NATIONAL ELECTRICITY FORECASTING REPORT

FOR THE NATIONAL ELECTRICITY MARKET

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

The 2014 National Electricity 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. This report is based on information available as at June 2014, unless otherwise specified.

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EXECUTIVE SUMMARY

Annual energy outlook to 2016-17

Electricity consumption in the National Electricity Market (NEM) is declining and is forecast to continue its decline for the next three years, aside from some growth in Queensland as a result of liquefied natural gas (LNG).

Table 1 below provides the average annual growth in consumption for the next three years, noting the key drivers underpinning the forecasts.

Table 1 — Annual energy outlook to 2016-17

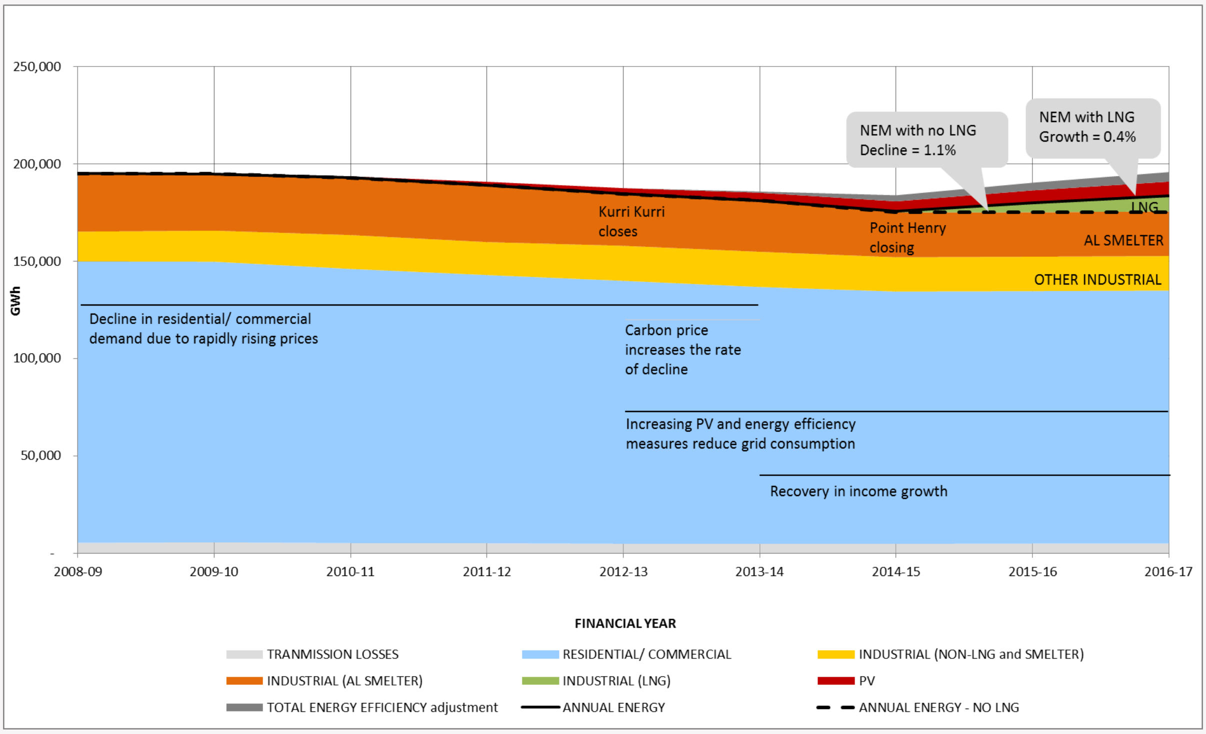
Annual energy - average annual growth			
	Total	**Large industrial**	**Residential and commercial**
NEM	0.4%	2.9%	-0.5%
NEM without LNG	-1.1%	-3.0%	-0.5%

Key Drivers:

- Increase in NEM electricity consumption is driven by LNG projects in Queensland.
- Decline in energy-intensive industries includes the Point Henry aluminium smelter closure in Victoria.
- Strong growth (24% annually) in rooftop PV installations, particularly in Queensland and Victoria.
- Strong growth (10% annually) in total energy efficiency savings, with key contributions from air conditioning, refrigeration and electronics.

The figure below provides a breakdown of the key forecast components.

Figure 1 — NEM annual energy forecast – key components



Queensland is the only region in the NEM experiencing industrial growth, due to LNG projects. It also has the strongest growth in rooftop PV installations, which drives down overall consumption from the grid.

New South Wales experiences a decline in consumption, due to reduced large industrial forecasts.

Victorian consumption is forecast to decline, driven by large industrial and manufacturing plant closures, including the Point Henry aluminium smelter in August 2014.

South Australian consumption is forecast to decline, with the desalination plant reducing consumption due to the completion of operational tests. Decreasing residential and commercial consumption is a result of the highest existing levels of installed rooftop PV per capita across the NEM.

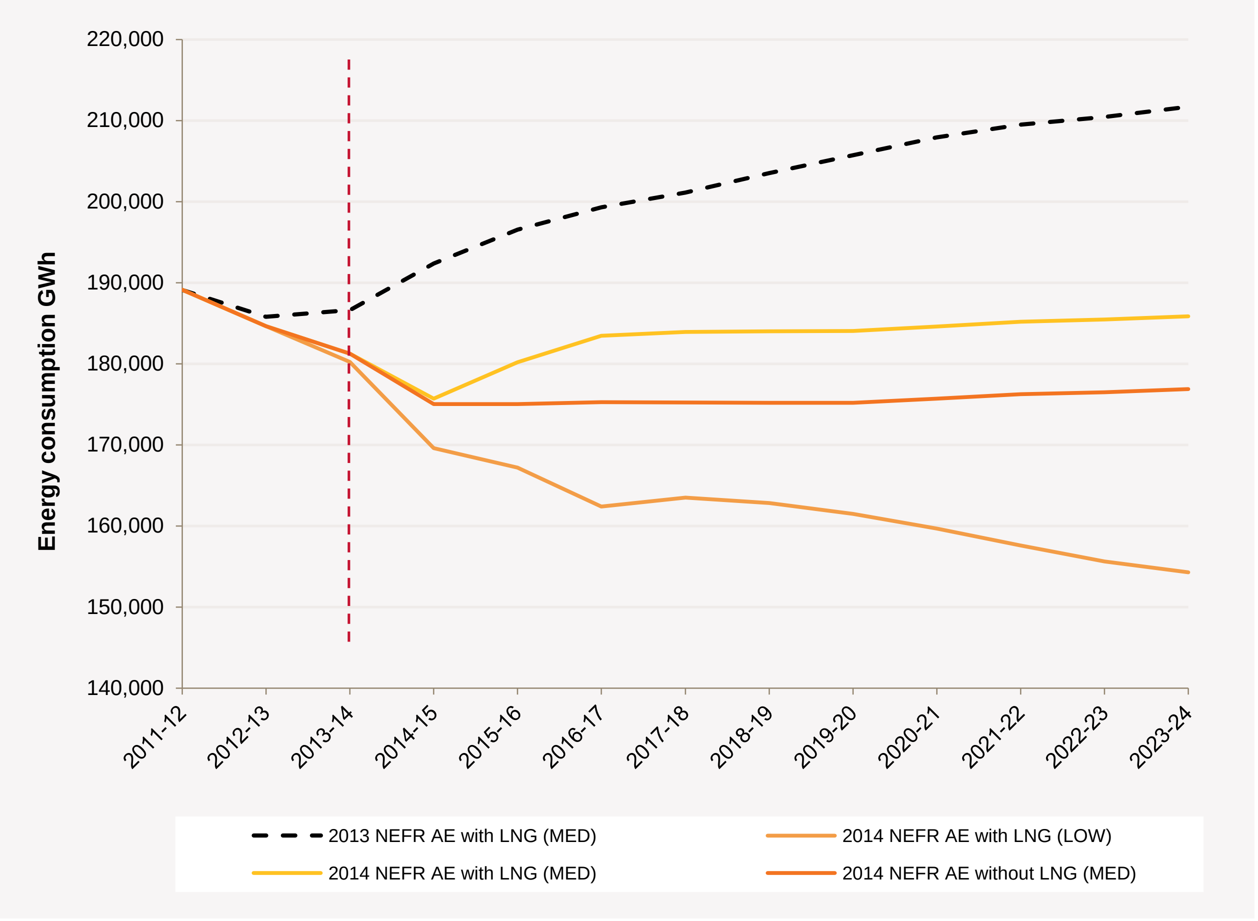
Tasmanian consumption is forecast to decline despite increased production at the Norske Skog Boyer paper mill. The decline reflects the lowest population growth in the NEM and high rooftop PV installations.

Annual energy outlook to 2023-24

Over the longer term, after the initial ramp-up due to LNG projects, NEM electricity consumption flattens.

To reflect the impact of unfavourable economic conditions on energy-intensive industries, the low scenario includes potential closures and reduced operations at existing aluminium smelters, as highlighted in Figure 2.

Figure 2 — NEM annual energy forecast 10-year outlook



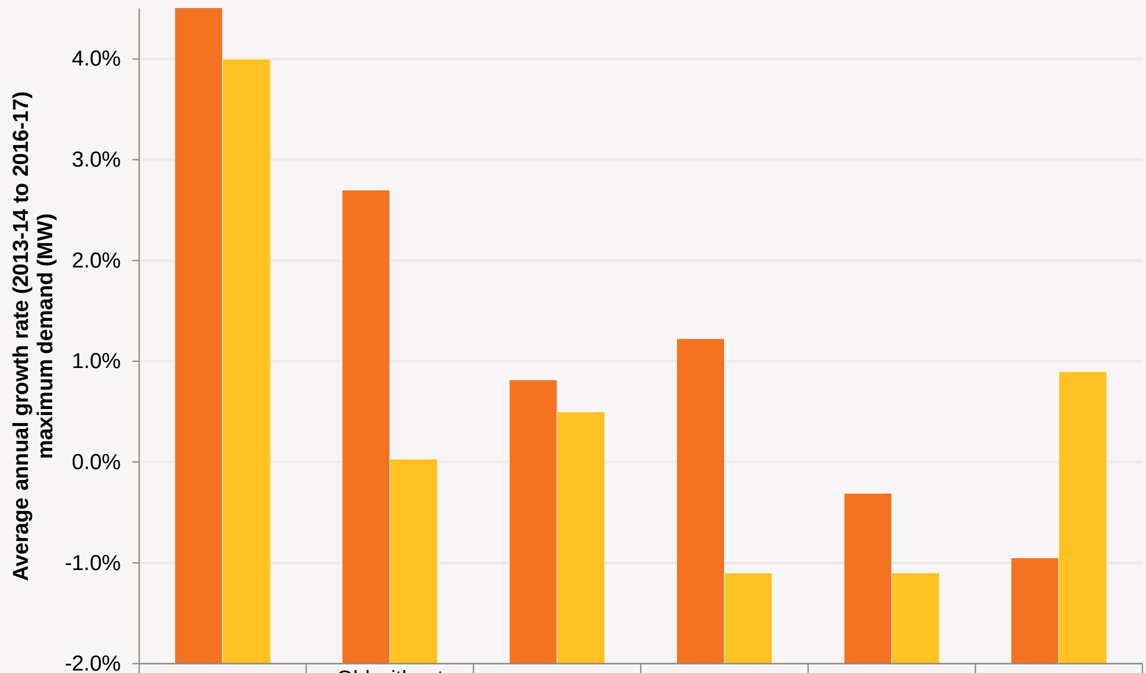
Maximum demand

Figure 3 compares the 2014 maximum demand forecasts for each NEM region against the 2013 NEFR forecasts, and provides the anticipated timing for a return to historical record maximum demands.

The forecasts show maximum demand growing at a marginally higher rate than annual energy in all regions except for Queensland. This leads to peakier maximum demands, shifting to later in the day due to rooftop PV, particularly in South Australia.

Only Queensland and New South Wales are expected to reach their historical record maximum demand within the long-term outlook period to 2034. Queensland reaches its historical record in 2015-16 due to LNG projects, and New South Wales in 2022-23 due to the lowest growth in rooftop PV installations across the NEM.

Figure 3 — Maximum demand growth in 2013 and 2014 NEFR



	Qld with LNG	Qld without LNG	NSW	Vic	SA	Tas
2013 NEFR	5.8%	2.7%	0.8%	1.2%	-0.3%	-0.9%
2014 NEFR	4.0%	0.03%	0.5%	-1.1%	-1.1%	0.9%
Return to historical record	2015-16	2021-22	2022-23	Beyond 2033-34	Beyond 2033-34	Beyond 2033-34

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CHAPTER 1 - ABOUT THE NEFR

1.1 National electricity forecasting

The National Electricity Forecasting Report (NEFR) provides independent electricity consumption forecasts for each National Electricity Market (NEM) region over a 10-year outlook period (2013–14 to 2023–24).

These forecasts, together with AEMO's planned connection point forecasts, inform stakeholders in infrastructure decision-making, and are considered by the Australian Energy Regulator (AER) in assessing transmission revenue reset applications. The energy consumption forecasts are also used to calculate marginal loss factors, and as a key input into AEMO's national transmission planning activities. AEMO also uses these energy consumption forecasts in determining NEM adequacy of supply.

As the independent market operator, AEMO is ideally placed to develop these forecasts across all regions, and to bring together the sophisticated and detailed processes for a fit-for-purpose result. AEMO is also well placed to lead collaboration with industry to produce consistent and reliable forecasts for each NEM region.

The forecasts explore a range of scenarios across high, medium, and low growth outlooks, where the medium scenario is considered the most likely. The medium scenario, short-term outlook (2013–14 to 2016–17) is the main focus of this report. Commentary and data regarding the low and high scenarios, and medium- to long-term outlook are also provided.

Comparisons between the 2013 and 2014 NEFR forecasts refer to the same or equivalent periods. These comparisons are informed by additional historical and 20-year forecast data. All data is available in the NEFR Excel workbooks available on AEMO's website.

These workbooks include all operational data and analysis as well as native data; this enables users to undertake their own comparative analysis of the forecasts. This main NEFR report uses operational annual energy data only.

The 2013–14 estimate is based on nine months of actual data from July 2013 to March 2014, and three months of forecast data from April to June 2014. This is due to the April to June data being unavailable when the report was being developed. The rooftop PV 2013-14 estimate was based on six months of actual data due to data being unavailable from the Clean Energy Regulator when the report was being developed.

For large industrial load, the 2013-14 estimate is also based on nine months of actual data from July 2013 to March 2014, and three months of forecast data from April to June 2014, unless specific information was provided by large industrial customers. The liquefied natural gas (LNG) forecast was developed by consultants Jacobs SKM. The 2013-14 estimate is based on eight months of actual data from July 2013 to February 2014, and four months of forecast data from March to June 2014.

1.2 Forecast scenarios

AEMO develops the annual energy and maximum demand (MD) forecasts using the three forecast scenarios.

The scenarios are developed in partnership with market participants, industry groups, and academics. They are reviewed as required to better reflect real-world trends by bringing them up-to-date with the current regulatory environment and changes in consumer behaviour. For the 2014 NEFR, the scenarios used in both the 2012 and 2013 NEFRs were revised. Given this, they are not necessarily comparable across successive NEFRs.

The 2014 scenarios represent high, medium, and low energy consumption for electricity from a centralised source (the national electricity transmission grid). This is a significant shift from the previous NEFR scenarios, and reflects the increasing impact of local energy generation and energy efficiency.

In addition to conducting research to explore impacts under the three scenarios, AEMO seeks guidance about future consumption changes directly from TNSPs and large industrial customers. The number of large industrial load customers consulted in 2014 was more than double the number in 2013.

In 2014, customer responses indicated minimal difference between the high and medium scenarios. In the low scenario, to reflect the increased risk of reduced production or closure of aluminium smelters, AEMO adopted a probabilistic approach, assuming a 50% reduction in operations across all NEM-connected aluminium smelters from 2015 to 2017. This is followed by closure once current arrangements with the respective state governments or electricity providers expire.

The scenarios are designed to reflect different levels of economic growth, residential and commercial consumption, large industrial consumption, rooftop PV output, energy efficiency, and SNSG. The terms “high”, “medium” and “low” are used throughout the report to identify the scenarios.

Table 2 — Scenarios for national electricity forecasting — shows the correlation between the scenarios and three variables that affect the forecast energy consumption, customer type, and economic activity in each. Full details of the scenarios are available in AEMO’s 2014 Scenarios Descriptions.[1]

Table 2 — Scenarios for national electricity forecasting

	High energy consumption from centralised sources[2]	Medium energy consumption from centralised sources	Low energy consumption from centralised sources
Energy consumption	High	Medium	Low
Type of consumer[3]	Low engagement	Highly engaged	Highly engaged
Economic activity	High	Medium	Low

1.3 Definitions

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

Operational consumption includes all residential and commercial[4] consumption, large industrial consumption, and transmission loss forecasts.

Native consumption is calculated as operational consumption plus the contribution from small non-scheduled generation (SNSG), which generally includes units with less than 30 MW capacity.

Maximum demand forecasts the highest level of instantaneous demand during summer and winter each year, averaged over a 30-minute period.

Measuring consumption

Electricity consumption is measured by metering supply to the network rather than consumption. Measuring consumption this way accounts for electricity used by customers, energy lost during transportation (transmission losses), and the energy used to generate the electricity (auxiliary loads).

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.

[1] Available at:http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/forecasting/2014_Planning_and_Forecasting_Scenarios.ashx.
[2] A centralised source refers to the national electricity transmission grid for electricity.
[3] “Engaged” refers to consumers who more proactively exercise choice of energy sources and usage patterns.
[4] Throughout the NEFR residential and commercial includes light industrial consumption.

The NEFR presents annual energy and MD forecasts as follows:

- Annual energy is presented on a sent-out basis.
- MD is presented on an as-generated basis. The forecast includes actual demand-side participation (DSP), but does not include additional forecast DSP.

The 2014 NEFR includes operational and native energy data for the current annual energy and MD forecasts. The 2015 NEFR will not include native energy.

Transmission losses and auxiliary load

Transmission losses are determined as a percentage of large industrial and residential and commercial energy.

Auxiliary loads are defined as the energy used by generating units to generate electricity. They are calculated as a percentage of the energy produced at each plant.

Small non-scheduled generation

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

Towards the end of the 10-year forecast period there is limited information about small non-scheduled generation (SNSG) projects. As such, SNSG profiles for annual energy and contribution to MD display little variation over the full 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; an increasing proportion of consumption 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.

Similar to the 2013 NEFR, the 2014 NEFR presents MD data based on 10% POE MD projections.

Also similar to the 2013 NEFR, the model considers heating degree days (HDD) and cooling degree days (CDD). 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.

Per capita consumption

Population is a key driver of energy consumption. A population rise, all other factors being equal, leads to a rise in consumption. To analyse the impact of other drivers on consumption, and hence underlying consumption patterns, the effect of population needs to be removed. AEMO achieves this by focussing on per capita consumption, defined as the annual consumption for a typical customer.

1.4 Improvements and inputs to the 2014 NEFR

In 2013, AEMO engaged Frontier Economics to provide an independent peer review of its forecasting methodologies. AEMO also conducted an internal review with assistance from econometric forecasting experts, Woodhall Investment Research. The findings were published in November[5] along with the 2014 NEFR Action Plan.[6]

In addition to addressing these findings for both annual energy and MD, AEMO collaborated with Monash University to implement key improvements to the 2014 MD forecasting models; these are outlined in the Action Plan.

The 2014 NEFR also provides a greater focus on short-term (three-year) forecasts.

Improvements to residential and commercial consumption calculations

A change to the econometric model places greater emphasis on the decline in consumption over the past few years. This reflects the greater importance being placed on recent declining consumption patterns in forecasting future trends.

AEMO used multiple weather stations in each NEM region to create a weighted average weather variable, which it then applied to each region. A single weather station per NEM region was used in previous NEFRs.

In the 2013 NEFR AEMO used different income variables, including state final demand and gross state product, for different states. In 2014 AEMO combined these into a single income variable for consistency between NEM regions.

Improvement to maximum demand calculations

An automatic step was introduced into the model to remove the need to manually adjust for extreme weather temperatures. Methodology changes, outlined under Key Inputs below, were also made to energy efficiency and rooftop PV calculations.

AEMO estimated the contribution from SNSG and large industrial loads towards MD using the 10 highest peak load intervals (30-minute average) over the past five years to establish a more representative correlation with peak load. In 2013, only the highest peak load interval was used from the previous year.

Large Industrial load methodology improvements

AEMO increased the sample size of large industrial customers that it contacted directly for information, from 38 customers in 2013 to 93 in 2014. This increase captured additional data and includes a more representative sample of distribution- and transmission-connected customers. All customers with a maximum demand greater than 10 MW were included.

Customers provided information on their likely load under the three scenarios (high, medium, and low), resulting in more realistic data being used in the forecasts. For more details see the Forecast Methodology Information Paper which will be available in July 2014.

Where limited or no information was provided by customers, AEMO developed high and low scenario forecasts based on information from economic consultants to calibrate the scenarios relative to the medium. The divergence between high and low scenarios to the medium was then adjusted based on advice from the economic consultants.

[5] Available at :http://www.aemo.com.au/Electricity/Planning/Forecasting/~/media/Files/Other/planning/NEFR/2013/Frontier_Economics_Review_of_AEMO_2013_National_Electricity_Forecasts_STC.ashx.

[6] Available at:http://www.aemo.com.au/Electricity/Planning/Forecasting/~/media/Files/Other/planning/NEFR/2013/2014_NEFR_Action_Plan_Final.ashx.

Improvements to energy efficiency estimates

The 2014 NEFR energy efficiency (EE) modelling includes industrial EE estimates calculated using the Energy Efficiency Opportunities (EEO) data sourced from ClimateWorks. In 2013 EE modelling did not include industrial EE estimates. The EEO Program[7] is an Australian Government initiative encouraging large energy-consuming businesses to increase EE by mandating the identification of cost-effective energy saving opportunities and voluntarily invest in those initiatives that fit the business (in terms of practicality and payback time).

Although the EEO program was scrapped as a part of the 2014 Federal Budget, AEMO has not adjusted the EE forecast. The forecasts assume that companies will implement EE savings already identified under the program and has not accounted for savings that could be identified in future years.

AEMO analyses the impacts of energy efficiency (EE) in various sectors to improve its forecast accuracy. In particular, it analyses the impact of appliance and building EE measures for commercial and residential settings.

The annual energy forecast includes EE calculated at the average historical uptake rate. In recent years, an additional post-model adjustment was added to account for the impacts of future programs targeting EE.

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

All three scenarios used in the 2014 NEFR use different EE uptake rates for AE and MD. However, the method for applying the EE contribution to MD has changed since 2013. AEMO applied different levels of EE at different POE levels to improve accuracy.

PV methodology improvements

The impact of rooftop PV on MD was incorporated directly into the MD model, allowing demand and PV generation to be modelled together for each half hour. In contrast, the 2013 NEFR simply assumed a constant PV contribution factor at the time of MD. This improvement better captures the shifts in maximum demand times caused by increasing amounts of rooftop PV, as well as the changing contribution of PV based on this MD shift.

The methodology used in 2014 better reflects the impact of policy changes on uptake, and also uses more recent data to more accurately reflect the growth rate in each region. This sees a revision of installed capacity forecasts in the medium to long term from last year, with New South Wales being revised down and all other NEM regions being revised up.

New South Wales forecasts were revised downwards to better reflect recent trends in PV uptake. Extended high levels of uptake prior to mid-2011 in New South Wales resulted in overly optimistic long-term growth rates for New South Wales in previous NEFRs. The extended high levels of uptake were driven by high gross feed-in tariffs of 60 c/kWh. In contrast, all other regions used net metering for feed-in tariffs.

The optimistic growth rates used in previous NEFRs would have resulted in even higher forecasts this year, which is not reflected in the latest PV uptake data. Further, a return to high feed-in tariffs is highly unlikely, so the growth seen between 2009 and 2011 is unlikely.

Supporting information and data is provided in the Forecast Methodology Information Paper. This enables users to undertake their own sensitivity analyses using higher or lower uptake rates to account for the uncertainties in estimating this component. More detail about the slow and rapid uptake scenarios is provided in the Forecast Methodology Information Paper.

[7] Available at: http://energyefficiencyopportunities.gov.au/.

SNSG methodology improvements

The 2014 methodology is based on SNSG installed capacity and future capacity factors calculated from historical output data over the past five years. It uses a weighted average across similar generation types, combined with information about potential new connections under each scenario. The 2013 forecast was based on capacity factors from the previous year using a non-weighted average.

Improvement to transmission loss calculations

AEMO revised the transmission loss model to reflect recent changes to generation and transmission patterns. The annual average figure is now calculated using five years of historical data. In 2013, 10 years of historical data was used, reducing the impact of more recent trends.

Demand-side participation

AEMO prepared three demand-side participation uptake scenarios for the 2014 NEFR. These are in the Forecast Methodology Information Paper to be published in July 2014, together with the methodology underpinning them.

1.5 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, which reflects medium economic growth. This is the “base case” scenario. Key high and low scenario results are also provided.

The 2014 NEFR 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 2014 NEFR

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

About the NEFR provides background information about AEMO’s 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 will be available on AEMO's website[8]:

- Historical actual annual energy and maximum demand data from 2005-06 to 2012-13, and input assumptions. To be published by 16 June 2014.
- Economic Outlook Report providing the economic forecasts used to generate the annual energy and MD forecasts. To be published by 30 June 2014.
- Forecast Methodology Information Paper explaining the approach used for the 2014 NEFR forecasts. To be published on 31 July 2014.

[8] AEMO. Available at: http://aemo.com.au/Electricity/Planning/Forecasting.

CHAPTER 2 - NEM FORECASTS

2.1 Annual energy forecasts

From 2009–10 to 2013–14, annual energy declined by 13,613 GWh (an annual average decline of 1.8%) to 181,239 GWh.

Key differences between the 2014 National Electricity Forecasting Report (NEFR) and the 2013 NEFR annual energy forecasts include the following:

- Current estimate for 2013–14: The current estimate for 2013–14 annual energy is 181,239 GWh, which is 5,364 GWh (2.9%) below the 2013 NEFR medium forecast.
- Medium short-term forecast (2013–14 to 2016–17): The 2014 forecast average annual growth rate is 0.4%, compared to 2.2% in the 2013 forecasts.

2.2 Key drivers: NEM forecasts in the short term

- Increase in NEM electricity consumption driven by LNG projects in Queensland.
- Decline in energy-intensive industries includes closure of the Point Henry aluminium smelter in Victoria.
- Strong growth (23.6% annually) in rooftop PV installations, particularly in Queensland and Victoria.
- Strong growth (10.0% annually) in total energy efficiency savings, with key contributions from air conditioning, refrigeration and electronics.

In the low scenario, AEMO has adopted a probabilistic approach to reflect the increased risk of reduced production or closure of aluminium smelters in response to less favourable economic conditions. This assumes a 50% reduction in operations across all NEM-connected aluminium smelters across 2015 to 2017, followed by closure once current arrangements with the respective State Governments or electricity providers expire.

Figure 4 — Annual energy forecasts for the NEM

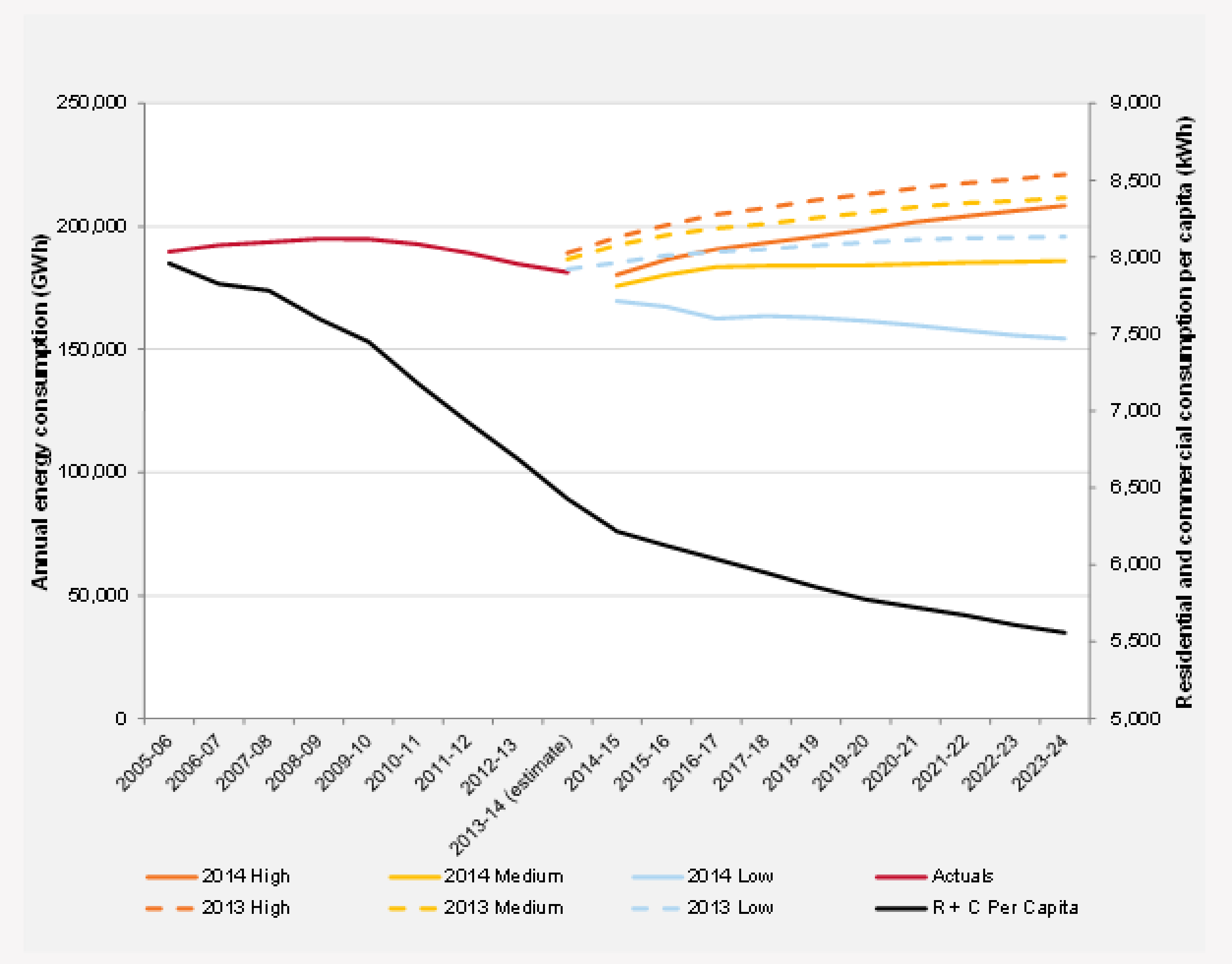
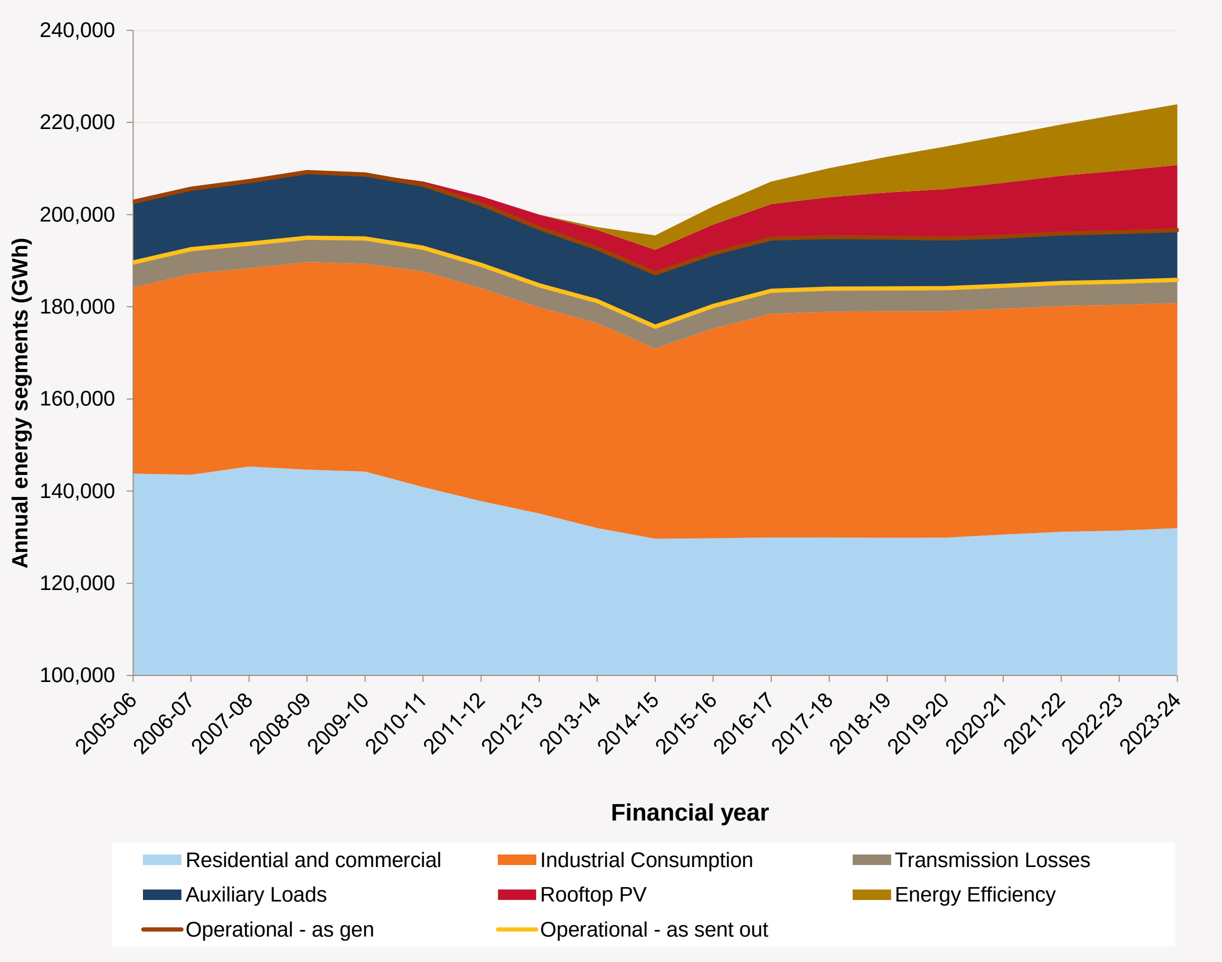


Table 3 — Annual energy forecasts for the NEM (GWh)

	Actual	High	Medium	Low
2013-14 (estimate)	181,239			
2014-15		180,176	175,692	169,606
2015-16		186,428	180,164	167,174
2016-17		190,742	183,452	162,391
2017-18		193,384	183,922	163,504
2018-19		195,885	184,002	162,802
2019-20		198,706	184,022	161,496
2020-21		201,848	184,584	159,673
2021-22		204,107	185,193	157,567
2022-23		206,345	185,448	155,603
2023-24		208,420	185,846	154,283
Average annual growth		1.4%	0.3%	-1.6%

2.2.1 Annual energy forecast segments

Figure 5 — Annual energy forecasts segments for the NEM



CHAPTER 3 - QUEENSLAND FORECASTS

3.1 Annual energy forecasts

From 2009–10 to 2013–14, annual energy declined by 2,813 GWh (an annual average decline of 1.5%) to 46,362 GWh.

Key differences between the 2014 National Electricity Forecasting Report (NEFR) and the 2013 NEFR annual energy forecasts include the following:

- Current estimate for 2013–14: The current estimate for 2013–14 annual energy is 46,362 GWh, which is 2,371 GWh (4.9%) below the 2013 NEFR medium forecast.
- Medium scenario short-term forecast (2013–14 to 2016–17): The 2014 forecast average annual growth rate is 4.1%, compared to 6.8% in the 2013 forecasts.

3.2 Maximum demand forecasts

Key differences between summer maximum demand (MD) forecasts in the 2013 and 2014 NEFRs are:

- 2013–14 summer MD was 8,374 MW on 22 January 2014. This was 495 MW below the 2013 NEFR 10% probability of exceedence (POE) forecast.
- The 10% POE MD is forecast to increase at an annual average rate of 4.0% over the short term (2013–14 to 2016–17) medium scenario forecast, compared to 5.8% in the 2013 NEFR.

3.3 Key drivers: Queensland short-term forecasts

- Increased large industrial forecasts, due to the LNG projects expected to come online from 2014-15. (Excluding LNG, large industrial is forecast to decline due to the Bulwer Island refinery closure in 2014-15).
- Reduced residential and commercial consumption forecasts due to the strongest growth in PV in the NEM, and continued growth in EE savings.
  - Queensland has the highest forecast growth in PV installations in the NEM. PV growth results from the fall in PV system costs while financial incentives stay the same and
  - EE growth is forecast to increase year on year driven by Federal Government programs
- Continued strong population and state income growth.
- PV is causing MD to shift to later in the day, but the impact of this is not noticeable in Queensland in the short term.

In the low scenario, AEMO has adopted a probabilistic approach to reflect the increased risk of reduced production or closure of aluminium smelters in response to less favourable economic conditions. This assumes a 50% reduction in operations across all NEM-connected aluminium smelters across 2015 to 2017, followed by closure once current arrangements with the respective State Governments or electricity providers expire.

Figure 6 — Annual energy forecasts for Queensland

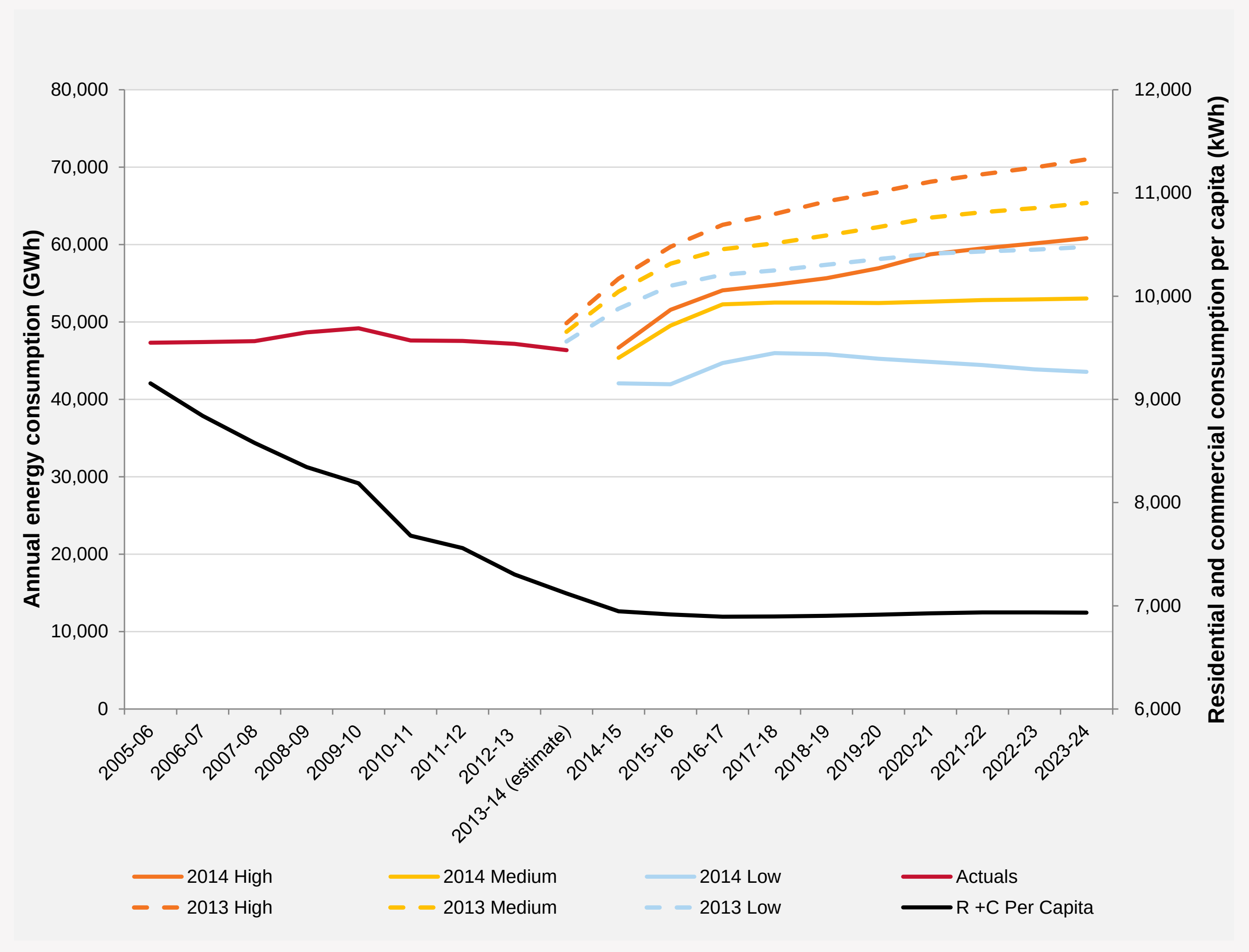
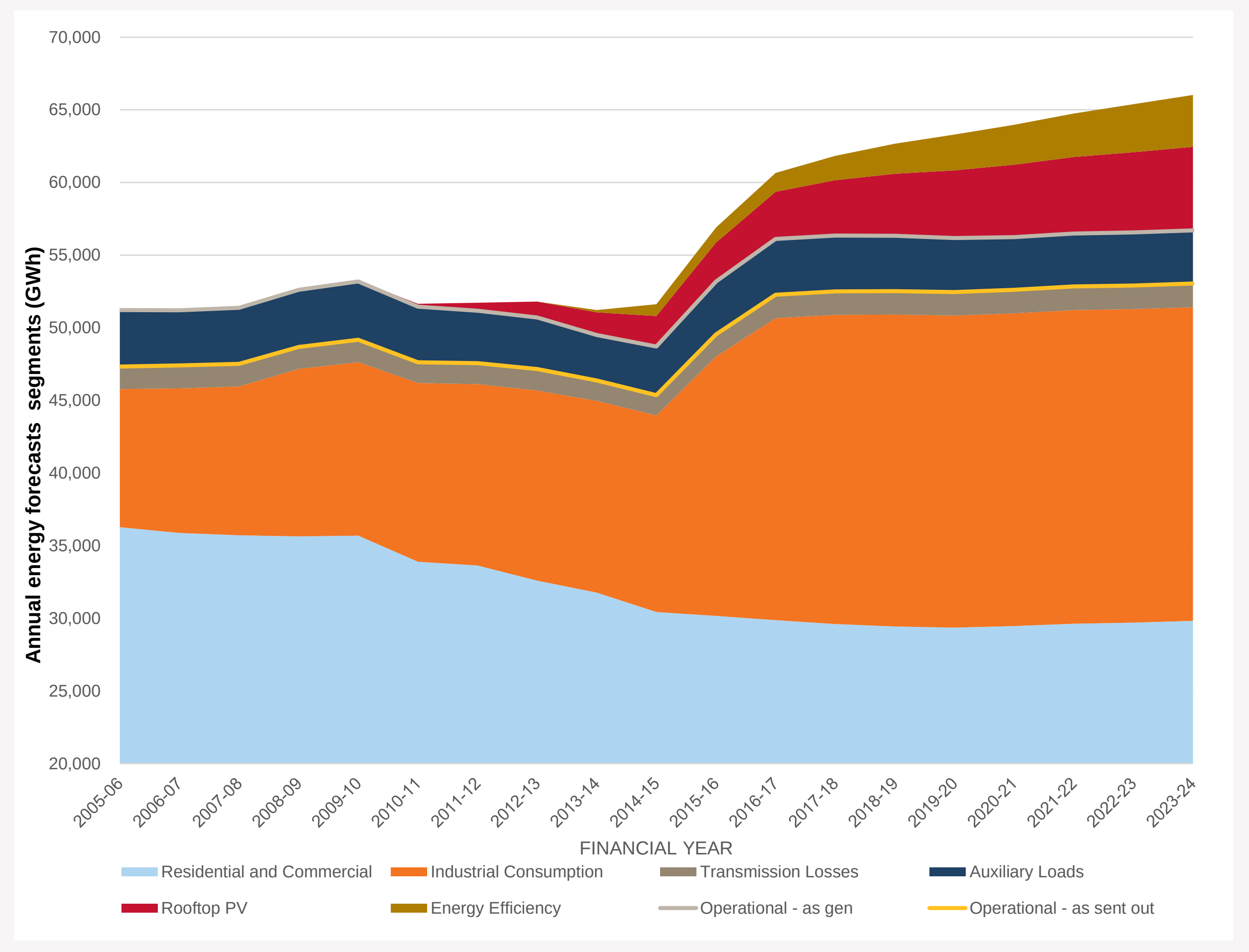


Table 4 — Annual energy forecasts for Queensland (GWh)

	Actual	High	Medium	Low
2013-14 (estimate)	46,362			
2014-15		46,682	45,362	42,076
2015-16		51,588	49,546	41,960
2016-17		54,082	52,267	44,704
2017-18		54,823	52,503	45,971
2018-19		55,650	52,521	45,837
2019-20		56,950	52,451	45,256
2020-21		58,746	52,609	44,831
2021-22		59,518	52,840	44,418
2022-23		60,145	52,910	43,881
2023-24		60,805	53,041	43,569

3.3.1 Annual energy forecast segments

Figure 7 — Annual energy forecasts segment for Queensland



3.4 Maximum demand

3.4.1 Summer maximum demand forecasts

Figure 8 — Summer 90%, 50% and 10% POE maximum demand forecasts for Queensland

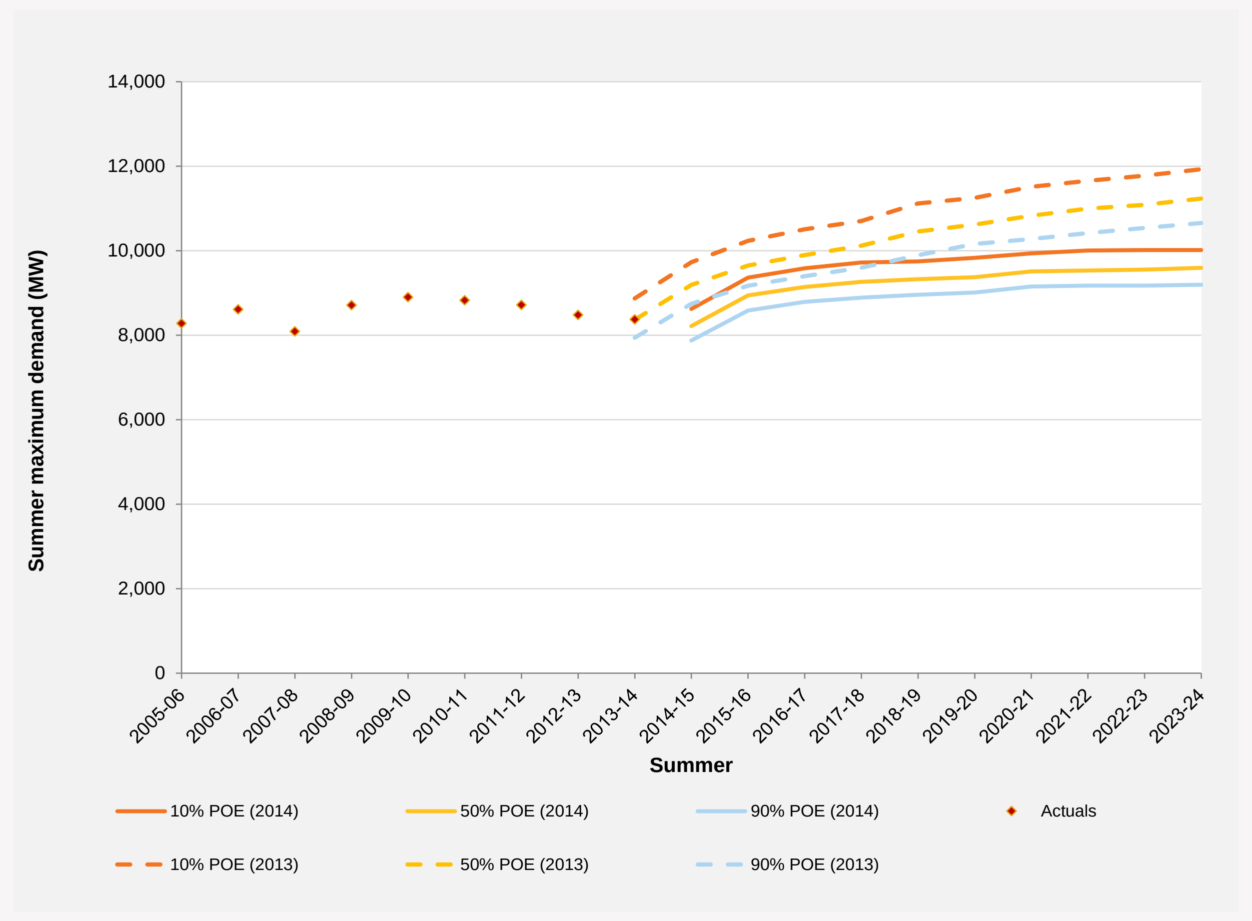
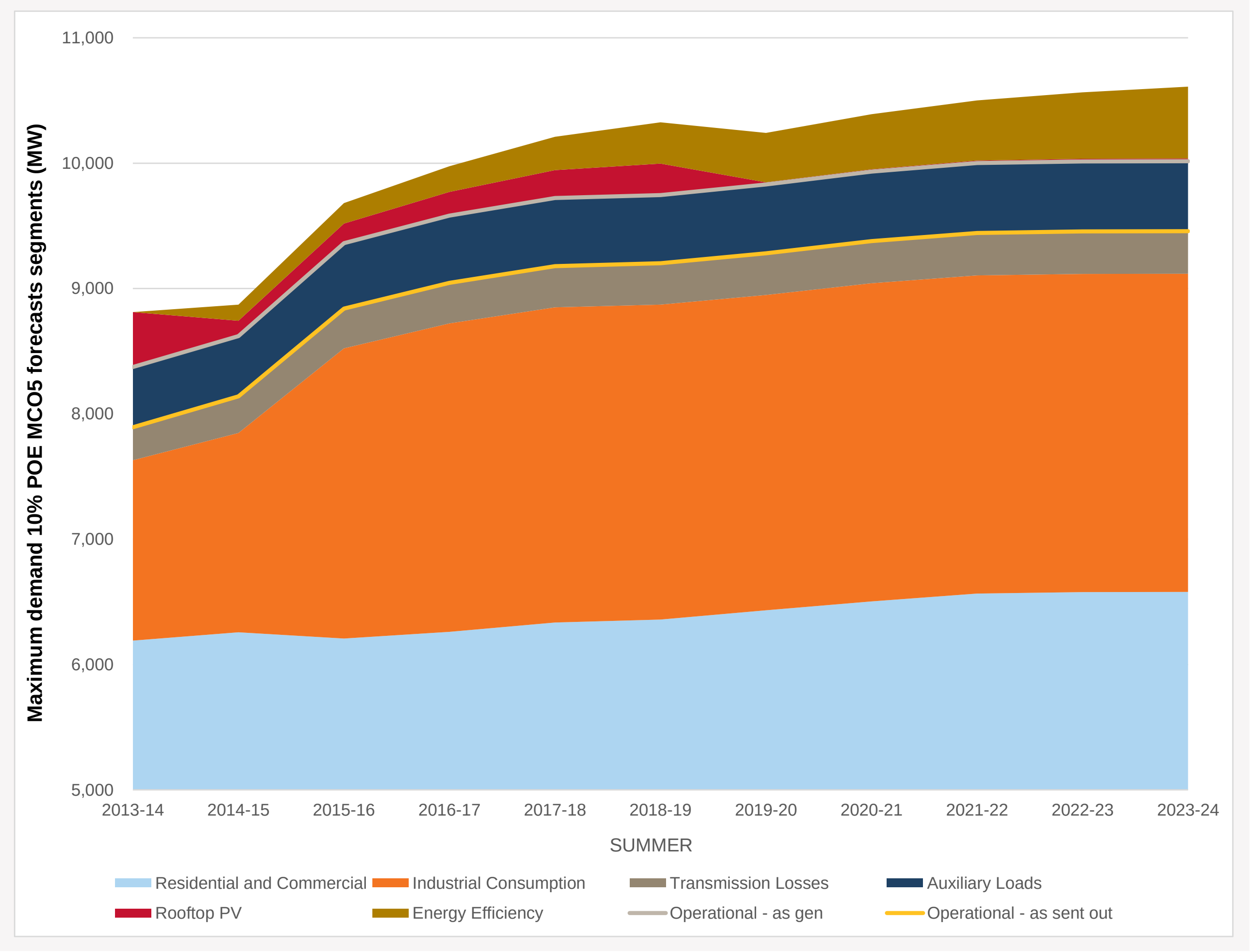


Table 5 — Summer 90%, 50% and 10% POE maximum demand forecasts for Queensland (MW)

	Actual	90% POE	50% POE	10% POE
2013-14	8,374			
2014-15		7,873	8,212	8,621
2015-16		8,581	8,941	9,362
2016-17		8,790	9,140	9,581
2017-18		8,889	9,260	9,722
2018-19		8,956	9,326	9,746
2019-20		9,010	9,370	9,830
2020-21		9,148	9,508	9,933
2021-22		9,170	9,532	10,002
2022-23		9,174	9,553	10,015
2023-24		9,195	9,594	10,016

3.4.2 Summer 10% POE maximum demand forecast segments

Figure 9 — Summer 10% POE maximum demand forecast segments for Queensland



CHAPTER 4 - NEW SOUTH WALES FORECASTS

4.1 Annual energy forecasts

From 2009–10 to 2013–14, annual energy declined by 7,817 GWh (an annual average decline of 2.8%) to 66,233 GWh.

Key differences between the 2014 National Electricity Forecasting Report (NEFR) and the 2013 NEFR annual energy forecasts are:

- Current estimate for 2013–14: The current estimate for 2013–14 annual energy is 66,233 GWh, which is 2,295 GWh (3.3%) below the 2013 NEFR medium forecast.
- Medium short-term forecast (2013–14 to 2016–17): The forecast average annual growth rate is a decline of 0.07%, compared to an increase of 0.3% in the 2013 forecasts.

4.2 Maximum demand forecasts

Key differences between summer maximum demand (MD) forecasts in the 2013 and 2014 NEFRs are:

- 2013–14 summer MD was 12,027 MW on 20 December 2013. This was 1,898 MW below the 2013 NEFR 10% probability of exceedence (POE) forecast.
- The 10% POE MD is forecast to increase at an annual average rate of 0.5% over the short term (2013–14 to 2016–17) medium scenario forecast, compared to 0.8% in the 2013 NEFR.

4.3 Key drivers: New South Wales short-term forecasts

- Decreased large industrial forecasts reflect lower production levels in key industries due to lower aluminium production than forecast in 2013, in response to the global demand trends, lower metal prices, the high Australian dollar of recent years, and higher input costs. This includes implementation of on-site electricity generation by some companies, and Caltex refinery converting to a fuel import terminal with reduced electricity requirements.[9]
- A slight decline in residential and commercial consumption forecasts due to the continued impact of high existing levels of PV (combined with EE impacts) offsets any increase driven by state population and income growth.
  - PV growth resulting from the fall in PV system costs while financial incentives stay the same. While New South Wales has the lowest forecast growth in rooftop PV installations of all NEM regions in the short term, it has high existing levels of PV output, which moderate the effect of state income and population growth.
  - EE growth is forecast to increase year on year driven by Federal Government programs
- PV is causing MD to shift to later in the day, but the impact of this is not noticeable in New South Wales in the short term.

In the low scenario, AEMO has adopted a probabilistic approach to reflect the increased risk of reduced production or closure of aluminium smelters in response to less favourable economic conditions. This assumes a 50% reduction in operations across all NEM-connected aluminium smelters across 2015 to 2017, followed by closure once current arrangements with the respective State Governments or electricity providers expire.

[9] Available at: http://www.caltex.com.au/CommunityAndEnvironment/KurnellSiteConversion/Pages/Home.aspx.

4.4 Annual energy

4.4.1 Annual energy forecast

Figure 10 — Annual energy forecasts for New South Wales

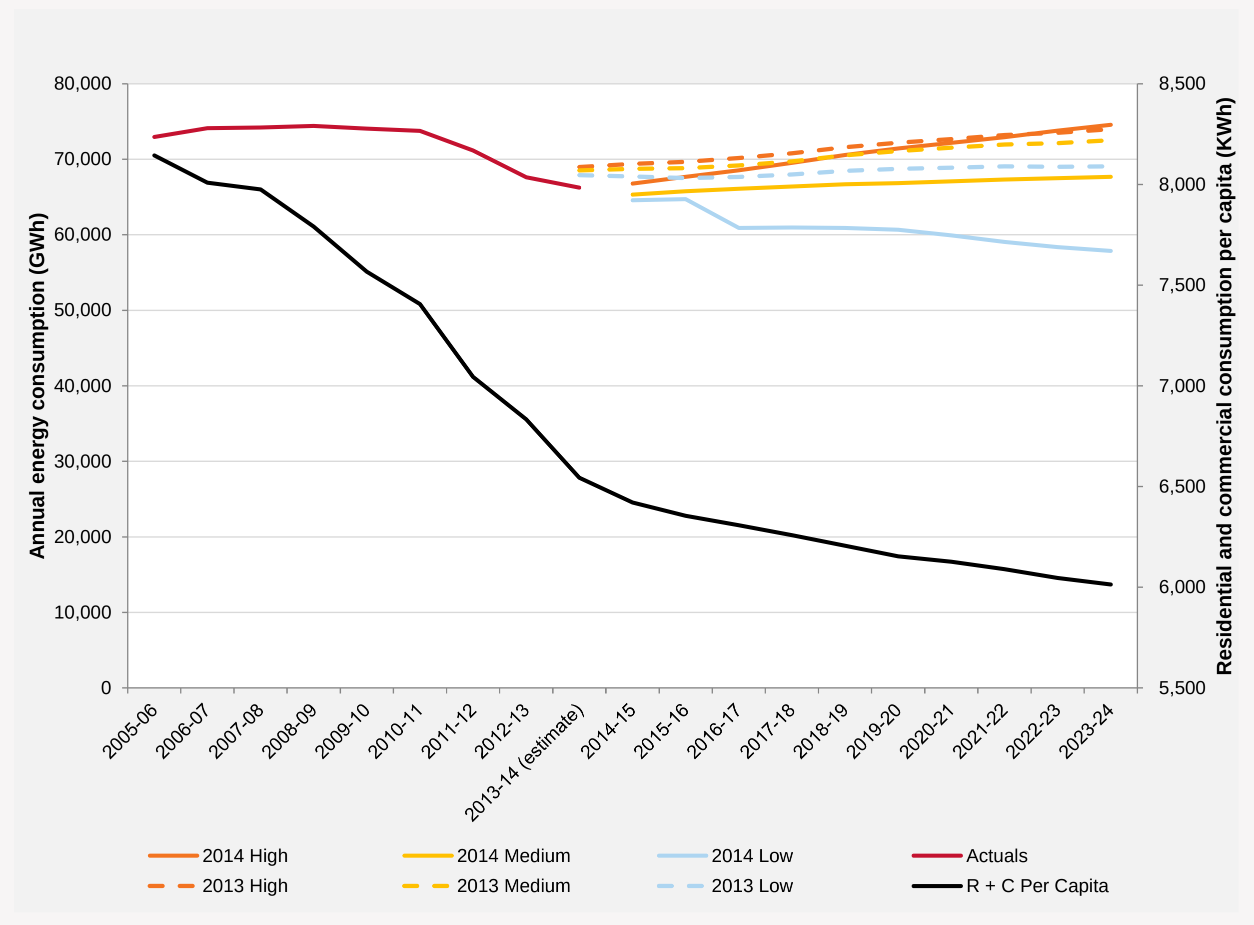
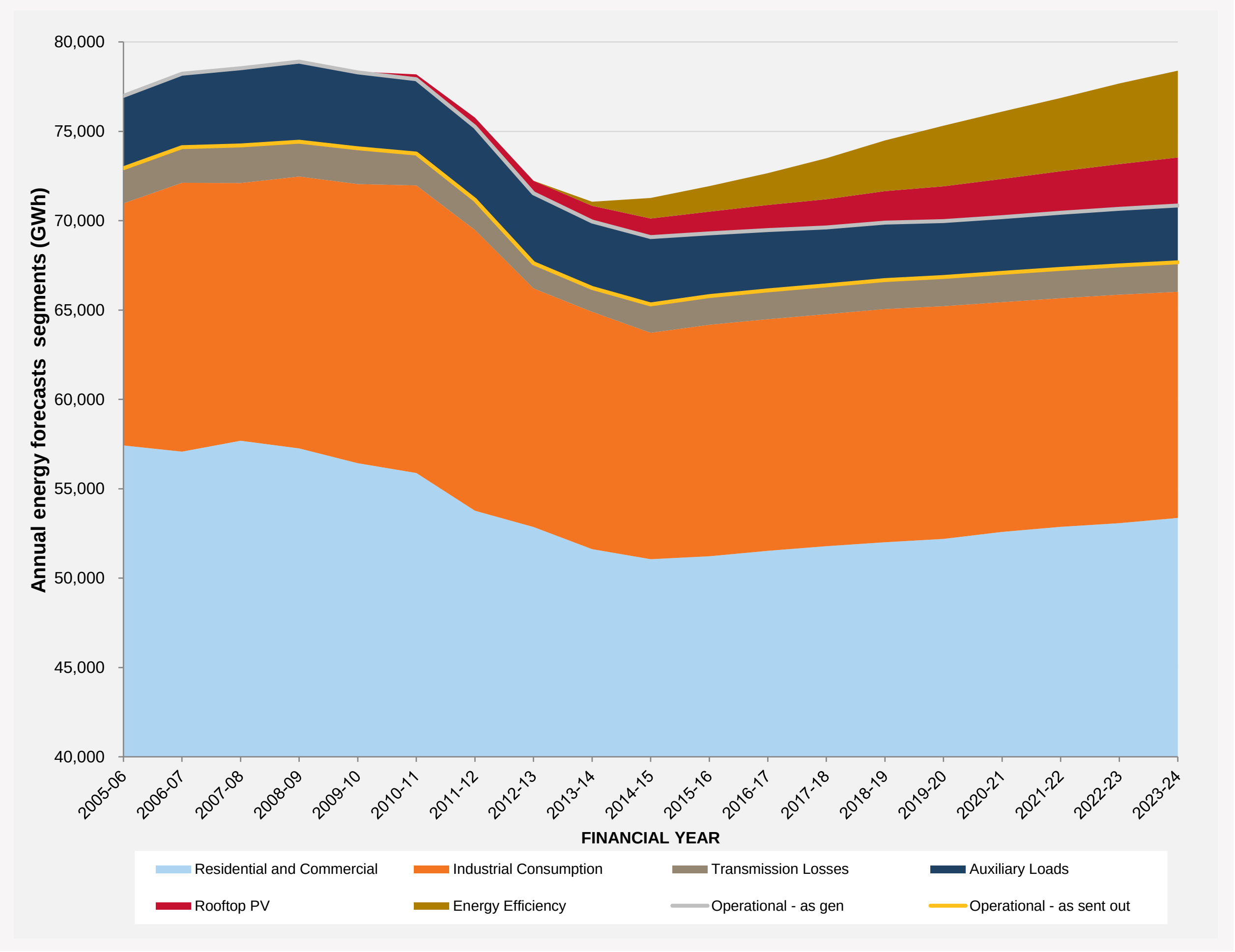


Table 6 — Annual energy forecasts for New South Wales (GWh)

	Actual	High	Medium	Low
2013-14 (estimate)	66,233			
2014-15		66,789	65,321	64,568
2015-16		67,678	65,780	64,735
2016-17		68,534	66,100	60,917
2017-18		69,529	66,389	60,975
2018-19		70,554	66,684	60,919
2019-20		71,438	66,849	60,655
2020-21		72,170	67,078	59,913
2021-22		72,936	67,305	59,050
2022-23		73,790	67,506	58,382
2023-24		74,557	67,672	57,852

4.4.2 Annual energy forecast segments

Figure 11 — Annual energy forecast segments for New South Wales



4.5 Maximum demand

4.5.1 Summer maximum demand forecasts

Figure 12 — Summer 90%, 50% and 10% POE maximum demand forecasts for New South Wales

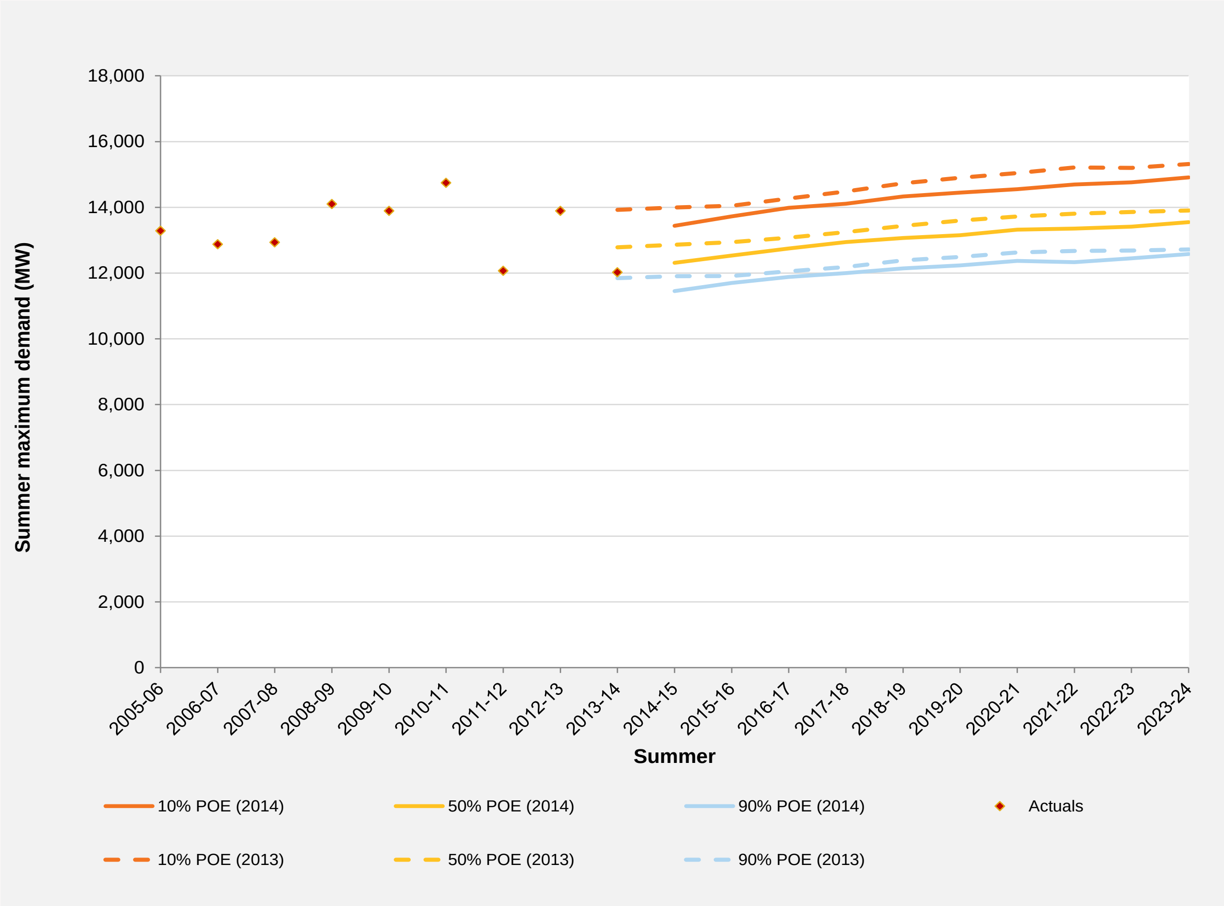
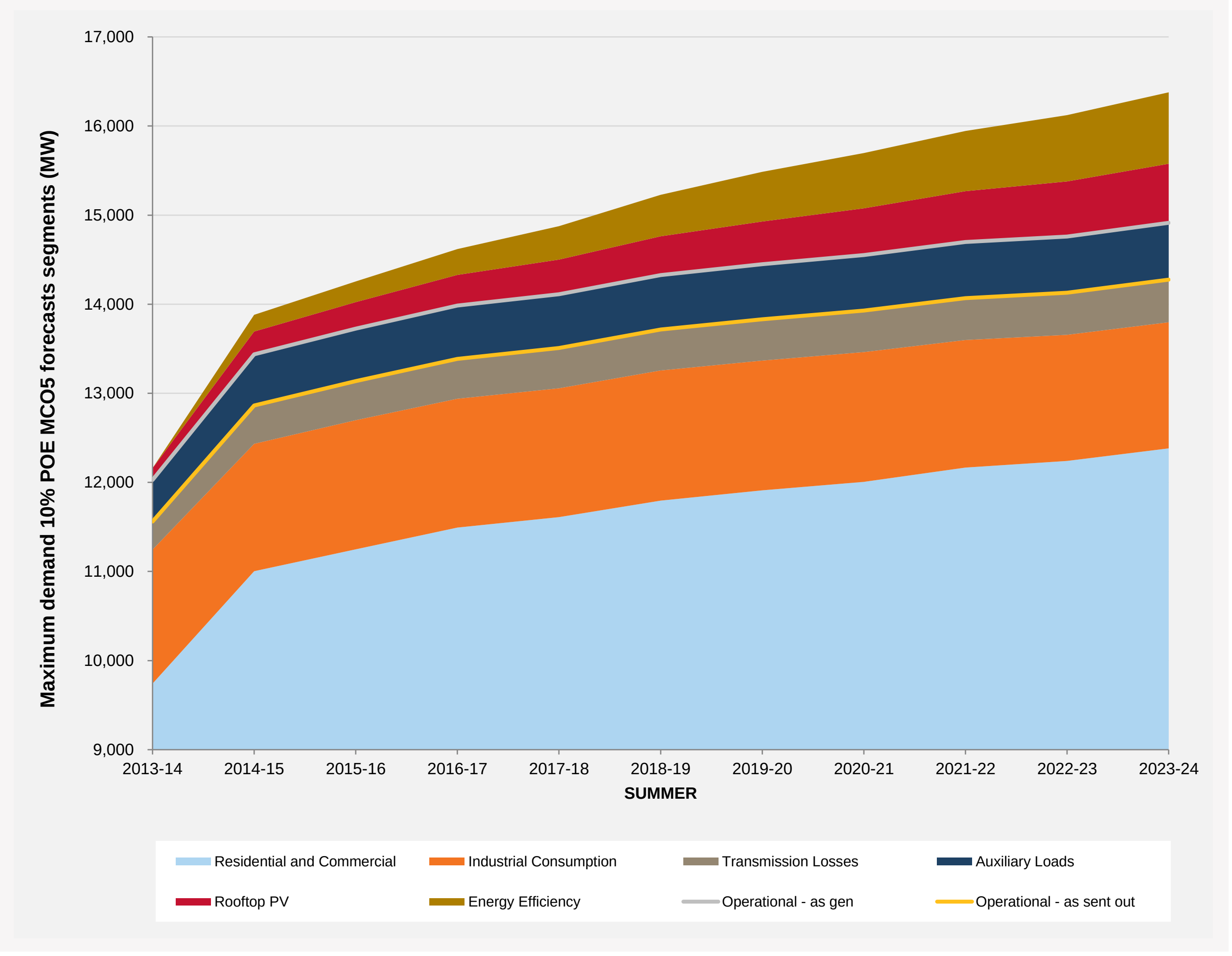


Table 7 — Summer 90%, 50% and 10% POE maximum demand forecasts for New South Wales (MW)

	Actual	90% POE	50% POE	10% POE
2013-14	12,027			
2014-15		11,453	12,310	13,438
2015-16		11,701	12,536	13,725
2016-17		11,885	12,749	13,985
2017-18		12,003	12,942	14,112
2018-19		12,142	13,069	14,328
2019-20		12,232	13,154	14,448
2020-21		12,373	13,322	14,551
2021-22		12,333	13,354	14,697
2022-23		12,448	13,410	14,760
2023-24		12,579	13,552	14,913

4.5.2 Summer 10% POE maximum demand forecast segments

Figure 13 — Summer 10% POE maximum demand forecast segments for New South Wales



CHAPTER 5 - SOUTH AUSTRALIA FORECASTS

5.1 Annual energy forecasts

From 2009–10 to 2013–14, annual energy declined by 761 GWh (an annual average decline of 1.3%) to 12,855 GWh.

Key differences between the 2014 National Electricity Forecasting Report (NEFR) and the 2013 NEFR annual energy forecasts are:

- Current estimate for 2013–14: The current estimate for 2013–14 annual energy is 12,855 GWh, which is 109 GWh (0.9%) above the 2013 NEFR medium forecast.
- Medium short-term forecast (2013–14 to 2016–17): The 2014 forecast is an average annual decline of 1.3%, compared to a decline of 1.1% in the 2013 forecasts.

5.2 Maximum demand forecasts

Key differences between summer maximum demand (MD) forecasts in the 2013 and 2014 NEFRs include the following:

- 2013–14 summer MD was 3,281 MW on16 January 2014. This was 67 MW above the 2013 NEFR 10% probability of exceedence (POE) forecast.
- The 10% POE MD is forecast to decrease at an annual average rate of 1.1% over the short term (2013–14 to 2016–17) medium scenario forecast, compared to a decline of 0.3% in the 2013 NEFR.

5.3 Key drivers: South Australian short-term forecasts

- A decline in large industrial forecasts due to SA Water's desalination plant reducing its consumption following completion of operational tests.
- A slight decline in residential and commercial forecasts due to highest existing levels of installed rooftop photovoltaic (PV) per capita across the NEM, and increased energy efficiency offsets.
  - PV growth results from the fall in PV system costs while financial incentives stay the same. While South Australia has the second lowest growth in rooftop PV installations forecast in the short term, it has the highest existing levels of installed rooftop PV per capita in comparison to other NEM regions.
  - EE growth is forecast to increase year on year driven by Federal Government programs
- PV is causing MD to shift to later in the day. This long-term trend is seen in the short term, but to a much lesser extent. South Australian MD is expected to shift back to later in the day by 60 minutes in the short term.

Figure 14 — Annual energy forecasts for South Australia

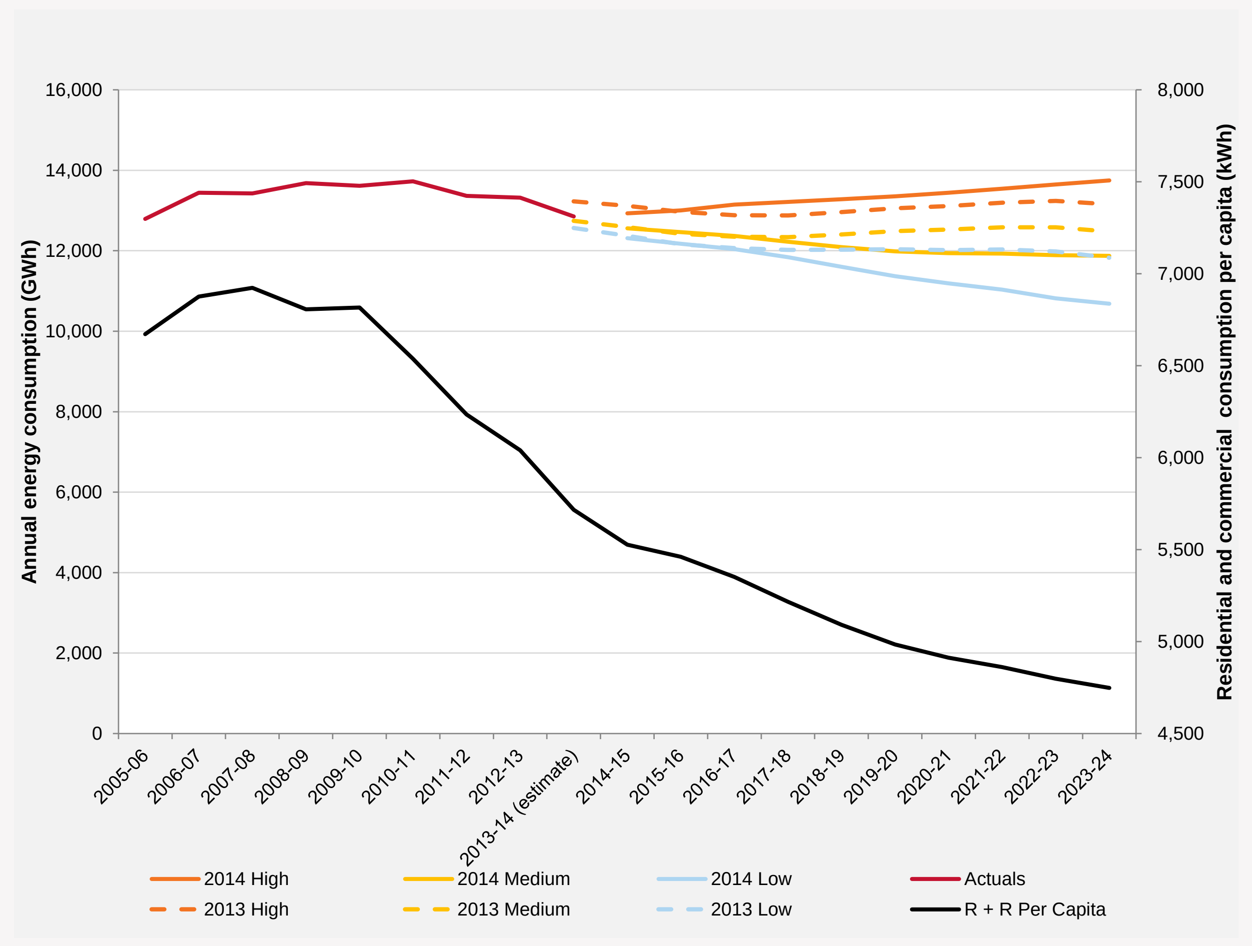
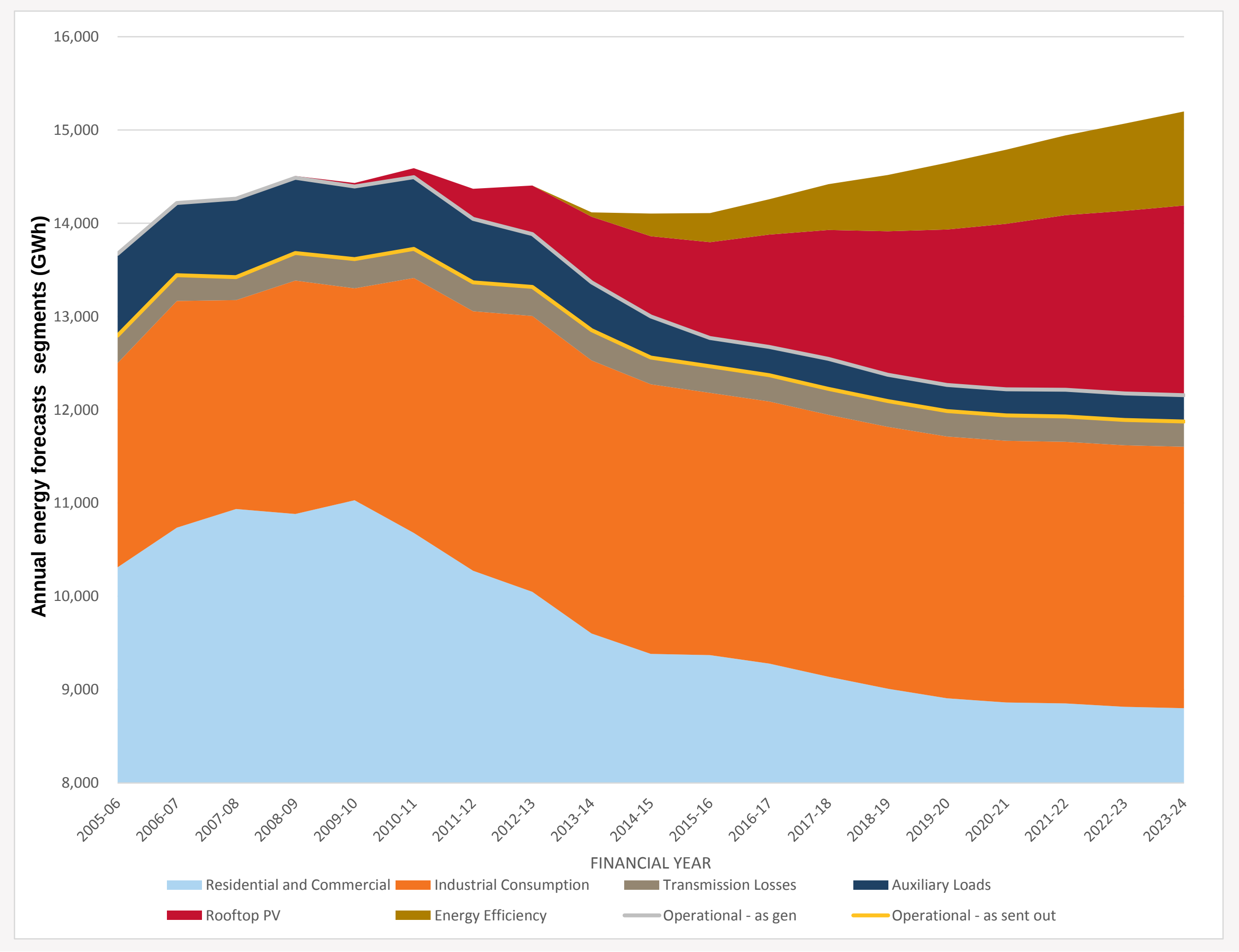


Table 8 — Annual energy forecasts for South Australia (GWh)

	Actual	High	Medium	Low
2013-14 (estimate)	12,855			
2014-15		12,929	12,560	12,313
2015-16		13,002	12,466	12,173
2016-17		13,147	12,371	12,043
2017-18		13,215	12,225	11,840
2018-19		13,281	12,093	11,602
2019-20		13,354	11,987	11,371
2020-21		13,444	11,940	11,189
2021-22		13,543	11,929	11,035
2022-23		13,649	11,891	10,820
2023-24		13,752	11,875	10,687

5.3.1 Annual energy forecast segments

Figure 15 — Annual energy forecasts segments for South Australia



5.4 Maximum demand

5.4.1 Summer maximum demand forecasts

Figure 16 — Summer 90%, 50% and 10% POE maximum demand forecasts for South Australia

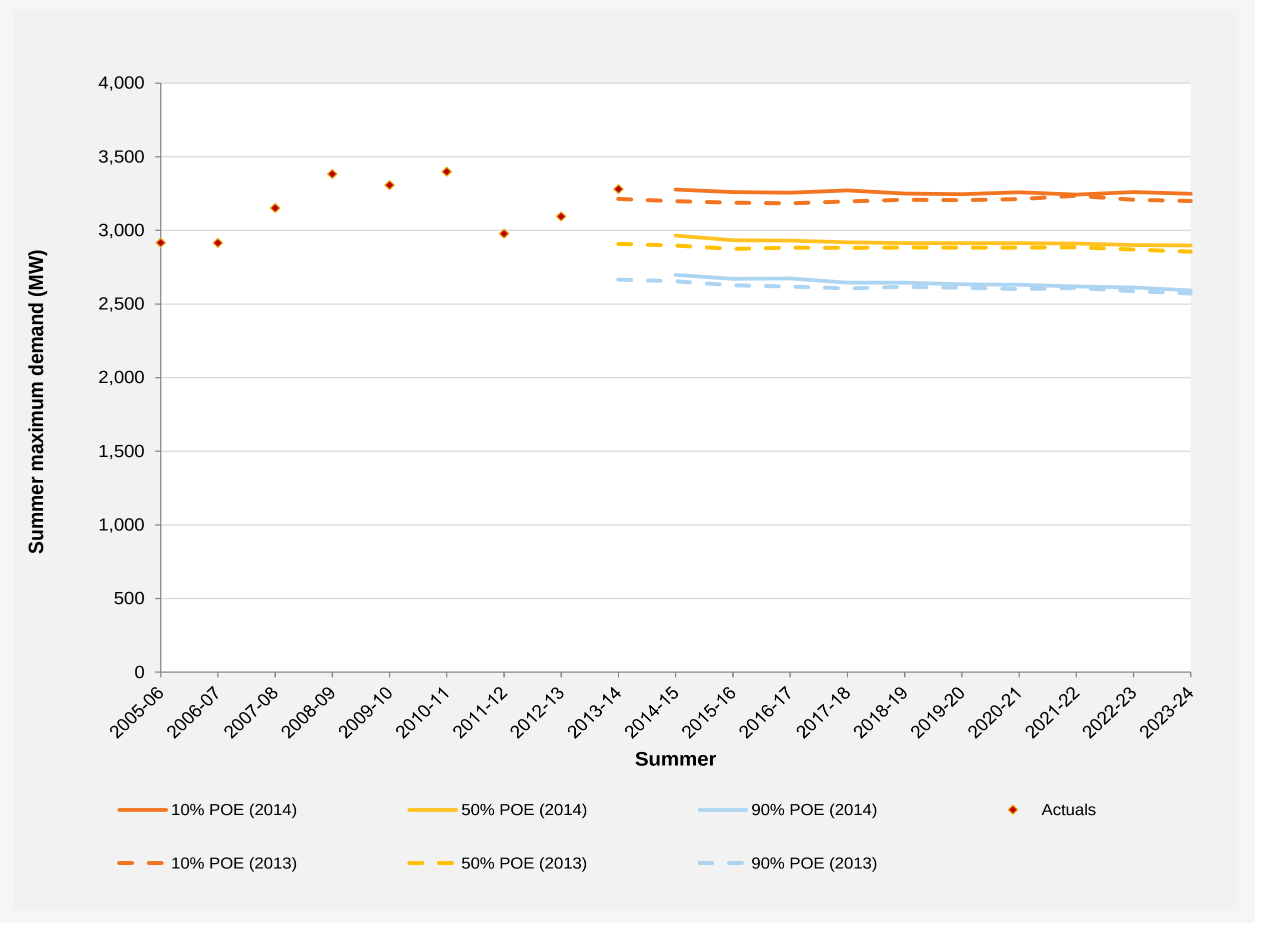
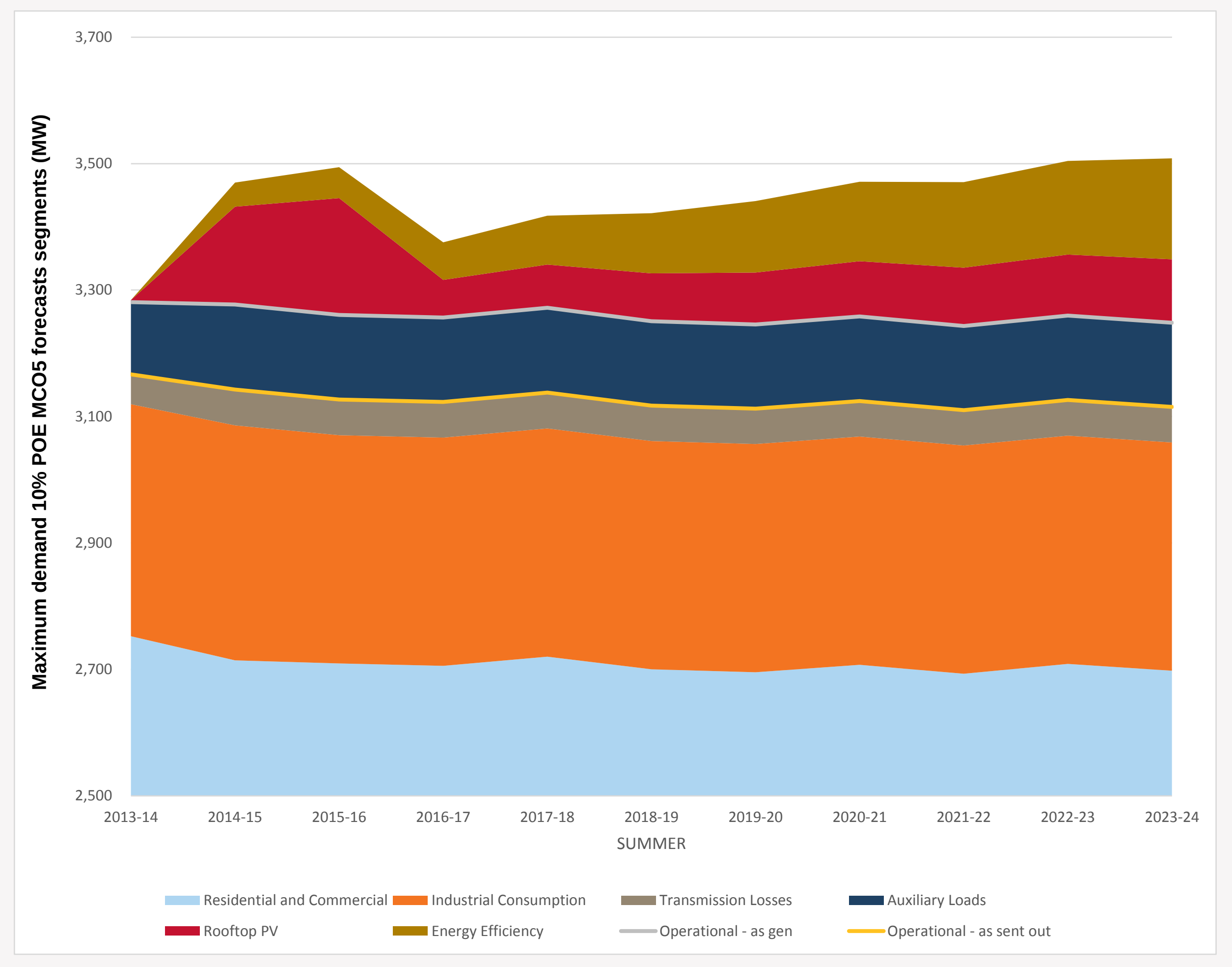


Table 9 — Summer 90%, 50% and 10% POE maximum demand forecasts for South Australia (MW)

	Actual	90% POE	50% POE	10% POE
2013-14	3,281			
2014-15		2,697	2,966	3,277
2015-16		2,671	2,934	3,261
2016-17		2,674	2,930	3,257
2017-18		2,646	2,920	3,272
2018-19		2,645	2,913	3,251
2019-20		2,634	2,914	3,246
2020-21		2,631	2,914	3,258
2021-22		2,619	2,910	3,243
2022-23		2,613	2,901	3,260
2023-24		2,593	2,898	3,248

5.4.2 Summer 10% POE maximum demand forecast segments

Figure 17 — Summer 10% POE maximum demand forecast segments for South Australia



CHAPTER 6 - VICTORIA FORECASTS

6.1 Annual energy forecasts

From 2009–10 to 2013–14, annual energy declined by 1,915 GWh (an annual average decline of 1.0%) to 45,691 GWh.

Key differences between the 2014 National Electricity Forecasting Report (NEFR) and the 2013 NEFR annual energy forecasts are:

- Current estimate for 2013–14: The current estimate for 2013–14 annual energy is 45,691 GWh, which is 829 GWh (1.8%) below the 2013 NEFR medium forecast.
- Medium short-term forecast (2013–14 to 2016–17): The 2014 forecast average annual growth rate is a decline of 2.1%, compared to an increase of 1.5% in the 2013 forecasts.

6.2 Maximum demand forecasts

Key differences between summer maximum demand (MD) forecasts in the 2013 and 2014 NEFRs include the following:

- 2013–14 summer MD was 10,313 MW on 28 January 2014. This was 160 MW below the 2013 NEFR 10% probability of exceedence (POE) forecast.
- The 10% POE MD is forecast to decrease at an annual average rate of 1.1% over the short term (2013–14 to 2016–17) medium scenario forecast, compared to an increase of 1.2% in the 2013 NEFR.

6.3 Key drivers: Victorian short-term forecasts

- Significant reduction in large industrial forecasts due to decreased aluminium and steel production, and reduced production at, or closure of, manufacturing plants. This includes the Point Henry aluminium smelter closure in August 2014, and car manufacturing plant closures.
- Increased residential and commercial consumption forecasts driven by the strongest population and income growth of all NEM regions. This increase is moderated by increased forecasts for rooftop photovoltaic (PV) penetration and energy efficiency offsets.
  - Victoria's strong growth in rooftop PV is the second highest in the NEM. PV growth results from the fall in PV system costs while financial incentives stay the same.
  - EE growth is forecast to increase year on year driven by Federal Government programs.
- PV is also causing MD to shift to later in the day. This long-term trend is seen in the short term, but to a much lesser extent. Victorian MD is expected to shift back to later in the day by 30 minutes in the short term

In the low scenario, AEMO has adopted a probabilistic approach to reflect the increased risk of reduced production or closure of aluminium smelters in response to less favourable economic conditions. This assumes a 50% reduction in operations across all NEM-connected aluminium smelters across 2015 to 2017, followed by closure once current arrangements with the respective State Governments or electricity providers expire.

6.3.1 Annual energy forecast

Figure 18 — Annual energy forecasts for Victoria

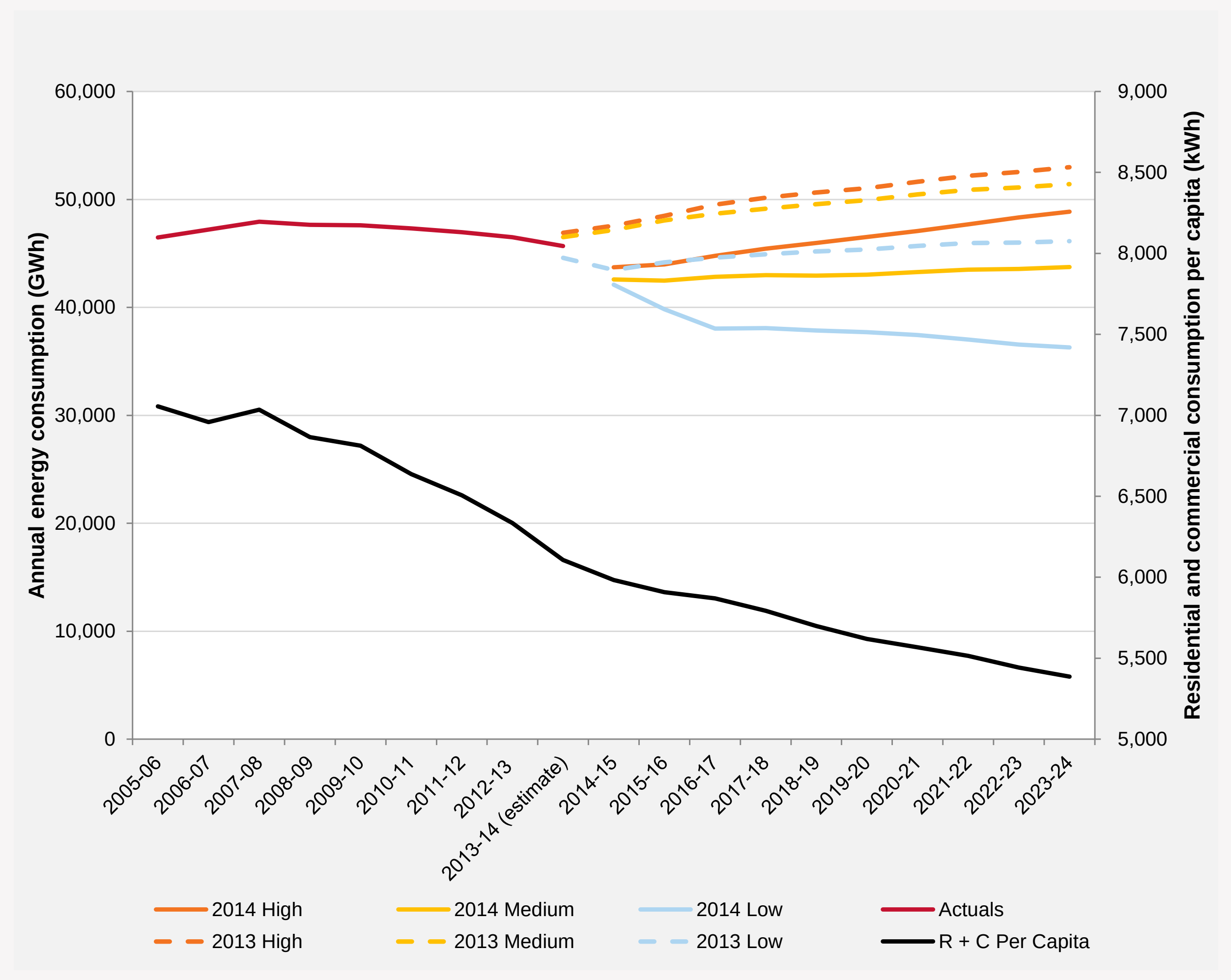
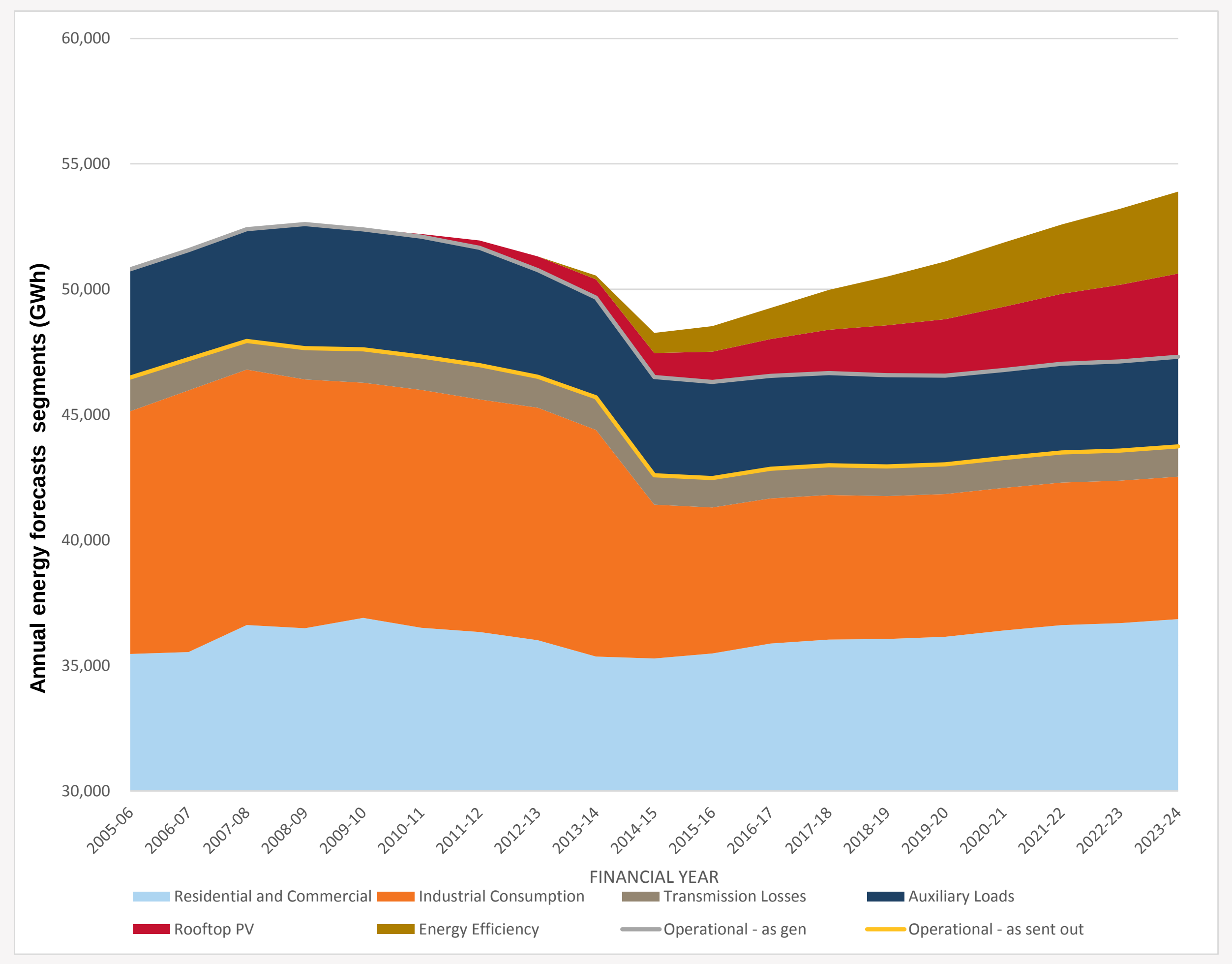


Table 10 — Annual energy forecasts for Victoria (GWh)

	Actual	High	Medium	Low
2013-14 (estimate)	45,691			
2014-15		43,707	42,586	42,095
2015-16		43,991	42,470	39,836
2016-17		44,770	42,842	38,044
2017-18		45,436	42,982	38,073
2018-19		45,976	42,938	37,856
2019-20		46,524	43,021	37,707
2020-21		47,068	43,272	37,447
2021-22		47,684	43,492	37,009
2022-23		48,325	43,570	36,547
2023-24		48,858	43,733	36,300

6.3.2 Annual energy forecast segments

Figure 19 — Annual energy forecast segments for Victoria



6.4 Maximum demand

6.4.1 Summer maximum demand forecasts

Figure 20 — Summer 90%, 50% and 10% POE maximum demand forecasts for Victoria

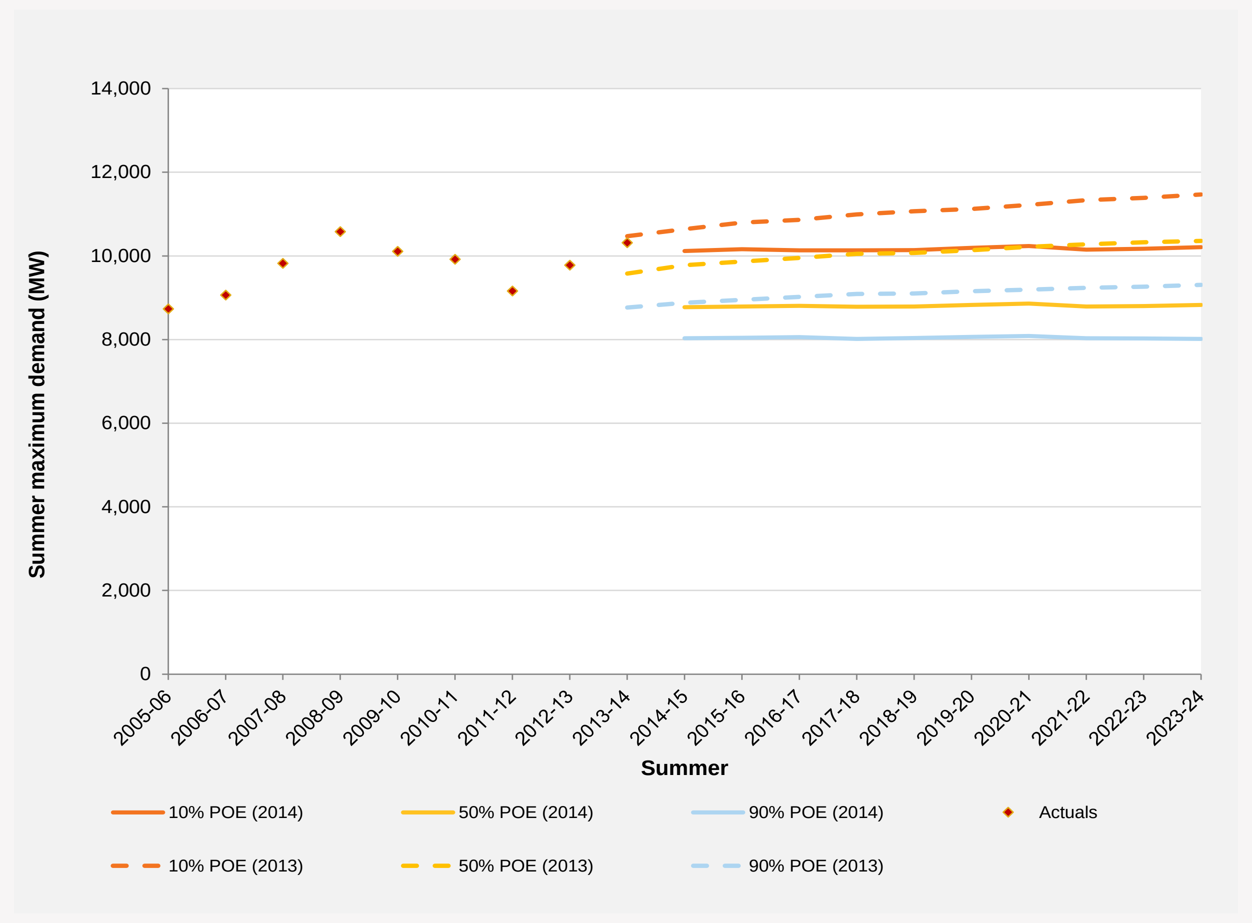
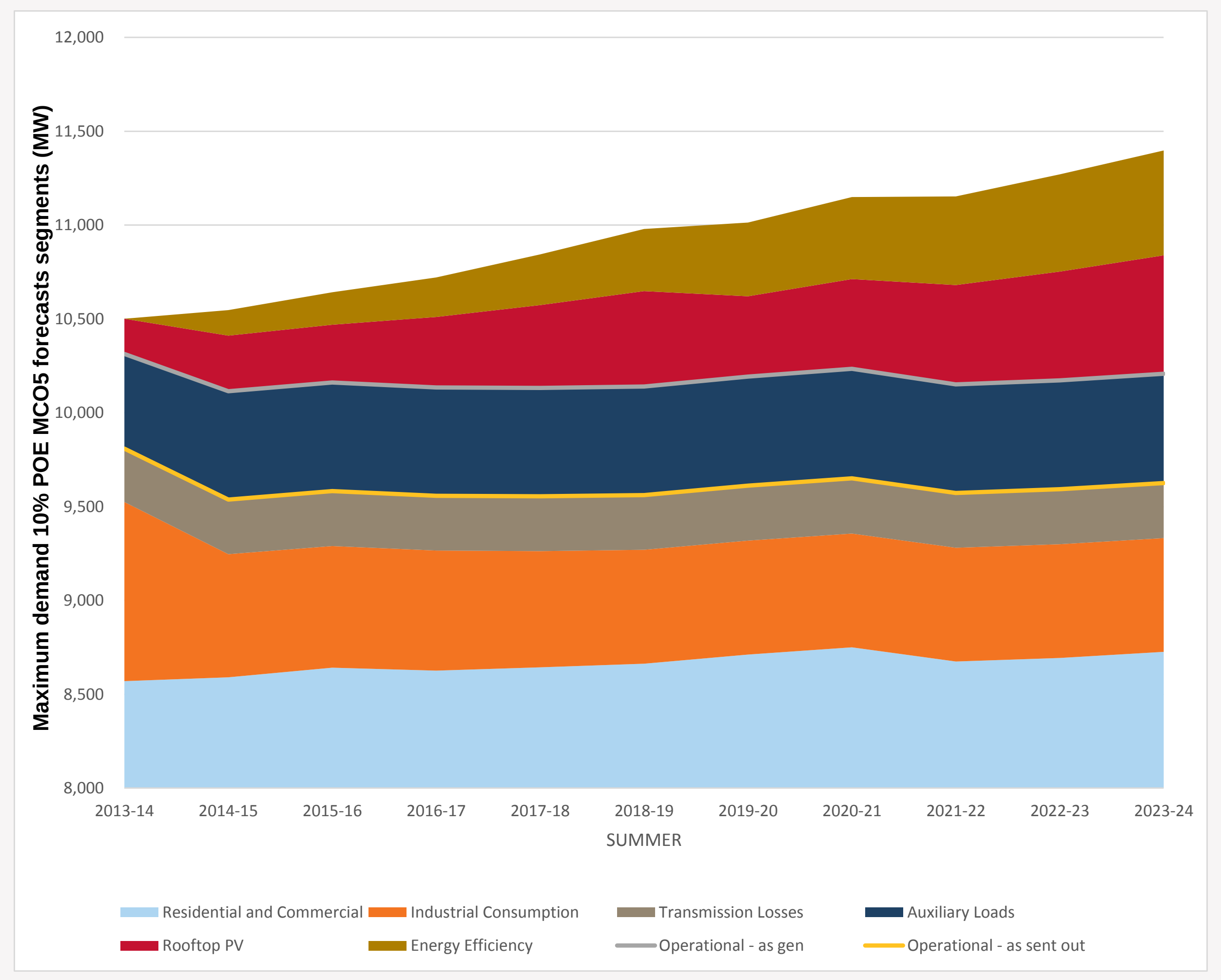


Table 11 — Summer 90%, 50% and 10% POE maximum demand forecasts for Victoria (MW)

	Actual	90% POE	50% POE	10% POE
2013-14	10,313			
2014-15		8,034	8,775	10,114
2015-16		8,041	8,791	10,162
2016-17		8,060	8,806	10,136
2017-18		8,014	8,787	10,132
2018-19		8,038	8,788	10,140
2019-20		8,062	8,829	10,193
2020-21		8,088	8,861	10,234
2021-22		8,030	8,789	10,152
2022-23		8,026	8,798	10,172
2023-24		8,014	8,827	10,208

6.4.2 Summer 10% POE maximum demand forecast segments

Figure 21 — Summer 10% POE maximum demand forecast segments for Victoria



CHAPTER 7 - TASMANIA FORECASTS

7.1 Annual energy forecasts

From 2009–10 to 2013–14, annual energy declined by 308 GWh (an annual average decline of 0.8%) to 10,098 GWh.

Key differences between the 2014 National Electricity Forecasting Report (NEFR) and the 2013 NEFR annual energy forecasts are:

- Current estimate for 2013–14: The current estimate for 2013–14 annual energy is 10,098 GWh, which is 21 GWh (0.2%) above the 2013 NEFR medium forecast.
- Medium short-term forecast (2013–14 to 2016–17): The 2014 forecast is an average annual decline of 0.8%, compared to a decline of 1.3% in the 2013 forecasts.

7.2 Maximum demand forecasts

Tasmania maximum demand (MD) occurs in winter. Key differences between winter MD forecasts in the 2013 and 2014 NEFRs are:

- 2013 winter MD was 1,683 MW on 24 June 2013. This was 33 MW below the 2013 NEFR 10% probability of exceedence (POE) forecast.
- The 10% POE MD is forecast to increase at an annual average rate of 0.9% over the short term (2013 to 2016) medium scenario forecast, compared to a decrease of 0.9% in the 2013 NEFR.

7.3 Key drivers: Tasmanian short-term forecasts

- Reduction in residential and commercial consumption forecasts due to the lowest population and state income growth across the NEM from 2013-14, and high PV uptake and EE savings
  - PV growth results from the fall in PV system costs while financial incentives stay the same.
  - EE growth is forecast to increase year on year driven Federal Government programs.
- A slight increase in large industrial forecasts reflects an increase in production at the Norske Skog Boyer paper mill, and an increase in Tasmania's mining activity.
- In winter, Tasmania experiences its MD in the morning, when contribution from PV is low. With the forecast growth in PV, the contribution from PV is expected to increase to the extent that the morning peak will become lower than the evening peak. When this occurs, MD will no longer be forecast to occur during the morning, but will move to late evening. This shift in time of MD is only seen in the long term. No shift occurs in the short term.

In the low scenario, AEMO has adopted a probabilistic approach to reflect the increased risk of reduced production or closure of aluminium smelters in response to less favourable economic conditions. This assumes a 50% reduction in operations across all NEM-connected aluminium smelters across 2015 to 2017, followed by closure once current arrangements with the respective State Governments or electricity providers expire.

Figure 22 — Annual energy forecasts for Tasmania

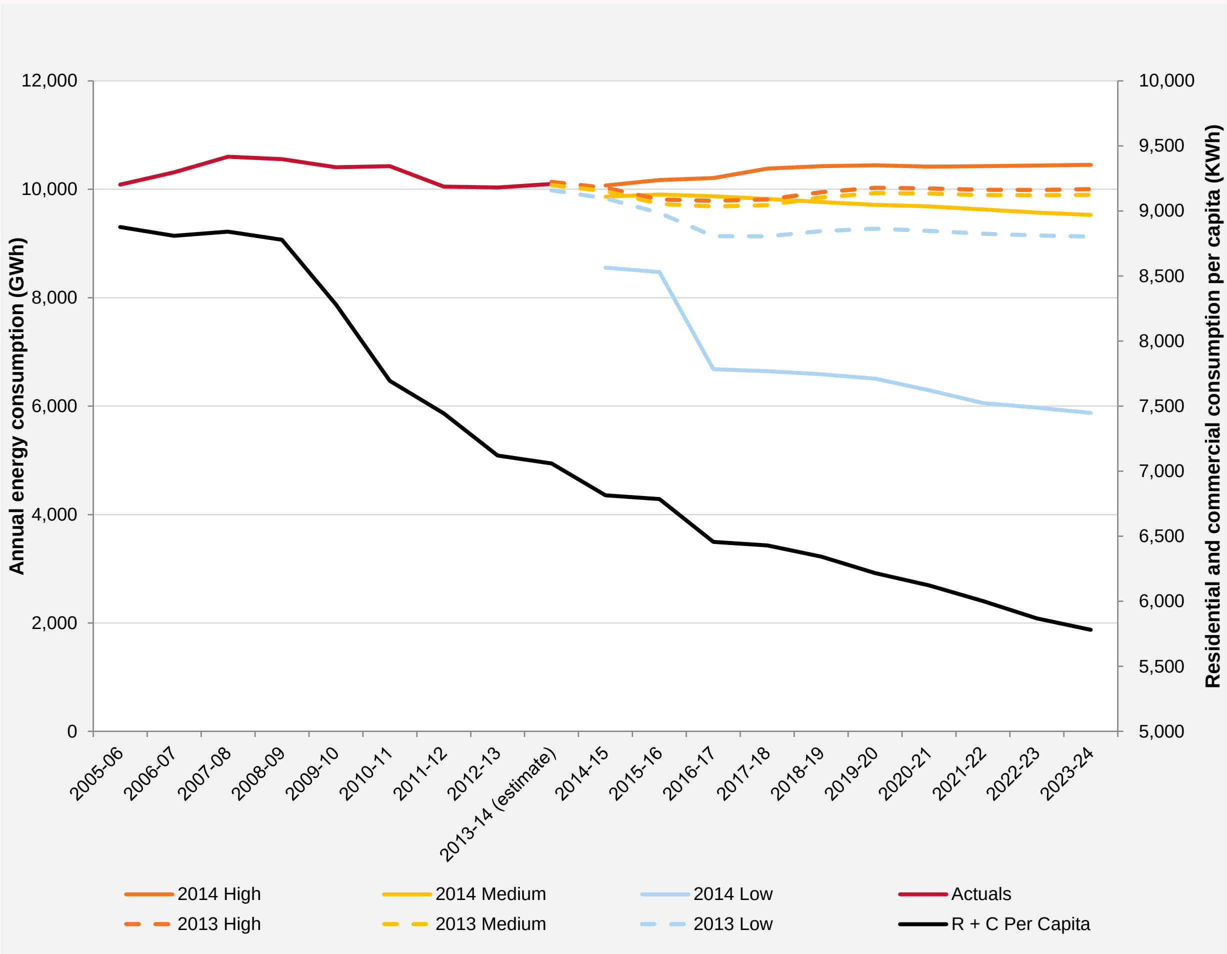
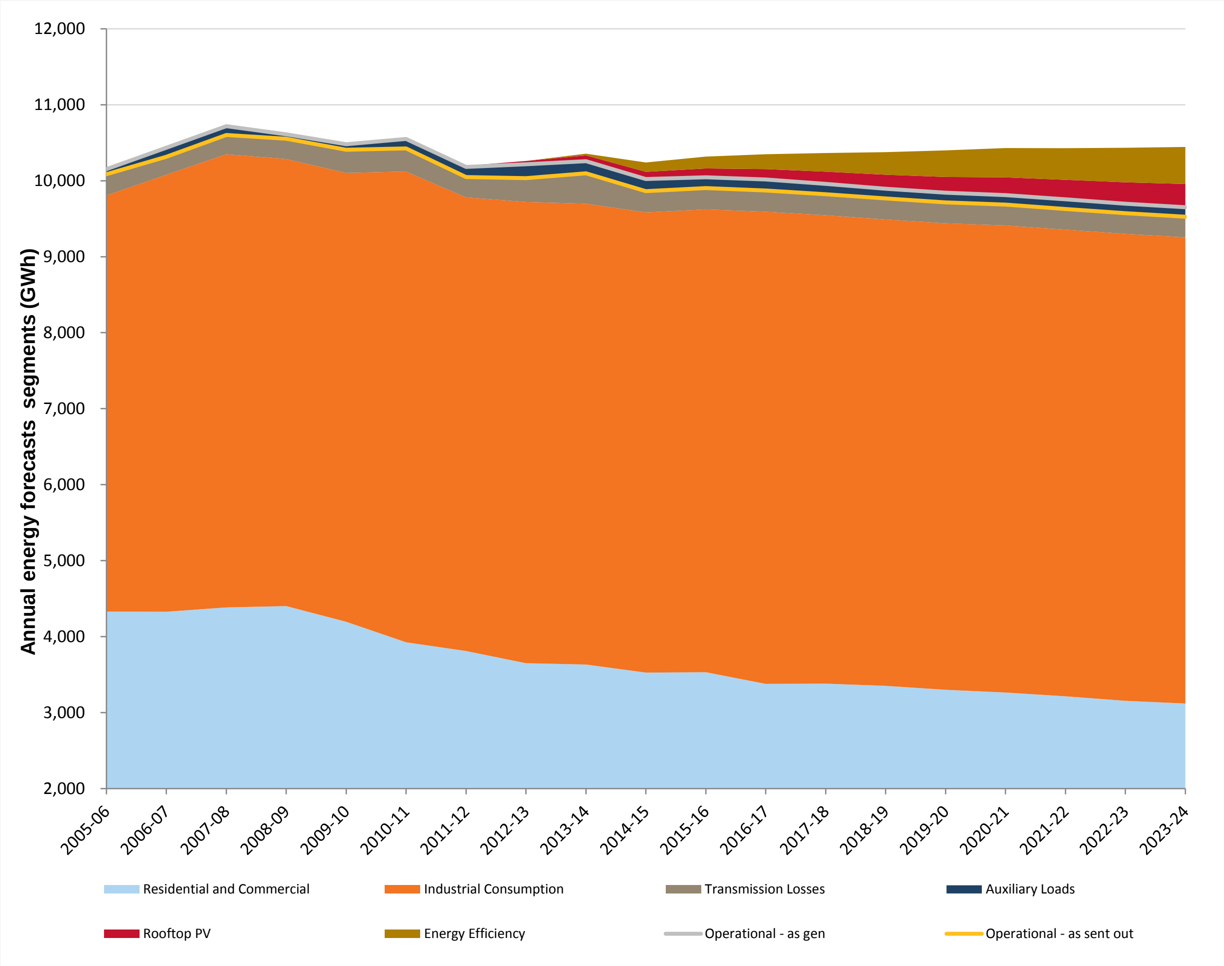


Table 12 — Annual energy forecasts for Tasmania (GWh)

	Actual	High	Medium	Low
2013-14 (estimate)	10,098			
2014-15		10,069	9,862	8,554
2015-16		10,169	9,903	8,471
2016-17		10,209	9,871	6,682
2017-18		10,382	9,823	6,646
2018-19		10,425	9,766	6,589
2019-20		10,441	9,714	6,508
2020-21		10,420	9,685	6,293
2021-22		10,426	9,629	6,055
2022-23		10,437	9,571	5,973
2023-24		10,450	9,525	5,875

7.3.1 Annual energy forecasts segments

Figure 23 — Annual energy forecasts segments for Tasmania



7.4 Maximum demand

7.4.1 Winter maximum demand forecasts

Figure 24 — Winter 90%, 50% and 10% POE maximum demand forecasts for Tasmania

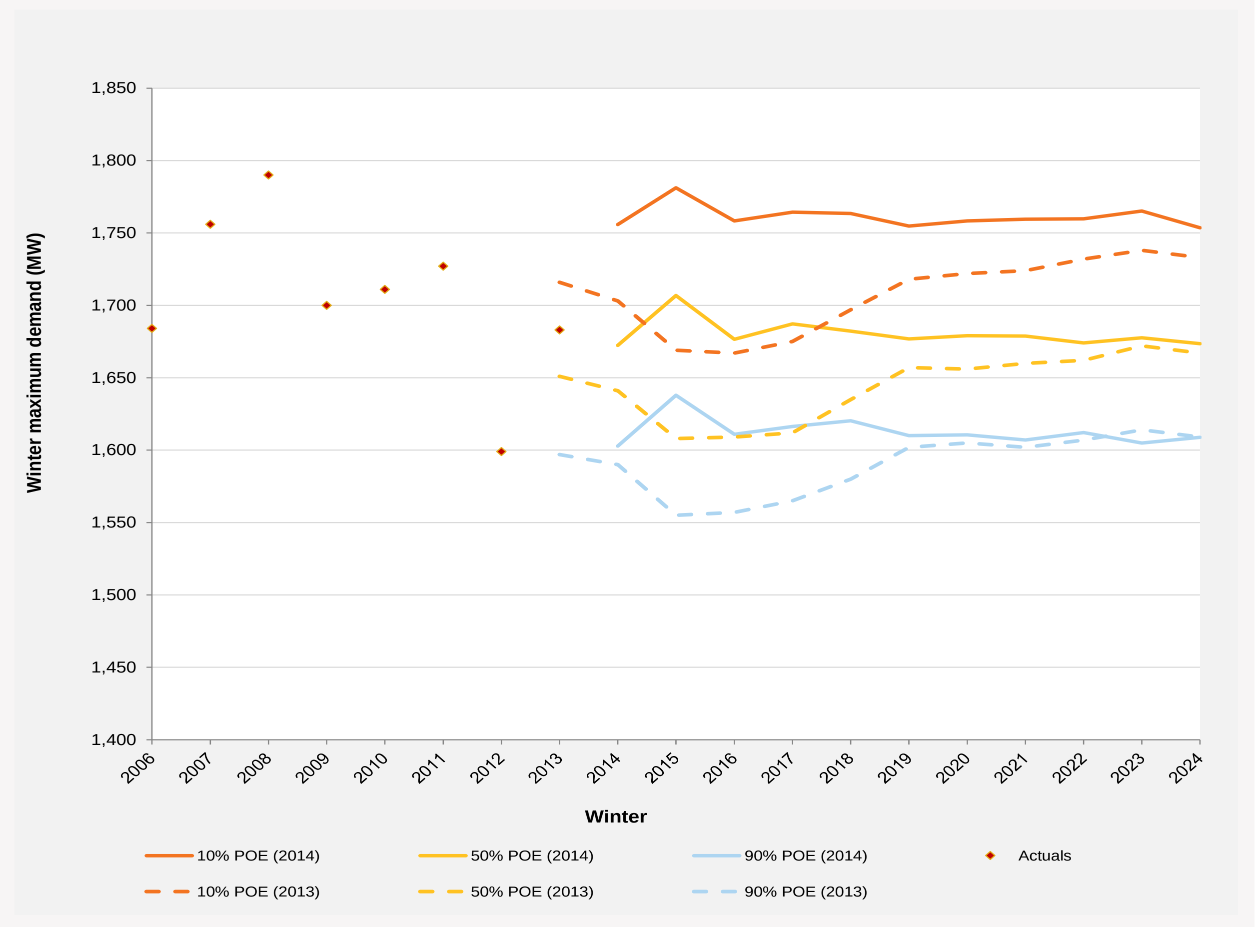
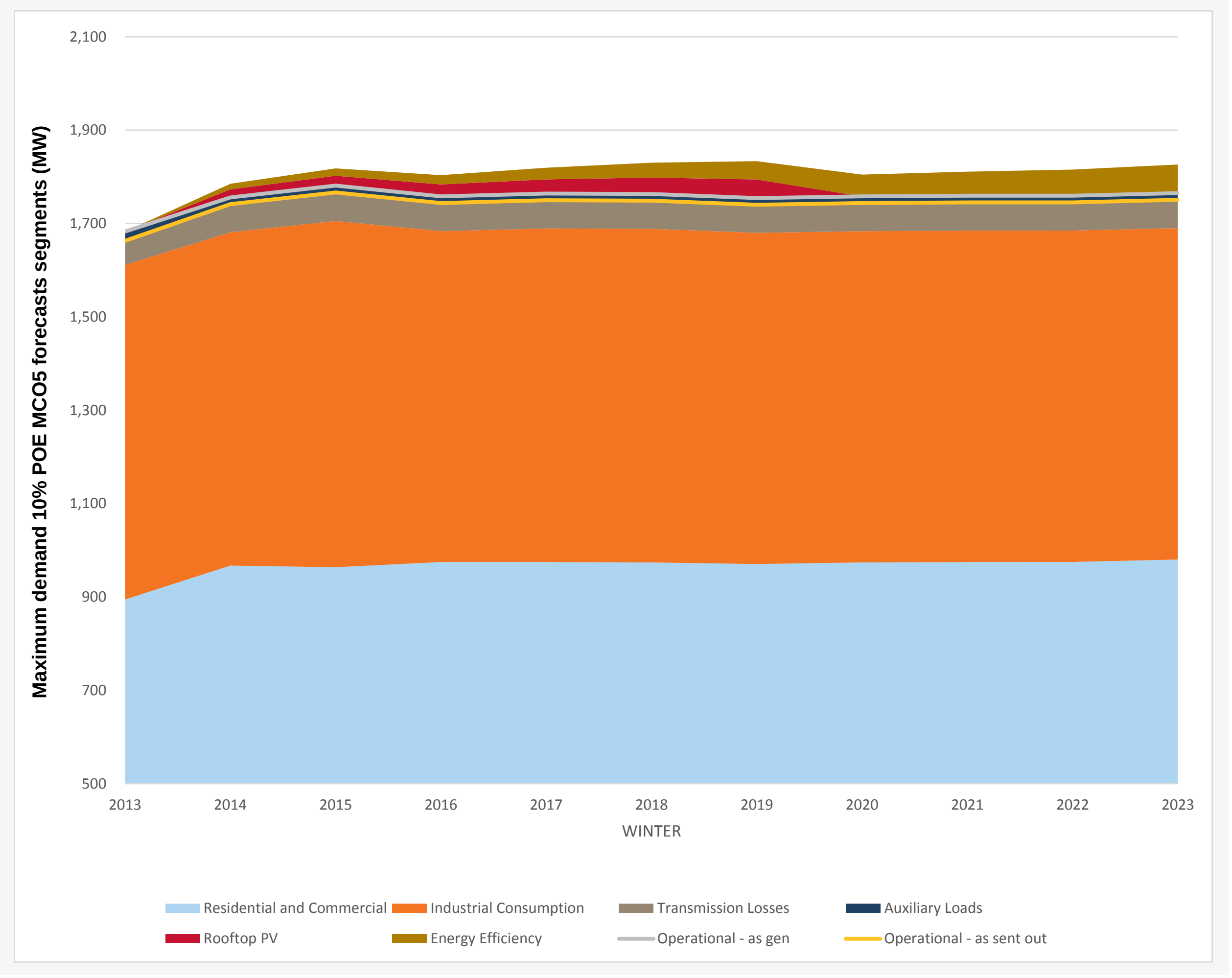


Table 13 — Winter 90%, 50% and 10% POE maximum demand forecasts for Tasmania (MW)

	Actual	90% POE	50% POE	10% POE
2013	1,683			
2014		1,603	1,672	1,756
2015		1,638	1,707	1,781
2016		1,611	1,677	1,758
2017		1,616	1,687	1,764
2018		1,620	1,682	1,764
2019		1,610	1,677	1,755
2020		1,611	1,679	1,758
2021		1,607	1,679	1,760
2022		1,612	1,674	1,760
2023		1,605	1,678	1,765

7.4.2 Winter 10% POE maximum demand forecasts segments

Figure 25 — Winter 10% POE maximum demand forecast segments for Tasmania



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
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
APR	Annual planning report
AUX	Power station auxiliaries
BOM	Bureau of Meteorology
DNSP	Distribution network service provider
DSP	Demand-side participation
EE	Energy efficiency
ESOO	Electricity Statement of Opportunities
GFC	Global financial crisis
GPG	Gas-powered generation
GSOO	Gas Statement of Opportunities
GSP	Gross state product

Abbreviation	Expanded name
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
MD	Maximum demand
NEM	National Electricity Market
NERF	National Electricity Repository for Forecasting
NIEIR	National Institute of Economic and Industry Research
NSW	New South Wales
NTNDP	National Transmission Network Development Plan
POE	Probability of exceedence
PV	Photovoltaic
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
TAS	Tasmania
TNSP	Transmission network service provider
VAPR	Victorian Annual Planning Report
VIC	Victoria

GLOSSARY

Definitions

Many of the listed terms are already defied in the National Electricity Rules (NER), version 54.10 For ease of reference, these terms are highlighted in blue. Some terms, although defined in the NER, have been clarified, and these terms are highlighted in green.

Term	Definition
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.

[10] An electronic copy of the latest version of the NER can be obtained from http://www.aemc.gov.au/rules.php.

Term	Definition
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.
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.
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 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.
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.
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.

Term	Definition
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.
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).

Term	Definition
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.
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 table lists the full name of companies that may be referred to in this document.

Group or short form name	Organisation or company name
AEMC	Australian Energy Market Commission
Clean Energy Council	Clean Energy Council Limited
ClimateWorks	ClimateWorks Australia
Point Henry aluminium smelter	Point Henry Aluminium Smelter (owned by Alcoa)
QCA	Queensland Competition Authority
SA Water	SA Water, Government of South Australia