2015 AEMO TRANSMISSION CONNECTION POINT FORECASTING REPORT

QUEENSLAND

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide transmission connection point forecasts for Queensland. It is based on information available to AEMO at 1 May 2015.

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

Disclaimer

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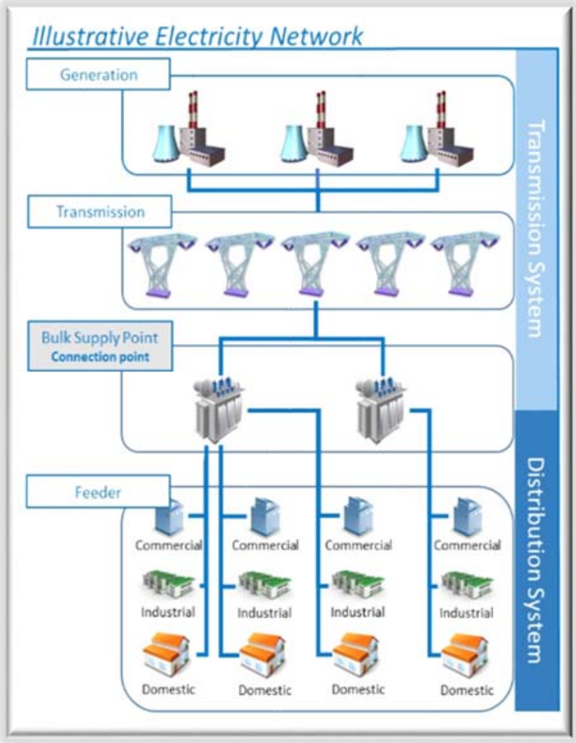
Acknowledgement

AEMO acknowledges the support, co-operation and contribution from Queensland network service providers Powerlink, Energex and Ergon in providing data and information used in this publication.

EXECUTIVE SUMMARY

AEMO has developed Maximum Demand (MD) transmission connection point forecasts in Queensland 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)[1], 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 Queensland shows:

- 4.7% increase from 2015–16 to 2016–17, attributed to the ramp-up of liquefied natural gas (LNG) projects.
- 0.9% average annual increase from 2017–18 to 2024–25, attributed to an increase in residential and commercial demand.

This compares with the 2015 NEFR MD[2] regional Queensland forecasts of:

- 4.5% from 2015–16 to 2016–17.
- 0.9% from 2017–18 to 2024–25.

The difference between the connection point summer forecast and NEFR MD forecast for 2015–16 to 2016–17 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.

[1] AEMO. 2015 National Electricity Forecasting Report. Available at http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report.
[2] The NEFR native MD, based on the medium scenario.

Key results 2015–16 to 2016–17

Table 1 MD forecast 2015–16 to 2016–17

Customer Sector	Attributed to	50% POE average annual rate of change*	10% POE average annual rate of change*
LNG projects	Ramp up of LNG plants.	2.9% increase	2.8% increase
Residential and commercial	Growth in Queensland population increases connection point MD, offset by increased rooftop PV uptake and increased energy efficiency.	1.8% increase	1.9% increase
Major industrial (coal mines, metal industries, manufacturing)	No major developments.	0.0%	0.0%
Net change		**4.7% increase**	**4.7% increase**

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

Key results 2017–18 to 2024–25

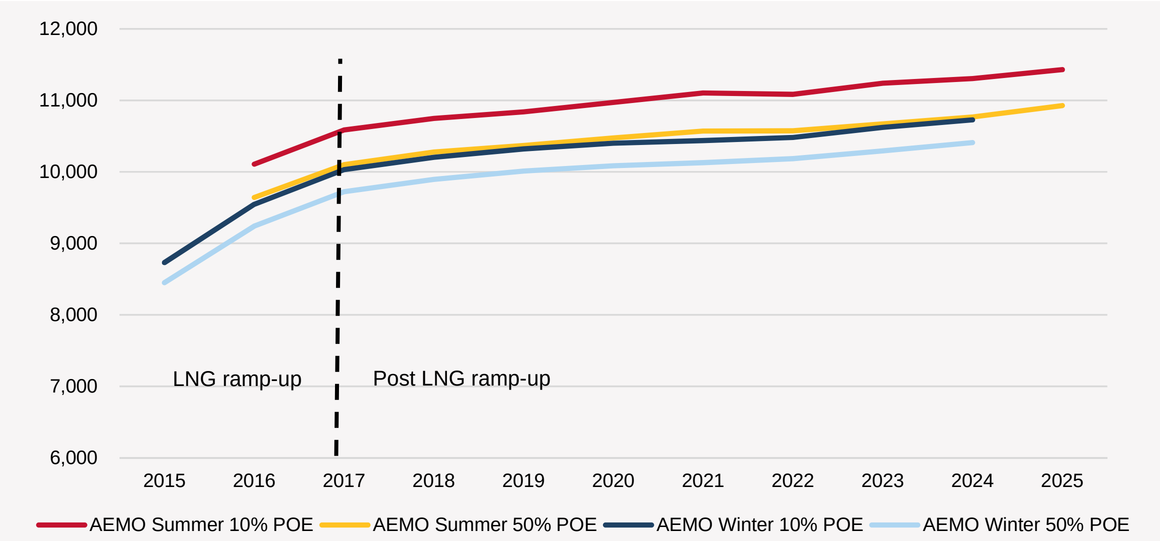
Table 2 MD forecast 2017–18 to 2024–25

Customer Sector	Attributed to	50% POE average annual rate of change*	10% POE average annual rate of change*
LNG projects	Ramp-up of LNG plants is complete by 2017 and no longer contributes to increases in MD.	0.0%	0.0%
Residential and commercial	Growth in Queensland population increases connection point MD, offset by increased rooftop PV uptake and increased energy efficiency.	0.9% increase	0.9% increase
Major Industrial (coal mines, metal industries, manufacturing)	Negligible change in demand.	0.0%	0.0%
Net change		**0.9% increase**	**0.9% 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 Queensland connection point forecasts are shown in Figure 1.

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



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1. INTRODUCTION

This is AEMO's first transmission connection point forecast for Queensland. 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[3], 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 NEM, electricity is notionally bought and sold at the regional reference node (RRN) in each NEM region. However, the electricity traded is physically measured at transmission connection points, represented in market metering and settlements processes by transmission node identifiers (TNIs).[4] 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.

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.

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

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

AEMO aims to maintain a forecasting process and methodology that incorporates the good forecasting characteristics identified by the Australian Energy Regulator (AER).[5]

3 AEMO. Connection Point Forecasting: A Nationally Consistent Methodology for Forecasting MD – Report. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting. Viewed: 23 January 2015.
4 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.
5 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 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.[6] In it, AEMO investigated possible areas of improvement in the forecasting process relating to forecast inputs and methodologies. Several improvements were incorporated into development of the current forecasts.

A summary is presented in Table 3.

Table 3 Improvements implemented for the Queensland forecasts

Improvement description	Approach	Benefit	Implemented
Adjust historical data for block loads, load transfers, and rooftop PV, at the daily or half-hourly level.	Adjustments for block loads and transfers and estimated rooftop PV output were applied to the data at the half-hourly level, before weather normalisation.	The adjustments resulted in: • Clearer handling of step changes that occurred mid-season. • A streamlined data preparation process for forecasting. • More realistic treatment of rooftop PV with variation 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, a cubic trend was fitted to the weather-normalised historical data to provide an alternative time trend for forecasting.	This reduced the need for subjective judgements in determining forecast rates of increase. 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.	Pooling data was tested and adopted using 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. • Inherently allows the time of MD to change as rooftop PV output increases with increasing installed capacity.	Yes

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

1.3 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 if it continues to be appropriate.

1.4 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.

[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 Aggregate connection point results and insights

The connection point summer forecast for Queensland shows:

- 4.7% increase from 2015–16 to 2016–17, attributed to the ramp-up of liquefied LNG projects.
- 0.9% average annual increase from 2017–18 to 2024–25, attributed to an increase in residential and commercial demand.[10]

The forecast shows a weaker increase in summer demand because higher levels of rooftop PV generation offset MD to a greater extent than in winter.

AEMO's connection point forecasts are reconciled[11] to the 2015 NEFR's 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 2015 NEFR.

2.2 Individual connection point trends

While aggregated MD across Queensland is forecast to increase, individual connection point forecasts increase at some points, and decrease at others, due to different drivers.

Key features of the summer forecasts 2015–16 to 2024–25:

- The greatest rate of increase is from new LNG loads in Queensland. See the 2015 NEFR for more information on aggregated forecasts for LNG load.
- The average annual rates of change are between +6.2% (Woolooga) and -3.9% (Pioneer Valley) for 50% POE. See Table 4 for details.
- 73% of connection points are forecast to have summer 50% POE average annual rates of less than +1.9% (which is the forecast average population growth rate).
- The highest forecast MD increases are at several large connection points in Brisbane, the Gold Coast and Sunshine Coast, where expected population growth is highest in Queensland.

Key features of the winter forecasts 2015 to 2024:

- The greatest rate of increase is from new LNG loads in Queensland.
- Otherwise, the average annual rates of change are between +5.9% (Mudgeeraba) and -2.8% for 50% POE (Cairns City).
- 63% of connection points are forecast to have winter 50% POE average annual rates of less than +1.9% (which is the forecast average population growth rate).
- The highest forecast MD increases are at several large connection points in Brisbane, the Gold Coast and the Sunshine Coast, where expected population growth is highest.

The greatest residential MD increases over the outlook period are expected at connection points in urban areas of Brisbane, the Gold Coast and Sunshine Coast. On the whole, MD at connection points in rural Queensland is forecast to increase at comparatively slower rates in response to expected population trends.

Connection points with average annual increases or decreases of more than 2% are shown in Table 4, as well as the drivers of demand.

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

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[10] Summing all the connection point forecasts together provides a high-level overview of the rate of increase in connection point MD. Rates of change will vary at different individual connection points, and may increase or decrease.

[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.

Table 4 Drivers at connection points with average annual rates of change greater than 2%

	Forecast MD increase greater than 2%	Forecast MD decrease greater than 2%
Summer	**Abermain 33 kV:** Population growth. **Alligator Creek 33 kV:** Population growth. **Belmont Wecker Road:** Population growth. **Cardwell:** Population growth. **Columboola:** New block loads. **Goodna:** Population growth. **Lilyvale**: New block loads. **Loganlea 110 kV:** Population growth. **Moranbah (Town):** Population growth. **Mudgeeraba 33kV:** Population growth. **Nebo:** Population growth. **Newlands:** Population growth. **Palmwoods:** Population growth. **Proserpine:** Population growth. **Redbank Plains:** Population growth. **Rocklea:** Population growth. **Ross:** Population growth. **Sumner:** Population growth. **Tarong:** New block loads. **Woolooga (Ergon):** Population growth. **Yarwun (Boat Creek):** New block loads.	**Pioneer Valley:** reductions due to rooftop PV offsetting population growth. **Tangkem:** reductions due to rooftop PV offsetting population growth. **Cairns:** due to rooftop PV offsetting population growth. **Cairns North:** due to rooftop PV offsetting population growth. **Oakey:** due to rooftop PV offsetting population growth.
Winter	**Abermain 33 kV:** Population growth. **Belmont Wecker Road:** Population growth. **Bulli Creek (Waggamba):** Population growth. **Cardwell:** Population growth. **Clare:** Population growth. **Columboola:** New block loads. **Edmonton:** Population growth. **Goodna:** Population growth. **Innisfail:** Population growth. **Kamerunga:** Population growth. **Lilyvale**: New block loads. **Molendinaar:** Population growth. **Moranbah (Town):** Population growth. **Moura:** Population growth. **Mudgeeraba 33kV:** Population growth. **Murarrie**: Population growth. **Nebo:** Population growth. **Oakey:** Population growth. **Palmwoods:** Population growth. **Proserpine:** Population growth. **Redbank Plains:** Population growth. **Rocklea:** Population growth. **Ross:** Population growth. **Sumner:** Population growth. **Tarong:** New block loads. **Teebar Creek:** Population growth. **Tully:** Population growth. **Yarwun (Boat Creek):** New block loads.	**Ashgrove West (110 kV):** rooftop PV offsetting population growth. **Cairns City:** rooftop PV offsetting population growth. **Runcorn:** rooftop PV offsetting population growth.

APPENDIX A. RATES OF CHANGE

Over the outlook period, annual average rates of change in MD for each connection point are summarised in Figure 2 (summer) and Figure 3 (winter).

Figure 2 Summer rates of change in MD (50% POE)

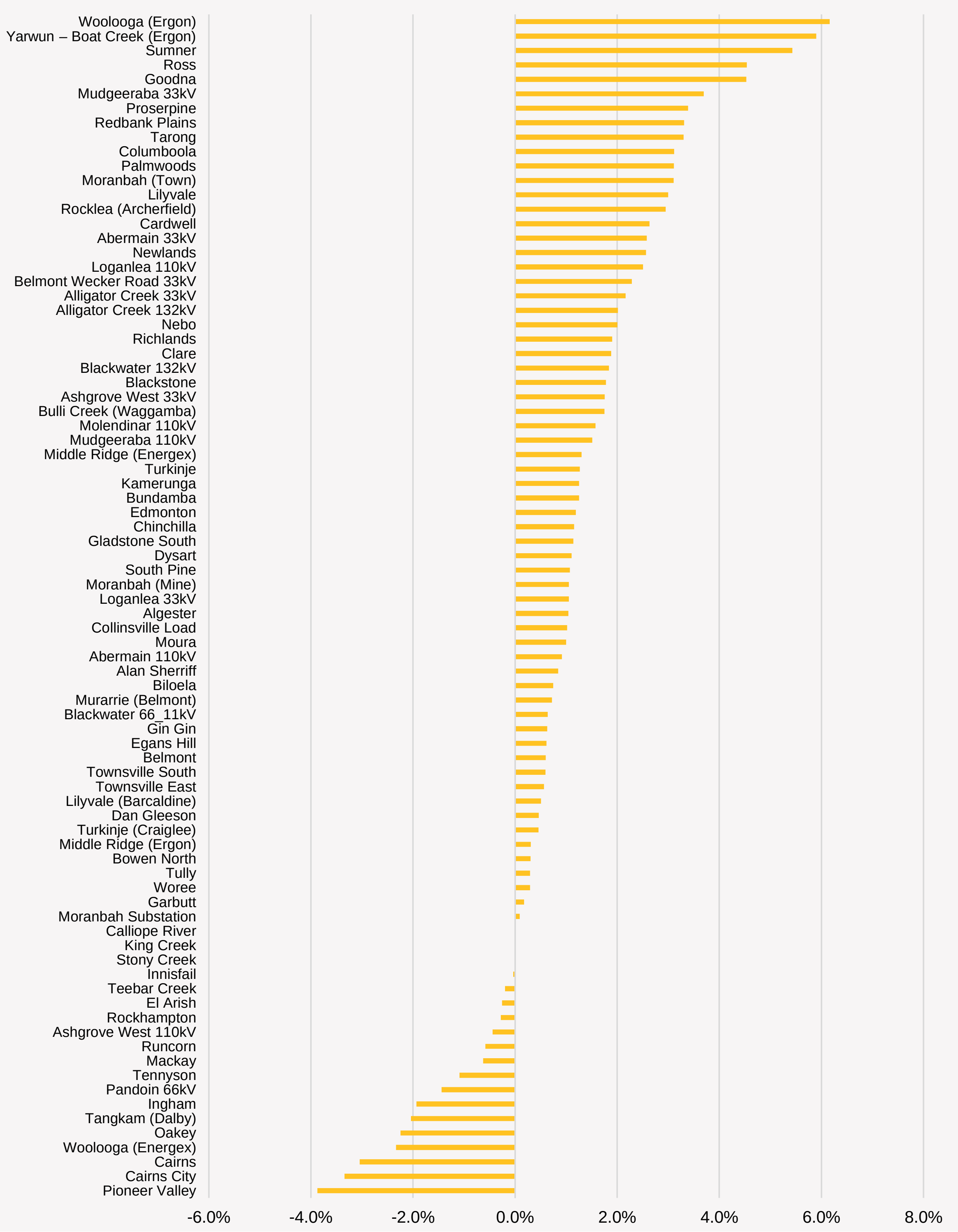
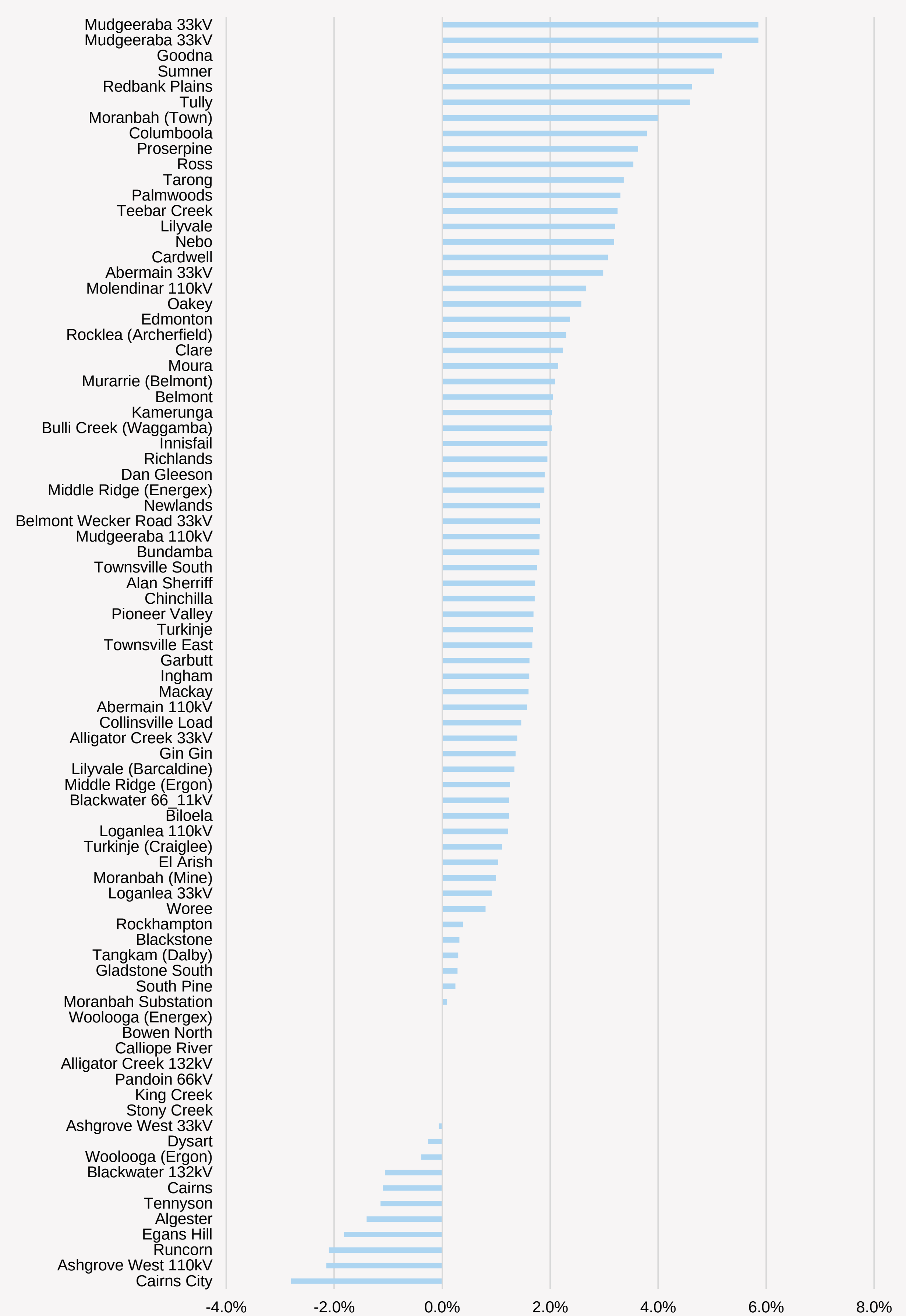


Figure 3 Winter rates of change in MD (50% POE)



APPENDIX B. DATA SHARED BY NETWORK SERVICE PROVIDERS

Network service providers provided crucial data during the forecasting development process. Table 5 summarises the data provided.

Table 5 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.
Maximum demand 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

The 2015 NEFR 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 in the 2015 NEFR 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 electrical 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	MD forecasts of a connection point at the time of system peak. See diversity factor.
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, which is connected to another transmission or distribution system. Connection assets on their own do not constitute a distribution system.
Diversity factor	Refers to the ratio of the MD 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 MD 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 NEM region. They generally maintain consistent levels of annual energy and MD 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.

Term	Definition
National Electricity Market (NEM)	The wholesale exchange of electricity operated by AEMO under the 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.
National Metering 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 NER.
Non-coincident forecasts	The MD forecasts of a connection point, irrespective of when the system peak occurs.
Power system	The 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)	The probability, as a percentage, that a 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 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 NER.
Residential and commercial load	The annual energy or MD 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 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 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 AER to be part of the transmission network.
Transmission Node Identity (TNI)	Identifier of connection points across the NEM.

Term	Definition
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
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
NMI	National Metering Identifier
POE	Probability of Exceedance
PV	Photovoltaic
QLD	Queensland
RRN	Regional Reference Node
TNI	Transmission Node Identifier
TNSP	Transmission Network Service Provider