AEMO TRANSMISSION CONNECTION POINT FORECASTING REPORT

FOR VICTORIA

FORECASTS DEVELOPED BY AEMO

Published: September 2014

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide information about transmission connection point forecasts for Victoria.

AEMO publishes these connection point forecasts as requested by the Council of Australian Governments' energy market reform implementation plan. This publication is based on information available to AEMO as at 18 September 2014, although AEMO has endeavoured to incorporate more recent information where practical.

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.

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Acknowledgement

AEMO acknowledges the support, co-operation and contribution from AusNet Services, CitiPower and Powercor Australia, United Energy, and Jemena in providing data and information used in this publication.

EXECUTIVE SUMMARY

The Australian Energy Market Operator (AEMO) has produced the first electricity demand forecasting report of maximum demand (MD) at transmission connection point level for Victoria. This follows the publication of AEMO's first Connection Point Forecasting Reports for New South Wales and Tasmania in July 2014[1].

AEMO has developed these connection point forecasts at the request of the Council of Australian Governments (COAG) as part of its energy market reform implementation plan, and will extend this work to include all NEM regions.

AEMO's MD forecasts, developed at the point where the transmission network meets the distribution network, provide transparent, granular demand information at a local level. Together with the regional level MD forecasts published in AEMO's National Electricity Forecasting Report[2] (NEFR), the forecasts provide an independent and holistic view of electricity demand in the National Electricity Market (NEM). The increased transparency of maximum demand forecasts supports efficient network investment for the long-term benefit of consumers.

MD forecasts at the connection point are also used as an input into AEMO's planning studies, further strengthening AEMO's independent assessment of network infrastructure development requirements across the transmission system.

AEMO consulted widely with stakeholders in developing these connection point forecasts, and in particular with the relevant distribution network service providers (DNSPs). This involved sharing local knowledge about the network, understanding differences in forecasting methodologies, and exchanging data.

In producing these connection point forecasts, AEMO applies the same forecasting methodology across all NEM regions, supporting a consistent and transparent approach to connection point forecasts in all regions.

AEMO also publishes the Victorian Terminal Station Demand Forecast (TSDF) in a separate report. The TSDF is not developed by AEMO; it is compiled by AEMO from forecasts provided by Victorian DNSPs and direct-connect customers, and reflects participant expectations of future demand.

Key findings of Victorian connection point forecasts from 2014–15 to 2023–24:

AEMO has developed 10% and 50% probability of exceedance (POE) MD forecasts, for active power (in MW) and reactive power (in MVAr), for a 10-year outlook period for summer (2014–15 to 2023–24) and winter (2014 to 2023).

Season	Region level average annual growth rate (10% POE)	Range of average annual connection point growth rates (10% POE)
Summer	0.1%	-6.5% to 11.3%
Winter	0.9%	-4.4% to 19.9%

Key Drivers:

- **Overall demand in Victoria is flattening, however there are some connection points that are growing requiring network investment.**
- **Positive growth is primarily driven by load transfers, population growth and a positive economic outlook, which is incorporated into the forecasts through reconciliation to the regional forecast (NEFR 2014).**
- **Declines in growth are driven primarily by load transfers, energy efficiency savings, and rooftop photovoltaic (PV) output during summer.**

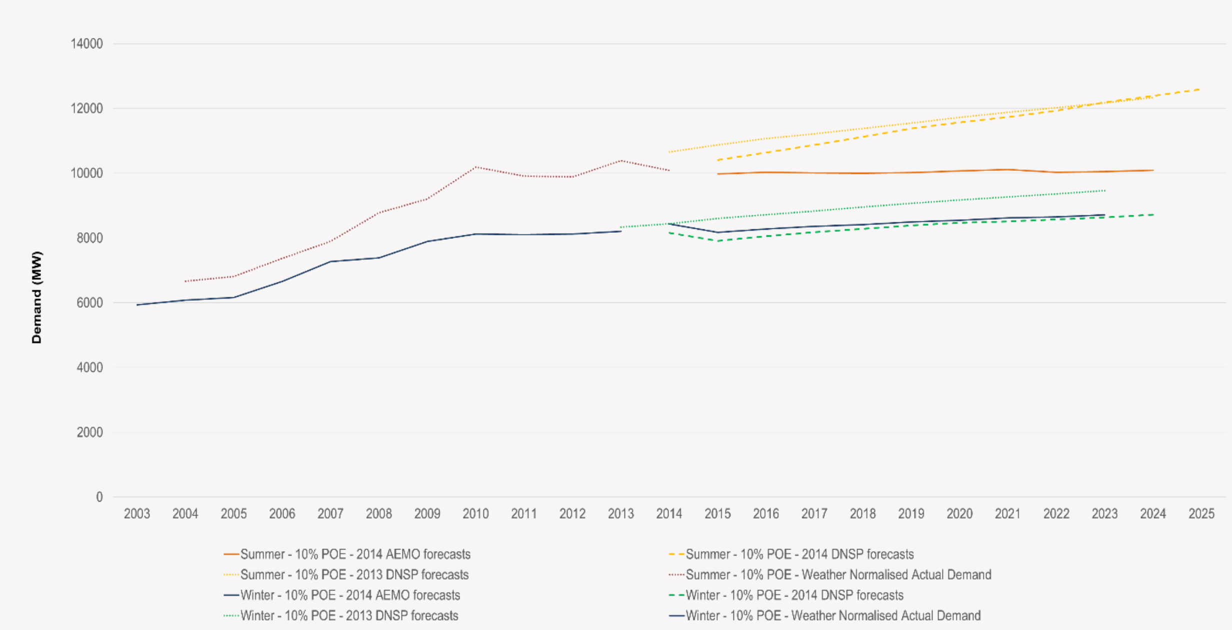
[1] AEMO. *Transmission Connection Point Forecasts.* Available at http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting/Transmission-Connection-Point-Forecasts. Viewed 23/09/2014.

[2] AEMO. *National Energy Forecasting Report 2014.* Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report. Viewed 11/09/2014.

Differences between the Victorian connection point forecasts and the Victorian TSDF

The aggregated Victorian connection point forecasts and the aggregated TSDF forecasts for 2013 and 2014 are show in Figure 1.

Figure 1 Aggregated 10% POE connection point forecast, compared with aggregated TSDF forecasts for 2013 and 2014.



Season	Differences in aggregated forecasts
Summer	The Victorian connection point forecast is > 2000 megawatts (MW) lower than the Victorian TSDF at end of 10 year outlook period
Winter	Both forecasts are similar at end of 10 year outlook period

Key Drivers:

- **Different assessment of forecast growth rates – TSDF forecasts higher growth rates.**
- **Different assessment of energy efficiency impact and rooftop (PV) output – TSDF forecasts lower impacts, and at some connection points models zero impact.**

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1. INTRODUCTION

Under Clause 5.12 in the National Electricity Rules (NER), each transmission network service provider (TNSP) must undertake an annual planning review that analyses the future operation of its transmission network. The review must use transmission connection point forecasts provided by the local DNSPs, planning proposals, and other relevant information.

AEMO publishes the Victorian Terminal Station Demand Forecast (TSDF) report, as required by the National Electricity Rules, clause 5.11.1(a). The TSDF is not developed by AEMO; it is compiled by AEMO from forecasts provided by Victorian DNSPs and direct-connect customers, and reflects participant expectations of future demand.

In its December 2012 energy market reform implementation plan[3], COAG requested that AEMO begin providing demand[4] forecasts to improve the Australian Energy Regulator's (AER's) ability to analyse the demand forecasts submitted by network service providers (NSPs). It is intended that this increased transparency will lead to more efficient network investment decisions, and ultimately providing long-term benefits to energy consumers.

This report details transmission connection point forecasts for Victoria, and follows the publication of AEMO's first Connection Point Forecasting Reports for New South Wales and Tasmania in July 2014[5].

In 2014–15, AEMO will extend this work to South Australia and Queensland, as well as update its forecasts for New South Wales and Tasmania.

By July 2015, AEMO will have developed its first complete set of transmission connection point forecasts for all NEM regions. These forecasts will be updated annually.

This report covers transmission connection point forecasts for Victoria. The forecasts are developed using a consistent methodology published on AEMO's website in June 2013[6], which facilitates:

- Consistency: across regional (state) borders.
- Relevance: taking into account economic, policy, and technological developments.
- Transparency: providing a breakdown of regional forecasts to increase understanding and help scenario analysis in investment decision-making.
- Accountability: performance monitoring of actual demand against forecast demand.

AEMO has developed 10% and 50% POE MD forecasts, for active power (in MW) and reactive power (in MVAr) , for a 10-year outlook period for summer (2014–15 to 2023–24) and winter (2014 to 2023).

In developing the forecasts, AEMO consulted with DNSPs in Victoria. This included meetings, workshops, data sharing, and exchanging local level information.

To further maintain the independence of these forecasts, AEMO engaged Frontier Economics as an independent peer reviewer, to the modelling process.

[3] COAG. *COAG Energy Market Reform – Implementation Plan.* Available at: https://www.coag.gov.au/node/481. Viewed 11/09/2014.
[4] Demand in this document is defined as operational demand of electricity from residential, commercial and large industrial sectors (excluding transmission losses) as supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, typically measured in megawatts.
[5] AEMO. *Transmission Connection Point Forecasts.* Available at http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting/Transmission-Connection-Point-Forecasts. Viewed 23/09/2014.
[6] AEMO. *Connection Point Forecasting: A Nationally Consistent Methodology for Forecasting Maximum Demand – Report.* Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting. Viewed 11/09/2014.

1.1 Report structure

This report is structured as follows:

- Chapter 1: Introduction
- Chapter 2: Provides an overview of the forecasting process. This includes a summary of the timeline, the methodology and how it was implemented.
- Chapter 3: Highlights key results for Victoria. This includes graphs of 10% and 50% POE (summer and winter) forecasts, a summary of the average annual growth rates for each connection point across the outlook period, and key features of the connection points.
- Chapter 4: Provides a list of improvements AEMO has identified as requiring further investigation.
- Appendix A: Provides a detailed breakdown of growth rates by connection point.
- Appendix B: Provides a list of data shared between AEMO and NSPs.

1.2 Supplementary information on AEMO's website

Supplementary information to this report includes:

- A spreadsheet with the following information for each transmission connection point:
  - 10% POE and 50% POE active power, measured in megawatts (MW), forecasts over a 10-year outlook period, summer and winter.
  - High-level commentary.
  - Historical and forecast data.
- A separate spreadsheet for reactive power, measured in megavolt-amperes-reactive (MVAr), for each transmission connection point.
- A report from Frontier Economics (independent peer reviewer) providing a review of AEMO's forecasts.

All documents are available with this report on AEMO's website.

2. FORECASTING PROCESS OVERVIEW

This section summarises the underlying forecasting principles and methodology used by AEMO to develop the connection point forecasts for Victoria.

2.1 Forecasting principles

To develop robust forecasts, AEMO followed several benchmark forecasting characteristics listed by the AER.[7] The table below lists these and outlines how AEMO addressed each characteristic.

Table 1 Characteristics of good forecasting techniques listed by the AER

Characteristic	AEMO implementation
Accuracy and unbiased data	Used AEMO wholesale meter data where possible. Data that was shared by the DNSPs was checked and verified with AEMO's databases where possible.
Transparency and repeatability	Engaged stakeholders in forecast development, including all DNSPs. Developed and published consistent methodology. Independent peer reviewer independently reproduced AEMO's forecasts using the same data and modelling code provided by AEMO. Code base was internally peer reviewed.
Incorporation of key drivers and exclusion of spurious drivers	Consistent methodology incorporates most relevant demand drivers from time series trends, technological improvements (e.g., solar PV and energy efficiency) and regional economic and demographic drivers.
Model validation and testing	Forecasts were independently reviewed by Frontier Economics. Incorporated statistical significance testing for selection of starting point.
Accuracy and consistency of forecasts at different levels of aggregation	Connection point forecasts have been reconciled to the 2014 NEFR forecasts. AEMO will monitor the accuracy of the forecasts.
Use of the most recent input information	AEMO used demand data to the end of April 2014; the latest data available given the project timeframe. AEMO also monitored new developments and incorporated them where possible.

7 AER. November 2011. *Draft Distribution Determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17.* Attachment 3.2 p. 76. Available at: http://www.aer.gov.au/sites/default/files/Aurora%202012-17%20draft%20distribution%20determination.pdf. Viewed 19/09/2014.

2.2 Connection point definition

AEMO's connection point forecasting methodology, published in June 2013[8], defines a connection point as the physical point at which the assets owned by a transmission network service provider (TNSP) meet the assets owned by a DNSP.

In the 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 connection points, represented in market metering and settlements processes by transmission node identities (TNIs)[9]. Each connection point TNI refers to a set of physical sub transmission lines that are owned by a DNSP and supply that DNSP's customers.

Connection points may be connected to one another at the distribution network level.

To maintain a nationally consistent approach to connection point forecasting, AEMO develops connection point forecasts at the TNI level for 61 Victorian distribution network connection points, and five connection points for direct transmission connected customers.

- The forecast is active power (MW) and reactive power (MVAr) maximum demand at each connection point.
- The forecast excludes transmission system losses, and power station auxiliary loads.
- Embedded generators are assumed to be off at the time of connection point maximum demand.
- Direct transmission connected customer forecasts are published if the customer has given permission to AEMO to do so.

[8] AEMO. *Connection Point Forecasting: A Nationally Consistent Methodology for Forecasting Maximum Demand – Report.* Available at: http://www.aemo.com.au/Electricity/Planning/Forecasting/Connection-Point-Forecasting. Viewed 16/09/2014.

[9] For a complete list of TNIs, refer to *List of regional boundaries and Marginal Loss Factors for the 2014-15 financial year.* Available at: 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 16/09/2014.

2.3 Forecasting methodology

To maintain a nationally consistent approach to connection point forecasting, AEMO's connection point forecasting methodology for active power (MW) comprises seven major steps.

Table 2 Key steps in forecasting methodology

Step	Description
1. Prepare data	Obtain and clean demand and weather data. Determine demand profile and demand mix.[10]
2. Weather normalise	Determine weather sensitivity at each connection point.
3. Select starting point	Determine where the forecasts should start from: last historical point or time trend line.
4. Select growth rate	Determine a growth rate to forecast future demand.
5. Baseline forecasts	Apply growth rate to selected starting point.
6. Apply post model adjustments	Adjust for rooftop PV and energy efficiency. The amount of rooftop PV and energy efficiency adjustments were derived from the 2014 NEFR.
7. Reconcile to system forecasts	Make the forecasts consistent with the 2014 NEFR thereby applying regional-level economic and demographic growth drivers at the connection point level. The regional forecasts were taken directly from the 2014 NEFR.[11]

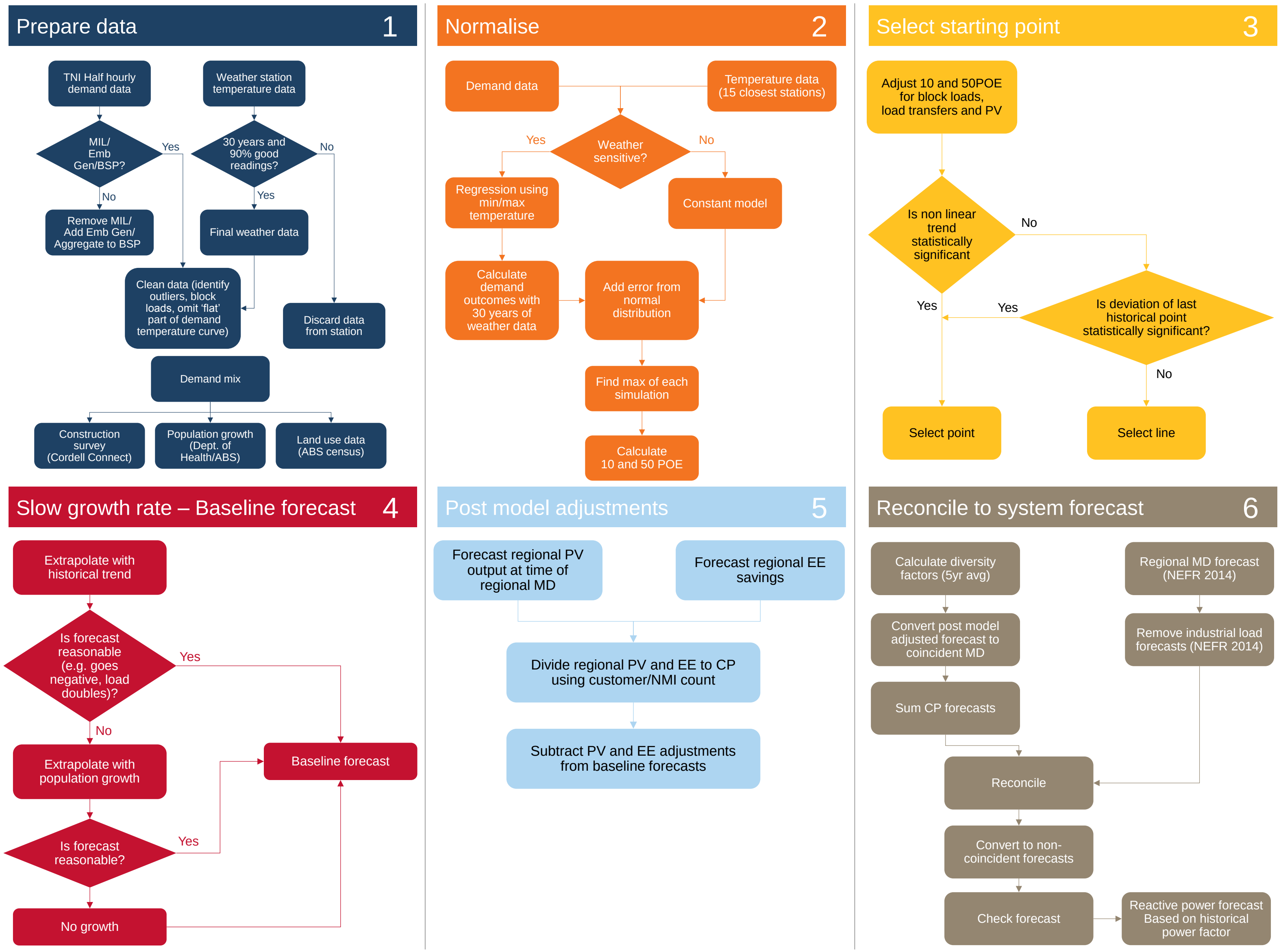
AEMO's forecasting methodology for calculating reactive power (MVAr) is based on using historical power factors for connection point maximum demand. Since these power factors remain constant over consecutive seasons, forecasts are developed by applying average historical power factors to the final active power (MW) forecast. DNSPs confirmed that these power factors were likely to remain constant over the 10 year outlook period.

AEMO will review this approach in future forecasting exercises to confirm its appropriateness.

The flowchart shown in Figure 1 details how AEMO has implemented this methodology.

[10] The type of loads connected to each connection point (e.g., residential, agricultural, industrial).

Figure 2 Implementation of forecasting methodology



2.4 Differences between AEMO and NSP methodologies

A key outcome of AEMO's engagement with network service providers (NSP) was a better understanding of NSP forecasting methodologies. Several key differences between AEMO's approach and the various methodologies used by NSPs were identified. These are summarised in the table below.

Table 3 Common differences between AEMO and NSP methodologies

Description	AEMO	Victorian DNSPs
Rooftop PV	Explicitly accounts for rooftop PV. Derived directly from the 2014 NEFR. Regional rooftop PV contributions are disaggregated to connection points based on installed PV capacity per connection point. Where installed PV capacity are not available, residential customers per connection point is used.	Of the four DNSPs, three account for rooftop PV explicitly in their connection point forecasts.
Energy efficiency	Accounts for energy efficiency above historical trend. Derived directly from the additional energy efficiency adjustment from the 2014 NEFR. Regional energy efficiency savings are disaggregated to connection points based on number of non-industrial customers per connection point.	Of the four DNSPs, one accounts for energy efficiency explicitly in their connection point forecasts. The remaining three DNSPs consider that energy efficiency savings are inherent in the historical data and need not be accounted for explicitly.
Reconciliation to region-level forecasts	The forecast is reconciled to the 2014 NEFR forecasts.	Of the four DNSPs, three reconcile their forecasts to a system level forecast.
Embedded generation	Embedded generating units are assumed not to be generating at the time of maximum demand.	Output of embedded generating units are assumed to be at a particular level at the time of maximum demand.

3. RESULT HIGHLIGHTS

This section summarises the key findings of the Victorian connection point forecasts, for the outlook period for summer (2014–15 to 2023–24) and winter (2014 to 2023). Additional information for each connection point is available in the supplementary spreadsheets on AEMO's website with this report.

3.1 Victoria

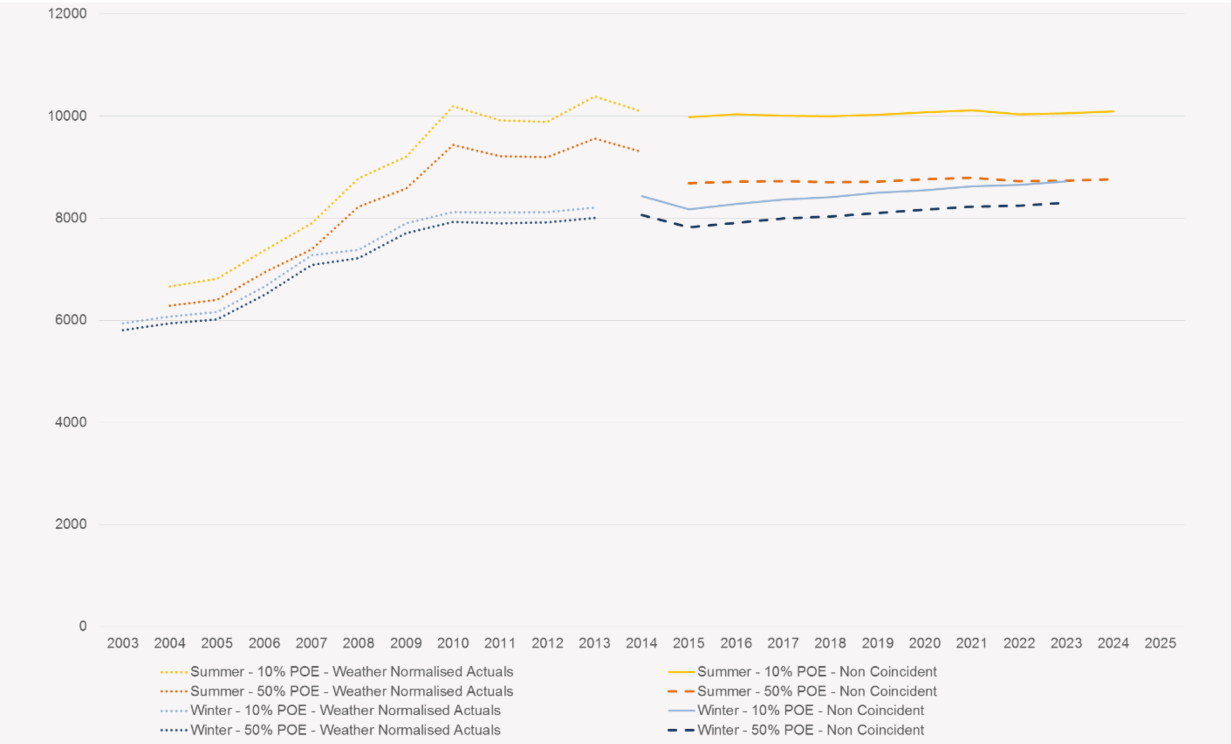
Aggregated connection point trend

Over the outlook period, summer demand is expected to remain flat as increased residential and commercial consumption is offset by industrial closures, increased rooftop PV penetration, and increased energy efficiency. This is modelled in the 2014 NEFR and captured at the connection point level through the reconciliation step of the process. Figure 2 shows both historical and forecast aggregated connection point demand.

The region average annual growth rate over the outlook period for summer is a modest 0.1% for both 50% and 10% POE forecasts. This aligns with the growth forecasts for the region in the 2014 NEFR over the outlook period.

Winter growth is higher at 0.9% per annum for both 50% and 10% POE.

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



Connection point trends

While the aggregate growth rate for Victoria is flat, average annual growth rates vary by connection point, and are distributed above and below the overall region summer growth rate of 0.1%.

Summer 50% POE annual average forecast growth ranges between -6.6% and 11.1%. The highest growth rate (11.1%) occurs at the new Brunswick (CitiPower) 66 kV connection point due to load transfers over the outlook period. The most significant decline (-6.6%) is expected to occur at the West Melbourne (CitiPower) 66 kV connection point due to load transfers to Brunswick (CitiPower) 66 kV over the outlook period.

By connection point, the average annual growth rate is -0.25% for the both the 50% and 10% POE summer forecasts. Figure 3 shows that 85% of connection points have summer 50% POE growth of less than 1.0%.

Winter growth is slightly stronger than summer, with 69% of connection points showing positive growth compared to 41% for summer. The difference is driven by increased rooftop solar PV uptake, which is driving a lower summer maximum demand to be later in the day, while the evening winter maximum demands are not affected by rooftop solar PV uptake.

Winter 50% POE annual average forecast growth ranges between -4.6% and 19.8%. The highest growth (19.8%) occurs at the new Brunswick (CitiPower) 66 kV connection point due to load transfers over the outlook period. The most significant decline (-4.6%) is expected to occur at the Richmond (CitiPower) 22 kV connection point due to load transfers to Richmond (CitiPower) 66 kV over the outlook period.

Figure 4 shows the distribution of winter growth rates.

As AEMO has applied constant power factors to determine the reactive power forecast, the growth distribution of growth rates is the same as the distribution of active power growth rates.

Figure 4 Distribution of summer MD growth rates for Victoria, 2015–24

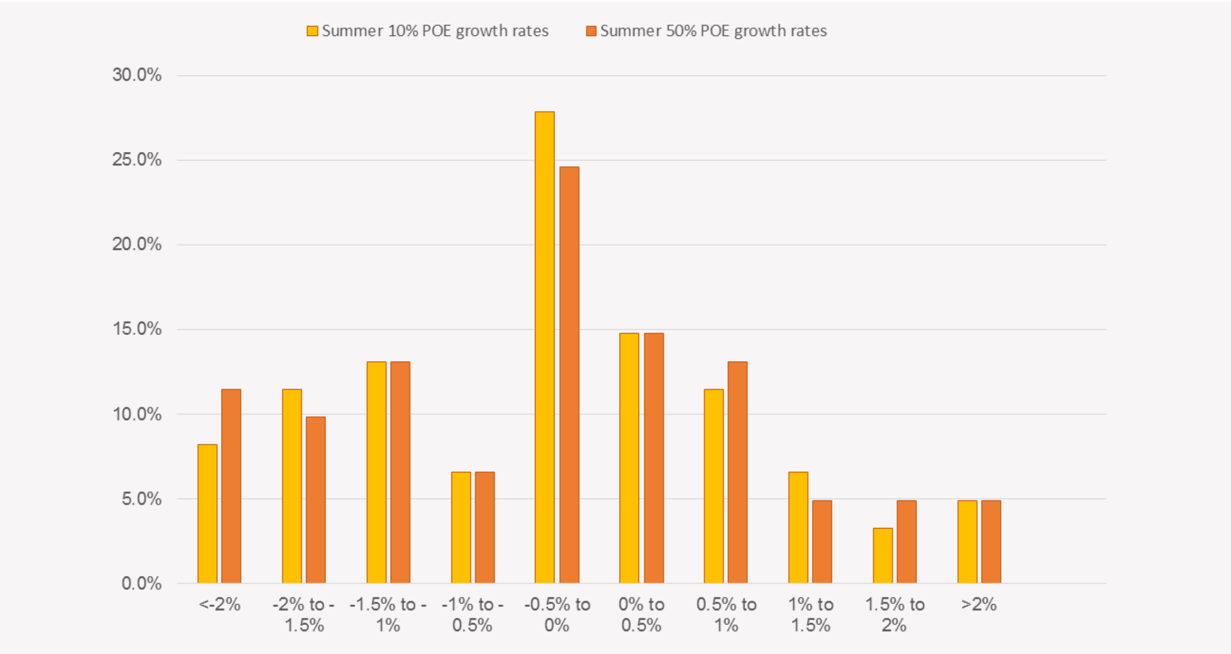
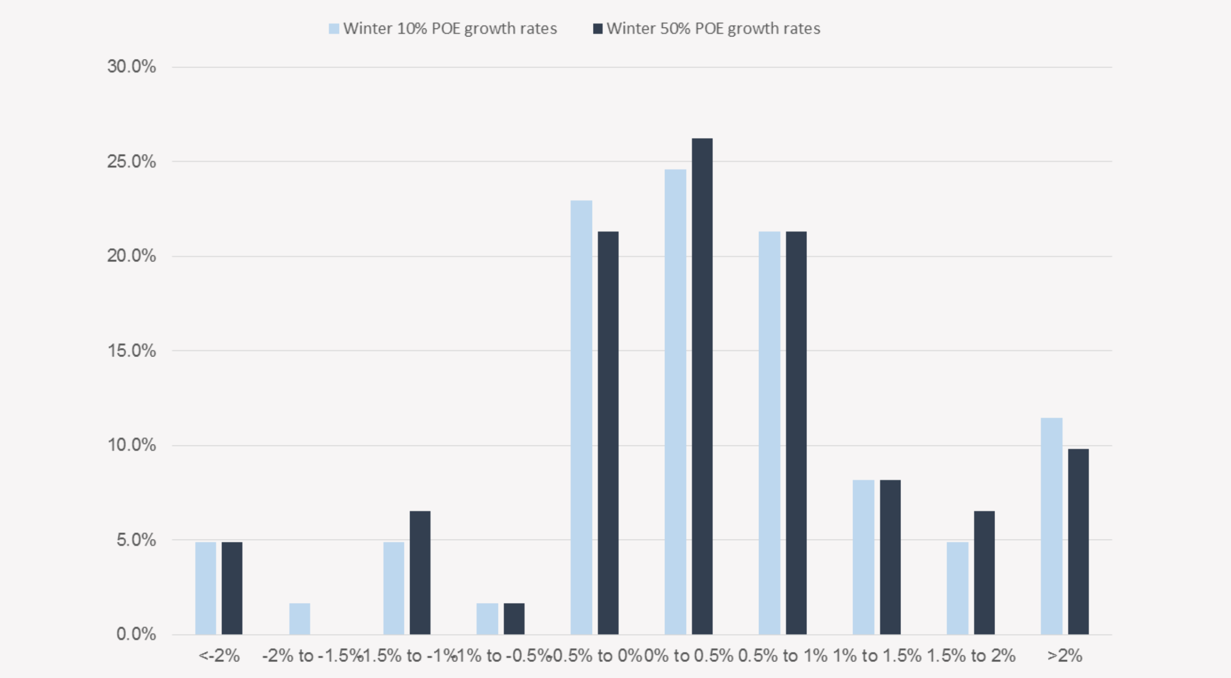


Figure 5 Distribution of winter MD growth rates for Victoria, 2014–23



Growth drivers

Appendix A shows a breakdown of the 10% POE growth rates for each connection point. Key growth drivers are shown in Table 4.

Table 4 Drivers at connection points with growth or decline greater than 2%.

Season	10% POE – average annual growth over 2%	10% POE – average annual growth less than -2%
Summer	**Keilor (Jemena) 66 kV**: supplying Melbourne northeast growth corridor. Tullamarine airport expansion expected to increase peak demand. New **Brunswick (CitiPower) 66 kV**: Expected to grow due to load transfers from Brunswick 22 kV, West Melbourne and Richmond. **Red Cliffs (Powercor) 66 kV**: Expected to grow due to growth in commercial, industrial and agricultural load consumption.	**West Melbourne (CitiPower) 66 kV, Brunswick (CitiPower) 22 kV**: are expected to decline as load is transferred to the new Brunswick (CitiPower) 66 kV connection point. **Keilor (Powercor) 66 kV**: expected to decline as load is transferred to the new Deer Park (CitiPower) 66 kV connection point. **Thomastown (Jemena) 66 kV, East Rowville (AusNet) 66 kV, Red Cliffs (Powercor) 22 kV and Mt Beauty (AusNet) 66 kV**: expected to decline due to weak underlying demand growth for electricity, increased rooftop PV uptake, and increased customer energy efficiency.
Winter	**Keilor (Jemena) 66 kV**: supplying Melbourne northeast growth corridor. Tullamarine airport expansion expected to increase peak demand. **Cranbourne (United Energy) 66 kV and Cranbourne (AusNet) 66 kV**: expected to grow supplying Melbourne south eastern growth corridor. **Brunswick (CitiPower) 66 kV**: expected to grow due to load transfers from Brunswick 22 kV, West Melbourne and Richmond.	**Richmond (CitiPower) 22 kV**: expected to decline due to load transfers to Richmond (CitiPower) 66 kV. **Keilor (Powercor) 66 kV**: expected to decline as load is transferred to the new Deer Park (CitiPower) 66 kV connection point. **West Melbourne (CitiPower) 66 kV**: expected to decline as load is transferred to the new Brunswick (CitiPower) 66 kV connection point.

4. FUTURE IMPROVEMENTS

In developing these connection point forecasts, AEMO identified several areas that require further investigation and improvement. These include:

- Comparing adopted weather normalisation approach to alternatives. Test the inclusion of additional weather variables in the weather model, such as humidity and wind speed.
- Investigating alternative approaches for rooftop PV and energy efficiency disaggregation.
- Improving modelling techniques to cater for non-linear behaviour in historical demand data.
- Incorporating new data sources and getting more direct access to local level sources.
- Gaining a better understanding of the different dynamics at the regional and connection point level and their relationship in the reconciliation process.
- Obtaining better timing information of forecast developments, such as new housing estates and land releases.
- Obtaining better information on large industrial loads and improving relationships with businesses.
- Investigating more representative accounting approaches for embedded generation in historical and forecast demand data.
- Examining economic assumptions more closely.

AEMO plans to investigate these items and publish an improvement action plan on its website before end of 2014.

APPENDIX A. GROWTH RATES BY CONNECTION POINT

Figure 6 Victoria 10% POE summer 10-year average annual growth rates, 2014–15 to 2023–24

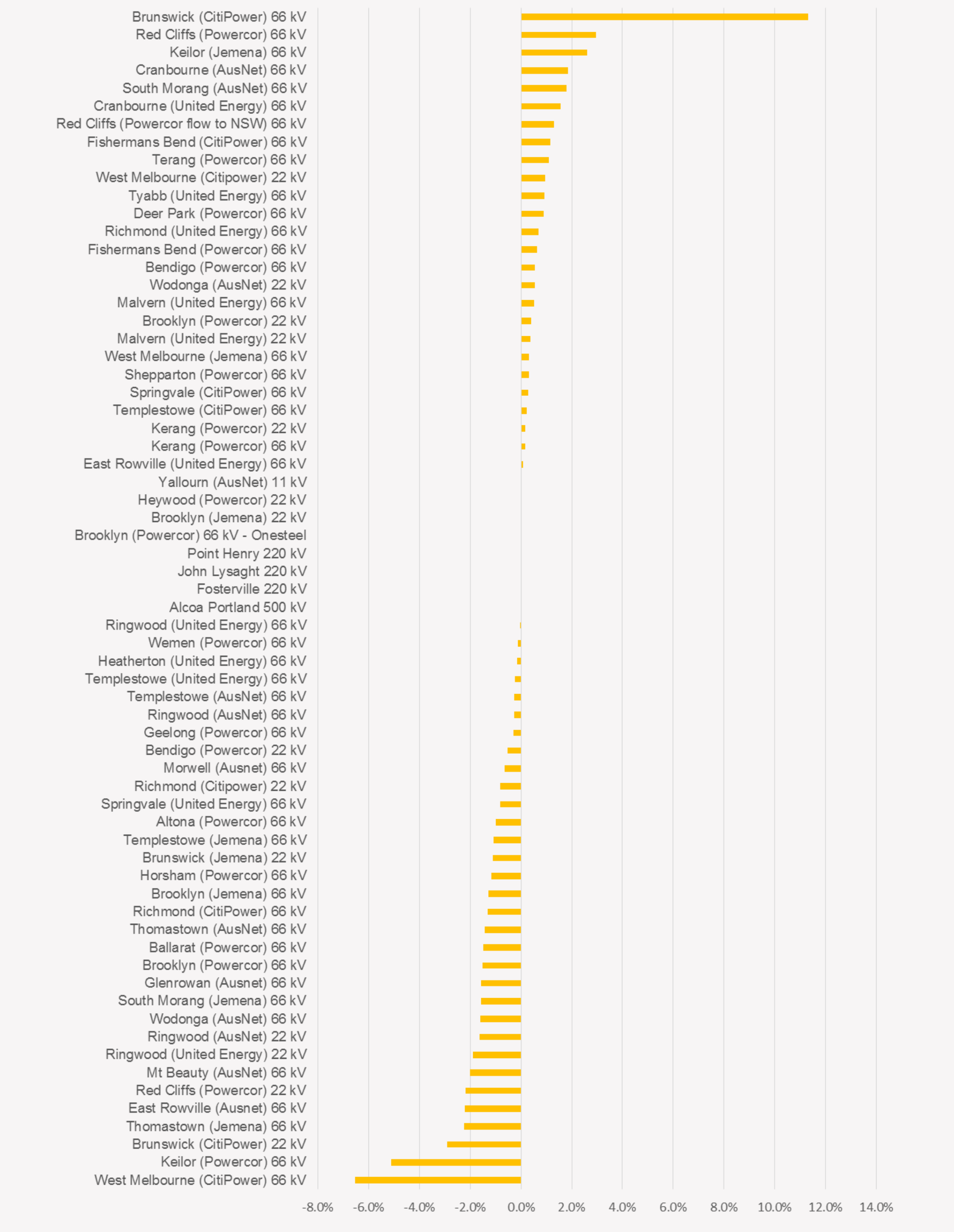
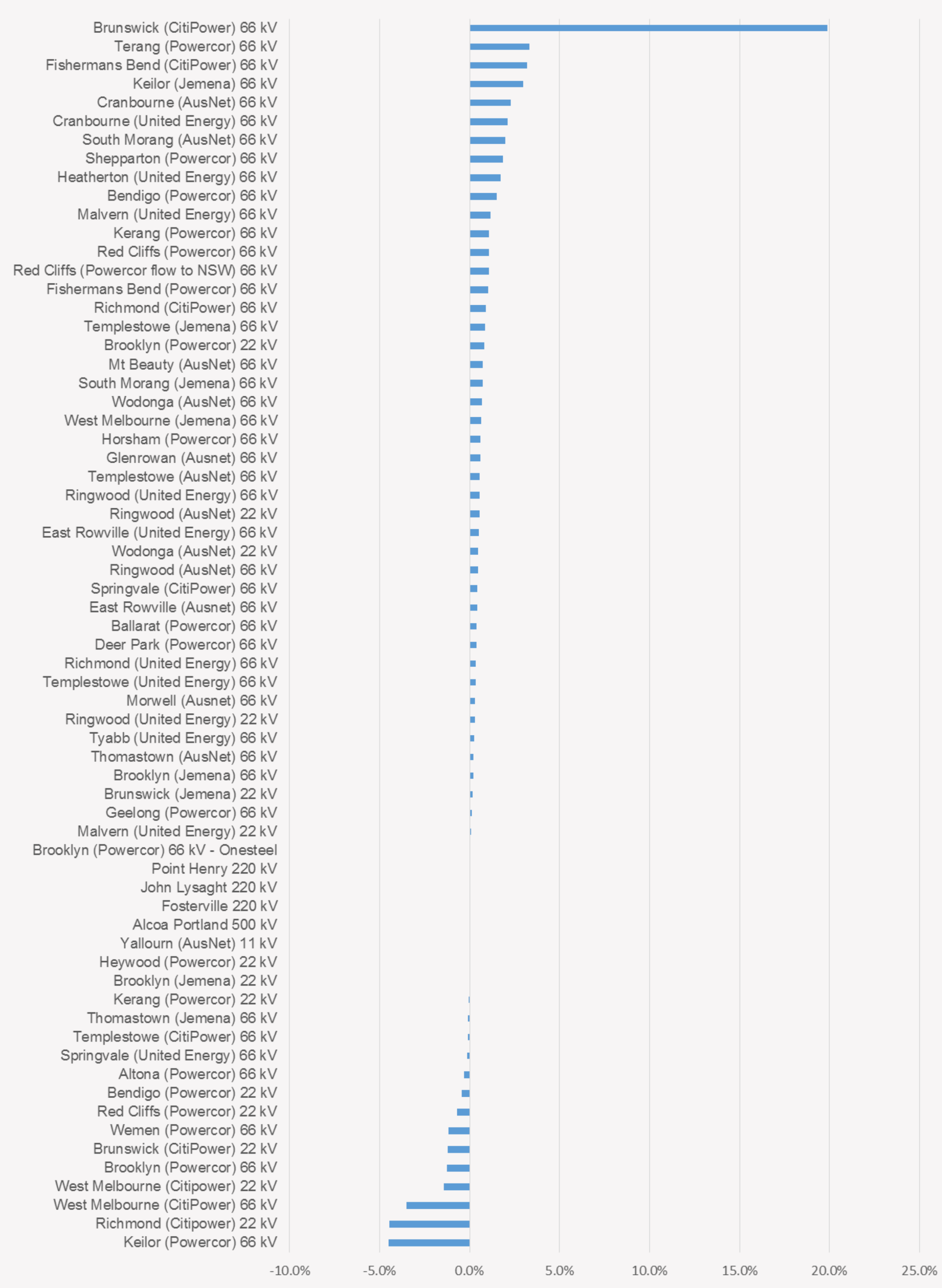


Figure 7 Victoria 10% POE winter 10-year average annual growth rates, 2014 to 2023



APPENDIX B. DATA SHARED BY NSPS

During the forecasting development process NSPs provided vital data. A list of data provided is outlined below:

Table 5 List of data provided by NSPs

Item	Description
Demand data	Half-hourly data was provided by most NSPs. Some provided peak demand information.
Embedded generation data	NMIs and half hourly data provided. This was cross-checked with AEMO data.
Exempt generation	NMIs or aggregated by TNI. Data provided at the half-hourly level where possible.
Industrial data	NMIs or aggregated by TNI. Data provided at the half-hourly level where possible.
Load transfers and block loads	Historical provided where possible. Forecasts were also provided where possible.
Maximum demand forecasts	Latest forecasts were made available to AEMO.
PV installed capacity	Provided by postcode and/or TNI where possible.
Network tariffs	Tariff types and volumes provided where possible.
Network configuration information	Provided on an ad hoc basis.
Demand mix and local information	Provided on an ad hoc basis.

GLOSSARY

Definitions

Many of the listed terms are already defined in the National Electricity Rules (NER), version 54.[12]
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 grey.

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.
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, expressed in megawatt hours (MWh).
Active power	The rate at which active energy is transferred, expressed in megawatts (MW).
Block loads	Large loads that are connected or disconnected from the network.
Bulk supply point	Station at which electricity is typically transformed from the higher transmission network voltage to a lower one.
Connection point	The point at which the transmission and distribution network meet.
Coincident forecasts	Maximum demand forecasts of a connection point at the time of system peak. See diversity factor.
Distribution losses	Electrical energy losses incurred in transporting electrical energy through a distribution system.
Distribution network	A network that is not a transmission network.
Distribution system	A distribution network, together with the connection assets associated with the distribution network (such as transformers), which is connected to another transmission or distribution system.
Diversity factor	Refers to the ratio of the maximum demand of a connection point/terminal station to the demand of that connection point at the time of system peak. This is sometimes referred to as the demand factor, and is always less than or equal to one. When the diversity factor equals one, the connection point peak coincides with the system peak.
Electrical energy	The average electrical power over a time period, multiplied by the length of the time period.
Electrical power	The instantaneous rate at which electrical energy is consumed, generated or transmitted.
Electricity demand	The electrical power requirement met by generating units.
Energy efficiency	Potential annual energy or maximum demand that is mitigated by the introduction of energy efficiency measures.
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.
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.

[12] An electronic copy of the latest version of the NER can be obtained from http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/Current-Rules.

Term	Definition
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.
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.
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.
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 consumption	The electrical energy supplied by scheduled, semi-scheduled, and significant non-scheduled generating units, less the electrical energy supplied by small non-scheduled generation, auxiliary loads and transmission losses, typically measured in megawatt hours (MWh).
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 exceedance (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.
Reactive energy	A measure in MVAr hours of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out-of-phase component of current flow across a connection point.
Reactive power	The rate at which reactive energy is transferred. Reactive power, which is different to active power, is a necessary component of alternating current electricity. In large power systems it is measured in MVAr (megavolt-amperes reactive). It is predominantly consumed in the creation of magnetic fields in motors and transformers and produced by plants such as: • Alternating current generators • Capacitors, including the capacitive effect of parallel transmission wires • Synchronous condensers.
Reconciled forecasts	Forecasts that have been scaled such that the sum of all connection points equal to the regional forecasts.
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).

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.
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 Node Identifier (TNI)	Identifier of connection points across the NEM.
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.
Winter	Unless otherwise specified, refers to the period 1 June – 31 August (for all regions).
Zone substation	Station within the distribution network where incoming electricity is transformed from a higher voltage from the connection or bulk supply point to a lower one. Electricity is then provided to feeders which lower the voltages even lower for distribution to customers.

MEASURES AND ABBREVIATIONS

Units of measure

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

Abbreviations

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
COAG	Council of Australian Governments
DNSP	Distribution Network Service Provider
MD	Maximum demand
NEFR	National Electricity Forecast Report
NEM	National Electricity Market
NER	National Electricity Rules
NSP	Network Service Provider
POE	Probability of Exceedance
PV	Photovoltaic
RRN	Regional Reference Node
SNSG	Small Non-scheduled Generation
TNI	Transmission Node Identifier
TNSP	Transmission Network Service Provider