NATIONAL ELECTRICITY FORECASTING REPORT

For the National Electricity Market

2013

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

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Published by

AEMO
Australian Energy Market Operator
ABN 94 072 010 327

FOREWORD

This is the second edition of the Australian Energy Market Operator's (AEMO) National Electricity Forecasting Report (NEFR). The 2013 NEFR highlights that annual energy is continuing to decline; this follows the trend seen in the 2012 NEFR. Compared to the 2012 NEFR forecast, the 2013 NEFR forecast indicates a 2.4% reduction in annual energy for 2013–14 under a medium economic growth scenario.

Over the 10-year outlook period, the 2013 NEFR shows a slower rate of growth in annual energy than forecast in the 2012 NEFR, with the increase being driven by population growth in eastern and south-eastern Australia, and a moderation in electricity price growth. An additional driver of this growth is the development of three large liquefied natural gas (LNG) projects in Queensland, particularly in the first half of the outlook period.

The increase in annual energy is offset by further growth in solar photovoltaic (PV) installations and a rise in energy efficiency savings in the residential, commercial and light industrial sectors. This follows a moderation in residential annual energy growth due to rising electricity prices in all National Electricity Market (NEM) regions over the past few years. Looking at residential annual energy on a per capita basis, electricity consumption declines and then flattens.

The economic climate and high Australian dollar of recent years have affected the competitiveness of domestic industry, impacting large industrial annual energy consumption. Some industrial projects that had been expected to commence are now not proceeding, are closing, or have been deferred.

The NEFR provides AEMO's independent electricity demand forecasts, developed on a consistent basis for the five NEM regions.

These forecasts are used for operational and planning purposes, including the calculation of marginal loss factors, and are a key input into AEMO's national transmission planning role, together with the Victorian Annual Planning Report (VAPR) and the South Australian Electricity Report (SAER).

The NEFR includes supporting information papers and reports that document the input data, assumptions, and methodology used to develop AEMO's annual energy and maximum demand forecasts for the NEM. Publication of these inputs promotes an open and transparent process which AEMO is committed to, and enables informed discussion with stakeholders to facilitate greater efficiency in operating the NEM.

This second edition sees several improvements since the inaugural report: models used to develop the 2013 NEFR demand forecasts are now independently reviewed by external experts, and there is a greater focus on short-term forecasts of one to five years in addition to the 10-year forecast. These improvements are expected to deliver a more accurate and robust demand forecast.

This edition also incorporates a new presentation format designed to provide a concise summary of essential information, with more detailed data contained in Excel workbooks. AEMO has made every effort to present this information in an easily accessible, simple-to-navigate format.

I look forward to AEMO's continuing engagement with stakeholders to ensure ongoing improvement to the quality and value of our forecasts.

M. Zema

Matt Zema

Managing Director and Chief Executive Officer

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EXECUTIVE SUMMARY

Annual energy

Electricity demand across the National Electricity Market (NEM) in 2013–14 is forecast to be 2.4% lower than estimated under the medium economic growth scenario in the 2012 NEFR.

Continued increases in rooftop photovoltaic (PV) systems and energy efficiency savings from new building regulations have offset growth in residential, commercial and light industrial annual energy.

Lower-than-expected growth in most industrial sectors reflects the closure of the Kurri Kurri aluminium smelter in New South Wales, changes in operating levels of Victoria's Wonthaggi desalination plant, and the Olympic Dam mine expansion deferral in South Australia. A high Australian dollar in recent years also contributed to the dampening in annual energy growth.

Under the same medium economic growth scenario, the 10-year outlook (2013–14 to 2022–23) sees annual energy forecast to grow by 1.3%.

The main growth drivers over this period are the three large industrial liquefied natural gas (LNG) projects in Queensland, population growth in most NEM regions, and an easing in electricity price growth over the 10-year outlook period.

Maximum demand

Maximum demand (MD) forecasts see a combined 728 MW reduction across the NEM for 2013–14 under the medium economic growth scenario in the 2012 NEFR.

This is due to a rise in solar PV installations; increased energy efficiency projections as a result of building standards; and changes in industrial operations, including a revised timing of LNG and new mining projects, reduced operation at Wonthaggi desalination plant and the indefinite deferral of the Olympic Dam mine expansion.

Under the same medium economic growth scenario, the 10-year outlook anticipates a lower growth trajectory in MD for most NEM regions compared to the 2012 forecast.

The exception is Queensland, where the current MD forecast reflects an increase on the 2012 forecast. See Figure 2.

MD forecasts are affected by reduced industrial demand and increased energy efficiency projections. Increased PV installation rates are additional drivers contributing to reduced maximum demand in all summer-peaking regions.

Key factors influencing changes in the 2013 demand forecasts

- **Three large LNG projects** in Queensland expected to come online from 2013–14 are the main drivers of the forecast increase in large industrial annual energy consumption, particularly in the first half of the outlook period. Average annual energy growth in the sector should moderate in the second half of the outlook period as projects mature and output reaches capacity.
- **Continued increases in rooftop PV** systems and energy efficiency savings from new building regulations offset NEM residential, commercial and light industrial annual energy growth. Increased PV installation rates are additional drivers contributing to reduced MD in all summer-peaking regions.
- **Population growth** is expected to drive overall increases in annual energy for residential, commercial and light industrial consumption; however, as shown in Figure 1, per capita electricity use declines and then flattens over the outlook period.
- **Lower-than-expected growth in most industrial sectors.** This reflects the closure of the Kurri Kurri aluminium smelter, changes in the operating levels of Wonthaggi desalination plant, and the deferral of the Olympic Dam mine expansion. Reduced global resource demand and a high Australian dollar in recent years contribute to a dampening of annual energy growth.
- In Tasmania, the restarting of the TEMCO smelter and facility upgrade to Norske Skog Boyer paper mill contribute to a 0.1% rise in large industrial electricity consumption.

Queensland

Queensland's annual energy for 2013–14 is expected to be 3.4% lower than the 2012 NEFR forecast due to large new industrial projects not coming online as early as expected.

Average annual energy growth over the 10-year outlook period is forecast to be 3.1%, higher than the 2.5% forecast in the 2012 NEFR, due to strong population and economic growth and an easing in electricity prices after 2014–15.

Queensland's MD (10% probability of exceedance, or POE) is expected to increase by an annual average of 3.2% over the 10-year outlook period under the medium economic growth scenario, with the biggest increase occurring in the first half of the outlook period due to the revised timing of LNG projects.

New South Wales

NSW's annual energy for 2013–14 is expected to be 2.2% lower under the medium economic growth scenario than forecast in the 2012 NEFR.

Average annual energy growth over the 10-year outlook period is forecast to be 0.6%, down from the 1.1% forecast in the 2012 NEFR. Rising population driving an increase in residential and commercial (including small industrial) electricity usage in New South Wales is behind the subdued annual energy growth over the next decade.

New South Wales MD has been reduced by 256 MW in 2013–14 and is now forecast to grow at an average annual rate of 1.0%, a slight decrease from the 1.1% forecast in 2012. This is due to increases in energy efficiency savings and a decrease in large industrial consumption.

Victoria

Victoria's forecast annual energy for 2013–14 is expected to be 2.2% lower under the medium economic growth scenario than forecast in the 2012 NEFR.

Average annual energy growth for the 10-year period is forecast to be 1.0%, down from the 1.3% forecast in the 2012 NEFR.

The Victorian MD (10% POE) has been reduced by 347 MW for 2013–14, and average annual growth over the 10-year outlook period is now forecast to be 0.9%, down from the 1.4% forecast in 2012, as a result of increased energy efficiency savings.

South Australia

Forecast annual energy in South Australia for 2013–14 is expected to be 3.6% lower than forecast in the 2012 NEFR under the medium economic growth scenario.

Annual energy for the 10-year outlook period is expected to decline at an average annual rate of 0.1%, a reduction on the 0.7% increase forecast in the 2012 NEFR, as a result of lower-than-expected population growth, the deferral of the Olympic Dam mining expansion announced by BHP Billiton, and an increase in rooftop solar PV and energy efficiency savings.

South Australia's MD has been reduced by 78 MW for 2013–14 in the 2013 forecast, reflecting a flat growth trend, and average annual growth over the 10-year outlook period is also expected to remain flat (at 0.0%) down from the 0.8% forecast in 2012.

Tasmania

Forecast annual energy in Tasmania for 2013–14 is expected to be 0.8% higher under the medium economic growth scenario than forecast in the 2012 NEFR.

Annual energy over the 10-year outlook period to 2022–23 is expected to decline by 0.2%, a reduction on the 2012 NEFR forecast of 1.0% growth as a result of lower population and economic growth compared to other NEM states.

Tasmania's MD has increased by 1 MW in the 2013 forecast, indicating no material change, and average annual growth over the 10-year outlook period is expected to remain flat. This is due to an increase in energy efficiency savings and an expected decrease in industrial consumption compared to 2012. In comparison, 1.3% average annual MD growth was forecast in the 2012 NEFR.

Conclusion

The NEFR includes electricity demand forecasts for each region of the NEM, together with national analysis, to provide an updated snapshot of Australia's annual energy usage. The NEFR provides essential information to inform energy industry participants and the broader community of the changes taking place in Australia's electricity demand profile.

Future changes in industrial consumption not modelled in the 2013 NEFR include the closure of Victoria's Ford vehicle manufacturing plants in 2016, the recommencement of operations at the Gunns plant in Tasmania and confirmation of the Hillside copper and gold mine in South Australia in 2016. The impacts of these changes will be detailed in the 2014 NEFR.

The validity and accuracy of the models used to develop the 2013 NEFR demand forecasts have been independently reviewed by external consultants, and are published with the 2013 NEFR. The 2013 modelling implements short-term (one-to-five-year) modelling outcomes, which are expected to provide a more accurate and robust demand forecast over the 10-year outlook period.

Figure 1 — NEM total annual energy (GWh)

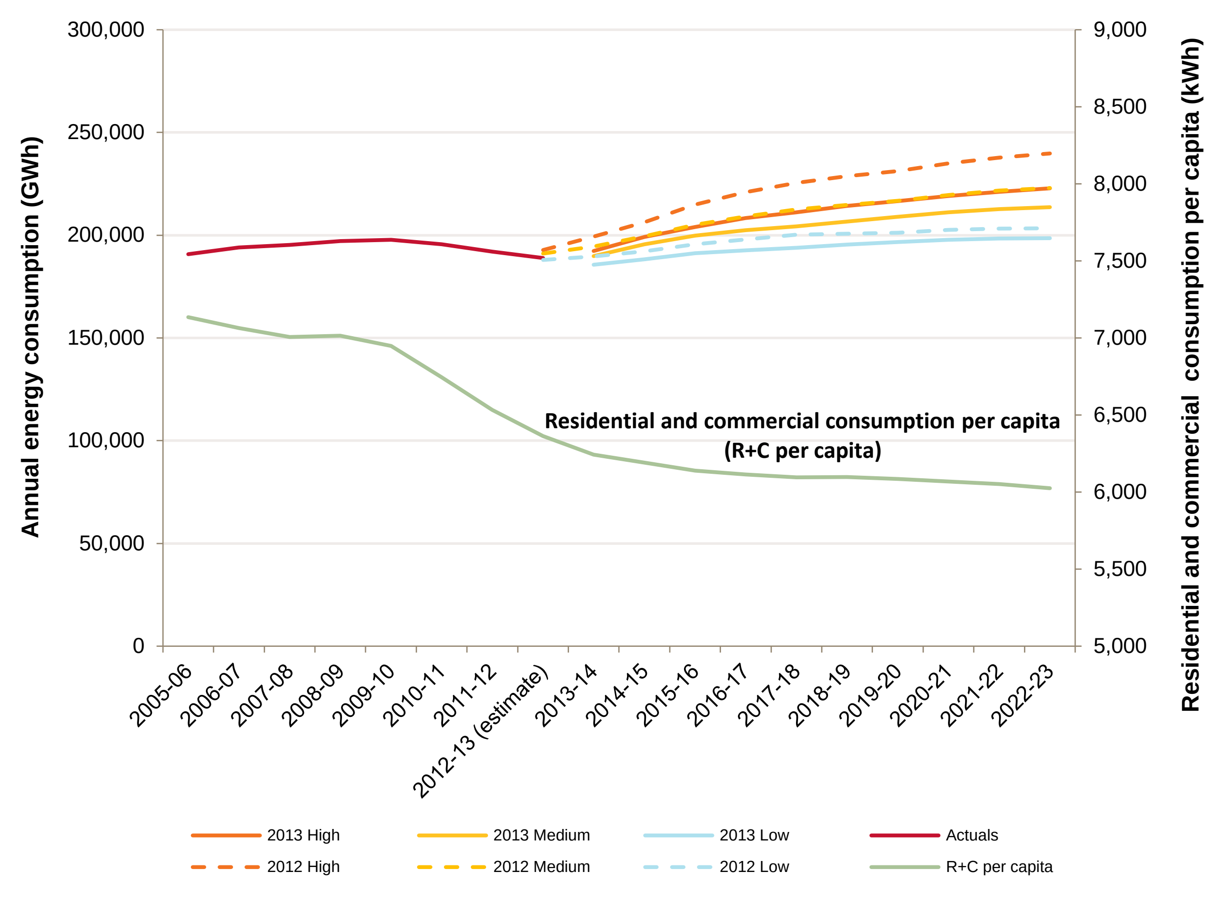
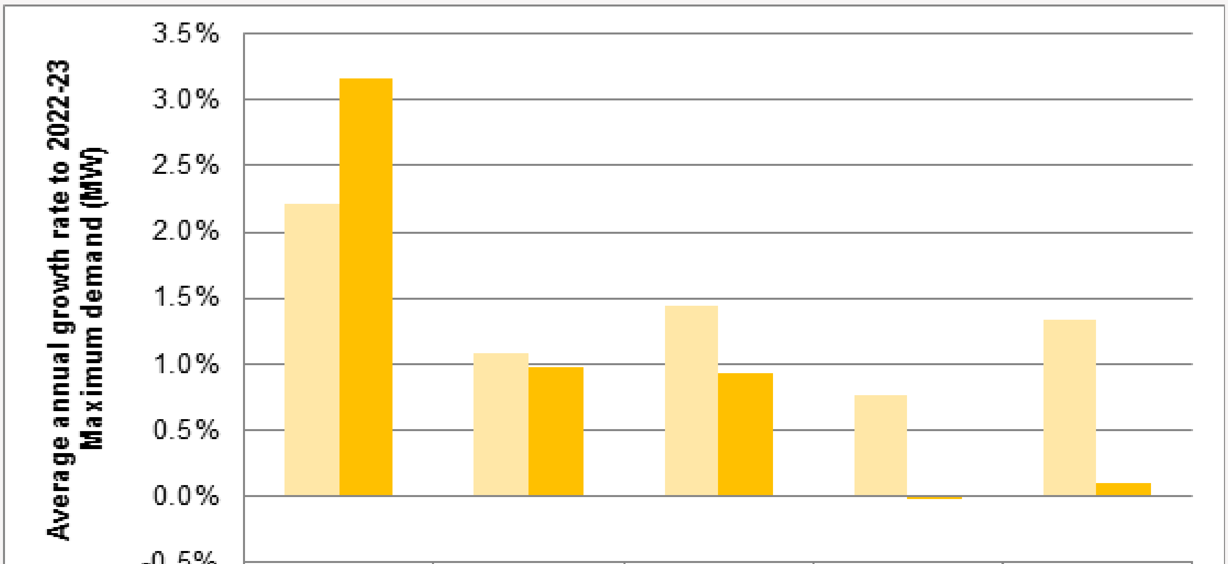


Figure 2 — Comparison of 2012 NEFR and 2013 NEFR 10-year growth in NEM MD



	QLD	NSW	VIC	SA	TAS
2012 NEFR	2.2%	1.1%	1.4%	0.8%	1.3%
2013 NEFR	3.2%	1.0%	0.9%	0.0%	0.1%

Table 1 — Overview of 2013 NEFR annual energy forecasts

Region	Historical Annual Energy (average annual growth)		
NEM	Overall decline of 1.6% from 2011–12 to 2012–13. Main drivers are the Kurri Kurri aluminium smelter closure in NSW, increased rooftop photovoltaic (PV) installations and energy efficiency initiatives, and increasing electricity prices.		
Region	**Annual Energy 10-year outlook (average annual growth)**		
	Overall	**Large industrial**	**Residential and commercial**
NEM	**1.3%**	**2.3%**	**1.0%**
QLD	**3.1%**	**6.6%**	**1.9%**
		3 large LNG projects online from 2013–14.	Population growth and economic projections. Increased electricity prices in 2013–14 and 2014–15, but constant for remainder of outlook period.
NSW	**0.6%**	**0.1%**	**0.7%**
			Moderate economic growth and higher electricity prices in the short term.
VIC	**1.0%**	**0.3%**	**1.2%**
		Wonthaggi desalination plant trended to expected long-term average consumption.	Population growth, economic projections and higher retail electricity prices in the short term.
SA	**-0.1%**	**-0.6%**	**-0.1%**
		BHP's deferral of the Olympic Dam project.	Increases in rooftop PV, energy efficiency initiatives, and economic projections. High electricity prices in the short term.
TAS	**-0.2%**	**0.1%**	**-0.6%**
		• TEMCO smelter - full production restarted. • Norske Skog Boyer paper mill - facility upgrade.	Increases in rooftop PV, energy efficiency initiatives, low population growth and economic projections.

<table>
<tr><th rowspan="3">Region</th><th colspan="3">How are we tracking this year?[1]</th><th colspan="2">Percentage change from 2012–13 to 2013–14</th><th>What does this table show?</th></tr>
<tr><th>2012 NEFR</th><th>2013 NEFR</th><th></th><th colspan="2">2013 NEFR</th><td rowspan="8">2012–13 actual demand is tracking 1.1% lower than forecast in the 2012 NEFR.

The 2013 NEFR forecasts 0.5% growth from 2012–13 to 2013–14.</td></tr>
<tr><th>Forecast 2012–13 (GWh)</th><th>Actual (estimated to end 2012–13) (GWh)</th><th>% Change</th><th>Forecast 2013–14 (GWh)</th><th>% Change 2012–13 to 2013–14</th></tr>
<tr><td>QLD</td><td>50,063</td><td>49,543</td><td>-1.0%</td><td>50,087</td><td>1.1%</td></tr>
<tr><td>NSW</td><td>70,007</td><td>68,834</td><td>-1.7%</td><td>69,363</td><td>0.8%</td></tr>
<tr><td>VIC</td><td>47,510</td><td>47,129</td><td>-0.8%</td><td>46,993</td><td>-0.3%</td></tr>
<tr><td>SA</td><td>13,031</td><td>13,144</td><td>0.9%</td><td>12,753</td><td>-3.0%</td></tr>
<tr><td>TAS</td><td>10,466</td><td>10,247</td><td>-2.1%</td><td>10,574</td><td>3.2%</td></tr>
<tr><td>NEM</td><td>191,076</td><td>188,898</td><td>-1.1%</td><td>189,770</td><td>0.5%</td></tr>
</table>

Table 2 — Overview of 2013 NEFR maximum demand forecasts (10% POE)

<table>
<tr><th rowspan="2">Region</th><th colspan="3">Maximum Demand 10-year outlook (average annual growth)</th></tr>
<tr><th>Overall</th><th>Large industrial</th><th>Residential and commercial</th></tr>
<tr><td>QLD</td><td>3.2%</td><td>6.3%</td><td>2.6%</td></tr>
<tr><td>NSW</td><td>1.0%</td><td>0.2%</td><td>1.1%</td></tr>
<tr><td>VIC</td><td>0.9%</td><td>0.0%</td><td>1.3%</td></tr>
<tr><td>SA</td><td>0.0%</td><td>0.0%</td><td>0.2%</td></tr>
<tr><td>TAS</td><td>0.1%</td><td>0.1%</td><td>0.1%</td></tr>
<tr><td colspan="2">Key Drivers
(All states)</td><td>QLD: 3 large LNG projects online from 2013–14.
NSW: Increased production in various mining sectors.
SA: Deferral of Olympic Dam expansion by BHP Billiton.
TAS: TEMCO smelter back to full production.
TAS: Norske Skog Boyer paper mill facility upgrade.</td><td>Population growth in Queensland and Victoria.
Very low population growth in Tasmania.
Increased forecast installed capacity for rooftop PV, resulting in higher offsets.
Forecast for energy efficiency impacts includes building standards, resulting in higher offsets.</td></tr>
</table>

[1] Statistics are based on medium economic scenario annual energy forecasts.

Region	Historical Native MD (MW)		2013–14 MD (MW)
	Actual	**Date**	**10% POE Forecast (medium)**
QLD	9,063	Mon 18 January 2010	8,958
NSW	14,863	Tue 1 February 2011	14,033
VIC	10,603	Thu 29 January 2009	10,530
SA	3,424	Mon 31 January 2011	3,254
TAS	1,879	Mon 21 July 2008	1,815

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TABLES

FIGURES

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CHAPTER 1 - ABOUT THE NEFR

1.1 National electricity forecasting

The National Electricity Forecasting Report (NEFR) provides independent electricity demand forecasts for each National Electricity Market (NEM) region over a 10-year outlook period (2013–14 to 2022–23). The forecasts explore a range of scenarios across high, medium and low economic growth outlooks.

The 2013 NEFR forecasts refers to a 10-year outlook period from 2013–14 to 2022–23. Historical, short-term, medium-term and 10-year outlook comparisons between the 2012 and 2013 NEFR refer to the same or equivalent period. This comparison uses the additional historical and forecast data published in the NEFR Excel workbooks.

The 2013 NEFR Excel workbooks include operational energy data and analysis in addition to native energy data; this better enables users to make their own comparative analysis of forecasts and against publicly available actual data on the AEMO website. In the main NEFR report, only native annual energy data is used.

Native demand includes all residential and commercial consumption, large industrial consumption, and transmission loss forecasts. **Operational demand** is calculated as native demand less the contribution from small non-scheduled generation (SNSG). (SNSG generally includes units with less then 30 MW capacity.)

The electricity demand forecasts are used for operational purposes, for calculating marginal loss factors, and as a key input into AEMO's national transmission planning role. A detailed understanding of how the forecasts are developed is required 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 industry to produce consistent, representative, and reliable forecasts for each NEM region.

Analysis for the 2012–13 estimate is based on six months of actual data from July 2012 to December 2012 and six months of forecast data from January 2013 to June 2013. Actual data is included only to the end of 2012 due to actual data for Q1 2013 being unavailable at the time of annual energy model development and it is preferable to include a forecast for Q1 and Q2 2013 rather than estimate data for an incomplete quarter.

In the case of large industrial load, Q1 and Q2 2013 data was taken from annual energy used during the same period in 2012, unless specific information was directly provided by large industrial customers.

Forecast scenarios

The annual energy and maximum demand (MD) forecasts were developed using high, medium, and low economic growth scenarios, which correspond to three of the six scenarios developed for the 2012 National Transmission Network Development Plan (NTNDP). These scenarios have been designed to reflect different levels of economic growth, residential and commercial[1] consumption, large industrial consumption, rooftop photovoltaic (PV) output, energy efficiency, and SNSG. The terms 'high', 'medium' and 'low' are used throughout the report to identify the scenarios, which are outlined in more detail in Table 1.1.

Table 1.1 lists the correlation between the national electricity forecasting scenarios and the related component forecasts. The scenarios were updated in 2012, and will be updated for the 2014 NEFR. They are available in AEMO's 2012 Scenarios Descriptions.[2]

[1] Includes light industrial.

[2] AEMO. www.aemo.com.au/~/media/Files/Other/planning/2012_Scenarios_Descriptions.ashx. Viewed 21 June 2013.

Table 1-1 — Scenarios for national electricity forecasting

2013 NEFR reference	2012 AEMO scenario	Related economic scenario	Related large industrial scenario	Related rooftop PV scenario	Related energy efficiency scenario	Related SNSG scenario
High	Scenario 2 - Fast World Recovery	HCO5	High	Moderate Uptake	Moderate Uptake	High Uptake
Medium	Scenario 3 - Planning	MCO5	Medium	Moderate Uptake	Moderate Uptake	Moderate Uptake
Low	Scenario 6 - Slow Growth	LCO5	Low	Moderate Uptake	Moderate Uptake	Slow Uptake

1.2 Annual energy and maximum demand definitions

This section provides an overview of key definitions and commonly used terms relating to electricity supply and demand important to understanding the annual energy and MD forecasts.

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 during transportation (transmission losses), and the energy used to generate the electricity (auxiliary loads).

The basis for measuring demand

Electricity (energy) supplied by generators can be measured in two ways:

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

The basis for projecting annual energy and MD

The NEFR annual energy and MD forecasts are presented as follows:

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

The 2013 NEFR includes both native and operational energy data for the current annual energy and MD forecasts. Operational demand is used by AEMO in determining adequacy of supply on the NEM.

Annual energy forecast improvements in the 2013 NEFR

AEMO has implemented key improvements to enhance the 2013 annual energy forecasting models. Specific improvements are:

- Implementation of the Dynamic Ordinary Least Squares method to determine the long-run relationship between demand and its key drivers. For more information about this method see the Forecast Methodology Information Paper to be published on 31 July 2013.
- Development of seasonally-adjusted forecast models to correct seasonality patterns in the data.
- Application of a consistent methodology to develop annual energy models across all NEM regions.

MD forecast improvements in the 2013 NEFR

AEMO, in collaboration with Monash University, has implemented key improvements to enhance the MD forecasting models. Specifically these are:

- Allowing for specific price responses observed at peak times, using peak price elasticities in the MD model based on research undertaken by Monash University.
- Allowing for changes in the load factor over time, based on research undertaken by Monash University. The MD forecast model now adjusts over time to allow a superior model fit.
- Incorporating simulated heating and cooling degree days in the MD distribution to allow for the effect of consistently hot or cold summers or winters in the MD probability distribution.
- Incorporating a half-hourly PV generation trace. This trace is added to the non-industrial demand, enabling a more complete view of demand at times of MD. Additionally, a broader sample set has been used in determining the PV contribution factor at times of MD for all regions, enabling a more accurate forecast for future rooftop PV contribution.

The Forecast Methodology Information Paper contains more information regarding improvements to the MD forecast modelling and rooftop PV.

Per capita consumption

The 2013 NEFR shows a growth trend in the annual energy forecast. To improve understanding of the drivers that impact annual energy forecasts, AEMO has included analysis about the effects of population on annual energy consumption for each NEM region.

A plot line for residential and commercial consumption per capita is included in the annual energy graph for each NEM region. This line represents energy consumption from a household perspective as a per capita forecast.

The historical trend shows that as population has been increasing, household consumption per capita has been decreasing, indicating that individual households are consuming less energy. Reasons for this include:

- Rising electricity prices.
- Increased rooftop PV penetration.
- Increased energy efficiency savings.

The forecasts indicate that decreased per capita household consumption is likely to moderate in the future due to:

- Electricity prices moderating and potentially decreasing as infrastructure investment plateaus.
- Saturation of rooftop PV and energy efficiency savings.

Native annual energy shows a continued increasing trend in annual energy. While households are consuming less energy, expected population growth means more households are contributing to annual energy usage.

Short-term one-to-five-year outlook

A key change in the 2013 NEFR is a greater focus on the short-term one-to-five-year forecast in the annual energy models.

In developing the annual energy forecasts for the 2013 NEFR, AEMO's initial 2012 NEFR models were revised. Suggested improvements by external consultants, Frontier Economics, were incorporated into the 2013 NEFR models to focus on the short-term period.

This approach, which results in more accurate outcomes, has been further reviewed by Frontier Economics and further improvements made in collaboration with Woodhall Investment Research. Details of these changes are discussed in a summary of key findings from the modelling and forecast process by Frontier Economics published with the NEFR. A more detailed methodology report will be available by 31 July 2013.

Transmission losses and auxiliary load

Transmission losses are determined as a percentage of large industrial and residential and commercial energy. Assessed against historical data, this method of calculation has been found to be more accurate than using a regression model, as was used in the previous NEFR.

Auxiliary load is defined as the energy used by a generating unit to generate electricity.

Small non-scheduled generation

The forecast methodology for small non-scheduled generation has changed since the 2012 NEFR. Changes include:

- Construction of generator-by-generator forecasts based on a fundamental appraisal of existing and future projects.
- Greater use of historical data to inform capacity factors and contribution to MD.
- Increased disaggregation of generator characteristics to encompass specific NEM regions and technologies.

Forecasts of SNSG are constructed by developing profiles of existing generators and future developments based on publicly available information.

Towards the end of the forecast period there is limited information regarding the development of SNSG projects. As such, SNSG profiles for annual energy and contribution to MD display little variation over the forecast period.

Defining the probability of exceedence

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

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

- A 10% POE MD projection is expected to be exceeded, on average, one year in 10.
- A 50% POE MD projection is expected to be exceeded, on average, five years in 10 (or one year in two).
- A 90% POE MD projection is expected to be exceeded, on average, nine years in 10.

The 2013 NEFR presents MD data based on 10% POE MD projections. Industry participants have indicated that this is more useful and of greater interest than information based on a 50% POE MD projection, which was presented in the 2012 NEFR.

The 2013 NEFR also incorporates additional simulated temperature data (via heating and cooling degree days) into the MD model. This provides a better representation of the POE distribution by allowing for additional temperature-related variations in MD caused by consistently hotter or colder summers and/or winters.

Scenario ranges

The narrowing spread (or difference) between scenarios, seen in both the 2013 NEFR annual energy and MD forecasts, does not indicate greater certainty of future outcomes. Rather, it is largely a function of changed methodology regarding large industrial forecasts.

For the 2013 NEFR, AEMO sought guidance directly from large industrial customers and transmission network service providers (TNSPs) on future usage, including possible expansions or reductions in consumption. This included advice on likely outcomes under the various scenarios. The responses indicated there was no significant spread between scenarios.

For the 2012 NEFR, AEMO approached TNSPs for similar advice, with inputs primarily applied only to the medium scenario. AEMO also conducted its own research. Future growth and possible plant closures were incorporated into the high and low scenarios without direct advice from industry; the result was a wider spread of outcomes between the high, medium and low scenarios.

1.3 Key inputs

This section provides information about the key inputs into the 2013 NEFR forecasts, including improvements since the 2012 NEFR.

Large industrial load

For the 2013 NEFR, AEMO directly contacted more than 40 large industrial customers, rather than relying on historical and TNSP-sourced information. Customers provided information on their likely load under the three economic growth scenarios (high, medium and low), resulting in more realistic data being used in the forecasts.

AEMO intends to gether similar information directly from large industrial customers for the 2014 NEFR, with further refinements to be incorporated into the process based on improvement opportunities identified in 2013.

Energy efficiency

The 2013 NEFR forecast modelling includes energy efficiency improvements equal to the average historical rate of uptake. An additional post-model adjustment has been added to account for additional impacts due to the increase in programs targeting energy efficiency in recent years.

The current forecast is based on recent, comprehensive data for all Commonwealth Government energy efficiency programs targeting electrical appliances as well as both existing and new building stock. For more details see the Forecast Methodology Information Paper.

The 2012 NEFR included limited building energy efficiency data, and estimates generally relied on information dating back to 2009.

The recent decline in annual energy use is partly explained by increased uptake of energy efficiency measures; however, energy efficiency is one of several influencing factors and the extent of its impact is not yet fully understood.

All three economic growth scenarios used in the 2013 NEFR assume a moderate uptake of energy efficiency measures. The supporting data, including details of the moderate uptake forecasts as well as the ‘slow uptake’ and ‘rapid uptake’ scenario forecasts will be provided as an appendix in the Forecast Methodology Information Paper to be published on 31 July 2013. This will enable users to undertake their own sensitivity analyses using higher or lower uptake rates to account for the uncertainty around this estimate.

Rooftop solar photovoltaic

The 2013 NEFR forecasts show an increasing PV offset of MD and annual energy in all regions over years due to a greater level of installed roofop PV capacity. AEMO recognises that as rooftop PV installed capacity in the NEM grows, it may vary the time at which MD occurs during the day.

The potential influence of installed PV capacity on the time of MD will be addressed in the 2014 NEFR.

All three economic growth scenarios in the 2013 NEFR assume a moderate uptake of rooftop PV growth. Supporting information will be provided in the Forecast Methodology Information Paper to be published on 31 July 2013. This will enable users to undertake their own sensitivity analyses using higher or lower uptake rates to account for the uncertainty around this estimate.

Further details about the ‘slow uptake’ and ‘rapid uptake’ scenarios will be provided in the Forecast Methodology Information Paper

Demand side participation

AEMO has prepared three demand side participation uptake scenarios for use with the 2013 NEFR. These, together with the methodology underpinning them, will be detailed in the Forecast Methodology Information Paper to be published on 31 July 2013.

Electricity prices

Commentary on electricity prices, and their impact on demand, is available in the Economic Outlook Paper, a supplementary report supporting the 2013 NEFR.

AEMO’s pricing forecasts have been compared to, and are broadly in line with, the pricing reports or determinations released by the Queensland Competition Authority (QCA), the Independent Pricing and Regulatory Tribunal (IPART) in NSW, the Essential Services Commission of South Australia (ESCOSA), the Essential Services Commission (ESC) in Victoria, and the Office of the Tasmanian Economic Regulator (OTTER).

1.4 Content and structure of the NEFR

The NEFR provides NEM-wide annual energy forecasts, and annual energy and MD forecasts for each NEM region. Key results are presented for the medium scenario—scenario 3 (planning) from 2012—which reflects medium economic growth. This is the “base case” scenario. Key high and low scenario results are also provided.

The 2013 NEFR structure comprises an executive summary and a set of NEM-wide and regional summaries supported by Excel workbooks containing more detailed information. A glossary and list of abbreviations is also provided.

The 2013 NEFR

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

About the NEFR provides background information about AEMO electricity forecasting.

NEM-wide summary (PDF) and spreadsheet workbook (Excel), provides NEM-wide annual energy forecasts.

Queensland summary (PDF) and spreadsheet workbook (Excel), provides the annual energy and MD forecasts for the Queensland region.

New South Wales summary (PDF) and spreadsheet workbook (Excel), provides the annual energy and MD forecasts for the New South Wales (including ACT) region.

Victoria summary (PDF) and spreadsheet workbook (Excel), provides the annual energy and MD forecasts for the Victoria region.

South Australia summary (PDF) and spreadsheet workbook (Excel), provides the annual energy and MD forecasts for the South Australia region.

Tasmania summary (PDF) and spreadsheet workbook (Excel), provides the annual energy and MD forecasts for the Tasmania region.

NEFR supplementary information

The following supplementary information is available from AEMO’s website[3]:

- Historical actual data and input assumptions.
- Forecast Accuracy Report assessing the accuracy of the 2012 NEFR forecasts.
- Economic Outlook Report providing the economic forecasts used to generate the annual energy and MD forecasts.
- Forecast Methodology Information Paper (to be published on 31 July 2013) explaining the approaches used for the 2013 NEFR forecasts.

[3] AEMO. Available at: http://aemo.com.au/Electricity/Planning/Forecasting. Viewed 17 May 2013.

CHAPTER 2 - NATIONAL ELECTRICITY MARKET FORECASTS

2.1 Annual energy forecasts

From 2008–09 to 2012–13, annual energy declined by 8,300 GWh (an annual average of 1.1%) to 188,898 GWh due to decreases in all National Electricity Market (NEM) regions, partly due to steep electricity price increases in the last couple of years.

Key differences between the 2013 National Electricity Forecasting Report (NEFR) and the 2012 NEFR annual energy forecasts include the following:

- **Current estimate for 2012–13:** The current estimate for 2012–13 annual energy is 188,898 GWh, which is 2,178 GWh (1.1%) below the 2012 NEFR medium forecast.
- **Medium forecast from 2013–14 to 2022–23:** The 2013 forecast average annual growth rate of 1.3% is lower than the 2012 forecast of 1.5%.

Key drivers contributing to annual energy forecast change

- Large industrial projects in Queensland coming online from 2013–14 onwards.
- Decline in residential and commercial consumption forecasts, due to:
    - Moderation in economic forecasts from the 2012 NEFR. In particular moderation in the gross domestic product (GDP) growth rate for 2012–13: The Australian economy is expected to grow 2.8% in the 2013 NEFR forecasts, compared to 3.3% in the 2012 NEFR.
    - In addition, Australian GDP forecasts showed a consistent growth for the first five years of the outlook period (2013–14 to 2017–18) with an average annual growth of 3.4% in the 2013 NEFR and 3.3% in the 2012 NEFR. For the medium to long term (2018–19 to 2022–23) GDP growth shows some moderation, with average annual growth rates of 2.2% for the 2013 NEFR compared to 2.5% in the 2012 NEFR. Over the 10-year outlook period annual average growth rates are forecast to be 2.8% in the 2013 NEFR compared to 2.9% in the 2012 NEFR.
    - Increased rooftop photovoltaic (PV) penetration forecasts, primarily driven by government incentives and small-scale technology certificate (STC) multipliers. Announced reductions in feed-in tariffs and the solar multiplier caused significantly higher uptake of rooftop PV installations before rebates were reduced.
    - Higher energy efficiency offsets compared to the 2012 NEFR due to the inclusion of efficiencies from new building regulations and large cooling loads.
    - Higher electricity prices compared to the 2012 NEFR forecasts during the first five years of the forecasting period for all the NEM regions.
    - Consumer response (residential and commercial) to rising electricity costs and energy efficiency measures.

2.2 Annual energy

2.2.1 Annual energy forecast

Figure 2-1 — Annual energy forecasts for the NEM

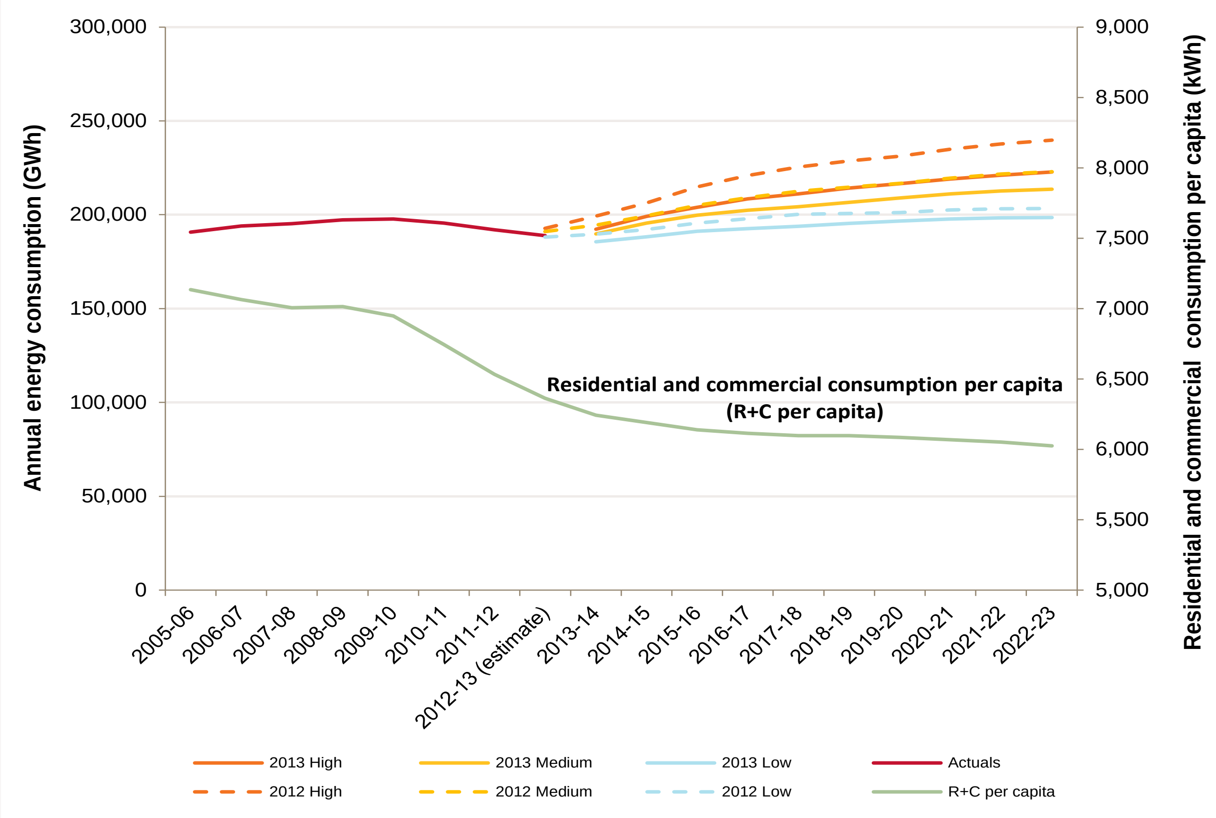
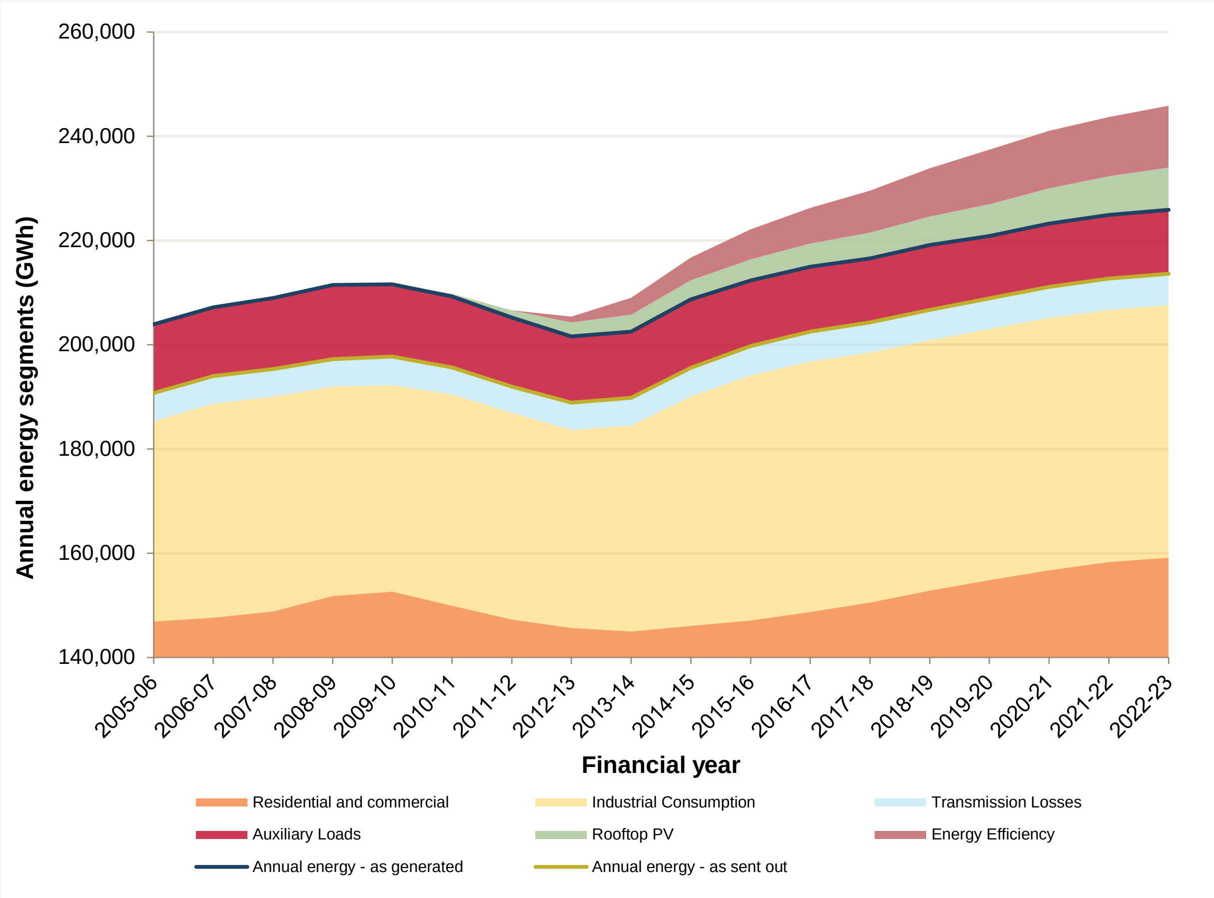


Table 2-1 — Annual energy forecasts for the NEM (GWh)

	Actual	High	Medium	Low
2012–13 (estimate)	188,898			
2013–14		192,247	189,770	185,588
2014–15		199,106	195,550	188,190
2015–16		204,036	199,727	191,158
2016–17		208,401	202,463	192,652
2017–18		211,067	204,256	193,782
2018–19		214,217	206,668	195,367
2019–20		216,587	208,878	196,600
2020–21		219,026	211,090	197,734
2021–22		221,145	212,669	198,437
2022–23		222,723	213,596	198,579
Average annual growth		1.6%	1.3%	0.8%

2.2.2 Annual energy forecast segments

Figure 2-2 — Annual energy forecasts segments for the NEM



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CHAPTER 3 - QUEENSLAND FORECASTS

3.1 Annual energy forecasts

From 2008–09 to 2012–13, annual energy declined by 224 GWh (an annual average decline of 0.1%) to 49,543 GWh.

Key differences between the 2013 National Electricity Forecasting Report (NEFR) and the 2012 NEFR annual energy forecasts include the following:

- **Current estimate for 2012–13:** The current estimate for 2012–13 annual energy, at 49,543 GWh, is 519 GWh (1.0%) below the 2012 NEFR medium forecast.
- **Medium forecast from 2013–14 to 2022–23:** Queensland's annual energy is forecast to increase by an annual average of 3.1%, compared to 2.5% in the 2012 NEFR.

Key drivers contributing to annual energy forecast change

- Additional energy from large industrial projects, principally liquefied natural gas (LNG).
- Decreased residential and commercial energy forecasts compared to the 2012 NEFR due to lower population forecasts and higher electricity prices in the first five years of the outlook period.

3.2 Maximum demand forecasts

Key differences between summer maximum demand (MD) forecasts in the 2013 and 2012 NEFRs include the following:

- The 2012–13 summer MD was 8,720 MW on 4 December 2012. This was 6 MW below the 2012 NEFR 90% probability of exceedence (POE) forecast, due to lower-than-expected residential and commercial load, lower-than-expected large industrial load, and increased penetration of rooftop photovoltaic (PV).
- The 2013–14 summer MD 10% POE forecast under the medium scenario is 600 MW below the 2012 forecast.
- The 10% POE MD is forecast to increase from 2013–14 to 2022–23 at an annual average rate of 3.2% under the medium scenario, compared to 2.2% in the 2012 NEFR. While the average annual growth rate for the 2013 forecast is a full 1.0% higher than in 2012, a decrease in MD is forecast for 2013–14. This is driven in part by the increased tariffs recently approved by the Queensland Competition Authority (QCA). This is followed by a substantial increase in MD between 2014–15 and 2016–17 as LNG projects begin ramping up operations.

Key drivers contributing to MD forecast change

- Decreased residential and commercial load driven by decreased population assumptions.
- Decreased large industrial load in 2013–14 due to later ramp up of LNG projects.
- Increased installed capacity of rooftop PV.
- Increased impact of energy efficiency, driven by the inclusion of building standards.
- Lower population projections in the 2013–14 forecasts.
- Greater spread between low, medium and high scenarios, due primarily including additional variables in the MD forecasting, such as cooling degree days and heating degree days (CDD and HDD). This allows for extra temperature-related variations in MD caused by consistently hotter or cooler summers/winters.

3.3 Annual energy

3.3.1 Annual energy forecasts

Figure 3-1 — Annual energy forecasts for Queensland

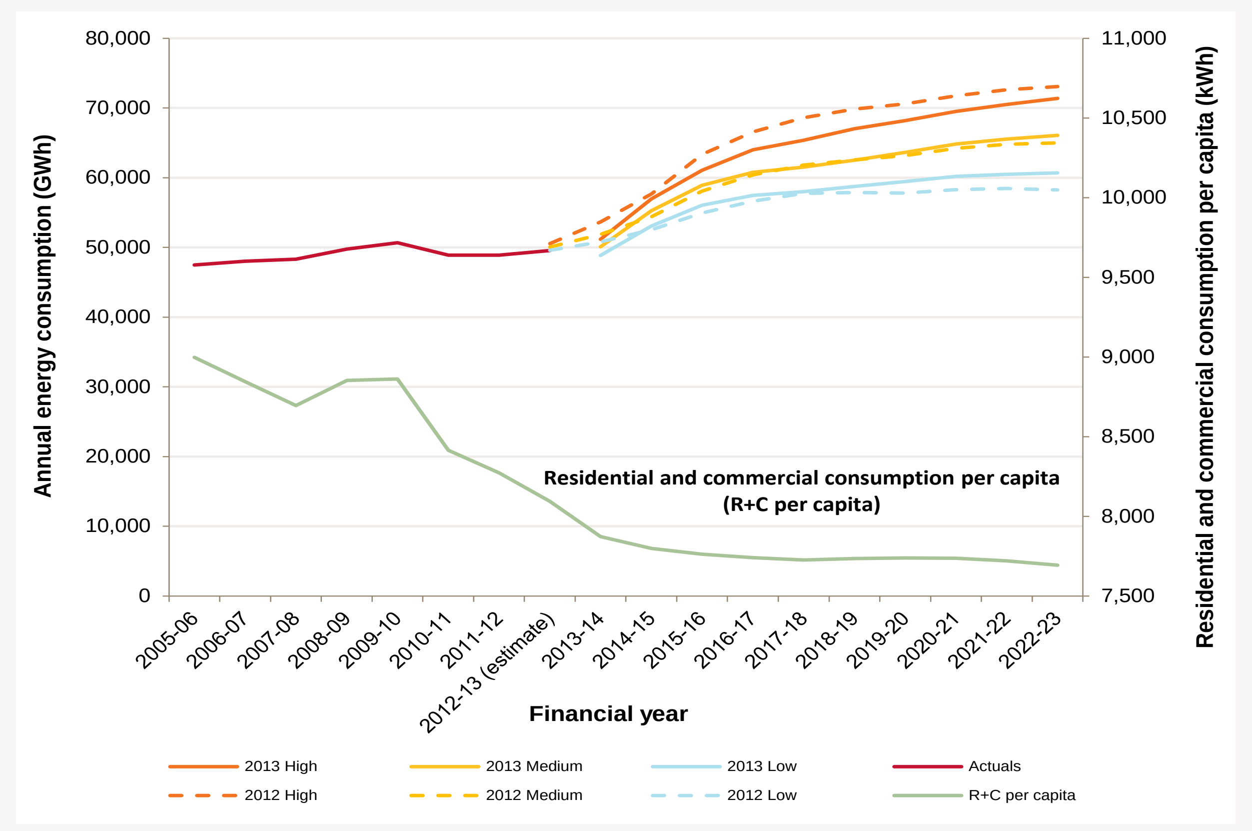
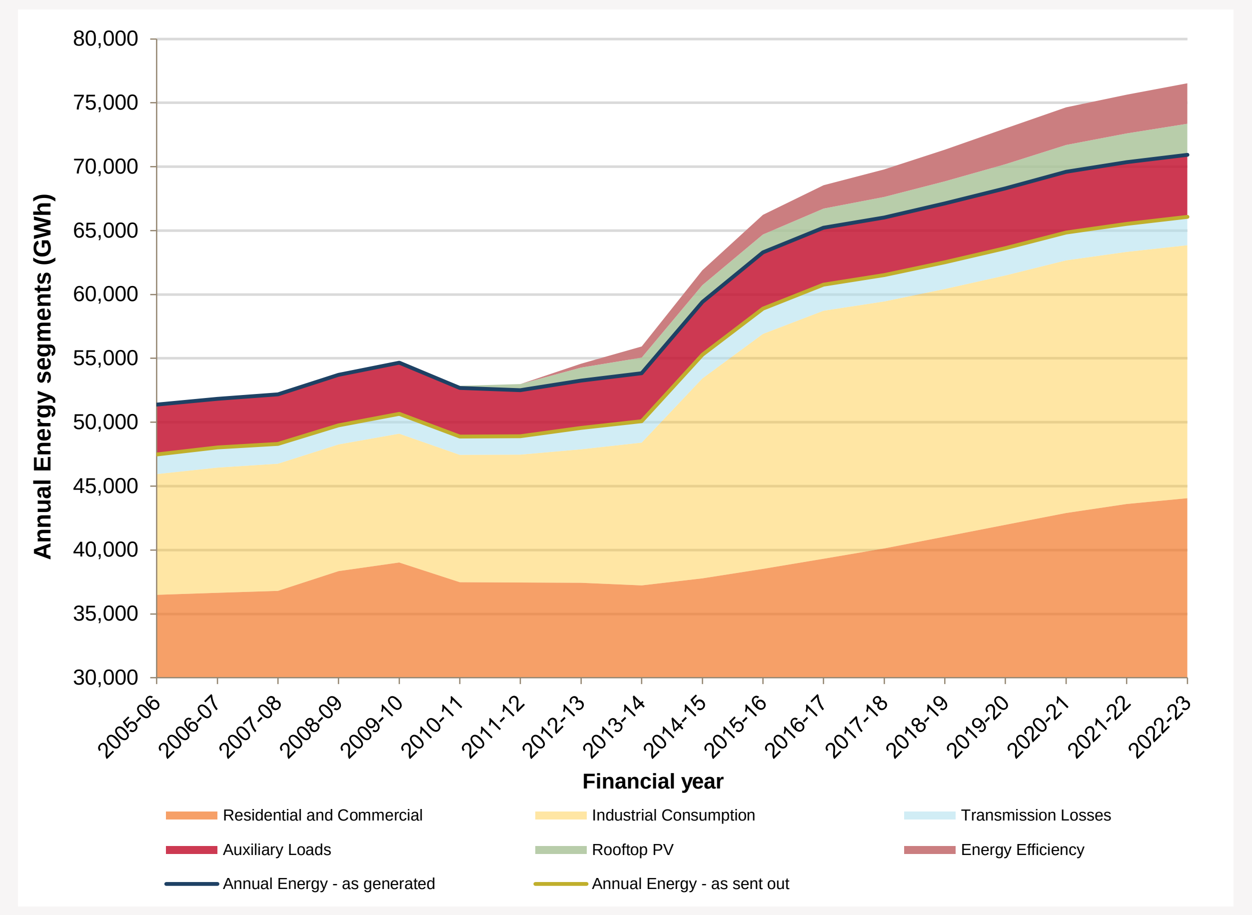


Table 3-1 — Annual energy forecasts for Queensland (GWh)

	Actual	High	Medium	Low
2012–13 (estimate)	49,543			
2013–14		51,183	50,087	48,833
2014–15		56,948	55,278	53,071
2015–16		61,071	58,889	56,035
2016–17		63,984	60,767	57,471
2017–18		65,368	61,517	58,010
2018–19		67,010	62,528	58,743
2019–20		68,195	63,625	59,462
2020–21		69,525	64,846	60,183
2021–22		70,502	65,533	60,465
2022–23		71,389	66,071	60,709
Average annual growth		3.8%	3.1%	2.4%

3.3.2 Annual energy forecasts segments

Figure 3-2 — Annual energy forecasts segments for Queensland



3.4 Maximum demand

3.4.1 Summer maximum demand forecasts

Figure 3-3 — Summer 90%, 50% and 10% POE maximum demand forecasts for Queensland

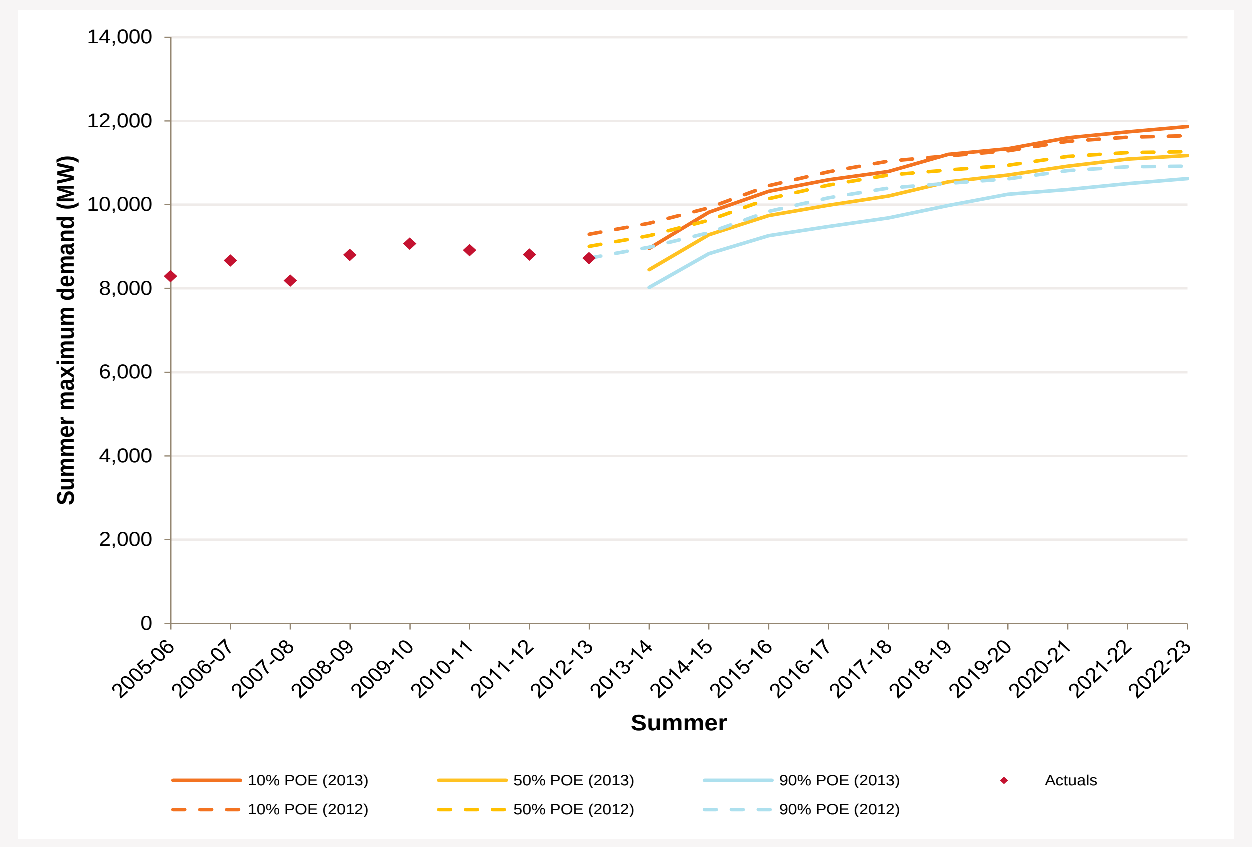
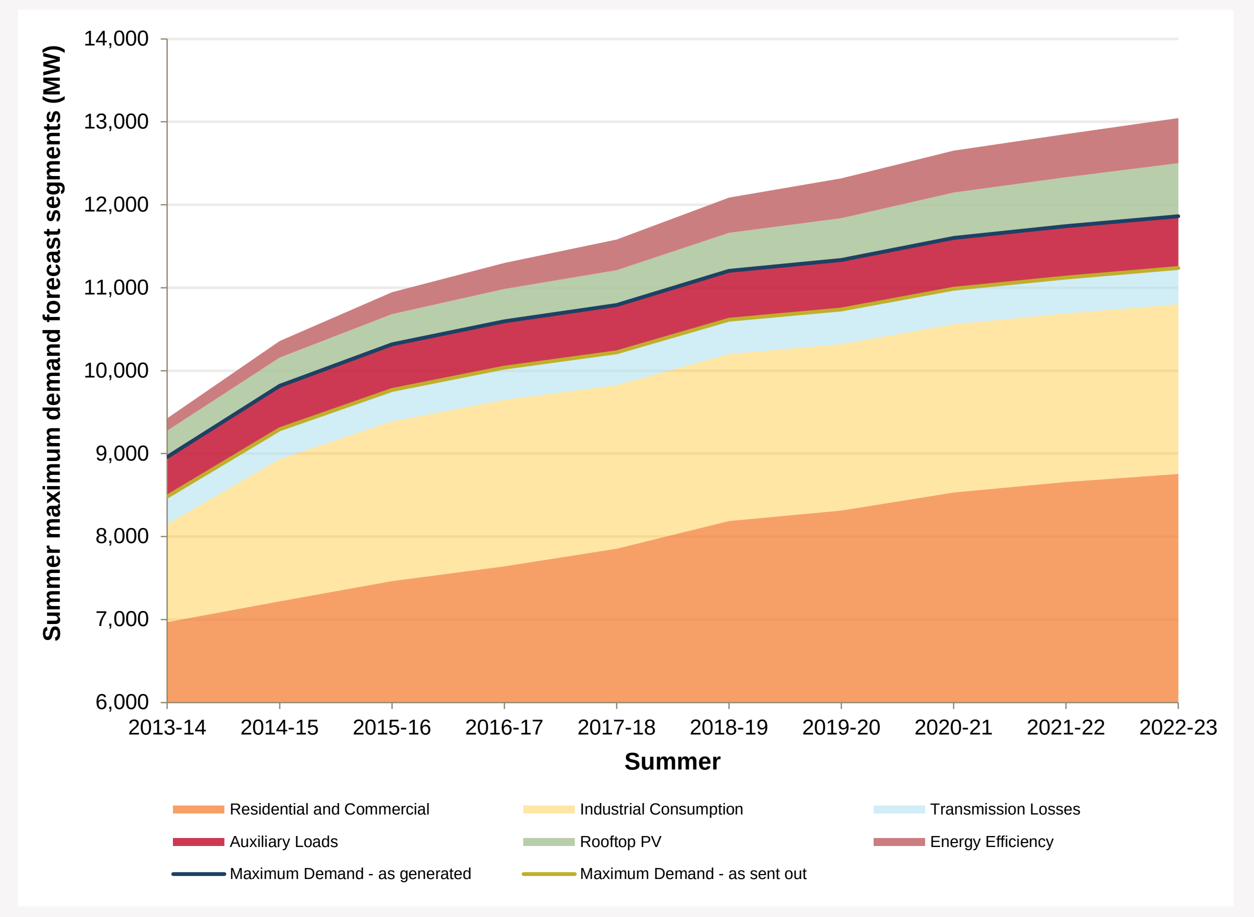


Table 3-2 — Summer 90%, 50% and 10% POE MD forecasts for Queensland (MW)

	Actual	90% POE	50% POE	10% POE
2012–13 (estimate)	8,720			
2013–14		8,027	8,452	8,958
2014–15		8,830	9,280	9,818
2015–16		9,259	9,737	10,319
2016–17		9,483	9,985	10,597
2017–18		9,686	10,208	10,792
2018–19		9,979	10,542	11,204
2019–20		10,248	10,706	11,335
2020–21		10,365	10,918	11,599
2021–22		10,506	11,086	11,741
2022–23		10,625	11,176	11,863
Average annual growth		3.2%	3.2%	3.2%

3.4.2 Summer 10% POE maximum demand forecast segments

Figure 3-4 — Summer 10% POE maximum demand segments for Queensland



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CHAPTER 4 - NEW SOUTH WALES FORECASTS

4.1 Annual energy forecasts

From 2008–09 to 2012–13, annual energy declined by 5,947 GWh (an annual average decline of 2.1%) to 68,834 GWh.

Key differences between the 2013 National Electricity Forecasting Report (NEFR) and the 2012 NEFR annual energy forecasts include the following:

- **Current estimate for 2012–13:** The current estimate for 2012–13 annual energy is 68,834 GWh, which is 1,173 GWh (1.7%) below the 2012 NEFR medium forecast.
- **Medium forecast from 2013–14 to 2022–23:** The 2013 forecast average annual growth rate is 0.6%, compared to 1.1% in the 2012 forecasts.
- **Lower spread between low, medium and high scenarios:** All three scenarios in the 2013 forecast are below the medium scenario in the 2012 NEFR.

Key drivers contributing to annual energy forecast change

- Reduction in residential and commercial consumption forecasts due to higher retail electricity prices, and an increased forecast for rooftop photovoltaic (PV) penetration and energy efficiency offsets.
- Large industrial forecasts have been revised down due to the closure of the Kurri Kurri aluminium smelter, the recent decrease in global metal prices, and the sustained high Australian dollar in recent years.
- The difference between low, medium and high scenarios is much narrower due primarily to the change in major industrial load forecast methodology.

4.2 Maximum demand forecasts

Key differences between summer maximum demand (MD) forecasts in the 2013 and 2012 NEFRs include the following:

- 2012–13 summer MD was 13,946 MW on 18 January 2013. This was 119 MW below the 2012 NEFR 10% probability of exceedence (POE) forecast.
- The 2013–14 summer MD 10% POE forecast under the medium scenario is 256 MW below the 2012 forecast.
- The 10% POE MD is forecast to increase from 2013–14 to 2022–23 at an annual average rate of 1.0% under the medium scenario, compared to 1.1% in the 2012 NEFR.

Key drivers contributing to MD forecast change

- Decreased large industrial forecasts due to revised projections from direct consultation with major industrial customers, including the reduction in demand resulting from the Kurri Kurri aluminium smelter closure.
- Increased energy efficiency impacts driven by the inclusion of building standards, changes in the methodology for converting from energy savings to savings at time of MD, and the inclusion of federal energy efficiency programmes targeting the building stock.
- Increased rooftop PV generation due to higher small-scale technology certificate (STC) prices and a higher contribution factor (derived from more complete analysis into rooftop PV contribution at peak times).
- Greater spread between low, medium and high scenarios, due primarily including additional variables in the MD forecasting, such as cooling degree days and heating degree days (CDD and HDD). This allows for extra temperature-related variations in MD caused by consistently hotter or cooler summers/winters.

4.3 Annual energy

4.3.1 Annual energy forecast

Figure 4-1 — Annual energy forecasts for New South Wales

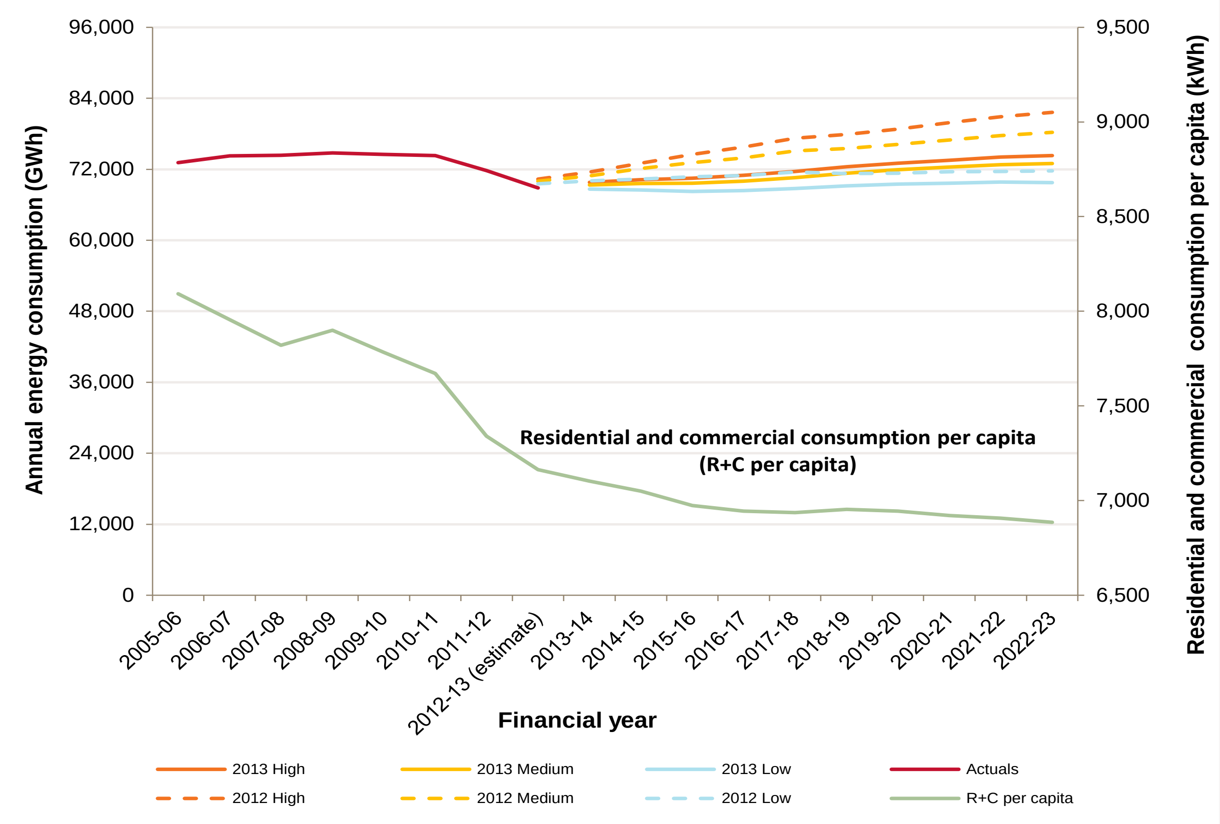
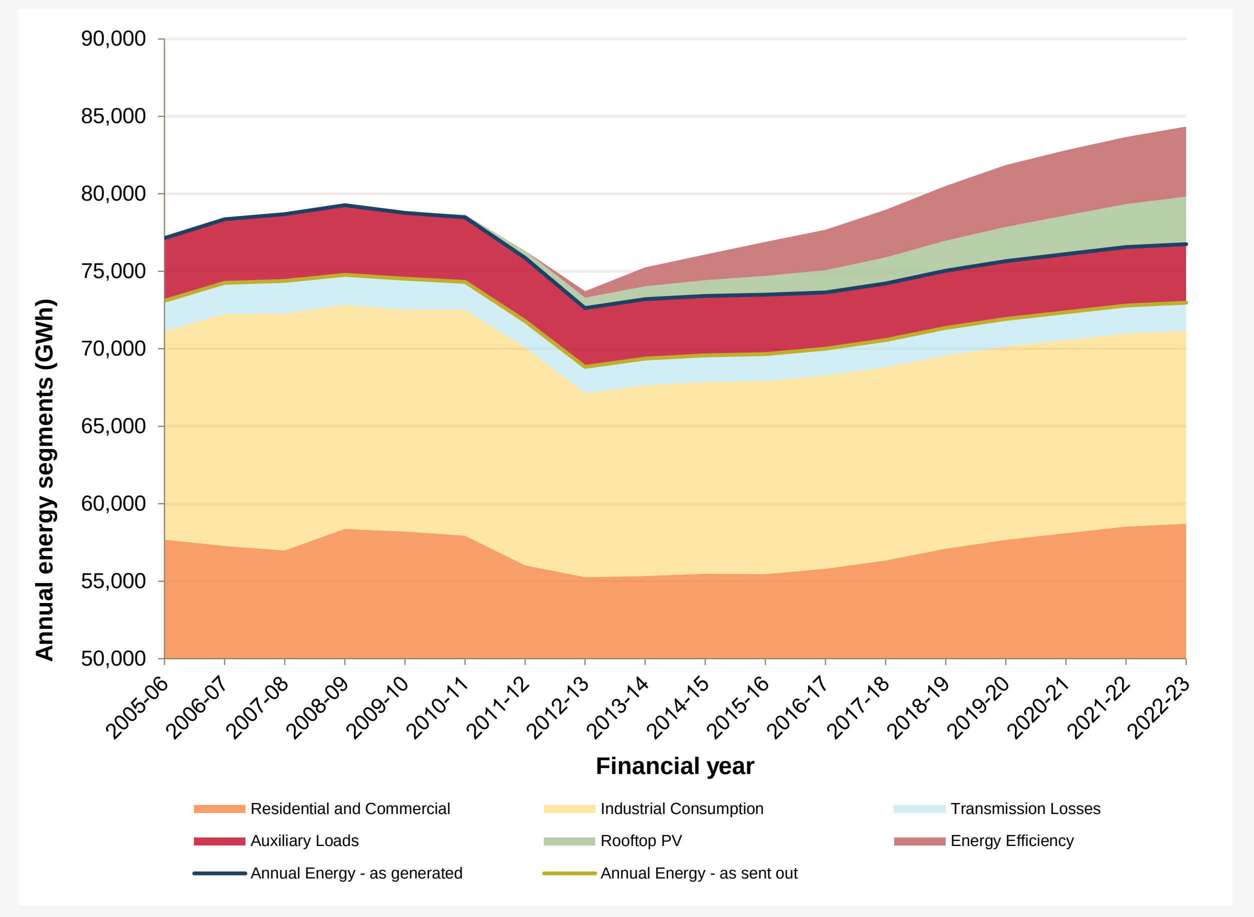


Table 4-1 — Annual energy forecasts for New South Wales (GWh)

	Actual	High	Medium	Low
2012–13 (estimate)	68,834			
2013–14		69,809	69,363	68,641
2014–15		70,216	69,574	68,485
2015–16		70,486	69,646	68,261
2016–17		70,997	70,012	68,403
2017–18		71,633	70,565	68,731
2018–19		72,438	71,344	69,205
2019–20		73,042	71,925	69,480
2020–21		73,519	72,361	69,641
2021–22		74,043	72,787	69,825
2022–23		74,337	72,975	69,756
Average annual growth		0.7%	0.6%	0.2%

4.3.2 Annual energy forecast segments

Figure 4-2 — Annual energy forecasts segments for New South Wales



4.4 Maximum demand

4.4.1 Summer maximum demand forecasts

Figure 4-3 — Summer 90%, 50% and 10% POE maximum demand forecasts for New South Wales

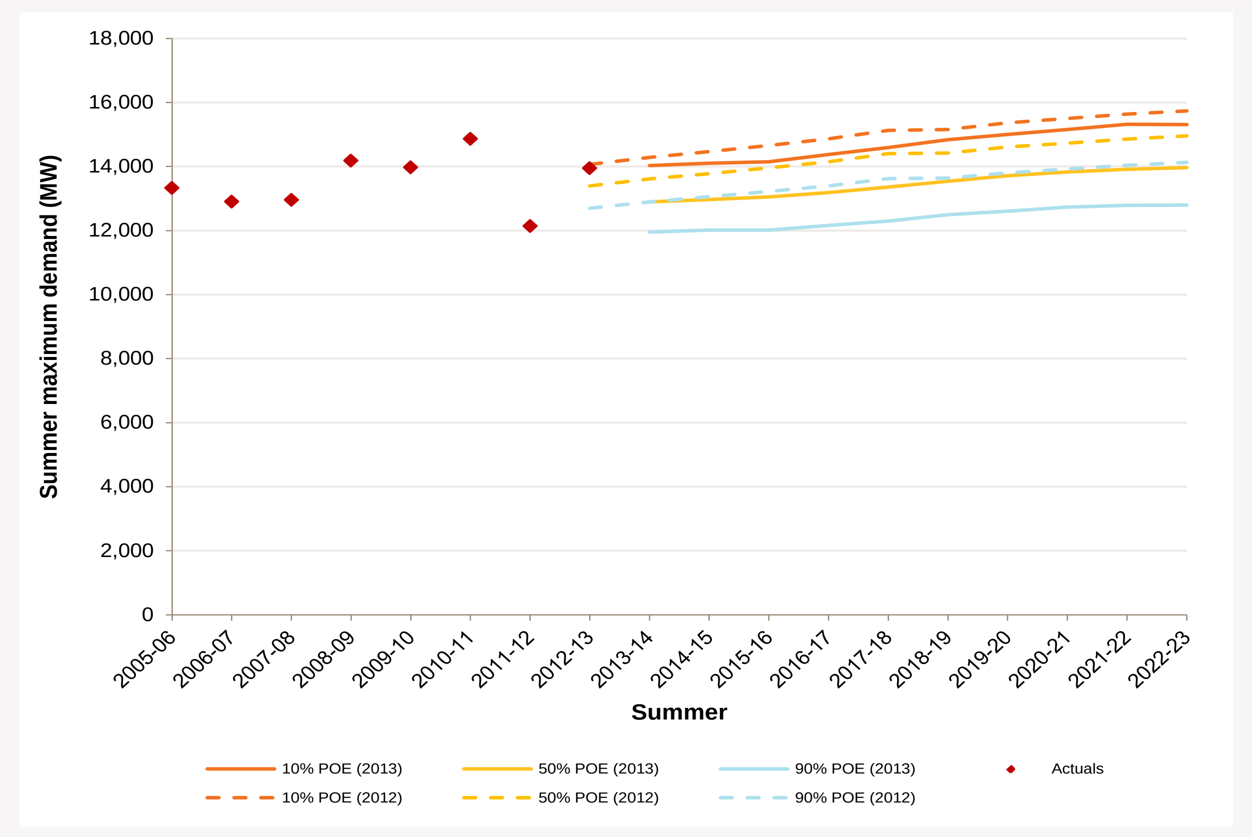
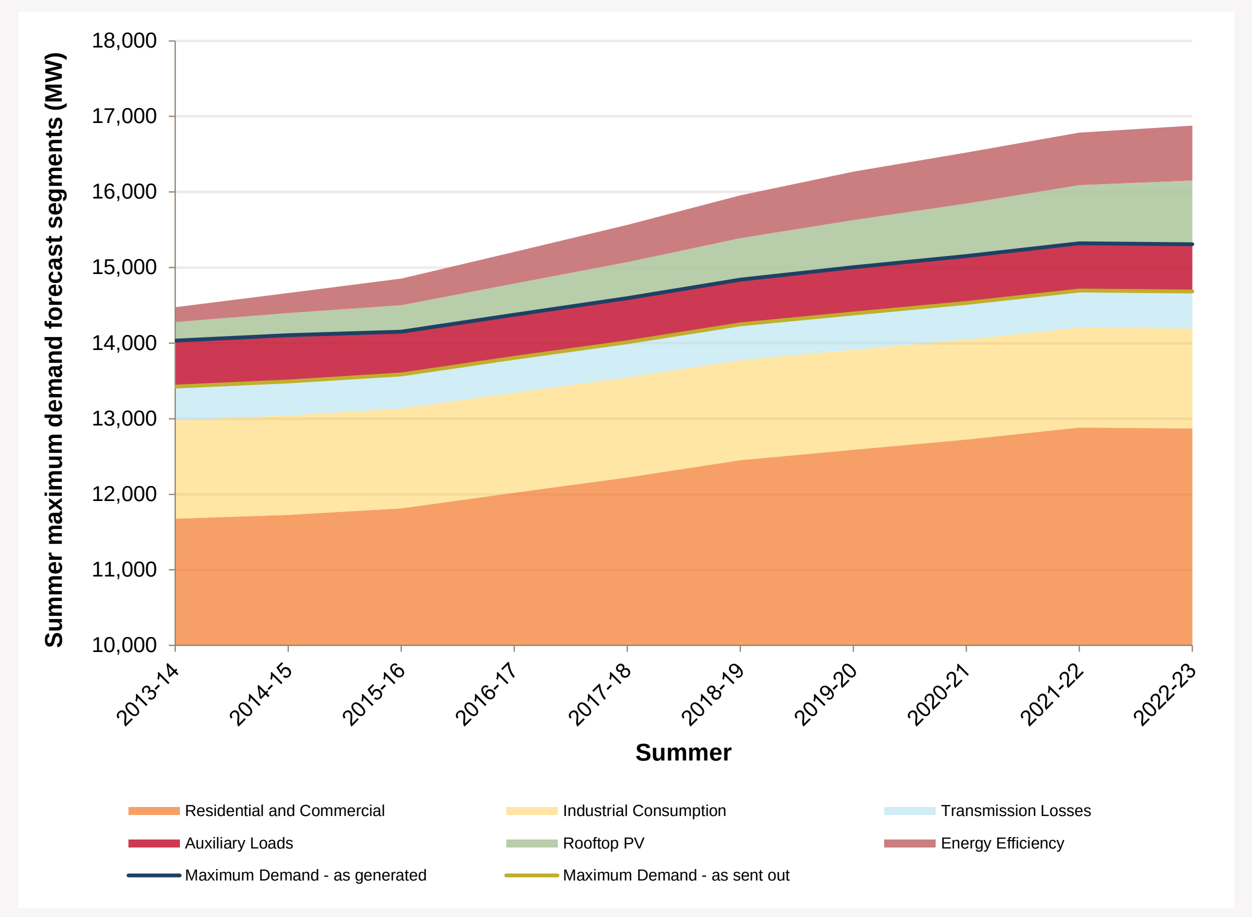


Table 4-2 — Summer 90%, 50% and 10% POE MD forecasts for New South Wales (MW)

	Actual	90% POE	50% POE	10% POE
2012–13 (estimate)	13,946			
2013–14		11,953	12,893	14,033
2014–15		12,011	12,971	14,103
2015–16		12,018	13,046	14,152
2016–17		12,163	13,185	14,377
2017–18		12,296	13,357	14,594
2018–19		12,492	13,544	14,840
2019–20		12,600	13,709	15,006
2020–21		12,734	13,831	15,151
2021–22		12,783	13,914	15,322
2022–23		12,795	13,964	15,309
Average annual growth		0.8%	0.9%	1.0%

4.4.2 Summer 10% POE maximum demand forecast segments

Figure 4-4 — Summer 10% POE maximum demand forecasts segments for New South Wales



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CHAPTER 5 - SOUTH AUSTRALIA FORECASTS

5.1 Annual energy forecasts

From 2008–09 to 2012–13, annual energy declined by 543 GWh (a 1.0% annual average decline) to 13,144 GWh.

Key differences between the 2013 National Electricity Forecasting Report (NEFR) and the 2012 NEFR annual energy forecasts include the following:

- **Current estimate for 2012–13:** The current estimate for 2012–13 annual energy, at 13,144 GWh, is materially unchanged, at 113 GWh (0.9%) higher than the 2012 NEFR medium forecast.
- **Medium forecast from 2013–14 to 2022–23:** Annual energy is forecast to decrease by an annual average of 0.1%, compared to an average 0.7% increase in the 2012 NEFR.
- **Lower spread between low, medium and high scenarios:** All three scenarios in the 2013 forecast are below the medium scenario in the 2012 NEFR.

Key drivers contributing to annual energy forecast change

- Significant downward revision in large industrial annual energy resulting from the Olympic Dam expansion deferral.
- Downward revision of residential and commercial forecasts due to increases in rooftop photovoltaic (PV) penetration forecasts and energy efficiency offsets. The declining annual energy trajectory to around 2017–18 is driven primarily by higher electricity prices in the first half of the outlook period and a decrease in overall population from the 2012 forecast. After 2017–18, annual energy flattens and grows slightly due to more stable electricity price growth after 2019–20 and positive population growth.
- The difference (or spread) between low, medium and high scenarios is much smaller due primarily to the change in major industrial load forecast methodology and the assumptions around Olympic Dam.

5.2 Maximum demand forecasts

Key differences between summer maximum demand (MD) forecasts in the 2013 and 2012 NEFRs are:

- 2012–13 summer MD was 3,158 MW on 18 February 2013. This was 113 MW below the 2012 NEFR 10% probability of exceedence (POE) forecast.
- The 2013–14 summer MD 10% POE forecast under the medium scenario is 78 MW below the 2012 forecast, due to the Olympic Dam expansion deferral, and increased energy efficiency offset and rooftop PV installations.
- The 10% POE MD is forecast to remain stable from 2013–14 to 2022–23 under the medium scenario, compared to 0.8% growth in the 2012 NEFR. This is driven by limited growth in large industrial demand, lower total population, and increasing offsets due to energy efficiency and rooftop PV.

Key drivers contributing to MD forecast change

- Increased impact of energy efficiency offsets, driven by the inclusion of building standards.
- Decreased large industrial forecasts due to revised projections from direct consultation with major industrial customers and the deferral of the Olympic Dam expansion by BHP Billiton.
- Lower population projections in the 2013–14 forecast.
- Higher rooftop PV forecasts.

- Greater spread between low, medium and high scenarios for the MD forecasts, is due primarily to the inclusion of additional variables in the MD forecasting, such as cooling degree days and heating degree days (CDD and HDD). This allows for extra temperature-related variations in MD caused by consistently hotter or cooler summers/winters.
- The smaller spreads between the medium and high scenario for the annual energy forecasts is due to the Olympic Dam expansion deferral, slowing operation to normal levels with non-significant increases for the high scenario. This is based on information provided by industry.

5.3 Annual energy

5.3.1 Annual energy forecast

Figure 5-1 — Annual energy forecasts for South Australia

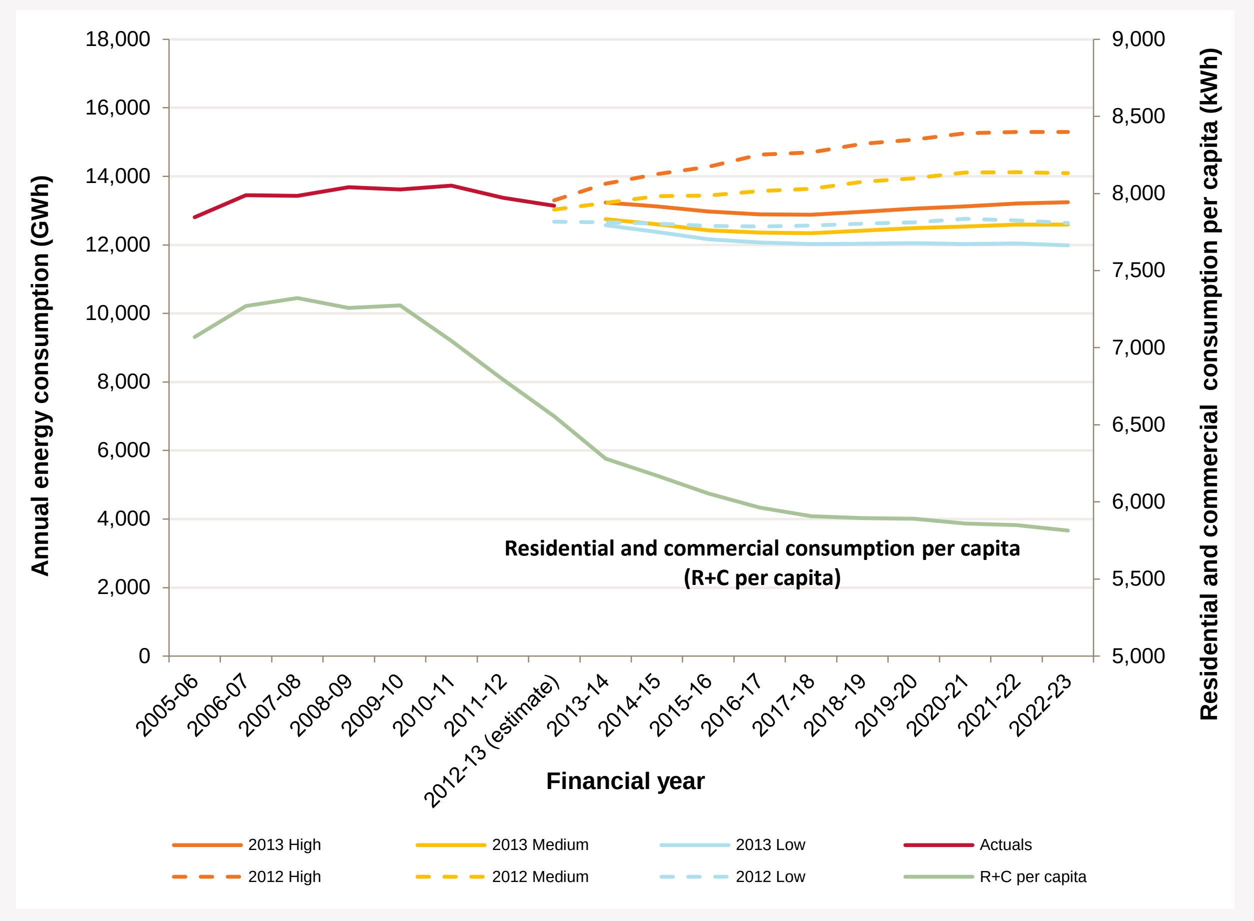
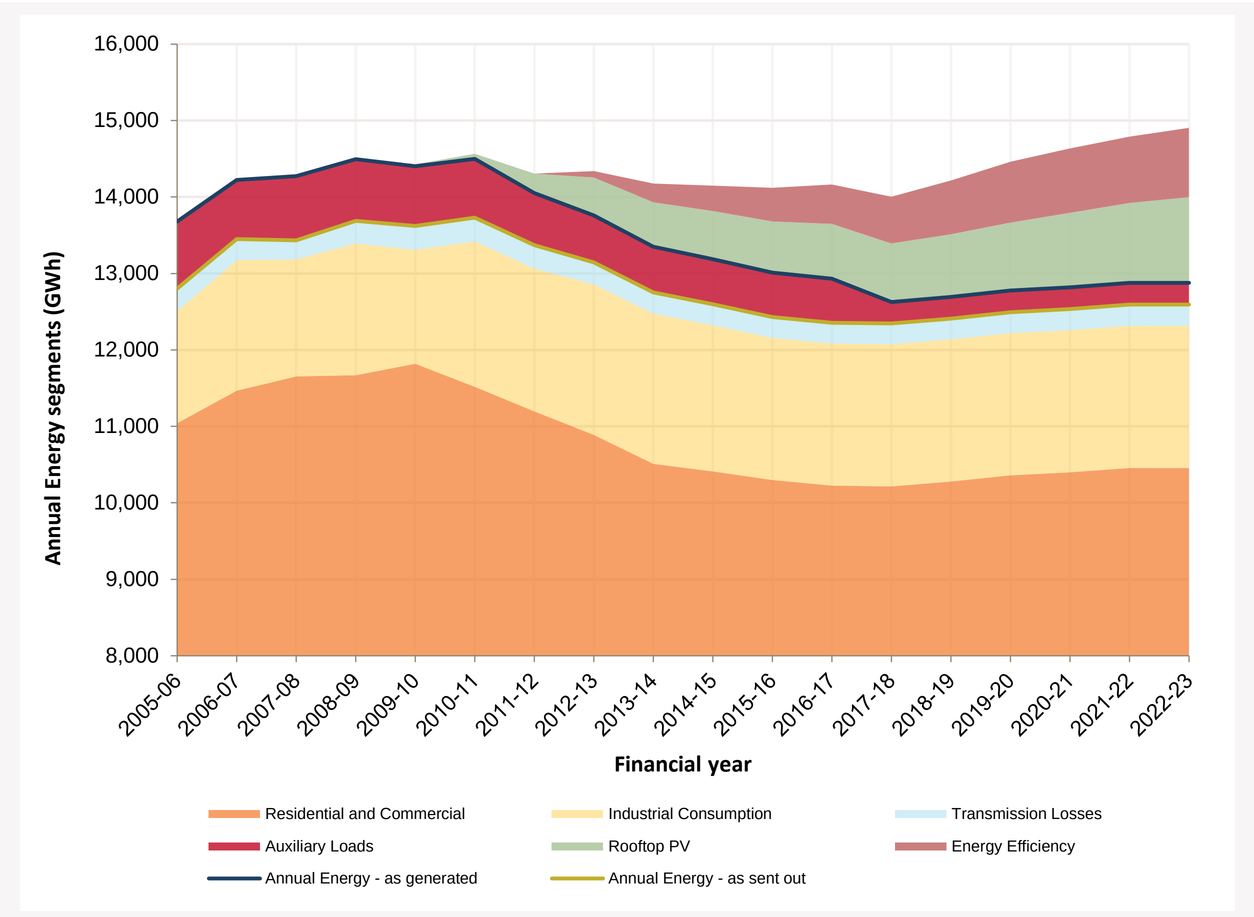


Table 5-1 — Annual energy forecasts for South Australia (GWh)

	Actual	High	Medium	Low
2012–13 (estimate)	13,144			
2013–14		13,238	12,753	12,573
2014–15		13,126	12,598	12,378
2015–16		12,973	12,429	12,167
2016–17		12,892	12,355	12,070
2017–18		12,883	12,345	12,026
2018–19		12,966	12,410	12,036
2019–20		13,062	12,493	12,047
2020–21		13,119	12,534	12,021
2021–22		13,203	12,591	12,040
2022–23		13,246	12,591	11,987
Average annual growth		0.0%	-0.1%	-0.5%

5.3.2 Annual energy forecast segments

Figure 5-2 — Annual energy forecasts segments for South Australia



5.4 Maximum demand

5.4.1 Summer maximum demand forecasts

Figure 5-3 — Summer 90%, 50% and 10% POE MD forecasts for South Australia

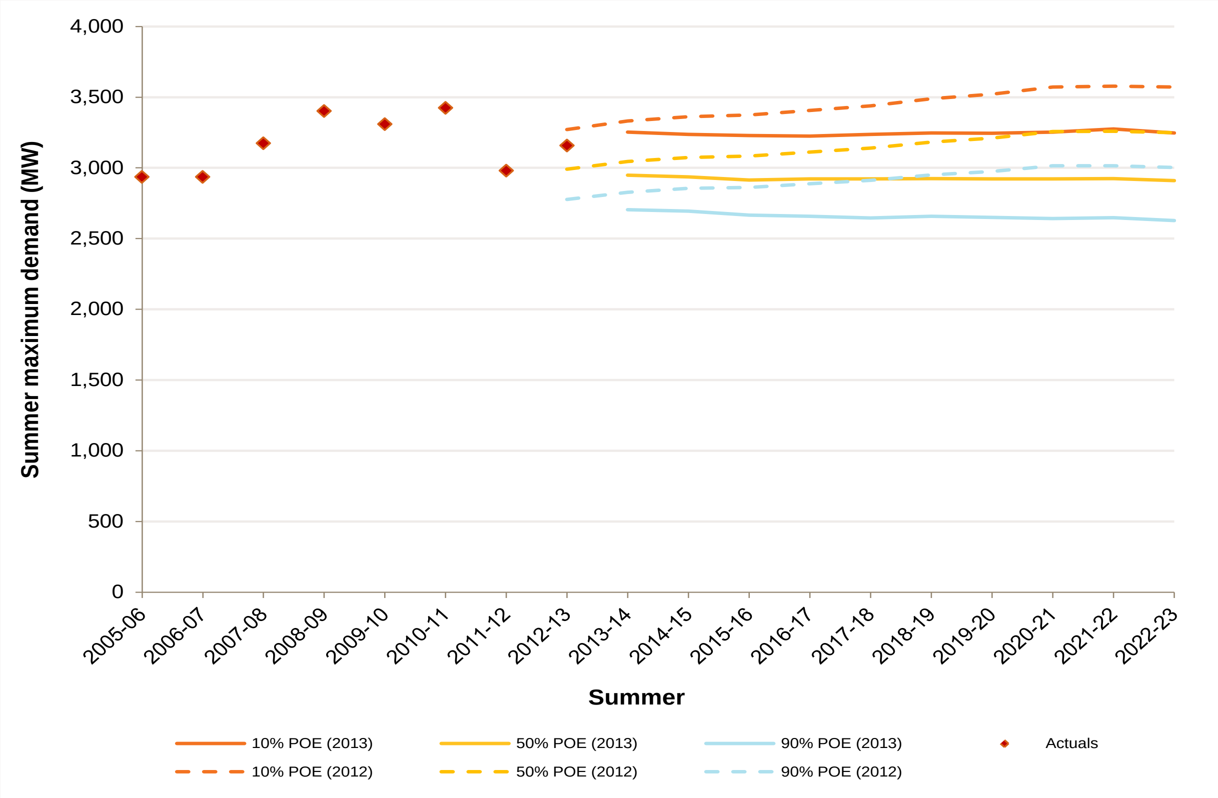
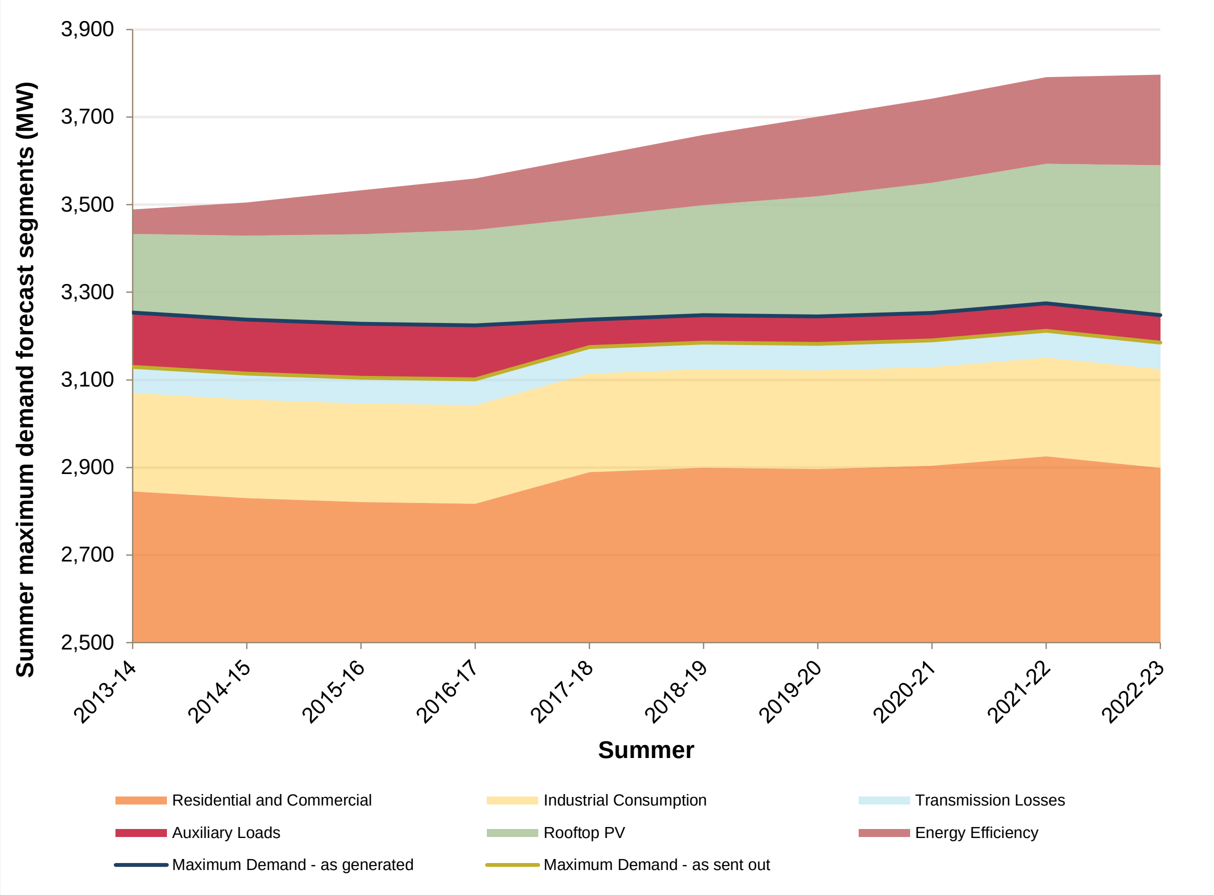


Table 5-2 — Summer 90%, 50% and 10% POE MD forecasts for South Australia (MW)

	Actual	90% POE	50% POE	10% POE
2012–13 (estimate)	3,158			
2013–14		2,705	2,948	3,254
2014–15		2,694	2,937	3,238
2015–16		2,667	2,914	3,228
2016–17		2,658	2,923	3,224
2017–18		2,645	2,921	3,237
2018–19		2,658	2,924	3,248
2019–20		2,650	2,922	3,245
2020–21		2,641	2,922	3,253
2021–22		2,648	2,925	3,275
2022–23		2,627	2,910	3,248
Average annual growth		-0.3%	-0.1%	0.0%

5.4.2 Summer 10% POE maximum demand forecast segments

Figure 5-4 — Summer 10% POE maximum demand segments for South Australia



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CHAPTER 6 - VICTORIA FORECASTS

6.1 Annual energy forecasts

From 2008–09 to 2012–13, annual energy declined by 855 GWh (an annual average decrease of 0.4%) to 47,129 GWh.

Key differences between the 2013 National Electricity Forecasting Report (NEFR) and the 2012 NEFR annual energy forecasts include the following:

- **Current estimate for 2012–13:** The current estimate for 2012–13 annual energy, at 47,129 GWh, is materially unchanged, at 381 GWh (0.8%) lower than the 2012 NEFR medium forecast.
- **Medium forecast from 2013–14 to 2022–23:** The 2013 forecast average annual growth rate of 1.0% is slightly lower than the 2012 forecast (1.3%).

Key drivers contributing to annual energy forecast change

- Decreased residential and commercial energy consumption due to higher retail electricity price forecasts, occurring in the short term (2013–15).
- Increased rooftop photovoltaic (PV) and energy efficiency offsets are also expected to reduce annual energy over the entire forecast period.
- Decreased large industrial forecasts over the entire forecast period.

6.2 Maximum demand forecasts

Key differences between summer maximum demand (MD) forecasts in the 2013 and 2012 NEFRs include the following:

- The 2012–13 summer MD was 9,793 MW on 12 March 2013. This was 103 MW above the 2012 NEFR 50% probability of exceedence (POE) forecast.
- The 2013–14 summer MD 10% POE forecast under the medium scenario is 347 MW below the 2012 forecast.
- The 10% POE MD is forecast to increase from 2013–14 to 2022–23 at an annual average rate of 0.9% under the medium scenario, compared to 1.4% in the 2012 NEFR. This is driven by a downward revision of population growth, increased energy efficiency scheme impacts, and increased rooftop PV generation relative to 2012 NEFR.

Key drivers contributing to MD forecast change

- Wonthaggi desalination plant assumptions changes. The plant is now assumed to not operate beyond normal operation at peak times.
- Decreased residential and commercial consumption; this is mainly due to decreased population projections, as well as increased impact of energy efficiency, driven by the inclusion of building standard schemes not included in last year’s forecast.
- Decreased auxiliary load due to generation displacement to less carbon-intensive generation occurs over the forecast period in support of the Renewable Energy Target (RET) scheme.
- The smaller spreads between the medium and high scenario for the annual energy forecasts is due to large industrial projects operating close to maximum capacity (medium scenario) and at maximum capacity (high scenario), based on information provided by industry.

6.3 Annual energy

6.3.1 Annual energy forecast

Figure 6-1 — Annual energy forecasts for Victoria

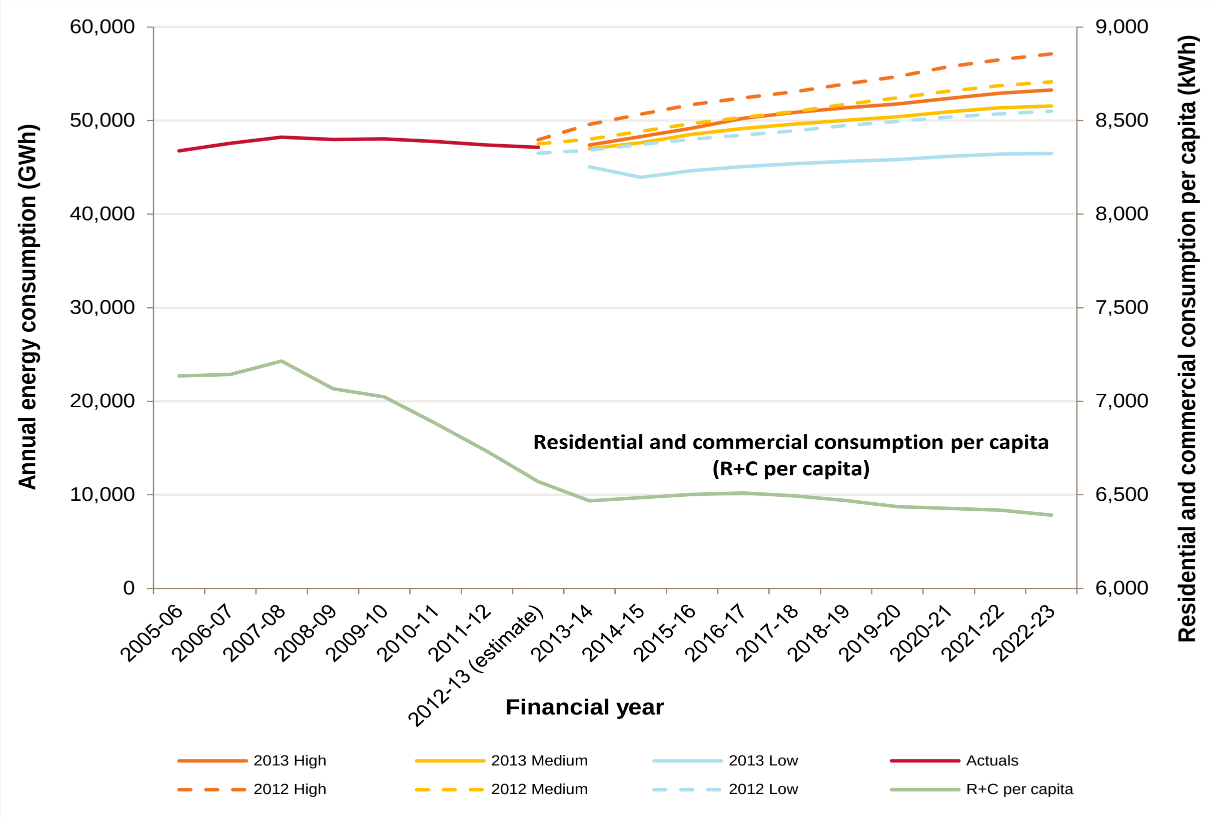
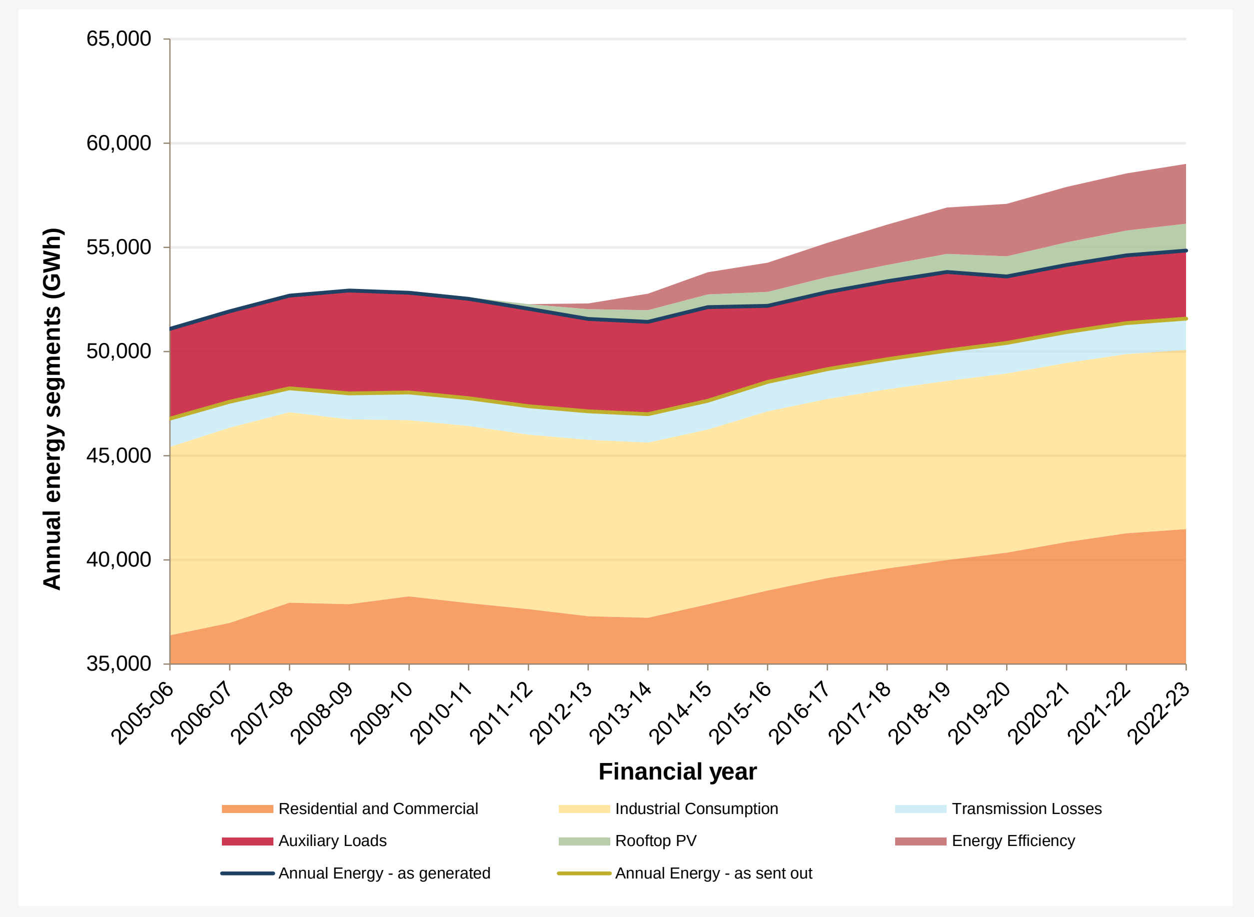


Table 6-1 — Annual energy forecasts for Victoria (GWh)

	Actual	High	Medium	Low
2012–13 (estimate)	47,129			
2013–14		47,383	46,993	45,062
2014–15		48,293	47,638	43,927
2015–16		49,194	48,537	44,632
2016–17		50,244	49,148	45,076
2017–18		50,871	49,624	45,386
2018–19		51,359	50,041	45,658
2019–20		51,764	50,408	45,841
2020–21		52,351	50,931	46,158
2021–22		52,912	51,365	46,432
2022–23		53,266	51,572	46,481
Average annual growth		1.3%	1.0%	0.3%

6.3.2 Annual energy forecast segments

Figure 6-2 — Annual energy forecasts segments for Victoria



6.4 Maximum demand

6.4.1 Summer maximum demand forecasts

Figure 6-3 — Summer 90%, 50% and 10% POE maximum demand forecasts for Victoria

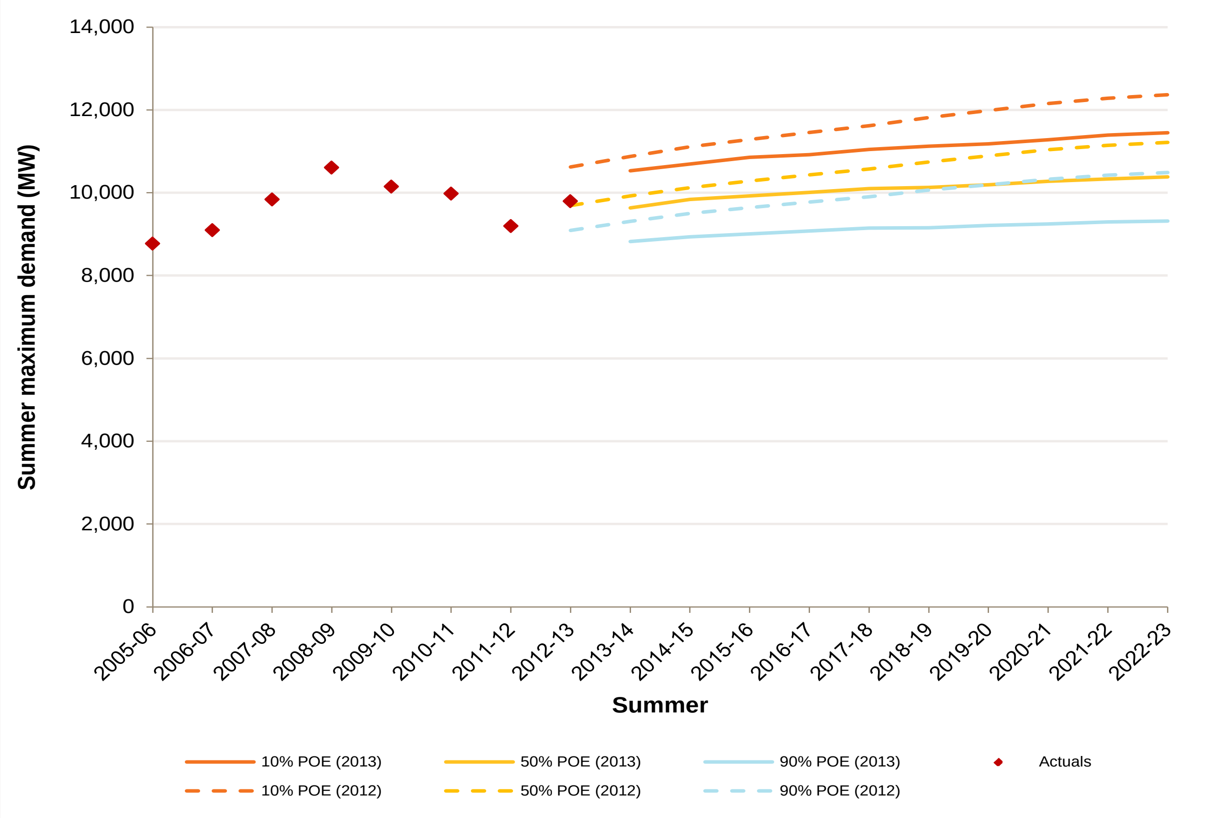
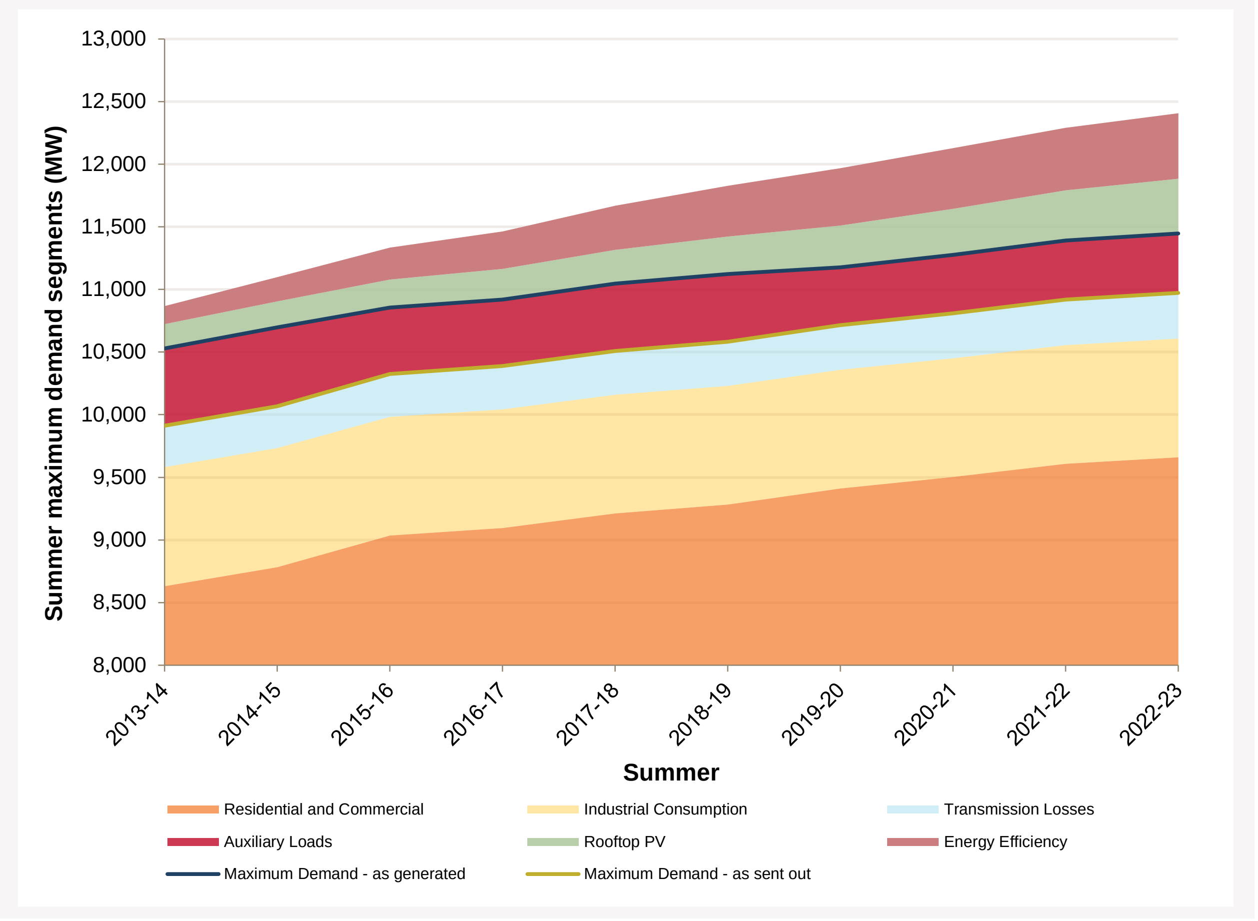


Table 6-2 — Summer 90%, 50% and 10% POE maximum demand forecasts for Victoria (MW)

	Actual	90% POE	50% POE	10% POE
2012–13 (estimate)	9,793			
2013–14		8,821	9,637	10,530
2014–15		8,933	9,838	10,697
2015–16		9,006	9,924	10,855
2016–17		9,078	10,010	10,920
2017–18		9,149	10,104	11,046
2018–19		9,156	10,129	11,123
2019–20		9,211	10,191	11,177
2020–21		9,248	10,274	11,276
2021–22		9,295	10,333	11,390
2022–23		9,320	10,385	11,446
Average annual growth		0.6%	0.8%	0.9%

6.4.2 Summer 10% POE maximum demand forecast segments

Figure 6-4 — Summer 10% POE maximum demand segments for Victoria



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CHAPTER 7 - TASMANIA FORECASTS

7.1 Annual energy forecasts

From 2008–09 to 2012–13, annual energy decreased by 732 GWh (an annual average of 1.7%) to 10,247 GWh.

Key differences between the 2013 National Electricity Forecasting Report (NEFR) and the 2012 NEFR annual energy forecasts include the following:

- **Current estimate for 2012–13:** The current estimate for 2012–13 annual energy, at 10,247 GWh, is 218 GWh (2.1%) below the 2012 NEFR medium forecast.
- **Medium forecast from 2013–14 to 2022–23:** The 2013 forecast decreases by an annual average of 0.2%. This is lower than the 2012 forecast of 1.0% growth, driven by lower population growth assumption of 0.5% (2012 forecast: 0.7%) and lower state income of 0.8% (2012 forecast: 2.3%).

Key drivers contributing to annual energy forecast change

- Decreased residential and commercial forecasts, driven by lower population growth and lower state income growth.
- Additional rooftop photovoltaic (PV) penetration and energy efficiency offsets.

7.2 Maximum demand forecasts

Key differences between winter maximum demand (MD) forecasts in the 2013 and 2012 NEFRs include the following:

- 2012 winter MD was 1,684 MW on 6 August 2012. This was 49 MW below the 2012 NEFR 90% probability of exceedence (POE) forecast, due to lower-than-expected industrial demand and residential and commercial consumption.
- The 2013 winter MD 10% POE forecast under the medium scenario is 3 MW below the 2012 forecast.
- The 10% POE MD is forecast to increase from 2013–22 at an annual average rate of 0.1% under the medium scenario, compared to 1.3% in the 2012 NEFR. It is forecast to decrease from 2013–17 at an annual average of 0.6%. This is driven by increases in energy efficiency forecasts (from 0 to 41 MW) in the 2013 NEFR, which will dampen MD, as well as decreases in commercial and residential consumption by an annual average of 1.0% primarily due to modest population growth at 0.5% (2012 forecast: 0.8%).
- The 10% POE MD is forecast to increase from 2018–22 at an annual average of 0.5%, driven by an annual average increase of 0.7% in commercial and residential consumption due to moderation in retail electricity prices and improved state income growth.

Key drivers contributing to MD forecast change

- Increased impact of energy efficiency offsets, driven by the inclusion of building standards.
- Revised large industrial forecasts due to direct consultation with major industrial customers.
- Decreased residential and commercial consumption due to lower population forecasts.
- The smaller spreads between the medium and high scenario for the annual energy forecasts is due to large industrial projects operating close to maximum capacity (medium scenario) and at maximum capacity (high scenario), based on information provided by industry.

7.3 Annual energy

7.3.1 Annual energy forecast

Figure 7-1 — Annual energy forecasts for Tasmania

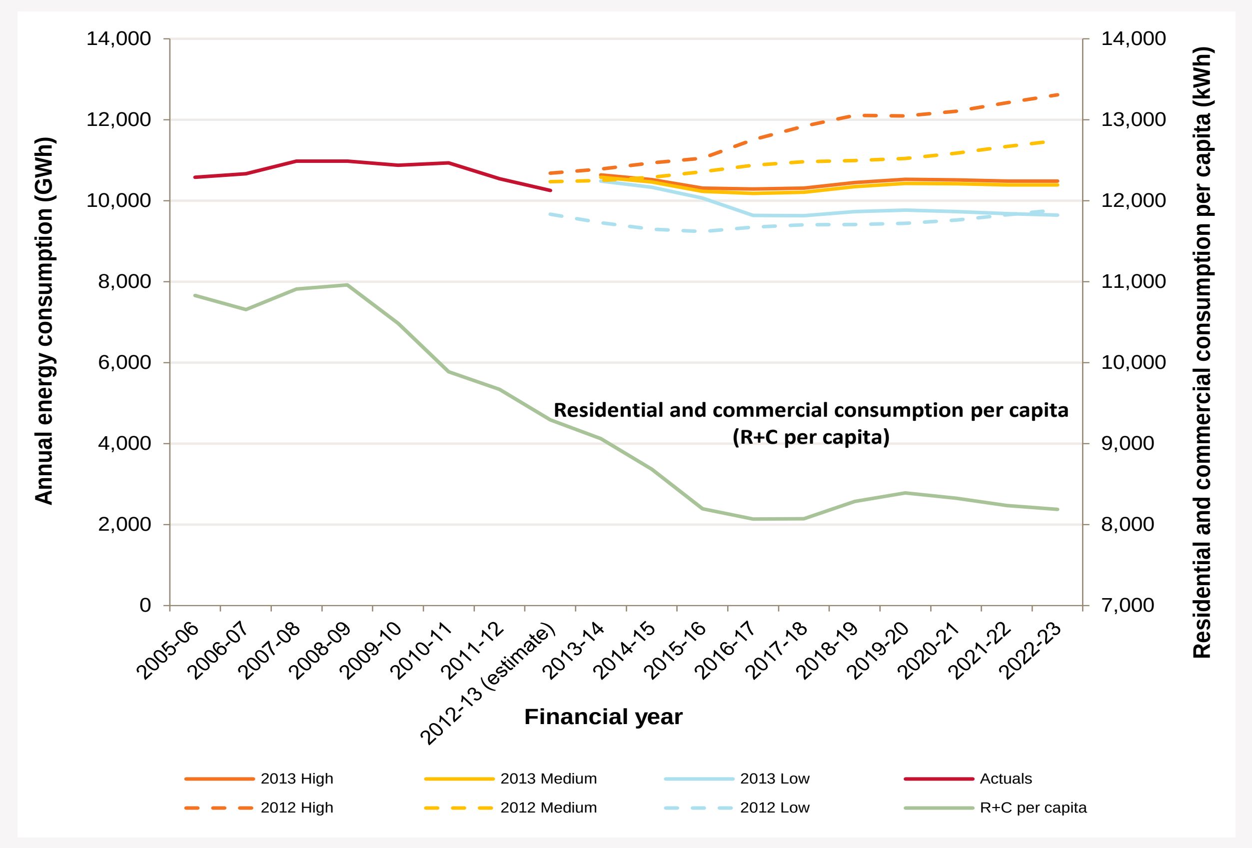
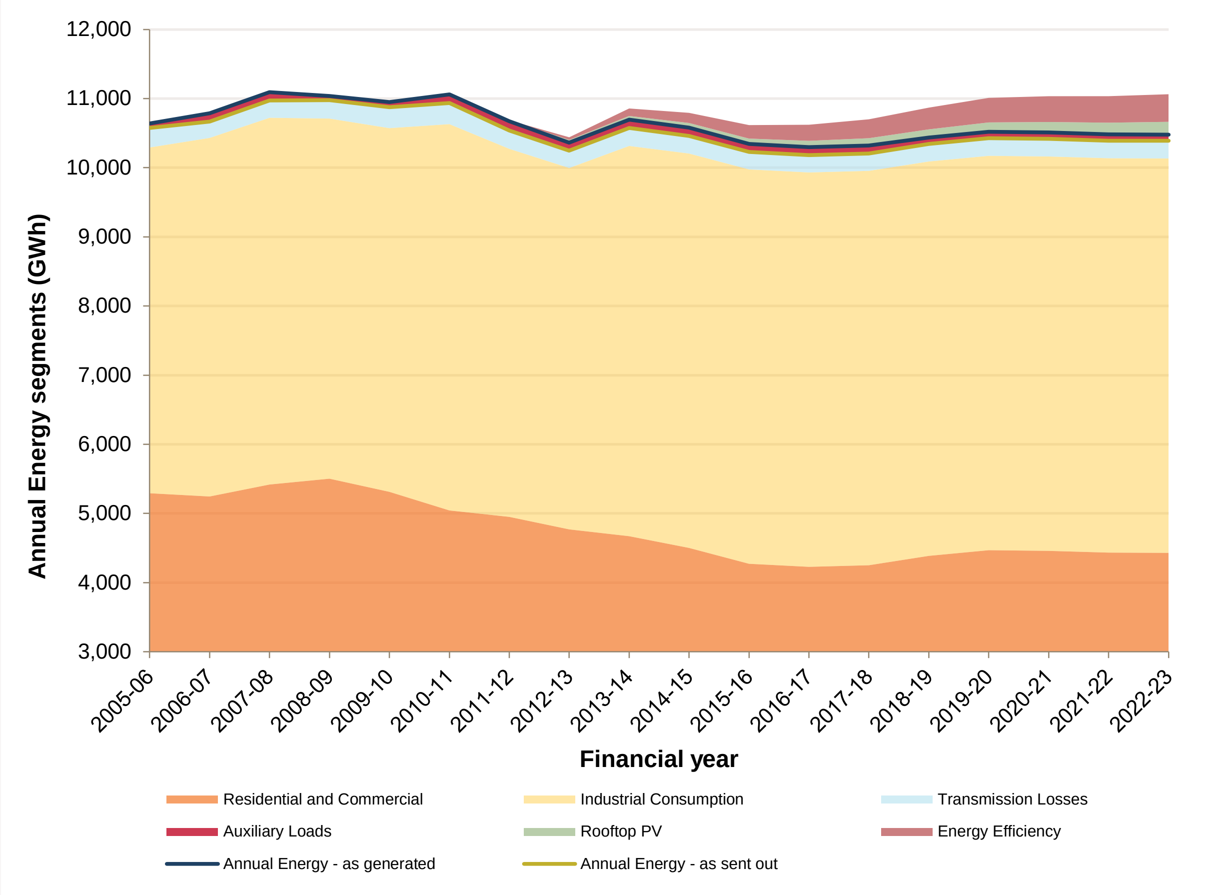


Table 7-1 — Annual energy forecasts for Tasmania (GWh)

	Actual	High	Medium	Low
2012–13 (estimate)	10,247			
2013–14		10,634	10,574	10,480
2014–15		10,522	10,462	10,329
2015–16		10,311	10,227	10,063
2016–17		10,284	10,181	9,632
2017–18		10,311	10,205	9,629
2018–19		10,445	10,344	9,726
2019–20		10,523	10,428	9,769
2020–21		10,513	10,418	9,731
2021–22		10,486	10,392	9,675
2022–23		10,485	10,388	9,645
Average annual growth		-0.2%	-0.2%	-0.9%

7.3.2 Annual energy forecast segments

Figure 7-2 — Annual energy forecasts segments for Tasmania



7.4 Maximum demand

7.4.1 Winter maximum demand forecasts

Figure 7-3 — Winter 90%, 50% and 10% POE maximum demand forecasts for Tasmania

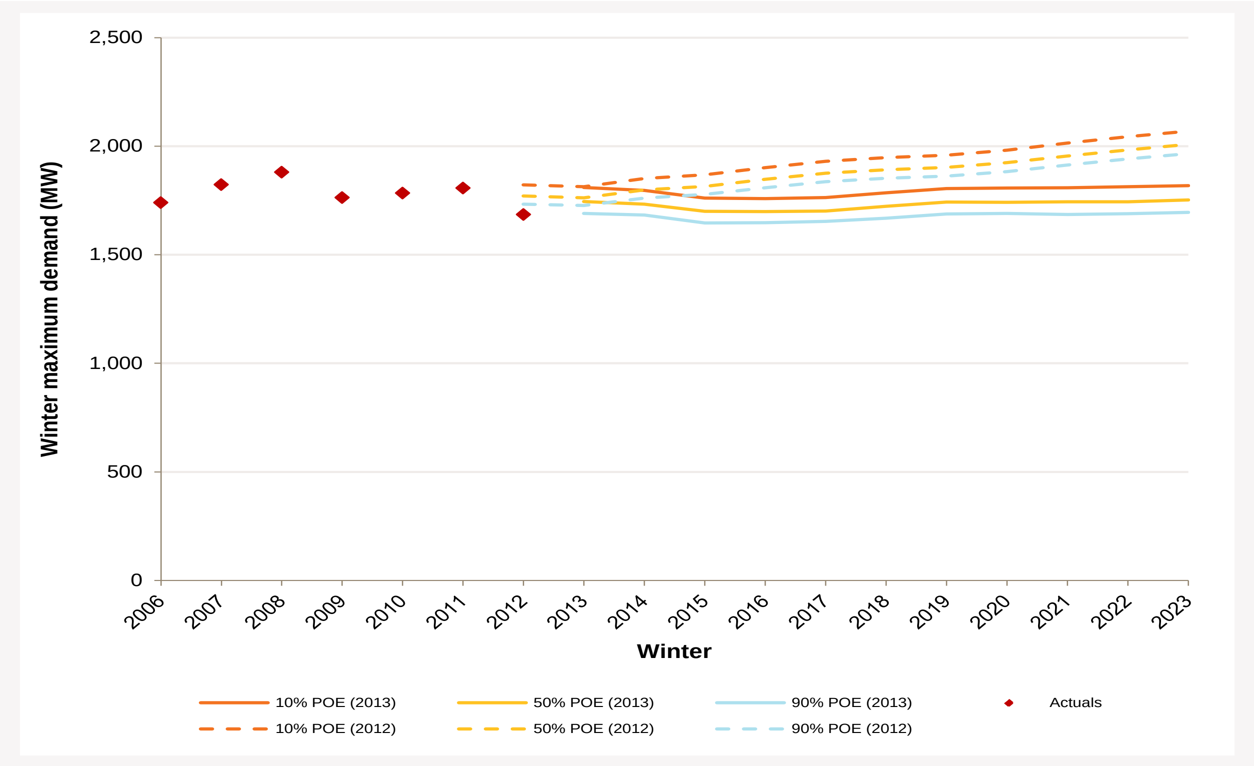
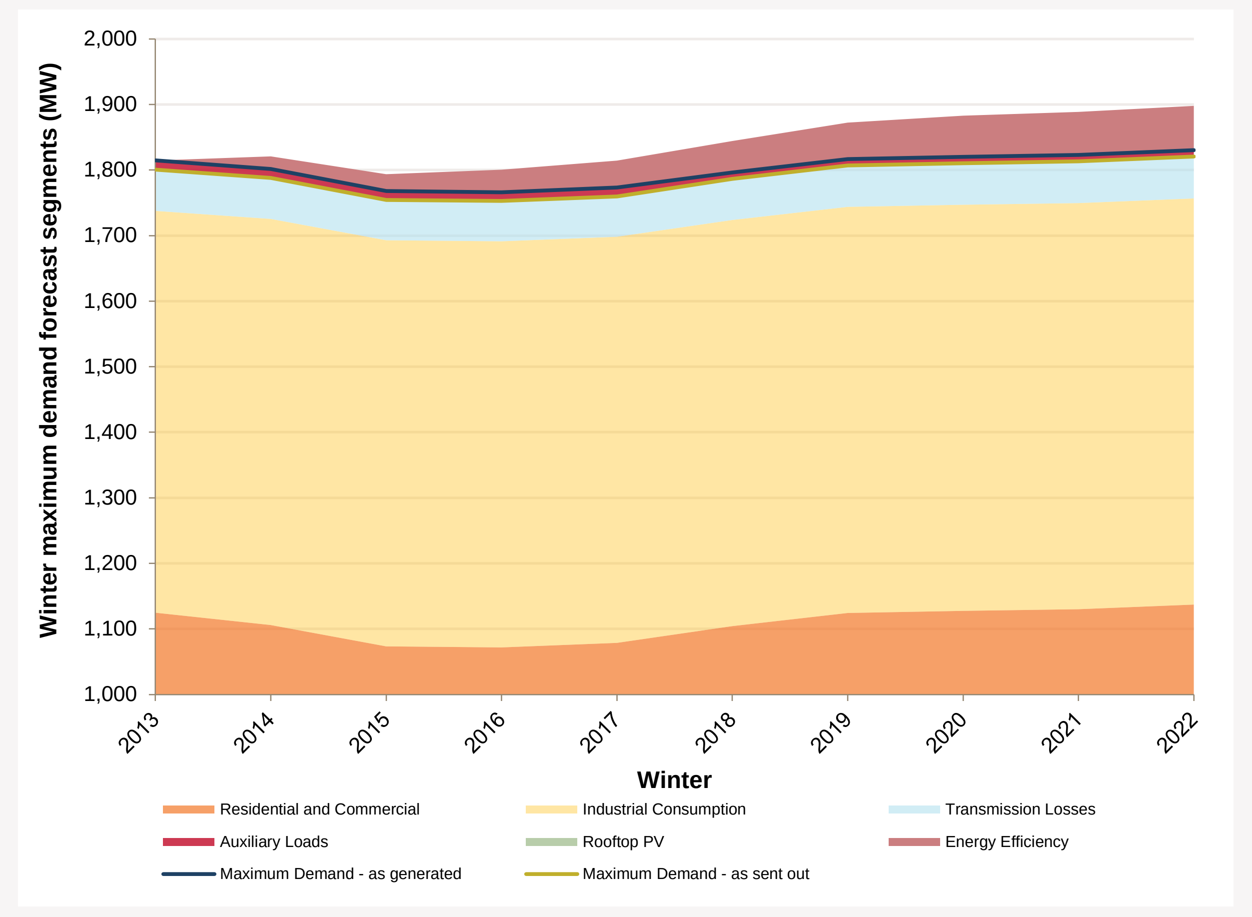


Table 7-2 — Winter 90%, 50% and 10% POE maximum demand forecasts for Tasmania (MW)

	Actual	90% POE	50% POE	10% POE
2012	1,684			
2013		1,695	1,750	1,815
2014		1,689	1,739	1,802
2015		1,653	1,707	1,768
2016		1,655	1,707	1,766
2017		1,663	1,711	1,773
2018		1,679	1,734	1,796
2019		1,700	1,755	1,817
2020		1,703	1,755	1,820
2021		1,700	1,759	1,823
2022		1,706	1,760	1,830
Average annual growth		0.1%	0.1%	0.1%

7.4.2 Winter 10% POE maximum demand forecast segments

Figure 7-4 — Winter 10% POE maximum demand segments for Tasmania



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DISCLAIMER

Purpose

The 2013 National Energy Forecasting Report has been prepared by the Australian Energy Market Operator Limited (AEMO) in connection with its national transmission planning and operational functions for the National Electricity Market. The report is based on information available as at 3 April, 2013, unless otherwise specified.

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Acknowledgements

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

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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

This document provides the glossary for the 2013 National Electricity Forecasting Report (NEFR).

Term	Definition
annualised average (growth rate)	The compound average growth rate, which is the year-over-year growth rate over a specified number of years.
annual energy	The amount of electrical energy consumed in a year.
as-generated	A measure of electricity demand or electrical energy at the terminals of a generating system. This measure includes electricity delivered to customers, transmission and distribution losses, and auxiliary load.
auxiliary load	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, and include loads to operate generating system co-located coal mines.
capacity factor	The output of generating units or systems, averaged over time, expressed as a percentage of rated or maximum output.
contribution factor	The rooftop PV power generation (in MW) as a percentage of the total rooftop PV (MW) installed capacity.
cooling degree days	A sum of the products of: • The time that a region experiences ambient temperatures above its threshold temperature; and • The number of degrees that the ambient temperature is above the threshold temperature.
deeming period (of STCs)	STCs can be claimed in advance for the electricity the system will displace over a future period. This is called a deeming period. Rooftop PV STCs, for example, may be created annually or at the start of each five year deeming period, or for a single 15 year deeming period.
demand-side participation (DSP)	The situation where customers vary their electricity consumption in response to a change in market conditions, such as the price of electricity. This encompasses both voluntary/reactionary and coordinated responses.
distribution losses	Electrical energy losses incurred in transporting electrical energy through a distribution system.
distribution network	A network that is not a transmission network.
distribution system	A distribution network, together with the connection assets associated with the distribution network (such as transformers), which is connected to another transmission or distribution system.
diversity factor	Refers to the ratio of the maximum demand of a connection point/terminal station to the demand of that connection point at the time of system peak. This is sometimes referred to as the demand factor, and is always less than or equal to one. When the diversity factor equals one, the connection point peak coincides with the system peak.
electrical energy	The average electrical power over a time period, multiplied by the length of the time period.
electrical power	The instantaneous rate at which electrical energy is consumed, generated or transmitted.
electricity demand	The electrical power requirement met by generating units.

Term	Definition
energy efficiency	Potential annual energy or maximum demand that is mitigated by the introduction of energy efficiency measures.
feed-in tariff	A tariff paid to consumers for electrical energy they export to the network, such as rooftop PV output that exceeds the consumers' load.
generating system	A system comprising one or more generating units and additional plant that is located on the generator's side of the connection point.
generating unit	The plant that generates 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.
gross domestic product (GDP)	A measure of the final goods and services produced within a country in a given period of time.
gross state product (GSP)	A measure of the final goods and services produced within a state or region in a given period of time.
heating degree days (HDD)	A sum of the products of: • The time that a region experiences ambient temperatures below its threshold temperature; and • The number of degrees that the ambient temperature is below the threshold temperature.
installed capacity	The generating capacity (in megawatts (MW)) of the following (for example): • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region. Rooftop PV installed capacity is the total amount of cumulative rooftop PV capacity installed at any given time.
large industrial load (annual energy or maximum demand)	There are a small number of large industrial loads—typically transmission-connected customers—that account for a large proportion of annual energy in each National Electricity Market (NEM) region. They generally maintain consistent levels of annual energy and maximum demand in the short term, and are weather insensitive. Significant changes in large industrial load occur when plants open, expand, close, or partially close.
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 duration curve (LDC)	A curve showing the distribution of a load trace after the data has been sorted in descending order according to the size of the load.
load factor	The ratio of average demand to maximum demand. This is calculate d by dividing average demand (MW) over the summer/winter period (Oct-Mar or Apr-Sep) the maximum demand for the same period.
mass market load (annual energy or maximum demand)	The annual energy or maximum demand relating to all consumers except large industrial load. Mass market load is the load on the network, after savings from energy efficiency and rooftop PV output have been taken into account. Includes light industrial load.
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.

Term	Definition
National Electricity Market (NEM)	The wholesale exchange of electricity operated by AEMO under the National Electricity Rules (NER).
native electrical energy	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled and small non-scheduled generating units.
network service provider (transmission – TNSP; distribution – DNSP)	A person who engages in the activity of owning, controlling, or operating a transmission or distribution system.
non-scheduled generating unit	A generating unit that does not have its output controlled through the central dispatch process and that is classified as a non-scheduled generating unit in accordance with Chapter 2 of the National Electricity Rules (NER).
on-site generation	Generation, generally small-scale, that is co-located with a major load, such as combined heat and power systems at industrial plants.
operational electrical energy	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, less the electrical energy supplied by small non-scheduled generation.
payback period	The time required for the return on an investment to equal the original investment amount.
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.
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 National Electricity Rules (NER).
Renewable Energy Target (RET)	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.
residential and commercial load (annual energy or maximum demand)	The annual energy or maximum demand relating to all consumers except large industrial load. Mass market load is the load on the network, after savings from energy efficiency and rooftop PV output have been taken into account. Includes light industrial load.
retail electricity price	The price paid by consumers to retailers for supplying them with electricity.
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.
saturation level	The estimated maximum rooftop PV capacity, reflecting the number of households, rooftop areas, and other siting factors.

Term	Definition
scenario	A consistent set of assumptions used to develop forecasts of demand, transmission, and supply.
scheduled generating unit	A generating unit that has its output controlled through the central dispatch process and that is classified as a scheduled generating unit in accordance with Chapter 2 of the National Electricity Rules (NER).
sent-out	A measure of demand or energy (in megawatts (MW) or 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.
semi-scheduled generating unit	A generating unit that has a total capacity of at least 30 MW, intermittent output, and may have its output limited to prevent violation of network constraint equations.
small non-scheduled generation (SNSG)	Non-scheduled generating units that generally have capacity less than 30 MW.
Small-scale Renewable Energy Scheme (SRES)	See ‘Renewable Energy Target (RET)’.
small-scale technology certificate (STC)	See ‘Renewable Energy Target (RET)’.
Small-scale Technology Certificate (STC) multiplier	A mechanism that multiplied the number of STCs that rooftop PV systems would usually create under the RET scheme. The multiplier ceased (was reduced to one) from 1 January 2013.
smart meter	An electricity meter that records electricity usage for discrete time intervals (such as for each 30-minute period) and automatically sends this data to the electricity supplier. Some smart meters have additional communications and load control functions.
state final demand (SFD)	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 and exports.
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).
transmission losses	Electrical energy losses incurred in transporting electrical energy through a transmission system.
transmission network	A network within any National Electricity Market (NEM) participating jurisdiction operating at nominal voltages of 220 kV and above plus: • (a) 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, • (b) 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	A transmission network, together with the connection assets associated with the transmission network (such as transformers), which is connected to another transmission or distribution system.
wholesale electricity price	Wholesale trading in electricity is conducted as a spot market, and the wholesale price is the spot price. It is based on the price that generators receive for generating electricity and the price that retailers pay for electricity they purchase. The spot price is the price in a trading interval (a 30-minute period) for one megawatt hour (MWh) of electricity at a regional reference node.
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
Arrium Limited	Arrium Limited (previously OneSteel)
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	Defence Support Centre 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
NorskHydro	NorskHydro Pty Ltd
OneSteel	OneSteel Ltd (now Arrium Limited)
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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