6% forecast in the 2011 ESOO.

Maximum demand

Key differences between the 2011 ESOO and 2012 NEFR summer maximum demand medium economic growth scenario forecasts includes the following:

- The 2011–12 actual summer maximum demand was 503 MW below AEMO's 90% probability of exceedence (POE) forecast.
- The 2012–13 forecast 10% POE summer maximum demand has been reduced by 746 MW.
- Average growth in 10% POE summer maximum demand for the 10-year outlook period is now forecast to be 1.6%, down from the 2.2% forecast in the 2011 ESOO.

Main factors contributing to forecast change

Annual energy and maximum demand forecasts have decreased since the 2011 ESOO for several main reasons:

- Reduced consumption from large industrial customers. The 2011 ESOO included a plan by the Portland aluminium smelter to increase operations to its pre-June 2009 level. However, this is no longer expected to occur and has not been included in the 2012 NEFR forecasts. Additional changes in consumption include other developments in the steel and aluminium smelting sectors, and the new desalination plant at Wonthaggi.
- Increasing penetration of rooftop photovoltaics (PV). In 2011–12, rooftop PV systems are estimated to have generated 304 GWh or 0.6% of estimated annual energy.[1] In 2012–13, rooftop PV energy is forecast to be 489 GWh or 1% of annual energy under the Planning (medium) scenario. By 2021–22, this is forecast to increase to 1,388 GWh or 2.6% of annual energy. Over the 10-year outlook period, the average annual growth rate of rooftop PV energy is expected to be 12.3%. For more information, see AEMO's Rooftop PV Information Paper.[2]
- Reduced manufacturing consumption in response to the high Australian dollar. An expected increase in cheaper imports is expected to partially offset domestic growth.

[1] Estimated annual energy does not include rooftop PV generation.
[2] AEMO, available http://www.aemo.com.au/en/Electricity/Forecasting. Viewed June 2012.

- Increasing (real) residential electricity prices. In 2011–12 and 2012–13, electricity prices are expected to increase, and then (on average) moderate from 2013–14 until the end of the outlook period.
- Consumer response (commercial and residential) to rising electricity costs and energy efficiency measures.

8.1 Annual energy forecasts

This section presents annual energy forecasts for Victoria based on AEMO modelling. For more information about the modelling, see AEMO's Forecasting Methodology Information Paper.[3]

Annual energy is defined on a 'sent-out' basis. Actual annual energy in 2011–12 includes two financial quarters of actual data and two financial quarters of estimated data.

8.1.1 Annual energy forecasts

Annual energy increased on average by 0.86% per year from 2000–01 to 2011–12. Historical annual energy peaked in 2007–08, and negative average annual growth of 1.2% in the last 24 months.

Annual energy in Victoria is projected to grow over the 10-year outlook period from 2012–13 to 2021–22 at an annual average rate of 1.4% under the medium scenario, and 1.8% and 1.0% under the high and the low scenarios, respectively.

Annual energy forecasts are offset by the penetration of rooftop PV and energy efficiency savings, which are expected to grow across the 10-year outlook period under these three main scenarios.

Figure 8-1 shows the forecast and actual energy under the three main scenarios. Table 8-1 lists the data used to plot the forecast charts.

[3] See note 2.

Figure 8-1 — Annual energy forecasts for Victoria

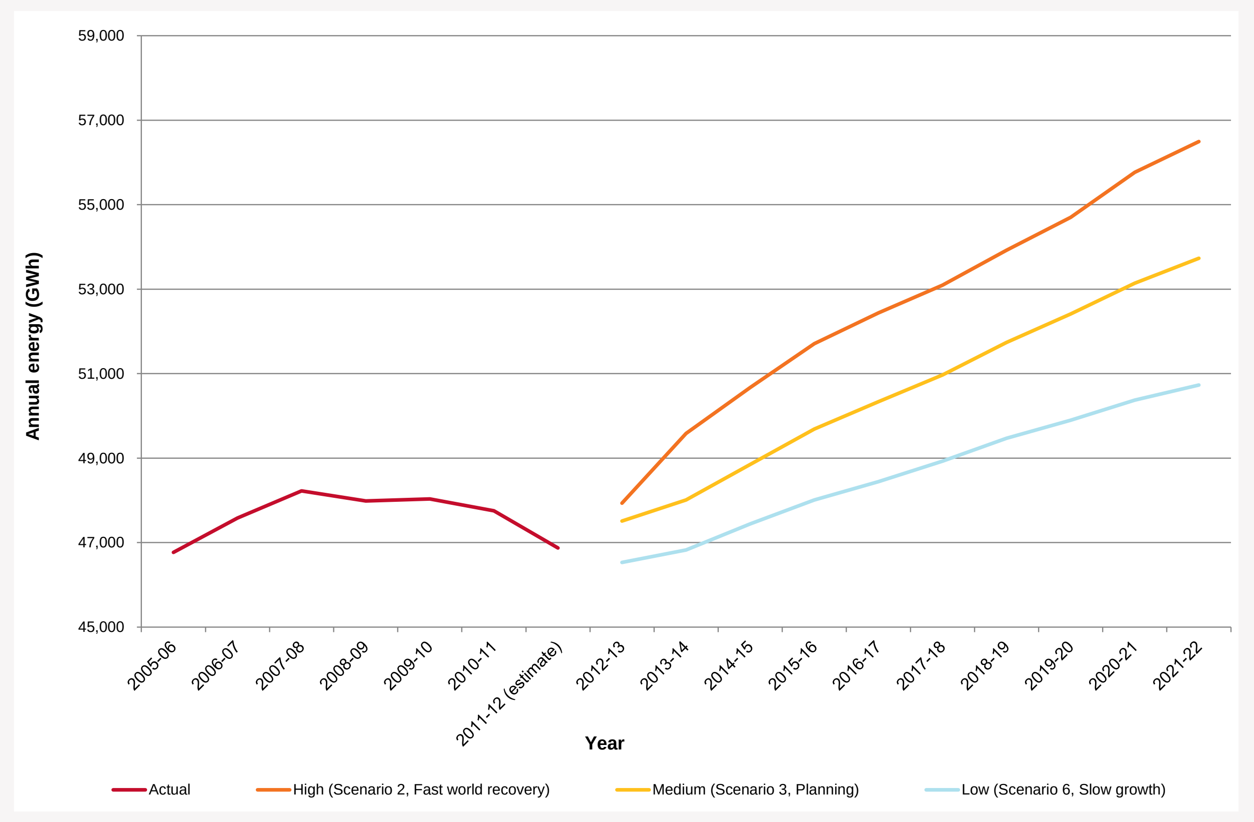


Table 8-1 — Annual energy forecasts for Victoria (GWh)

	Actual	High (Scenario 2, Fast World Recovery)	Medium (Scenario 3, Planning)	Low (Scenario 6, Slow Growth)
2005–06	46,768	-	-	-
2006–07	47,584	-	-	-
2007–08	48,223	-	-	-
2008–09	47,984	-	-	-
2009–10	48,033	-	-	-
2010–11	47,754	-	-	-
2011–12 (estimate)	46,871	-	-	-
2012–13	-	47,935	47,510	46,530
2013–14	-	49,585	48,012	46,824
2014–15	-	50,671	48,852	47,441
2015–16	-	51,710	49,687	48,010
2016–17	-	52,436	50,335	48,440
2017–18	-	53,096	50,970	48,925
2018–19	-	53,920	51,738	49,468
2019–20	-	54,702	52,415	49,896
2020–21	-	55,768	53,141	50,373
2021–22	-	56,496	53,731	50,730
Average annual growth	-	1.8%	1.4%	1.0%

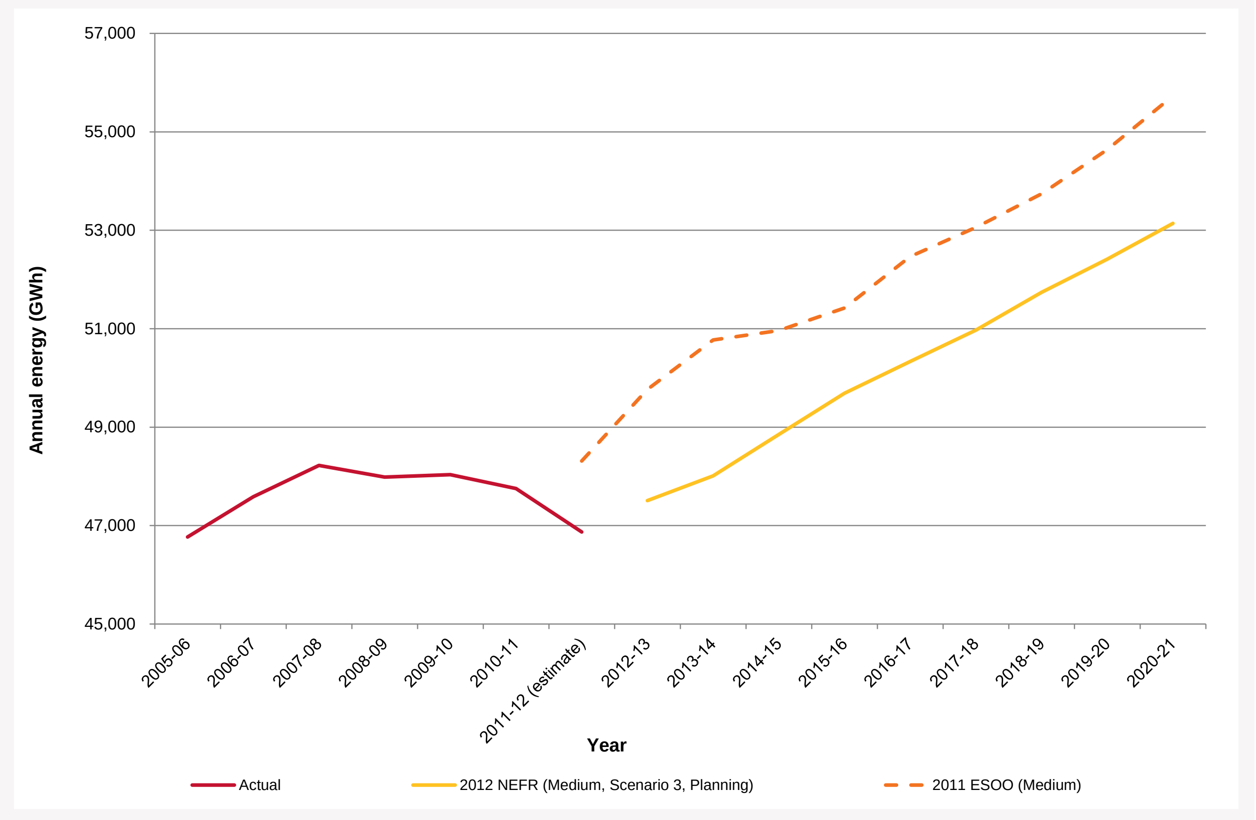
2011 and 2012 forecast comparison

Over the 9-year outlook period from 2012–13 to 2020–21, there is an average decrease in annual energy of approximately 2,211 GWh from the 2011 ESOO's medium economic growth scenario forecasts when compared to the 2012 medium scenario forecasts. This is equivalent to a decrease in average annual growth, from 1.6% in the 2011 ESOO to 1.4% in the 2012 NEFR.

Figure 8-2 shows actual energy and compares the forecast energy for the two forecasts.

In the near term, 2011–12 annual energy is expected to be 3.0% lower than the 2011 ESOO forecast. From 2011–12 to 2012–13, it is expected to grow by 1.4%, with the annual energy forecast for 2012–13 representing a 4.5% reduction from the 2011 ESOO forecasts.

Figure 8-2 — Comparison of the 2012 NEFR and 2011 ESOO annual energy forecasts for Victoria



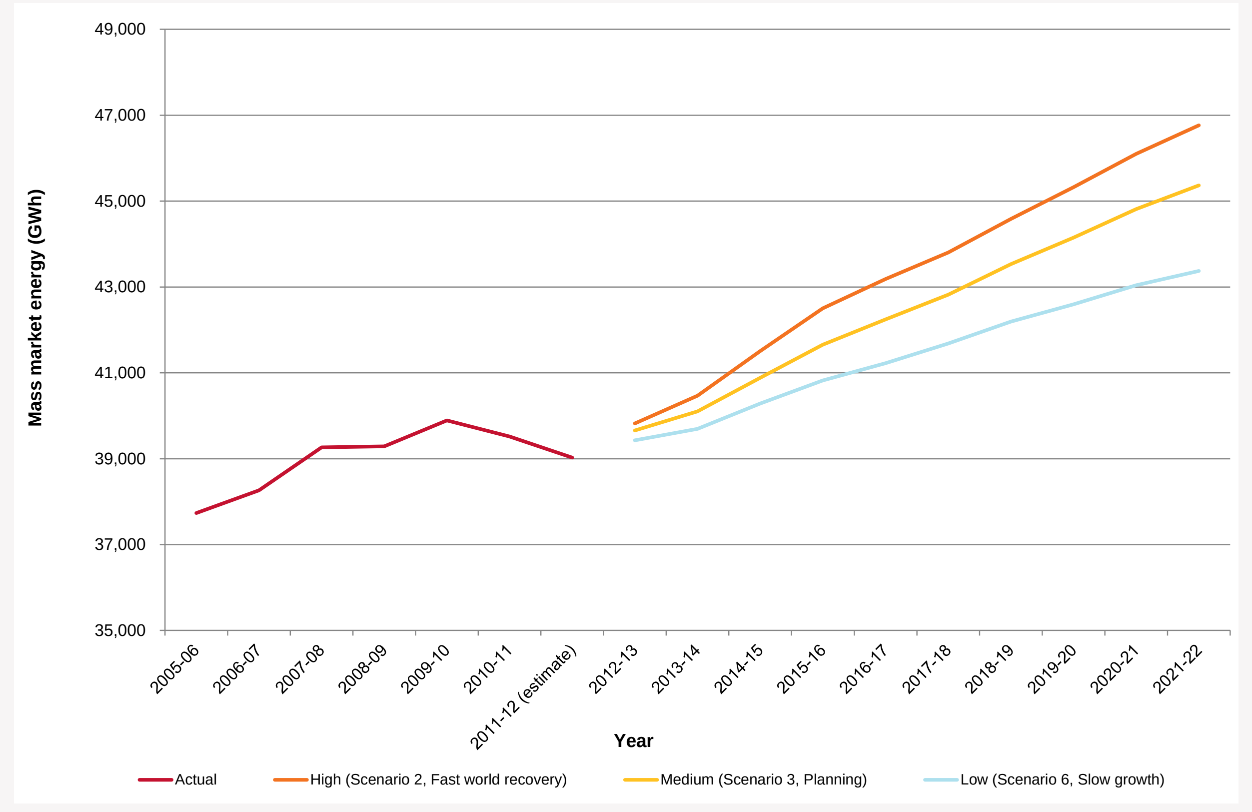
8.1.2 Mass market forecasts

Over the 10-year outlook period, the average annual growth rate for the medium, high and low scenarios is expected to be 1.5%, 1.8% and 1.1%, respectively.

Figure 8-3 shows forecast and actual consumption in the mass market sector under the three main scenarios.

Forecasts for the mass market have been calculated by developing a model for non-large industrial consumption, and then subtracting forecasts for rooftop PV and energy efficiency savings. For more information about the model for non-large industrial consumption, see Appendix A.

Figure 8-3 — Mass market forecasts for Victoria



8.1.3 Large industrial forecasts

Since 2006–07, industrial loads have steadily declined in Victoria, mainly in the manufacturing sector. This has been caused by a high Australian dollar and competition from cheap imports.

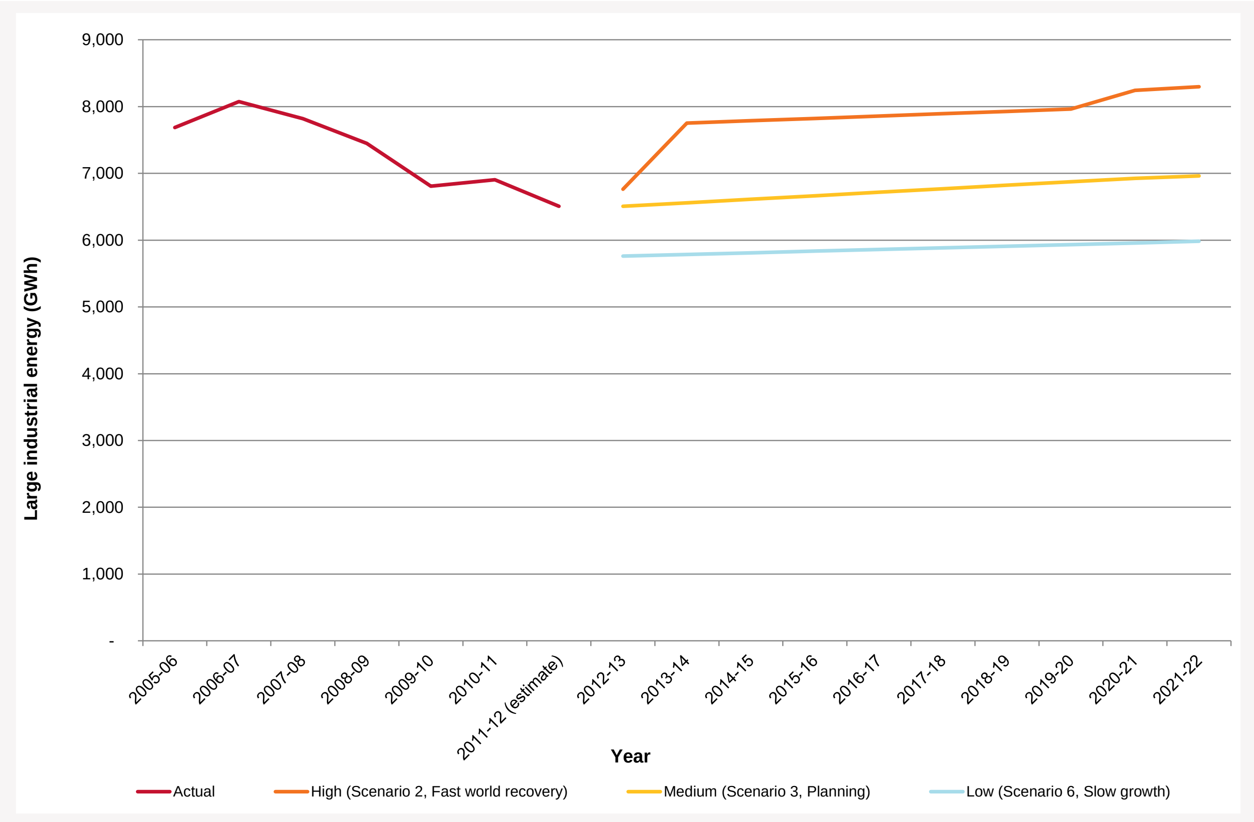
The large industrial forecasts account for a number of new large industrial projects:

- Energy consumed by the steel and aluminium smelting sectors, with the three scenarios assuming different levels of development.
- The new desalination plant at Wonthaggi. The Victorian Government has ordered no water for 2012–13, so its electrical energy during this year will be negligible. Future energy consumption depends on rainfall and water supply from other sources.

Alcoa is currently reviewing operations at its Point Henry aluminium smelter, and plans for this facility are expected to be announced in early 2012–13. As a result, AEMO has not included changes in demand from this load in the current set of forecasts.

Figure 8-4 shows forecast and actual consumption in the large industrial sector under the three main scenarios. Energy consumption is forecast to increase over the next 10 years at an annual average rate of 0.8% under the medium scenario, and 2.3% and 0.4% under the high and low scenarios, respectively.

Figure 8-4 — Large industrial forecasts for Victoria



8.1.4 Annual electrical energy requirement breakdown

Table 8-2 provides a breakdown of the annual energy forecasts by customer sales, network losses, and auxiliary energy use by generators under the medium scenario.

Table 8-2 — Annual electrical energy requirement breakdown for Victoria (GWh)

	Customer sales	Transmission network losses	Annual energy (sent out basis)[a]	Auxiliary energy use	Annual energy (as-generated basis)[b]
Actual					
2005–06	45,419	1,348	46,768	4,308	51,076
2006–07	46,340	1,244	47,584	4,349	51,933
2007–08	47,084	1,139	48,223	4,461	52,684
2008–09	46,738	1,245	47,984	4,945	52,929
2009–10	46,700	1,333	48,033	4,776	52,810
2010–11	46,421	1,333	47,754	4,774	52,529
2011–12 (estimate)	45,531	1,341	46,871	4,472	51,343
Scenario 3 - Planning					
2012–13	46,163	1,346	47,510	4,474	51,984
2013–14	46,661	1,351	48,012	4,500	52,512
2014–15	47,493	1,358	48,852	4,518	53,370
2015–16	48,321	1,366	49,687	4,515	54,202
2016–17	48,963	1,372	50,335	4,501	54,836
2017–18	49,592	1,378	50,970	4,527	55,497
2018–19	50,353	1,385	51,738	4,544	56,283
2019–20	51,023	1,392	52,415	4,556	56,971
2020–21	51,742	1,399	53,141	4,531	57,672
2021–22	52,327	1,405	53,731	4,539	58,270

a Annual energy (sent out basis) is defined as the total of customer sales and transmission network losses.

b Annual energy (as-generated basis) is defined as the total of annual energy (sent out basis) and auxiliary energy use.

8.2 Maximum demand forecasts

The maximum demand in Victoria occurs in summer.

Half-hourly temperature data was obtained from weather stations located in Melbourne and Frankston.

8.2.1 Summer maximum demand forecasts

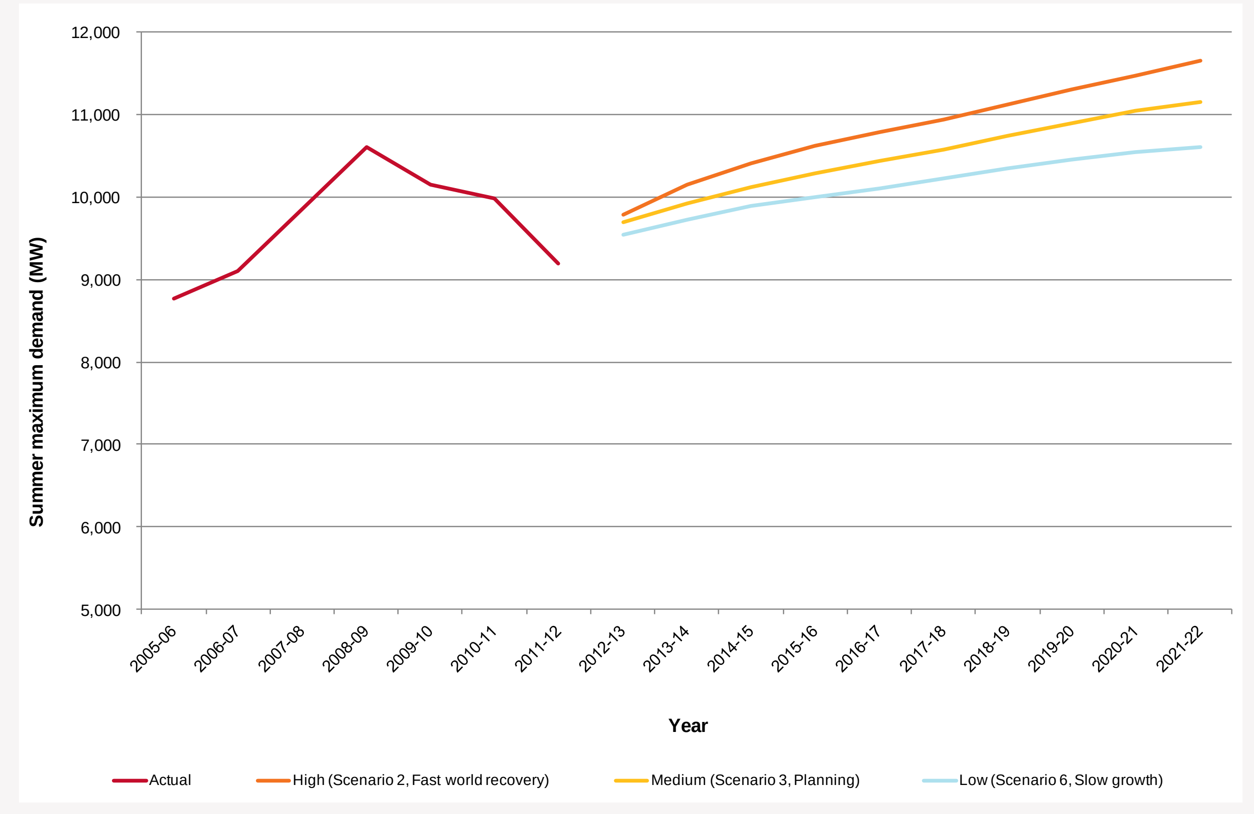
Figure 8-5 shows summer 50% POE maximum demand forecasts under the three main scenarios (and actual data).

The summer 50% POE maximum demand is forecast to increase over the next 10 years at an annual average rate of 1.6% under the medium scenario, and 2.0% and 1.2% under the high and low scenarios, respectively. Trends in maximum demand are largely the same as annual energy.

The load factor[4] for summer has averaged approximately 20% during the last seven years. Summer maximum demand peaked on 29 January 2009 at 10,603 MW, decreasing by 1,413 MW to summer 2011–12.

In Victoria, summer maximum demand is driven by space cooling on hot days, and tends to occur around 4:00 PM. Actual maximum demands vary significantly from year to year, depending on the occurrence of extreme weather days. After a severe heatwave in January 2009 (prior to the Black Saturday bushfires), the last few summers have been relatively mild.

Figure 8-5 — Summer 50% POE maximum demand forecasts for Victoria



[4] The load factor is defined as the annual maximum demand divided by the annual energy.

Table 8-3 presents actual and forecast summer 10%, 50% and 90% POE maximum demand for Victoria under the three main scenarios.

Table 8-3 — Summer maximum demand forecasts for Victoria (MW)

	Actual	High (Scenario 2, Fast World Recovery)			Medium (Scenario 3, Planning)			Low (Scenario 6, Slow Growth)		
		10%	50%	90%	10%	50%	90%	10%	50%	90%
2005–06	8,767	-	-	-	-	-	-	-	-	-
2006–07	9,098	-	-	-	-	-	-	-	-	-
2007–08	9,839	-	-	-	-	-	-	-	-	-
2008–09	10,603	-	-	-	-	-	-	-	-	-
2009–10	10,144	-	-	-	-	-	-	-	-	-
2010–11	9,978	-	-	-	-	-	-	-	-	-
2011–12	9,190	-	-	-	-	-	-	-	-	-
2012–13	-	10,723	9,781	9,181	10,624	9,690	9,092	10,472	9,547	8,946
2013–14	-	11,121	10,146	9,532	10,877	9,921	9,312	10,673	9,730	9,127
2014–15	-	11,419	10,410	9,768	11,109	10,124	9,499	10,858	9,891	9,275
2015–16	-	11,653	10,617	9,964	11,289	10,284	9,644	10,981	10,000	9,373
2016–17	-	11,839	10,782	10,112	11,456	10,430	9,776	11,105	10,106	9,468
2017–18	-	12,010	10,929	10,247	11,618	10,570	9,903	11,237	10,219	9,571
2018–19	-	12,231	11,121	10,424	11,817	10,744	10,063	11,386	10,348	9,688
2019–20	-	12,429	11,293	10,579	11,986	10,891	10,194	11,499	10,445	9,774
2020–21	-	12,623	11,461	10,732	12,157	11,036	10,326	11,613	10,541	9,860
2021–22	-	12,825	11,642	10,899	12,285	11,147	10,426	11,687	10,603	9,914
Average annual growth	-	2.0%	2.0%	1.9%	1.6%	1.6%	1.5%	1.2%	1.2%	1.1%

2011 and 2012 forecast comparison

Figure 8-6 compares the 2012 NEFR medium scenario and 2011 ESOO medium economic growth scenario summer 10%, 50% and 90% POE maximum demand forecasts.

The average annual summer 10% POE maximum demand forecast growth rate is expected to be 1.6% over the 9-year outlook period from 2012–13 to 2020–21, representing a reduction from 2.2% from the 2011 ESOO forecasts.

Figure 8-6 — Comparison of the 2012 NEFR and 2011 ESOO summer maximum demand forecasts for Victoria

8.2.2 Winter maximum demand forecasts

Figure 8-7 shows winter 50% POE maximum demand forecasts for the three main scenarios (and actual data).

The winter 50% POE maximum demand is forecast to increase over the next 10 years at an annual average rate of 1.6% under the medium scenario, and 1.8% and 1.2% under the high and low scenarios, respectively. Trends in maximum demand are largely the same as annual energy.

Winter maximum demand peaked in 2007 at 8,393 MW, decreasing by 43 MW in 2011.

The impact of rooftop PV on winter maximum demand is assumed to be zero due to the maximum demand in Victoria often occurring in the evening around 6:00 PM, coinciding with increased use of reverse-cycle air-conditioning and electrical appliances.

Figure 8-7 — Winter 50% POE maximum demand forecasts for Victoria

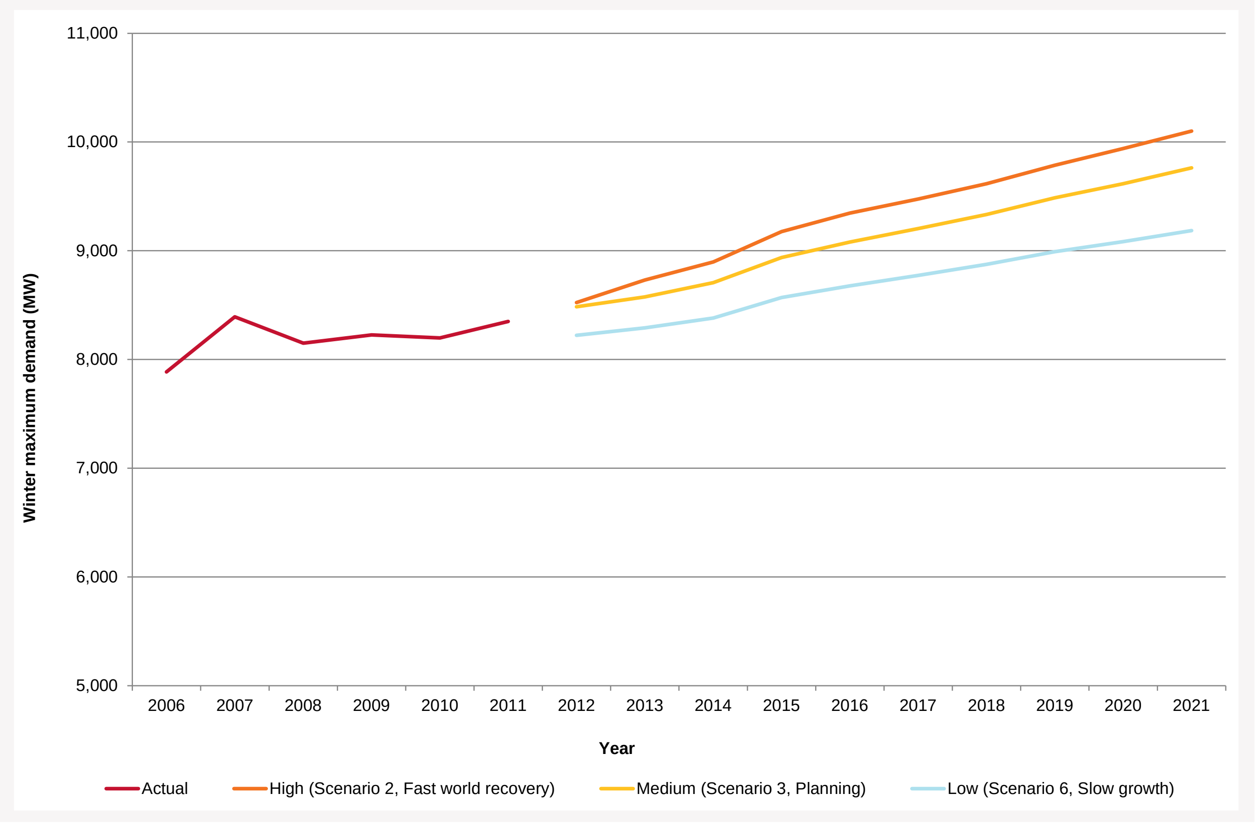


Table 8-4 presents actual and forecast winter 10%, 50% and 90% POE maximum demand for Victoria under the three main scenarios.

Table 8-4 — Winter maximum demand forecasts for Victoria (MW)

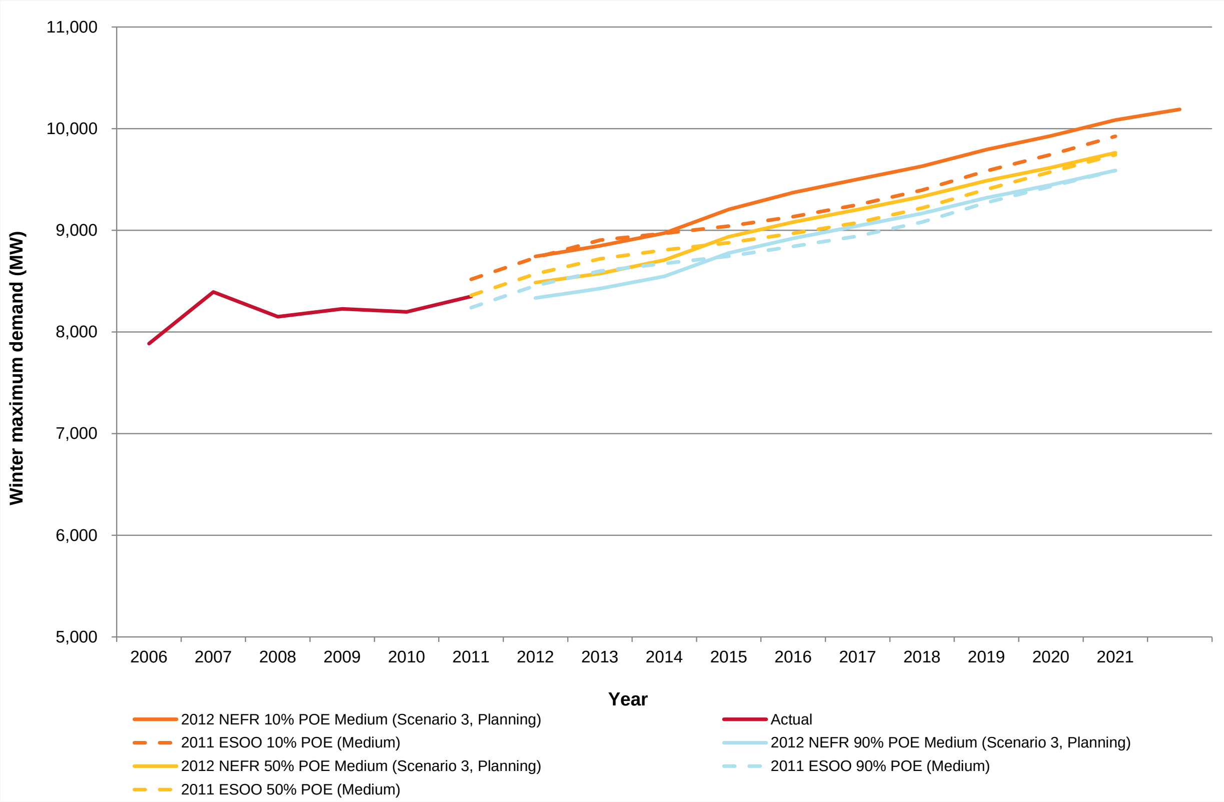
	Actual	High (Scenario 2, Fast World Recovery)			Medium (Scenario 3, Planning)			Low (Scenario 6, Slow Growth)		
		10%	50%	90%	10%	50%	90%	10%	50%	90%
2006	7,886	-	-	-	-	-	-	-	-	-
2007	8,393	-	-	-	-	-	-	-	-	-
2008	8,150	-	-	-	-	-	-	-	-	-
2009	8,227	-	-	-	-	-	-	-	-	-
2010	8,198	-	-	-	-	-	-	-	-	-
2011	8,350	-	-	-	-	-	-	-	-	-
2012	-	8,780	8,523	8,371	8,743	8,486	8,335	8,628	8,372	8,222
2013	-	9,010	8,731	8,577	8,849	8,576	8,426	8,708	8,439	8,290
2014	-	9,171	8,897	8,739	8,972	8,707	8,548	8,796	8,536	8,380
2015	-	9,458	9,176	9,013	9,206	8,937	8,776	8,993	8,730	8,571
2016	-	9,649	9,346	9,178	9,371	9,080	8,921	9,116	8,830	8,677
2017	-	9,784	9,476	9,306	9,502	9,203	9,043	9,219	8,931	8,774
2018	-	9,924	9,616	9,447	9,631	9,333	9,166	9,327	9,038	8,874
2019	-	10,105	9,787	9,612	9,794	9,487	9,320	9,450	9,154	8,991
2020	-	10,266	9,940	9,758	9,929	9,616	9,446	9,550	9,249	9,084
2021	-	10,440	10,101	9,914	10,085	9,763	9,589	9,661	9,351	9,186
Average annual growth	-	1.8%	1.8%	1.8%	1.6%	1.6%	1.6%	1.2%	1.2%	1.2%

2011 and 2012 forecast comparison

Figure 8-8 compares the 2012 NEFR medium scenario and 2011 ESOO medium economic growth scenario winter 10%, 50% and 90% POE maximum demand forecasts.

The 2012 NEFR winter 50% POE maximum demand is 1% lower than the 2011 ESOO forecast due to different economic forecast assumptions, otherwise the two forecasts are very similar.

Figure 8-8 — Comparison of the 2012 NEFR and 2011 ESOO winter maximum demand forecasts for Victoria



8.3 Small non-scheduled generation forecasts

This section presents forecasts of the contribution from small non-scheduled generation (excluding semi-scheduled, significant non-scheduled, and exempt generation) to annual energy and maximum demand, which are not included in the definition of operational demand.

It is possible that some non-scheduled generators may not be included due to their small size, lack of production, or lack of accurate data. These forecasts consider all non-scheduled generation (as nominated by the jurisdictional planning bodies (JPBs)), which is different from previous reports.

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 only on the demand met by scheduled and semi-scheduled generation, 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 generation.

The small non-scheduled generation forecasts presented in this section are subtracted from both the annual energy and maximum demand forecasts to calculate operational generation forecasts used in the supply-demand outlook.

For a list of the scheduled and semi-scheduled generators (by region) used to calculate these forecasts, see Appendix C.

Forecasts of small non-scheduled generation energy for Victoria

Table 8-5 lists the forecast and actual energy of small non-scheduled generation under the three main scenarios.

Table 8-6 presents forecasts of the contribution to summer and winter maximum demand from Victoria small non-scheduled generation.

Energy supplied by small non-scheduled generating units in Victoria is projected to increase over the next 10 years at an annual average rate of between 2.1% and 6.6% (depending on economic scenario), compared with historical annual average growth of 5.8%.

The majority of large projects are expected to register as semi-scheduled rather than non-scheduled. This contributes to relatively low to medium projected growth in non-scheduled energy, capacity, and contribution to summer maximum demand.

Table 8-5 — Forecasts of small non-scheduled generation energy for Victoria (GWh)

	Actual	High (Scenario 2, Fast World Recovery)[a]	Medium (Scenario 3, Planning)[a]	Low (Scenario 6, Slow Growth)[a]
2005–06	318	-	-	-
2006–07	390	-	-	-
2007–08	392	-	-	-
2008–09	393	-	-	-
2009–10	422	-	-	-
2010–11	435	-	-	-
2011–12 (estimate)	447	-	-	-
2012–13	-	468	468	468
2013–14	-	489	489	489
2014–15	-	510	510	510
2015–16	-	531	531	531
2016–17	-	553	553	553
2017–18	-	574	574	574
2018–19	-	595	595	595
2019–20	-	616	616	616
2020–21	-	637	637	637
2021–22	-	658	658	658
Average annual growth	5.8%	3.9%	3.9%	3.9%

a. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

Table 8-6 — Forecasts of the small non-scheduled generation contribution to maximum demand for Victoria (MW)

	Actual	Summer maximum demand			Actual	Winter maximum demand		
		High (Scenario 2, Fast World Recovery) [a]	Medium (Scenario 3, Planning)[a]	Low (Scenario 6, Slow Growth)[a]		High (Scenario 2, Fast World Recovery)[b]	Medium (Scenario 3, Planning)[b]	Low (Scenario 6, Slow Growth)[b]
2005–06	37	-	-	-	-	-	-	-
2006–07	36	-	-	-	23	-	-	-
2007–08	21	-	-	-	42	-	-	-
2008–09	20	-	-	-	26	-	-	-
2009–10	39	-	-	-	33	-	-	-
2010–11	64	-	-	-	58	-	-	-
2011–12	20	-	-	-	83	-	-	-
2012–13	-	21	21	21	-	20	20	20
2013–14	-	23	23	23	-	21	21	21
2014–15	-	24	24	24	-	23	23	23
2015–16	-	25	25	25	-	24	24	24
2016–17	-	26	26	26	-	25	25	25
2017–18	-	27	27	27	-	26	26	26
2018–19	-	28	28	28	-	27	27	27
2019–20	-	29	29	29	-	28	28	28
2020–21	-	30	30	30	-	29	29	29
2021–22	-	31	31	31	-	30	30	30
Average annual growth	-	4.0%	4.0%	4.0%	-	4.2%	4.2%	4.2%

a. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

b. These scenarios assume the same medium (moderate) forecast for small non-scheduled generation.

APPENDIX A - REGIONAL MODEL EQUATIONS FOR NON-LARGE INDUSTRIAL CONSUMPTION

This appendix provides model equations for non-large industrial consumption for each NEM region.

A.1 New South Wales (including the ACT)

The model equation for non-large industrial consumption, which is based on a Vector Error Correction model has been constructed on a quarterly basis and is outlined as follows:

$\Delta \ln(y) = -0.53\hat{e}_{t-1}$

$-0.28\Delta \ln(y_{t-1}) - 0.05\Delta \ln(y_{t-3}) - 0.08\Delta \ln(y_{t-4})$

$+0.21\Delta \ln(i_{t-1}) + 0.03\Delta \ln(i_{t-3}) - 0.23\Delta \ln(i_{t-4})$

$+0.15\Delta \ln(p_{t-1}) - 0.26\Delta \ln(p_{t-3}) - 0.07\Delta \ln(p_{t-4})$

$+0.004S1 + 0.11S2 + 0.10S3$

$+0.0003HDD + 0.0002CDD * (1 + AC)$

Where

$$\hat{e} = 2.25 - 0.29\ln(p) + 0.62\ln(i) - y$$

Or

$$y = 2.25 - 0.29\ln(p) + 0.62\ln(i)$$

- y = per capita electricity consumption in kWh per quarter per person
- i = state final demand per capita in 2009–10 dollars per quarter
- p = real residential electricity price in 2009–10 c/kWh
- HDD = heating degree days per quarter in Sydney (Observatory Hill)

  $\sum Max(0, \bar{T} - 18)$ where $\bar{T}$ is average daily temperature on a 6:00 PM to 6:00 PM basis
- CDD = cooling degree days per quarter in Sydney (Observatory Hill)

  $\sum Max(0,19 - \bar{T})$ where $\bar{T}$ is average daily temperature on a 6:00 PM to 6:00 PM basis
- AC = Air conditioning ownership variable developed by AEMO
- S1 = seasonal dummy for the March quarter (1 when period is the March quarter, 0 otherwise)
- S2 = seasonal dummy for the June quarter (1 when period is the June quarter, 0 otherwise)
- S3 = seasonal dummy for the September quarter (1 when period is the September quarter, 0 otherwise)

Due to the complex nature of the VEC model, it is best to focus on the error component for the long-run driver relationships. Putting the long-run relationship simply:

$$y = 2.25 - 0.29\ln(p) + 0.62\ln(i)$$

Key observations in the short run include:

- Lags of consumption, price and income allow for short-run effects of these variables.
- Heating degree days (the heating load) and cooling degree days (the cooling load) along with an air conditioning ownership variable explain the short-run variations in electricity consumption.
- Seasonal (quarterly) dummy variables allow adjustment for the non-temperature related quarterly seasonality in electricity consumption.

Key observations in the long run include:

- Per capita consumption has a fixed component (2.25 kWh per person) and a price elasticity of -0.29, implying that the long-run response to a 1% increase in electricity price is a 0.29% decrease in electricity consumption.
- Per capita consumption also has an income elasticity of +0.62, meaning that the long-run response to an increase in state final demand per capita of 1% is a 0.62% increase in electricity consumption.

A.2 Queensland

The model equation for non-large industrial consumption, which is based on an Auto-Regressive Distributed Lag (ARDL) model has been constructed on a quarterly basis and is outlined as follows:

$\ln(y) = 5.53$

$+0.26\ln(i) - 0.18\ln(p_{t-3}) - 0.03\ln(r_{t-1})$

$-0.012S1 + 0.012S2 + 0.021S3$

$+0.00035CDD - 0.008w$

Where:

- y = per capita electricity consumption in kWh per quarter per person
- i = gross state product per capita in 2009–10 dollars per person per quarter
- p = real total electricity price in 2009–10 c/kWh
- r = real interest rate, defined as (((svr/100)+1)/(1+log(cpi/cpi(-4))))-1 where svr is quarterly standard variable interest rate[1] and cpi is quarterly consumer price index
- CDD = cooling degree days per quarter in Brisbane (Archerfield)

  $\sum Max(0{,}21 - \bar{T})$ where $\bar{T}$ is average daily temperature on a 6:00 PM to 6:00 PM basis
- S1 = seasonal dummy for the March quarter (1 when period is the March quarter, 0 otherwise)
- S2 = seasonal dummy for the June quarter (1 when period is the June quarter, 0 otherwise)
- S3 = seasonal dummy for the September quarter (1 when period is the September quarter, 0 otherwise)
- w = dummy for the Queensland floods in 2010–11 (1 for December 2010 quarter, March 2011 quarter and June 2011 quarter)

Weather components include cooling degree days (the cooling load), and a dummy variable to adjust for the impact of 2010–11 Queensland floods. Additionally, there are seasonal (quarterly) dummy variables that allow adjustment for the non-temperature related quarterly seasonality in electricity consumption.

Key observations include:

- Per capita consumption has a fixed component (5.53 kWh per person).
- A lagged total electricity price with elasticity of -0.18, implying that a 1% increase in total electricity price nine months ago will result in a 0.18% decrease in electricity consumption today.
- A lagged real interest rate with elasticity of -0.03, implying that a 1% increase in real interest rate three months ago will result in a 0.03% decrease in electricity consumption today.
- A gross state product per capita with income elasticity of +0.26, implying that an increase in gross state product per capita of 1% will result in a 0.26% increase in electricity consumption.

[1]Standard variable banks housing loan rates published by Reserve Bank of Australia, Table F5 Indicator Lending Rates.

A.3 South Australia

The model equation for non-large industrial consumption, which is based on a Vector Error Correction model, has been constructed on a quarterly basis and is outlined as follows:

$\Delta\, ln(y) = -0.82\hat{e}_{t-1}$

$-0.12\Delta\, ln(y_{t-1}) - .08\Delta\, ln(y_{t-2})$

$+0.13\Delta\, ln(i_{t-1}) + 0.09\Delta\, ln(i_{t-2})$

$+0.13\Delta\, ln(p_{t-1}) + 0.03\Delta\, ln(p_{t-2})$

$+0.007S1 + 0.04S2 + 0.07S3$

$+0.0004HDD + 0.0005CDD$

Where

$$\hat{\mathrm{e}} = 7.10 - 0.25\ln(\mathrm{p}) + 0.34\ln(\mathrm{i}) - \mathrm{y}$$

Or

$$\mathrm{y} = 7.10 - 0.25\ln(\mathrm{p}) + 0.34\ln(\mathrm{i})$$

- y = per capita electricity consumption in kWh per quarter per person
- i = state final demand per capita in 2009–10 dollars per person per quarter
- p = real residential electricity price in 2009–10 c/kWh
- HDD = heating degree days per quarter in Adelaide (Kent Town)

  $\sum \mathrm{Max}(0, \overline{\mathrm{T}} - 17.5)$ where $\overline{\mathrm{T}}$ is average daily temperature on a 6:00 PM to 6:00 PM basis
- CDD = cooling degree days per quarter in Adelaide (Kent Town)

  $\sum \mathrm{Max}(0, 19.5 - \overline{\mathrm{T}})$ where $\overline{\mathrm{T}}$ is average daily temperature on a 6:00 PM to 6:00 PM basis
- S1 = seasonal dummy for the March quarter (1 when period is the March quarter, 0 otherwise)
- S2 = seasonal dummy for the June quarter (1 when period is the June quarter, 0 otherwise)
- S3 = seasonal dummy for the September quarter (1 when period is the September quarter, 0 otherwise)

Due to the complex nature of the VEC model, it is best to focus on the error component for the long-run driver relationships. Putting the long-run relationship simply:

$$\mathrm{y} = 7.10 - 0.25\ln(\mathrm{p}) + 0.34\ln(\mathrm{i})$$

Key observations in the short run include:

- Lags of consumption, price and income allow for short-run effects of these variables.
- Heating degree days (the heating load) and cooling degree days (the cooling load) along with an air conditioning ownership variable explain the short-run variations in electricity consumption.
- Seasonal (quarterly) dummy variables allow adjustment for the non-temperature related quarterly seasonality in electricity consumption.

Key observations in the long run include:

- Per capita consumption has a fixed component (7.10 kWh per person) and a price elasticity of -0.25, implying that the long-run response to a 1% increase in electricity price is a 0.25% decrease in electricity consumption.
- Per capita consumption also has an income elasticity of +0.34, meaning that the long-run response to an increase in state final demand per capita of 1% is a 0.34% increase in electricity consumption.

A.4 Tasmania

The model equation for non-large industrial consumption, which is based on a Vector Error Correction model has been constructed on a quarterly basis and is outlined as follows:

$\Delta\, ln(y) = -0.58\hat{e}_{t-1}$

$-0.17\Delta\, ln(y_{t-1}) + 0.24\Delta\, ln(i_{t-1}) + 0.21\Delta\, ln(p_{t-1}) + 0.13\Delta\, ln(INDEX_{t-1})$

$+0.05S1 + 0.16S2 + 0.16S3$

$+0.0004HDD$

Where

$$\hat{e} = 2.85 + 0.68\ln(i) - 0.69\ln(p) + 0.13\ln(INDEX) - y$$

Or

$$y = 2.85 + 0.68\ln(i) - 0.69\ln(p) + 0.13\ln(INDEX)$$

- y = per capita electricity consumption in kWh per quarter per person
- i = state final demand per capita in 2009–10 dollars per person per quarter
- p = real residential electricity price in 2009–10 c/kWh
- INDEX = Gas and Other Household Fuels Price Index (ABS CPI Series 6401)
- HDD = heating degree days per quarter in Hobart (Ellerslie Road)

  $\sum Max(0, \bar{T} - 19)$ where $\bar{T}$ is average daily temperature on a 6:00 PM to 6:00 PM basis
- S1 = seasonal dummy for the March quarter (1 when period is the March quarter, 0 otherwise)
- S2 = seasonal dummy for the June quarter (1 when period is the June quarter, 0 otherwise)
- S3 = seasonal dummy for the September quarter (1 when period is the September quarter, 0 otherwise)

Due to the complex nature of the VEC model, it is best to focus on the error component for the long-run driver relationships. Putting the long-run relationship simply:

$$y = 2.85 + 0.68\ln(i) - 0.69\ln(p) + 0.13\ln(INDEX)$$

Key observations in the short run include:

- Lags of consumption, price, income, and the alternative fuels index allow for short-run effects of these variables.
- Heating degree days (the heating load) explain the short-run variations in electricity consumption.
- Seasonal (quarterly) dummy variables allow adjustment for the non-temperature related quarterly seasonality in electricity consumption.

Key observations in the long run include:

- Per capita consumption has a fixed component (2.85 kWh per person) and a price elasticity of -0.69, implying that the long-run response to a 1% increase in electricity price is a 0.69% decrease in electricity consumption.
- Per capita consumption has an income elasticity of +0.69, meaning that the long-run response to an increase in state final demand per capita of 1%, is a 0.69% increase in electricity consumption.
- The alternative fuel index has an elasticity of 0.13%, meaning that the long-run response to an increase in alternative fuels of 1% is a 0.13% increase in electricity consumption. The inclusion of this variable was based on the alternative fuel availability in Tasmania (for example, gas and wood) for heating. However, electricity price and income are the major determinants of electricity consumption in the mass market sector.

A.5 Victoria

The model equation for non-large industrial consumption, which is based on an Auto-Regressive Distributed Lag (ARDL) model has been constructed on a quarterly basis and is outlined as follows:

$$\ln(y) = 4.54$$

$$+0.34\ln(i) - 0.04\ln(p) - 0.05\ln(p_{t-2}) + 0.046\ln(p_{t-3}) - 0.096\ln(p_{t-4})$$

$$-0.0026S1 + 0.023S2 + 0.03S3$$

$$+0.00032CDD + 0.00037HDD$$

Where:

- y = per capita electricity consumption in kWh per quarter per person
- i = gross state product per capita in 2009–10 dollars per person per quarter
- p = real residential electricity price in 2009–10 c/kWh
- CDD = cooling degree days per quarter in Melbourne (Melbourne Airport)
  $\sum \mathrm{Max}(0,18 - \overline{\mathrm{T}})$ where $\overline{\mathrm{T}}$ is average daily temperature on a 6:00 PM to 6:00 PM basis
- HDD = heating degree days per quarter in Melbourne (Melbourne Airport)
  $\sum \mathrm{Max}(0, \overline{\mathrm{T} - 17})$ where $\overline{\mathrm{T}}$ is average daily temperature on a 6:00 PM to 6:00 PM basis
- S1 = seasonal dummy for the March quarter (1 when period is the March quarter, 0 otherwise)
- S2 = seasonal dummy for the June quarter (1 when period is the June quarter, 0 otherwise)
- S3 = seasonal dummy for the September quarter (1 when period is the September quarter, 0 otherwise)

The weather components include cooling degree days (the cooling load) and heating degree days (the heating load). Additionally, there are seasonal (quarterly) dummy variables that allow adjustment for the non-temperature related quarterly seasonality in electricity consumption.

Key observations include:

- Per capita consumption has a fixed component (4.54 kWh per person).
- A real residential electricity price with elasticity of -0.14, implying that a 1% increase in residential electricity price during the last 12 months will result in a 0.14% decrease in electricity consumption today.
- A GSP per capita with income elasticity of +0.34, implying that an increase in GSP per capita of 1% will result in a 0.34% increase in electricity consumption.

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APPENDIX B - ENERGY EFFICIENCY

B.1 Introduction

B.1.1 Energy efficiency impacts as a post-model adjustment

This appendix analyses and forecasts the impact of a range of energy efficiency and greenhouse gas abatement measures on future electricity consumption and maximum demand in the National Electricity Market (NEM). The forecasts are then used together with forecasts of rooftop photovoltaics (PV) as post-model adjustments to the electricity forecasts for non-large industrial consumption produced by econometric modeling in the national electricity forecasting project.

Various policies are in place on both the national and the state level to achieve energy efficiency objectives and to reduce greenhouse gas emissions.

The main national policies reviewed in this forecast are the Clean Energy Future package, the national Renewable Energy Target (RET) scheme, Mandatory Disclosure (*Energy Efficiency Disclosure Act 2010*), Minimum Energy Performance Standards (MEPS), and various building energy efficiency codes.

Some of the state government energy efficiency policies are measured individually to develop energy efficiency impact forecasts for each state, such as the New South Wales Energy Savings Scheme, South Australian Residential Energy Efficiency Scheme (REES), Queensland Renewable Energy Plan, and the Victorian Energy Efficiency Target (VEET). See Table B-1 for the full list of policy measures covered in this appendix.

The impacts from the assessed policy measures are forecast in both annual energy (gigawatt hours (GWh)) and maximum demand (megawatts (MW)) by region. Maximum demand is expected to be an approximation, as it is less predictable in terms of how households, businesses will behave and appliances will perform during maximum demand events.

The appendix mainly focuses on existing energy efficiency policies or measures affecting the residential sector. The commercial and industrial sector is considered only when the relevant reduction targets are explicitly stated in these policies.

B.1.2 Energy efficiency definition

The World Energy Council has defined energy efficiency improvement[1] as being a reduction in the energy used for a given service (for example, heating, cooling, and lighting) or level of activity. The reduction in the energy consumption is usually associated with technological changes, but not always, since it can also result from better organization and management or improved economic conditions in the sector (referred to as non-technical factors).

Energy efficiency can result from several areas:

- Individual behaviour to avoid unnecessary consumption of energy, such as switching off lights or air-conditioning when not needed, and the employment of standby power controllers.
- Choosing the most appropriate equipment to reduce energy consumption (such as electrical appliances with higher energy ratings) and better building standards (including installing insulation).

B.1.3 Impacts on demand forecasting

Energy efficiency and emission reduction policies, coupled with rising energy prices in recent years, have encouraged households and businesses to undertake energy efficiency measures to reduce their electricity bills.

[1] World Energy Council. 'Energy Efficiency Policies around the World: Review and Evaluation'. Available: http://www.worldenergy.org/publications/energy_efficiency_policies_around_the_world_review_and_evaluation/1_introduction/1175.asp. Viewed 14 June 2012.

Energy efficiency though policy incentives, technological improvements or consumer behaviour change is expected to have a long-lasting effect on energy and maximum demand in the NEM.

When estimating historical annual energy or forecasting future demand, it is important to account for the contribution from energy efficiency. Omitting the contribution from energy efficiency can result in demand forecast overestimation.

This paper forecasts the impact of energy efficiency policies on electricity demand for the 20-year outlook period from 2012 to 2031. The forecasts are largely based on the existing energy efficiency policies and do not take potential future policy changes into consideration.

The analysis presented here will form part of the electricity forecasts, which will reduce the mass market demand forecasts from the econometric modelling.

In Scenario 2, Fast World Recovery; Scenario 3, Planning; Scenario 4, Decentralised World; Scenario 5, Slow Rate of Change; and Scenario 6, Slow Growth, 50% of the energy efficiency impact is incorporated in the annual energy forecasts and the maximum demand forecasts for each region.

Only Scenario 1, Fast Rate of Change, has assumed a 100% energy efficiency impact.

B.1.4 Future work

This is the first time AEMO has undertaken a study of energy efficiency policies that influence electricity demand, which aims to establish a framework for future work and improvement in the following areas:

- Increased collaboration with government agencies, energy efficiency bodies, transmission network service providers (TNSP) and distribution network service providers (DNSP) to understand consumer behaviour changes.
- More closely monitoring the implementation of energy policies and measure the impact of these policies.
- Develop a robust data collection process by appliance and by sector.
- Build accurate inventory for major electrical appliances in the NEM.
- More in-depth analysis and modelling in the following areas:
  - Energy efficiency potential in the residential sector.
  - Commercial and industrial energy efficiency opportunities.
  - Energy efficiency impacts on maximum demand.
- Measuring how electricity prices influence consumer choices and interact with energy efficiency policies.

B.2 Energy efficiency policies, drivers and methodology

B.2.1 Energy efficiency policies

This section describes current state government and Australian Government policies that might impact electricity demand.

Table B-1 provides an overview of six national policies, some of which are described in more detail in Section B.13.

Table B-1 — Key national policies that may impact NEM electricity demand

Program	Measure	Description of impact on electricity demand
Clean Energy Future plan [2]	Carbon price, energy efficiency, renewable energy.	Impact on generation merit order, price elasticity of demand by sector, and energy efficiency measures.
Energy Efficiency Opportunities Programs [3]	Assessment of energy efficiency opportunities from large energy users.	Energy savings, potential renewable energy, cogeneration and trigeneration opportunities.
Minimum Energy Performance Standards (MEPS) [4]	Mandatory for a range of electrical products manufactured in or imported into Australia. The Energy Rating Labelling Scheme is a mandatory scheme for a range of appliances, which currently include refrigerators, freezers, clothes washers, clothes dryers, dishwashers, air conditioners and televisions.	Electricity appliance penetration and appliance efficiency.
Mandatory Disclosure (*Energy Efficiency Disclosure Act 2010*)[5]	Residential and commercial energy performance when sold or leased (existing buildings).	Impacts electricity use for space heating/cooling, and lighting.
Home Insulation Program 2009–10 [6]	Insulation subsidy for existing uninsulated dwellings.	Program ended in 2010, but has an ongoing impact on electricity demand.
Renewable Energy Target (RET) [7]	Targeted renewable energy production through a certificate scheme. Hot water eligible.	Impact via switch to solar water heaters and heat pumps.

Table B-2 provides an overview of key state energy efficiency policies that impact electricity demand, which are described in more detail in Section B.14.

[2] Clean Energy Future, available at http://www.cleanenergyfuture.gov.au/clean-energy-future/our-plan/. Viewed 25 June 2012.
[3] Energy Efficiency Opportunities, available at http://www.ret.gov.au/energy/efficiency/eeo/Pages/default.aspx. Viewed 25 June 2012.
[4] Minimum Energy Performance Standards, available at http://www.energyrating.gov.au/. Viewed 25 June 2012.
[5] National Framework for Energy Efficiency, available at http://www.ret.gov.au/documents/mce/energy-eff/nfee/committees/buildings/default.html. View 25 June 2012.
[6] Insulation Rebate, available at http://www.australian-government-insulation-rebates.com/Rebates/federal-government-rebate.html. Viewed 25 June 2012.
[7] Renewable Energy Target, available at http://www.climatechange.gov.au/ret. Viewed 25 June 2012.

Table B-2 — Key state policies that may impact NEM electricity demand

Jurisdiction	Program	Measure	Description of impact on electricity demand
Victoria	Victorian Energy Efficiency Target (VEET)[8], Phase Two.	Retailers are required to meet targets mainly through energy efficiency measures.	Impact on electricity demand through lightings upgrade, standby power etc. by residential customers.
New South Wales	Energy Savings Scheme[9].	Businesses are required to meet targets mainly through energy efficiency measures.	Impact through the surrender of Energy Savings Certificates (ESCs) by residential, commercial and industrial customers undertaking energy saving activities.
Queensland	Queensland Renewable Energy Plan[10].	Total 2,635 MW renewable energy capacity by 2020, involving Solar Hot Water Rebate, the Solar Bonus Scheme, and The Solar City.	Energy savings on grid through renewable energy incentives.
South Australia	South Australian Residential Energy Efficiency Scheme (REES)[11].	Energy providers are required to achieve greenhouse gas reduction targets mainly through energy saving measures.	Impact on electricity demand through lighting, showerheads, insulation, heating/cooling, and electric appliances.
Tasmania	Energy Saving Guide[12].	Educational material for government agencies to address climate change and greenhouse gas emissions.	No real target on energy savings or energy efficiency.

B.3 Drivers of energy efficiency

Energy efficiency and emission reduction policies, coupled with recent increasing energy prices, have encouraged households and businesses to undertake energy efficiency measures to reduce costs.

A range of activities are accounted for in developing the energy efficiency policy impact forecasts:

- The replacement of incandescent lighting with fluorescent and LED lights.
- The replacement of electric heaters or coolers with gas heaters, heat pumps, or reverse-cycle air-conditioners.
- The replacement of electric hot water systems with gas or solar water heaters.
- The installation standby power controllers and In-home displays.
- The replacement of electrical appliances with appliances with higher energy ratings.
- More energy-efficient building standards.

[8] Available at https://www.veet.vic.gov.au/Public/Public.aspx?id=Home. Viewed 25 June 2012.
[9] Overview of the Scheme, available at http://www.ess.nsw.gov.au/Overview_of_the_scheme. Viewed 25 June 2012.
[10] Queensland Renewable Energy Plan, available at http://www.cleanenergy.qld.gov.au/renewable-energy/renewable-energy-plan.htm. Viewed 25 June 2012.
[11] Residential Energy Efficiency Scheme, available at http://www.escosa.sa.gov.au/consumer-information/residential-energy-efficiency-scheme.aspx. Viewed 25 June 2012.
[12] Energy Saving Guide, available at http://www.education.tas.gov.au/dept/strategies/energy-saving-guide. Viewed 25 June 2012.

B.4 Energy efficiency impact forecast category

A range of energy efficient appliances and equipment have been considered:

- Lighting (the phase-out of incandescent light bulbs).
- Heating and cooling systems.
- Hot water systems (the phase-out of electric storage hot water systems).
- Standby power controllers.
- Building standards.
- Other appliances covered by the MEPS.

B.5 Energy efficiency impact base scenario and data sources

Energy efficiency policy impacts are forecast for the medium, base case scenario only, which is used to develop the annual energy and maximum demand forecasts for all scenarios.

The energy efficiency policy impact forecast development is largely based on a series of secondary information sources:

- Government reviews of the energy efficiency programs.
- Consultancy reports.
- Australian Bureaux of Statistics (ABS) demographic and electrical appliance statistics.
- Economic forecasts developed by the National Institute of Economic and Industry Research (NIEIR).

The accuracy of the forecasts depends on the accuracy of this information.

B.6 Estimating energy efficiency policy impacts

Three main steps were used to develop the forecasts:

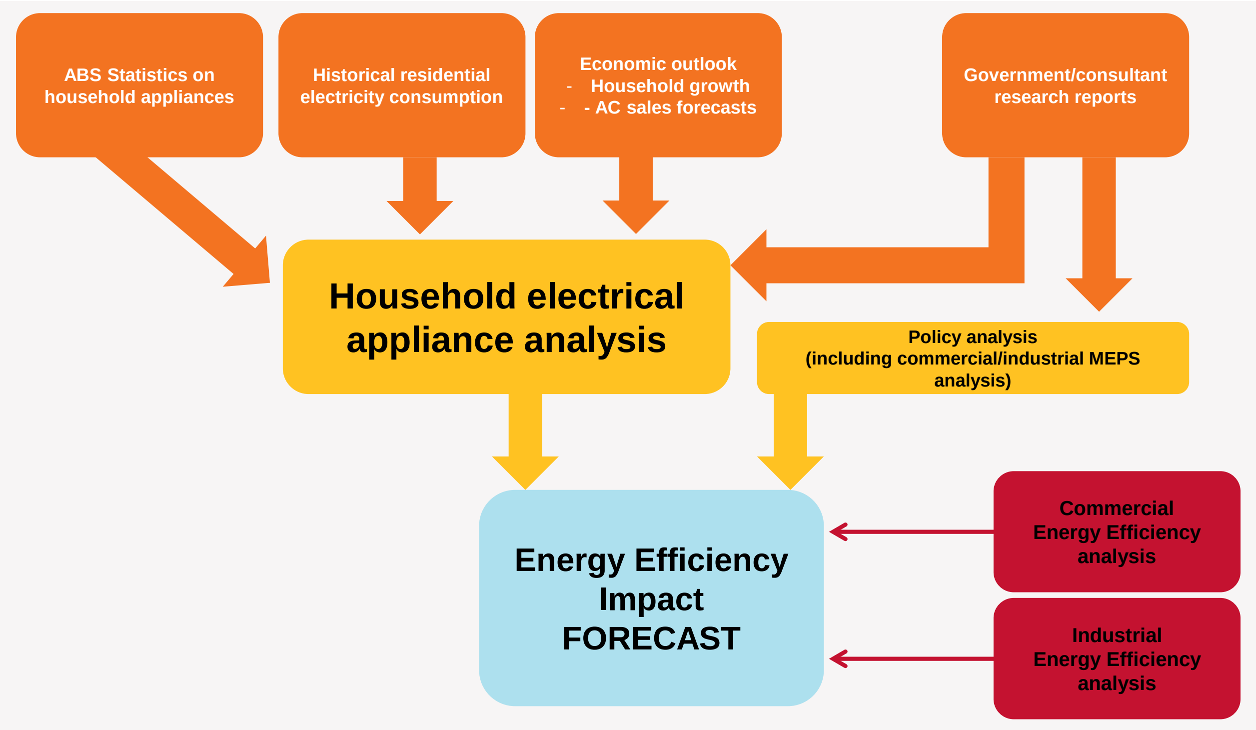
- Step 1, calibrating historical energy efficiency impacts based on ABS household appliances data and electricity demand by NEM region from 2007–08 till 2010–11.
- Step 2, estimating total energy savings using average household consumption patterns from step 1 categorised by lighting, hot water, heating and cooling, standby power, and MEPS, taking into consideration the potential impact of energy efficiency policies.
- Step 3, forecasting the maximum demand based on the annual energy forecasts, and efficiency gains from each category specified in step 2.

Each forecast category is analysed separately for annual energy and maximum demand forecasts based on its distinctive feature in terms of influencing annual energy and maximum demand.

For example, appliances such as commercial lighting and refrigeration, and energy efficient buildings, are more likely to reduce both electricity consumption and maximum demand, whereas other appliances such as televisions, cooking appliances, heating and cooling systems, and hot water systems may have more effect on electricity consumption than maximum demand.

Figure B-1 illustrates the modelling framework for the policy impact forecast.

Figure B-1 — Modelling framework for the policy impact forecast



Where possible, a residential electrical appliance analysis of the following appliances is performed to match historical residential electricity consumption:

- Electric hot water and electric-boosted solar water heaters.
- Electric heating.
- Electric cooling (air-conditioning, refrigerated and evaporative systems).
- Pools and spas (Queensland only).
- Fridges/freezers.
- Washing machines and dryers.
- Electric cooktops and electric ovens.
- Televisions, home theaters and stereos.
- Computers and game consoles.
- Standby power.

Commercial and industrial analysis is performed based on the MEPS only.

B.7 Modelling limitations

The energy efficiency policy impact forecasts are primarily based on existing policies and measures with real energy savings targets, and potential policy changes are not considered or assessed.

Policies on the national level and policies on the state level may not be mutually exclusive. For example, in the water heating area, a number of measures currently exist in parallel on a both national and a state level, including rebates for replacing electric resistance water heating, state solar water heater rebates, building standards, and eligibility of solar water heating for the national RET scheme.

The forecast categories in some cases may overlap with each other. Energy efficient lighting, heating and cooling systems, hot water systems are potentially also covered in the Building Standards. To minimise the possibility of double counting, a growth rate for each appliance is assumed.

The impact on electricity consumption co-exists in both electricity price response, energy efficiency and the uptake of distributed energy such as rooftop PV. The interaction among these three aspects is not analysed in this report and the potential overlap is not measured in these forecasts.

In addition, rebound effects, for example using more efficient lighting, the rebound effect may off-set the potential energy saving. Lighting, space conditioning (air conditioning and heating) and hot water use are likely to have an element of rebound.

The rebound effects are not analysed and therefore not measured in these forecasts.

B.8 Energy efficiency policy impacts in the NEM

AEMO independently studied energy efficiency policy impacts to understand the current and forecast impact of energy efficiency policies on the NEM. This is the first time AEMO has undertaken a study of this type, and the methodology will continue to develop. This first step has, however, provided insight into the current setting of energy efficiency policies and their impacts on the NEM.

Various energy efficiency program reviews and consultancy reports are available, mostly targeting individual programs, some of which have been incorporated into the forecasts.

The historical and forecast estimates for the NEM are an aggregation of each of the five regions.

The analysis discussed here forms the basis for AEMO's energy forecast calculations.

B.9 Historical analysis

The impact of energy efficiency on overall electricity demand in the NEM has become noticeable over the last few years. This has been reflected in the average consumption per household, estimated using ABS household appliances data and electricity demand by NEM region from 2007–08 to 2010–11.

Estimates suggest that the regions with mandatory residential energy efficiency targets have seen a reduction of average household electricity consumption over this period.

This reduction was largely a result of more efficient lighting and electrical appliances, better energy ratings in building standards, and a certain degree of behaviour changes responding to the increased energy prices.

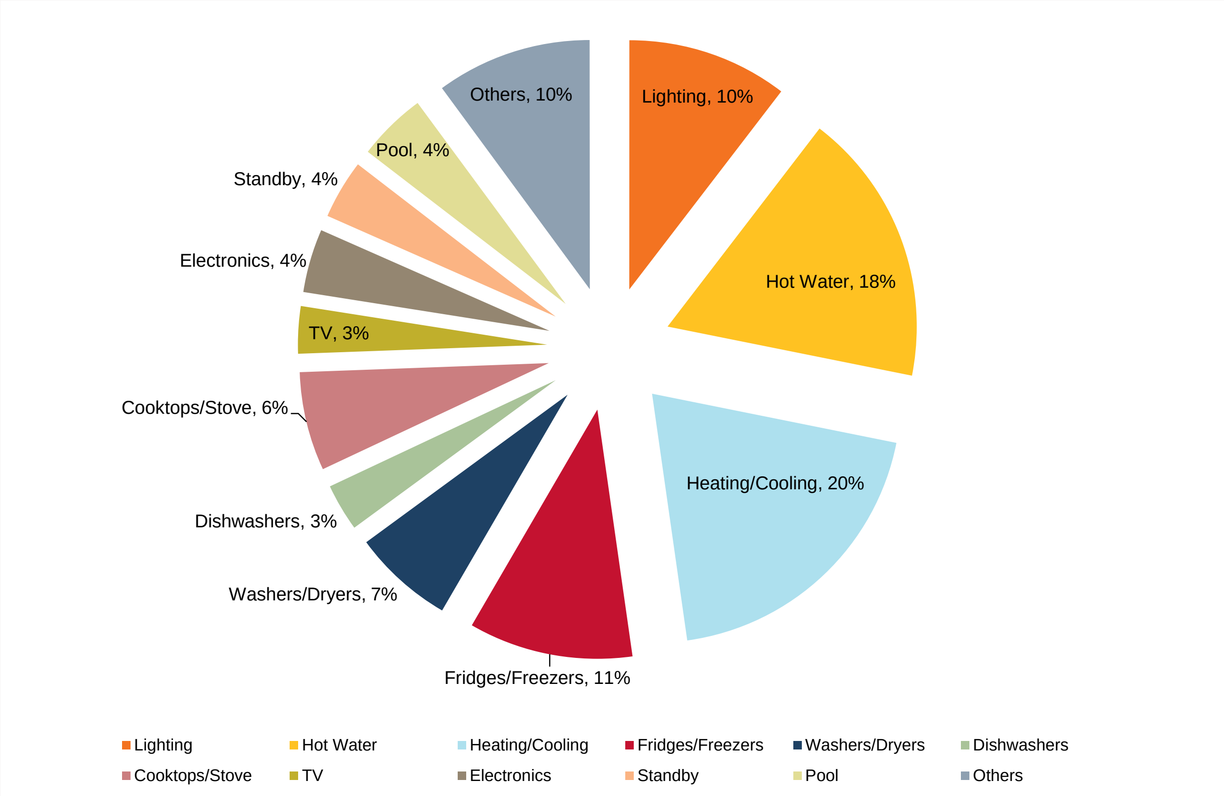
Table B-3 lists the estimated average daily consumption per household in kWh in 2004–05, 2007–08 and 2010–11.

Table B-3 — Estimated average daily consumption per household in kWh by NEM region in 2004–05, 2007–08 and 2010–11

Daily consumption per household (kwh)	2004–05	2007–08	2010–11
Victoria	16.37	17.68	16.07
Queensland	21.38	21.57	22.14
New South Wales (and the ACT)	17.94	18.00	17.74
South Australia	17.65	18.15	17.82
Tasmania	27.80	27.47	29.56

Figure B-2 shows the breakdown of estimated residential electricity consumption by appliance in the NEM.

Figure B-2 — Residential electricity consumption by appliance in the NEM

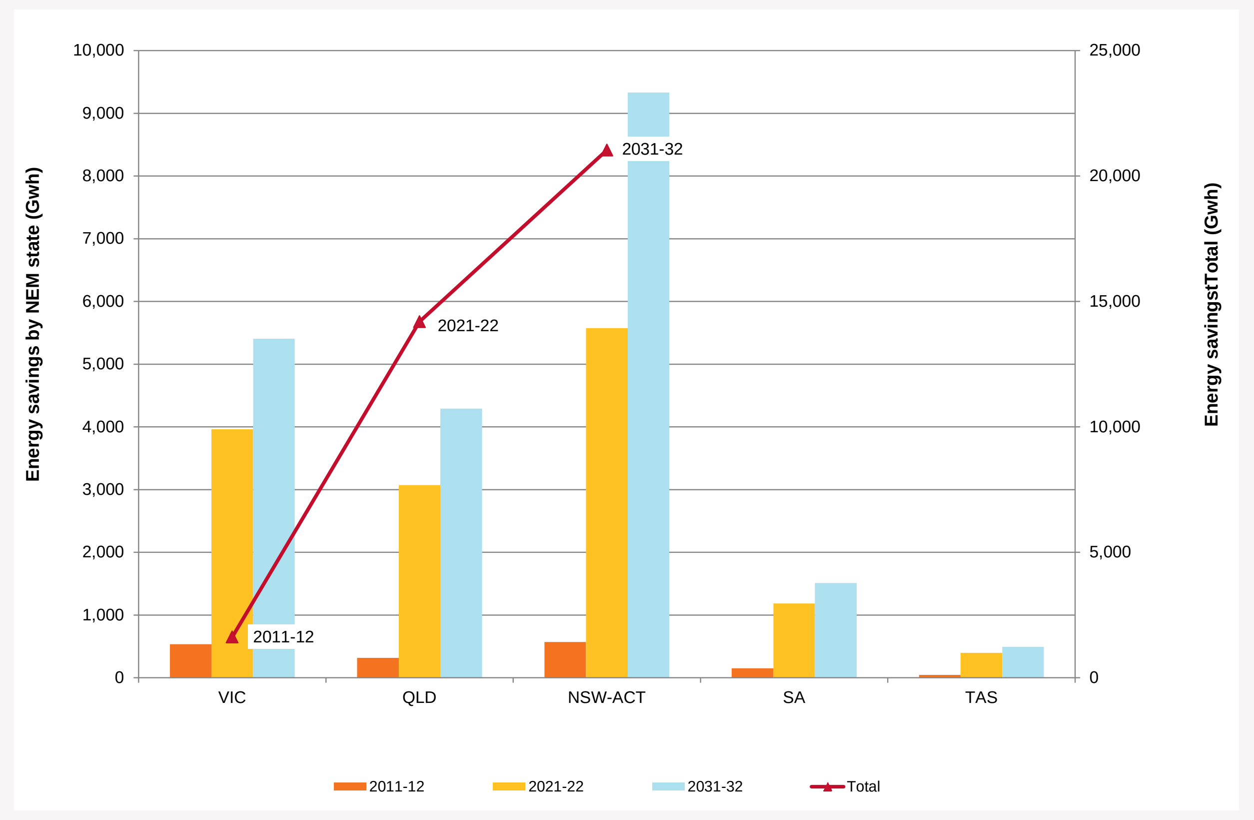


B.10 Annual energy

Figure B-3 shows the forecast energy saving for energy efficiency for each NEM region in 2011–12, 2021–22 and 2031–32.

In the NEM, annual energy savings due to energy efficiency policy impacts are forecast to reach approximately 14,191 GWh by 2021–22 and 21,032 GWh by 2031–32.

Figure B-3 — Energy efficiency policy, annual energy impact forecasts by NEM region



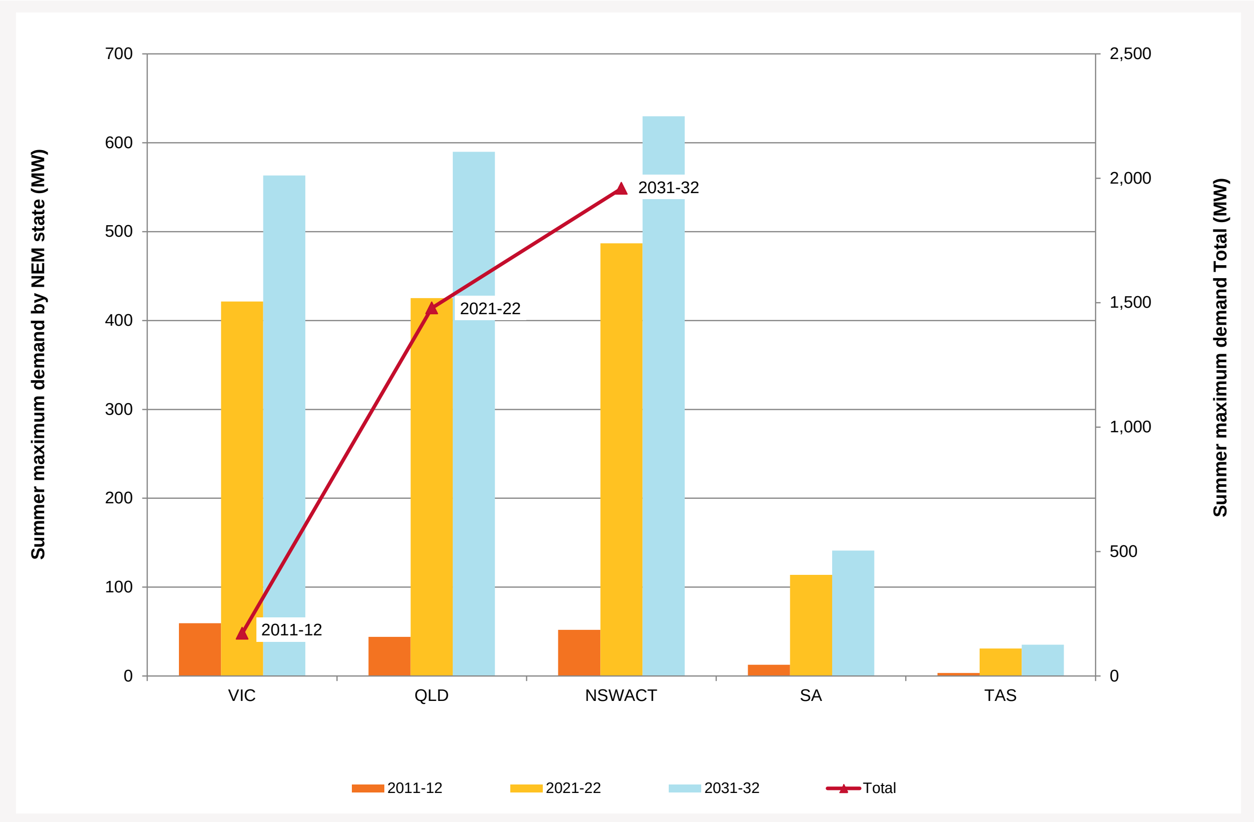
The larger forecast for New South Wales (and the ACT) is due to the more measurable commercial and industrial sector energy efficiency potential. The forecasts for the other regions primarily concern the residential sector.

B.11 Maximum demand

Figure B-4 shows the forecast energy efficiency impact on summer maximum demand (MW) by region in 2011–12, 2021–22 and 2031–32 (in Tasmania, the maximum demand occurs during winter).

Estimated summer peak energy savings are approximately 1,479 MW by 2021–22 and 1,959 MW by 2031–32.

Figure B-4 — Energy efficiency policy, summer maximum demand impact forecasts by NEM region



B.12 Regional energy efficiency policy impact

This section provides information about historical and forecast estimates for energy efficiency policy impact in each region. Providing an initial overall picture of energy efficiency policy impacts, additional modelling and data mining work is required to improve the forecasts.

B.12.1 New South Wales (and the Australian Capital Territory)

The New South Wales Energy Savings Scheme[13] is the key policy considered in developing forecasts for energy efficiency for New South Wales (including the Australian Capital Territory). For an overview of the scheme and the assumptions made in developing these forecasts, see Section B.14.1.

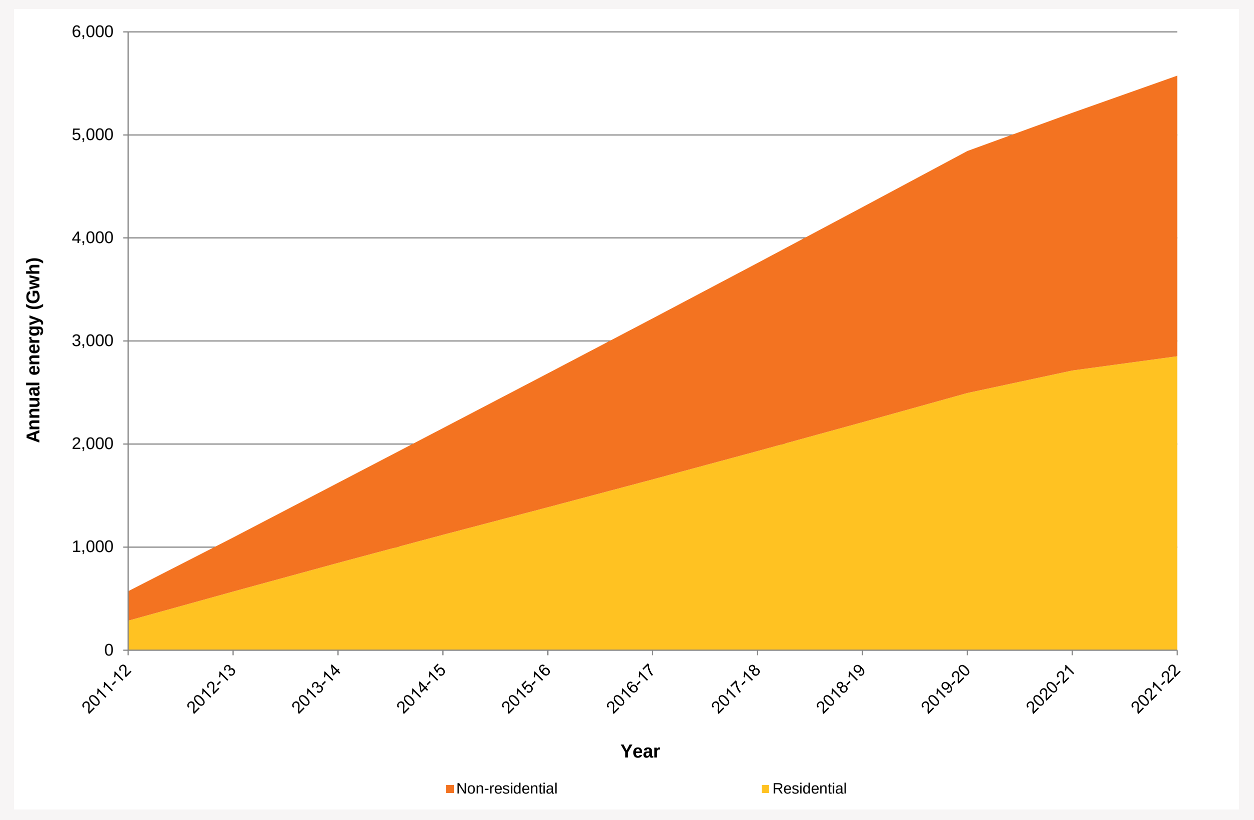
Annual energy

Figure B-5 shows the forecast impact from energy efficiency for New South Wales (including the Australian Capital Territory).

The impact is forecast to grow continuously during the forecast period in both the residential and business sectors (with residential sector growth anticipated to slow after 2021 due to high saturation), and is estimated to reach 5,575 GWh by 2021–22 and 9,331 GWh by 2031–32, which is approximately 7.2% and 11.5% (respectively) of total forecast sent-out energy in New South Wales (including the ACT).

[13] See note 9.

Figure B-5 — Energy efficiency impact annual energy forecasts for New South Wales (and the Australian Capital Territory)



Maximum demand

Figure B-6 and Figure B-7 show energy efficiency policy impact summer and winter maximum demand forecasts.

Energy efficiency policy summer maximum demand impacts reach 487 MW in 2021–22 and 630 MW in 2031–32.

The winter maximum demand impact is estimated to be similar to the summer maximum demand, because improved energy efficient lighting, refrigeration, and building is most likely to consistently impact in both summer and winter.

Figure B-6 — Energy efficiency impact summer maximum demand forecasts for New South Wales (and the Australian Capital Territory)

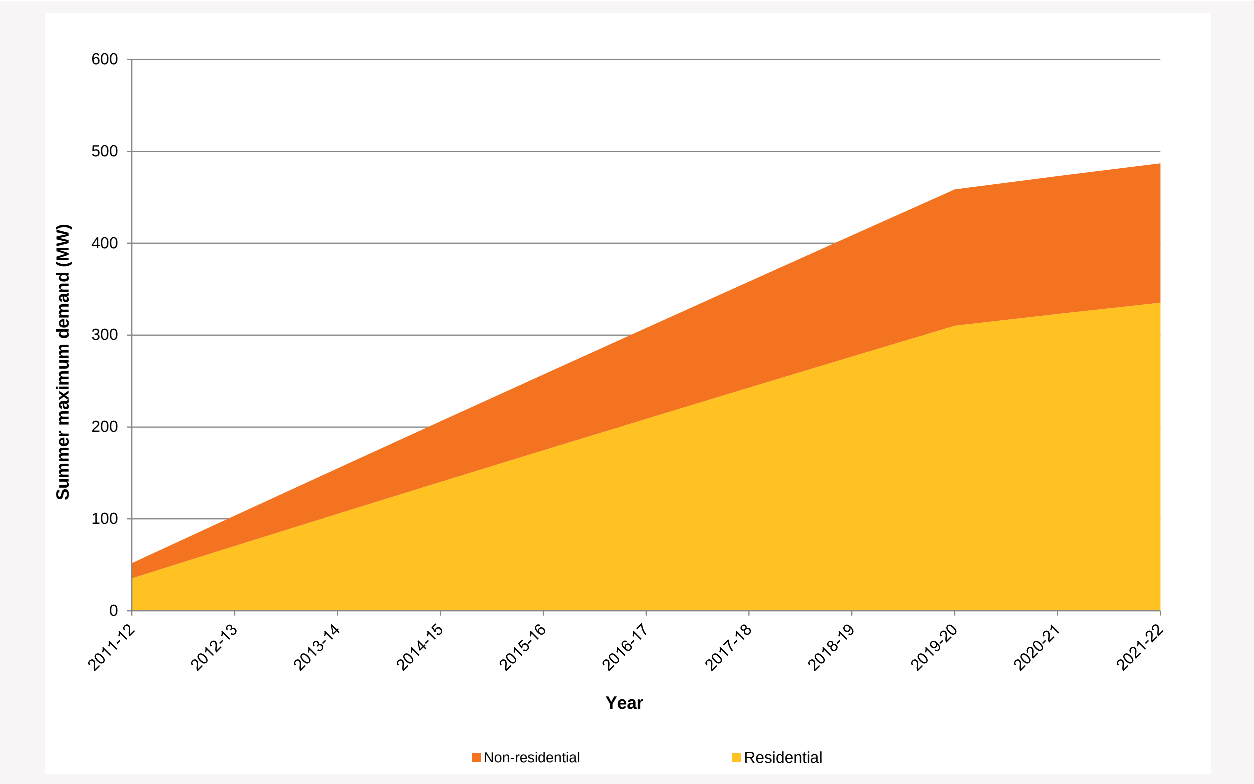
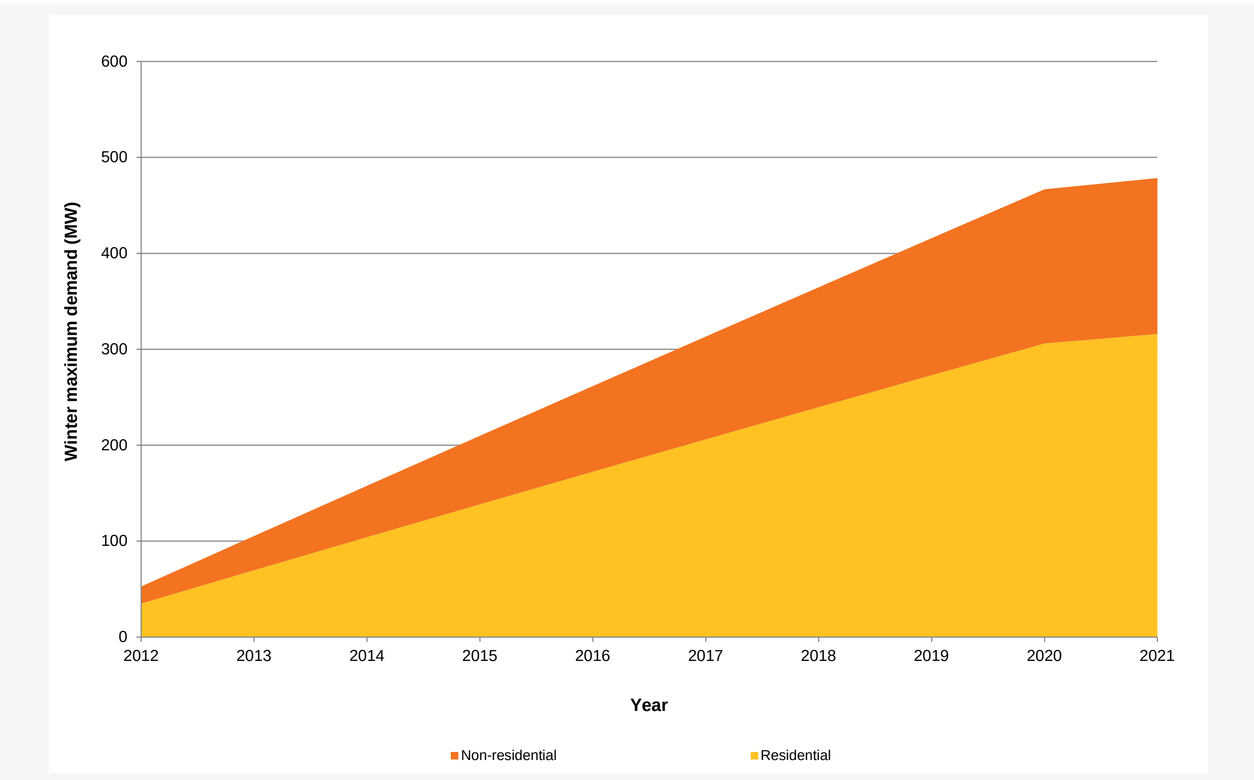


Figure B-7 — Energy efficiency impact winter maximum demand forecasts for New South Wales (and the Australian Capital Territory)



B.12.2 Queensland

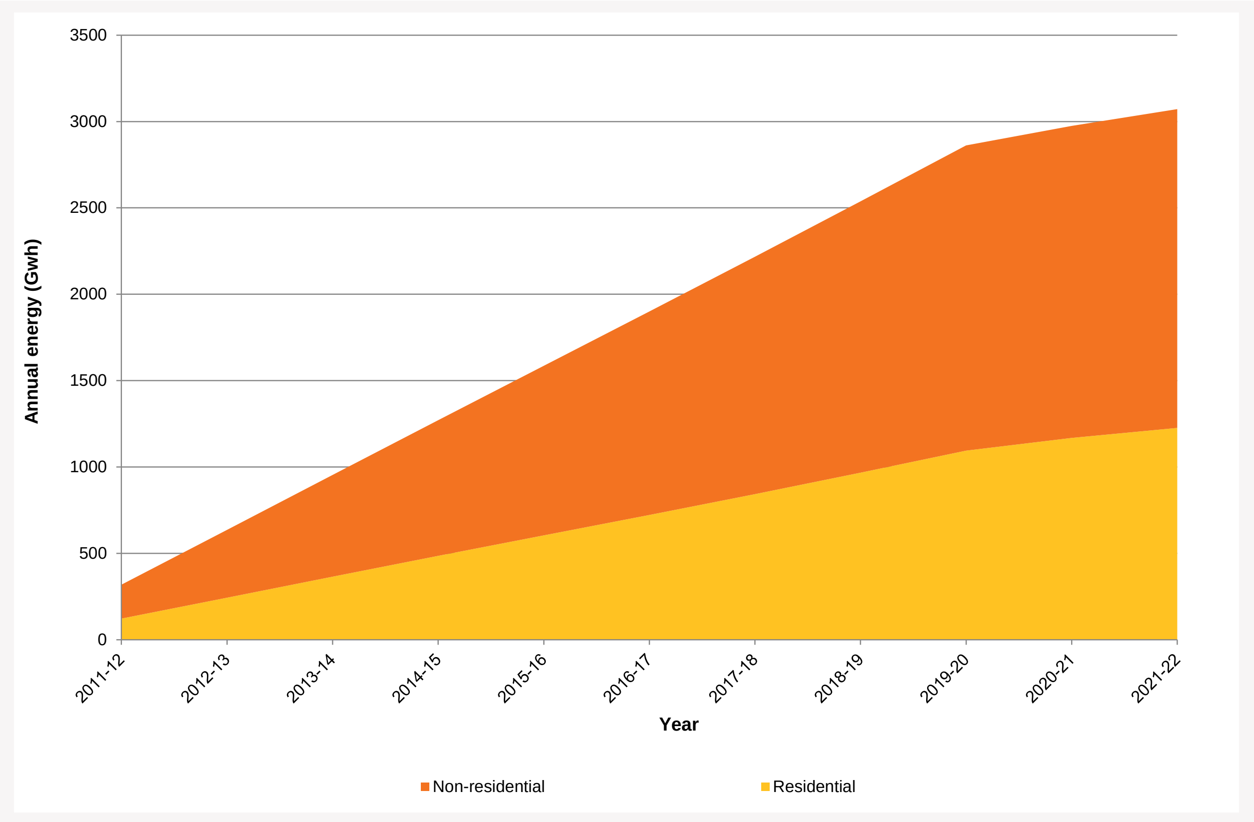
The Queensland Renewable Energy Plan[14] is the key policy considered in developing forecasts for energy efficiency for Queensland. For an overview of the scheme and the assumptions made in developing these forecasts, see Section B.14.2.

Annual energy

Figure B-8 shows the forecast impact from energy efficiency for Queensland.

The impact is forecast to grow continuously during the forecast period in both the residential and business sectors, and is estimated to reach 3,072 GWh by 2021–22 and 4,291 GWh by 2031–32, which is approximately 4.7% and 6.0% (respectively) of total forecast sent-out energy in Queensland.

Figure B-8 — Energy efficiency impact annual energy forecasts for Queensland



[14] See note 10.

Maximum demand

Figure B-9 and Figure B-10 show energy efficiency policy impact summer and winter maximum demand forecasts.

Energy efficiency policy summer maximum demand impacts reach 425 MW in 2021–22 and 589 MW in 2031–32.

The winter maximum demand impact is estimated to be slightly lower than the summer maximum demand based on the assumption that the cooling requirement is lower in winter.

Figure B-9 — Energy efficiency impact summer maximum demand forecasts for Queensland

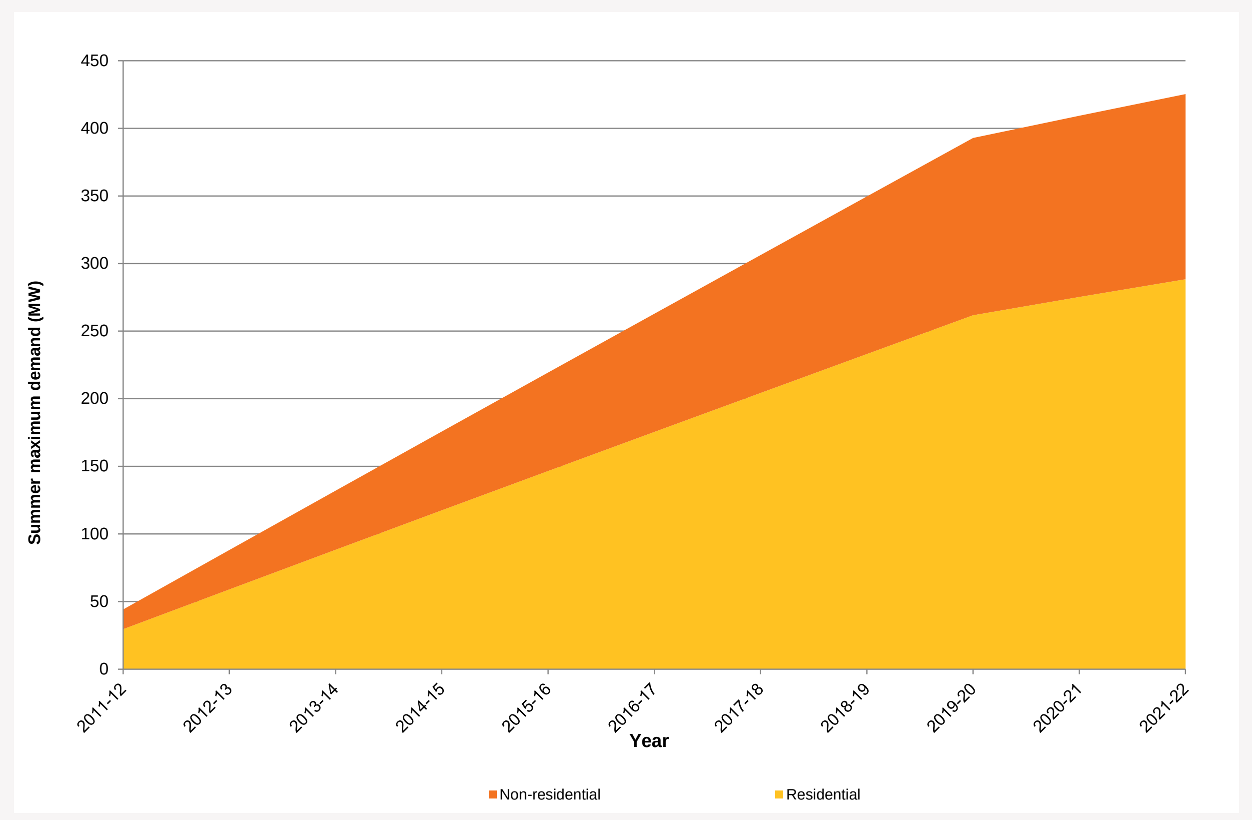
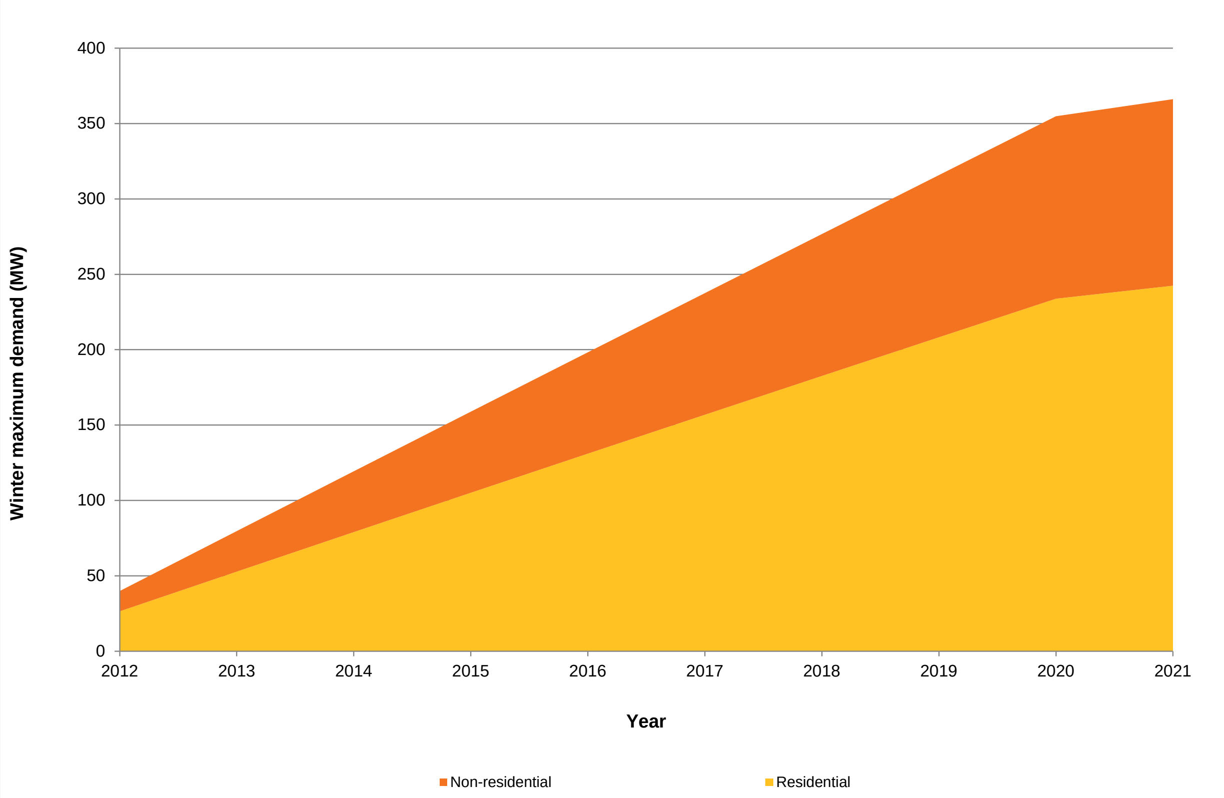


Figure B-10 — Energy efficiency impact winter maximum demand forecasts for Queensland



B.12.3 South Australia

The South Australian Residential Energy Efficiency Scheme (REES)[15] is the key policy considered in developing forecasts for energy efficiency for South Australia. For an overview of the scheme and the assumptions made in developing these forecasts, see Section B.14.3.

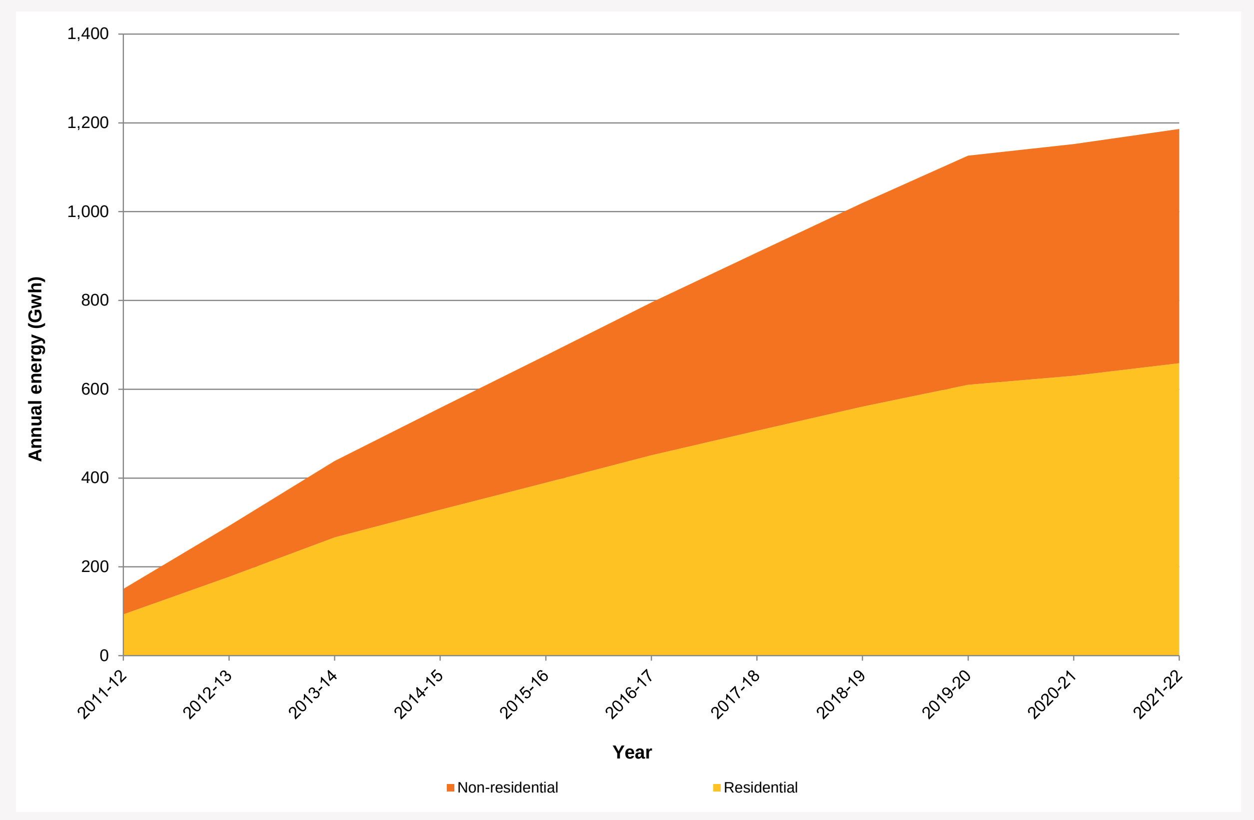
Annual energy

Figure B-11 shows the forecast impact from energy efficiency for South Australia.

The impact is forecast to grow continuously during the forecast period in both the residential and business sectors, and is estimated to reach 1,186 GWh by 2021–22 and 1,512 GWh by 2031–32, around 8.4% and 10.7% (respectively) of total forecast sent-out energy in South Australia.

[15] See note 11.

Figure B-11 — Energy efficiency impact annual energy forecasts for South Australia



Maximum demand

Figure B-12 and Figure B-13 show energy efficiency policy impact summer and winter maximum demand forecasts.

Energy efficiency policy summer maximum demand impacts reach 114 MW in 2021–22 and 141 MW in 2031–32.

The winter maximum demand impact is estimated to be slightly lower than the summer maximum demand based on the assumption that the cooling requirement is lower in winter.

Figure B-12 — Energy efficiency impact summer maximum demand forecasts for South Australia

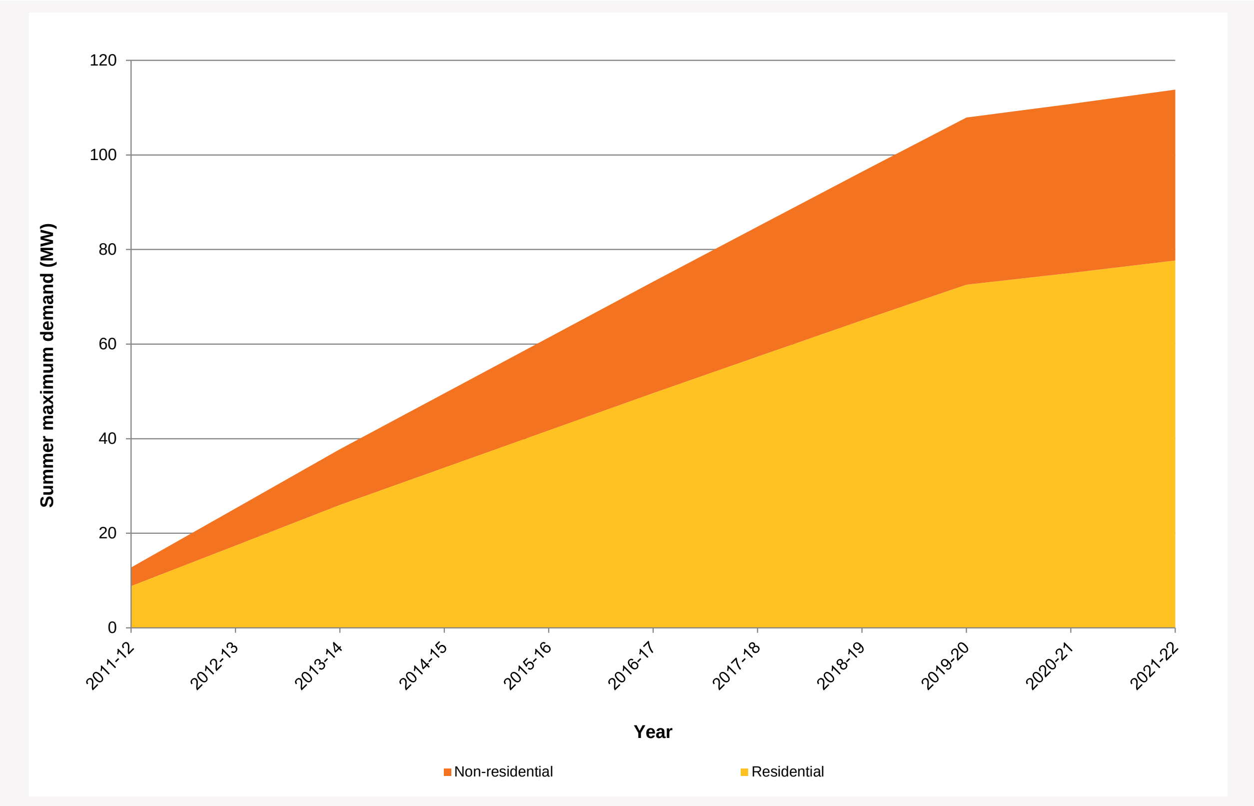
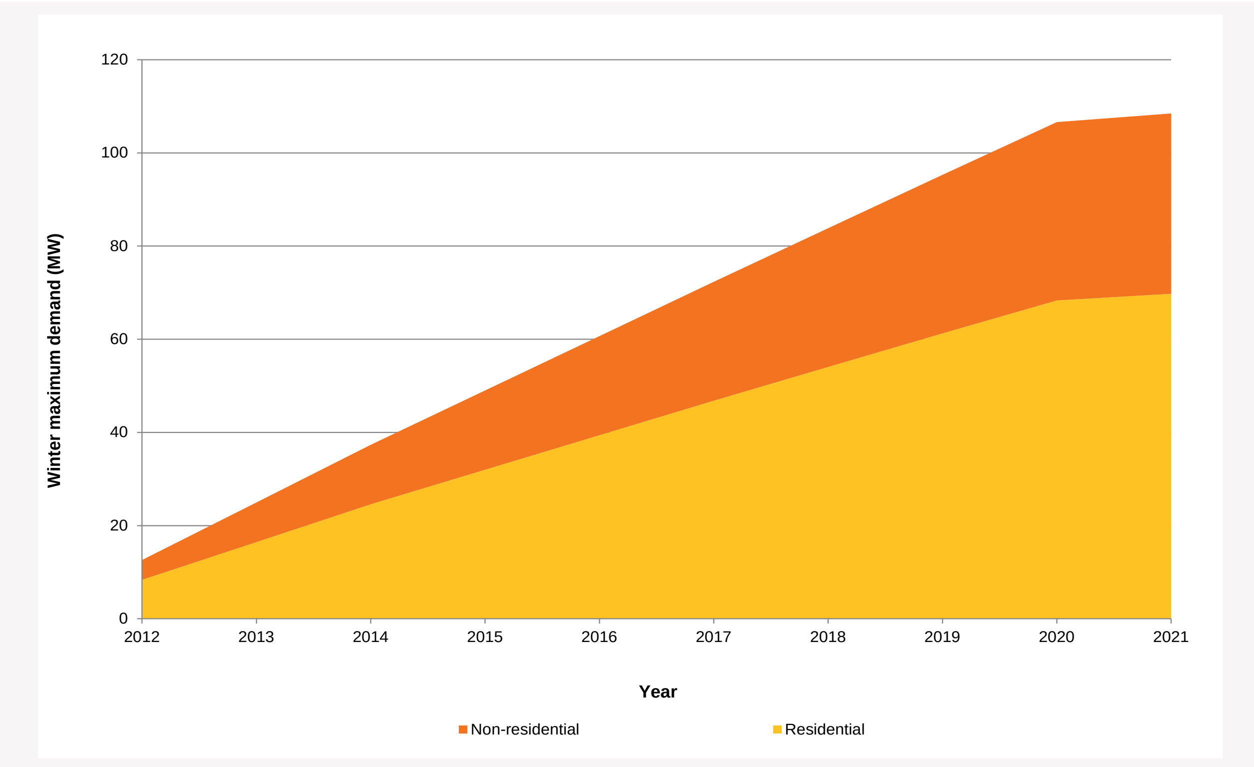


Figure B-13 — Energy efficiency impact winter maximum demand forecasts for South Australia



B.12.4 Tasmania

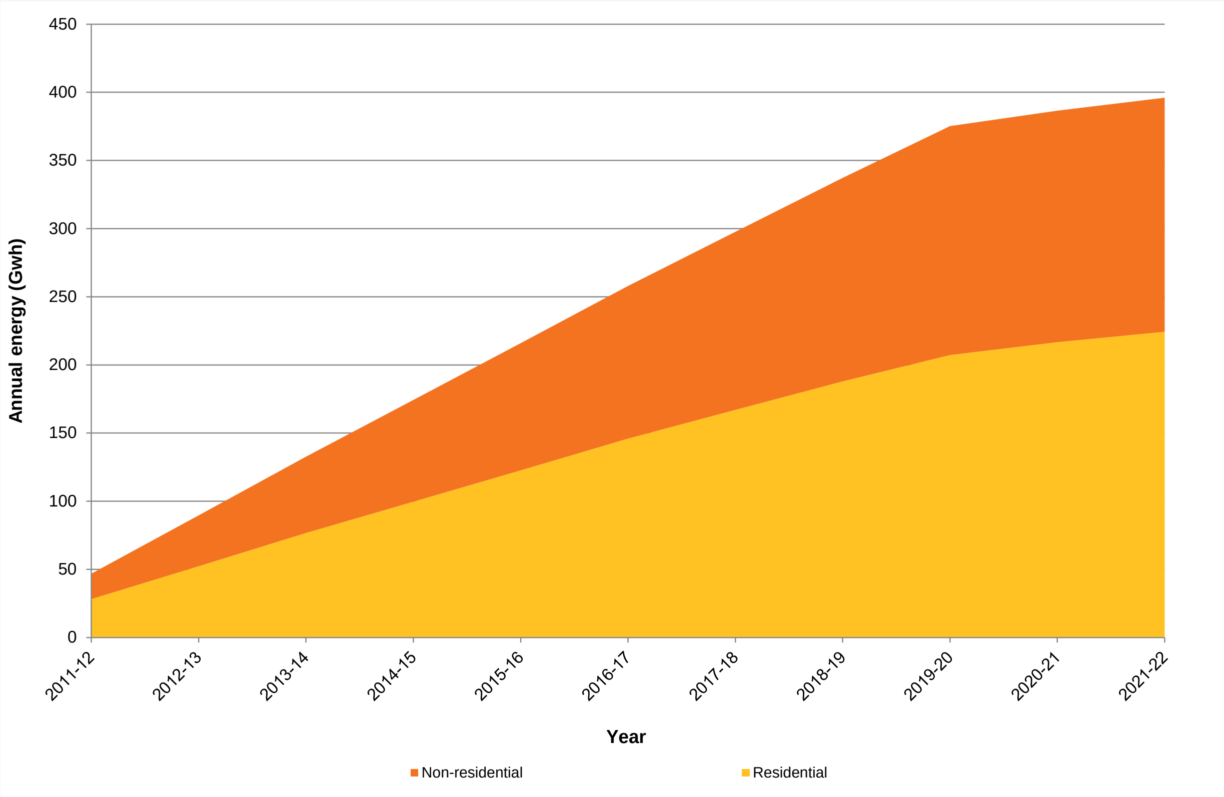
The Energy Saving Guide[16] published by the Tasmanian Government has no material measures for energy efficiency. National energy efficiency policies (such as the MEPS) represent the key policies in developing the forecast for Tasmania. For an overview of the MEPS, see Section B.13.5.

Annual energy

Figure B-14 shows the forecast impact from energy efficiency for Tasmania.

The impact is forecast to grow continuously during the forecast period in both the residential and business sectors, and is estimated to reach 396 GWh by 2021–22 and 493 GWh by 2031-32, which is approximately 3.5% and 4.0% (respectively) of total forecast sent-out energy in Tasmania.

Figure B-14 — Energy efficiency impact annual energy forecasts for Tasmania



Maximum demand

Figure B-15 and Figure B-16 show energy efficiency policy impact summer and winter maximum demand forecasts.

Energy efficiency policy summer maximum demand impacts reach 31 MW in 2021–22 and 35 MW in 2031–32.

The winter maximum demand impact is estimated to be slightly higher than summer due to Tasmanian electricity consumption peaking during winter.

[16] See note 12.

Figure B-15 — Energy efficiency impact summer maximum demand forecasts for Tasmania

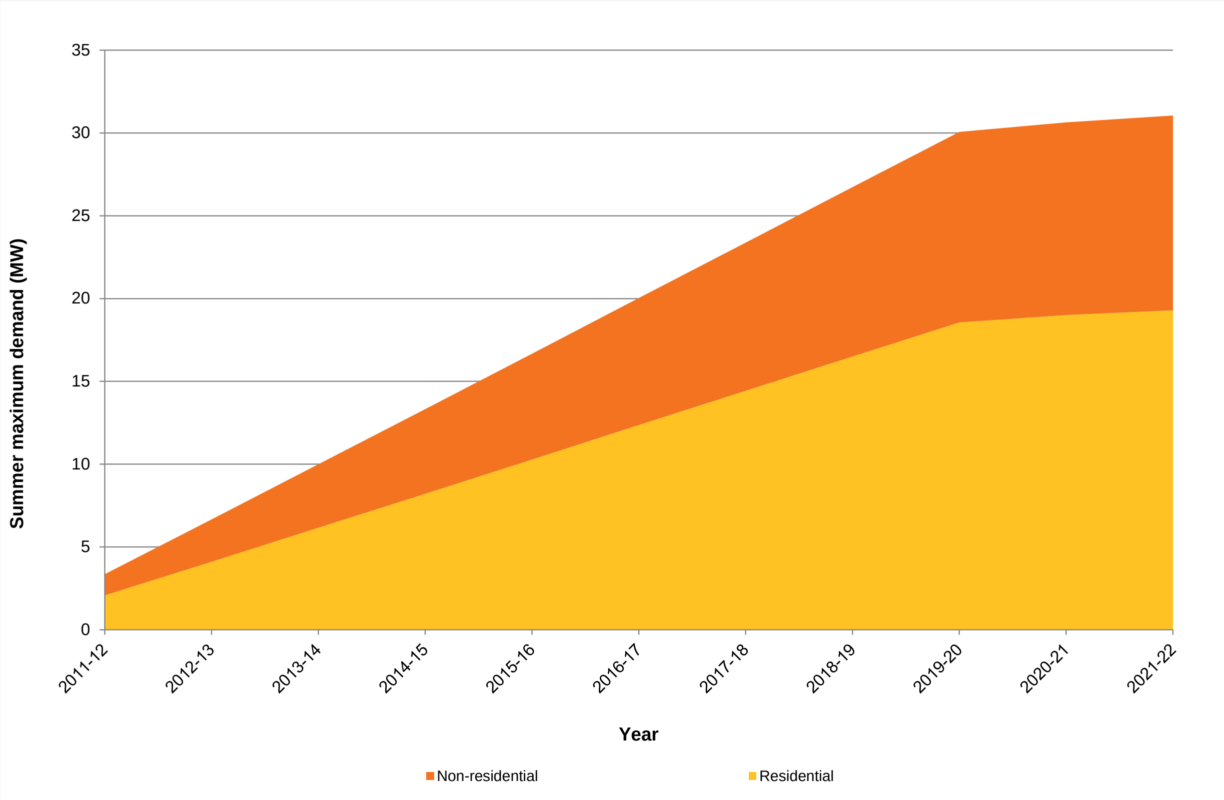
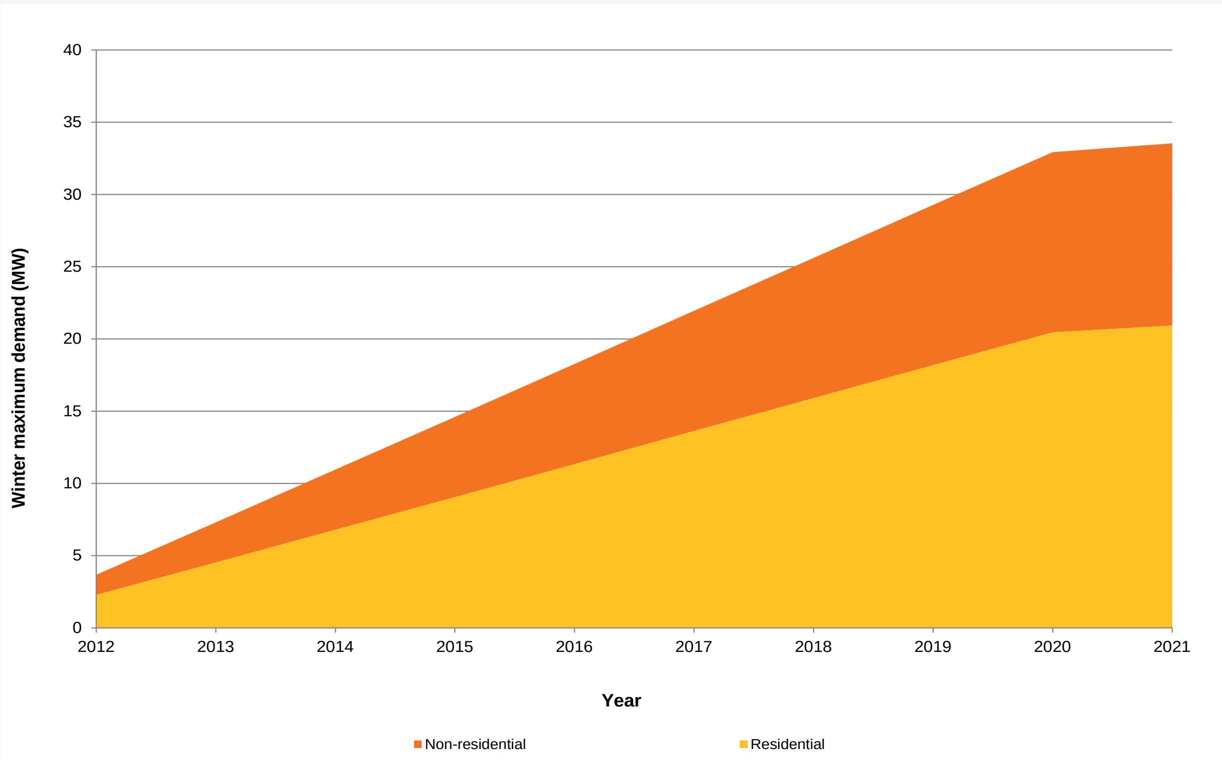


Figure B-16 — Energy efficiency impact winter maximum demand forecasts for Tasmania



B.12.5 Victoria

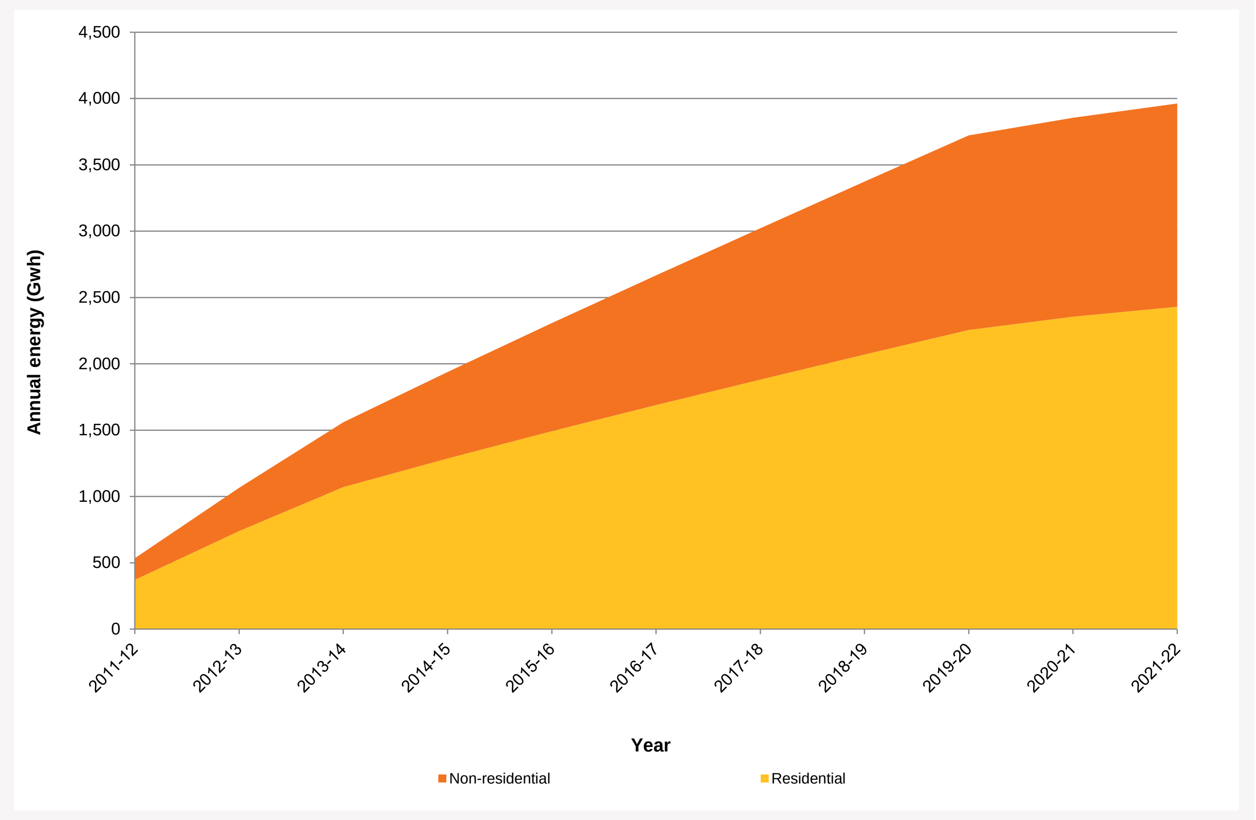
The Victorian Energy Efficiency Target[17] (VEET) scheme is the key policy considered in developing forecasts for energy efficiency for Victoria. For an overview of the scheme and the assumptions made in developing these forecasts, see Section B.14.4.

Annual energy

Figure B-17 shows the forecast impact from energy efficiency for Victoria.

The impact is more significant in the residential sector than in the business sector during the forecast period, due to financial incentives from the VEET scheme. The impact is estimated to reach 3,962 GWh by 2021–22 and 5,404 GWh by 2031–32, which is approximately 7.3% and 9.2% (respectively) of total forecast sent-out energy in Victoria.

Figure B-17 — Energy efficiency impact annual energy forecasts for Victoria



Maximum demand

Figure B-18 and Figure B-19 show energy efficiency policy impact summer and winter maximum demand forecasts.

Energy efficiency policy summer maximum demand impacts reach 421 MW in 2021–22 and 563 MW in 2031–32.

The winter maximum demand impact is estimated to be lower than the summer maximum demand due to a higher percentage of gas heating in Victoria.

[17] See note 8.

Figure B-18 — Energy efficiency impact summer maximum demand forecasts for Victoria

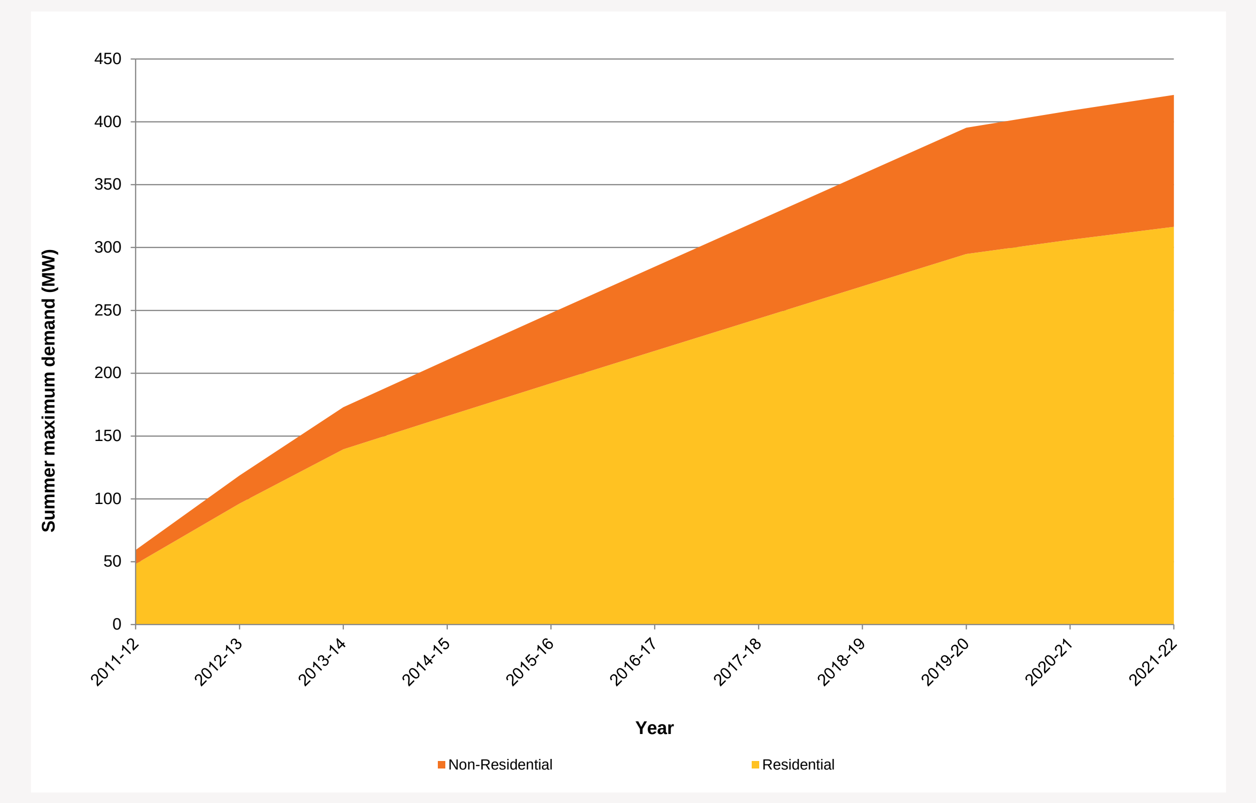
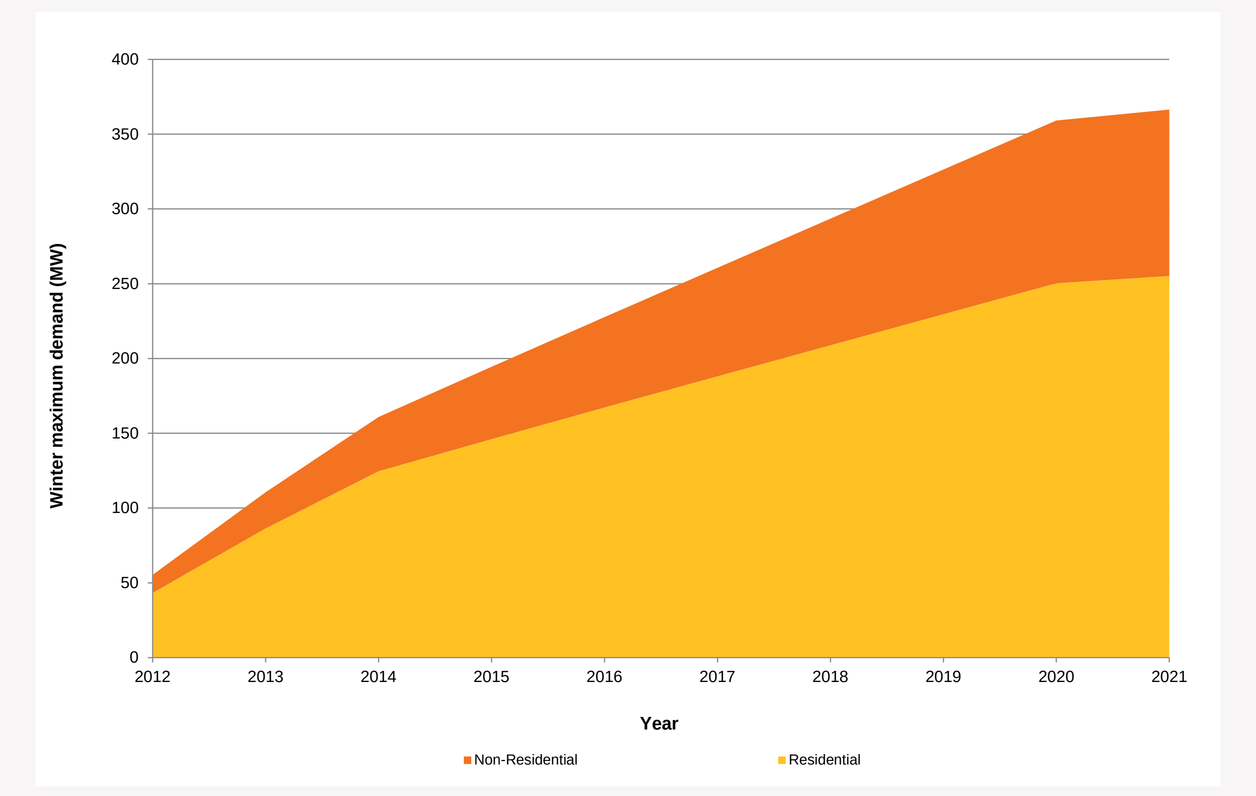


Figure B-19 — Energy efficiency impact winter maximum demand forecasts for Victoria



B.13 National energy efficiency policies

B.13.1 Clean Energy Future Plan

On 8 November 2011, the Australian Government's Clean Energy Future Plan[18] was passed into law. Under the plan, Australia will reduce greenhouse gas pollution by at least 5% (compared with 2000 levels) by 2020, equivalent to removing 159 Mt/yr CO2-e from the atmosphere by 2020.

The legislation includes the following measures:

- Pricing carbon pollution.
- Promoting innovation and investment in renewable energy.
- Improving energy efficiency.
- Creating opportunities in the land-use sector to cut carbon pollution.

Carbon price

The introduction of a carbon price mechanism was announced by the Australian Government in July 2011, after an agreement reached by the Multi-Party Climate Change Committee.[19]

Recent modelling work by Treasury for the Australian Government's Clean Energy Future Plan has led to several carbon price assumptions:

- Fixed carbon pricing will start on 1 July 2012, at a nominal price of $23/t CO2-e, rising to 2.5% in real terms for the subsequent two years.
- A flexible phase will be introduced on 1 July 2015, with the carbon price determined through an emission trading scheme (ETS) with a transitional price cap and floor applied.
- Real growth in the carbon price of 5% per year on average plus inflation from 2015–16 onwards.

This legislation is designed to achieve a reduction in Australian carbon emissions of 5% below 2000 levels by 2020 with a long-term target to cut pollution by 80% below 2000 levels by 2050.

Clean Energy Finance Corporation

A $10 billion commercially oriented Clean Energy Finance Corporation will drive innovation through investments in clean energy. The corporation will leverage private sector financing for renewable energy and clean technology projects, with a focus on renewable energy, energy efficiency, and low-emissions technologies, and the transformation of existing manufacturing businesses to refocus on meeting demand for inputs for these sectors.

National Energy Savings Initiative (ESI)

Under the Clean Energy Future Plan, the Australian Government committed to do further work to investigate the merits of a national Energy Savings Initiative (ESI)[20], which will place obligations on energy retailers to find and implement energy savings in households and businesses. The design of any national scheme will need the following features:

- A broad coverage involving the residential, commercial and industrial sectors.
- Creation of an incentive or a requirement to create certificates in both low-income households and in ways that reduce peak demand.

[18] See note 2.
[19] The Australian Government's Treasury and the Department of Climate Change and Energy Efficiency modelled the potential economic impacts of reducing emissions over the medium and long term proposed in the 'Strong Growth, Low Pollution, Modelling a Carbon Price' Report, released on 10 July 2011, available http://archive.treasury.gov.au/carbonpricemodelling/content/default.asp. Viewed May 2012.
[20] Australian Government, available at http://www.climatechange.gov.au/government/initiatives/energy-savings-initiative.aspx. Viewed 20 June 2012.

Subject to the findings of economic modelling and regulatory impact analysis, the Australian Government will make a final decision to adopt a national ESI, which will be conditional on the agreement of the Council of Australian Governments (COAG) and the abolition of existing and planned state schemes.

B.13.2 Renewable Energy Target

The national Renewable Energy Target (RET) scheme requires 20% of Australia's electricity to be produced from renewable energy sources by 2020.[21] The scheme requires Australian electricity retailers and large wholesale purchasers of electricity to meet annual targets, creating a financial incentive for investment in renewable energy sources through the creation and sale of certificates. The scheme is split into two parts:

- The Large-scale Renewable Energy Target (LRET) has a target of 41,000 GWh by 2020 and only large-scale renewable energy projects are eligible.
- The Small-scale Renewable Energy Scheme (SRES) targets a theoretical 4,000 GWh annually and is eligible only to small-scale or household installations.

Solar water heaters and heat pumps remain supported through the SRES. Under this scheme, these are assigned a number of Small-scale Technology Certificates (STCs). For information about these policies, see Section 0.

B.13.3 Energy Efficiency Opportunities Regulations

The *Energy Efficiency Opportunities Act 2006* mandates that corporations that individually or as part of a corporate group use more than 0.5 PJ of energy per year must report on energy savings opportunities with a less than four year payback, and report on their implementation. The first phase of the Energy Efficiency Opportunities (EEO) program extended over the period 2006 to 2011. The second phase covering the period 2012 to 2017 is now being planned.

The program applies to over 310 corporations from the manufacturing, mining, resource processing, electricity generation, transport and commercial sectors. These corporations represent approximately 57% of Australia's total energy use.

As part of the Australian Government's Clean Energy Future plan, the EEO program will be expanded in the following ways[22]:

- Extending base funding for the program to 30 June 2017.
- Expanding the program to include energy transmission and distribution networks, and major greenfield and expansion projects, as recommended in the 2010 Prime Minister's Task Group on Energy Efficiency.
- Establishing a voluntary scheme for medium-sized energy users.

The Government aims to have the temporary exemption of this sector removed from the EEO regulations by 1 July 2012, and a stakeholder consultation is currently underway. Under the expansion, network businesses that use more than 0.5 PJ of energy in a financial year will be required to register for the EEO program. Energy use is intended to include both own use (such as the fuel used in gas pipeline compressors), and a network's energy losses.

B.13.4 Residential and commercial building mandatory disclosure

From 1 November 2010 under the *Building Energy Efficiency Disclosure Act 2010*, commercial mandatory disclosure requires most sellers or lessors of office space of 2,000 or more square metres to obtain and disclose an up-to-date energy efficiency rating.[23] New commercial building standards and promotion of higher star ratings is promoting better energy performance investment in new and existing buildings. This will reduce energy demand for these buildings.

[21] See note 7.
[22] See note 3.
[23] Australian Government, available http://www.cbd.gov.au/LegalResponsibilities.aspx. Viewed 20 June 2012.

The Standing Council on Energy and Resources released the Regulatory Impact Statement for Residential Mandatory Disclosure[24] on 21 July 2011, detailing the options under consideration for implementing this legislation, and signalling the start of the public consultation process.

A draft National Building Energy Standard-Setting, Assessment and Rating Framework[25] is going through a public consultation process to develop a Framework–Policy Statement for consideration by governments in early 2013.

The Draft Framework is open to feedback on specific policy proposals to provide direction on future energy efficiency standards that involve the following:

- Increasingly stringent minimum building standards set over time for new buildings and renovations.
- Covering all types of residential and commercial buildings, including new and existing buildings.
- Including building equipment and services as well as the building envelope in energy efficiency ratings.
- Improving the accuracy of building performance assessments and ratings through consistent measurement and reporting.
- Encouraging innovation and flexibility to meet defined performance standards.
- Increasing compatibility amongst rating tools used for existing and new buildings.
- Including broader sustainability issues over time, including the level of greenhouse gas emissions generated and water used by buildings.
- Continuing a star ratings approach to communicating building performance.
- Facilitating effective monitoring and compliance.

B.13.5 Minimum Energy Performance Standards

Mandatory Minimum Energy Performance Standards (MEPS) and Energy Rating Labels[26] are implemented through a collaborative initiative called the Equipment Energy Efficiency Program involving representatives drawn from all jurisdictions in Australia and New Zealand.

It is mandatory for a range of electrical products manufactured in or imported into Australia to meet the MEPS levels specified in the relevant Australian Standards.

The Energy Rating Labelling Scheme is a mandatory scheme for a range of appliances, which currently include refrigerators, freezers, clothes washers, clothes dryers, dishwashers, air conditioners and televisions.

The report “Prevention is Cheaper than Cure – Avoiding Carbon Emissions through Energy Efficiency”[27], published by the E3 committee, is used as a guide to measure the energy efficiency impact on residential and non-residential sectors for each NEM region.

B.13.6 Energy Efficiency Building Standards

The 2010 Building Code of Australia (BCA), which takes effect from 1 May 2010, will require all new houses to be built in Australia to a six-star energy efficiency rating equivalence[28,29]. Apartments will have to have an average rating of six stars or equivalent.

[24] See note 6.
[25] Australian Government, available at http://www.climatechange.gov.au/government/submissions/national-building-framework.aspx. Viewed 20 June 2012.
[26] Australian Government, available http://www.energyrating.gov.au/. Viewed 20 June 2012.
[27] “Prevention is Cheaper than Cure – Avoiding Carbon Emissions through Energy Efficiency”. An initiative forming part of the Australian National Framework for Energy Efficiency and the New Zealand National Energy Efficiency and Conservation Strategy, January 2009
[28] Building Commission, available http://www.buildingcommission.com.au/www/html/2562-introduction-of-6-star.asp. Viewed 20 June 2012.
[29] ACT Government, available http://www.actpla.act.gov.au/customer_information/industry/bca_2010_energy_efficiency_changes. Viewed 20 June 2012.

Following the establishment of the BCA, each NEM region has introduced its own energy efficiency building standards. Table B-4 lists the time of the introduction, and summarises the building standard.

Table B-4 — State building standards

Jurisdiction	Year of introduction	Measure	Description of impact on electricity demand
Victoria	1 May 2011.	6-Star Building Standards.	The 6-Star Standard applies to the thermal performance of a new home, home renovations, alterations, additions and relocations plus the requirement to install a solar water heater system or a rainwater tank for toilet flushing in new homes
New South Wales	October 2005.	NSW BAXIS program (minimum 5-star energy equivalence rating).	All new dwellings in the state to commit to mandatory water and emission (energy) reduction targets based on the 40% fewer greenhouse gases and 40% less water requirement.
Australian Capital Territory	1 July 2006.	Minimum five star energy efficiency rating.[a]	All new houses must comply with minimum five star energy efficiency rating.
Queensland	1 May 2010	6 Star Building Standards.	New houses and townhouses, and major renovations to existing buildings, must achieve a minimum 6-star energy equivalence rating.[b] New unit buildings and major renovations to units must achieve a 5-star energy equivalence rating.
South Australia	September 2010.	Mandatory 5 star building standards.	All new homes and extensions built in South Australia need to achieve a 6-star level of energy efficiency.[c] In addition to achieving a 6-star level for thermal comfort, new houses must also meet lighting requirements and have energy-efficient water heaters.
Tasmania	1 January 2010.	5 star building standards.	Energy efficiency requirements apply to the construction or alteration of houses.[d]

a. "Towards more solar efficient housing Issues Paper", ACT Planning & Land Authority, July 2008.

b. Available at http://www.dlgp.qld.gov.au/sustainable-housing/6-star-energy-equivalence-rating-requirement-for-houses-and-townhouses.html

c. South Australian Government, availablehttp://sa.gov.au/subject/Housing%2C+property+and+land/Building+and+development/Residential+building+regulations/Building+rules%2C+regulations+and+information/Sustainability+and+efficiency+regulations/Six+star+energy+efficiency+requirements+for+new+homes. Viewed 20 June 2012.

d. Tasmanian Government, available http://www.wst.tas.gov.au/industries/building/bca/5_star_energy. Viewed 20 June 2012.

Six Star homes are projected to use 24% less energy through heating and cooling compared to 5 Star homes.[30] A 20% energy saving is assumed for all new homes in this forecast.

[30] Building Commission, available http://www.buildingcommission.com.au/www/html/2562-introduction-of-6-star.asp. Viewed 20-year outlook period June 2012.

B.13.7 Phase-out of Electric Storage Hot Water Systems and Solar Hot Water Rebate

Phase-out of Electric Hot Water Systems

The Australian Government as part of its National Strategy for Energy Efficiency[31] has announced a phase out of greenhouse intensive electric hot water systems from new buildings from 2011.

The restrictions have been placed on the installation of greenhouse intensive water heaters in new detached, terrace, row and town houses (Class 1 buildings under the Building Code of Australia 2010). These regulations apply in all jurisdictions except Tasmania.

Solar Hot Water Rebate

On 28 February 2012, the Australian Government announced the end of the Renewable Energy Bonus Scheme (REBS) by 30 June 2012.[32] The Federal Solar Hot Water Rebate will be concluded as a part of the REBS.

Solar water heater systems remain supported through the SRES. Under this scheme, solar and heat-pump water heater systems are assigned a number of Small-scale Technology Certificates (STCs).

Some state rebates on solar water heater systems still exist. A list of Australian, state and territory government solar water heater initiatives up to April 2012 can be found on Clean Energy Council's website.[33]

These initiatives have provided incentives to install more energy-efficient solar water heater systems to replace electric hot water systems.

Yearly replacement rates of electric hot water systems are applied to estimate the energy efficiency impact on annual energy consumption. Its impact on maximum demand is assumed to be zero.

B.14 State energy efficiency policies

B.14.1 New South Wales Energy Savings Scheme

The New South Wales Energy Savings Scheme (ESS)[34] establishes legislated annual energy savings targets that must be met through the creation and surrender of energy saving certificates (ESC). In the first year, the target has been set to 0.4% of total electricity sales, increasing to 4% over the period to 2014.

The energy savings target is allocated each year to electricity retailers in proportion to their liable electricity sales, which are total sales less sales to partially exempt, emissions-intensive trade-exposed industries or activities. The list of activities that are partially exempt under the ESS takes into account the national approach to exemptions for the expanded RET scheme and the proposed Carbon Pollution Reduction Scheme (CPRS). If exemptions were not included, the mandated energy savings requirement for retailers would start at 0.5% of liable sales, then increase to 5% by 2014 and continue at that level until 2020. Table B-5 — lists the target's gradual increase until 2014, after which it remains constant until 2020.

[31] Phase-out of greenhouse intensive hot water heaters, available at http://www.climatechange.gov.au/en/what-you-need-to-know/appliances-and-equipment/hot-water-systems.aspx. Viewed 25 June 2012..

[32] Renewable Energy Bonus Scheme - Solar hot water rebate, Department of Climate Change and Energy Efficiency.

[33] Government Initiatives, available at http://www.cleanenergycouncil.org.au/resourcecentre/Government-Initiatives.html. Viewed 25 June 2012.

[34] See note 9.

Table B-5 — Energy Savings Scheme

Target Year	Effective scheme target (% of annual NSW electricity sales)	Retailer compliance obligation (% of annual liable electricity sales)
2009	0.4%	0.5%
2010	1.2%	1.5%
2011	2.0%	2.5%
2012	2.8%	3.5%
2013	3.6%	4.5%
2014–2020	4.0%	5.0%

A summer study[35] done on the New South Wales ESS by the Independent Pricing and Regulatory Tribunal (IPART) in February 2012 is used as a guide to develop the forecasts for New South Wales and the Australian Capital Territory.

B.14.2 Queensland Renewable Energy Plan 2012

The Queensland Renewable Energy Plan (QREP) 2012 retains the original QREP goal of achieving 9,000 GWh of renewable generation in Queensland by 2020, equating to approximately 2,900 MW of renewable energy generation capacity (according to updated forecasts) and reduced greenhouse gas emissions by up to 40 million tonnes within the next 10 years.[36]

QREP 2012 refocuses Queensland's renewable energy agenda with the following objectives:

- Accelerating deployment of projects and renewable energy infrastructure.
- Promoting smart industry, jobs and investment.
- Developing stronger partnerships and links.

It also encourages the continued uptake of small-scale solar systems through a series of programs and projects:

- The virtual solar power station.
- The Queensland Government Solar Bonus Scheme.
- The Queensland Government Solar Hot Water Rebate.
- Small-scale renewable energy systems in remote communities.
- The Solar Sport and Community Group Grant.
- The Solar Kindergarten Program.

The potential energy savings from the renewable energy plan are not directly measured. The energy efficiency impact forecasts are developed based on the estimation of each forecast category (for more information, see Section B.1.1).

B.14.3 South Australia Residential Energy Efficiency Scheme (REES)

The Residential Energy Efficiency Scheme (REES)[37] commenced on 1 January 2009. Under the REES, energy retailers with 5,000 or more electricity or gas residential customers will be required to provide incentives for South

[35] The Energy Savings Scheme, An Effective Model for a National Energy Savings Initiative?, IPART, 29 February 2012
[36] See note 10.
[37] See note 11.

Australian households to achieve greenhouse gas reductions and potentially lower their energy bills through reduced energy consumption.

The first stage of the scheme was in operation from 2009–2011. The second stage runs from 2012–2014.

Table B-6 lists the annual greenhouse gas reduction targets (expressed in tonnes of carbon dioxide equivalent) for the first and second REES stages.

Table B-6 — Annual greenhouse gas reduction targets for REES stage 1 and 2 (CO2-e tonnes)

	Energy efficiency activities targets					
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Total	155,000	235,000	255,000	255,000	335,000	410,000
Electricity	136,446	208,423	226,206	226,206(e)	297,173(e)	363,704(e)

(e). Estimated annual targets from electricity.

The greenhouse gas reduction targets for REES are incorporated into the energy efficiency impact forecasts for South Australia.

B.14.4 Victorian Energy Efficiency Target

The Victorian Energy Efficiency Target[38] (VEET) scheme commenced on 1 January 2009. It sets a target for energy savings, initially in the residential sector, and requires energy retailers to meet their own targets through energy efficiency activities such as providing households with energy saving products and services. The VEET scheme plays a role in achieving the Victorian Government's target of reducing Victoria's greenhouse gas emissions to 60% by 2050.

The *Victorian Energy Efficiency Target Act 2007* (VEET Act) provides for the VEET scheme to operate in three-year phases, with new scheme targets and prescribed activities set for each phase. The first phase of the VEET scheme operates from 1 January 2009 to 31 December 2011.

On 24 May 2011 the Minister for Energy and Resources amended regulations to double the scheme target to 5.4 Mt/yr CO2-e for the second three-year phase beginning on 1 January 2012. Separately, the Minister announced that the scheme would be expanded from the residential to the business sector from the same date.

AEMO's forecasts incorporate a notional impact of the VEET scheme on residential electricity demand. The VEET scheme electricity usage can be substituted by gas or solar electricity, or the reduction of electricity usage due to higher energy efficiency in the household.

[38] See note 8.

APPENDIX C - SMALL NON-SCHEDULED GENERATION

This appendix provides two lists of small non-scheduled power stations for each region:

- The first lists the power stations used to develop operational demand forecasts.
- The second lists the power stations used to develop annual energy forecasts.

C.1 New South Wales

Table C-1 — List of power stations used for operational demand forecasts for New South Wales (including ACT)

Power station	Installed Capacity (MW)	Plant Type	Fuel Type	Dispatch Type
Bayswater	2,640	Steam Sub Critical	Black Coal	S
Blowering	70	Hydro - Gravity	Water	S
Capital Wind Farm	141	Wind - Onshore	Wind	NS
Collongra	724	OCGT	Natural Gas Pipeline	S
Cullerin Range Wind Farm	30	Wind - Onshore	Wind	NS
Eraring	2,820	Steam Sub Critical	Black Coal	S
Gunning Wind Farm	46.5	Wind	Wind	SS
Guthega	60	Hydro - Gravity	Water	S
Hume NSW	29	Hydro - Gravity	Water	S
Hunter Valley GT	50	OCGT	Fuel Oil	S
Liddell	2,000	Steam Sub Critical	Black Coal	S
Mt Piper	1,400	Steam Sub Critical	Black Coal	S
Munmorah	600	Steam Sub Critical	Black Coal	S
Redbank	144	Steam Sub Critical	Black Coal	S
Smithfield Energy Facility	171	CCGT	Natural Gas Pipeline	S
Tallawarra	420	CCGT	Natural Gas Pipeline	S
Tumut 1 (Upper Tumut)	720	Hydro - Gravity	Water	S
Tumut 3	1,500	Hydro - Gravity	Water	S
Uranquinty	664	OCGT	Natural Gas Pipeline	S
Vales Point "B"	1,320	Steam Sub Critical	Black Coal	S
Wallerawang "C"	1,000	Steam Sub Critical	Black Coal	S
Woodlawn Wind Farm	48	Wind	Wind	SS

Table C-2 — List of power stations used for annual energy forecasts for New South Wales (including ACT)

Power station	Installed Capacity (MW)	Plant Type	Fuel Type	Dispatch Type	Part of Operational Demand (✓)
Awaba PS	1.1	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Bankstown Sports Club	2.1	Compression Reciprocating Engine	Diesel	NS	
Bayswater	2,640	Steam Sub Critical	Black Coal	S	✓
Bendeela / Kangaroo Valley Power Station / Pumps	240	Hydro - Gravity	Water	NS	
Blowering	70	Hydro - Gravity	Water	S	✓
Broadwater Power Station	30	Steam Sub Critical	Bagasse	NS	
Broken Hill GT	50	OCGT	Diesel	NS	
Brown Mount	5.4	Hydro - Gravity	Water	NS	
Burrendong Hydro	18	Hydro - Gravity	Water	NS	
Burrinjuck PS	27	Hydro - Gravity	Water	NS	
Capital Wind Farm	141	Wind - Onshore	Wind	NS	✓
Collongra	724	OCGT	Natural Gas Pipeline	S	✓
Condong PS	30	Steam Sub Critical	Bagasse	NS	
Copeton Hydro	20	Hydro - Gravity	Water	NS	
Cullerin Range Wind Farm	30	Wind - Onshore	Wind	NS	✓
EarthPower Biomass	3.9	Spark Ignition Reciprocating Engine	Biomass recycled municipal and industrial materials	NS	
Eastern Creek PS	5	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Eraring	2,820	Steam Sub Critical	Black Coal	S	✓
Glenbawn Hydro	5	Hydro - Gravity	Water	NS	
Glennies Creek PS	13	Compression Reciprocating Engine	Coal Seam Methane	NS	
Grange Avenue	2	Compression Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Gunning Wind Farm	46.5	Wind	Wind	SS	✓
Guthega	60	Hydro - Gravity	Water	S	✓
Hume NSW	29	Hydro - Gravity	Water	S	✓
Hunter Valley GT	50	OCGT	Fuel Oil	S	✓
Jacks Gully	2.3	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Jindabyne	1.1	Hydro - Gravity	Water	NS	
Jounama	14.4	Hydro - Gravity	Water	NS	
Keepit	6.5	Hydro - Gravity	Water	NS	
Liddell	2,000	Steam Sub Critical	Black Coal	S	✓
Mt Piper	1,400	Steam Sub Critical	Black Coal	S	✓
Munmorah	600	Steam Sub Critical	Black Coal	S	✓
Nine Network Willoughby	3.2	Compression Reciprocating Engine	Diesel	NS	
Pindari Hydro	5.7	Hydro - Gravity	Water	NS	
Redbank	143.8	Steam Sub Critical	Black Coal	S	✓

Power station	Installed Capacity (MW)	Plant Type	Fuel Type	Dispatch Type	Part of Operational Demand (✓)
St Georges League Club	1.48	Compression Reciprocating Engine	Diesel	NS	
Smithfield Energy Facility	171	CCGT	Natural Gas Pipeline	S	✓
Tallawarra	420	CCGT	Natural Gas Pipeline	S	✓
Teralba	8	Compression Reciprocating Engine	Coal Seam Methane	NS	
Tumut 1 (Upper Tumut)	720	Hydro - Gravity	Water	S	✓
Tumut 3	1,500	Hydro - Gravity	Water	S	✓
Uranquinty	664	OCGT	Natural Gas Pipeline	S	✓
Vales Point "B"	1,320	Steam Sub Critical	Black Coal	S	✓
Wallerawang "C"	1,000	Steam Sub Critical	Black Coal	S	✓
Western Suburbs League Club	1.3	Compression Reciprocating Engine	Diesel	NS	
West Illawarra	1	Compression Reciprocating Engine	Diesel	NS	
West Nowra Landfill	1	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Whytes Gully	2.5	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Wilga Park	10	Spark Ignition Reciprocating Engine	Natural Gas - Unprocessed	NS	
Woodlawn Bioreactor	4.3	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Woodlawn Wind Farm	48	Wind	Wind	SS	✓
Wyangala A	20	Hydro - Gravity	Water	NS	
Wyangala B	4	Hydro - Gravity	Water	NS	

C.2 Queensland

Table C-3 — List of power stations used for operational demand forecasts for Queensland

Power station	Installed Capacity (MW)	Plant Type	Fuel Type	Dispatch Type
Barcaldine	55	CCGT	Natural Gas Pipeline	S
Barron Gorge	66	Run of River	Water	S
Braemar	504	OCGT	Coal Seam Methane	S
Braemar 2	519	OCGT	Coal Seam Methane	S
Callide B	700	Steam Sub Critical	Black Coal	S
Callide Power Plant	950	Steam Super Critical	Black Coal	S
Collinsville	190	Steam Sub Critical	Black Coal	S
Condamine A	144	CCGT	Coal Seam Methane	S
Darling Downs	644	CCGT	Coal Seam Methane	S
Gladstone	1,680	Steam Sub Critical	Black Coal	S
Kareeya	88	Run of River	Water	S
Kogan Creek	744	Steam Super Critical	Black Coal	S
Mackay Gas Turbine	34	OCGT	Diesel	S
Millmerran Power Plant	856	Steam Super Critical	Black Coal	S
Mt Stuart	424	OCGT	Kerosene Aviation fuel used for stationary energy - avtur	S
Oakey	282	OCGT	Diesel	S
Roma Gas Turbine	80	OCGT	Natural Gas Pipeline	S
Stanwell	1,460	Steam Sub Critical	Black Coal	S
Swanbank B	250	Steam Sub Critical	Black Coal	S
Swanbank E GT	385	CCGT	Coal Seam Methane	S
Tarong	1,400	Steam Sub Critical	Black Coal	S
Tarong North	450	Steam Super Critical	Black Coal	S
Townsville Gas Turbine 1 (Yabulu)	160	CCGT	Coal Seam Methane	S
Townsville Gas Turbine 2 (Yabulu2)	84	CCGT	Coal Seam Methane	S
Wivenhoe	500	Pump Storage	Water	S
Yarwun	154	CCGT	Natural Gas Pipeline	NS

Table C-4 — List of power stations used for annual energy forecasts for Queensland

Power station	Installed Capacity (MW)	Plant Type	Fuel Type	Dispatch Type	Part of Operational Demand (✓)
Barcaldine	55	CCGT	Natural Gas Pipeline	S	✓
Barron Gorge	66	Run of River	Water	S	✓
Braemar	504	OCGT	Coal Seam Methane	S	✓
Braemar 2	519	OCGT	Coal Seam Methane	S	✓
Callide B	700	Steam Sub Critical	Black Coal	S	✓
Callide A4	30	Steam Sub Critical	Black Coal	NS	
Callide Power Plant	950	Steam Super Critical	Black Coal	S	✓
Collinsville	190	Steam Sub Critical	Black Coal	S	✓
Condamine A	144	CCGT	Coal Seam Methane	S	✓
Daandine PS	30	Compression Reciprocating Engine	Coal Seam Methane	NS	
Darling Downs	644	CCGT	Coal Seam Methane	S	✓
Roghan Road LFG Plant	1.03	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
German Creek	31.8	Spark Ignition Reciprocating Engine	Waste Coal Mine Gas	NS	
Gladstone	1,680	Steam Sub Critical	Black Coal	S	✓
ISIS Central Sugar Mill Cogen	25	Steam Sub Critical	Bagasse	NS	
Invicta	39	Steam Sub Critical	Bagasse	NS	
Kareeya	88	Run of River	Water	S	✓
Kogan Creek	744	Steam Super Critical	Black Coal	S	✓
KRC Cogen	5	Steam Sub Critical	Natural Gas Pipeline	NS	
Mackay Gas Turbine	34	OCGT	Diesel	S	✓
Millmerran Power Plant	856	Steam Super Critical	Black Coal	S	✓
Moranbah PS	12	Compression Reciprocating Engine	Waste Coal Mine Gas	NS	
Moranbah North PS	45.6	Spark Ignition Reciprocating Engine	Waste Coal Mine Gas	NS	
Mt Stuart	424	OCGT	Kerosene Aviation fuel used for stationary energy - avtur	S	✓
Oakey	282	OCGT	Diesel	S	✓
Oaky Creek	20	Compression Reciprocating Engine	Coal Seam Methane	NS	
Pioneer	67.8	Steam Sub Critical	Bagasse	NS	
Rochdale Renewable Energy	4.1	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Rocky Point	30	Steam Sub Critical	Green and air dried wood	NS	
Roma Gas Turbine	80	OCGT	Natural Gas Pipeline	S	✓
Somerset Dam (Wivenhoe Small Hydro)	4.7	Run of river	Hydro	NS	
Southbank Institute of Tech	1	OCGT	Diesel	NS	

Power station	Installed Capacity (MW)	Plant Type	Fuel Type	Dispatch Type	Part of Operational Demand (✓)
Stanwell	1,460	Steam Sub Critical	Black Coal	S	✓
Swanbank B	250	Steam Sub Critical	Black Coal	S	✓
Swanbank E GT	385	CCGT	Coal Seam Methane	S	✓
Suncoast Gold Macadamias	1.5	Steam Sub Critical	Macadamia Nut Shells	NS	
Tarong	1,400	Steam Sub Critical	Black Coal	S	✓
Tarong North	450	Steam Super Critical	Black Coal	S	✓
Townsville Gas Turbine 1 (Yabulu)	160	CCGT	Coal Seam Methane	S	✓
Townsville Gas Turbine 2 (Yabulu2)	84	CCGT	Coal Seam Methane	S	✓
Veolia Ti Tree Bioreactor	3.3	Compression Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Victoria Mill	24	Steam Sub Critical	Bagasse	NS	
Whitwood Road Renewable	1.1	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Windy Hill	12	Steam Sub Critical	Green and air dried wood	NS	
Wivenhoe	500	Pump Storage	Water	S	✓
Yarwun	154	CCGT	Natural Gas Pipeline	NS	✓

C.3 South Australia

Table C-5 — List of power stations used for operational demand forecasts for South Australia

Power station	Installed Capacity (MW)	Plant Type	Fuel Type	Dispatch Type
Dry Creek Gas Turbine Station	156	OCGT	Natural Gas Pipeline	S
Hallett GT	228.3	OCGT	Natural Gas Pipeline	S
Ladbroke Grove Power Station	80	OCGT	Natural Gas Pipeline	S
Mintaro Gas Turbine Station	90	OCGT	Natural Gas Pipeline	S
Northern Power Station	530	Steam Sub Critical	Brown Coal	S
Osborne Power Station	180	CCGT	Natural Gas Pipeline	S
Pelican Point Power Station	478	CCGT	Natural Gas Pipeline	S
Playford B Power Station	240	Steam Sub Critical	Brown Coal	S
Port Lincoln Gas Turbine	73.5	OCGT	Diesel	S
Quarantine Power Station	224	OCGT	Natural Gas Pipeline	S
Snuggery Power Station	63	OCGT	Diesel	S
Torrens Island A	480	Steam Sub Critical	Natural Gas Pipeline	S
Torrens Island B	800	Steam Sub Critical	Natural Gas Pipeline	S
Canunda Wind Farm	46	Wind	Wind	NS
Cathedral Rocks Wind Farm	66	Wind	Wind	NS
Clements Gap Wind Farm	56.7	Wind	Wind	SS
Hallett 1 (Brown Hill)	94.5	Wind	Wind	SS
Hallett 2 (Hallet Hill)	71.4	Wind	Wind	SS
Hallett 4 (Nth Brown Hill)	132.3	Wind	Wind	SS
Hallett 5 (The Bluff)	52.5	Wind	Wind	SS
Lake Bonney Wind Farm	80.5	Wind	Wind	NS
Lake Bonney Stage 2 Wind Farm	159	Wind	Wind	SS
Lake Bonney Stage 3 Wind Farm	39	Wind	Wind	SS
Mt Millar Wind Farm	70	Wind	Wind	NS
Snowtown Wind Farm Units 1 And 47	98.7	Wind	Wind	SS
Starfish Hill Wind Farm	34.5	Wind	Wind	NS
Waterloo Wind Farm	111	Wind	Wind	SS
Wattle Point Wind Farm	91	Wind - Onshore	Wind	NS

Table C-6 — List of power stations used for annual energy forecasts for South Australia

Power station	Installed Capacity (MW)	Plant Type	Fuel Type	Dispatch Type	Part of Operational Demand (✓)
Angaston	50	Compression Reciprocating Engine	Diesel	NS	
Amcor Glass	4.02	Compression Reciprocating Engine	Diesel	NS	✓
Canunda Wind Farm	46	Wind	Wind	NS	✓
Cathedral Rocks Wind Farm	66	Wind	Wind	NS	✓
Clements Gap Wind Farm	56.7	Wind	Wind	SS	✓
Dry Creek Gas Turbine Station	156	OCGT	Natural Gas Pipeline	S	✓
Hallett 1 (Brown Hill)	94.5	Wind	Wind	SS	✓
Hallett 2 (Hallet Hill)	71.4	Wind	Wind	SS	✓
Hallett 4 (Nth Brown Hill)	132.3	Wind	Wind	SS	✓
Hallett 5 (The Bluff)	52.5	Wind	Wind	SS	✓
Hallett GT	228.3	OCGT	Natural Gas Pipeline	S	✓
Ladbroke Grove Power Station	80	OCGT	Natural Gas Pipeline	S	✓
Lake Bonney Wind Farm	80.5	Wind	Wind	NS	✓
Lake Bonney Stage 2 Wind Farm	159	Wind	Wind	SS	✓
Lake Bonney Stage 3 Wind Farm	39	Wind	Wind	SS	✓
Lonsdale	20.7	Compression Reciprocating Engine	Diesel	NS	
Mintaro Gas Turbine Station	90	OCGT	Natural Gas Pipeline	S	✓
Mt Millar Wind Farm	70	Wind	Wind	NS	✓
Northern Power Station	530	Steam Sub Critical	Brown Coal	S	✓
Osborne Power Station	180	CCGT	Natural Gas Pipeline	S	✓
Pelican Point Power Station	478	CCGT	Natural Gas Pipeline	S	✓
Playford B Power Station	240	Steam Sub Critical	Brown Coal	S	✓
Port Lincoln Gas Turbine	73.5	OCGT	Diesel	S	✓
Quarantine Power Station	224	OCGT	Natural Gas Pipeline	S	✓
Snowtown Wind Farm Units 1 And 47	98.7	Wind	Wind	SS	✓
Snuggery Power Station	63	OCGT	Diesel	S	✓
Starfish Hill Wind Farm	34.5	Wind	Wind	NS	✓
Torrens Island A	480	Steam Sub Critical	Natural Gas Pipeline	S	✓
Torrens Island B	800	Steam Sub Critical	Natural Gas Pipeline	S	✓
Tatiara Meats	0.5	Compression Reciprocating Engine	Diesel	NS	✓
Terminal Storage Mini Hydro	2.5	Hydro - Gravity	Water	NS	
Waterloo Wind Farm	111	Wind	Wind	SS	✓
Wattle Point Wind Farm	91	Wind - Onshore	Wind	NS	✓

C.4 Tasmania

Table C-7 — List of power stations used for operational demand forecasts for Tasmania

Power station	Installed Capacity (MW)	Plant Type	Fuel Type	Dispatch Type
Bastyan	80	Hydro - Gravity	Water	S
Bell Bay Three	120	OCGT	Natural Gas Pipeline	S
Catagunya / Liapootah / Wayatinah	170	Hydro - Gravity	Water	S
Cethana	85	Hydro - Gravity	Water	S
Devils Gate	60	Hydro - Gravity	Water	S
Fisher	43.2	Hydro - Gravity	Water	S
Gordon	432	Hydro - Gravity	Water	S
John Butters	144	Hydro - Gravity	Water	S
Lake Echo	32.4	Hydro - Gravity	Water	S
Lemonthyme / Wilmot	81.6	Hydro - Gravity	Water	S
Mackintosh	80	Hydro - Gravity	Water	S
Meadowbank	40	Hydro - Gravity	Water	S
Poatina	300	Hydro - Gravity	Water	S
Reece	231	Hydro - Gravity	Water	S
Tamar Valley Combined Cycle	208	CCGT	Natural Gas Pipeline	S
Tamar Valley Peaking	58	OCGT	Natural Gas Pipeline	S
Tarraleah	90	Hydro - Gravity	Water	S
Trevallyn	80	Hydro - Gravity	Water	S
Tribute	82.8	Hydro - Gravity	Water	S
Tungatinah	125	Hydro - Gravity	Water	S
Woolnorth Studland Bay / Bluff Point Wind Farm	140	Wind - Onshore	Wind	NS

Table C-8 — List of power stations used for annual energy forecasts for Tasmania

Power station	Installed Capacity (MW)	Plant Type	Fuel Type	Dispatch Type	Part of Operational Demand (✓)
Bastyan	80	Hydro - Gravity	Water	S	✓
Bell Bay Three	120	OCGT	Natural Gas Pipeline	S	✓
Butlers Gorge Rev	14.4	Hydro - Gravity	Water	NS	
Catagunya / Liapootah / Wayatinah	170	Hydro - Gravity	Water	S	✓
Cethana	85	Hydro - Gravity	Water	S	✓
Cluny	17	Hydro - Gravity	Water	NS	
Devils Gate	60	Hydro - Gravity	Water	S	✓
Fisher	43.2	Hydro - Gravity	Water	S	✓
Gordon	432	Hydro - Gravity	Water	S	✓
John Butters	144	Hydro - Gravity	Water	S	✓
Lake Echo	32.4	Hydro - Gravity	Water	S	✓
Lemonthyme / Wilmot	82	Hydro - Gravity	Water	S	✓
Mackintosh	80	Hydro - Gravity	Water	S	✓
Meadowbank	40	Hydro - Gravity	Water	S	✓
Paloona	28	Hydro - Gravity	Water	NS	
Poatina	300	Hydro - Gravity	Water	S	✓
Reece	231	Hydro - Gravity	Water	S	✓
Remount	2.2	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Repulse	28	Hydro - Gravity	Water	NS	
Rowallan	10.5	Hydro - Gravity	Water	NS	
Tamar Valley Combined Cycle	208	CCGT	Natural Gas Pipeline	S	✓
Tamar Valley Peaking	58	OCGT	Natural Gas Pipeline	S	✓
Tarraleah	90	Hydro - Gravity	Water	S	✓
Trevallyn	80	Hydro - Gravity	Water	S	✓
Tribute	82.8	Hydro - Gravity	Water	S	✓
Tungatinah	125	Hydro - Gravity	Water	S	✓
Woolnorth Studland Bay / Bluff Point Wind Farm	140	Wind - Onshore	Wind	NS	✓

C.5 Victoria

Table C-9 — List of power stations used for operational demand forecasts for Victoria

Power station	Installed Capacity (MW)	Plant Type	Fuel Type	Dispatch Type
Anglesea	150	Steam Sub Critical	Brown Coal	
Bairnsdale	94	OCGT	Natural Gas Pipeline	S
Bogong / Mckay	300	Hydro - Gravity	Water	S
Dartmouth	185	Hydro - Gravity	Water	S
Eildon 1	60	Hydro - Gravity	Water	S
Eildon 2	60	Hydro - Gravity	Water	S
Energy Brix Complex (Morwell)	189	Steam Sub Critical	Brown Coal	S
Hazelwood	1,600	Steam Sub Critical	Brown Coal	S
Hume VIC	29	Hydro - Gravity	Water	S
Jeeralang A	212	OCGT	Natural Gas Pipeline	S
Jeeralang B	228	OCGT	Natural Gas Pipeline	S
Laverton North	312	OCGT	Natural Gas Pipeline	S
Loy Yang A	2,180	Steam Sub Critical	Brown Coal	S
Loy Yang B	1,000	Steam Sub Critical	Brown Coal	S
Mortlake Units	566	OCGT	Natural Gas Pipeline	S
Murray 1	950	Hydro - Gravity	Water	S
Murray 2	552	Hydro - Gravity	Water	S
Newport	500	Steam Sub Critical	Natural Gas Pipeline	S
Somerton	160	OCGT	Natural Gas Pipeline	S
Valley Power Peaking Facility	300	OCGT	Natural Gas Pipeline	S
West Kiewa	60	Hydro - Gravity	Water	S
Yallourn W	1,480	Steam Sub Critical	Brown Coal	S
Challicum Hills Wind Farm	52.5	Wind - Onshore	Wind	NS
Oaklands Hill Wind Farm	67.2	Wind	Wind	SS
Portland Wind Farm	164	Wind - Onshore	Wind	NS
Waubra Wind Farm	192	Wind - Onshore	Wind	NS
Yambuk Wind Farm	30	Wind - Onshore	Wind	NS

Table C-10 — List of power stations used for annual energy forecasts for Victoria

Power station	Installed Capacity (MW)	Plant Type	Fuel Type	Dispatch Type	Part of Operational Demand (✓)
Anglesea	150	Steam Sub Critical	Brown Coal		✓
Bairnsdale	94	OCGT	Natural Gas Pipeline	S	✓
Ballarat Base hospital	2.04	Spark Ignition Reciprocating Engine	Natural Gas Pipeline	NS	
Banimboola PS	12.5	Hydro - Gravity	Water	NS	
Berwick	4.6	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Bogong / Mckay	300	Hydro - Gravity	Water	S	✓
Brooklyn Landfill	2.83	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Dartmouth	185	Hydro - Gravity	Water	S	✓
Eildon 1	60	Hydro - Gravity	Water	S	✓
Eildon 2	60	Hydro - Gravity	Water	S	✓
Energy Brix Complex (Morwell)	189	Steam Sub Critical	Brown Coal	S	✓
Hallam Road	6.7	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Hallam Hydro - SEW	0.25	Hydro - Gravity	Water	NS	
Hazelwood	1,600	Steam Sub Critical	Brown Coal	S	✓
HRL Tramway Road	5	OCGT	Diesel	NS	
Hume VIC	29	Hydro - Gravity	Water	S	✓
Jeeralang A	212	OCGT	Natural Gas Pipeline	S	✓
Jeeralang B	228	OCGT	Natural Gas Pipeline	S	✓
Laverton North	312	OCGT	Natural Gas Pipeline	S	✓
Longford	31.8	OCGT	Natural Gas Pipeline	NS	
Loy Yang A	2,180	Steam Sub Critical	Brown Coal	S	✓
Loy Yang B	1,000	Steam Sub Critical	Brown Coal	S	✓
Mornington Waste Disposal	0.77	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Wyndham Waste Disposal	1	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Mortlake Units	566	OCGT	Natural Gas Pipeline	S	✓
Murray 1	950	Hydro - Gravity	Water	S	✓
Murray 2	552	Hydro - Gravity	Water	S	✓
Newport	500	Steam Sub Critical	Natural Gas Pipeline	S	✓
Rubicon	13.5	Hydro - Gravity	Water	NS	

Power station	Installed Capacity (MW)	Plant Type	Fuel Type	Dispatch Type	Part of Operational Demand (✓)
Shepparton Wastewater	1.1	Spark Ignition Reciprocating Engine	Sewerage / Waste Water	NS	
Somerton	160	OCGT	Natural Gas Pipeline	S	✓
Sunshine Energy	8.7	Spark Ignition Reciprocating Engine	Landfill Methane / Landfill Gas	NS	
Symex	5.9	OCGT	Natural Gas Pipeline	NS	
Tatura Biomass	1.1	Spark Ignition Reciprocating Engine	Sewerage / Waste Water	NS	
Valley Power Peaking Facility	300	OCGT	Natural Gas Pipeline	S	✓
West Kiewa	60	Hydro - Gravity	Water	S	✓
Yallourn W	1,480	Steam Sub Critical	Brown Coal	S	✓
Yarrawonga Hydro	9.5	Hydro - Gravity	Water	NS	
Challicum Hills Wind Farm	52.5	Wind - Onshore	Wind	NS	✓
Codrington Wind Farm	18.2	Wind - Onshore	Wind	NS	
Hepburn Wind Farm (Leonards Hill)	4.1	Wind - Onshore	Wind	NS	
Oaklands Hill Wind Farm	67.2	Wind	Wind	SS	✓
Portland Wind Farm	164	Wind - Onshore	Wind	NS	✓
Toora Wind Farm	21	Wind - Onshore	Wind	NS	
Waubra Wind Farm	192	Wind - Onshore	Wind	NS	✓
Wonthagi Wind Farm	12	Wind - Onshore	Wind	NS	
Yambuk Wind Farm	30	Wind - Onshore	Wind	NS	✓

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APPENDIX D - DEMAND-SIDE PARTICIPATION

Demand-side participation (DSP) refers to measures of short-term, market-driven demand reductions that AEMO includes in the supply-demand outlook, and 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)[1]. 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. In the latter case it is important to distinguish between the operation of registered generation units (which are captured on the supply side) and small unregistered generating units whose potential output may be counted by AEMO as DSP.

Examples of load curtailment that would count as DSP include the following.

- Large consumers subject to real-time pricing, critical peak pricing or other pricing structures (including discounting) may have an incentive to reduce load in response to temporary periods of high market prices.
- Energy consumers may also have non-price incentives to reduce load at or near the time of the regional maximum demand, for example due to any verifiable demand management scheme (although this does not include continuously operating changes in load between peak and off-peak periods such as off-peak hot water heating).
- Other arrangements that could come within the scope of DSP are appliance direct load control, network support agreements or any other non-tariff contractual agreement involving an obligation to reduce load or increase on-site generation at or near the time of the regional maximum demand.

In 2011 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.

D.1 Survey and analysis of results

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 megawatt values that could be regarded as 'committed' or 'non-committed'. These amounts were then aggregated to create regional totals.

The annual DSP survey and analysis procedure involves the following steps:

- National Metering Identifiers (NMIs) are collected by surveying demand response aggregators, NSPs, retailers and other market customers. The NMIs collected are from direct market customers, price-responsive retail customers, and customers with specific demand-response arrangements, including network support agreements.
- The energy data associated with the NMIs is aggregated for each region for the period January 2008 to March 2011. Each regional model was then constructed to test the relationship between this energy data and spike prices in the NEM, using a price function equal to the market price above $1000 or else zero. Normal prices (below $1000) and non-price related movements in the energy data, including time- and calendar-related movements, were also included in the empirical model.

[1] The AEMC has defined DSP in the following manner: "DSP refers to the ability of consumers to make informed decisions about the quantity and timing of their electricity use, which reflects the value that they obtain from using electricity services". For further information see Directions Paper at: http://www.aemc.gov.au/Market-Reviews/Open/stage-3-demand-side-participation-review-facilitating-consumer-choices-and-energy-efficiency.html**. Viewed June 2012.**

- The estimated energy-spike price relationships were then used to predict the energy data 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-spike price scenario.
- For each region, the seasonal maximum difference between the predicted energy under actual price spikes and the prediction of what would have occurred if there were no price spikes is defined as historical 'committed' DSP. 'Maximum potential' DSP is defined as the total identified price-responsive load. 'Non-committed' DSP is the difference between maximum potential and committed DSP.
- Future DSP is identified by aggregating the amounts nominated by the same survey respondents supplying the NMIs. These amounts are placed by the respondents into one of three categories: 'very likely', 'even chance', or 'extremely unlikely'. Medium, high, and low DSP scenario projections are developed based on the 'very likely' DSP starting-year amounts. These DSP projections should be regarded as being aligned with previously advised 'committed' DSP amounts.

D.2 Demand-side participation forecasts

The section presents estimated historical DSP and projected future DSP for each region.

Table D-1 shows the estimated committed and non-committed historical results from the 2011 DSP survey.

Table D-1 — 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 [a]	32	145	80	90
Tasmania	0	0	0	0

a. DSP data is aggregated to maintain the confidentiality of the small number of DSP providers in these regions.

Table D-2 shows the results of the 2011 DSP survey regarding the amount of DSP available for the 2012–13 summer season.

Table D-2 — DSP available for the 2012-13 summer (MW)

	Very likely	Even chance	Very unlikely
Queensland	78	111	111
New South Wales	31	71	98
Victoria and South Australia [a]	109	121	149
Tasmania	0	0	0

a. DSP data is aggregated to maintain the confidentiality of the small number of DSP providers in these regions.

Table D-3 shows future growth scenarios for DSP. The medium growth scenario is based on the 'very likely' amounts shown in Table D-2, 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 D-2, which are expected to remain static. The high growth scenario shows a significant increase in growth rate compared with the medium growth scenario, while DSP generally remains unchanged in the low growth scenario.

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

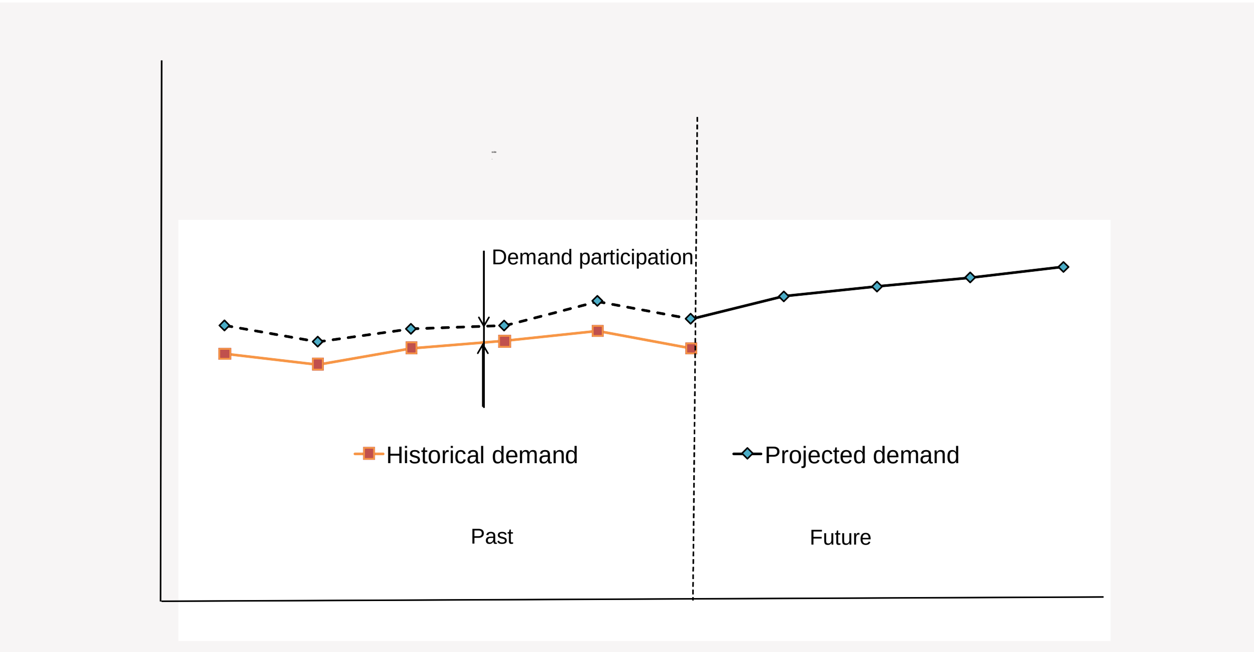
	Medium	High	Low
Queensland	3.7%	6.6%	0.0%
New South Wales	3.2%	5.8%	0.0%
Victoria and South Australia [a]	5.4%	8.4%	2.1%
Tasmania	0.0%	0.0%	0.0%

a. DSP data is aggregated to maintain the confidentiality of the small number of DSP providers in these regions.

D.3 Treatment of demand-side participation in the maximum demand projections

Figure D-1 shows how DSP is treated by the demand projections. Historical DSP is added back to historical demand as a demand correction, returning it to the level it would have achieved without the retailer's or customer's decision to interrupt. The corrected figure is then used to determine projected maximum demand trends.

Figure D-1 — Overview of forecasting process



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DISCLAIMER

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MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
CDD	Cooling degree days
DD	Degree days
EDD	Effective degree days
GWh	Gigawatt hours
HDD	Heating degree days
kV	Kilovolts
kWh	Kilowatt hours
MVA	Megavolt amperes
MVAr	Megavolt amperes reactive
MW	Megawatts
MWh	Megawatt hours
$	Australian dollars
$/kWh	Australian dollars per kilowatt hour
$/MWh	Australian dollars per megawatt hour

Abbreviations

Abbreviation	Expanded name
AC	Air conditioning
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
APR	Annual planning report
ARDL model	Auto-Regressive Distributed Lag Model
AUX	Power station auxiliaries
BOM	Bureau of Meteorology
CO2-e	Carbon dioxide equivalent
CSG	Coal seam gas
DNSP	Distribution network service provider
DSP	Demand-side participation
EE	Energy efficiency
ESOO	Electricity Statement of Opportunities
GDP	Gross domestic product
GFC	Global financial crisis
GPG	Gas powered generation
GSOO	Gas Statement of Opportunities
GSP	Gross state product
JPB	Jurisdictional planning body
LIL	Large industrial loads
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
MD	Maximum demand
MEPS	Minimum Energy Performance Standards
MRET	Mandatory Renewable Energy Target
MT PASA	Medium-term Projected Assessment of System Adequacy
NEM	National Electricity Market
NERF	National Electricity Repository for Forecasting
NIEIR	National Institute of Economic and Industry Research
NLIC	Non-large industrial consumption
NSW	New South Wales
NTNDP	National Transmission Network Development Plan
POE	Probability of exceedence

Abbreviation	Expanded name
PV	Photovoltaics
QGC	Queensland Gas Company
QLD	Queensland
REC	Renewable Energy Certificate
RET	Renewable Energy Target - national Renewable Energy Target scheme
Rooftop PV	Rooftop photovoltaic
SA	South Australia
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificates
ST PASA	Short-term Projected Assessment of System Adequacy
TAS	Tasmania
TNSP	Transmission network service provider
TX	Transmission losses
US dollar	United States dollar
VAPR	Victorian Annual Planning Report
VEC model	Vector error correction model
VIC	Victoria

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GLOSSARY AND LIST OF COMPANY NAMES

Glossary

Term	Definition
active power	See electrical power.
Annual energy	The amount of electrical energy consumed in a year. See also ‘electrical energy’.
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.
auxiliary loads	The load from equipment used by a generating system for ongoing operation. Auxiliary loads are located on the generating system’s side of the connection point.
back assessment	The comparison of old maximum demand (MD) projections with actual (historical) MD values.
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.
capacity factor	The output of generating units or systems, averaged over time, expressed as a percentage of rated or maximum output.
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.
compound average growth rate	The year-over-year growth rate over a specified period of time.
connection point (electricity)	The agreed point of supply established between network service provider(s) and another registered participant, non-reregistered customer or franchise customer.
consumer	See customer (electricity).
customer (electricity)	A person who engages in the activity of purchasing electricity supplied through a transmission or distribution system to a connection point.
demand	See electricity demand.
demand diversity	Referring to both intra and inter-regional demand diversity in the following terms: • ‘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. • ‘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.
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).

Term	Definition
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.
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’.
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.
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 following: • The electrical power consumed by the consumer load. • Distribution and transmission losses. • 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’.
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.
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.

Term	Definition
generation centre	A geographically concentrated area containing a generating unit or generating units with significant combined generating capability.
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)) the following: • Consumer load. • Transmission and distribution losses. • Generating unit auxiliary load. • Generator transformer losses.
gross domestic product	A measure of the economic output of a country.
gross state product	A measure of the economic output of a state.
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.
Large-scale Renewable Energy Target (LRET)	See 'national Renewable Energy Target scheme'.
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 factor	The load factor is defined as the annual maximum demand divided by the annual energy.
Mandatory Renewable Energy Target (MRET)	See 'national Renewable Energy Target scheme'.
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).
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 economic growth scenario	An economic growth scenario used in the projection of energy and maximum demand growth for the 2011 Electricity Statement of Opportunities (ESOO). The 2011 ESOO projection also included scenarios of low and high economic growth.
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).
National Electricity Market (NEM)	The wholesale exchange of electricity operated by AEMO under the NER.

Term	Definition
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). • 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.
native energy	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units.
network losses	See ‘transmission losses’.
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).
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).
peak coincidence	Peak coincidence is a measure of the correlation in the timing of maximum demands in each different region. As all regions are unlikely to have their maximum demand at the same time, a diversity factor is applied to the sum of all the regional forecasts.
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.
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.
power	See ‘electrical power’.
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.

Term	Definition
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.
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.
Renewable Energy Target (RET)	See 'national Renewable Energy Target scheme'.
rooftop photovoltaic (PV) systems	A system comprising one or more photovoltaic panels, installed on a residential or commercial building rooftop to convert sunlight into electricity.
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 with the following qualities: • An output controlled through the central dispatch process. • Classification 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).
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.

Term	Definition
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 the following qualities: • An intermittent output. • A total capacity of 30 megawatts (MW) or greater. • That may have its output limited to prevent the violation of network constraint equations.
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.
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 generating units classified as follows: • Market non-scheduled (MNS) generating units. • 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'.
state final demand	A measure of the total value of goods and services sold in a state for consumption or retention as capital assets. It excludes sales for production inputs, exports, or to add to inventories.
Statement of Opportunities	The (gas or electricity) Statement of Opportunities published annually by AEMO.
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).
supply	The delivery of electricity.
supply-demand outlook	The future state of supply's ability to meet projected demand.
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 system (electricity)	A transmission network, together with the connection assets associated with the transmission network, which is connected to another transmission or distribution system.
winter	Unless otherwise specified, refers to the period 1 June–31 August (for all regions).

List of company names

The following companies and organisations have provided AEMO with information which is referred to in this report:

Group or short form name	Organisation or company name
AEMC	Australian Energy Market Commission
Alcoa	Alcoa of Australia Ltd
Alinta Energy	Alinta Energy (Australia) Pty Ltd
AMCOR	Amcor Ltd
Arrow Energy	Arrow Energy Pty Ltd
Australian Pacific LNG	Australia Pacific LNG
BHP Billiton	BHP Billiton Ltd
BlueScope Steel	BlueScope Steel Limited
Clean Energy Council	Clean Energy Council Limited
DSC Woomera	DSC Woomera
ElectraNet	Electranet Pty Limited
Gunns	Gunns Limited
Hydro Tasmania	Hydro-Electric Corporation
Kimberly Clark	Kimberly-Clark Australia and New Zealand
Kurri Kurri aluminium smelter	Hydro Aluminium Kurri Kurri Pty Ltd (owned by Norsk Hydro)
Monash University	Monash University
Newcrest	Newcrest Mining Limited
NIEIR	National Institute of Economic and Industry Research Pty Ltd
Norsk Hydro	Norsk Hydro Pty Ltd
OneSteel	OneSteel Ltd
Powerlink Queensland	Queensland Electricity Transmission Corporation Limiited
QGC	QGC Pty Ltd
Santos	Santos Ltd
SA Water	SA Water, Government of South Australia
Transend Networks	Transend Networks Pty Ltd
TransGrid	TransGrid
Wonthaggi desalination plant	Wonthaggi desalination plant (also referred to as the Victorian Desalination Project)
Xstrata	Xstrata Coal Pty Limited

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