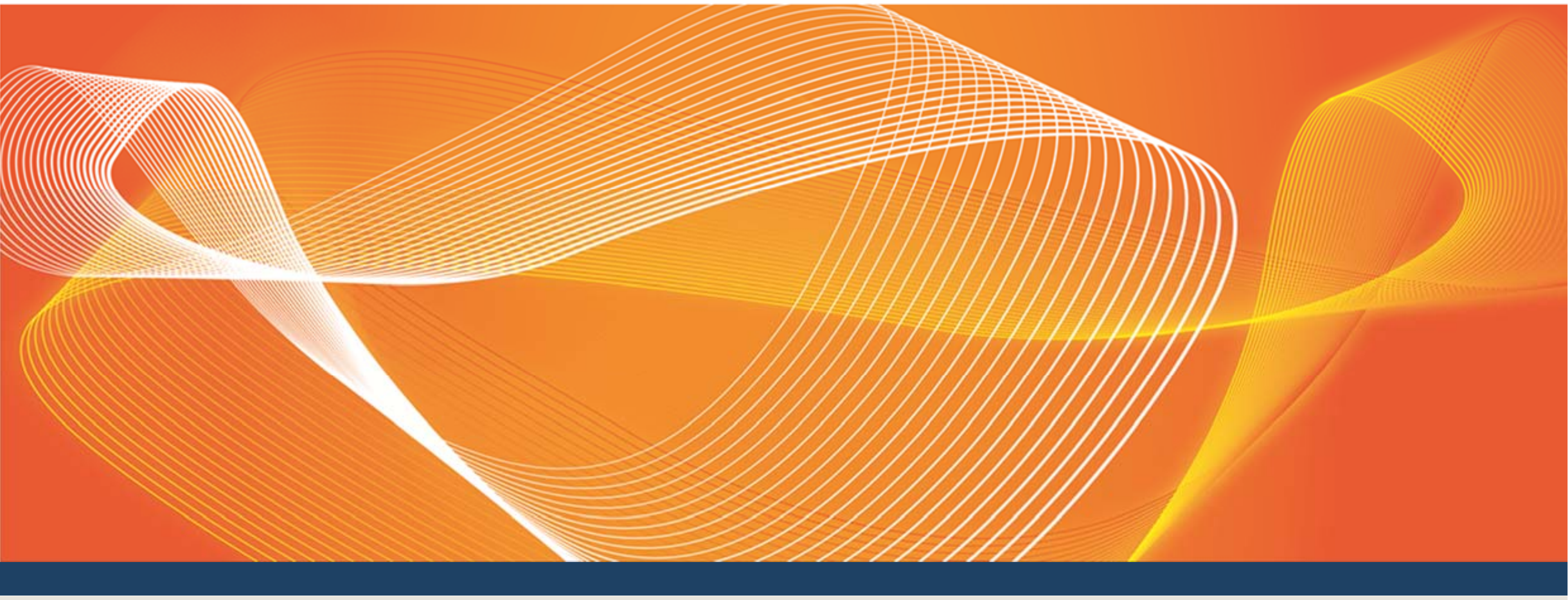
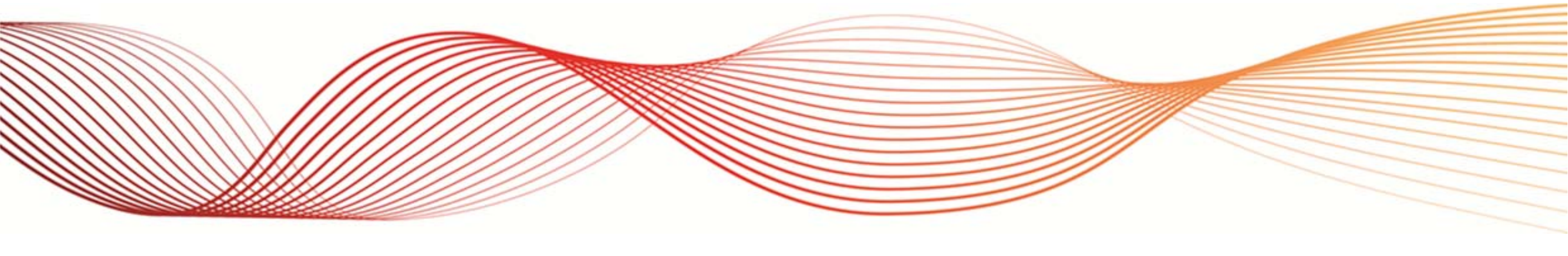


2015 AEMO TRANSMISSION CONNECTION POINT FORECASTING REPORT

FOR NEW SOUTH WALES
INCLDUING THE AUSTRALIAN CAPITAL TERRITORY

Published: **June 2015**



AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide information about transmission connection point forecasts for New South Wales including the Australian Capital Territory.

AEMO publishes the connection point forecasts as requested by the Council of Australian Governments through its energy market reform implementation plan.

This publication is based on information available to AEMO at 1 May 2015.

Disclaimer

AEMO has made every effort to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances.

This publication does not include all of the information that an investor, participant or potential participant in the national electricity market might require, and does not amount to a recommendation of any investment.

Anyone proposing to use the information in this publication (including information and reports from third parties) should independently verify and check its accuracy, completeness and suitability for purpose, and obtain independent and specific advice from appropriate experts.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this publication:

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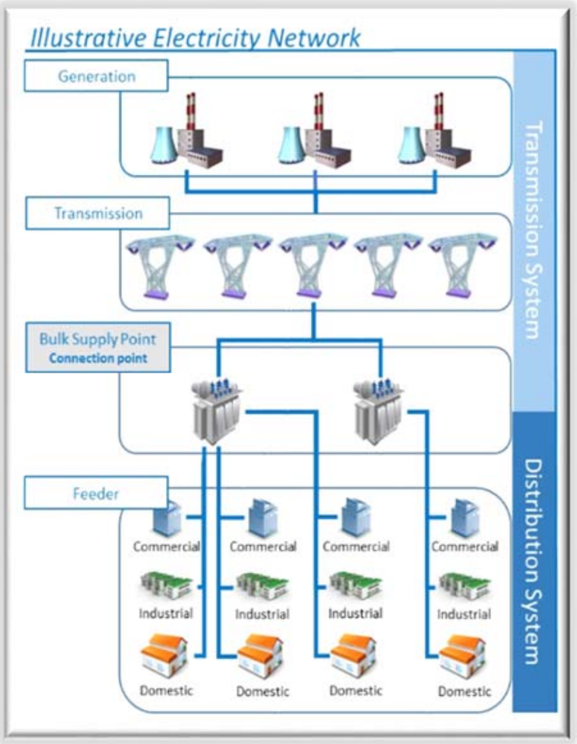
Acknowledgement

AEMO acknowledges the support, co-operation and contribution from NSW and ACT network service providers in providing data and information used in this publication.

EXECUTIVE SUMMARY

AEMO has developed Maximum Demand (MD) transmission connection point forecasts in New South Wales, including the Australian Capital Territory (ACT)[1], to provide detailed insights to local changes in demand from 2015–16 to 2024–25.



MD refers to the maximum amount of electricity used at a specific point in time, expressed in Megawatts (MW). A transmission connection point is where the transmission network meets the distribution network (see illustration).

Transmission connection point forecasts provide transparent, detailed demand information and trends at a local level. Together with the regional level MD forecasts published in AEMO's National Electricity Forecasting Report (NEFR)[2], the forecasts provide an independent and holistic view of electricity demand in the National Electricity Market (NEM). It is intended that this increased transparency will lead to more efficient network investment decisions, and ultimately provide long-term benefits to energy consumers.

AEMO has prepared MD forecasts based on 10% and 50% Probability of Exceedance (POE) forecasts, for both summer (2015–16 to 2024–25) and winter (2015 to 2024).

A POE refers to the likelihood that a MD forecast will be met or exceeded. A 10% POE MD forecast is expected to be exceeded, on average, one year in 10, while 50% POE forecasts are expected to be exceeded, on average, one year out of two.

Key results

AEMO's connection point summer forecast for New South Wales shows:

- 1.3% (10% POE) and 1.1% (50% POE) increase per annum from 2015–16 to 2024–25, attributed to population and economic growth.

This compares with the 2015 NEFR MD[3] regional New South Wales forecasts of:

- 1.3% (10% POE) and 1.2% (50% POE) per annum from 2015–16 to 2014–25.

The difference between the connection point summer forecast and NEFR MD forecast is due to AEMO presenting non-coincident connection point forecasts in this report, compared with the system peak forecasts in the NEFR. The sum of the MDs at each connection point may not equal the peak at each connection point because of differences in customer type or weather patterns during a day.

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[1] New South Wales forecasts refer to New South Wales including the ACT.

[2] AEMO. 2015 National Electricity Forecasting Report. Available at http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report.

[3] The NEFR native MD, based on the medium scenario.

Key results 2015–16 to 2024–25

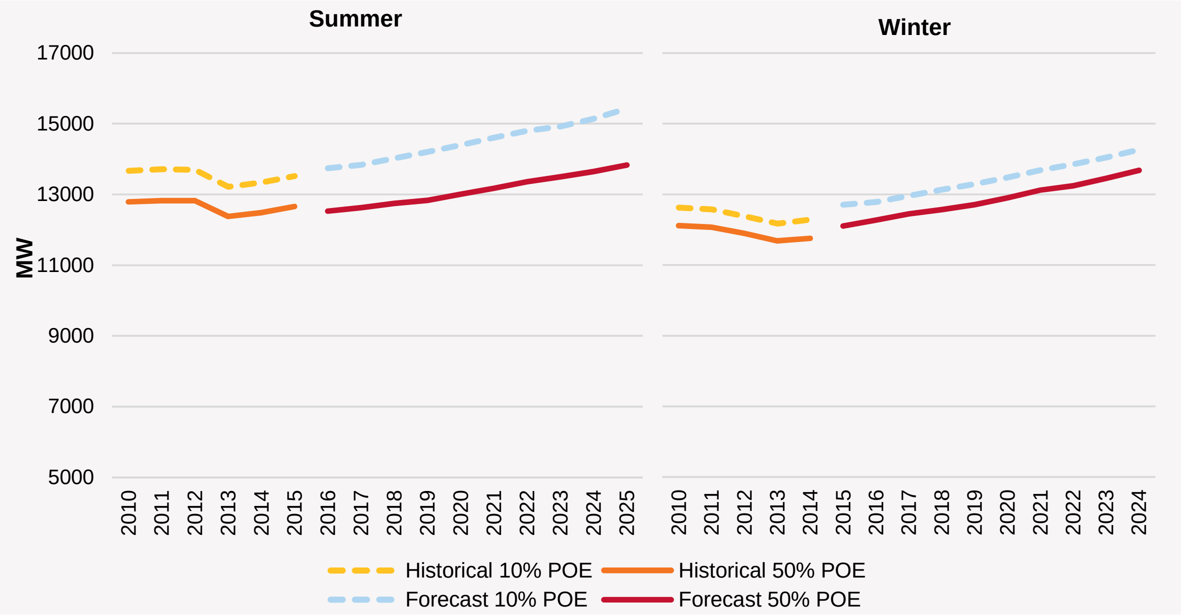
Table 1 MD forecast 2015–16 to 2024–25

Customer Sector	Attributed to	50% POE average annual rate of change*	10% POE average annual rate of change*
Residential and commercial	Population and economic growth increases connection point MD, offset by increased rooftop PV uptake and increased energy efficiency.	1.1% increase	1.3% increase
Major industrial (coal mines, metal industries, manufacturing)	No major developments.	0.0%	0.0%
Net change		**1.1% increase**	**1.3% increase**

*Note that this is the average rate of change. There is variation in the rates of change for individual connection points.

AEMO's aggregated New South Wales connection point forecasts are shown in Figure 1.The summer 50% POE forecast from 2015–16 begins 1.1% below its 2014–15 historical level, mainly due to rooftop PV and energy efficiency initiatives which reduce MD.

Figure 1 AEMO summer and winter forecasts for 10% POE and 50% POE



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1. INTRODUCTION

In its role as independent market and system operator, AEMO develops these forecasts for each transmission connection point to provide a higher level of detail than AEMO's NEFR about changes in demand, and observations on local trends. Together with the regional level MD forecasts published in the NEFR, the transmission connection point forecasts provide an independent and transparent view of electricity demand in the NEM, supporting efficient network investment and policy decisions for the long-term benefit of consumers.

AEMO provides transmission connection point forecasts for 10% and 50% POE MD levels for active power. This report focuses on 50% POE levels. The main purpose of the 10% POE forecasts, provided in the supplementary information to this report, is to assess the network's ability to withstand a single contingency under a limited set of generation dispatch patterns or interconnection power flow.

AEMO uses non-coincident forecasts in this report because they represent the MD required for network and asset planning. Non-coincident forecasts are the MD forecasts of a connection point, regardless of when the system peak occurs. Coincident forecasts are the MD forecasts of a connection point at the time system peak occurs.

1.1 Connection point definition

AEMO's connection point forecasting methodology, published in June 2013[4], defines a transmission connection point as the physical point at which the assets owned by a transmission network service provider (TNSP) meet the assets owned by a distribution network service provider (DNSP). These may also be known as bulk supply points (BSP).

In the National Electricity Market (NEM), electricity is notionally bought and sold at the regional reference node (RRN) in each NEM region. However, electricity is physically bought and sold at transmission connection points, represented in market metering and settlements processes by transmission node identities (TNIs).[5] Each connection point TNI refers to a set of physical sub-transmission lines owned by a DNSP and supplying a DNSP's customers.

To maintain a nationally consistent approach to transmission connection point forecasting, AEMO develops connection point forecasts at the TNI level:

- The forecasts apply to active power (MW) and reactive power (MVAr) MD at each connection point.
- The forecasts exclude transmission system losses and power station auxiliary loads.
- Embedded generators, where mentioned in forecast commentary, are assumed to be off at the time of MD.

Direct transmission connected customer forecasts are only published if AEMO has permission.

Connection points may be connected to one another at the distribution network level. In situations where this interconnectivity is extensive, AEMO develops a forecast for the aggregated load.

AEMO aims to maintain a forecasting process and methodology that incorporates the good forecasting characteristics listed by the AER.[6]

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[4] AEMO. Connection Point Forecasting: A Nationally Consistent Methodology for Forecasting Maximum Demand – Report. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting. Viewed: 23 January 2015.

[5] For a complete list of TNIs, refer to List of regional boundaries and Marginal Loss Factors for the 2014-15 financial year. Available: http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/List-of-Regional-Boundaries-and-Marginal-Loss-Factors-the-2014-15-Financial-Year. Viewed: 23 January 2015.

[6] AER. November 2011. Draft Distribution Determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17. Attachment 3.2 p.76. Available: http://www.aer.gov.au/sites/default/files/Aurora%202012-17%20draft%20distribution%20determination.pdf. Viewed: 23 January 2015.

1.2 Reactive power forecasts

AEMO estimates reactive power for the time of MD.[7] AEMO applies constant power factors to determine the reactive power forecast, so the distribution of reactive power and of active power rates of increase are the same.

AEMO's forecasting methodology for reactive power is based on historical power factors at the time of connection point MD. These power factors generally remain constant over consecutive seasons. For this reason, reactive power forecasts are developed by applying typical power factors to the final active power forecasts.

AEMO will review this approach in future forecasting exercises to confirm that it is still appropriate.

1.3 Supplementary information

Supplementary information, including the individual forecasts, is available on AEMO's website[8], and includes:

- Release of forecasts on AEMO's planning map[9], giving users a new opportunity to view dynamic information and to download csv files, covering 10% POE and 50% POE active and reactive power forecasts over a 10-year outlook period, summer and winter. High level commentary, and historical and forecast data, is also available on this map.
- Improvements to data processing and modelling in the methodology.
- Improvements to treatment of rooftop PV.
- An independent peer review of AEMO's forecasts from Frontier Economics.

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[7] Note: Reactive power estimates provide complementary information for power system studies.
[8] The dynamic interface: http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting
[9] The dynamic map: http://www.aemo.com.au/Electricity/Planning/Interactive-Planning-Maps

2. RESULTS AND INSIGHTS

2.1 Aggregated connection point results and insights

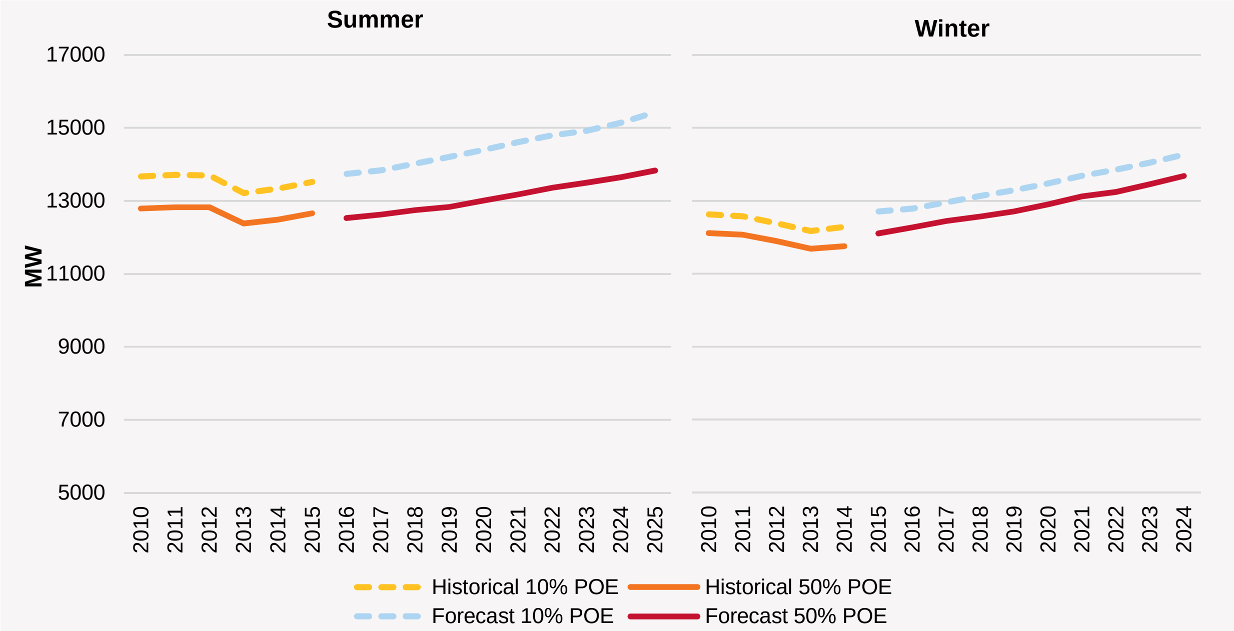
The connection point forecast for New South Wales shows:

- 1.3% (10% POE) and 1.1% (50% POE) increase per annum from 2015–16 to 2024–25 in summer.
- 1.3% (10% POE) and 1.4% (50% POE) increase per annum from 2015–16 to 2024–25 in winter.

The increases are attributed to growth in population and gross state product (GSP).

Figure 2 shows a continual year-on-year increase in the 2015 forecasts, in addition to historical (since 2010) weather-normalised demand, for 50% and 10% probability of exceedance (POE).

Figure 2 AEMO's aggregated, non-coincident 2015 forecasts



Overall, in NSW, the time of summer MD is not expected to shift to later in the day due to rooftop PV generation.[10] As such, the growth in 50% POE demand is offset by rooftop PV generation. In winter, demand is not offset by rooftop PV generation due to demand peaking in the evening when there is no PV generation.

Both summer and winter 10% POE forecasts are increasing by 1.3% per annum, based on aggregated non-coincident forecasts. Non-coincident forecasts are the MD forecasts of a connection point, regardless of when the system peak occurs. Coincident forecasts are the MD forecasts of a connection point at the time system peak occurs.

The summer 50% POE forecast from 2015–16 begins 1.1% below its 2014–15 historical level, mainly due to rooftop PV and energy efficiency initiatives which reduce MD. The summer and winter 10% POE forecasts and 50% winter forecast are also reduced by rooftop PV and energy efficiency initiatives but the reconciliation process increases the starting point of these forecasts.

AEMO's forecasts are reconciled[11] to the NEFR regional MD forecast, to include state-level economic drivers which are not included at the connection point level. This step also keeps the forecasts consistent with the NEFR.

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[10] This is consistent with the 2015 NEFR, which shows time of MD in all states, except NSW, is shifting to later in the day due to rooftop PV.

[11] Refer to Connection Point Forecasting report by ACIL Allen. Available at http://www.aemo.com.au/Electricity/Planning/Forecasting/~/media/Files/Other/planning/ConnectionPointForecastingANationallyConsistentMethodologyforForecastingMaximumElectricityDemandpdf.ashx. Viewed 16 June 2015

2.2 Individual connection point results and insights

While the aggregated demand is increasing, individual connection point forecasts[12] increase at some locations, and decrease at others, due to different drivers.

Key features of the summer forecasts:

- Average annual rates of change are between +5.8% (Mount Piper) and -2.6% (Munyang) for 50% POE. Drivers are listed in Table 2.
- 93% of connection points are forecast to have summer 50% POE average annual rates of less than +1.2% (which is the approximate NSW and ACT population growth rate).
- Impact of rooftop PV is expected to increase, with the overall offset growing from 2.9% to 5.1% over the outlook period.

Key features of the winter forecasts:

- Average annual rates of change are between +6.3% (Mount Piper) and -2.8% (Wagga North 66kV) for 50% POE. Drivers are listed in Table 2. Note also that new, direct, mining connections are excluded from this analysis due to confidentiality.
- 83% of connection points are forecast to have winter 50% POE average annual rates of less than 1.2% (which is the approximate NSW and ACT population growth rate).
- Rooftop PV is expected to offset demand by 0.1% over the outlook period because most connection points peak in the evening.

At the transmission connection point level, forecast changes in MD are generally in line with population growth. MD is expected to increase in urban and suburban areas due to population growth. In many NSW rural areas, demand is forecast to decrease or remain flat in line with a slower population growth.[13]

Connection points with average annual increases or decreases of more than 2% are shown in Table 2, as well as the drivers of demand.

See Appendix A for plotted individual 50% POE rates of change for each connection point.

Table 2 Drivers at connection points with average annual increase or decrease greater than 2%

Season	Forecast MD increase greater than 2%	Forecast MD decrease greater than 2%
Summer	**Mount Piper:** Mining load increase. **Western Sydney grouping:** Population growth. **Beryl 66 kV:** Mining load increase.	**Munyang:** The decline is 0.061 MW/year. It follows the historical trend.
Winter	**Mount Piper:** Mining load increase. **Western Sydney Grouping:** Population growth. **Wagga North 132kV:** Load transfer from Wagga North 66kV in 2015. **Sydney Grouping:** Population growth. **Queanbeyan (Essential Energy):** Population growth. **Beryl 66 kV:** Mining load increase.	**Wagga North 66kV:** Load transfer to Wagga North 132kV in 2015.

Note: 2% is set to capture extreme rates. One direct-connect mining load is excluded from the table due to confidentiality.

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[12] Refer to the dynamic interface for detailed information on individual connection points. Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting

[13] The 2014 population projections of the NSW Department of Planning & Environment were adopted. Last Accessed (19/06/2015) at: http://www.planning.nsw.gov.au/en-us/deliveringhomes/populationandhouseholdprojections.aspx

3. COMPARISON TO AEMO'S 2014 FORECASTS

AEMO's 2015 forecasts are higher than the AEMO's 2014 forecasts at the end of the outlook period. The differences are due to increases (in the 2015 forecasts) in population and GSP, and also lower and slower growth in residential electricity prices following the AER's price determinations.[14]

The 2015 50% POE forecasts are 2.4% higher for summer and 4.6% higher for winter. This can be seen in Figure 3, and the differences are further detailed in Table 3.

The 2015 50% POE forecasts have a stronger average annual increase in winter, compared to the 2014 forecasts (1.1% in 2015, 1.4% in 2014) following the increases in population and GSP. Commercial rooftop PV systems were included in 2015 forecasts, however this did not affect the winter forecasts as the time of peak is later in the day. Summer 50% POE forecasts have the same average annual increase as the 2014 forecasts (1.1%) because increased rooftop PV generation has mitigated the growth from increases in population and GSP.

Figure 3 AEMO 10% and 50% POE non-coincident aggregated connection point forecasts

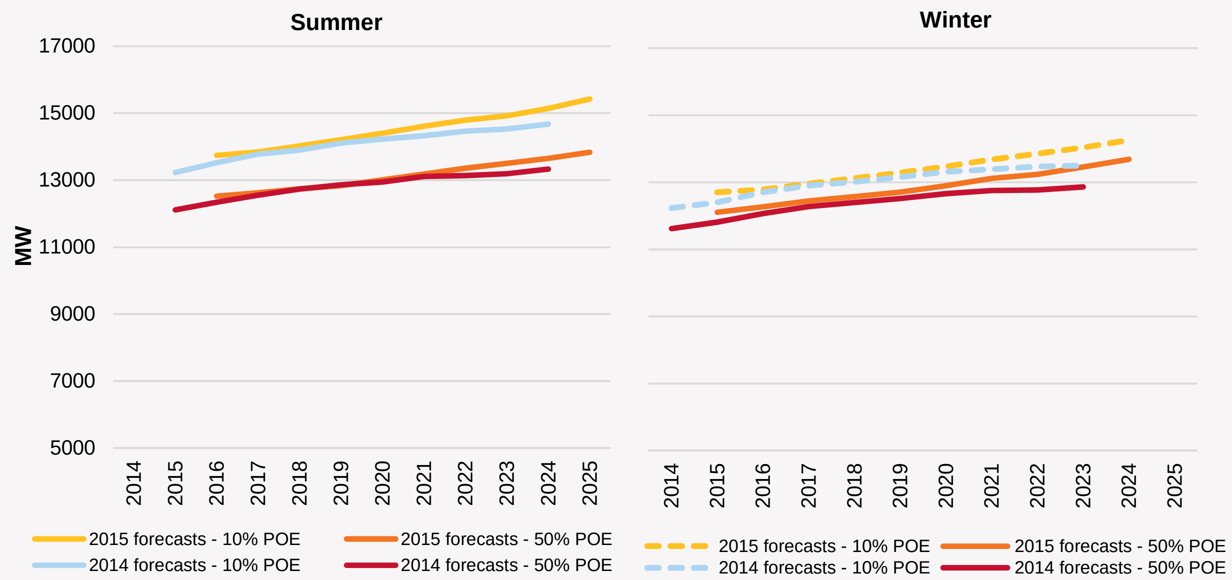

Table 3 Differences between AEMO's 2015 and 2014 aggregated forecasts

Forecast Demand	Differences between AEMO 2015 and 2014 forecasts (50% POE, aggregated forecasts)
Summer MD	AEMO's 2015 connection point forecast is 2.4% (319 MW) higher than the 2014 forecast at 2023–24.
Winter MD	AEMO's 2015 connection point forecast is 4.6% (592 MW) higher than the 2014 forecast at 2023.
Key drivers of differences: • Increased population and GSP. • A decrease in electricity price forecasts due to AER price determinations.	

The comparison between average annual increases in demand are summarised in Table 4, showing that the 2015 winter forecasts, overall, have increased when compared to the 2014 forecasts, whereas the summer increase remains unchanged.

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[14] 2015 NEFR Detailed summary of forecasts. http://aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report.

Table 4 Annual average increases (aggregated forecasts) of AEMO's 2015 and 2014 forecasts

Forecast	2015 Region-level average annual increase (50% POE)	2014 Region-level average annual increase (50% POE)
Summer	1.1%	1.1%
Winter	1.4%	1.1%

Table 5 lists methodology improvements that AEMO has made since the release of the 2014 forecasts. The changes are consistent with the actions outlined in AEMO's Transmission Connection Point Forecasting Action Plan. See Appendix B for further discussion on methodology improvements.

Table 5 Methodology improvements between AEMO 2014 and 2015 forecasts

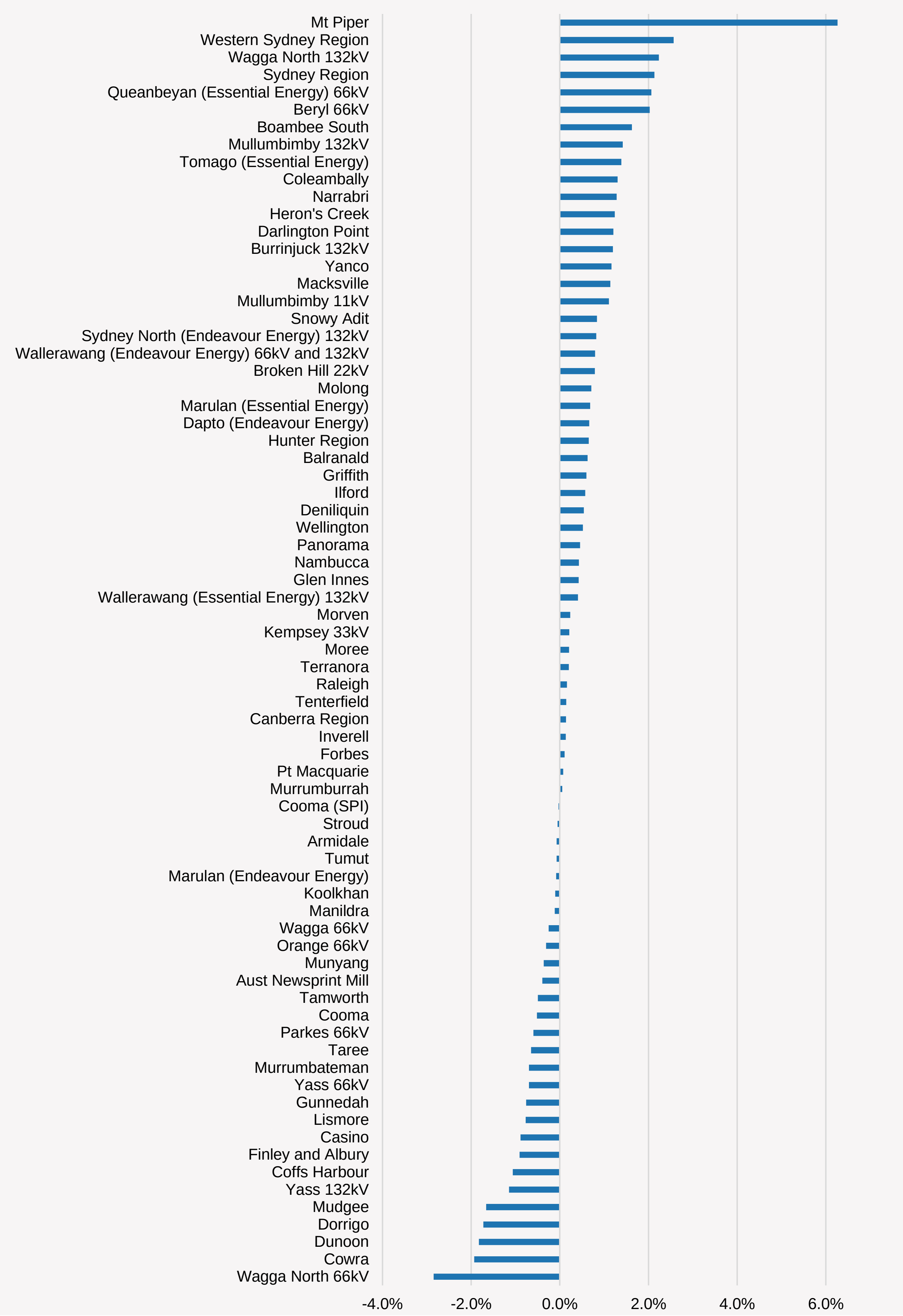
Forecast	Methodology improvements between AEMO 2014 and 2015 MD forecasts
Weather normalisation	Developed weather-demand relationships using three-year windows of data ('pooling'), improving the stability of the weather demand modelling process.
Rooftop PV	AEMO and the University of Melbourne developed a rooftop PV model which was used to improve estimates of PV generation at connection points. Improved the calculation of rooftop PV post-model adjustments, now equivalent to the recent forecasts for South Australia, Tasmania and Queensland. Commercial rooftop PV systems have been included in the forecasts through use of the 2015 NEFR rooftop PV forecasts.
Time trends	Fitted non-linear (cubic) models to weather-normalised historical data, to accommodate non-linear historical trends. Previously, only linear trends were fitted to the weather-normalised historical data.
Embedded generation	Expanded the embedded generator list and included large, non-market generators in the forecasts as generating 0 MW. This primarily increased the Western Sydney grouping, by approximately 270 MW.
Energy efficiency	NSW state-based schemes and a more granular approach to analysis of appliance impacts on MD were incorporated through use of the 2015 NEFR energy efficiency forecasts.

APPENDIX A. AVERAGE ANNUAL RATES OF CHANGE

Annual average rates of change in MD for each connection point are summarised in Figure 4 (summer) and Figure 5 (winter). Note that some connection points supplying industrial customers are excluded for confidentiality reasons.

Figure 4 Summer average annual rates of change in MD (50% POE)

Figure 5 Winter average annual rates of change in MD (50% POE)



APPENDIX B. FORECASTING PROCESS OVERVIEW

Improvements to the forecasting methodology

As part of its commitment to continuous improvement, AEMO published the Transmission Connection Point Forecasting Action Plan in October 2014.[15] In accordance with the plan, AEMO investigated possible areas of improvement in the forecasting process relating to forecast inputs and methodologies, and incorporated several improvements into the development of the current forecasts.

A summary of improvements since the 2014 forecasts were released is presented in Table 6.

Table 6 Improvements implemented for the NSW and ACT forecasts

Improvement description	Approach	Benefit	Implemented
Adjust historical data for block loads, load transfers, and rooftop PV at the daily or half-hourly level.	Applied adjustments for block loads and transfers and estimated rooftop PV output to the data at the half-hourly level, before weather normalisation.	The data was adjusted for: • Clearer handling of step changes that occurred mid-season. • A streamlined data preparation process for forecasting. • Realistic treatment of rooftop PV by using an adjustment that varies depending on the time of day and level of cloud cover.	Yes
Investigate use of non-linear models for time series trends and implement if improvements are found.	In addition to the linear trend, fitted a cubic trend to the weather-normalised historical data to provide an alternative time trend for forecasting.	This reduced the need for subjective judgements in determining forecast growth rates. The cubic trend provided an impartial alternative forecast for situations when the time trend was found to be non-linear (statistical test).	Yes
Investigate effectiveness of using pooled data across years to determine sensitivity to weather.	Tested and adopted pooling data using rolling three-year windows.	The improvement increased the stability of coefficients in the weather-demand modelling process.	Yes
Account for the time of day when making post-model adjustments for rooftop PV.	Using typical, connection point-specific, daily traces of demand on MD days, calculated the difference between the peak with and without rooftop PV, and applied this difference as the post-model adjustment.	The adjustment takes into account the daily load profile at each connection point. The adjustment inherently allows the time of MD to change as rooftop PV output increases with increasing installed capacity.	Yes

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[15] AEMO. Transmission Connection Point Forecasts. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting. Viewed: 23 January 2015.

APPENDIX C. DATA SHARED BY NETWORK SERVICE PROVIDERS

Network service providers provided crucial data during the forecasting development process.

Table 7 summarises the data provided.

Table 7 List of data provided by network service providers

Item	Description
Demand data	Half-hourly data at points not covered by national grid meters.
Embedded generation data	NMIs and descriptions for registered and exempt generators.
Industrial data	NMIs for industrial loads. Data at the half-hourly level (provided for the NEFR).
Load transfers and block loads	Permanent shifts at the 10% POE level, for historical and forecast periods.
MD forecasts	Latest forecasts.
PV installed capacity	List of NMIs.
Customer types	Numbers of customers by category, by connection point.
Network configuration information	Wholesale NMIs and transformers provided an understanding of the network and knowledge on network configuration.
Demand mix and local information	Provided on an ad hoc basis.

GLOSSARY

Definitions

This report uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified. Other key terms used are listed below.

Term	Definition
Active energy	A measure of electrical energy flow, being the time integral of the product of voltage and the in-phase component of current flow across a connection point, expressed in watthour (Wh).
Active power	The rate at which active energy is transferred.
Average annual (rate of change)	The compound average growth rate, which is the year-over-year growth rate over a specified number of years.
Block loads	Large loads that are connected or disconnected from the network.
Bulk supply point	A substation at which electricity is typically transformed from the higher transmission network voltage to a lower one.
Connection point	A point at which the transmission and distribution network meet.
Coincident forecasts	Maximum demand forecasts of a connection point at the time of system peak.
Distribution network	A network which is not a transmission network.
Distribution system	A distribution network, together with the connection assets associated with the distribution network (such as a transformer), which is connected to another transmission or distribution system. Connection assets on their own do not constitute a distribution system.
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.
Generating unit	The actual generator of electricity and all the related equipment essential to its functioning as a single entity.
Generation	The production of electrical power by converting another form of energy in a generating unit.
Installed capacity	The generating capacity in megawatts 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	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 transfer	A deliberate shift of electricity demand from one point to another.
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).
Network service provider (transmission – TNSP; distribution – DNSP)	A person who engages in the activity of owning, controlling or operating a transmission or distribution system and who is registered by AEMO as a Network Service Provider.
Network Meter Identifier (NMI)	A unique identifier for connection points and associated metering points used for customer registration and transfer, change control and data transfer.

Term	Definition
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).
Non-coincident forecasts	The maximum demand forecasts of a connection point, irrespective of when the system peak occurs.
Probability of exceedance (POE) maximum demand (MD)	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.
Reactive energy	A measure, in varhour (varh), of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of current flow across a connection point.
Reactive power	The rate at which reactive energy is transferred. Reactive power is a necessary component of alternating current electricity which is separate from active power and is predominantly consumed in the creation of magnetic fields in motors and transformers and produced by plant such as: • Alternating current generators • Capacitors, including the capacitive effect of parallel transmission wires • Synchronous condensers.
Region	An area determined by the AEMC in accordance with Chapter 2A of the National Electricity Rules (NER).
Regional Reference Node	A location on a transmission or distribution network to be determined for each region by the AEMC in accordance with Chapter 2A of the National Electricity Rules (NER).
Residential and commercial load	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.
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.
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).
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.
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 Node Identity (TNI)	Identifier of connection points across the NEM.
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.
Winter	Unless otherwise specified, refers to the period 1 June – 31 August (for all regions).

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
kV	Kilovolt
MW	Megawatt
MWh	Megawatt hour
MVAr	Megavolt ampere reactive

Abbreviations

Abbreviation	Expanded name
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
BSP	Bulk Supply Point
DNSP	Distribution Network Service Provider
GSP	Gross state product
MD	Maximum demand
NEFR	National Electricity Forecast Report
NEM	National Electricity Market
NER	National Electricity Rules
NSW	New South Wales
POE	Probability of Exceedance
PV	Photovoltaic
RRN	Regional Reference Node
TNI	Transmission Node Identifier
TNSP	Transmission Network Service Provider